OVERVIEW OF OPERATING REVENUE

In this Application, CNPI is presenting its operating revenue for 2013 Approved, 2013 Actual, 2014 Actual, 2015 Actual, the 2016 Bridge Year and the 2017 Test Year. In this Exhibit, CNPI provides a detailed variance analysis by rate class of the operating revenue. This information is contained in Exhibit 3, Tab 3, Schedule 1, Accuracy of Load Forecast and Variance Analysis on Throughput Revenue. Further, in Exhibit 3, Tab 4, Schedule 1, CNPI presents an analysis of other distribution revenue, which includes revenues such as late payment charges; specific service charges; etc.

CNPI is proposing a total Service Revenue Requirement of $22,294,752 for the 2017 Test Year. This amount includes a Base Revenue Requirement of $19,870,307 to be recovered through rates, plus revenue offsets of $2,424,445 to be recovered through Other Distribution Revenue.

A summary of all operating revenue is presented here in Table 3.1.1.1 and provides a comparison of total revenues from the 2013 approved year to the 2017 Test Year. Revenue related to the 2017 Test Year is presented on the basis of existing electricity rates as well as those being proposed in this Application.

Table 3.1.1.1 Summary of Operating Revenue

OEB Account	Description	2013 Board Approved	2013 Actual	2014 Actual	2015 Actual	2016 Bridge Year	2017 Test Year @ Existing Rates	2017 Test Year @ Proposed Rates
	Distribution Revenue							
	Residential	$ 9,931,421	$ 9,817,477	$ 10,026,457	$ 10,090,894	$ 10,269,122	$ 10,344,877	$ 11,827,584
	General Service Less Than 50 kW	2,426,082	2,329,902	2,403,023	2,399,395	2,439,995	2,405,938	2,726,265
	General Service Greater Than 50 kW	4,608,377	4,538,276	4,593,869	4,363,283	4,323,749	4,164,653	4,719,136
	Embedded Distributor	-	-	-	-	-	93,571	120,987
	Unmetered Scattered Load	80,218	117,611	99,292	78,374	75,051	40,027	61,365
	Sentinel Lighting	69,351	51,256	57,476	57,479	57,869	53,757	60,914
	Streetlights	447,549	446,349	468,375	452,386	449,919	432,790	354,056
	Rate Rider for Tax Changes	-	(70,054)	(12)	(2)	-	-	-
	Rate Rider for PILS	-	103,271	87,089	82,080	85,000	-	-
	Rate Rider for HST	-	(32,819)	(33,313)	(5,998)	-	-	-
	Smart Meter Disposition	-	2,048,984	-	-	-	-	-
4080	**Total Distribution Revenue**	**17,562,998**	**19,350,254**	**17,702,255**	**17,517,892**	**17,700,705**	**17,535,614**	**19,870,307**
	% of Total Revenue	***92.6%***	***99.0%***	***92.2%***	***91.0%***	***93.3%***	***87.9%***	***89.1%***
	Other Operating Revenue (per Appendix 2-H)							
4086	SSS Administration Revenue	79,562	80,385	80,807	81,576	80,841	81,035	81,035
4082	Retail Services Revenues	33,500	23,310	25,190	21,397	24,250	24,600	24,600
4084	Service Transaction Requests (STR) Revenues	1,400	791	821	579	806	800	800
4210	Rent from Electric Property	317,100	320,462	328,193	322,464	324,327	327,500	327,500
4220	Other Electric Revenues	9,873	(946,693)	26,048	78,960	15,541	15,700	15,700
4225	Late Payment Charges	361,102	397,363	391,595	373,070	340,573	354,100	354,100
4235	Miscellaneous Service Revenues	151,355	151,022	160,714	159,803	156,539	158,264	158,264
4325	Revenues from Merchandise, Jobbing, Etc.	556,692	383,707	575,419	773,569	437,084	432,852	432,852
4330	Costs and Expenses of Merchandising, Jobbing, Etc.	(137,400)	(143,740)	(235,995)	(166,989)	(108,235)	(109,623)	(109,623)
4360	Loss on Disposition of Utility and Other Property	-	(19,692)	74,502	46,779	-	-	-
4375	Revenues from Non-Utility Operations	-	-	-	-	-	1,139,217	1,139,217
4390	Miscellaneous Non-Operating Income	-	-	-	-	-	-	-
4398	Foreign Exchange Gains and Losses, Including Amortization	-	3,713	(11,746)	(28,155)	-	-	-
4405	Interest and Dividend Income	30,000	(54,940)	76,421	72,103	-	-	-
	Total Other Operating Revenue	**1,403,185**	**195,687**	**1,491,968**	**1,735,157**	**1,271,727**	**2,424,445**	**2,424,445**
	% of Total Revenue	***7.4%***	***1.0%***	***7.8%***	***9.0%***	***6.7%***	***12.1%***	***10.9%***
	GRAND TOTAL	**$ 18,966,183**	**$ 19,545,941**	**$ 19,194,223**	**$ 19,253,049**	**$ 18,972,432**	**$ 19,960,059**	**$ 22,294,752**

LOAD FORECASTING AND WEATHER NORMALIZATION METHODOLOGY

CNPI's load forecast is based on methodology that uses multivariate regression analysis in accordance with the Filing Requirements. CNPI has maintained its historical consumption and customer data and has provided this data to Elenchus Research Associates ("ERA"). ERA, in consultation with CNPI, has developed a weather normal load forecast for 2016 - 2017 as well as weather normalized historical consumption for the available years. This report entitled "Weather Normalized Distribution System Load Forecast–2017 Cost of Service" is provided as Appendix A to this Schedule. All of the items outlined in the Filing Requirements - Section 2.3.1.1 – Multivariate Regression Model are addressed in this Report.

In accordance with the Filing Requirements, a working Microsoft Excel model of the regression analysis completed by ERA has been filed in conjunction with this Application.

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 following tables show the actual and forecast trends for customer/connection counts, kWh consumption and billed kW demand. Further description of CDM adjustments to the load forecast are provided in Exhibit 3, Tab 2, Schedule 1.

Normal Forecast

kWh	2014 Actual	2015 Actual	2015 Normalized	2016 Forecast	2017 Forecast
Residential	203,019,188	199,982,619	203,249,666	199,830,975	199,613,296
GS < 50	69,999,358	69,530,292	70,666,185	69,477,568	69,401,885
GS > 50	226,629,154	193,620,890	196,784,008	193,474,070	193,263,316
Embedded Distributor	4,975,331	5,138,938	5,222,891	5,135,041	5,129,448
Street Light	4,324,650	3,719,644	3,719,644	3,719,850	3,720,056
Sentinel Light	700,647	691,109	691,109	659,331	629,014
USL	1,506,300	1,506,177	1,506,177	1,484,310	1,462,761
Total	511,154,628	474,189,669	481,839,680	473,781,145	473,219,776

CDM Adjusted

kWh	2017 Weather Normal Forecast	CDM Adjustment	2017 CDM Adjusted Forecast
Residential	199,613,296	1,535,494	198,077,803
GS < 50	69,401,885	1,494,554	67,907,332
GS > 50	193,263,316	8,319,113	184,944,203
Embedded Distributor	5,129,448	0	5,129,448
Street Light	3,720,056	938,500	2,781,556
Sentinel Light	629,014	0	629,014
USL	1,462,761	0	1,462,761
Total	473,219,776	12,287,660	460,932,116

Normal Forecast

kW	2014 Actual	2015 Actual	2016 Forecast	2017 Forecast
GS > 50	660,625	621,222	620,750	620,074
Embedded Distributor	12,958	13,742	13,732	13,717
Street Light	13,289	11,489	11,489	11,490
Sentinel Light	2,138	2,105	2,008	1,916
Total	689,010	648,558	647,980	647,197

CDM Adjusted

kW	2017 Weather Normal Forecast	CDM Adjustment	2017 CDM Adjusted Forecast
GS > 50	620,074	26,691	593,383
Embedded Distributor	13,717	0	13,717
Street Light	11,490	2,899	8,591
Sentinel Light	1,916	0	1,916
Total	647,197	29,590	617,607

Customer Connections

	2014 Actual	2015 Actual	2016 Forecast	2017 Forecast
Residential	25,861	25,917	25,995	26,074
GS < 50	2,513	2,492	2,491	2,489
GS > 50	225	220	218	217
Embedded Distributor	1	1	1	1
Street Light	5,717	5,713	5,713	5,713
Sentinel Light	775	763	728	695
USL	40	36	36	35
Total	35,132	35,142	35,182	35,224

Appendix A

2016 - 2017 Weather Normalized Load Forecast - Elenchus Report

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Weather Normalized Distribution System Load Forecast: 2017 Cost of Service

A Report Prepared by
Elenchus Research Associates Inc.

On Behalf of
CNPI

07/03/2016

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1 INTRODUCTION

This report outlines the methodology used to derive the weather normal load forecast for the Canadian Niagara Power Inc. (CNPI) service territories for the 2017 cost-of-service rate application. In CNPI's last rate application for 2013 rates, a separate forecasts had been generated for each area, Eastern Ontario Power (EOP), Fort Erie (FE), and Port Colborne (PC). CNPI is now operating with aggregated consumption information, and is requesting harmonized rates for all service territories. In addition, CNPI has an embedded distributor, and is proposing to create a new customer class for this customer.

As explained in more detail below, and as was the case in the 2013 Cost of Service rate application, class level data have presented challenges. Historical monthly wholesale and retail class data are available. However, the retail class data does not correlate well with degree day data for classes such as residential which would be expected to exhibit weather sensitivity.

In general, it is desirable to develop class specific weather normalization models wherever possible. However, sometimes this is not possible due to data considerations. In some instances, there may not be enough monthly data to perform a credible regression analysis. In other cases, class specific meter data may not accurately reflect monthly consumption due to variable meter read dates and billing periods. After analysis of CNPI's class billing data, the latter appears to be the case. This is not an uncommon issue when developing weather-normalized load forecast regression models.

A standard fall back to this problem is to utilize the wholesale purchase data to develop load forecasting regression equations. Generally, wholesale purchase data accurately reflect monthly consumption within the LDC service territory and therefore the variations due to weather patterns. In the 2013 rate application, this fallback could not be used given that the GS > 50 class in the EOP service territory experience a significant decline in consumption, reducing the 2009 consumption to less than half of the 2005 level. Less pronounced, but still problematic changes were noticed in the other service territories.

In this 2017 application, the fall back was re-examined, and it appears much more workable now. Since 2009, demand has been relatively stable, with declines observed in 2013 and 2015. These declines are most likely attributable to the GS > 50 rate class. Two customers are known to have closed in early 2013, but they alone do not account for the decrease observed. The cause of the decline in 2015 is unknown, and does not appear to be related the actions of one or a few of the largest GS > 50 customers.

1.1 SUMMARIZED RESULTS

The following table summarizes the historic and forecast kWh for 2014-2017:

Normal Forecast

kWh	2014 Actual	2015 Actual	2015 Normalized	2016 Forecast	2017 Forecast
Residential	203,019,188	199,982,619	203,249,666	199,830,975	199,613,296
GS < 50	69,999,358	69,530,292	70,666,185	69,477,568	69,401,885
GS > 50	226,629,154	193,620,890	196,784,008	193,474,070	193,263,316
Embedded Distributor	4,975,331	5,138,938	5,222,891	5,135,041	5,129,448
Street Light	4,324,650	3,719,644	3,719,644	3,719,850	3,720,056
Sentinel Light	700,647	691,109	691,109	659,331	629,014
USL	1,506,300	1,506,177	1,506,177	1,484,310	1,462,761
Total	511,154,628	474,189,669	481,839,680	473,781,145	473,219,776

Table 1 kWh forecast by class

The following table summarizes 2017 CDM Adjusted Load Forecast kWh. Details for this calculation can be found in Schedule 6 of this report.

CDM Adjusted

kWh	2017 Weather Normal Forecast	CDM Adjustment	2017 CDM Adjusted Forecast
Residential	199,613,296	1,535,494	198,077,803
GS < 50	69,401,885	1,494,554	67,907,332
GS > 50	193,263,316	8,319,113	184,944,203
Embedded Distributor	5,129,448	0	5,129,448
Street Light	3,720,056	938,500	2,781,556
Sentinel Light	629,014	0	629,014
USL	1,462,761	0	1,462,761
Total	473,219,776	12,287,660	460,932,116

Table 2 CDM Adjusted kWh forecast

The following table summarizes the historic and forecast kW for 2014-2017. The calculations can be found as follows:

Normal Forecast

kW	2014 Actual	2015 Actual	2016 Forecast	2017 Forecast
GS > 50	660,625	621,222	620,750	620,074
Embedded Distributor	12,958	13,742	13,732	13,717
Street Light	13,289	11,489	11,489	11,490
Sentinel Light	2,138	2,105	2,008	1,916
Total	689,010	648,558	647,980	647,197

Table 3 kW Forecast

The following table summarizes 2017 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	2017 Weather Normal Forecast	CDM Adjustment	2017 CDM Adjusted Forecast
GS > 50	620,074	26,691	593,383
Embedded Distributor	13,717	0	13,717
Street Light	11,490	2,899	8,591
Sentinel Light	1,916	0	1,916
Total	647,197	29,590	617,607

Table 4 CDM Adjusted kW Forecast

The following table summarizes the forecast customer/connections for 2014-2017:

Customer Connections

	2014 Actual	2015 Actual	2016 Forecast	2017 Forecast
Residential	25,861	25,917	25,995	26,074
GS < 50	2,513	2,492	2,491	2,489
GS > 50	225	220	218	217
Embedded Distributor	1	1	1	1
Street Light	5,717	5,713	5,713	5,713
Sentinel Light	775	763	728	695
USL	40	36	36	35
Total	35,132	35,142	35,182	35,224

Table 5 Customer / Connection Forecast for 2009-2020

2 WHOLESALE KWH REGRESSION

For the Wholesale kWh consumption the equation was estimated using 84 observations from 2009:01-2015:12.

The regression equations used to normalize and forecast CNPI's wholesale energy purchases use monthly heating degree days and cooling degree days as measured at Environment Canada's Welland-Pelham station to take into account temperature sensitivity. This location is approximately 10 km north-west of Port Colborne and has the most complete temperature observations in the area of Port Colborne and Fort Erie. This station came into operation in late 2005, and was used for observations from 2006-2015, covering the time period used for regression equations and the 10-year average weather normalization methodology. The nearby Welland weather station, which closed in August 2014 was used for the years 1996-2005 in the 20-year trend calculation. 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. In order to measure the impact of change in economic activity on energy consumption, a data series must be chosen which represents, as much as possible, that of the service territory. 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 Ontario, as reported in Statistics Canada's Monthly Labour Force Survey (CANSIM series Table 282-0116) is used. Localized employment indicator for the Niagara region and Kingston regions of Ontario are available, but the Ontario measure is a more statistically significant predictor of energy use in CNPI's service territory.

A Trend variable was used, indicating 1 in January 2009, and incrementing once each month, reaching 84 in the last month of the regression, December 2015.

To reflect the lost customers at the end of 2012, and following apparent decline in GS > 50 demand, two variables were added. A dummy variable that indicates 0 in all observations in 2009-2012, and indicates 1 in all observations in 2013-2015 was added to capture the immediate loss. A second trend variable that indicates 0 in all observations in 2009-2012, 1 in January 2013, increasing by one each month, and reaching 36 in December 2015 was used to capture the following decline in consumption.

Finally, binary indicator variables for January, March, July, August, and November were used.

Several other variables were examined, and found to not show a statistically significant relationship to energy usage. Those included weather for the Kingston area (the closest weather station to the former

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

Eastern Ontario Power customers), customer counts, reflecting the number of customers in each rate class in each month, an economic indicator of full time employment in the Niagara region, the number of days in the month, and binary indicators designating spring and fall shoulder seasons.

The following table outlines the resulting regression model:

Model 1: OLS, using observations 2009:01-2015:12 (T = 84)
Dependent variable: WholesalekWh

	coefficient	std. error	t-ratio	p-value
const	-50030433.62	16900766.45	-2.960246434	0.004176123
PC_HDD	15866.56858	834.3087263	19.01762271	1.41E-29
PC_CDD	94458.56462	6990.042382	13.51330356	2.60E-21
Ontario_FTE	12305.66807	2686.348231	4.580816412	1.93E-05
Trend	-68171.95248	22316.76237	-3.054742053	0.003171145
PeakDays	463997.3989	134778.0627	3.442677464	9.70E-04
LostCustomers	-1915347.892	479784.8091	-3.992097823	1.58E-04
LostCustomersTrend	-112200.4455	20825.56533	-5.387630238	8.82E-07
Jan	2661551.712	557795.9341	4.771550936	9.48E-06
Mar	1638607.915	559335.2462	2.929563131	0.004561269
Jul	2373564.509	666039.4389	3.563699641	6.59E-04
Aug	3749602.879	552595.0084	6.785444714	2.90E-09
Nov	-1777261.987	453841.9838	-3.916036969	0.000204545

Mean dependent var	45308130.17	S.D. dependent var	4659371.529
Sum squared resid	7.70246E+13	S.E. of regression	1041563.037
R-squared	0.957253881	Adjusted R-squared	0.950029185
F(12, 71)	132.4974582	P-value(F)	1.42E-43
Log-likelihood	-1276.052663	Akaike criterion	2578.105327
Schwarz criterion	2609.705945	Hannan-Quinn	2590.808509
rho	0.388885896	Durbin-Watson	1.221234855
Theil's U	0.22172		

Table 6 Wholesale Regression Model

Using the above model coefficients we derive the following:

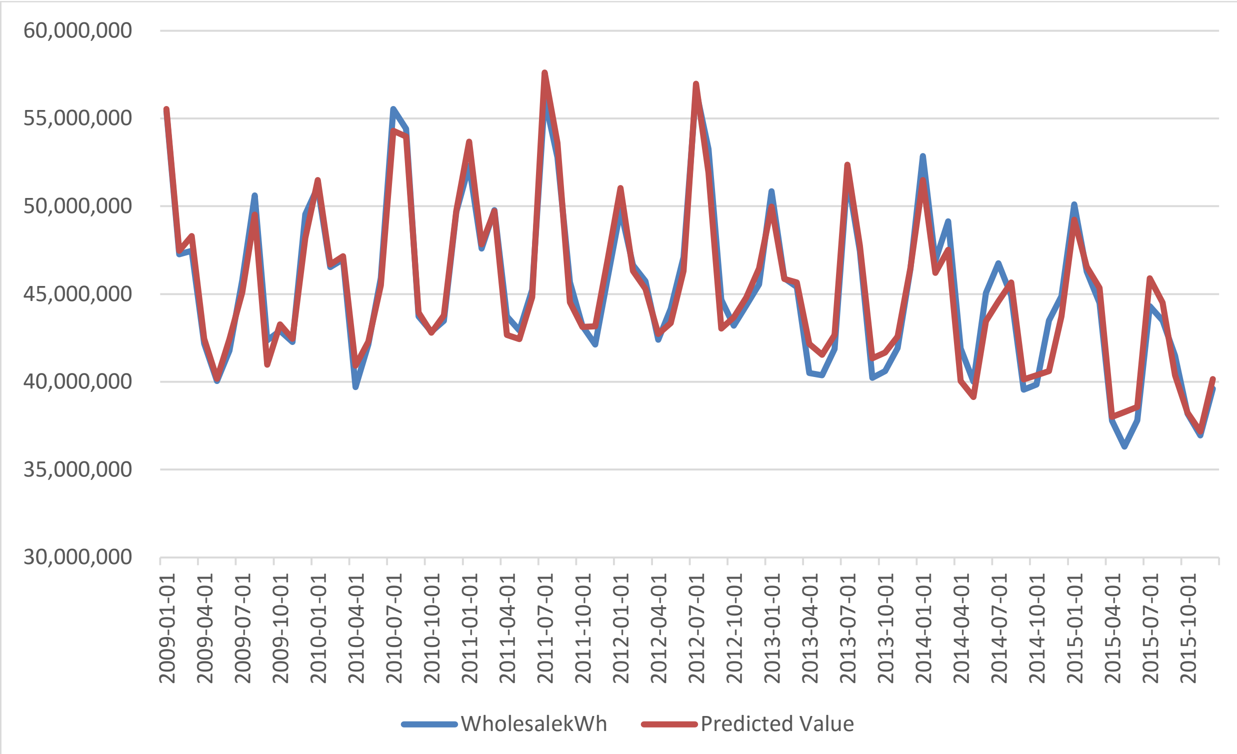

Figure 1 Wholesale Predicted vs Actual observations

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 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 1.7%.

	WholesalekWh		Absolute
Year	Actual	Predicted	Error (%)
2009	547,655,164	545,870,439	0.3%
2010	562,004,269	562,557,893	0.1%
2011	567,403,427	570,188,381	0.5%
2012	563,484,611	561,930,758	0.3%
2013	533,215,540	540,068,609	1.3%
2014	535,322,551	522,957,073	2.3%
2015	496,797,372	502,309,781	1.1%
Mean Absolute Percentage of Error (Annual)			0.8%
Mean Absolute Percentage of Error (Monthly)			1.7%

Table 7 Wholesale 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, CNPI 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 Welland-Pelham, which is used as the weather station for CNPI.

10 Year Average

		HDD	CDD
Welland-Pelham	January	685.86	0
Welland-Pelham	February	660.08	0
Welland-Pelham	March	543.44	0.24
Welland-Pelham	April	313.53	17.5
Welland-Pelham	May	134.15	73.01
Welland-Pelham	June	28.41	106.29
Welland-Pelham	July	5.84	81.07
Welland-Pelham	August	10.42	31.57
Welland-Pelham	September	69.52	3.63
Welland-Pelham	October	236.61	0
Welland-Pelham	November	398.35	0
Welland-Pelham	December	558.69	0

Table 8 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
Welland-Pelham	January	715.88	0.00
Welland-Pelham	February	719.18	0.00
Welland-Pelham	March	555.21	0.04
Welland-Pelham	April	309.38	0.51
Welland-Pelham	May	117.94	13.41
Welland-Pelham	June	28.17	71.25
Welland-Pelham	July	5.16	110.54
Welland-Pelham	August	12.15	91.59
Welland-Pelham	September	67.72	36.19
Welland-Pelham	October	233.78	3.25
Welland-Pelham	November	383.24	0.00
Welland-Pelham	December	547.75	0.00

Table 9 20 Year Trend HDD and CDD

Forecasts for Ontario's employment outlook for 2016 and 2017 are available from four Canadian Chartered Banks at time of writing. Their forecasts are summarized below.

Employment Forecast - Ontario

(figures in annual percentage change)

	BMO	TD	Scotia	RBC	Average
	Jan-16	Dec-15	Jan-16	Dec-15	
2016	0.90%	0.70%	0.80%	1.20%	0.90%
2017	0.90%	0.70%	1.00%	1.00%	0.90%

Table 10 Employment Forecast

In order to give the annual forecast change in employment a monthly periodicity, monthly employment levels for 2015 are compared to the annual average for that year. For each month, the average ratio of monthly employment level to annual average employment for 2015, is used to project the monthly employment into 2016-2017.

4 WHOLESALE NORMALIZED FORECAST

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

Year	Wholesale kWh Actual	Annual Change	Normalized	Annual Change
2009	547,655,164		557,711,332	
2010	562,004,269	2.6%	560,325,757	0.5%
2011	567,403,427	1.0%	568,525,651	1.5%
2012	563,484,611	-0.7%	565,704,736	-0.5%
2013	533,215,540	-5.4%	541,942,470	-4.2%
2014	535,322,551	0.4%	525,044,348	-3.1%
2015	496,797,372	-7.2%	504,913,380	-3.8%
2016			496,420,657	-1.7%
2017			495,879,899	-0.1%

Table 11 Actual vs Normalized Wholesale kWh

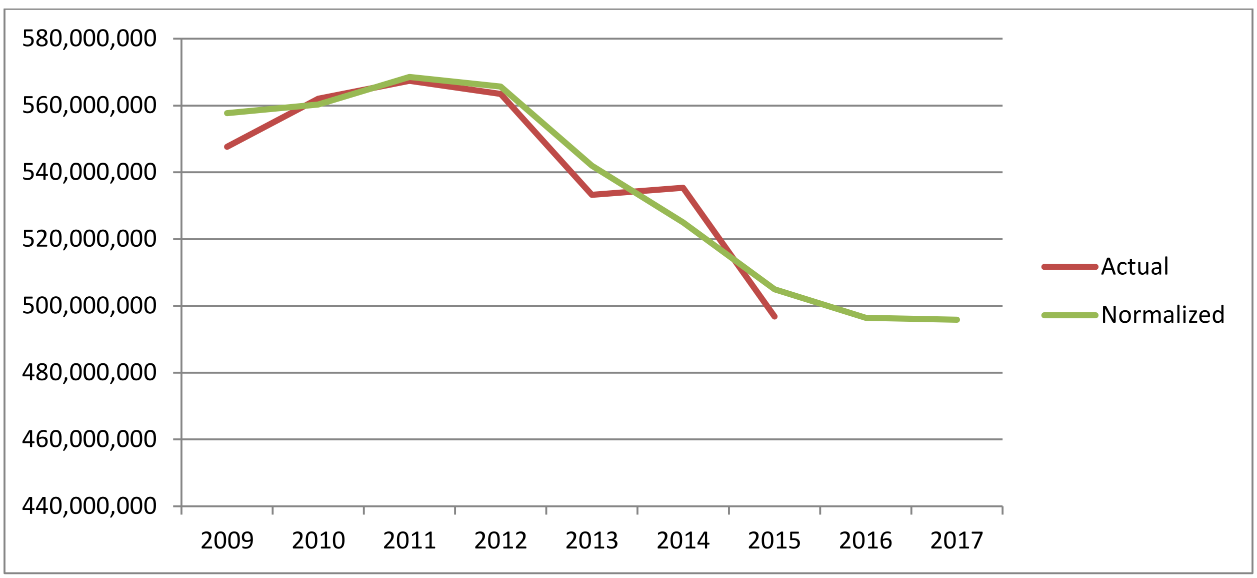

Figure 2 Actual vs Normalized Residential kWh

5 Class Specific Normalized Forecasts

The rate classes known to show sensitivity to weather and economic variables, Residential, GS < 50, and GS > 50 were assigned a portion of the Wholesale forecast equivalent to their share of the wholesale forecast in 2015. Given the declined in wholesale consumption observed in 2013 and 2015, and the apparent connection to a decline in the GS > 50 consumption, an average over several years would not realistically reflect present or most likely future consumption.

5.1 Residential

Apportioning the Wholesale forecast, based on the actual Residential percentage share of Wholesale, the following weather corrected consumption and forecast values are calculated:

Year	Res kWh Actual	% of Wholesale	Normalized	Annual Change
2009	204,220,525	37.3%	207,970,469	
2010	206,940,793	36.8%	206,322,732	-0.8%
2011	206,782,727	36.4%	207,191,707	0.4%
2012	202,637,712	36.0%	203,436,103	-1.8%
2013	206,257,081	38.7%	209,632,810	3.0%
2014	203,019,188	37.9%	199,121,216	-5.0%
2015	199,982,619	40.3%	203,249,666	2.1%
2016		40.3%	199,830,975	-1.7%
2017		40.3%	199,613,296	-0.1%

Table 12 Actual vs Normalized Residential kWh

While 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 2009 to 2015 was used to forecast the growth rate from 2016 to 2017.

Year	Residential Customers	Annual Change
2009	25,522	
2010	25,529	0.03%
2011	25,560	0.12%
2012	25,711	0.59%
2013	25,798	0.34%
2014	25,861	0.25%
2015	25,917	0.22%
2016	25,995	0.30%
2017	26,074	0.30%

Table 13 Forecasted Residential Customer Count

5.2 GS < 50

Apportioning the Wholesale forecast, based on the actual GS < 50 percentage share of Wholesale, the following weather corrected consumption and forecast values are calculated:

Year	GS < 50 Actual	% of Wholesale	Normalized	Annual Change
2009	69,599,095	12.7%	70,877,089	
2010	69,974,111	12.5%	69,765,123	-1.6%
2011	70,933,036	12.5%	71,073,329	1.9%
2012	70,882,241	12.6%	71,161,517	0.1%
2013	69,535,541	13.0%	70,673,602	-0.7%
2014	69,999,358	13.1%	68,655,369	-2.9%
2015	69,530,292	14.0%	70,666,185	2.9%
2016		14.0%	69,477,568	-1.7%
2017		14.0%	69,401,885	-0.1%

Table 14 Actual vs Normalized GS < 50 kWh

While 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 2009 to 2015 was used to forecast the growth rate from 2016 to 2017.

Year	GS < 50 Customers	Annual Change
2009	2,520	
2010	2,501	-0.75%
2011	2,506	0.20%
2012	2,531	0.98%
2013	2,525	-0.23%
2014	2,513	-0.48%
2015	2,492	-0.81%
2016	2,491	-0.07%
2017	2,489	-0.07%

Table 15 Forecasted GS < 50 Customer Count*

5.3 GS > 50

Apportioning the Wholesale forecast, based on the actual GS > 50 percentage share of Wholesale after removing the Embedded Distributor, the following weather corrected consumption and forecast values are calculated:

Year	GS > 50 Actual	% of Wholesale	Normalized	Annual Change
2009	241,348,800	44.1%	245,780,501	
2010	244,269,810	43.5%	243,540,261	-0.9%
2011	234,668,425	41.4%	235,132,558	-3.5%
2012	252,249,792	44.8%	253,243,654	7.7%
2013	214,645,103	40.3%	218,158,115	-13.9%
2014	226,629,154	42.3%	222,277,870	1.9%
2015	193,620,890	39.0%	196,784,008	-11.5%
2016		39.0%	193,474,070	-1.7%
2017		39.0%	193,263,316	-0.1%

Table 168 Actual vs Normalized GS > 50 kWh

While 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 2009 to 2015 was used to forecast the growth rate from 2016 to 2017. The Embedded Distributor was removed from all years to appropriately reflect the trend.

Year	GS > 50 Customers	Annual Change
2009	244	
2010	233	-4.51%
2011	226	-3.22%
2012	225	-0.37%
2013	225	0.19%
2014	225	0.04%
2015	220	-2.44%
2016	218	-0.65%
2017	217	-0.65%

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 ratio from the most recent historic year is used to forecast kW for all future years.

		GS>50	
Year	kWh Actual	Ratio	kW Actual
	A	**C = B / A**	**B**
2009	241,348,800	0.003179	767,319
2010	244,269,810	0.003249	793,686
2011	234,668,425	0.003189	748,282
2012	252,249,792	0.003013	759,959
2013	214,645,103	0.003218	690,762
2014	226,629,154	0.002915	660,625
2015	193,620,890	0.003208	621,222
	kWh Normalized		
	D	**E**	**F = D * E**
2016	193,474,070	0.003208	620,750
2017	193,263,316	0.003208	620,074

Table 18 Forecasted GS > 50 kW

5.4 EMBEDDED DISTRIBUTOR

Apportioning the Wholesale forecast, based on the actual Embedded Distributor percentage share of Wholesale, the following weather corrected consumption and forecast values are calculated:

Year	Embedded Actual	% of Wholesale	Normalized	Annual Change
2009	5,037,472	0.9%	5,129,972	
2010	5,131,021	0.9%	5,115,697	-0.3%
2011	5,010,547	0.9%	5,020,457	-1.9%
2012	5,264,499	0.9%	5,285,241	5.3%
2013	4,854,404	0.9%	4,933,854	-6.6%
2014	4,975,331	0.9%	4,879,805	-1.1%
2015	5,138,938	1.0%	5,222,891	7.0%
2016		1.0%	5,135,041	-1.7%
2017		1.0%	5,129,448	-0.1%

Table 19 Actual vs Normalized GS > 50 kWh

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 ratio from the most recent historic year is used to forecast kW for all future years.

	Embedded Distributor		
Year	kWh Actual	Ratio	kW Actual
	A	**C = B / A**	**B**
2009	5,037,472	0.00243222	12,252
2010	5,131,021	0.002485119	12,751
2011	5,010,547	0.002396673	12,009
2012	5,264,499	0.002409096	12,683
2013	4,854,404	0.00248056	12,042
2014	4,975,331	0.00260453	12,958
2015	5,138,938	0.002674171	13,742
	kWh Normalized		
	D	**E**	**F = D * E**
2016	5,135,041	0.002674171	13,732
2017	5,129,448	0.002674171	13,717

Table 20 Forecasted GS > 50 kW

6 STREET LIGHT, SENTINEL, AND USL FORECAST

The Street Lighting, Sentinel Lighting, 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.

For these classes, the Geometric Mean growth of the connection count was forecasted. These forecasts are given below:

Street Light Year	Lamps / Devices	Annual Change
2009	5,743	
2010	5,711	-0.56%
2011	5,696	-0.26%
2012	5,713	0.30%
2013	5,723	0.18%
2014	5,717	-0.12%
2015	5,713	-0.07%
2016	5,713	0.01%
2017	5,713	0.01%

Table 921 Forecasted Street Light lamps (devices)

Sentinel Year	Connections	Annual Change
2009	1,088	
2010	966	-11.21%
2011	961	-0.52%
2012	870	-9.46%
2013	768	-11.69%
2014	775	0.91%
2015	763	-1.54%
2016	728	-4.60%
2017	695	-4.60%

Table 22 Forecasted Sentinel connections

USL Year	Connections	Annual Change
2009	39	
2010	39	0.00%
2011	39	-0.85%
2012	38	-1.08%
2013	40	4.79%
2014	40	-0.83%
2015	36	-8.81%
2016	36	-1.45%
2017	35	-1.45%

Table 23 Forecasted USL connections

Causation for changes in Street Light demand and energy, is typically based on connection counts. Given the changes in equipment and connection methodologies throughout the industry, and lack of any reason to believe that more than one year of history would be required to predict the future, the full year 2015 was used as the basis for forecasting energy use.

Year	Street Light Actual	Normalized	Annual Change
2009	4,543,568	4,543,568	
2010	3,872,998	3,872,998	-14.8%
2011	4,475,403	4,475,403	15.6%
2012	4,830,569	4,830,569	7.9%
2013	4,446,822	4,446,822	-7.9%
2014	4,324,650	4,324,650	-2.7%
2015	3,719,644	3,719,644	-14.0%
2016		3,719,850	0.0%
2017		3,720,056	0.0%

Table 24 Forecasted Street Light kWh

Street Light			
Year	kWh Actual	Ratio	kW Actual
	A	**C = B / A**	**B**
2009	4,543,568	0.003153	14,328
2010	3,872,998	0.00374	14,484
2011	4,475,403	0.003066	13,723
2012	4,830,569	0.002764	13,353
2013	4,446,822	0.002993	13,311
2014	4,324,650	0.003073	13,289
2015	3,719,644	0.003089	11,489
	kWh Normalized		
	D	**E**	**F = D * E**
2016	3,719,850	0.003089	11,489
2017	3,720,056	0.003089	11,490

Table 25 Forecasted Street Light kW

Causation for changes in Sentinel demand and energy, is typically based on connection counts. The full year 2015 was used as the basis for forecasting energy use.

Year	Sentinel Actual	Normalized	Annual Change
2009	767,005	767,005	
2010	789,879	789,879	3.0%
2011	761,035	761,035	-3.7%
2012	713,312	713,312	-6.3%
2013	679,025	679,025	-4.8%
2014	700,647	700,647	3.2%
2015	691,109	691,109	-1.4%
2016		659,331	-4.6%
2017		629,014	-4.6%

Table 26 Forecasted Sentinel kWh

		Sentinel	
Year	kWh Actual	Ratio	kW Actual
	A	**C = B / A**	**B**
2009	767,005	0.003295	2,527
2010	789,879	0.003539	2,795
2011	761,035	0.003029	2,305
2012	713,312	0.003038	2,167
2013	679,025	0.003079	2,091
2014	700,647	0.003051	2,138
2015	691,109	0.003046	2,105
	kWh Normalized		
	D	**E**	**F = D * E**
2016	659,331	0.003046	2,008
2017	629,014	0.003046	1,916

Table 27 Forecasted Street Light kW

Causation for changes in USL demand and energy, is typically based on connection counts, changes in equipment, and re-classifications. Of these, only changes in connection counts can reasonably be forecasted. Therefore, in forecasting USL, the full year 2014 was used as the basis for forecasting USL energy going forward, with adjustments for forecasted connection counts.

	USL		Annual Change
Year	Actual	Normalized	
2009	1,584,330	1,584,330	
2010	1,524,248	1,524,248	-3.8%
2011	1,527,928	1,527,928	0.2%
2012	1,530,173	1,530,173	0.1%
2013	1,532,742	1,532,742	0.2%
2014	1,506,300	1,506,300	-1.7%
2015	1,506,177	1,506,177	0.0%
2016		1,484,310	-1.5%
2017		1,462,761	-1.5%

Table 28 Forecasted USL kWh

7 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 tables shows CNPI's proposed annual CDM targets.

6 Year (2015-2020) kWh Target:							
28,530,000							
	2015	**2016**	**2017**	**2018**	**2019**	**2020**	**Total**
%							
2015 Programs	22.7%						22.7%
2016 Programs		22.3%					22.3%
2017 Programs			18.9%				18.9%
2018 Programs				15.0%			15.0%
2019 Programs					11.2%		11.2%
2020 Programs						10.0%	10.0%
Total in Year	**22.7%**	**22.3%**	**18.9%**	**15.0%**	**11.2%**	**10.0%**	**100.0%**
kWh							
2015 Programs	6,435,320						6,435,320
2016 Programs		6,358,000					6,358,000
2017 Programs			5,394,000				5,394,000
2018 Programs				4,275,000			4,275,000
2019 Programs					3,181,950		3,181,950
2020 Programs						2859,950	2,859,950
Total in Year	6,435,320	6,358,000	5,394,000	4,275,000	3,181,950	2,859,950	28,534,220

Table 29 Proposed CDM Targets

	2015	2016	2017	2018	2019	2020
Residential	493,987	929,000	719,000	596,000	360,000	341,000
GS<50	901,107	776,000	536,000	436,000	302,000	224,000
GS>50	4,650,226	4,007,000	3,974,000	3,243,000	2,092,000	1,867,000
Streetlights	420,000	646,000	165,000			
Unassigned					427,950	427,950
Total	**6,465,320**	**6,358,000**	**5,394,000**	**4,275,000**	**3,181,950**	**2,859,950**

Table 30 Proposed CDM Targets by class

Consistent with recent Board decisions Elenchus includes the full value of the estimated 2016 CDM in 2017. Persistence is included assuming that the full influence of those programs would continue through to 2020. It is also assumed that only one half of the estimated programs would impact the year in which they are delivered.

	Program Delivery			
	2015	**2016**	**2017**	**Total**
Weight	0.5	1	0.5	
Residential	246,994	929,000	359,500	1,535,494
GS < 50	450,554	776,000	268,000	1,494,554
GS > 50	2,325,113	4,007,000	1,987,000	8,319,113
Street Light	210,000	646,000	82,500	938,500
Total	**3,232,660**	**6,358,000**	**2,697,000**	**12,287,660**

Table 31 Proposed CDM Impacts

The following is the proposed allocation of the CDM kWh load forecast adjustment and final proposed load forecast.

Retail kWh	Weather Normalized 2017 (Elenchus)	CDM Load Forecast Adjustment	2015 CDM Adjusted Load Forecast
Residential (kWh)	199,613,296	1,535,494	198,077,803
GS<50 (kWh)	69,401,885	1,494,554	67,907,332
GS>50 (kW)	193,263,316	8,319,113	184,944,203
Street Light	3,720,056	938,500	2,781,556
Total Customer (kWh)	465,998,554	12,287,660	453,710,894

Table 32 roposed kWh CDM Adjustment

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

Retail kW	Weather Normalized 2017 (Elenchus)	CDM Load Forecast Adjustment	2015 CDM Adjusted Load Forecast
GS>50 (kW)	620,074	26,691	593,383
Street Light	11,490	2,899	8,591
Total Customer (kW)	620,074	26,691	593,383

Table 33 Proposed kW CDM adjustment

For LRAMVA Elenchus reasons that the effects of 2015-2017 IESO CDM programs should be included in the LRAMVA calculation.

	Program Delivery			
	2015	**2016**	**2017**	**Total**
Weight	0.5	1	1	
Residential	246,994	929,000	719,000	1,894,994
GS < 50	450,554	776,000	536,000	1,762,554
GS > 50	2,325,113	4,007,000	3,974,000	10,306,113
Street Light	210,000	646,000	165,000	1,021,000
Total	**3,232,660**	**6,358,000**	**5,394,000**	**14,984,660**

Table 34 Proposed LRAMVA CDM Thresholds

kWh	Weather Normalized 2017 (Elenchus)	LRAMVA (kWh)
Residential (kWh)	199,613,296	1,894,994
GS<50 (kWh)	69,401,885	1,762,554
GS>50 (kW)	193,263,316	10,306,113
Street Light	3,720,056	1,021,000
Total Customer (kWh)	462,278,497.30	2,141,987

Table 35 LRAMVA kWh threshold by class

kW	Weather Normalized 2017 (Elenchus)	LRAMVA (kW)
GS>50 (kW)	620,074	33,067
Street Light	11,490	3,153
Total Customer (kW)	620,074	33,067

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

Table 36 LRAMVA kW threshold by class

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LOAD FORECAST – MICROSOFT EXCEL MODEL

Please refer to the file “CNPI Load Forecast.xlsx” for the Microsoft Excel model of the load forecast performed by Elenchus Research Associates.

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CDM ADJUSTMENTS TO LOAD FORECAST

The load forecast model developed by Elenchus includes historical CDM programs and the impact of new CDM programs in the Bridge and Test Years by rate class based on the CDM targets approved by the Board.

CNPI based its forecasted CDM savings under the new 2015-2020 “Conservation First” on planned program delivery. This results in slightly more CDM activity up-front with less activity in the last year.

All verified conservation savings achieved from 2010-2014 are integrated into the current application’s load forecast. Projected future savings to be achieved from 2015 through 2020 are outlined in the Load Forecast Appendix 2-I found in Appendix A to this schedule, and have been integrated into CNPI’s 2017 Load forecast.

In order to ensure that CNPI and its customers are kept whole in regards to projected conservation savings and lost revenues, CNPI is applying for continuance of its LRAMVA account. Going forward, this variance account will track savings achievements against this load forecast’s projected 2015-2020 savings, rather than assuming a base case going forward that does not include conservation impacts.

Full details of the CDM adjustment are available in Appendix A to this Schedule. Details of CNPI’s application for LRAMVA disposition are available in Exhibit 9, Tab 6, Schedule 1.

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Appendix 2-I
Load Forecast CDM Adjustment Work Form (2017)

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 determined the amount of kWh (and with translation, kW of demand) savings that were converted in dollars balances for the LRAMVA, and also to determine the related adjustment to the load forecast to account for OPA-reported savings. Beginning for the 2015 year, it has been adjusted because of the persistence of 2011-2014 CDM programs will be an adjustment to the load forecast in addition to the estimated savings for the first year (2015) for the new 2015-2020 CDM plan.

2017 is the third 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 program in completed, although in some instances disdposition of the amounts has been deferred. For the purposes of the 2015-2020 LRAMVA, and the impact of CDM on the load forecast, CDM programs in 2014 and earlier are implicit in the historical data on which the base load forecast is developed. Only impacts of 2015 to 2017 CDM programs need to be reflected in for the manual load forecast adjustment and for the LRAMVA threshold amount in 2017 and carrying forward, although the half-year impact of 2015 CDM programs on the 2015 historical data is also assumed to be reflected in the base load

The new six year (2015-2020) CDM program works similarly to the previous 2011-2014 CDM program, meaning that distributors will offer programs each year that, over the six years (from January 1, 2015 to December 31, 2020) will strive to cumulatively achieve savings meeting the new six year CDM target. In other words, distributors will be able to offer and execute programs on a basis so that cumulatively over the period, the measuyred impacts, including persistence, of the CDM programs will accumulate towards achieving each distributor's 2015-2020 CDM target.

2015-2020 CDM Program - 2017, third 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. The new targets for 2015-2020 do not take into account persistence beyond the first year, but the IESO will encourage distributors to promote and implement CDM plans that will have longer term persistence of savings. This results in each year's program being about 1/6 (18.67%) of the cumulative 2015-2020 CDM target for kWh savings. A distributor may propose an alternative approach but would be expected to document in its application why it believes that its proposal is more reasonable. In its proposal, the distributor should ensure that the sum of the results for each year's CDM program from 2015 to 2020 add up to its 2015-2020 CDM target as established by the IESO.

6 Year (2015-2020) kWh Target: 28,534,220							
	2015	2016	2017	2018	2019	2020	Total
%							
2015 CDM Programs	22.66%	0.00%	0.00%	0.00%	0.00%	0.00%	22.66%
2016 CDM Programs		22.28%	0.00%	0.00%	0.00%	0.00%	22.28%
2017 CDM Programs			18.90%	0.00%	0.00%	0.00%	18.90%
2018 CDM Programs				14.98%	0.00%	0.00%	14.98%
2019 CDM Programs					11.15%	0.00%	11.15%
2020 CDM Programs						10.02%	10.02%
Total in Year	**22.66%**	**22.28%**	**18.90%**	**14.98%**	**11.15%**	**10.02%**	**100.00%**
kWh							
2015 CDM Programs	6,465,320.00						6,465,320.00
2016 CDM Programs		6,358,000.00					6,358,000.00
2017 CDM Programs			5,394,000.00				5,394,000.00
2018 CDM Programs				4,275,000.00			4,275,000.00
2019 CDM Programs					3,181,950.00		3,181,950.00
2020 CDM Programs						2,859,950.00	2,859,950.00
Total in Year	**6,465,320.00**	**6,358,000.00**	**5,394,000.00**	**4,275,000.00**	**3,181,950.00**	**2,859,950.00**	**28,534,220.00**

Note: The default formulae in the above table assume that 1/21 of the 2015-2020 kWh CDM target is required each year so that, including persistence, 100% of the kWh target is achieved by the end of 2020. The distributor can input the 2015 CDM savings, including persistence from 2016 to 2020, once the reports become available. The distributor can also input their estimates or forecasts of the 2016 nd 2017 CDM programs if it believes that these are more realistic; such information would typically be derived from the CDM plans that the distributor has filed with the IESO. Similarly, CDM savings and persistence into future years can be estimated for 2018, 2019 and 2020 CDM programs. However, the distributor will have to support its proposals for estimated or forecasted savings, particularly beyond the 2017 test year. The sum of cumulative savings, including persistence, should equal the target entered into cell A25.

Determination of 2017 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 has also been used in Settlement Agreements accepted by the Board in other 2013 and 2-14 applications. The distributor should select whether the adjustment is done on a "net" or "gross" basis, but must support a proposal for the adjustment being done on a "gross" basis. Sheet 2-I defaults to the adjustment being done on a "net" basis consistent with Board policy and practice.

From each of the 2006-2010 CDM Final Report, and the 2011, 2012, 2013, 2014 and 2015 CDM Final Reports, issued by the OPA/IESO for the distributor, the distributor should input the "gross" and "net" results of the cumulative CDM savings for 2014 into cells D84 to E88. The model will calculate the cumulative savings for all programs from 2006 to 2012 and determine the "net" to "gross" factor "g".

	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				
2006 to 2015 OPA CDM programs: Persistence to 2017	0	0	0	0.00%

The default values represent the factor that each year's CDM program is factored into the manual CDM adjustment. Distributors can choose alternative weights of "0", "0.5" or "1" from the drop-down menu for each cell, but must support its alternatives.

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 the historical years that are the basis for the load forecast prior to any manual CDM adjustment for the 2017 test year.

Weight Factor for Inclusion in CDM Adjustment to 2017 Load Forecast

	2015	2016	2017	2018	2019	2020	
Weight Factor for each year's CDM program impact on 2014 load forecast	**0.5**	**1**	**0.5**	**0**	**0**	**0**	Distributor can select "0", "0.5", or "1" from drop-down list
Default Value selection rationale.	*Default is 0, but one option is for full year impact of persistence of 2015 CDM programs on 2017 load forecast, but 50% impact in base forecast (first year impact of 2014 CDM programs on 2014 actuals, which is part of the data for the load forecast.*	*Full year impact of persistence of 2015 programs on 2015 load forecast. 2015 CDM program impacts are not in the base forecast.*	*Only 50% of 2016 CDM programs are assumed to impact the 2016 load forecast based on the "half-year" rule.*	*2018, 2019 and 2020 are future years beyond the 2017 test year. No impacts of CDM programs beyond the 2017 test year are factored into the test year load forecast.*			

2015-2020 LRAMVA and 2017 CDM adjustment to Load Forecast

One manual adjustment for CDM impacts to the 2017 load forecast is made. There is a different but related threshold amount that is used for the 2017 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 2014, for assessing performance against the four-year target. The base amount for 2011-2013 is 0 (zero) for 2014 Cost of Service applications, as the utility rebased prior to the 2011-2014 CDM programs, and there was no adjustment to reflect the impacts of the 2011-2014 programs on the load forecast used to determine their last cost of service-based rates.

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 2017 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 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 OPA-measured impacts were
1 directed at specific customer classes), for both the LRAMVA and for the load forecast adjustment.

	2015	2016	2017	2018	2019	2020	Total for 2017
Amount used for CDM threshold for LRAMVA (2017)	6,465,320.00	6,358,000.00	5,394,000.00				18,217,320.00
Manual Adjustment for 2017 Load Forecast (billed basis)	3,232,660.00	6,358,000.00	2,697,000.00	-	-	-	12,287,660.00
Proposed Loss Factor (TLF)	5.42%						
Manual Adjustment for 2017 Load Forecast (system purchased basis)	3,407,870.17	6,702,603.60	2,843,177.40	-	-	-	12,953,651.17

Manual adjustment uses "gross" versus "net" (i.e. numbers multiplied by (1 + g). The Weight factor is also used calculate the impact of each year's program on the CDM adjustment to the 2017 load forecast.

ACCURACY OF LOAD FORECAST AND VARIANCE ANALYSIS

This schedule provides a year over year variance analysis on CNPI's distribution revenue and billing determinants. The following variance analyses are presented in accordance with Section 2.3.3 of the filing requirements:

- 2013 Actual vs 2013 Board Approved;
- 2013 Weather Normalized vs 2013 Board Approved (Load Only);
- Historical 2013-2015 Actual;
- Historical 2013-2015 Weather Normalized (Load Only);
- 2016 Bridge Year vs 2015 (Actual/Forecast Revenue; Weather Normalized Load); and
- 2017 Test Year vs 2016 Bridge Year (Forecast Revenue; Weather Normalized Load)

For the explanation of variances in revenue amounts, CNPI has used the materiality threshold of $100,000 presented in Exhibit 1, Tab 5, Schedule 1. For the explanations in variances of billing determinants, CNPI has used a threshold of 5% as a reasonable threshold to avoid repetitive discussion of model error in Weather normalization and load forecasting as well as minor year-over-year changes in consumption patterns.

The distribution revenue variance analysis is based on information provided in Table 3.3.1.1 below. Material variances in year-over-year revenue by rate class are explained in conjunction with the billing determinant variance analysis that follows as the two items are interrelated.

The billing determinant variance analysis is based on the data contained within the Elenchus Research Associates ("ERA") Weather Normalized Load Forecast, and the values in Appendix 2-IA, both of which are provided in Tab 1 of this Exhibit. Relevant data is summarized in tables associated with each of the analyses in the following sections. In addition, an adjusted version of Appendix 2-IA is attached as Appendix A to this Schedule. The adjustments from the original Appendix 2-IA include presenting values across all years as weather normalized, presenting 2017 Test Year values pre-CDM adjustment, and inclusion of the Embedded Distributor determinants in the GS 50 to 4999 kW class. These adjustments allow the following variance explanations to be compared against annual billing determinants that are presented in a more consistent manner year-over-year.

Table 3.3.1.1 – Distribution Rate Revenue 2013-2017

Description	2013 Board Approved	2013 Actual	2014 Actual	2015 Actual	2016 Bridge Year	2017 Test Year @ Existing Rates	2017 Test Year @ Proposed Rates
Distribution Revenue							
Residential	$ 9,931,421	$ 9,817,477	$ 10,026,457	$ 10,090,894	$ 10,269,122	$ 10,344,877	$ 11,827,584
General Service Less Than 50 kW	2,426,082	2,329,902	2,403,023	2,399,395	2,439,995	2,405,938	2,726,265
General Service Greater Than 50 kW	4,608,377	4,538,276	4,593,869	4,363,283	4,323,749	4,164,653	4,719,136
Embedded Distributor	-	-	-	-	-	93,571	120,987
Unmetered Scattered Load	80,218	117,611	99,292	78,374	75,051	40,027	61,365
Sentinel Lighting	69,351	51,256	57,476	57,479	57,869	53,757	60,914
Streetlights	447,549	446,349	468,375	452,386	449,919	432,790	354,056
Total Distribution Rate Revnue	**17,562,998**	**17,300,871**	**17,648,492**	**17,441,812**	**17,615,705**	**17,535,614**	**19,870,307**

Variance Analysis of Distribution Operating Revenue and Billing Determinants

<u>2013 Actual & Weather Normalized vs 2013 Board Approved</u>

Distribution Rate Revenue – 2013 Actual vs 2013 Board Approved

Description	2013 Board Approved	2013 Actual	Variance	Variance %
Distribution Revenue				
Residential	$ 9,931,421	$ 9,817,477	$ (113,944)	-1.15%
General Service Less Than 50 kW	2,426,082	2,329,902	$ (96,180)	-3.96%
General Service Greater Than 50 kW	4,608,377	4,538,276	$ (70,101)	-1.52%
Embedded Distributor	-	-	$ -	
Unmetered Scattered Load	80,218	117,611	$ 37,393	46.61%
Sentinel Lighting	69,351	51,256	$ (18,095)	-26.09%
Streetlights	447,549	446,349	$ (1,200)	-0.27%
Total Distribution Rate Revnue	**17,562,998**	**17,300,871**	**(262,127)**	**-1.49%**

Approximately $96,000 of the Residential variance is due to a 2013 journal entry related to PILS adjustments.

Billing Determinants – 2013 Actual vs 2013 Board Approved

	Customers/Connections			kWh		kW			
Billing Determinants	2013 Approved	2013 Actual	Difference	2013 Approved	2013 Actual	2013 Approved	2013 Actual	Volumetric Difference	Volumetric % Difference
Residential	25,689	25,798	109	208,287,976	206,257,081			-2,030,895	-1.0%
GS Less Than 50 kW	2,521	2,525	4	72,454,602	69,535,541			-2,919,061	-4.0%
GS 50 to 4,999 kW	228	225	-3			691,366	702,804	11,438	1.7%
USL	39	40	1	1,527,929	1,532,742			4,813	0.3%
Sentinel Lighting	961	768	-193			2,334	2,091	-243	-10.4%
Street Lighting	5,696	5,723	27			11,789	13,311	1,522	12.9%
Total	**35,134**	**35,079**	**-55**	**282,270,507**	**277,325,364**	**705,489**	**718,205**		

The difference in Sentinel Lighting is due to a declining trend in the overall number of Sentinel lights.

2013 actual kW billed to the Street Lighting class is in line with historical averages. The 2013 Approved value was understated due to an error in the 2011 actual kW billing determinant used for the Street Lighting class in CNPI's 2013 Load Forecast.

Billing Determinants – 2013 Weather Normalized vs 2013 Board Approved

	Customers/Connections			kWh		kW			
Billing Determinants	2013 Approved	2013 Actual	Difference	2013 Approved	2013 Weather Normalized	2013 Approved	2013 Weather Normalized	Volumetric Difference	Volumetric % Difference
Residential	25,689	25,798	109	208,287,976	209,632,810			1,344,834	0.6%
GS Less Than 50 kW	2,521	2,525	4	72,454,602	70,673,602			-1,781,000	-2.5%
GS 50 to 4,999 kW	228	225	-3			691,366	714,306	22,940	3.3%
USL	39	40	1	1,527,929	1,532,742			4,813	0.3%
Sentinel Lighting	961	768	-193			2,334	2,091	-243	-10.4%
Street Lighting	5,696	5,723	27			11,789	13,311	1,522	12.9%
Total	**35,134**	**35,079**	**-55**	**282,270,507**	**281,839,154**	**705,489**	**729,707**		

Please refer to the previous section (2013 Actual vs Board Approved) for explanations on Sentinel and Street Lighting variances as weather normalization has no impact on these classes.

<u>2014 vs 2013 (Actuals & Weather Normalized)</u>

Distribution Rate Revenue – 2014 Actual vs 2013 Actual

Description	2013 Actual	2014 Actual	Variance	Variance %
Distribution Revenue				
Residential	$ 9,817,477	$ 10,026,457	$ 208,980	2.13%
General Service Less Than 50 kW	2,329,902	2,403,023	$ 73,122	3.14%
General Service Greater Than 50 kW	4,538,276	4,593,869	$ 55,593	1.22%
Embedded Distributor	-	-	$ -	
Unmetered Scattered Load	117,611	99,292	$ (18,320)	-15.58%
Sentinel Lighting	51,256	57,476	$ 6,220	12.14%
Streetlights	446,349	468,375	$ 22,026	4.93%
Total Distribution Rate Revnue	**17,300,871**	**17,648,492**	**347,621**	**2.01%**

The increase in customer count in the Residential was partially offset by a decrease in billed kWh. This resulted in a net revenue increase of approximately $113,000. The remaining approximately $96,000 relates to the journal entry described in the 2013 variance section above.

Billing Determinants – 2014 Actual vs 2013 Actual

	Customers/Connections			kWh		kW		Volumetric	%
Billing Determinants	**2013 Actual**	**2014 Actual**	**Difference**	**2013 Actual**	**2014 Actual**	**2013 Actual**	**2014 Actual**	**Difference**	**Difference**
Residential	25,798	25,861	63	206,257,081	203,019,188			-3,237,893	-1.6%
GS Less Than 50 kW	2,525	2,513	-12	69,535,541	69,999,358			463,817	0.7%
GS 50 to 4,999 kW	225	225	0			702,804	673,584	-29,220	-4.2%
USL	40	40	0	1,532,742	1,506,300			-26,442	-1.7%
Sentinel Lighting	768	775	7			2,091	2,138	47	2.3%
Street Lighting	5,723	5,717	-6			13,311	13,289	-22	-0.2%
Total	**35,079**	**35,131**	**52**	**277,325,364**	**274,524,846**	**718,205**	**689,011**		

There are no material variances on an actual basis.

Billing Determinants – 2014 Weather Normalized vs 2013 Weather Normalized

	Customers/Connections			kWh		kW			
Billing Determinants	2013 Actual	2014 Actual	Difference	2013 Weather Normalized	2014 Weather Normalized	2013 Weather Normalized	2014 Weather Normalized	Volumetric Difference	Volumetric % Difference
Residential	25,798	25,861	63	209,632,810	199,121,216			-10,511,594	-5.0%
GS Less Than 50 kW	2,525	2,513	-12	70,673,602	68,655,369			-2,018,233	-2.9%
GS 50 to 4,999 kW	225	225	0			714,306	660,651	-53,655	-7.5%
USL	40	40	0	1,532,742	1,506,300			-26,442	-1.7%
Sentinel Lighting	768	775	7			2,091	2,138	47	2.3%
Street Lighting	5,723	5,717	-6			13,311	13,289	-22	-0.2%
Total	**35,079**	**35,131**	**52**	**281,839,154**	**269,282,885**	**729,707**	**676,078**		

The Residential and General Service classes have been generally trending downward since 2013. 2013 to 2014 saw a particularly large decrease on a weather normalized basis.

<u>2015 vs 2014 (Actuals & Weather Normalized)</u>

Distribution Rate Revenue – 2015 Actual vs 2014 Actual

Description	2014 Actual	2015 Actual	Variance	Variance %
Distribution Revenue				
Residential	$ 10,026,457	$ 10,090,894	$ 64,438	0.64%
General Service Less Than 50 kW	2,403,023	2,399,395	$ (3,628)	-0.15%
General Service Greater Than 50 kW	4,593,869	4,363,283	$ (230,586)	-5.02%
Embedded Distributor	-	-	$ -	
Unmetered Scattered Load	99,292	78,374	$ (20,918)	-21.07%
Sentinel Lighting	57,476	57,479	$ 4	0.01%
Streetlights	468,375	452,386	$ (15,990)	-3.41%
Total Distribution Rate Revnue	**17,648,492**	**17,441,812**	**(206,680)**	**-1.17%**

The decrease in GS>50 revenue from 2014 to 2015 is due to a decrease in both the number of customers and the total demand for that class.

Billing Determinants – 2015 Actual vs 2014 Actual

	Customers/Connections			kWh		kW		Volumetric	%
Billing Determinants	2014 Actual	2015 Actual	Difference	2014 Actual	2015 Actual	2014 Actual	2015 Actual	Difference	Difference
Residential	25,861	25,917	56	203,019,188	199,982,619			-3,036,569	-1.5%
GS Less Than 50 kW	2,513	2,492	-21	69,999,358	69,530,292			-469,066	-0.7%
GS 50 to 4,999 kW	225	220	-5			673,584	634,964	-38,620	-5.7%
USL	40	36	-4	1,506,300	1,506,177			-123	0.0%
Sentinel Lighting	775	763	-12			2,138	2,105	-32	-1.5%
Street Lighting	5,717	5,713	-4			13,289	11,489	-1,801	-13.5%
Total	**35,131**	**35,141**	**10**	**274,524,846**	**271,019,088**	**689,011**	**648,558**		

The decrease in GS>50 demand can be attributed to a decline in customer count.

The significant reduction in Street Lighting demand is a result of conversion to LED streetlights.

Billing Determinants – 2015 Weather Normalized vs 2014 Weather Normalized

	Customers/Connections			kWh		kW			
Billing Determinants	2014 Actual	2015 Actual	Difference	2014 Weather Normalized	2015 Weather Normalized	2014 Weather Normalized	2015 Weather Normalized	Volumetric Difference	Volumetric % Difference
Residential	25,861	25,917	56	199,121,216	203,249,666			4,128,451	2.1%
GS Less Than 50 kW	2,513	2,492	-21	68,655,369	70,666,185			2,010,816	2.9%
GS 50 to 4,999 kW	225	220	-5			660,651	645,337	-15,314	-2.3%
USL	40	36	-4	1,506,300	1,506,177			-123	0.0%
Sentinel Lighting	775	763	-12			2,138	2,105	-32	-1.5%
Street Lighting	5,717	5,713	-4			13,289	11,489	-1,801	-13.5%
Total	**35,131**	**35,141**	**10**	**269,282,885**	**275,422,028**	**676,078**	**658,931**		

The significant reduction in Street Lighting demand is a result of conversion to LED streetlights.

<u>2016 Bridge vs 2015 (Actual/Forecast Revenue; Actual/Weather Normalized Load)</u>

Distribution Operating Revenue – 2016 Bridge to 2015 Weather Normalized

Description	2015 Actual	2016 Bridge Year	Variance	Variance %
Distribution Revenue				
Residential	$ 10,090,894	$ 10,269,122	$ 178,227	1.77%
General Service Less Than 50 kW	2,399,395	2,439,995	$ 40,599	1.69%
General Service Greater Than 50 kW	4,363,283	4,323,749	$ (39,534)	-0.91%
Embedded Distributor	-	-	$ -	
Unmetered Scattered Load	78,374	75,051	$ (3,323)	-4.24%
Sentinel Lighting	57,479	57,869	$ 390	0.68%
Streetlights	452,386	449,919	$ (2,466)	-0.55%
Total Distribution Rate Revnue	**17,441,812**	**17,615,705**	**173,893**	**1.00%**

The increase in the Residential class is due to a projected increase in Residential customer count associated with new housing developments, combined with implementation of the first annual adjustment for transition to a fixed monthly distribution rate for that class.

Billing Determinants – 2016 Bridge to 2015 Actual

	Customers/Connections			kWh		kW		Volumetric	%
Billing Determinants	**2015 Actual**	**2016 Bridge**	**Difference**	**2015 Actual**	**2016 Bridge**	**2015 Actual**	**2016 Bridge**	**Difference**	**Difference**
Residential	25,917	25,995	78	199,982,619	199,830,975			-151,644	-0.1%
GS Less Than 50 kW	2,492	2,491	-1	69,530,292	69,477,568			-52,724	-0.1%
GS 50 to 4,999 kW	220	218	-2			634,964	634,482	-482	-0.1%
USL	36	36	0	1,506,177	1,484,310			-21,867	-1.5%
Sentinel Lighting	763	728	-35			2,105	2,008	-97	-4.6%
Street Lighting	5,713	5,713	0			11,489	11,489	1	0.0%
Total	**35,141**	**35,181**	**40**	**271,019,088**	**270,792,853**	**648,558**	**647,980**		

There are no material variances in actual billing determinants.

Billing Determinants – 2016Bridge to 2015 Weather Normalized

	Customers/Connections			kWh		kW			
Billing Determinants	2015 Actual	2016 Bridge	Difference	2015 Weather Normalized	2016 Bridge	2015 Weather Normalized	2016 Bridge	Volumetric Difference	Volumetric % Difference
Residential	25,917	25,995	78	203,249,666	199,830,975			-3,418,692	-1.7%
GS Less Than 50 kW	2,492	2,491	-1	70,666,185	69,477,568			-1,188,616	-1.7%
GS 50 to 4,999 kW	220	218	-2			645,337	634,482	-10,855	-1.7%
USL	36	36	0	1,506,177	1,484,310			-21,867	-1.5%
Sentinel Lighting	763	728	-35			2,105	2,008	-97	-4.6%
Street Lighting	5,713	5,713	0			11,489	11,489	1	0.0%
Total	**35,141**	**35,181**	**40**	**275,422,028**	**270,792,853**	**658,931**	**647,980**		

There are no material variances in actual billing determinants.

<u>2017 Test vs 2016 Bridge (Forecast Revenue; Weather Normalized Load)</u>

Distribution Operating Revenue – 2017 Test to 2016 Bridge

Description	2016 Bridge Year	2017 Test Year @ Proposed Rates	Variance	Variance %
Distribution Revenue				
Residential	$ 10,269,122	$ 11,827,584	$ 1,558,462	15.18%
General Service Less Than 50 kW	2,439,995	2,726,265	$ 286,270	11.73%
General Service Greater Than 50 kW	4,323,749	4,719,136	$ 395,387	9.14%
Embedded Distributor	-	120,987	$ 120,987	
Unmetered Scattered Load	75,051	61,365	$ (13,685)	-18.23%
Sentinel Lighting	57,869	60,914	$ 3,045	5.26%
Streetlights	449,919	354,056	$ (95,863)	-21.31%
Total Distribution Rate Revnue	**17,615,705**	**19,870,307**	**2,254,602**	**12.80%**

The overall increase is due to the increase in Revenue Requirement detailed in Exhibit 6. Variances across classes result from the Cost Allocation and Rate Design processes detailed in Exhibits 7 and 8, respectively. A comparison of 2017 revenue at existing rates is provided below.

Description	2016 Bridge Year	2017 Test Year @ Existing Rates	Variance	Variance %
Distribution Revenue				
Residential	$ 10,269,122	$ 10,344,877	$ 75,755	0.74%
General Service Less Than 50 kW	2,439,995	2,405,938	$ (34,056)	-1.40%
General Service Greater Than 50 kW	4,323,749	4,164,653	$ (159,096)	-3.68%
Embedded Distributor	-	93,571	$ 93,571	
Unmetered Scattered Load	75,051	40,027	$ (35,024)	-46.67%
Sentinel Lighting	57,869	53,757	$ (4,112)	-7.11%
Streetlights	449,919	432,790	$ (17,129)	-3.81%
Total Distribution Rate Revnue	**17,615,705**	**17,535,614**	**(80,091)**	**-0.45%**

The only material variance is for the GS>50 class, and is directly related to the reduced demand forecast for that class as described below.

Billing Determinants – 2017 Test to 2016 Bridge

	Customers/Connections			kWh		kW		Volumetric	%
Billing Determinants	2016 Bridge	2017 Test	Difference	2016 Bridge	2017 Test	2016 Bridge	2017 Test	Difference	Difference
Residential	25,995	26,074	79	199,830,975	198,077,803			-1,753,172	-0.9%
GS Less Than 50 kW	2,491	2,489	-2	69,477,568	67,907,332			-1,570,236	-2.3%
GS 50 to 4,999 kW	218	217	-1			634,482	593,383	-41,099	-6.5%
USL	36	35	-1	1,484,310	1,462,761			-21,549	-1.5%
Sentinel Lighting	728	695	-33			2,008	1,916	-92	-4.6%
Street Lighting	5,713	5,713	0			11,489	8,591	-2,898	-25.2%
Total	**35,181**	**35,223**	**42**	**270,792,853**	**267,447,895**	**647,980**	**603,890**		

Overall reductions across all classes are consistent with the output of the weather normalized load forecast performed by Elenchus Research Associates, which is described in detail at Exhibit 3, Tab 1, Schedule 2.

The significant decline in Street Lighting class is due to ongoing conversions to LED fixtures.

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Adjusted Summary and Variances of Actual and Forecast Data
(Based on Format of Appendix 2-IA)

Summary of Adjustments from Appendix 2-IA:
1. 2013-2015 Actuals are adjusted to present Weather Normalized values
2. 2017 Test Year values are presented pre-CDM adjustments
3. 2017 Embedded Distributor total are included in the GS 50 to 4999 kW (consistent with current billing practice for this customer)

	2013 Board Approved	2013 WN	2014 WN	2015 WN	2016 Bridge	2017 Test (Pre-CDM)
Residential						
# of Customers	25,689	25,798	25,861	25,917	25,995	26,074
kWh	208,287,976	209,632,810	199,121,216	203,249,666	199,830,975	199,613,296
kW						
Variance Analysis						
# of Customers		0.42%	0.67%	0.89%	1.19%	1.50%
kWh		0.65%	-4.40%	-2.42%	-4.06%	-4.16%
kW		0.00%	0.00%	0.00%	0.00%	0.00%
GS Less Than 50 kW						
# of Customers	2,521	2,525	2,513	2,492	2,491	2,489
kWh	72,454,602	70,673,602	68,655,369	70,666,185	69,477,568	69,401,885
kW						
Variance Analysis						
# of Customers		0.16%	-0.32%	-1.15%	-1.19%	-1.27%
kWh		-2.46%	-5.24%	-2.47%	-4.11%	-4.21%
kW		0.00%	0.00%	0.00%	0.00%	0.00%

GS 50 to 4,999 kW (Includes Embedded Distributor)						
# of Customers	228	225	225	220	218	218
kWh	224,300,691	219,499,506	231,604,485	198,759,828	198,609,111	184,944,203
kW	691,366	714,306	660,651	645,337	634,482	633,791
Variance Analysis						
# of Customers		-1.32%	-1.32%	-3.51%	-4.39%	-4.39%
kWh		-2.14%	3.26%	-11.39%	-11.45%	-17.55%
kW		3.32%	-4.44%	-6.66%	-8.23%	-8.33%
Unmetred Scattered Load						
# of Connections	39	40	40	36	36	35
kWh	1,527,929	1,532,742	1,506,300	1,506,177	1,484,310	1,462,761
kW						
Variance Analysis						
# of Connections		2.56%	2.56%	-7.69%	-7.69%	-10.26%
kWh		0.32%	-1.42%	-1.42%	-2.85%	-4.27%
kW		0.00%	0.00%	0.00%	0.00%	0.00%
Sentinel Lighting						
# of Customers	961	768	775	763	728	695
kWh	761,037	679,025	700,647	691,109	659,331	629,014
kW	2,334	2,091	2,138	2,105	2,008	1,916
Variance Analysis						
# of Customers		-20.08%	-19.35%	-20.60%	-24.25%	-27.68%
kWh		-10.78%	-7.94%	-9.19%	-13.36%	-17.35%
kW		-10.43%	-8.41%	-9.81%	-13.95%	-17.91%

Street Lighting						
# of Connections	5,696	5,723	5,717	5,713	5,713	5,713
kWh	4,475,403	4,446,822	4,324,650	3,719,644	3,719,850	2,781,556
kW	11,789	13,311	13,289	11,489	11,489	11,490
Variance Analysis						
# of Connections		0.47%	0.37%	0.30%	0.30%	0.30%
kWh		-0.64%	-3.37%	-16.89%	-16.88%	-37.85%
kW		12.91%	12.73%	-2.55%	-2.54%	-2.54%
Totals						
Customers / Connections	35,134	35,079	35,131	35,141	35,181	35,224
kWh	511,807,638	506,464,507	505,912,667	478,592,609	473,781,145	458,832,716
kW from applicable classes	705,489	729,707	676,078	658,931	647,980	647,197
Totals - Variance						
Customers / Connections		-0.16%	-0.01%	0.02%	0.13%	0.26%
kWh		-1.04%	-1.15%	-6.49%	-7.43%	-10.35%
kW from applicable classes		3.43%	-4.17%	-6.60%	-8.15%	-8.26%

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OVERVIEW OF OTHER DISTRIBUTION REVENUE OFFSET

Other distribution revenue is primarily comprised of charges to retailers for distributor and retailer consolidated billing, pole rental, specific services charges and other miscellaneous revenues. Other distribution revenue will be used as a revenue offset in the 2017 model. CNPI is not proposing any changes to miscellaneous rates and charges for 2017. The table below summarizes the revenues from the 2013 Board Approved to the 2017 Test Year.

Other Distribution Revenue Offset Table

USoA #	USoA Description	Board Approved	2013 Actual	2014 Actual	Actual Year	Bridge Year	Test Year
		2013	2013	2014	2015	2016	2017
	Reporting Basis						
4235	**Specific Service Charges**	$ 151,355	$ 151,022	$ 160,714	$ 159,803	$ 156,539	$ 158,264
4225	**Late Payment Charges**	$ 361,102	$ 397,363	$ 391,595	$ 373,070	$ 340,573	$ 354,100
4082	**Retail Services Revenues**	$ 33,500	$ 23,310	$ 25,190	$ 21,397	$ 24,250	$ 24,600
4084	Service Transaction Requests (STR) Revenues	$ 1,400	$ 791	$ 821	$ 579	$ 806	$ 800
4086	SSS Administration Revenue	$ 79,562	$ 80,385	$ 80,807	$ 81,576	$ 80,841	$ 81,035
4210	Rent from Electric Property	$ 317,100	$ 320,462	$ 328,193	$ 322,464	$ 324,327	$ 327,500
4220	Other Electric Revenues	$ 9,873	$ (946,693)	$ 26,048	$ 78,960	$ 15,541	$ 15,700
4325	Revenues from Merchandise, Jobbing, Etc.	$ 556,692	$ 383,707	$ 575,419	$ 773,569	$ 437,084	$ 432,852
4330	Costs and Expenses of Merchandising, Jobbing, Etc.	$ (137,400)	$ (143,740)	$ (235,995)	$ (166,989)	$ (108,235)	$ (109,623)
4360	Loss on Disposition of Utility and Other Property	$ -	$ (19,692)	$ 74,502	$ 46,779	$ -	$ -
4375	Revenues from Non-Utility Operations	$ -	$ -	$ -	$ -	$ -	$ 1,139,217
4398	Foreign Exchange Gains and Losses, Including Amortization	$ -	$ 3,713	$ (11,746)	$ (28,155)	$ -	$ -
4405	Interest and Dividend Income	$ 30,000	$ (54,940)	$ 76,421	$ 72,103	$ -	$ -
Total		$ 1,403,185	$ 195,687	$ 1,491,968	$ 1,735,157	$ 1,271,727	$ 2,424,445

SSS Administration Revenue (OEB Account 4086)

Revenues generated from the $0.25 charge for SSS billing.

Retail Services Revenue (OEB Account 4082)

Revenues generated from monthly fixed and variable charges and bill ready charges that are billed to electricity retailers.

Service Transaction Requests (STR) Revenues (OEB Account 4084)

Revenues generated from STR request fees and processing fees.

Rent from Electric Property (OEB Account 4210)

Revenues generated from poles shared with telecommunication providers and rental revenue from cable television providers and fiber optic companies.

Other Electric Revenue (OEB Account 4220)

Revenues generated from miscellaneous electric revenue and fees collected for returned cheques. There are no changes to specific service charges being requested for 2017. In 2013, as per OEB FAQ, CNPI disposed of its smart meter and ROE on smart meter balance to account 4220 in the amount of $1,004,322.

Late Payment Charges (OEB Account 4225)

Revenues generated from late payment charges (1.5% monthly, or 19.56% per annum) resulting from non-payment of overdue accounts as well as collection fees for processing and delivering final collection notices.

Miscellaneous Service Revenues (OEB Account 4235)

Revenues generated from other specific service charges. There are no changes to specific service charges being requested for 2017.

Revenues from Merchandise, Jobbing, etc. (OEB Account 4325)

Revenues generated from third party job orders. Includes revenues associated with the IT Services Agreements with each of CNPI's associated (10% interest) companies that use CNPI's SAP system which is discussed further in Exhibit 3, Tab 4, Schedule 2 of this Application.

Costs and Expenses of Merchandising, Jobbing, etc. (OEB Account 4330)

Costs associated with third party job orders. Includes the internal costs associated with the IT Services Agreements with each of CNPI's associated (10% interest) companies that use CNPI's SAP system which is discussed further in Exhibit 3, Tab 4, Schedule 2 of this Application.

Loss on Disposition of Utility and Other Property (OEB Account 4360)

Losses in the disposal of utility property. CNPI is not forecasting any losses or disposals for 2016 or 2017.

Revenues from Non-Utility Operations (OEB Account 4375)

In 2017, as discussed in Exhibit 2, Tab 1, Schedule 1 under shared assets, CNPI has included shared IT and equipment charges as revenue offsets within the RRWF for 2017 in the amount of $1,139,217.

Foreign Exchange Gains and Losses, including Amortization (OEB Account 4398)

Foreign exchange gains and losses. CNPI is not forecasting any foreign exchange gains or losses for 2016 and 2017.

Interest and Dividend Income (OEB Account 4405)

Interest earned on Canadian and US bank accounts, as well as interest on regulatory assets. CNPI is not forecasting any amounts for 2016 and 2017.

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ASSOCIATE INFORMATION TECHNOLOGY SERVICES AGREEMENTS

Overview

CNPI has entered into five year IT Services Agreements with its associated (10% ownership interest) companies that use SAP: Grimsby Power Inc. and Westario Power Inc. The services include shared use of CNPI's IT system for the purpose of conducting business. The CNPI email, file/print systems and infrastructure also support these activities.

Support Services

Delivery of the support services under the IT Services Agreements is provided by CNPI's IT department staff. Requests from either associated company are received via the IT help desk system, reviewed and assigned on a priority basis to an appropriate member of the IT department. All time and material for support requests are accurately tracked within this system. This includes timely completion of incoming requests as well as ensuring any requests common to all organizations participating in the use of SAP are delivered in a consistent manner. Cost sharing of system improvements is utilized.

Fees for Services

The fees have been calculated to include the fully allocated costs associated with the agreed services plus a return on invested capital. Fees set forth in the services agreements are defined in three distinct areas:

- *Asset Utilization:* Calculated utilizing a fixed monthly rate and covering the cost of capital and related administration of the system assets utilized by the associate.
- *Help Desk Services:* Calculated on a per request basis submitted within the ticketing system and covers SAP specific support.
- *New Development (SAP):* Calculated on a per request basis. A formal specification document is created in partnership with CNPI support staff and associate staff. Based on the scope, a time and materials statement of work will be submitted and approved by the associate companies before work begins on

the request. This would include system improvements such as new functionality related to business processes or reports as required by the associated company.

Appendix 2-H
Other Operating Revenue

USoA #	USoA Description	Board Approved 2013	2013 Actual 2013	2014 Actual 2014	Actual Year 2015	Bridge Year 2016	Test Year 2017
	Reporting Basis						
4235	**Specific Service Charges**	$ 151,355	$ 151,022	$ 160,714	$ 159,803	$ 156,539	$ 158,264
4225	**Late Payment Charges**	$ 361,102	$ 397,363	$ 391,595	$ 373,070	$ 340,573	$ 354,100
4082	**Retail Services Revenues**	$ 33,500	$ 23,310	$ 25,190	$ 21,397	$ 24,250	$ 24,600
4084	Service Transaction Requests (STR) Revenues	$ 1,400	$ 791	$ 821	$ 579	$ 806	$ 800
4086	SSS Administration Revenue	$ 79,562	$ 80,385	$ 80,807	$ 81,576	$ 80,841	$ 81,035
4210	Rent from Electric Property	$ 317,100	$ 320,462	$ 328,193	$ 322,464	$ 324,327	$ 327,500
4220	Other Electric Revenues	$ 9,873	$ (946,693)	$ 26,048	$ 78,960	$ 15,541	$ 15,700
4325	Revenues from Merchandise, Jobbing, Etc.	$ 556,692	$ 383,707	$ 575,419	$ 773,569	$ 437,084	$ 432,852
4330	Costs and Expenses of Merchandising, Jobbing, Etc.	$ (137,400)	$ (143,740)	$ (235,995)	$ (166,989)	$ (108,235)	$ (109,623)
4360	Loss on Disposition of Utility and Other Property	$ -	$ (19,692)	$ 74,502	$ 46,779	$ -	$ -
4375	Revenues from Non-Utility Operations	$ -	$ -	$ -	$ -	$ -	$ 1,139,217
4398	Foreign Exchange Gains and Losses, Including Amortization	$ -	$ 3,713	$ (11,746)	$ (28,155)	$ -	$ -
4405	Interest and Dividend Income	$ 30,000	$ (54,940)	$ 76,421	$ 72,103	$ -	$ -
Specific Service Charges		$ 151,355	$ 151,022	$ 160,714	$ 159,803	$ 156,539	$ 158,264
Late Payment Charges		$ 361,102	$ 397,363	$ 391,595	$ 373,070	$ 340,573	$ 354,100
Other Operating Revenues		$ 441,435	$ (521,746)	$ 461,059	$ 504,976	$ 445,766	$ 449,635
Other Income or Deductions		$ 449,292	$ 169,049	$ 478,599	$ 697,307	$ 328,849	$ 1,462,446
Total		$ 1,403,185	$ 195,687	$ 1,491,968	$ 1,735,157	$ 1,271,727	$ 2,424,445

Account 4082 - Retail Services Revenue

	Board Approved 2013	2013 Actual 2013	2014 Actual 2014	Actual Year 2015	Bridge Year 2016	Test Year 2017
Reporting Basis						
Monthly fixed retail charge	$ 2,740	$ 3,560	$ 3,880	$ 3,620	$ 3,720	$ 3,700
Monthly variable service charge	$ 19,800	$ 12,490	$ 13,361	$ 11,163	$ 12,925	$ 13,100
Bill-ready charge	$ 10,960	$ 7,260	$ 7,849	$ 6,614	$ 7,555	$ 7,700
Other	$ -	$ -	$ 100	$ -	$ 50	$ 100
Total	$ 33,500	$ 23,310	$ 25,190	$ 21,397	$ 24,250	$ 24,600

Account 4084 - Service Transaction Requests (STR) Revenues

	Board Approved 2013	2013 Actual 2013	2014 Actual 2014	Actual Year 2015	Bridge Year 2016	Test Year 2017
Reporting Basis						
STR request fee	$ 550	$ 340	$ 332	$ 225	$ 336	$ 300
STR processing fee	$ 850	$ 451	$ 489	$ 354	$ 470	$ 500
Total	$ 1,400	$ 791	$ 821	$ 579	$ 806	$ 800

Account 4086 - SSS Administrative Revenue

	Board Approved 2013	2013 Actual 2013	2014 Actual 2014	Actual Year 2015	Bridge Year 2016	Test Year 2017
Reporting Basis						
Administrative charge	$ 79,562	$ 80,385	$ 80,807	$ 81,576	$ 80,841	$ 81,035
Total	$ 79,562	$ 80,385	$ 80,807	$ 81,576	$ 80,841	$ 81,035

Account 4210 - Rent from Electric Property

	Board Approved	2013 Actual	2014 Actual	Actual Year	Bridge Year	Test Year
	2013	2013	2014	2015	2016	2017
Reporting Basis						
Pole rentals	$ 317,100	$ 320,462	$ 328,193	$ 322,464	$ 324,327	$ 327,500
Total	$ 317,100	$ 320,462	$ 328,193	$ 322,464	$ 324,327	$ 327,500

Account 4220 - Other Electric Revenues

	Board Approved	2013 Actual	2014 Actual	Actual Year	Bridge Year	Test Year
	2013	2013	2014	2015	2016	2017
Reporting Basis						
Returned cheque	$ 4,100	$ 3,399	$ 4,225	$ 2,942	$ 3,541	$ 3,600
Other revenue	$ 5,773	$ 54,230	$ 21,823	$ 10,491	$ 12,000	$ 12,100
Smart meter ROE/disposition balances per OEB FAQ	$ -	$ (1,004,322)	$ -	$ -	$ -	$ -
CDM Revenues	$ -	$ -	$ -	$ 65,527	$ -	$ -
Total	$ 9,873	$ (946,693)	$ 26,048	$ 78,960	$ 15,541	$ 15,700

Account 4325 - Revenue from Merchandise, Jobbing, Etc.

	Board Approved	2013 Actual	2014 Actual	Actual Year	Bridge Year	Test Year
	2013	2013	2014	2015	2016	2017
Reporting Basis						
Job order revenue	$ -	$ 121,564	$ 175,307	$ 365,695	$ 84,429	$ 74,505
IT outside services with related parties	$ 556,692	$ 262,143	$ 400,112	$ 407,874	$ 352,655	$ 358,347
Total	$ 556,692	$ 383,707	$ 575,419	$ 773,569	$ 437,084	$ 432,852

Account 4330 - Costs and Expenses of Merchandise, Jobbing, Etc.

	Board Approved	2013 Actual	2014 Actual	Actual Year	Bridge Year	Test Year
	2013	2013	2014	2015	2016	2017
Reporting Basis						
Job order costs	$ -	$ (110,784)	$ (148,650)	$ (105,304)	$ (75,029)	$ (75,105)
IT outside services with related parties	$ (137,400)	$ (32,956)	$ (87,345)	$ (61,685)	$ (33,206)	$ (34,518)
Total	$ (137,400)	$ (143,740)	$ (235,995)	$ (166,989)	$ (108,235)	$ (109,623)

Account 4360 - Loss on Disposition of Utility and Other Property

	Board Approved	2013 Actual	2014 Actual	Actual Year	Bridge Year	Test Year
	2013	2013	2014	2015	2016	2017
Reporting Basis						
Loss on disposals/retirement	$ -	$ (19,692)	$ 74,502	$ 46,779	$ -	$ -
Total	$ -	$ (19,692)	$ 74,502	$ 46,779	$ -	$ -

Account 4375 - Revenues from Non-Utility Operations

	Board Approved	2013 Actual	2014 Actual	Actual Year	Bridge Year	Test Year
	2013	2013	2014	2015	2016	2017
Reporting Basis						
Shared IT and equipment charges	$ -	$ -	$ -	$ -	$ -	$ 1,139,217
Total	$ -	$ -	$ -	$ -	$ -	$ 1,139,217

Account 4398 - Foreign Exchange Gains and Losses, Including Amortization

	Board Approved	2013 Actual	2014 Actual	Actual Year	Bridge Year	Test Year
	2013	2013	2014	2015	2016	2017
Reporting Basis						
Gain/loss on foreign exchange	$ -	$ 3,713	$ (11,746)	$ (28,155)	$ -	$ -
Total	$ -	$ 3,713	$ (11,746)	$ (28,155)	$ -	$ -

Account 4405 - Interest and Dividend Income

	Board Approved	2013 Actual	2014 Actual	Actual Year	Bridge Year	Test Year
	2013	2013	2014	2015	2016	2017
Reporting Basis						
Interest on regulatory assets	$ -	$ (81,812)	$ 45,679	$ 42,361	$ -	$ -
Other interest	$ 30,000	$ 26,872	$ 30,742	$ 29,742	$ -	$ -
Total	$ 30,000	$ (54,940)	$ 76,421	$ 72,103	$ -	$ -

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VARIANCE ANALYSIS ON OTHER DISTRIBUTION REVENUE OFFSET

See table 3.4.4.1 below for variances on Other Distribution Revenue Offset. In accordance with materiality discussed in Exhibit 1, Tab 5, Schedule 1, CNPI has analyzed any variances greater than $100,000 below.

Table 3.4.4.1 Appendix 2-H - Modified with Variances
Other Operating Revenue

USoA #	USoA Description	Board Approved	2013 Actual	2014 Actual	Actual Year	Bridge Year	Test Year	Variance	Variance
		2013	2013	2014	2015	2016	2017	2017 Test Year vs 2013 Board Approved	2017 Test Year vs 2015 Actual
	Reporting Basis								
4235	**Specific Service Charges**	$ 151,355	$ 151,022	$ 160,714	$ 159,803	$ 156,539	$ 158,264	$ 6,909	-$ 1,539
4225	**Late Payment Charges**	$ 361,102	$ 397,363	$ 391,595	$ 373,070	$ 340,573	$ 354,100	-$ 7,002	-$ 18,970
4082	**Retail Services Revenues**	$ 33,500	$ 23,310	$ 25,190	$ 21,397	$ 24,250	$ 24,600	-$ 8,900	$ 3,203
4084	Service Transaction Requests (STR) Revenues	$ 1,400	$ 791	$ 821	$ 579	$ 806	$ 800	-$ 600	$ 221
4086	SSS Administration Revenue	$ 79,562	$ 80,385	$ 80,807	$ 81,576	$ 80,841	$ 81,035	$ 1,473	-$ 540
4210	Rent from Electric Property	$ 317,100	$ 320,462	$ 328,193	$ 322,464	$ 324,327	$ 327,500	$ 10,400	$ 5,036
4220	Other Electric Revenues	$ 9,873	$ (946,693)	$ 26,048	$ 78,960	$ 15,541	$ 15,700	$ 5,827	-$ 63,260
4325	Revenues from Merchandise, Jobbing, Etc.	$ 556,692	$ 383,707	$ 575,419	$ 773,569	$ 437,084	$ 432,852	-$ 123,840	-$ 340,717
4330	Costs and Expenses of Merchandising, Jobbing, Etc.	$ (137,400)	$ (143,740)	$ (235,995)	$ (166,989)	$ (108,235)	$ (109,623)	$ 27,777	$ 57,366
4360	Loss on Disposition of Utility and Other Property	$ -	$ (19,692)	$ 74,502	$ 46,779	$ -	$ -	$ -	-$ 46,779
4375	Revenues from Non-Utility Operations	$ -	$ -	$ -	$ -	$ -	$ 1,139,217	$ 1,139,217	$ 1,139,217
4398	Foreign Exchange Gains and Losses, Including Amortization	$ -	$ 3,713	$ (11,746)	$ (28,155)	$ -	$ -	$ -	$ 28,155
4405	Interest and Dividend Income	$ 30,000	$ (54,940)	$ 76,421	$ 72,103	$ -	$ -	-$ 30,000	-$ 72,103
Total		$ 1,403,185	$ 195,687	$ 1,491,968	$ 1,735,157	$ 1,271,727	$ 2,424,445	$ 1,021,260	$ 689,288

2017 Test Year vs 2013 Board Approved

Revenues from Merchandise, Jobbing, etc. (OEB Account 4325)

The decrease of $123,840 from the $556,692 2013 Board Approved to $432,852 for the 2017 Test Year is primarily the resultant of a decrease in the variable component of revenues associated with the IT Services Agreements with each of CNPI's associated (10% interest) companies that use CNPI's SAP system. CNPI's 2017 Test Year value of approximately $358,000 for IT Services Agreements is more reflective of the average of 2013, 2014 and 2015 Actuals and is comparable to 2016 Test Year forecast of approximately $353,000.

Revenues from Non-Utility Operations (OEB Account 4375)

The increase from the $0 2013 Board Approved to $1,139,217 for the 2017 Test Year is the resultant of a change in accounting for shared assets as proposed in Exhibit 2, Tab 1, Schedule 1 of this Application. This accounting change for CNPI has resulted in a corresponding increase in rate base.

2017 Test Year vs 2015 Actual Year

Revenues from Merchandise, Jobbing, etc. (OEB Account 4325)

The decrease of $340,717 from the $773,569 2015 Actual Year to $432,852 for the 2017 Test Year is primarily the resultant of a decrease in Job Order Costs of approximately $291,000. In CNPI's 2015 Actual Year, a significant and non-recurring job with revenue of $250,000 was recorded. Given that this was a specific to 2015, the amount has not been included in the 2017 Test Year.

Revenues from Non-Utility Operations (OEB Account 4375)

The increase from the $0 2015 Actual Year to $1,139,217 for the 2017 Test Year is the resultant of a change in accounting for shared assets as proposed in Exhibit 2, Tab 1, Schedule 1 of this Application.

OVERVIEW OF OPERATING FUNCTIONS

This Exhibit 4 (Operating Costs) sets out CNPI's operating costs forecasted for 2017 Test Year, including the following: operations, maintenance, and administration expenses ("OM&A expenses"), amortization expense, and income tax.

A summary of the OM&A expenses for CNPI is provided in the table 4.1.1.1 below.

Table 4.1.1.1 Summary of Operating Expenses

	Last Rebasing Year (2013 Board-Approved)	Last Rebasing Year (2013 Actuals)	2014 Actuals	2015 Actuals	2016 Bridge Year	2017 Test Year
Operations	$ 1,464,548	$ 1,533,641	$ 1,726,744	$ 1,702,685	$ 1,658,103	$ 1,847,897
Maintenance	$ 1,912,478	$ 1,939,325	$ 1,893,749	$ 1,912,871	$ 2,203,670	$ 2,259,049
Billing and Collecting	$ 2,061,053	$ 1,874,779	$ 1,768,363	$ 1,754,606	$ 1,874,259	$ 1,960,026
Community Relations	$ 35,700	$ 22,685	$ 14,503	$ 22,126	$ 25,300	$ 40,150
Administrative and General	$ 4,362,183	$ 3,493,634	$ 4,031,454	$ 4,126,646	$ 4,369,484	$ 4,437,601
Total	**$ 9,835,961**	**$ 8,864,063**	**$ 9,434,813**	**$ 9,518,933**	**$ 10,130,816**	**$ 10,544,723**

Functional Overview

To provide a more comprehensive understanding of CNPI's OM&A expenses, below is an overview of the functional departments within the organization.

Health, Safety & Environment Department

An integral component of CNPI's operations is its Health, Safety & Environment ("HS&E") department and its systematic approach to proactively managing safety and the environment.

CNPI utilizes an integrated management system for HS&E, consistent with the standards of OHSAS 18001 (Health & Safety) and ISO 14001 (Environment) and developed within the context of FortisOntario's structure. The management system is based upon the premise of "Plan, Do, Check and Act". Both of these standards have been developed based on a foundation of a strong "Internal Responsibility System". This is a key value contained in the *Occupational Health and Safety Act*. All HS&E responsibilities are identified through the management system and have been clearly assigned to constituents within CNPI including: the Board of Directors, the Executive, Departments (Managers, Supervisors and workers) and Committees (Executive Environmental & Safety Committee, Central Environmental & Safety

Committee, Joint Health & Safety Committee and Environmental Leadership Team). The following is an overview of CNPI's HS&E functions.

- Hazard Assessment
- Legal Compliance
- Performance Indicators
- Training
- Audits and Inspections

One of the core principles consistent to both of the standards associated with the CNPI HS&E management system is the need for continual improvement. The HS&E department explores new ideas and facilitates recommendations to improve the system, and to promote HS&E responsibility. In an industry in which technology is evolving rapidly, and in an environment where CNPI's workers are exposed to risk, it is imperative that CNPI continues to commit the appropriate resources to sustain its current level of HS&E performance. In that regard, CNPI has consistently achieved high levels of success in the areas of health, safety and environmental management. CNPI has gone almost fourteen (14) years without a high risk lost time occurrence.

Customer Service

The customer service department handles all call centre activities, credit and collections, account receivable management, smart meter activities and billing and retail settlement. All AMI billing activities are centralized in Fort Erie and call centres are located in Fort Erie for the Niagara operations, in Cornwall for the Eastern operations and in Sault Ste. Marie for the Northern operations.

The department is focused on providing a consistently high level of customer service while maintaining efficient operations. Annual customer satisfaction surveys have been completed for over ten years. The 2015 overall customer satisfaction rating was 94 per cent exceeding the Ontario benchmark of 88 per cent.

There have been a number of changes to the Business Environment in recient years, primarily involving enhanced technology. Smart meters were installed and as a result manual meter reading was replaced with AMI technology. CNPI implemented time-of-use billing in 2012 on a calendar bill cycle to assist the customers in monthly consumption comparison. Customers were provided with a tool to view their time-of-use consumption to assist with management of their electrical invoices. E-billing was introduced in late 2012 and enrollment has continued to grow since. To date 14 per cent of CNPI customers are enrolled with E-billing.

Changes in credit and collection procedures have resulted in the discontinuance of mailed reminder notices which have been replaced with automated phone calls in an effort to efficiently collect on overdue receivables.

The introduction of social media in 2015 has provided CNPI and its customers with additional channels for communication. CNPI is able to send out timely information to customers as required in addition to providing timely responses to customer inquiries.

Human Resources

Headquarted in Fort Erie, the Human Resources department has corporate responsibilities throughout the organization. The priorities of the department are to ensure adequate staffing levels, succession planning with focus on employee development and on-going labour relations. A leadership coaching and development training program has been offered to a number of management and supervisory employees to further develop their management and leadership skill set.

Health plan cost management, pension administration and workplace safety and insurance board administration, and other benefit related activities are managed by the Human Resources department. The company maintains a modified return to work program and regularly tracks, reports and manages human resources in an effort to remain aligned with corporate objectives. CNPI maintains positive labour relations with its represented employees and has a cooperative working relationship with I.B.E.W. leadership.

To further develop its high potential employees CNPI introduced a mentoring program to pair up individuals throughout the organization in an effort to share knowledge and experience.

Corporate Communications and Community Involvement (Community Relations)

Community Involvement and public relations remain an important core value of CNPI. Continued local community involvement in selective focus areas contribute to CNPI being recognized as a valued member of the communities served.

The implementation of social media (twitter and Facebook) have provided additional channels to promote CNPI's community involvement initiatives.

Information Technology

The Information Technology department is responsible for all hardware and software maintenance and programming. As explained in detail in Exhibit 2, Tab 2, Schedule 3 (Information Technology Strategy) and Exhibit 2, Tab 2, Schedule 4 (Information Technology Projects), SAP is the enterprise wide software solution CNPI implemented in 1999. Since that time CNPI has focused on developing in-house expertise to eliminate the need to use outside consultants. The majority of required changes to SAP are configured, implemented and tested by CNPI employees. Over time, these IT efficiencies and increased automations will continue to reduce overall operating expenses and/or improve productivity.

Finance

The Finance department supports all back office operations of the company. Located centrally in the Fort Erie office, the Finance department is responsible for all company accounts payable, payroll and financial reporting. In addition, the department is responsible for all retail related billing, OEB data collection and reporting as well as monthly financial statements.

Regulatory

The Regulatory department provides regulatory guidance to the company and maintains compliance with its regulatory requirements. CNPI uses internal resources to perform the majority of these functions which also provides for the development of in-house regulatory competency rather than relying on third party consultants for the core regulatory functions.

Operations

The Operations departments are responsible for the effective and efficient delivery of all aspects of system engineering and planning, construction, maintenance and operations of the distribution systems. Operations includes the following departments; Systems Control, Line Services, Meter Services, Planning and Engineering, Property and Procurement, Fleet and Facilities. The CNPI Fort Erie Service Centre is the main headquarters for the delivery of services to Fort Erie and Port Colborne. The Eastern Ontario Power Service Centre is the main headquarters for the delivery of services to Gananoque.

Since CNPI's last Cost of Service application in 2013, there have been three significant business environment changes that will impact operating costs; the introduction of Metering Inside the Settlement Timeframe (MIST) for all General Service customers above 50 kW, the inclusion of a pole testing program, and the Emerald Ash Borer mitigation program.

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Appendix 2-JA
Summary of Recoverable OM&A Expenses

	Last Rebasing Year (2013 Board-Approved)	Last Rebasing Year (2013 Actuals)	2014 Actuals	2015 Actuals	2016 Bridge Year	2017 Test Year
Reporting Basis = ASPE						
Operations	$ 1,464,548	$ 1,533,641	$ 1,726,744	$ 1,702,685	$ 1,658,103	$ 1,847,897
Maintenance	$ 1,912,478	$ 1,939,325	$ 1,893,749	$ 1,912,871	$ 2,203,670	$ 2,259,049
SubTotal	**$ 3,377,025**	**$ 3,472,966**	**$ 3,620,493**	**$ 3,615,556**	**$ 3,861,773**	**$ 4,106,946**
%Change (year over year)			4.2%	-0.1%	6.8%	6.3%
%Change (Test Year vs Last Rebasing Year - Actual)						18.3%
Billing and Collecting	$ 2,061,053	$ 1,874,779	$ 1,768,363	$ 1,754,606	$ 1,874,259	$ 1,960,026
Community Relations	$ 35,700	$ 22,685	$ 14,503	$ 22,126	$ 25,300	$ 40,150
Administrative and General	$ 4,362,183	$ 3,493,634	$ 4,031,454	$ 4,126,646	$ 4,369,484	$ 4,437,601
SubTotal	**$ 6,458,936**	**$ 5,391,097**	**$ 5,814,320**	**$ 5,903,378**	**$ 6,269,043**	**$ 6,437,777**
%Change (year over year)			7.9%	1.5%	6.2%	2.7%
%Change (Test Year vs Last Rebasing Year - Actual)						19.4%
Total	**$ 9,835,961**	**$ 8,864,063**	**$ 9,434,813**	**$ 9,518,933**	**$ 10,130,816**	**$ 10,544,723**
%Change (year over year)			6.4%	0.9%	6.4%	4.1%

	Last Rebasing Year (2013 Board-Approved)	Last Rebasing Year (2013 Actuals)	2014 Actuals	2015 Actuals	2016 Bridge Year	2017 Test Year
Operations	$ 1,464,548	$ 1,533,641	$ 1,726,744	$ 1,702,685	$ 1,658,103	$ 1,847,897
Maintenance	$ 1,912,478	$ 1,939,325	$ 1,893,749	$ 1,912,871	$ 2,203,670	$ 2,259,049
Billing and Collecting	$ 2,061,053	$ 1,874,779	$ 1,768,363	$ 1,754,606	$ 1,874,259	$ 1,960,026
Community Relations	$ 35,700	$ 22,685	$ 14,503	$ 22,126	$ 25,300	$ 40,150
Administrative and General	$ 4,362,183	$ 3,493,634	$ 4,031,454	$ 4,126,646	$ 4,369,484	$ 4,437,601
Total	**$ 9,835,961**	**$ 8,864,063**	**$ 9,434,813**	**$ 9,518,933**	**$ 10,130,816**	**$ 10,544,723**
%Change (year over year)			6.4%	0.9%	6.4%	4.1%

Appendix 2-JA
Summary of Recoverable OM&A Expenses

	Last Rebasing Year (2013 Board-Approved)	Last Rebasing Year (2013 Actuals)	Variance 2013 BA vs. 2013 Actuals	2014 Actuals	Variance 2014 Actuals vs. 2013 Actuals	2015 Actuals	Variance 2015 Actuals vs. 2014 Actuals	2016 Bridge Year	Variance 2016 Bridge vs. 2015 Actuals	2017 Test Year	Variance 2017 Test vs. 2016 Bridge
Operations	$ 1,464,548	$ 1,533,641	-$ 69,093	$ 1,726,744	$ 193,103	$ 1,702,685	-$ 24,059	$ 1,658,103	-$ 44,582	$ 1,847,897	$ 189,794
Maintenance	$ 1,912,478	$ 1,939,325	-$ 26,847	$ 1,893,749	-$ 45,575	$ 1,912,871	$ 19,121	$ 2,203,670	$ 290,799	$ 2,259,049	$ 55,379
Billing and Collecting	$ 2,061,053	$ 1,874,779	$ 186,274	$ 1,768,363	-$ 106,416	$ 1,754,606	-$ 13,758	$ 1,874,259	$ 119,654	$ 1,960,026	$ 85,767
Community Relations	$ 35,700	$ 22,685	$ 13,015	$ 14,503	-$ 8,182	$ 22,126	$ 7,623	$ 25,300	$ 3,174	$ 40,150	$ 14,850
Administrative and General	$ 4,362,183	$ 3,493,634	$ 868,549	$ 4,031,454	$ 537,820	$ 4,126,646	$ 95,192	$ 4,369,484	$ 242,838	$ 4,437,601	$ 68,117
Total OM&A Expenses	$ 9,835,961	$ 8,864,063	$ 971,898	$ 9,434,813	$ 570,750	$ 9,518,933	$ 84,120	$10,130,816	$ 611,883	$ 10,544,723	$ 413,906
Adjustments for Total non-recoverable items (from Appendices 2-JA and 2-JB)											
Total Recoverable OM&A Expenses	$ 9,835,961	$ 8,864,063	$ 971,898	$ 9,434,813	$ 570,750	$ 9,518,933	$ 84,120	$10,130,816	$ 611,883	$ 10,544,723	$ 413,906
Variance from previous year				$ 570,750		$ 84,120		$ 611,883		$ 413,906	
Percent change (year over year)				6%		1%		6%		4%	
Percent Change: Test year vs. Most Current Actual						10.78%					
Simple average of %variance for all years						18.96%					4%
Compound Annual Growth Rate for all years											3.5%
Compound Growth Rate (2015 Actuals vs. 2013 Actuals)						2.40%					

OM&A COST DRIVER ANALYSIS

See Table 4.2.2.1 below for Appendix 2-JB of the Filing Requirements, along with explanations subsequent to the table. Within Table 4.2.2.1, CNPI has identified specific significant items that drive operating expenses either upwards or downwards. CNPI notes that in addition to the specific items in the table below, there is a general increase in operating expenses period over period that can be attributable to inflationary and related upwards pressures on expenses.

Table 4.2.2.1 Recoverable OM&A Cost Driver Table
Appendix 2-JB

OM&A	Last Rebasing Year (2013 Actuals)	2014 Actuals	2015 Actuals	2016 Bridge Year	2017 Test Year
Reporting Basis = ASPE					
Opening Balance	$ 9,835,961	$ 8,864,063	$ 9,434,813	$ 9,518,933	$ 10,130,816
CDM Staffing	$ (85,000)	$ 56,000		$ 26,000	
Vehicle Depreciation Credit	$ (351,000)	$ 351,000			
Approved IFRS Costs	$ (85,000)	$ 85,000			
Port Colborne Service Center Closure	$ (35,000)	$ (20,000)			
Regulatory Staffing	$ (100,000)				
Customer Service Staffing and Charge-outs	$ (92,000)	$ (70,000)	$ (30,000)	$ 30,000	
Collections and Bad Debts	$ (8,000)	$ (99,000)	$ 29,000	$ 49,000	$ 38,000
Shared Service Allocation		$ 63,000		$ 45,000	$ (11,000)
ON1Call Initiative		$ 40,000			
Vacant IT Position			$ (40,000)	$ 40,000	
IT Billable Costs			$ (28,000)	$ 28,000	
Pole Testing Program				$ 150,000	
MIST O&M				$ 44,000	
EAB Program					$ 100,000
Load Dispatching					$ 65,000
Asset Management					$ 30,000
Miscellaneous	(215,898)	164,750	153,120	199,883	191,906
Closing Balance	$ 8,864,063	$ 9,434,813	$ 9,518,933	$ 10,130,816	$ 10,544,723

CDM Staffing

<u>2013 Board Approved vs 2013 Actuals, 2014 Actuals vs 2013 Actuals, 2016 Bridge vs 2015 Actuals</u>

Decrease of $85k, Increase of $56k, Increase of $26k

As the CDM initiatives evolved and became more comprehensive, certain CNPI resources were required on a temporary basis to focus a portion of their effort on CDM related programs and initiatives. The decrease of $85k represents costs taken out of distribution and entered into CDM to account for the effort required to work on the roll-out of CDM including the establishment of a CDM department. The CDM costs have been tracked outside of OM&A reported within this Application; hence the decrease in 2013 Actuals as compared to 2013 Board Approved. The subsequent increase of $56k and $26k recognizes reduction of distribution staff effort with the establishment of a permanent CDM department and the return of those OM&A costs back to distribution.

Vehicle Depreciation Credit

<u>2013 Board Approved vs 2013 Actuals, 2014 Actuals vs 2013 Actuals</u>

Decrease of $351k, Increase of $351k

CNPI adopted MIFRS accounting effective January 1, 2013 as submitted with the last Cost of Service Application (EB-2012-0112). This accounting policy change resulted in the inclusion of vehicle depreciation within the burden rates calculated for operational departments. For 2013 Board Approved, CNPI classified the offsetting credit as a reduction in depreciation expense, whereas for 2013 Actuals, the credit was recorded within General and Administrative expenses. Per Board staff direction, in 2014, the vehicle credit was recorded as a reduction in depreciation expenses; hence the decrease of $351k and then the subsequent reversal of this amount the following year.

Approved IFRS Costs

<u>2013 Board Approved vs 2013 Actuals, 2014 Actuals vs 2013 Actuals</u>

Decrease of $85k, Increase of $85k

In CNPI's last Cost of Service Application (EB-2012-0112), the Board approved the recovery of IFRS costs incurred. CNPI had previously booked a provision against these costs and this provision was reversed in 2013.

Port Colborne Service Center Closure

<u>2013 Board Approved vs 2013 Actuals, 2014 Actuals vs 2013 Actuals</u>

Decrease of $35k, Decrease of $20k

In 2013, the Port Colborne service center was sold, and as a result an estimated annualized savings of approximately $55k in operating and maintenance expenses was realized, of which $35k was to be realized in 2013, with the remaining $20k recognized in 2014.

Regulatory Staffing

<u>2013 Board Approved vs 2013 Actuals</u>

Decrease of $100k

In 2013 Board Approved, CNPI had budgeted for a Senior Regulatory Specialist position. This position was initially filled during 2012 but subsequently became vacant. CNPI has not filled this vacant position since that time and this position is not budgeted for in the 2016 Bridge and 2017 Test years.

Customer Service Staffing and Charge-outs

<u>2013 Actuals vs 2013 Board Approved, 2014 Actuals vs 2013 Actuals, 2015 Actuals vs 2014 Actuals, 2016 Bridge vs 2015 Actuals</u>

Decrease of $92k, Decrease of $70k, Decrease of $30k, Increase of $30k

In 2013 Actuals, CNPI's headquarters in Fort Erie commenced the primary duties of the billing functions of its affiliate; Algoma Power Inc. ("API"). This meant a charge-out to API of time spent and a reduction in CNPI customer service expenses. Also during 2013, with the closure of CNPI's Port Colborne service center, efficiencies were gained and one FTE was reduced from the customer service department. An additional part-time customer service clerk position was eliminated with the automation of EBT. The decreases noted in the 2013 Actuals vs 2013 Board Approved and 2014 Actuals vs 2013 Actuals are explained by these items.

During 2015, additional capital work was performed by the customer service department including the IPL Project (CNPI Transmission) and OESP program implementation. These types of extraordinary capital projects are not expected to occur into the future, and therefore 2015 operating expenses were lower, but subsequently reversed in the 2016 Bridge year.

Collections and Bad Debts

<u>2013 Actuals vs 2013 Board Approved, 2014 Actuals vs 2013 Actuals, 2015 Actuals vs 2014 Actuals, 2016 Bridge vs 2015 Actuals, 2017 Test vs 2016 Bridge</u>

Decrease of $8k, Decrease of $99k, Increase of $29k, Increase of $49k, Increase of $38k

In 2014, CNPI outsourced its collections to a new collection agency as well as a second collection agency. Also, certain collection related functionality was automated within the billing system, and mailed reminder notices were discontinued. All of these contributed primarily to a $79k decrease in collections costs. Additionally, bad debt expenses were lower in 2014 Actuals as compared to 2013 Actuals.

Due to market conditions along with the fact that the Ontario Clean Energy Benefit program expired at the end of 2015, CNPI is forecasting increases in collection and bad debt expenses in 2016 and 2017.

Shared Service Allocation

<u>2014 Actuals vs 2013 Actuals, 2016 Bridge vs 2015 Actuals, 2017 Test vs 2016 Bridge</u>

Increase of $63k, Increase of $45k, Decrease of $11k

For 2014 Actuals, 2016 Bridge, and 2017 Test CNPI identified costs within its shared service allocation that were deemed to be costs specific to the Fort Erie service territory. Examples of these costs include Health and Safety specific training costs and union contract negotiation costs. These costs were therefore removed from the shared service allocation calculation; hence the increase in operating expenses to CNPI. Also, the 2017 Test Year operating expense decrease includes the impact of the updated shared service allocations, as outlined in the BDR report within Tab 5 of this Exhibit.

ON1Call Initiative

<u>2014 Actuals vs 2013 Actuals</u>

Increase of $40k

In accordance with the Ontario Underground Infrastructure Notification System Act, 2012, CNPI began supporting the Ontario One Call system by providing locates (and related information) in 2014. The incremental increase in operating costs to support this mandated initiative resulted in a $40k increase; most of which has been incurred as third party contracted services.

Vacant IT Position

2015 Actuals vs 2014 Actuals, 2016 Bridge vs 2015 Actuals

Decrease of $40k, Increase of $40k

During 2015, an IT position (IT Technician) position became vacant. This position is expected to be filled during 2016 which will restore operating costs back to normalized values.

IT Billable Costs

2015 Actuals vs 2014 Actuals, 2016 Bridge vs 2015 Actuals

Decrease of $28k, Increase of $28k

During 2015, the IT function performed additional billable support as part of a five year IT services agreement between CNPI and two associate companies. This effort is variable in nature and as a result 2015 operating expenses are approximately $28k lower than expected for 2016 Bridge and 2017 Test.

Pole Testing Program

<u>2016 Bridge vs 2015 Actuals</u>

Increase of $150k

Included in the 2016 Bridge Year and forward 5 years is the addition of CNPI`s detailed wood pole inspection and testing program. As discussed in section 5.2.2.2. of CNPI`s Distribution Asset Management Program, the program at an annual cost of approximately $75k will test all wood poles under certain criteria. The test results will help CNPI to develop a more effective pole replacement program.

An additional $75k has been budgeted to accommodate immediate pole repairs including Grade 1 repairs to pole guy guards, down grounds, anchors, crossarms, insulators and other associated materials identified during the pole inspection and testing program.

MIST O&M

<u>2016 Bridge vs 2015 Actuals</u>

Increase of $44k

In accordance with amendments to the DSC in 2014, in 2015 CNPI installed MIST meters that had a monthly peak demand over 50 kW, not including interval metered installations. Within Exhibit 9 of this Application CNPI details the incremental operating costs projected to be $44k in 2016.

EAB Program

<u>2017 Test vs 2016 Bridge</u>

The Emerald Ash Borer (EAB) Program is intended to manage burdens resulting from the infestation of Ash trees within CNPI's service territories. A $100,000 increase to operating expenses is anticipated as a result of the EAB Program. This program is focused on sustaining service reliability by proactively eliminating risks associated with this infestation and includes the following mitigation strategies:

- Completion of risk assessment
- Removal of infested tress on CNPI owned land
- Assisting stakeholders
  - Creation of electrically safe work zones
  - Additional Ash tree trimming in support of clearances for the purpose of removal
- Asset repairs as a result of Ash tree failure

The EAB Program is detailed in Section 5.2.4.2 of CNPI's Distribution Asset Management Program. (Appendix to DSP at Exhibit 2, Tab 2, Schedule 1, Appendix A)

Load Dispatching

<u>2017 Test vs 2016 Bridge</u>

Increase of $65k

In 2017, CNPI has budgeted for an increase in load dispatching efforts as a result of staff assuming on-call duties on a full time basis. Once training of Operations Techs to provide backup for CNPI's control room is complete, efforts will remain constant in order to facilitate the ongoing operation of CNPI's control room.

Asset Management

2017 Test vs 2016 Bridge

Increase of $30k

As the capital portion of the GIS system is being concluded, CNPI's estimates that there will be approximately $30k per year incurred to maintain the system.

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Appendix 2-L
Recoverable OM&A Cost per Customer and per FTE

	Last Rebasing Year (2013 Board-Approved)	Last Rebasing Year (2013 Actuals)	2014 Actuals	2015 Actuals	2016 Bridge Year	2017 Test Year
Reporting Basis						
Number of Customers	28,438	28,584	28,627	28,670	28,705	28,781
Total Recoverable OM&A from Appendix 2-JB	$ 9,835,961	$ 8,864,063	$ 9,434,813	$ 9,518,933	$ 10,130,816	$ 10,544,723
OM&A cost per customer	345.87	310.11	329.58	332.02	352.93	366.38
Number of FTEs	70.68	71.25	69.34	69.45	71.11	71.41
Customers/FTEs	402.34	401.20	412.84	412.83	403.65	403.07
OM&A Cost per FTE	$ 139,159.94	$ 124,414.93	$ 136,061.18	$ 137,066.36	$ 142,458.97	$ 147,674.68

Notes:

The customer numbers for 2013 Board Approved are taken from the Elenchus report from EB-2012-0112. 2013 Actuals and 2014 Actuals are taken from the Yearbook of Electricity Distributors. 2015 Actuals are taken as the average of OEB 2.1.2 RRR filings. 2016 Bridge and 2017 Test are taken from the Elenchus report provided within this Application. Consistent with the calculations within the OEB Yearbook, the number of customers is the sum of residential, GS<50, GS>50, and Embedded Distrubutor rate classes.

The FTEs for 2013 Board Approved, 2013 Actuals, 2014 Actuals, 2015 Actuals, 2016 Bridge and 2017 Test agree to the values in Appendix 2-K (Exhibit 4, Tab 4, Schedule 1, Appendix A) of this Application.

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PROGRAM DELIVERY COSTS WITH VARIANCE ANALYSIS

MATERIALITY

For the purpose of this variance analysis, the threshold has been set at $100,000, consistent with the calculations noted in Exhibit 1, Tab 5, Schedule 1.

OM&A PROOGRAM COSTS VARIANCE ANALYSIS

In Appendix 2-JC, CNPI presents a listing of its annual OM&A expenditures by Program, for the period from the last Board Approved rebasing year of 2013 to the 2017 Test Year. For each Program, variances are calculated between the 2017 Test Year budget and the 2013 Board Approved budget and between the 2017 Test Year budget and the 2015 Actual spending. Explanations for program variances that exceed the materiality threshold in appendix 2-JC are set out below.

Some of the variance explanations below include annual increases in labour and material. CNPI labour rates were specified based on the collective agreements. Additionally, fluctuations in US exchange rates have seen a substantial increase since 2013, putting upward pressure on certain material costs.

Variance Analysis 2017 Test Year budget vs. 2013 Board Approved budget

<u>Operations: Overhead</u>

Last Rebasing Year (2013 BA)	2017 Test Year	Variance (Test year vs. 2013 Board Approved)
90,368	202,592	112,224

Beginning in 2014, CNPI's Meter department redefined its comprehensive Power Quality program which focused on customer inquiries regarding flickering lights and/or voltage concerns. Metering department staff conduct an investigation and develop solutions to address customer inquiries in a timely manner. This program contributes approximately

$45,000 in labour charges to the variance and ensures that service entrance voltages are within acceptable limits as defined in CNPI's Conditions of Service. These labour charges include efforts previously allocated to Maintenance Supervision and Engineering, which have decreased as a result.

A realignment of accounts resulted in approximately $20,000 in line department labour efforts are now being allocated to Overhead Distribution Transformers-Operations. These efforts were previously allocated to Maintenance of Line Transformers, which decreased as a result.

Additionally, beginning in 2014, CNPI implemented its Infrared Scanning and Insulator Washing programs, resulting in $13,000 of ongoing, annual third party charges.

<u>Operations: Meters</u>

Last Rebasing Year (2013 BA)	2017 Test Year	Variance (Test year vs. 2013 Board Approved)
324,504	484,963	160,459

A $77,000 increase between CNPI's 2017 Test Year and CNPI's last rebasing is due to an increase in Utilismart Services and communication expenses across CNPI service territories, resulting from legislated requirement; *Metering Inside Settlement Timeframe* (MIST) and increased interval customer counts. Beginning in 2016, Utilismart Services include collection and settlement of MIST metering data.

CNPI anticipates an increase in customer disconnections in 2017 over 2013 and in response, has refined its credit, collection and customer disconnection processes. These refined processes are expected to increase efforts and contribute approximately $40,000 of increases to the variance.

Since 2013, labour rate increases have contributed approximately $12,000 of increase to the variance.

Operations: Miscellaneous Distribution Expenses

Last Rebasing Year (2013 BA)	2017 Test Year	Variance (Test Year vs. 2013 Board Approved)
216,778	373,291	156,513

2017 Test Year budget includes approximately $55,000 in overhead and underground rental expenses which were previously budgeted for under a variety of different areas on a per case basis.

Additionally, $60,000 in administrative labour charges pertaining to transformer inventory and mapping updates were budgeted for in 2017. These efforts were previously captured within the Maintenance Overhead, Supervision and Engineering accounts. The realignment of account settlement occurred during 2013 when Fort Erie and Port Colborne activity orders were merged into a consolidated listing.

Approximately $40,000 of labour efforts previously realized within Customer Service Billing, Collecting and Miscellaneous orders were reallocated to Operations: Miscellaneous Distribution Expenses. These efforts include Chapter 5 compliance, account management, variance analysis, scheduling of customer engagement, MicroFIT project management and other various operational activities. This reallocation of effort resulted in a decrease of the Customer Service Billing, Collecting and Miscellaneous orders.

Maintenance: Overhead

Last Rebasing Year (2013 BA)	2017 Test Year	Variance (Test Year vs. 2013 Board Approved)
1,060,695	1,504,565	443,870

The Emerald Ash Borer (EAB) Program is intended to manage burdens resulting from the infestation of Ash trees within CNPI's service territories. A $100,000 increase to operating expenses is anticipated as a result of the EAB Program. This program is focused on sustaining service reliability by proactively eliminating risks associated with this infestation and includes the following mitigation strategies:

- Completion of risk assessment
- Removal of infested tress on CNPI owned land
- Assisting stakeholders
    - Creation of electrically safe work zones
    - Additional Ash tree trimming in support of clearances for the purpose of removal
- Asset repairs as a result of Ash tree failure

The EAB Program is detailed in Section 5.2.4.2 of CNPI's Distribution Asset Management Program (Appendix to DSP at Appendix A).

Included in the 2017 Test Year and forward 4 years, is the addition of CNPI`s detailed wood pole inspection and testing program that started in 2016. As discussed in section 5.2.2.2. of CNPI`s Distribution Asset Management Program, the program at an annual cost of approximately $75,000, will test all wood poles under certain criteria. The test results will help CNPI to develop a more effective pole replacement program.

An additional, $75,000 has been budgeted to accommodate immediate pole repairs including Grade 1 repairs to pole guy guards, down grounds, anchors, crossarms, insulators and other associated materials identified during the pole inspection and testing program.

Since 2013, labour rate increases have contributed approximately $100,000 to the variance increase.

Account realignments have seen approximately $30,000 in annual charges settling under Maintenance: Overhead. These charges were previously realized in a number of areas, resulting in their decrease.

Administrative: Salaries and Related Expenses

Last Rebasing Year (2013 BA)	2017 Test Year	Variance (Test Year vs. 2013 Board Approved)
1,147,470	1,499,684	352,214

The increase of $352,000 from $1,147,000 2013 Board Approved to $1,500,000 for 2017 Test Year, is primarily the resultant of two main drivers; the creation of a Niagara operating center (merger of Fort Erie and Port Colborne operating centers) and general salary and related expense increases year-over-year.

In 2014, due to the fact that operationally the Fort Erie and Port Colborne service territories were being managed by the same group of employees (based out of the Fort Erie service center), a Niagara operating center was created and the tracking of operating costs specific to each of Fort Erie and Port Colborne service territories was discontinued. The impact that this had on Salaries and Related Expenses is that formerly the intercompany shared service allocations to Port Colborne (from Fort Erie) were credited out of Salaries and Related Expenses, and then with offsetting debits were recorded partially within this same category, and remaining debits recorded in Rent and Maintenance of Property, and Regulatory Expenses. The impact of this accounting change in 2014 (as compared to 2013 Board Approved) was a net debit (increase in Salaries and Related Expenses) of $186,000, a credit of $133,000 in Rent and Maintenance of Property, and a credit of $53,000 in Regulatory Expenses.

The remaining $166,000 represents a 14.5% (approx. 3.6% per annum) increase from 2013 Board Approved to 2017 Test Year and is primarily due to general salaries and related expense increases year-over-year.

Administrative: General Admin

Last Rebasing Year (2013 BA)	2017 Test Year	Variance (Test Year vs. 2013 Board Approved)
1,208,049	1,054,361	(153,688)

The decrease of $154,000 from $1,208,000 2013 Board Approved to $1,054,000 for 2017 Test Year is primarily the resultant of two main drivers; reduction of IT related maintenance agreements costs, and offset by general inflationary and other related increases year-over-year.

Administrative: Rent and Maintenance of Property

Last Rebasing Year (2013 BA)	2017 Test Year	Variance (Test Year vs. 2013 Board Approved)
1,082,478	952,915	(129,563)

The decrease of $130,000 from $1,082,000 2013 Board Approved to $953,000 for 2017 Test Year is primarily the resultant of three main drivers; the creation of a Niagara operating center (merger of Fort Erie and Port Colborne operating centers), the closure of the Port Colborne service center, and offset by inflationary and other related increases year-over-year.

As discussed in the Administration – Salaries and Related Expenses (net of transfers) variances above, in 2014 a Niagara operating center was created and the tracking of operating costs specific to each of Fort Erie and Port Colborne service territory was discontinued. This resulted in a credit of $133,000 in Rent and Maintenance of Property due to the elimination of the intercompany shared service allocations to Port Colborne.

Additionally, during 2013, the Port Colborne service center was sold, and as a result an estimated annualized savings of approximately $55,000 in operating expenses was realized, of which $35,000 was to be realized in 2013.

The offsetting $38,000 (3.5% or approx. 0.9% per annum) increase from 2013 Board Approved to 2017 Test Year primarily relates to inflationary and other related increases year-over-year.

Variance Analysis 2017 Test Year vs. 2015 Actuals

Operations: Meters

2015 Actuals	2017 Test Year	Variance (Test Year vs. 2015 Actuals)
359,287	484,963	125,676

2017 meter department operations activity increased $30,000 over 2015 activity as a result of a shift in efforts from capital to maintenance through the completion of the capital MIST metering project.

2017 also includes a $77,000 increase in Utilismart Services and communication expenses across CNPI service territories resulting from the addition of MIST metering points and increased interval customer counts.

Maintenance: Overhead

2015 Actuals	2017 Test Year	Variance (Test Year vs. 2015 Actuals)
1,145,709	1,504,565	358,856

The Emerald Ash Borer (EAB) Program is intended to manage burdens resulting from the infestation of Ash trees within CNPI's service territories. A $100,000 increase to operating expenses is anticipated as a result of the EAB Program. This program is focused on sustaining service reliability by proactively eliminating risks associated with this infestation and includes the following mitigation strategies:

- Completion of risk assessment
- Removal of infested tress on CNPI owned land
- Assisting stakeholders
    - Creation of electrically safe work zones
    - Additional Ash tree trimming in support of clearances for the purpose of removal
- Asset repairs as a result of Ash tree failure

The EAB Program is detailed in Section 5.2.4.2 of CNPI's Distribution Asset Management Program (Appendix to DSP at Appendix A).

Included in the 2017 Test Year and forward 4 years, is the addition of CNPI`s detailed wood pole inspection and testing program. As discussed in section 5.2.2.2. of CNPI`s Distribution Asset Management Program, the program at an annual cost of approximately $75,000 will test all wood poles under certain criteria. The test results will help CNPI to develop a more effective pole replacement program.

An additional $75,000 has been budgeted to accommodate immediate pole repairs including Grade 1 repairs to pole guy guards, down grounds, anchors, crossarms, insulators and other associated materials identified during the pole inspection and testing program.

In 2015, some of Gananoque service territory's maintenance efforts were delayed to ensure additional capital projects were completed. This resulted in an approximate $91,000 reduction in O&M spending.

Administrative: Salaries and Related Expenses

2015 Actuals	2017 Test Year	Variance (Test Year vs. 2015 Actuals)
1,373,995	1,499,684	125,689

The increase of $126,000 from $1,374,000 2015 Actuals to $1,500,000 for 2017 Test Year is primarily the resultant of three main drivers; a vacant IT position for a portion of 2015, additional IT billable work completed in 2015, and general salary and related expense increases year-over-year.

During 2015, an IT position (IT Technician) position became vacant. This position is expected to be filled during 2016. The impact of this vacant position was estimated to be a $40,000 decrease in 2015 operating expenses.

Also during 2015, the IT function performed additional billable support as part of a five year IT services agreement between Canadian Niagara Power Inc. and two associate companies, Grimsby and Westario Power. This effort is variable in nature and as a result, 2015 operating expenses are approximately $28,000 lower than expected.

The remaining $62,000 represents a 4.5% (approx. 2.25% per annum) increase from 2015 Actuals to 2017 Test Year and is primarily due to general salaries and related expense increases year-over-year.

Administrative: General Admin.

2015 Actuals	2017 Test Year	Variance (Test Year vs. 2015 Actuals)
926,846	1,054,361	127,514

The increase of $128,000 from $927,000 2015 Actuals to $1,054,000 for 2017 Test Year is primarily the resultant of one main driver; year over year variations in Office Supplies and Expenses (OEB 5620).

The 2017 Test Year forecast of $568,000 for Office Supplies and Expenses reflects a normalized average of the 3 historical years plus estimated inflationary and other related increases year-over-year. This forecast is approximately $121,000 higher than 2015 Actuals.

The above primarily explains the net increase of $128,000 in General Admin from 2015 Actuals to 2017 Test Year.

Appendix 2-JC
OM&A Programs Table

Programs	Last Rebasing Year (2013 Board-Approved)	Last Rebasing Year (2013 Actuals)	2014 Actuals	2015 Actuals	2016 Bridge Year	2017 Test Year	Variance (Test Year vs. 2015 Actuals)	Variance (Test Year vs. Last Rebasing Year (2013 Board-Approved)
Reporting Basis								
Operations								
Supervision and Engineering	151,373	21,436	95,309	70,274	64,726	125,073	54,800	(26,300)
Load Dispatching	259,040	283,868	272,190	280,924	163,129	201,457	(79,466)	(57,583)
Distribution Stations	249,151	281,886	237,483	248,695	266,058	290,004	41,309	40,853
Overhead	90,368	166,849	184,630	147,544	210,406	202,592	55,048	112,224
Underground	173,332	276,953	255,655	173,169	182,883	170,517	(2,652)	(2,816)
Meters	324,504	289,776	334,674	359,287	405,592	484,963	125,676	160,459
Miscellaneous Distribution Expense	216,778	212,872	346,803	422,793	365,308	373,291	(49,503)	156,513
Sub-Total	1,464,548	1,533,641	1,726,744	1,702,685	1,658,103	1,847,897	145,212	383,350
Maintenance								
Supervision and Engineering	98,183	123,446	24,520	33,812	10,704	22,193	(11,619)	(75,990)
Distribution Stations	189,439	133,611	167,171	237,026	201,769	165,081	(71,946)	(24,359)
Overhead	1,060,695	1,049,270	1,200,792	1,145,709	1,445,786	1,504,565	358,856	443,870
Underground	84,932	71,795	57,766	95,522	84,351	103,870	8,348	18,938
Transformers	95,141	124,816	76,671	31,679	29,902	35,141	3,462	(60,001)
Meters	380,487	431,316	366,828	369,007	411,157	408,200	39,193	27,713
Miscellaneous Distribution Expense	3,600	5,070	-	115	20,000	20,000	19,885	16,400
Sub-Total	1,912,478	1,939,325	1,893,749	1,912,871	2,203,670	2,259,049	346,178	346,571
Customer Service								
Supervision	167,557	148,484	147,872	135,935	158,638	165,581	29,646	(1,976)
Meter Reading	93,026	29,114	98,199	89,467	80,288	87,471	(1,995)	(5,555)
Billing and Collections	967,425	888,894	831,248	835,921	847,762	879,785	43,863	(87,640)
Bad Debts	252,000	208,129	188,227	218,239	241,000	262,000	43,761	10,000
Community Relations	40,700	26,414	17,007	34,295	28,300	43,150	8,855	2,450
Miscellaneous Customer Accounts	581,045	600,158	502,817	475,044	546,571	565,189	90,145	(15,857)
Sub-Total	2,101,753	1,901,193	1,785,370	1,788,901	1,902,559	2,003,176	214,275	(98,577)
Administration								
Salaries and Related Expenses (net of transfers)	1,147,470	777,961	1,401,197	1,373,995	1,495,054	1,499,684	125,690	352,214
General Admin	1,208,049	851,901	951,312	926,846	998,070	1,054,361	127,514	(153,688)
Rent and Maintenance of Property	1,082,478	1,001,422	907,742	976,829	988,742	952,915	(23,914)	(129,563)
Other Services Purchased	460,697	447,726	430,877	480,141	542,688	553,334	73,193	92,637
Regulatory Expenses	320,690	235,111	216,055	232,673	216,172	247,407	14,733	(73,284)
Sub-Total	4,219,384	3,314,122	3,907,183	3,990,485	4,240,725	4,307,701	317,216	88,317
Program Name #5								
							-	-
							-	-
							-	-
							-	-
							-	-
Sub-Total	-	-	-	-	-	-	-	-
Miscellaneous	137,799	175,783	121,767	123,992	125,759	126,900	2,908	(10,899)
Total	**9,835,961**	**8,864,063**	**9,434,813**	**9,518,933**	**10,130,816**	**10,544,723**	**1,025,789**	**708,762**

Notes:

1 Please provide a breakdown of the major components of each OM&A Program undertaken in each year. Please ensure that all Programs below the materiality threshold are included in

2 The applicant should group projects appropriately and avoid presentations that result in classification of significant components of the OM&A budget in the miscellaneous category

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EMPLOYEE COMPENSATION, INCENTIVE PLAN EXPENSES AND OTHER BENEFITS

OVERVIEW

This Exhibit 4, Tab 4, Schedule 1, provides an overview of CNPI's compensation framework including an outline of CNPI's approach to employee incentive pay. Appendix 2-K (Employee Costs) provides a summary of total compensation costs from 2013 Board Approved to 2017 Test Year. Exhibit 4, Tab 4, Schedule 1, Appendix B (Compensation Variance Analysis) provides an explanation of year-over-year variances. Exhibit 4, Tab 4, Schedule 1, Appendix C (HayGroup Letter) projects 2017 salary increases. Exhibit 4, Tab 4 Schedule 2 (Pension and Post-Retirement Benefits) outlines the status of CNPI's pension funding and assumptions used in the analysis.

BASE PAY COMPENSATION – EXECUTIVE, MANAGEMENT, NON-UNION STAFF

Overall compensation for all employees of CNPI is designed to reflect market compensation to be competitive so as to attract and retain qualified personnel. Overall compensation includes base pay and a portion of the pay which is at risk. The following outlines the process followed by the Company in making changes to Executive, Management and Non-Union Compensation.

CNPI uses the Hay Method of position evaluation. The Hay Method of job evaluation is the most widely used job measurement system in the world. Position evaluations for the FortisOntario President and CEO and Vice President positions were established by the HayGroup. Management and Non-Union positions are evaluated jointly with Hay trained personnel.

CNPI uses a reference community of participants in the Hay Compensation Comparison. CNPI uses this reference community to establish the market rates for similar positions in Ontario. To attract and retain qualified staff, the Company sets midpoint salaries using a policy line recommended by the HayGroup management consultants. Actual salaries are set by reference to these recommendations and based on corporate and individual performance.

For members of the Executive, the Board of Directors of FortisOntario considers Hay compensation data and other policies to validate that the compensation practices are market competitive. All Executive salaries are set and all increases must be approved by the Board of Directors of FortisOntario.

Salary increases are based on market information provided by the HayGroup. The resulting salaries are reflective of base compensation for comparable-sized positions in the national marketplace. All salaries are approved by senior management and/or the Board of Directors as applicable. Executive and Management employees are not paid overtime.

SHORT-TERM INCENTIVE COMPENSATION AVAILABLE TO MANAGEMENT AND NON-UNION STAFF

Description

One element of CNPI's overall compensation package is incentive compensation. Implicit in the analysis contained in the HayGroup management consultant's recommendations is the fact that incentive compensation is a normal component of compensation for management positions in Canadian corporations.

Incentive compensation for all employees for CNPI reflects an element of compensation put at risk to elicit and sustain continued good performance. The more senior the employee, the greater the percentage of overall compensation is put at risk.

Application

The short-term incentive ("STI") plan is available to the Executive, Management and Non-Union staff of CNPI. Unionized employees do not participate in the STI plan and do not receive incentive compensation.

Format

CNPI's STI plan includes both an individual and a corporate component for all Executive, Management and Non-Union staff. Key aspects of this plan together with the targets are outlined below.

Minimum Corporate Performance Criterion

Prior to any incentive payments being made, a minimum corporate performance criterion, or trigger, must be reached. CNPI must achieve a pre-determined corporate threshold/target as approved by the Board of Directors of FortisOntario; otherwise, no incentive payments will be made. For more information on these criterion, see "Corporate Targets" below.

PAYOUT SUMMARY

Basis

Table 4.4.1.1 Corporate Targets

POSITION	STI PAYOUT % OF BASE SALARY	
	Target Payout 100%	**Maximum Payout 150%**
President & CEO	50%	75%
Vice Presidents	35%	52.5%
Managers	15%	22.5%
Other Management/Non-Union	7.5%	11.25%

The normal maximum payout is 150% of the targeted amount. There is no payout if performance falls below the 50% target level.

The individual performance component is designed to better reflect the degree of opportunity which employees in each management group have to influence corporate performance. The weighting for the individual component will vary by position level.

Table 4.4.1.2 STI Weighting

POSITION	STI WEIGHTING	
	Corporate Targets	Individual Targets
President and CEO	70%	30%
Vice Presidents	50%	50%
Management Staff	25%	75%

The incentive regime is structured in a manner that emphasizes the greater ability of the more senior individuals to affect corporate performance by making a greater portion of their compensation dependent on corporate as opposed to individual performance. For the President and CEO, 70% of the incentive opportunity is based on corporate performance and 30% on individual performance. For the Vice Presidents, the split is 50% corporate and 50% individual. For Management staff the split is 25% corporate and 75% individual.

Corporate Targets

Corporate targets may include the following: cost reduction, capital project completion, customer service, safety and environment, regulatory compliance, employee training, and reliability. Accordingly, all corporate incentive payments included in the 2013 Actual to 2017 Test Year relate to benefits to ratepayers as described below. Corporate measures have three performance levels and are reflective of key corporate targets or goals.

Each of the corporate targets benefits the ratepayers. In particular, the cost reduction measure sets targets for maintaining or reducing operating costs. The capital project measure sets targets for meeting budgeted capital project costs, and completing projects with respect to scope and schedule. These measures are primarily customer-related as they represent a cost reduction target that directly benefits ratepayers through lower rates or rates that could otherwise be higher. Customer service corporate measures ensure efficient and effective levels of service that meet Board standards and service quality indices. Safety and environmental measures benefit the ratepayer by minimizing high risk incidents and promoting a proactive approach to managing safety and the environment. Regulatory compliance primarily benefits ratepayers as it ensures reliable supply of electricity, and efficient customer service at approved rates. Employee training primarily benefits ratepayers by ensuring that ratepayers receive appropriate service levels from employees by keeping abreast of various job-related skills including regulatory, safety and environmental, technical and customer service related policies and procedures. Reliability measures primarily benefit the ratepayer by ensuring a reliable supply of electricity.

Individual Targets

Individual targets, like the corporate targets, support the broader design objective of aligning the interests of all stakeholder groups in CNPI with an overall focus on efficient delivery of service to customers.

Individual measures are developed in consultation with individuals and their immediate superiors. Each measure has three performance levels, is reflective of key projects or goals and focuses on departmental or divisional priorities. Individual measures may include the following: human resources, safety and environment, reliability, regulatory compliance, customer service, efficiencies, capital project completion, cost reduction and training targets. These measures primarily benefit ratepayers for the reasons discussed herein. Human resources primarily benefit the ratepayer by ensuring that skilled personnel are recruited and retained to provide safe and reliable service and to maintain service levels. Cost reduction, capital project and efficiency measures relate to maintaining or reducing operating costs which flow directly to the ratepayer through stable rates. Safety and environment, training, reliability, regulatory compliance and customer service measures directly benefit ratepayers in the form of a safe and reliable supply of electricity in compliance with regulations and established customer service levels.

Assessment and Payment

The Board of Directors of FortisOntario, CNPI's parent company, approves the corporate targets for all participants and the individual targets for the Executive. Corporate measures are reflective of key corporate targets or goals and are approved annually by the Board of Directors of FortisOntario. Actual corporate performance is assessed and approved annually by the Board of Directors of FortisOntario. Actual performance against individual targets is evaluated by the individual's immediate superior. The President and Chief Executive Officer makes recommendations in relation to the Vice Presidents' individual awards. The Board of Directors of FortisOntario makes recommendations and approves the President and Chief Executive Officer award, and reviews the recommendations and approves payments respecting the Vice Presidents. Payments will be made generally in February, once all corporate and individual performance measures of the financial year have been finalized. CNPI budgets for incentive payments at target payment levels.

OTHER BENEFITS

Other benefits include employer portion of Canadian Pension Plan, employer portion of Employment Insurance, Employee Health Tax expense, WSIB expense, defined contribution pension expense, insurance benefit, extended health and dental care plan expense, defined benefit pension expense, post-retirement benefit, share purchase plan top-up expense, wellness reimbursements (fitness memberships) and employee assistance plan services.

COMPENSATION FOR UNIONIZED EMPLOYEES

Unionized employees of CNPI (Niagara) and CNPI (EOP) are both represented by Local Union 636 of the International Brotherhood of Electrical Workers ("IBEW Local 636"). The terms of employment, including compensation, overtime and benefits are set out in two collective agreements between CNPI and IBEW Local 636 entered into June 1, 2012 – February 29, 2016 (Niagara), and August 1, 2012 – July 31, 2016 (EOP). Unionized employees for CNPI (Niagara) received 2.8% on June 1, 2012, 2.9% on June 1, 2013, 3% on June 1, 2014 and 3.1% on June 1, 2015. CNPI (EOP) employees received 2.8% on August 1, 2012, 2.9% on August 1, 2013, 3% on August 1, 2014 and 3.1% on August 1, 2015. Negotiations were recently completed for CNPI (Niagara) with an agreement entered into from March 1, 2016 through to February 28, 2019 with 2% increases each year. Negotiations are currently scheduled to renew the CNPI (EOP) collective agreement with IBEW Local 636 during the summer of 2016.

APPENDICES

Attached to this Schedule are the following Appendices:

- Appendix A 2-K (Employee Costs)
- Appendix B – Compensation Variance Analysis
- Appendix C – HayGroup Letter

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Appendix 2-K
Employee Costs

	Last Rebasing Year - 2013- Board Approved (1)	2013 Approved Restated (1)	2013 Actual	2014 Actual	2015 Actual	2016 Bridge Year	2017 Test Year
Number of Employees (FTEs including Part-Time)							
Management (including executive)	21.85	15.12	15.86	14.81	12.95	13.28	13.43
Non-Management (union and non-union)	66.35	55.57	55.39	54.53	56.50	57.83	57.98
Total	88.20	70.68	71.25	69.34	69.45	71.11	71.41
Total Salary and Wages including overtime and incentive pay							
Management (including executive) (2)	$ 2,783,596		$ 1,669,248	$ 1,698,156	$ 1,593,693	$ 1,609,427	$ 1,671,147
Non-Management (union and non-union) (2)	$ 4,629,939		$ 4,440,690	$ 4,467,960	$ 4,944,323	$ 5,049,737	$ 5,215,544
Total	$ 7,413,535		$ 6,109,938	$ 6,166,116	$ 6,538,015	$ 6,659,164	$ 6,886,691
Total Benefits (Current + Accrued)							
Management (including executive)	$ 657,117		$ 491,598	$ 457,838	$ 411,373	$ 417,062	$ 452,780
Non-Management (union and non-union)	$ 1,466,883		$ 1,525,441	$ 1,475,997	$ 1,567,299	$ 1,560,883	$ 1,701,780
Total	$ 2,124,000		$ 2,017,039	$ 1,933,835	$ 1,978,672	$ 1,977,944	$ 2,154,560
Total Compensation (Salary, Wages, & Benefits)							
Management (including executive)	$ 3,440,713		$ 2,160,846	$ 2,155,994	$ 2,005,066	$ 2,026,489	$ 2,123,927
Non-Management (union and non-union)	$ 6,096,822		$ 5,966,131	$ 5,943,956	$ 6,511,622	$ 6,610,620	$ 6,917,324
Total	$ 9,537,535		$ 8,126,977	$ 8,099,951	$ 8,516,688	$ 8,637,108	$ 9,041,251

(1) The 2013 Board Approved numbers in EB-2012-0112 as presented was based on all CNPI employees (i.e. headcount) whose time is allocated to CNPI Tx as well as other business units within FortisOntario. In this application, beginning with the Board Approved Restated, CNPI included FTEs allocated to CNPI Dx.

(2) The allocation of management and non-management compensation is based on FTE ratios.

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COMPENSATION VARIANCE ANALYSIS

CNPI has prepared Appendix 2-K using total FTEs. This includes FTEs that are employees of CNPI as well as other FortisOntario employees allocating hours to the CNPI distribution business.

FTE VARIANCE SUMMARY

The FTE's for the 2013 Board Approved have been restated because the Board Approved FTE numbers in CNPI's 2013 cost of service application (EB-2012-0112) were based on all CNPI employees (i.e. headcount) whose time is allocated to CNPI's Transmission business unit, as well as other business units within FortisOntario. In this Application, CNPI includes only those FTE's allocated to its Distribution business unit.

The number of FTEs from the 2013 Board Approved (restated) to the 2017 Test Year has increased by 0.7 FTE's, a 1.0% increase.

CNPI's FTEs have fluctuated over the years as a result of retirements, turnover and departmental reorganizations to create efficiencies while continuing to meet workloads. FTE variance is also explained by the change in actual workload allocations to the CNPI distribution business.

2013 Board Approved (restated) to 2013 Actual

As discussed above, 2013 Board Approved (restated) was recalculated based on FTE's solely allocated to CNPI distribution business. There was a 0.6 (or 0.8%) increase of FTE's from 2013 Board Approved (restated) to 2013 Actual. This change was mainly attributable to the net effect of an increase in Engineering FTE's (1.9) which included the hiring of two engineers in-training as well as an increase in Transmission and Distribution Operations FTE's (0.9)., offset mainly by a decrease in Information Technology FTE's (1.1) including the termination of an Information Technology Administrator and a decrease in Customer Service FTE's (1.3) due to the closure of the Port Colborne office.

2013 Actual to 2014 Actual

From 2013 Actual to 2014 Actual there was a 1.9 (or 2.7 %.) decrease in FTE's. This change is mainly attributable to a net effect of a decrease in Transmission and Distribution Operations FTE's (1.1) including retirements and a decrease in Customer Service FTE's (1.4) due to the closure of the Port Colborne office, offset by an increase in Engineering FTE's (0.7).

2014 Actual to 2015 Actual

From 2014 Actual to 2015 Actual there was a 0.1(or 0.2%) increase in FTE's. This can be attributed to slight changes in Transmission and Distribution Operations and Engineering FTE's.

2015 Actual to 2016 Bridge

From 2015 Actual to 2016 Bridge Year there was a 1.7 (or 2.4%) increase in FTE's. The main contributor to this increase is the hiring of a lineman apprentice for succession planning, as well as the hiring of a new electrician in the last quarter of 2015.

2016 Bridge to 2017 Test

From the 2016 Bridge Year to 2017 Test Year, CNPI forecasts an increase of 0.3 (or 0.4%) FTE's. This is the net result of slight allocation changes across several departments.

Total Salary and Wages

On average, total salary and wages will increase 3% year over year from 2013 Actual to 2017 Test Year. There are two drivers to the average increase in total salaries and wages allocated to CNPI Distribution. The first driver is as set out above, the changes in allocated FTE's. The second driver is the effect of individual progressions and economic adjustments to the salaries and wages paid to the employees.

Negotiated collective bargaining unit increases and details regarding non-union and management salary increases and incentive payment structure are described in 'Employee Compensation, Incentive Plan Expenses and Other Benefits' at Exhibit 4, Tab 4, Schedule 1.

Total Benefits

Total benefits increase on average 1.7% year over year from 2013 Actual to 2017 Test Year. The contributors of this would be the following: the corresponding benefit and pension increases to wage increases; annual increase of premiums for Extended Health and Dental Plan; as well as the increase in post-retirement expenses. The 9% forecasted increase in total benefits from the 2016 Bridge Year to the 2017 Test Year is partially attributable to the defined benefit pension expense increase as provided by Mercers including the reduction in the expected long-term rate of return on the plan assets (see Exhibit 4, Tab 4, Schedule 2).

Total Compensation Variance

The average increase in total salary and wages allocated to CNPI Dx from 2013 Actual to 2017 Test Year is 2.7% annually.

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Appendix C
Hay Group Letter

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www.Hay Group.com/ca

October 7, 2015

Ms. Kristine Carmichael
Manager, Human Resources, Customer Service & Corporate Communications
FortisOntario Inc.
1130 Bertie Street
P.O. Box 1218
Fort Erie, Ontario
L2A 5Y2

Dear Kristine,

Re: 2017 Salary Projection for Canadian Niagara Power

Hay Group Limited ("Hay Group") has been asked by FortisOntario Inc. ("FortisOntario") to provide an estimate of base salary increases for 2017.

Methodology

Annually, we provide salary increase forecasts based on survey responses from our database participants collated in August / September (the "Compensation Planning Update") each year. Our most recent Compensation Planning Update (September 2015) forecasts 2016 salary increases. 2017 projections from this source will not be available until September 2016.

In lieu of this data source for forecasting base salary increases for 2017, we performed various scenario analyses on historical base salary movement as compared to key Canadian economic indicators, including:

1) The relationship between historical industrial base salary movements in the Hay Group database and movements in the Canadian Headline Consumer Price Index ("Headline CPI");
2) The historical spread between industrial base salary movements in the Hay Group database and the Headline CPI; and
3) The relationship between historical industrial base salary movements in the Hay Group database and Canadian Real Gross Domestic Product ("Real GDP") growth.

Based on the resulting arithmetic differentials and regression analyses, we have applied our findings to the latest forecasts for Canadian Headline CPI and Real GDP growth in 2017 published by the Bank of Canada and large Canadian financial institutions. A range of projected base salary increases were calculated in consideration of these analyses as well as the historic salary increase pattern among utilities organizations in the Hay Group database.

2017 Salary Forecast

Based on currently available information, we project actual base salary increases to range between 2.6% and 2.9%, with an average of 2.76%, for 2017.

Our estimates are based on the projected growth of the Canadian economy, using a compilation of the latest available economic data. With falling commodity and oil prices, there is still considerable volatility facing the Canadian economy and actual 2017 salary increases may be subject to change as companies continue to adjust their compensation planning based on economic and market conditions through the end of 2016.

Kristine, we trust this is of assistance to you. Please feel free to contact us to discuss the contents of this letter or the underlying analyses supporting our opinion.

Best Regards,

HAY GROUP LIMITED

Christopher Chen, LLB
National Director
Executive Compensation

Kennedy Lee
Consultant
Executive Compensation

PENSION EXPENSE AND POST RETIREMENT BENEFITS EXPENSE

PENSION EXPENSE

CNPI participates in three pension plans; a defined benefit plan, a defined contribution plan, and the Ontario Municipal Employees Retirement System ("OMERS").

The FortisOntario Inc. Combined Pension Fund, registered under the Pension Benefits Act (Ontario), 1990, is the asset trust fund for two pension plans sponsored by FortisOntario Inc. The first, the FortisOntario Inc. Employees' Retirement Plan ("Employees' Retirement Plan") is a defined benefit plan to which RBC serves as Trustee. The second is the FortisOntario Supplementary Retirement Plan, a defined contribution plan to which Sun Life Financial serves as Trustee. Mercer's Human Resource Consulting ("Mercers") serves as the actuary.

The FortisOntario Inc. Combined Pension Fund includes retired employees of FortisOntario and CNPI, and active employees of CNPI. The allocation of pension costs is determined by Mercers.

Employees' Retirement Plan

The plan is available to all employees hired prior to July 1, 1999. Funding is based on a tri-annual actuarial valuation. The last valuation was completed on December 31, 2014 (See Exhibit 4, Tab 4, Schedule 2, Appendix A). A member will receive an annual pension determined on a prescribed formula based primarily on the number of years of credited service and earnings.

Defined Benefit Pension Expense

	2013 Actual	2013 Board Approved	2014 Actual	2015 Actual	2016 Bridge Year	2017 Test Year
Pension expense	618,000	512,362	519,506	506,864	203,736	430,524
Funded status-surplus	1,086,000	660,597	3,697,838	4,618,851	5,497,296	5,607,242

Significant assumptions used:

Discount rate	**4.75%**	**5.10%**	**4.75%**	**4.75%**	**4.75%**	**4.75%**
Expected long-term rate of return on plan assets	**6.00%**	**6.25%**	**6.00%**	**5.50%**	**5.50%**	**5.00%**
Rate of compensation increase	**4.00%**	**4.00%**	**4.00%**	**4.00%**	**3.50%**	**3.50%**
Average remaining service period of active employees [years]	**6**	**6**	**5**	**5**	**4**	**3**

The defined benefit pension expense amounts are prepared for CNPI by Mercers. In February 2016, Mercers provided updated estimates of the 2016 and 2017 pension expense amounts based on current known market information as of January 31, 2016.

Supplementary Retirement Plan

This plan is available to employees who are not currently enrolled in the OMERS plan after completing six months of employment. Members of the Employees' Retirement Plan, as described above, may make contributions to the Supplementary Pension Plan ranging from 2% to 6% of their basic earnings. CNPI matches 50% of the members' contribution.

Eligible employees who are not members of the Employees' Retirement Plan may contribute to the Supplementary Retirement Plan from 1% to a maximum of 6.5% of their annual basic earnings. CNPI matches 100% of the members' contribution. Contributions cannot exceed the overall maximum under the Income Tax Act (Canada).

Defined Contribution Pension Expense

DC Pension	2013 Actual	2013 Board Approved	2014 Actual	2015 Actual	2016 Bridge Year	2017 Test Year
Pension premiums	242,654	218,544	255,366	272,475	247,704	255,132

OMERS

Employees who were enrolled in OMERS at the time of a lease, merger or an acquisition with CNPI are eligible for the OMERS plan.

OMERS Pension Expense

	2013 Actual	2013 Board Approved	2014 Actual	2015 Actual	2016 Bridge Year	2017 Test Year
Pension premiums	151,352	111,998	155,860	166,843	164,904	169,848

POST RETIREMENT BENEFITS EXPENSE

CNPI provides certain health, dental, and life insurance benefits, under unfunded defined benefits plans, on behalf of its retired employees. The post retirement benefit expense amounts are prepared for CNPI by Mercers. In February 2016, Mercers provided updated estimates of the 2016 and 2017 post retirement benefit expense amounts.

Post-Retirement Benefits Expense

Post-retirement Benefits	2013 Actual	2013 Board Approved	2014 Actual	2015 Actual	2016 Bridge Year	2017 Test Year
Post-retirement benefit expense	451,600	430,100	470,600	591,800	620,700	563,004
Funded status-(deficit)	(6,498,000)	(5,770,900)	(6,651,600)	(7,402,200)	(7,535,700)	(7,686,400)

Significant assumptions used:						
Discount rate	**4.75%**	**5.25%**	**4.75%**	**4.75%**	**4.75%**	**4.75%**
Assumed health care trend rate	**4.50%**	**4.50%**	**4.50%**	**4.50%**	**4.50%**	**4.50%**
Average remaining service period of active employees [years]	**17**	**15**	**16**	**17**	**15**	**14**

APPENDIX A

Recent Actuary Report

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MERCER

MAKE TOMORROW, TODAY

FORTISONTARIO INC. EMPLOYEES' RETIREMENT AND SUPPLEMENTARY PENSION PLAN

REPORT ON THE ACTUARIAL VALUATION FOR FUNDING PURPOSES AS AT DECEMBER 31, 2014

SEPTEMBER 23, 2015

Financial Services Commission of Ontario Registration Number: 0271247
Canada Revenue Agency Registration Number: 0271247

MARSH & McLENNAN COMPANIES

Note to reader regarding actuarial valuations:

This valuation report may not be relied upon for any purpose other than those explicitly noted in the Introduction, nor may it be relied upon by any party other than the parties noted in the Introduction. Mercer is not responsible for the consequences of any other use. A valuation report is a snapshot of a plan's estimated financial condition at a particular point in time; it does not predict a pension plan's future financial condition or its ability to pay benefits in the future. If maintained indefinitely, a plan's total cost will depend on a number of factors, including the amount of benefits the plan pays, the number of people paid benefits, the amount of plan expenses, and the amount earned on any assets invested to pay the benefits. These amounts and other variables are uncertain and unknowable at the valuation date. The content of the report may not be modified, incorporated into or used in other material, sold or otherwise provided, in whole or in part, to any other person or entity, without Mercer's permission. All parts of this report, including any documents incorporated by reference, are integral to understanding and explaining its contents; no part may be taken out of context, used, or relied upon without reference to the report as a whole.

To prepare the results in this report, actuarial assumptions are used to model a single scenario from a range of possibilities for each valuation basis. The results based on that single scenario are included in this report. However, the future is uncertain and the plan's actual experience will differ from those assumptions; these differences may be significant or material. Different assumptions or scenarios within the range of possibilities may also be reasonable, and results based on those assumptions would be different. Furthermore, actuarial assumptions may be changed from one valuation to the next because of changes in regulatory and professional requirements, developments in case law, plan experience, changes in expectations about the future, and other factors.

The valuation results shown in this report also illustrate the sensitivity to one of the key actuarial assumptions, the discount rate. We note that the results presented herein rely on many assumptions, all of which are subject to uncertainty, with a broad range of possible outcomes, and the results are sensitive to all the assumptions used in the valuation.

Should the plan be wound up, the going concern funded status and solvency financial position, if different from the wind-up financial position, become irrelevant. The hypothetical wind-up financial position estimates the financial position of the plan assuming it is wound up on the valuation date. Emerging experience will affect the wind-up financial position of the plan assuming it is wound up in the future. In fact, even if the plan were wound up on the valuation date, the financial position would continue to fluctuate until the benefits are fully settled.

Decisions about benefit changes, granting new benefits, investment policy, funding policy, benefit security, and/or benefit-related issues should not be made solely on the basis of this valuation, but only after careful consideration of alternative economic, financial, demographic, and societal factors, including financial scenarios that assume future sustained investment losses.

Funding calculations reflect our understanding of the requirements of Pension Benefits Act, the Income Tax Act, and related regulations that are effective as of the valuation date. Mercer is not a law firm, and the analysis presented in this report is not intended to be a legal opinion. You should consider securing the advice of legal counsel with respect to any legal matters related to this report.

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Summary of Results – excluding DC Component

	31.12.2014	31.12.2011
Going Concern Financial Status		
Market value of assets	$29,900,381	$22,788,818
Going concern funding target	$23,669,985	$24,247,727
Funding excess (shortfall)	$6,230,396	($1,458,909)
Hypothetical Wind-up Financial Position		
Wind-up assets	$29,825,381	$22,713,818
Wind-up liability	$27,959,666	$27,090,174
Wind-up excess (shortfall)	$1,865,715	($4,376,356)
Funding Requirements in the Year Following the Valuation [1]		
Total current service cost	$317,845	$343,722
Expense allowance	$175,000	$175,000
Total	$492,845	$518,722
Employer's current service cost as a percentage of members' pensionable earnings	19.7%	18.7%
Minimum special payments	$0	$1,159,933
Estimated minimum employer contribution	$0	$1,678,655
Estimated maximum eligible employer contribution	$0	$4,895,078
Next required valuation date	31.12.2017	31.12.2014

[1] Provided for reference purposes only. Contributions must be remitted to the Plan in accordance with the Minimum Funding Requirements and Maximum Eligible Contributions sections of this report.

2

Introduction

To FortisOntario Inc.

At the request of FortisOntario Inc., we have conducted an actuarial valuation of the FortisOntario Inc. Employees' Retirement and Supplementary Pension Plan (the "Plan"), sponsored by FortisOntario Inc. (the "Company"), as at the valuation date, December 31, 2014. We are pleased to present the results of the valuation.

Purpose

The purpose of this valuation is to determine:

- The funded status of the plan as at December 31, 2014 on going concern, hypothetical wind-up, and solvency bases;
- The minimum required funding contributions from January 1 2015 to December 31, 2017, in accordance with the *Pension Benefits Act* (the "Act"); and
- The maximum permissible funding contributions from 2015, in accordance with the *Income Tax Act.*

The information contained in this report was prepared for the internal use of the Company, and for filing with the Financial Services Commission of Ontario and with the Canada Revenue Agency, in connection with our actuarial valuation of the Plan. This report will be filed with the Financial Services Commission of Ontario and with the Canada Revenue Agency. This report is not intended or suitable for any other purpose.

In accordance with pension benefits legislation, the next actuarial valuation of the Plan will be required as at a date not later than December 31, 2017, or as at the date of an earlier amendment to the Plan.

Terms of Engagement

In accordance with our terms of engagement with the Company, our actuarial valuation of the Plan is based on the following material terms:

- It has been prepared in accordance with applicable pension legislation and actuarial standards of practice in Canada
- As instructed by the Company, the going concern discount rate reflects a margin for adverse deviations of 0.60% per year
- We have reflected the Company's decisions for determining the solvency funding requirements, summarized as follows:
- The same plan wind-up scenario was hypothesized for both hypothetical wind-up and solvency valuations.
- Although permissible, no benefits were excluded from the solvency liabilities.
- The solvency financial position was determined on a market value basis.
- No funding relief measures have been applied.

See the Valuation Results - Solvency section of the report for more information.

Events since the Last Valuation at December 31, 2011

Pension Plan

There have been no special events since the last valuation date.

This valuation reflects the provisions of the Plan as at December 31, 2014. The Plan has not been amended since the date of the previous valuation. However the Plan will be amended to reflect changes in the Act. We are not aware of any other pending definitive or virtually definitive amendments coming into effect during the period covered by this report. The Plan provisions are summarized in Appendix F.

Assumptions

We have used the same going concern valuation assumptions and methods as were used for the previous valuation, except for the following:

	Current valuation	**Previous valuation**
Inflation:	2.00%	2.50%
ITA limit / YMPE increases:	3.00%	3.50%
Pensionable earnings increases:	3.50%	4.00%
Mortality rates:	100% of the rates of the 2014 Private Sector Canadian Pensioners Mortality Table (CPM2014Priv)	100% of the rates of the 1994 Uninsured Pensioner Mortality Table
Mortality improvements:	Fully generational using CPM Improvement Scale B (CPM-B)	Fully generational using Scale AA

A summary of the going concern methods and assumptions is provided in Appendix C.

The hypothetical wind-up and solvency assumptions have been updated to reflect market conditions at the valuation date. A summary of the hypothetical wind-up and solvency methods and assumptions is provided in Appendix D.

Regulatory Environment and Actuarial Standards

There have been a number of changes to the Act and regulations which impact the funding of the Plan.

The Government of Ontario has announced its intentions to makes changes to the funding requirements for pension plans registered in Ontario. Since then Bill 120 received Royal assent. However, the intended changes to the funding requirements which impact the funding of single-employer pension plans will be contained in regulations which have not yet been adopted.

Effective July 1, 2012, the *Pension Benefits Act (Ontario)* and the Regulations to the Act were amended to require plans to provide immediate vesting to all Ontario plan members and to provide grow-in benefits to certain Ontario members whose employment is terminated at the initiation of their employer. The plan will be amended to reflect these requirements. The cost of these legislated minimum benefit improvements has been reflected in the valuation. The cost of these legislated minimum benefit improvements did not increase the going concern funding target nor the current service cost since no pre-retirement decrements are assumed.

The Regulations to the Pension Benefits Act were amended in November 2012 to reflect previously announced changes. The measures introduced are as follows:

On a permanent basis, the regulations were amended to:

- Permit solvency and going concern special payments to be amortized beginning up to one year after the valuation date;
- Permit the use of irrevocable letters of credit from financial institutions to cover solvency deficiencies up to 15 per cent of a plan's solvency liabilities, in lieu of special payments to eliminate the deficiency over the prescribed period.

CIA Transfer Value

On December 4, 2014, the Actuarial Standards Board has issued a memorandum on the promulgation of the mortality table referenced in the Canadian Institute of Actuaries Standards of Practice for Pension Plans in respect of the computation of pension commuted values ("CIA CV Standard") for calculations from August 1, 2015. On April 27, 2015, the Actuarial Standards Board advised that the effective date of the change will be deferred from August 1, 2015 to October 1, 2015. The proposed change affects the mortality assumption used to value the solvency and wind-up liabilities for benefits assumed to be settled through a lump sum transfer. The financial impact of the proposed change in the CIA CV Standard has not been reflected in this actuarial valuation on a solvency and hypothetical wind-up basis.

Subsequent Events

After checking with representatives of the Company, to the best of our knowledge there have been no events subsequent to the valuation date which, in our opinion, would have a material impact on the results of the valuation. Our valuation reflects the financial position of the Plan as of the valuation date and does not take into account any experience after the valuation date.

Impact of Case Law

This report has been prepared on the assumption that all of the assets in the pension fund are available to meet all of the claims on the Plan. We are not in a position to assess the impact that the Ontario Court of Appeal's decision in *Aegon Canada Inc. and Transamerica Life Canada versus ING Canada Inc.* or similar decisions in other jurisdictions might have on the validity of this assumption.

On July 29, 2004, the Supreme Court of Canada dismissed the appeal in Monsanto Canada Inc. versus Superintendent of Financial Services ("Monsanto"), thereby upholding the requirements to distribute surplus on partial plan wind-up under the *Pension Benefits Act (Ontario).* The decision has retroactive application and applies on the termination of Ontario employees if they are included in a partial plan wind-up, regardless of the province in which the pension plan is registered.

We are not aware of any partial plan wind-up having been declared in respect of the Plan where the Monsanto decision may apply. In preparing this actuarial valuation, we have therefore assumed that all the Plan's assets are available to cover the Plan's liabilities presented in this report. The subsequent declaration of a partial wind-up of the Plan where Monsanto may apply in respect of a past event, or disclosure of an existing past partial wind-up, could cause an additional claim on the Plan's assets, the consequences of which would be addressed in a subsequent report. We note the discretionary nature of the power of the regulatory authorities to declare partial wind-ups, and the lack of clarity with respect to the retroactive scope of that power. We are making no representation as to whether the regulatory authorities might declare a partial wind-up in respect of other events in the Plan's history.

3

Defined Contribution Component of the Plan

The Plan is made up of defined contribution ("DC") and defined benefit ("DB") components. The DC component is considered in this Section. The remainder of the report relates to the DB component of the Plan, unless otherwise noted.

Reconciliation of DC Assets

The DC assets are held by SunLife Financial. In preparing this report, we have relied upon the auditors' report signed by Ernst & Young LLP.

A reconciliation of the DC assets from the date of the previous valuation is as follows:

	2012	2013	2014
January 1st	$2,574,608	$2,931,240	$3,533,405
PLUS			
Members' contribution[2]	$0	$0	$0
Company's contributions	$281,576	$300,464	$341,521
Investment returns from all sources, net of expenses	$177,443	$398,770	$338,376
	$459,019	$699,234	$679,897
LESS			
Benefits paid to members	$102,387	$97,069	$175,839
	$102,387	$97,069	$175,839
December 31st	$2,931,240	$3,533,405	$4,037,463

Current Service Cost

We have estimated the employer's DC current service cost based on 2014 contributions increased by the going-concern salary increase assumption. The projection until the next actuarial valuation follows:

	2015	2016	2017
Employer DC current service cost	$353,000	$365,000	$378,000

For reference, the Plan terms are summarized in Appendix F.

[2] Members contributions are made into a Group RRSP arrangement.

4

Valuation Results – Going Concern

Financial Status

A going concern valuation compares the relationship between the value of Plan assets and the present value of expected future benefit cash flows in respect of accrued service, assuming the Plan will be maintained indefinitely.

The results of the current valuation, compared with those from the previous valuation, are summarized as follows:

	31.12.2014	31.12.2011
Assets		
Market value of assets	$29,900,381	$22,788,818
Going concern funding target		
• Active members	$8,477,955	$8,287,660
• Pensioners and survivors	$15,032,250	$15,825,684
• Deferred pensioners	$159,780	$134,383
Total	$23,669,985	$24,247,727
Funding excess (shortfall)	$6,230,396	($1,458,909)

Reconciliation of Financial Status

Funding excess (shortfall) as at previous valuation		($1,458,909)
Interest on funding excess (funding shortfall) at 4.75% per year		(217,926)
Employer's special payments, with interest		3,824,405
Expected funding excess (funding shortfall)		$2,147,570
Net experience gains (losses)		
• Net Investment return	$3,703,435	
• Increases in pensionable earnings	211,053	
• Mortality	742,233	
• Retirement	47,104	
Total experience gains (losses)	$4,703,825	4,703,825
Impact of changes in assumptions		(686,562)
Data corrections		122,247
Net impact of other elements of gains and losses		(56,684)
Funding excess (shortfall) as at current valuation		$6,230,396

Current Service Cost

The current service cost is an estimate of the present value of the additional expected future benefit cash flows in respect of pensionable service that will accrue after the valuation date, assuming the Plan will be maintained indefinitely.

The current service cost during the year following the valuation date, compared with the corresponding value determined in the previous valuation, is as follows:

	2015	2012
Total current service cost	$317,845	$343,722
Expense allowance	$175,000	$175,000
Total estimated employer's current service cost	$492,845	$ 518,722
Employer's current service cost expressed as a percentage of members' pensionable earnings excluding expense allowance	19.7%	18.7%

The key factors that have caused a change in the employer's current service cost excluding the expense allowance since the previous valuation are summarized in the following table:

Employer's current service cost as at previous valuation	18.7%
Demographic changes	0.7%
Changes in assumptions	0.3%
Employer's current service cost as at current valuation	19.7%

Discount Rate Sensitivity

The following table summarizes the effect on the going concern funding target shown in this report of using a discount rate which is 1% lower than that used in the valuation.

Scenario	**Valuation Basis**	**Reduce Discount Rate by 1%**
Going concern funding target	$23,669,985	$26,640,307
Current service cost		
• Total current service cost	$317,845	$375,674
• Expense allowance	$175,000	$175,000
Total	$492,845	$550,674

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Valuation Results – Hypothetical Wind-up

Financial Position

When conducting a hypothetical wind-up valuation, we determine the relationship between the respective values of the Plan's assets and its liabilities assuming the Plan is wound up and settled on the valuation date, assuming benefits are settled in accordance with the Act and under circumstances producing the maximum wind-up liabilities on the valuation date. However, to the extent permitted by law, the actuary may disregard:

- Benefits that would not be payable under the hypothesized scenario.
- Plan member earnings after the valuation date.

The hypothetical wind-up financial position as of the valuation date, compared with that at the previous valuation, is as follows:

	31.12.2014	**31.12.2011**
Assets		
Market value of assets	$29,900,381	$22,788,818
Termination expense provision	($75,000)	($75,000)
Wind-up assets	$29,825,381	$22,713,818
Present value of accrued benefits for:		
• Active members	$10,030,073	$8,808,229
• Pensioners and survivors	$17,729,672	$18,111,398
• Deferred pensioners	$199,921	$170,547
Total wind-up liability	$27,959,666	$27,090,174
Wind-up excess (shortfall)	$1,865,715	($4,376,356)

Wind-up Incremental Cost

The wind-up incremental cost is an estimate of the present value of the projected change in the hypothetical wind-up liabilities from the valuation date until the next scheduled valuation date, adjusted for the benefit payments expected to be made in that period.

The hypothetical wind-up incremental cost determined in this valuation, compared with the corresponding value determined in the previous valuation, is as follows:

	31.12.2014	**31.12.2011**
Number of years covered by report	3 years	3 years
Total hypothetical wind-up liabilities at the valuation date (A)	$27,959,666	$27,090,174
Present value of projected hypothetical wind-up liability at the next required valuation (including expected new entrants) plus benefit payments until the next required valuation (B)	$29,140,542	$29,254,123
Hypothetical wind-up incremental cost (B – A)	$1,180,876	$2,163,949

The incremental cost is not an appropriate measure of the contributions that would be required to maintain the financial position of the Plan on a hypothetical wind-up basis unchanged from the valuation date to the next required valuation date, if actual experience is exactly in accordance with the going concern valuation assumptions. This is because it does not reflect the fact that the expected return on plan assets (based on the going concern assumptions) is greater than the discount rate used to determine the hypothetical wind-up liabilities.

Also note that the above incremental cost does not take into account the impact of the proposed change in the mortality table to be used for the computation of pension commuted values as described in the introduction of this report.

Discount Rate Sensitivity

The following table summarizes the effect on the hypothetical wind-up liabilities shown in this report of using a discount rate which is 1% lower than that used in the valuation:

Scenario	**Valuation Basis**	**Reduce Discount Rate by 1%**
Total hypothetical wind-up liability	$27,959,666	$31,635,166

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Valuation Results – Solvency

Overview

The Act also requires the financial position of the Plan to be determined on a solvency basis. The financial position on a solvency basis is determined in a similar manner to the Hypothetical Wind-up Basis, except for the following:

Exceptions	Reflected in valuation based on the terms of engagement
The circumstance under which the Plan is assumed to be wound up could differ for the solvency and hypothetical wind-up valuations.	The same circumstances were assumed for the solvency valuation as were assumed for the hypothetical wind-up valuation.
Certain benefits can be excluded from the solvency financial position. These include: (a) any escalated adjustment (e.g. indexing), (b) certain plant closure benefits, (c) certain permanent layoff benefits, (d) special allowances other than funded special allowances, (e) consent benefits other than funded consent benefits, (f) prospective benefit increases, (g) potential early retirement window benefit values, and (h) pension benefits and ancillary benefits payable under a qualifying annuity contract.	No benefits were excluded from the solvency liabilities shown in this valuation.
The financial position on the solvency basis needs to be adjusted for any Prior Year Credit Balance.	Not applicable.
The solvency financial position can be determined by smoothing assets and the solvency discount rate over a period of up to 5 years.	Smoothing was not used.
The benefit rate increases coming into effect after the valuation date can be reflected in the solvency valuation.	Not applicable.

Financial Position

The financial position on a solvency basis is the same as the financial position on the Hypothetical Wind-up basis shown in the previous section. The Transfer Ratio is 107% compared to 84% at the previous valuation.

The financial position on a solvency basis, compared with the corresponding figures from the previous valuation, is as follows:

	31.12.2014	31.12.2011
Assets		
Market value of assets	$29,900,381	$22,788,818
Termination expense provision	($75,000)	($75,000)
Net assets	$29,825,381	$22,713,818
Liabilities		
Total hypothetical wind-up liabilities	$27,959,666	$27,090,174
Difference in circumstances of assumed wind-up	$0	$0
Value of excluded benefits	($0)	($0)
Liabilities on a solvency basis	$27,959,666	$27,090,174
Surplus (shortfall) on a market value basis	$1,865,715	($4,376,356)
Liability smoothing adjustment	$0	$0
Asset smoothing adjustment	$0	$0
Surplus (shortfall) on a solvency basis	$1,865,715	($4,376,356)
Transfer Ratio	107%	84%

7

Minimum Funding Requirements

The Act prescribes the minimum contributions that FortisOntario Inc. must make to the Plan. The minimum contributions in respect of a defined benefit component of a pension plan are comprised of going concern current service cost and special payments to fund any going concern or solvency shortfalls.

There is a funding excess and no special payments are required for solvency purposes on the basis of the assumptions and methods described in this report. Under these circumstances the Act does not require the employer to contribute to the Plan until after the funding excess has been applied towards the employer's current service cost.

Once the funding excess has been so applied, employer contributions must resume. On the basis of the assumptions and methods described in this report, the rule for determining the minimum required employer monthly contributions, as well as an estimate of the employer contributions, from the valuation date until the next required valuation are as follows:

	Employer's contribution rule		Estimated employer's contributions		
Period beginning	**Monthly current service cost[3]**	**Explicit monthly expense allowance**	**Monthly current service cost including expense allowance**	**Funding excess applied[4]**	**Minimum monthly contributions**
January 1, 2015	19.7%	$14,583	$41,070	$41,070	$0
January 1, 2016	19.7%	$14,583	$41,997	$41,997	$0
January 1, 2017	19.7%	$14,583	$42,957	$42,957	$0

The estimated contribution amounts above are based on projected members' pensionable earnings. Therefore, the actual employer's current service cost may be different from the above estimates and, as such, the contribution requirements should be monitored closely to ensure contributions resume in accordance with the Act.

Other Considerations

Differences Between Valuation Bases

There is no provision in the minimum funding requirements to fund the difference between the hypothetical wind-up and solvency shortfalls, if any.

[3] Expressed as a percentage of members' pensionable earnings.

[4] Notwithstanding the funding excess in the Plan, the terms of the Plan [or collective agreement] may require the Company to make current service cost contributions.

In addition, although minimum funding requirements do include a requirement to fund the going concern current service cost, there is no requirement to fund the expected growth in the hypothetical wind-up or solvency liability after the valuation date, which could be greater than the going concern current service cost.

Timing of Contributions

Funding contributions are due on a monthly basis. Contributions for current service cost including the expense allowance must be made within 30 days following the month to which they apply. Special payment contributions must be made in the month to which they apply.

Retroactive Contributions

The Company must contribute the excess, if any, of the minimum contribution recommended in this report over contributions actually made in respect of the period following the valuation date. This contribution, along with an allowance for interest, is due no later than 60 days following the date this report is filed.

Payment of Benefits

The Act imposes certain restrictions on the payment of lump sums from the Plan when the transfer ratio revealed in an actuarial valuation is less than one. If the transfer ratio shown in this report is less than one, the plan administrator should ensure that the monthly special payments are sufficient to meet the requirements of the Act to allow for the full payment of benefits, and otherwise should take the prescribed actions.

Additional restrictions are imposed when:

- The transfer ratio revealed in the most recently filed actuarial valuation is less than one and the administrator knows or 'ought to know' that the transfer ratio of the Plan has declined by 10% or more since the date the last valuation was filed.

- The transfer ratio revealed in the most recently filed actuarial valuation is greater than or equal to one and the administrator knows or 'ought to know' that the transfer ratio of the Plan has declined to less than 0.9 since the date the last valuation was filed.

As such, the administrator should monitor the transfer ratio of the Plan and, if necessary, take the prescribed actions.

Letters of Credit

Minimum funding requirements in respect of solvency deficiencies that otherwise require monthly contributions to the pension fund may be met, in the alternative, by establishing an irrevocable letter of credit subject to the conditions established by the Act. Required solvency special payments in excess of those met by a letter of credit must be met by monthly contributions to the pension fund.

Contributions to the DC Component

In addition to any contribution requirements in respect of the DB component of the Plan, and notwithstanding any prohibition to fund the DB component of the Plan, contributions to the individual member DC accounts should be made in accordance with the Plan terms.

If the DB component of the Plan is fully funded on both going concern and solvency bases then, subject to the Act, the Plan terms, and any collective or employment agreement, it may be possible for the Company to apply DB assets in satisfaction of its contribution requirements for the DC component of the Plan.

8

Maximum Eligible Contributions

The *Income Tax Act* (the "ITA") limits the amount of employer contributions that can be remitted to the defined benefit component of a registered pension plan.

In accordance with Section 147.2 of the ITA and *Income Tax Regulation* 8516, for a plan which is underfunded on either a going concern or on a hypothetical wind-up basis, the maximum permitted contributions are equal to the employer's current service cost, including the explicit expense allowance if applicable, plus the greater of the going concern funding shortfall and hypothetical wind-up shortfall.

For a plan which is fully funded on both going concern and hypothetical wind-up bases, the employer can remit a contribution equal to the employer's current service cost, including the explicit expense allowance if applicable, as long as the surplus in the plan does not exceed a prescribed threshold. Specifically, in accordance with Section 147.2 of the ITA, for a plan which is fully funded on both going concern and hypothetical wind-up bases, the plan may not retain its registered status if the employer makes a contribution while the going concern funding excess exceeds 25% of the going concern funding target.

Schedule of Maximum Contributions

Since the surplus exceeds 25% of the going concern funding target, no contributions are permitted until the funding excess has been reduced to less than $5,917,496 (i.e. 25% of the going concern funding target of $23,669,985); otherwise, the Plan's registered status may be revoked.

Contributions to the DC Component

In addition to any contribution requirements in respect of the DB component of the Plan, and notwithstanding any prohibition to fund the DB component of the Plan, contributions to the individual member DC accounts can be made in accordance with the Plan terms.

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Actuarial Opinion

In our opinion, for the purposes of the valuations,

- the membership data on which the valuation is based are sufficient and reliable.
- the assumptions are appropriate.
- the methods employed in the valuation are appropriate.

This report has been prepared, and our opinions given, in accordance with accepted actuarial practice in Canada. It has also been prepared in accordance with the funding and solvency standards set by the *Pension Benefits Act (Ontario)*.

M. Scott Cushing
Fellow of the Society of Actuaries
Fellow of the Canadian Institute of Actuaries

September 22, 2015
Date

Armando Fernandes
Fellow of the Society of Actuaries
Fellow of the Canadian Institute of Actuaries

September 22, 2015
Date

APPENDIX A

Prescribed Disclosure

Definitions

The Act defines a number of terms as follows:

Defined Term	Description	Result
Transfer Ratio	The ratio of: (a) solvency assets minus the lesser of the Prior Year Credit Balance and the minimum required employer contributions until the next required valuation; to (b) the sum of the solvency liabilities and liabilities for benefits, other than benefits payable under qualifying annuity contracts that were excluded in calculating the solvency liabilities.	1.07
Prior Year Credit Balance	Accumulated excess of contributions made to the pension plan in excess of the minimum required contributions (note: only applies if the Company chooses to treat the excess contributions as a Prior Year Credit Balance).	$0
Solvency Assets	Market value of assets including accrued or receivable income and excluding the value of any qualifying annuity contracts.[5]	$29,825,381
Solvency Asset Adjustment	The sum of:	
	(a) the difference between smoothed value of assets and the market value of assets	$0
	(b) the present value of going concern special payments (including those identified in this report) within 6 years following the valuation date	$0
	(c) the present value of any previously scheduled solvency special payments (excluding those identified in this report)	$0
		$0

[5] In accordance with accepted actuarial practice, for purposes of determining the financial position, the market value of plan assets was reduced by a provision for estimated termination expenses payable from the Plan's assets that may reasonably be expected to be incurred in terminating the Plan and to be charged to the Plan

Defined Term	Description	Result
Solvency Liabilities	Liabilities determined as if the plan had been wound up on the valuation date, including liabilities for plant closure benefits or permanent layoff benefits that would be immediately payable if the employer's business were discontinued on the valuation date of the report, but, if elected by the plan sponsor, excluding liabilities for, (a) any escalated adjustment, (b) excluded plant closure benefits, (c) excluded permanent layoff benefits, (d) special allowances other than funded special allowances, (e) consent benefits other than funded consent benefits, (f) prospective benefit increases, (g) potential early retirement window benefit values, and (h) pension benefits and ancillary benefits payable under a qualifying annuity contract.	$27,959,666
Solvency Liability Adjustment	The amount by which solvency liabilities are adjusted as a result of using a solvency valuation interest rate that is the average of market interest rates calculated over the period of time used in the determination of the smoothed value of assets.	$0
Solvency Deficiency	The amount, if any, by which the sum of:	
	(a) the solvency liabilities	$27,959,666
	(b) the solvency liability adjustment	$0
	(c) the prior year credit balance	$0
		$27,959,666
	Exceeds the sum of	
	(d) the solvency assets net of estimated termination expenses	$29,825,381
	(e) the solvency asset adjustment	$0
		$29,825,381
		$0

Timing of Next Required Valuation

In accordance with the Act the next valuation of the Plan would be required at an effective date within one year of the current valuation date if:

- The ratio of solvency assets to solvency liabilities is less than 85%.
- The employer elected to exclude plant closure or permanent lay-off benefits under Section 5(18) of the regulations, and has not rescinded that election.

Otherwise, the next valuation of the Plan would be required at an effective date no later than three years after the current valuation date.

Accordingly, the next valuation of the Plan will be required as of December 31, 2017.

Special Payments

As the Plan does not have a going concern deficit or a solvency deficit, no special payments are required.

Pension Benefit Guarantee Fund (PBGF) Assessment

The PBGF assessment base and liabilities are derived as follows:

Solvency assets	$29,900,381	(a)
PBGF liabilities	$27,959,666	(b)
Solvency liabilities	$27,959,666	(c)
Ontario asset ratio	100%	(d) = (b) ÷ (c)
Ontario portion of the fund	$29,900,381	(e) = (a) x (d)
PBGF assessment base	$0	(f) = (b) – (e)
Amount of additional liability for plant closure and/or permanent layoff benefits which is not funded and subject to the 2% assessment pursuant to s.37(4)	$0	(g)

The PBGF assessment is calculated as follows:

$5 for each Ontario member	$445	(h)
0.5% of PBGF assessment base up to 10% of PBGF liabilities	$0	(i)
1.0% of PBGF assessment base between 10% and 20% of PBGF liabilities	$0	(j)
1.5% of PBGF assessment base over 20% of PBGF liabilities	$0	(k)
Sum of (h), (i), (j) and (k)	$445	(l)
$300 for each Ontario member	$26,700	(m)
Lesser of (l) and (m)	$445	(n)
2.0% of additional liabilities ((g) x 2%)	$0	(o)
Total Guarantee Fund Assessment ((n) + (o), no less than $250) (before applicable tax)	$445	(p)

APPENDIX B

Plan Assets

The pension fund is held by RBC Investor and Treasury Services and is invested in Blackrock pooled equity and fixed income funds. In preparing this report, we have relied upon fund statements prepared by RBC Investor and Treasury Services without further audit. Customarily, this information would not be verified by a plan's actuary. We have reviewed the information for internal consistency and we have no reason to doubt its substantial accuracy.

Reconciliation of Market Value of Plan Assets

The pension fund transactions since the last valuation are summarized in the following table:

	2012	2013	2014
January 1	$22,788,818	$24,353,761	$25,796,749
PLUS			
Company's contributions	$1,687,752	$1,551,364	$1,847,733
Investment Income	$888,463	$986,166	$891,737
Realized gains (losses)	$22,527	$411,451	$87,348
Unrealized gains (losses)	$756,150	$127,816	$2,924,304
	$3,354,892	$3,076,797	$5,751,122
LESS			
Pensions paid	$1,536,411	$1,474,864	$1,422,184
Lump-sums paid	$0	$0	$103,321
Other disbursements	$1,110	$516	$432
Administration and investment fees	$252,428	$158,429	$121,553
	$1,789,949	$1,633,809	$1,647,490
December 31	$24,353,761	$25,796,749	$29,900,381
Gross rate of return[6]	7.3%	6.3%	15.1%
Rate of return net of expenses[7]	6.2%	5.6%	14.6%

We have tested the pensions paid, the lump-sums paid, and the contributions for consistency with the membership data for the Plan members who have received benefits or made contributions. The results of these tests were satisfactory.

[6] Assuming mid-period cash flows.

[7] Assuming mid-period cash flows.

Investment Policy

The plan administrator has adopted a statement of investment policy and procedures. This policy is intended to provide guidelines for the manager(s) as to the level of risk that is consistent with the Plan's investment objectives. A significant component of this investment policy is the asset mix.

The plan administrator is solely responsible for selecting the plan's investment policies, asset allocations, and individual investments.

The constraints on the asset mix and the actual asset mix at the valuation date are provided for information purposes:

	Investment Policy			Actual Asset Mix as at December 31, 2014
	Minimum	Target	Maximum	
Equities	30%	40%	50%	38%
Fixed Income	50%	60%	70%	60%
Cash and cash equivalents	0%	0%	0%	2%
		100%		100%

Because of the mismatch between the Plan's assets (which are invested in accordance with the above investment policy) and the Plan's liabilities (which tend to behave like long bonds) the Plan's financial position will fluctuate over time. These fluctuations could be significant and could cause the Plan to become underfunded or overfunded even if the Company contributes to the Plan based on the funding requirements presented in this report.

APPENDIX C

Methods and Assumptions – Going Concern

Valuation of Assets

For this valuation, we have used the market value of assets.

Going Concern Funding Target

Over time, the real cost to the employer of a pension plan is the excess of benefits and expenses over member contributions and investment earnings. The actuarial cost method allocates this cost to annual time periods.

For purposes of the going concern valuation, we have continued to use the projected unit credit actuarial cost method. Under this method, we determine the present value of benefit cash flows expected to be paid in respect of service accrued prior to the valuation date, based on projected final average earnings. This is referred to as the funding target.

The funding excess or funding shortfall, as the case may be, is the difference between the market or smoothed value of assets and the funding target. A funding excess on a market value basis indicates that the current market value of assets and expected investment earnings are expected to be sufficient to meet the cash flows in respect of benefits accrued to the valuation date as well as expected expenses – assuming the plan is maintained indefinitely. A funding shortfall on a market value basis indicates the opposite – that the current market value of the assets is not expected to be sufficient to meet the plan's cash flow requirements in respect of accrued benefits, absent additional contributions.

As required under the Act, a funding shortfall must be amortized over no more than 15 years through special payments. A funding excess may, from an actuarial standpoint, be applied immediately to reduce required employer current service contributions unless precluded by the terms of the plan or by legislation.

The actuarial cost method used for the purposes of this valuation produces a reasonable matching of contributions with accruing benefits. Because benefits are recognized as they accrue, the actuarial cost method provides an effective funding target for a plan that is maintained indefinitely.

Current Service Cost

The current service cost is the present value of projected benefits to be paid under the plan with respect to service expected to accrue during the period until the next valuation.

The employer's current service cost has been expressed as a percentage of the members' pensionable earnings to provide an automatic adjustment in the event of fluctuations in membership and/or pensionable earnings.

Under the projected unit credit actuarial cost method, the current service cost for an individual member will increase each year as the member approaches retirement. Since the plan is closed to new entrants, the current service cost of the entire group, expressed as a percentage of the members' pensionable earnings, can be expected to increase as the average age of the group increases as the members near retirement.

Actuarial Assumptions – Going Concern Basis

The present value of future benefit payment cash flows is based on economic and demographic assumptions. At each valuation we determine whether, in our opinion, the actuarial assumptions are still appropriate for the purposes of the valuation, and we revise them, if necessary. Emerging experience will result in gains or losses that will be revealed and considered in future actuarial valuations.

The table below shows the various assumptions used in the current valuation in comparison with those used in the previous valuation.

Assumption	Current valuation	Previous valuation
Discount rate:	4.75%	4.75%
Explicit expenses:	$175,000	$175,000
Inflation:	2.00%	2.50%
ITA limit / YMPE increases:	3.00%	3.50%
Pensionable earnings increases:	3.50%	4.00%
Retirement rates:	All members retire at age 60	All members retire at age 60
Termination rates:	None	None
Mortality rates:	100% of the rates of the 2014 Private Sector Canadian Pensioners Mortality Table (CPM2014Priv)	100% of the rates of the 1994 Uninsured Pensioner Mortality Table
Mortality improvements:	Fully generational using CPM Improvement Scale B (CPM-B)	Fully generational using Scale AA
Disability rates:	None	None

The assumptions are best-estimate with the exception that the discount rate includes a margin for adverse deviations, as shown below.

Pensionable Earnings

The benefits ultimately paid will depend on each member's final average earnings. To calculate the pension benefits payable upon retirement, death, or termination of employment, we have taken 2014 earnings and assumed that such pensionable earnings will increase at the assumed rate.

Rationale for Assumptions

A rationale for each of the assumptions used in the current valuation is provided below.

Discount Rate

We have discounted the expected benefit payment cash flows using the expected investment return on the market value of the fund net of fees and less a margin for adverse deviations. Other bases for discounting the expected benefit payment cash flows may be appropriate, particularly for purposes other than those specifically identified in this valuation report.

The discount rate is comprised of the following:

- Estimated returns for each major asset class consistent with market conditions on the valuation date, the expected time horizon over which benefits are expected to be paid, and the target asset mix specified in the Plan's investment policy.
- A margin for adverse deviations of 0.60%

The discount rate was developed as follows:

Assumed investment return	5.35%
Margin for adverse deviation	(0.60%)
Net discount rate	4.75%

Expenses

The assumption is based on the average amount of investment and administrative expenses over the last 3 years.

Inflation

The inflation assumption is based on market expectations of long-term inflation implied by the yields on nominal and real return bonds at the valuation date of, taking into account the mid-point of the Bank of Canada's inflation target range of between 1% and 3%.

Income Tax Act Pension Limit and Year's Maximum Pensionable Earnings

The assumption is based on historical real economic growth and the underlying inflation assumption.

Pensionable Earnings

The assumption is based on general wage growth assumptions increased by our best estimate of future merit and promotional increases over general wage growth considering current economic and financial market conditions.

Post-Retirement Pension Increases

The Plan does not provide automatic indexing.

Retirement Rates

Due to the size of the Plan, there is no meaningful retirement experience. The assumption is based on the Plan provisions and our experience with similar plans and employee groups.

Termination Rates

Use of a different assumption would not have a material impact on the valuation.

Mortality Rates

The assumption for the mortality rates is based on the Canadian Pensioners' Mortality (CPM) study published by the Canadian Institute of Actuaries in February 2014.

Due to the size of the Plan, specific data on plan mortality experience is insufficient to determine the mortality rates. After considering plan-specific characteristics, such as the type of employment, the industry experience, pension and employment income for the plan members, and data in the CPM study, it was determined to use the CPM mortality rates from the private sector without adjustment.

There is broad consensus among actuaries and other longevity experts that mortality improvement will continue in the future, but the degree of future mortality improvement is uncertain. The mortality improvement scale published in the CPM study represents one reasonable outlook for future improvement. We have used the CPM mortality improvement scale B without adjustment.

Based on the assumption used, the life expectancy of a member age 65 at the valuation date is 21.4 years for males and 23.9 years for females.

Disability Rates

Use of a different assumption would not have a material impact on the valuation.

APPENDIX D

Methods and Assumptions – Hypothetical Wind-up and Solvency

Hypothetical Wind-up Basis

The Canadian Institute of Actuaries requires actuaries to report the financial position of a pension plan on the assumption that the plan is wound up on the effective date of the valuation, with benefits determined on the assumption that the pension plan has neither a surplus nor a deficit. For the purposes of the hypothetical wind-up valuation, the plan wind-up is assumed to occur in circumstances that maximize the actuarial liability.

To determine the actuarial liability on the hypothetical wind-up basis, we have valued those benefits that would have been paid had the Plan been wound up on the valuation date, with all members fully vested in their accrued benefits.

There are no benefits under the plan contingent upon the circumstances of the plan wind-up or contingent upon other factors. In particular, there are no additional benefits that would be immediately payable if the employer's business were discontinued on the valuation date. Therefore, it was not necessary to postulate a scenario upon which the hypothetical wind-up valuation is made. Therefore, no benefits payable on plan wind-up were excluded from our calculations.

Upon plan wind-up, members are given options for the method of settling their benefit entitlements. The options vary by eligibility and by province of employment, but in general, involve either a lump sum transfer or an immediate or deferred pension.

The value of benefits assumed to be settled through a lump sum transfer is based on the assumptions described in Section 3500 – *Pension Commuted Values* of the Canadian Institute of Actuaries' Standards of Practice applicable for December 31, 2014.

Benefits provided as an immediate or deferred pension are assumed to be settled through the purchase of annuities based on an estimate of the cost of purchasing annuities.

We have estimated the cost of settlement through purchase of annuities in accordance with the *Canadian Institute of Actuaries Educational Note: Assumptions for Hypothetical Wind-up and Solvency Valuations with Effective Dates Between December 31, 2014 and December 30, 2015.*

We have not included a margin for adverse deviation in the solvency and hypothetical wind-up valuations.

The assumptions are as follows:

Form of Benefit Settlement Elected by Member	
Lump sum	70% of active members under age 55, and 50% of active members over age 55, elect to receive their benefit entitlement in a lump sum
Annuity purchase	All remaining members are assumed to elect to receive their benefit entitlement in the form of a deferred or immediate pension. These benefits are assumed to be settled through the purchase of deferred or immediate annuities from a life insurance company.
Basis for Benefits Assumed to be Settled through a Lump Sum	
Mortality rates:	UP94 with fully generational improvements using Scale AA
Interest rate:	2.50% per year for 10 years, 3.80% per year thereafter
Basis for Benefits Assumed to be Settled through the Purchase of an Annuity	
Mortality rates:	UP94 with fully generational improvements using Scale AA
Interest rate:	2.53% per year based on a duration of 11.0 years determined for the liabilities assumed to be settled through the purchase of an annuity.
Retirement Age	
Maximum value:	Members are assumed to retire at the age which maximizes the value of their entitlement from the Plan, based on the eligibility requirements which have been met at the valuation date
Grow-in:	The benefit entitlement and assumed retirement age of Ontario members whose age plus service equals at least 55 at the valuation date reflect their entitlement to grow into early retirement subsidies
Other Assumptions	
Final average earnings:	Based on actual pensionable earnings over the averaging period
Maximum pension limit:	$2,770.00 The Plan terms require the limit to be calculated at pension commencement. However, no member is limited by the current limit, therefore the limit is not projected for simplicity.
Termination expenses:	$75,000

To determine the hypothetical wind-up position of the Plan, a provision has been made for estimated termination expenses payable from the Plan's assets in respect of actuarial and administration expenses that may reasonably be expected to be incurred in terminating the Plan and to be charged to the Plan.

Because the settlement of all benefits on wind-up is assumed to occur on the valuation date and is assumed to be uncontested, the provision for termination expenses does not include custodial, investment management, auditing, consulting, and legal expenses that would be incurred between the wind-up date and the settlement date or due to the terms of a wind-up being contested.

Expenses associated with the distribution of any surplus assets that might arise on an actual wind-up are also not included in the estimated termination expense provisions.

The provision for termination expenses payable from the Plan's assets determined is not dependent upon the plan sponsor being solvent or not on the wind-up date.] We have also assumed, without analysis, that the Plan's terms as well as applicable legislation and court decisions would permit the relevant expenses to be paid from the Plan.

Actual fees incurred on an actual plan wind-up may differ materially from the estimates disclosed in this report.

Incremental Cost

In order to determine the incremental cost, we estimate the solvency liabilities at the next valuation date. We have assumed that the cost of settling benefits by way of a lump sum or purchasing annuities remains consistent with the assumptions described above. Since the projected solvency liabilities will depend on the membership in the Plan at the next valuation date, we must make assumptions about how the Plan membership will evolve over the period until the next valuation.

We have assumed that the Plan membership will evolve in a manner consistent with the going concern assumptions as follows:

- Members terminate, retire, and die consistent with the termination, retirement, and mortality rates used for the going concern valuation.
- Pensionable earnings, the Income Tax Act pension limit, and the Year's Maximum Pensionable Earnings increase in accordance with the related going concern assumptions.
- Active members accrue pensionable service in accordance with the terms of the Plan.

Solvency Basis

In determining the financial position of the Plan on the solvency basis, we have used the same assumptions and methodology as were used for determining the financial position of the Plan on the hypothetical wind-up basis.

The solvency position is determined in accordance with the requirements of the Act.

APPENDIX E

Membership Data

Analysis of Membership Data

The actuarial valuation is based on membership data as at December 31, 2014, provided by FortisOntario Inc.

We have applied tests for internal consistency, as well as for consistency with the data used for the previous valuation. These tests were applied to membership reconciliation, basic information (date of birth, date of hire, date of membership, gender, etc.), pensionable earnings, credited service, and pensions to retirees and other members entitled to a deferred pension. Contributions, lump sum payments, and pensions to retirees were compared with corresponding amounts reported in financial statements. The results of these tests were satisfactory.

If the data supplied are not sufficient and reliable for its intended purpose, the results of our calculation may differ significantly from the results that would be obtained with such data. Although Mercer has reviewed the suitability of the data for its intended use in accordance with accepted actuarial practice in Canada, Mercer has not verified or audited any of the data or information provided.

Plan membership data are summarized below. For comparison, we have also summarized corresponding data from the previous valuation.

	31.12.2014	31.12.2011
Active Members		
Number	19	23
Total pensionable earnings for the following year	$1,666,240	$1,840,207
Average pensionable earnings for the following year	$87,697	$80,009
Average years of pensionable service	27.1	24.4
Average age	53.7	52.0
Deferred Pensioners		
Number	6	6
Total annual pension	$16,454	$16,454
Average annual pension	$2,742	$2,742
Average age	61.8	58.8
Pensioners and Survivors		
Number	64	70
Total annual lifetime pension	$1,285,950	$1,363,867
Total annual bridge pension	$123,060	$200,679
Average annual lifetime pension	$20,093	$19,484
Average annual bridge pension (for those receiving a bridge)	$15,383	$14,334
Average age	73.7	71.9

The membership movement for all categories of membership since the previous actuarial valuation is as follows:

	Actives	Deferred Pensioners	Pensioners and Beneficiaries	Total
Total at 31.12.2011	23	6	70	99
New entrants				
Terminations:				
• Not vested				
• Transfers/lump sums				
• Deferred pensions				
Deaths			(10)	(10)
Retirements	(4)		4	0
Beneficiaries				
Total at 31.12.2014	19	6	64	89

The distribution of the active members by age and pensionable service as at the valuation date is summarized as follows:

	Years of Pensionable Service							
Age	**0-4**	**5-9**	**10-14**	**15-19**	**20-24**	**25-29**	**30 +**	**Total**
Under 20								
20 to 24								
25 to 29								
30 to 34								
35 to 39								
40 to 44					3			3
45 to 49					3	1		4
50 to 54					1		1	2
55 to 59					2	2	2	6
60 to 64							3	3
65 +					1			1
Total					10	3	6	19

The distribution of the inactive members by age as at the valuation date is summarized as follows:

	Deferred Pensioners		Pensioners and Survivors		
Age	**Number**	**Average Pension**	**Number**	**Average Pension**	**Average Bridge**
45 – 49	1	4,972			
50 – 54					
55 – 59			6	29,210	14,604
60 – 64	2	3,795	6	25,440	16,161
65 – 69	2	1,386	20	21,276	
70 – 74	1	1,119	7	17,674	
75 – 79			5	16,585	
80 – 84			8	15,685	
85 – 89			7	16,626	
90 – 94			4	16,243	
95 – 99			1	19,051	
100 +					
Total	6	2,742	64	20,093	15,383

APPENDIX F

Summary of Plan Provisions

Mercer has used and relied on the plan documents, including amendments and interpretations of plan provisions, supplied by FortisOntario Inc.. If any plan provisions supplied are not accurate and complete, the results of any calculation may differ significantly from the results that would be obtained with accurate and complete information. Moreover, plan documents may be susceptible to different interpretations, each of which could be reasonable, and the results of estimates under each of the different interpretations could vary.

This valuation is based on the plan provisions in effect on December 31, 1964. Since the previous valuation, the Plan has not been amended.

DB Component

The following is a summary of the main provisions of the DB component of the Plan in effect on December 31, 2014. This summary is not intended as a complete description of the Plan.

Background	Retirement incomes are provided for employees of FortisOntario Inc. (the "Company") under the Company Sponsored Combined Plan comprised of the Employees' Retirement Plan (the "Retirement Plan") and the Supplementary Pension Plan (the "Supplementary Plan"). The Retirement Plan is a non-contributory defined benefit plan. Membership in the Retirement Plan is compulsory. On the other hand, membership in the Supplementary Plan, which is a non-contributory money purchase plan, is contingent upon employees electing membership in the Company's Group Registered Retirement Savings Plan. The Plan became effective December 31, 1964.
Eligibility for membership	Membership in the Retirement Plan is mandatory. A full-time employee shall enrol as a member of the Plan on the first day of the month next following the date of hire. A part-time employee who satisfies certain minimum hours worked or an earnings test must enrol as a member of the Plan on the first day of any month next following the date the employee has completed 2 years of continuous service. The Retirement Plan is closed to new entrants as at July 1, 1999.
Employee Contributions	No employee contributions are required.
Retirement Dates	Normal Retirement Date • The first day of the month coincident with or next following the member's attainment of the age of 65 years. Early Retirement Date • Early retirement is permitted from age 55.
Normal Retirement Pension	A member who retires on normal retirement date will receive an annual pension equal to 1.50% of member's highest 3-year average Earnings, multiplied by years of credited service.
Pensionable earnings	Base pay excluding overtime and bonus.

Early Retirement Pension	Early retirement benefits are reduced by 0.5% for each full month by which the early retirement date precedes age 60. Early retirement benefits are unreduced if the member has attained the age of 60 years, or if age and credited service add up to at least 90.
Normal Form of Retirement Pension	The normal form of pension is a pension payable for the lifetime of the member. If the member has a spouse at his retirement date, then the member must take an actuarially reduced pension payable to him for his lifetime, with a 60% continuance to his spouse on his death. The spouse may waive this requirement by completing and signing the appropriate form.
Maximum Pension	The total annual pension payable from the Plan upon retirement, death or termination of employment cannot exceed the lesser of: • 2% of the average of the best three consecutive years of total compensation paid to the member by the Company, multiplied by total credited service; and • $2,770.00 or such other maximum permitted under the Income Tax Act, multiplied by the member's total credited service. The maximum pension is determined at the date of pension commencement.
Death Benefits	Pre-retirement: • If a member dies before the normal retirement date and before any pension payments have begun, the member's spouse, or beneficiary if there is no spouse, will receive a lump sum settlement equal to the value of the benefits to which the member would have been entitled had employment terminated on the date of death. Post retirement: • The normal form of payment is a lifetime pension. However, the member may elect to receive an optional form of pension on an actuarial equivalent basis.
Termination Benefits	If the member terminates employment by reason other than death or retirement, he shall be entitled to a deferred pension, payable from his normal retirement date, equal to his accrued vested pension at his date of termination.
Vesting	Benefits are fully vested immediately.

DC Component

The following is a summary of the main provisions of the DC component of the Plan in effect on December 31, 2014. This summary is not intended as a complete description of the Plan.

Eligibility for Membership	Any Employee of the Company may enrol as a participant of the Supplementary Plan on the first day of the month next following the completion of six months of continuous service. Participation in the Supplementary Plan is voluntary.
Cost	The Employer contributes the entire cost to fund the benefits. For an employee who also participates in the Retirement Plan, each year the Company contributes to the Plan an amount equal to 50% of the participant's basic contribution to the Group Registered Retirement Savings Plan (RRSP), to the extent permitted by Canada Customs and Revenue Agency in accordance with the maximum allowable contribution limits. For an employee who only participates in the Supplementary Plan, each year the Company contributes to the Plan an amount equal to 100% of the participants' basic contribution to the Group RRSP, to a maximum of 6.5% of Earnings.
Normal Retirement Date	The first day of the month coincident with or next following the participant's attainment of the age of 65 years.
Retirement Pension	(a) Pension Commencement Date The first of any month following the participant's retirement date under the Retirement Plan but before the end of the year in which the participant attains the age of 71 years. (b) Pension Account Balance The value of a participant's pension account as determined on the valuation date immediately preceding the allocations of the share. (c) Valuation Date The last day of March, June, September or December of each year, with respect to the common share account or the normal valuation date for a mutual fund, with respect to the mutual fund account. (d) Amount of Pension The amount of pension provided by applying the participant's pension account balance to purchase a pension from a life insurance company licensed to transact business in Canada. (e) Normal Pension Form If the participant does not have a spouse, the pension is payable for the lifetime of the participant. If the participant has a spouse, pension is payable in a joint and survivor form that pays a pension for the participant's lifetime, continuing to the participant's spouse at a rate of 60% of pension payable prior to the participant's death. (f) Payer of the Pension The life insurance company from which the pension has been purchased.

	(g) Small Account Balance If the account balance is small, it may be transferred to the participant's non-locked RRSP. (h) Canada Revenue Agency Limits The total pension from the Retirement Plan and the Supplementary Plan does not exceed the Canada Revenue Agency maximum allowable pension limits.
Optional Pensions	Any other forms elected by the participant and his eligible spouse, provided it is consistent with the requirement of any governmental authority having jurisdiction over the Supplementary Plan.
Death Benefits	The account balance on the valuation date next following the date of death is payable to a participant's designated beneficiary, or if there is no beneficiary, to the participant's estate.
Vesting	Benefits are fully vested immediately.

APPENDIX G

Employer Certification

With respect to the Report on the Actuarial Valuation for Funding Purposes as at December 31, 2014 of the FortisOntario Inc. Employees' Retirement and Supplementary Pension Plan, I hereby certify that, to the best of my knowledge and belief:

- The valuation reflects the terms of the Company's engagement with the actuary described in Section 2 of this report, particularly the requirement to include a margin of 0.60% in the discount rate used to perform the going concern valuation and the Company's decisions in regards to determining the going-concern and solvency funding requirements.

- A copy of the official plan documents and of all amendments made up to December 31, 2014 was provided to the actuary and is reflected appropriately in the summary of plan provisions contained herein.

- The asset information summarized in Appendix B is reflective of the Plan's assets.

- The membership data provided to the actuary included a complete and accurate description of every person who is entitled to benefits under the terms of the Plan for service up to December 31, 2014.

- All events subsequent to December 31, 2014 that may have an impact on the Plan have been communicated to the actuary.

September 22, 2015
Date

Signed

Glen King
Name VP Finance & CFO

MERCER

MAKE TOMORROW, TODAY

Mercer
120 Bremner Blvd
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SHARED SERVICES/CORPORATE COST ALLOCATION

CNPI is a wholly owned subsidiary of FortisOntario Inc. ("FortisOntario") FortisOntario also owns two other regulated distribution businesses licensed by the OEB; Algoma Power Inc. ("API") and Cornwall Street Railway Light and Power Company Limited ("Cornwall Electric"). In addition, FortisOntario owns an unregulated district heating plant in Cornwall (i.e., Cornwall District Heating).

The business units of the FortisOntario group are as follows:

- FortisOntario (includes Executive and Cornwall District Heating)
- API;
- Cornwall Electric;
- CNPI – Distribution; and
- CNPI – Transmission.

Service Agreements

Pursuant to a Services Agreement between FortisOntario and its Board licensed affiliates, CNPI shares certain services with its affiliates. In addition to shared services, certain assets and employees are also shared. The Services Agreement is attached as Appendix A.

Corporate and Administrative Services – Shared Services

In order to maximize efficiencies of scale and avoid duplication, certain administrative and corporate services are shared by the business units. The shared services include executive, finance, information technology, customer service, human resources, health, safety and environmental, regulatory and materials management. Cost-based pricing is used for the shared services. Each of the individual functions was reviewed to determine the appropriate allocation ultimately resulting in assigning full time equivalents to each business unit. BDR was engaged by CNPI to review the cost allocation methodology and provide its opinion as to the reasonableness thereof. A copy of the BDR Report confirming BDR's opinion is attached as Appendix B.

Corporate Services – Fortis Inc.

Fortis Inc., FortisOntario's parent company, charges FortisOntario, and other Fortis-owned companies, for strategic planning, finance and administrative services such as costs incurred related to the listing of Fortis shares on the Toronto Stock Exchange and charges related to the administration of share purchase plans, and other costs. Consumers benefit from these services by providing CNPI with access to capital, which provides the required capital investment in the CNPI distribution system for a reliable and safe supply of electricity. The charges are allocated to FortisOntario. The charges allocated to FortisOntario are subsequently charged to the five business units within FortisOntario based on assets and share purchase plan participants. Cost-based pricing is used for the charges.

Board of Director Related Costs

There are no Board of Director-related costs for affiliates included in CNPI's costs.

VARIANCE ANALYSIS

Appendix 2-N, Shared Services/Corporate Cost Allocation – Canadian Niagara Power Inc., is provided on the following page and details the services/corporate cost allocations from the 2013 Board Approved to the 2017 Test Year.

Table 4.5.1.1 shown below details the variances from the last Board approved, 2013, to the 2017 Test Year. The materiality threshold used for explanation of variances is $100,000, as calculated in Exhibit 1, Tab 5, Schedule 1.

Appendix 2-N
Shared Services/Corporate Cost Allocation - Canadian Niagara Power Inc.

Year: 2013 Board Approved

Name of Company From	Name of Company To	Service Offered	Pricing Methodology	Price for the Service $	Cost for the Service $	Percentage Allocation %
FortisOntario	CNPI-Distribution	corporate services	cost based	506,044	506,044	24%
FortisOntario	CNPI-Distribution	building rent	market based	342,711	342,711	67%
CNPI-Distribution	Cornwall Electric	administrative services	cost based	954,583	954,583	20%
CNPI-Distribution	FortisOntario	administrative services	cost based	132,732	132,732	5%
CNPI-Distribution	CNPI-Transmission	administrative services	cost based	388,587	388,587	10%
CNPI-Distribution	Algoma Power	administrative services	cost based	1,397,112	1,397,112	30%
Cornwall Electric	CNPI-Distribution	administrative services	cost based	71,426	71,426	34%
Fortis Inc.	CNPI-Distribution	administrative services	cost based	121,352	121,352	37%

Year: 2013 Actual

Name of Company From	Name of Company To	Service Offered	Pricing Methodology	Price for the Service $	Cost for the Service $	Percentage Allocation %
FortisOntario	CNPI-Distribution	corporate services	cost based	443,223	443,223	24%
FortisOntario	CNPI-Distribution	building rent	market based	342,711	342,711	67%
CNPI-Distribution	Cornwall Electric	administrative services	cost based	950,303	950,303	18%
CNPI-Distribution	FortisOntario	administrative services	cost based	130,682	130,682	2%
CNPI-Distribution	CNPI-Transmission	administrative services	cost based	382,546	382,546	7%
CNPI-Distribution	Algoma Power	administrative services	cost based	1,388,928	1,388,928	26%
Cornwall Electric	CNPI-Distribution	administrative services	cost based	57,822	57,822	34%
Fortis Inc.	CNPI-Distribution	administrative services	cost based	135,614	135,614	37%

Year: 2014 Actual

Name of Company From	Name of Company To	Service Offered	Pricing Methodology	Price for the Service $	Cost for the Service $	Percentage Allocation %
FortisOntario	CNPI-Distribution	corporate services	cost based	488,654	488,654	24%
FortisOntario	CNPI-Distribution	building rent	market based	335,868	335,868	64%
CNPI-Distribution	Cornwall Electric	administrative services	cost based	991,803	991,803	18%
CNPI-Distribution	FortisOntario	administrative services	cost based	79,142	79,142	1%
CNPI-Distribution	CNPI-Transmission	administrative services	cost based	380,375	380,375	7%
CNPI-Distribution	Algoma Power	administrative services	cost based	1,377,606	1,377,606	24%
Cornwall Electric	CNPI-Distribution	administrative services	cost based	28,801	28,801	20%
Fortis Inc.	CNPI-Distribution	administrative services	cost based	167,084	167,084	34%

Year: 2015 Actual

Name of Company From	Name of Company To	Service Offered	Pricing Methodology	Price for the Service $	Cost for the Service $	Percentage Allocation %
FortisOntario	CNPI-Distribution	corporate services	cost based	498,468	498,468	24%
FortisOntario	CNPI-Distribution	building rent	market based	342,585	342,585	64%
CNPI-Distribution	Cornwall Electric	administrative services	cost based	1,027,037	1,027,037	17%
CNPI-Distribution	FortisOntario	administrative services	cost based	81,977	81,977	1%
CNPI-Distribution	CNPI-Transmission	administrative services	cost based	397,854	397,854	7%
CNPI-Distribution	Algoma Power	administrative services	cost based	1,426,761	1,426,761	24%
Cornwall Electric	CNPI-Distribution	administrative services	cost based	32,535	32,535	20%
Fortis Inc.	CNPI-Distribution	administrative services	cost based	160,643	160,643	37%

Year: 2016 Bridge

Name of Company From	Name of Company To	Service Offered	Pricing Methodology	Price for the Service $	Cost for the Service $	Percentage Allocation %
FortisOntario	CNPI-Distribution	corporate services	cost based	523,208	523,208	24%
FortisOntario	CNPI-Distribution	building rent	market based	349,437	349,437	64%
CNPI-Distribution	Cornwall Electric	administrative services	cost based	1,017,801	1,017,801	17%
CNPI-Distribution	FortisOntario	administrative services	cost based	82,218	82,218	1%
CNPI-Distribution	CNPI-Transmission	administrative services	cost based	414,068	414,068	7%
CNPI-Distribution	Algoma Power	administrative services	cost based	1,398,626	1,398,626	24%
Cornwall Electric	CNPI-Distribution	administrative services	cost based	38,678	38,678	20%
Fortis Inc.	CNPI-Distribution	administrative services	cost based	197,140	197,140	37%

Year: 2017 Test

Name of Company From	Name of Company To	Service Offered	Pricing Methodology	Price for the Service $	Cost for the Service $	Percentage Allocation %
FortisOntario	CNPI-Distribution	corporate services	cost based	536,686	536,686	24%
FortisOntario	CNPI-Distribution	building rent	market based	342,503	342,503	62%
CNPI-Distribution	Cornwall Electric	administrative services	cost based	998,396	998,396	16%
CNPI-Distribution	FortisOntario	administrative services	cost based	100,069	100,069	2%
CNPI-Distribution	CNPI-Transmission	administrative services	cost based	441,904	441,904	7%
CNPI-Distribution	Algoma Power	administrative services	cost based	1,508,302	1,508,302	25%
Cornwall Electric	CNPI-Distribution	administrative services	cost based	25,946	25,946	13%
Fortis Inc.	CNPI-Distribution	administrative services	cost based	197,140	197,140	37%
CNPI-Distribution	Cornwall Electric	shared IT	cost based (Note 1)	404,139	404,139	24%
CNPI-Distribution	FortisOntario	shared IT	cost based (Note 1)	14,986	14,986	1%
CNPI-Distribution	CNPI-Transmission	shared IT	cost based (Note 1)	91,117	91,117	6%
CNPI-Distribution	Algoma Power	shared IT	cost based (Note 1)	571,402	571,402	35%
CNPI-Distribution	Cornwall Electric	shared equipment	cost based (Note 1)	4,606	4,606	2%
CNPI-Distribution	CNPI-Transmission	shared equipment	cost based (Note 1)	52,967	52,967	23%

Note 1: Price for the Service is the depreciation cost plus cost of capital based on average NBV

Table 4.5.1.1

Shared Services Cost Variances - 2017 Test Year to 2013 Board Approved					
Name of Company			**Cost for the Service**		
From	**To**	**Service Offered**	**2013 Board Approved**	**2017 Test Year**	**Variance**
FortisOntario	CNPI-Distribution	corporate services	$ 506,044	$ 536,686	$ 30,642
FortisOntario	CNPI-Distribution	building rent	$ 342,711	$ 342,503	-$ 208
CNPI-Distribution	Cornwall Electric	administrative services	$ 954,583	$ 998,396	$ 43,813
CNPI-Distribution	FortisOntario	administrative services	$ 132,732	$ 100,069	-$ 32,663
CNPI-Distribution	CNPI-Transmission	administrative services	$ 388,587	$ 441,904	$ 53,317
CNPI-Distribution	Algoma Power	administrative services	$ 1,397,112	$ 1,508,302	$ 111,191
Cornwall Electric	CNPI-Distribution	administrative services	$ 71,426	$ 25,946	-$ 45,480
Fortis Inc.	CNPI-Distribution	administrative services	$ 121,352	$ 197,140	$ 75,788
CNPI-Distribution	Cornwall Electric	shared IT		$ 404,139	$ 404,139
CNPI-Distribution	FortisOntario	shared IT		$ 14,986	$ 14,986
CNPI-Distribution	CNPI-Transmission	shared IT		$ 91,117	$ 91,117
CNPI-Distribution	Algoma Power	shared IT		$ 571,402	$ 571,402
CNPI-Distribution	Cornwall Electric	shared equipment		$ 4,606	$ 4,606
CNPI-Distribution	CNPI-Transmission	shared equipment		$ 52,967	$ 52,967

The variance of $111,191 in administrative costs allocated from CNPI-Distribution to Algoma Power relates primarily to an increase the percentage of costs from administrative departments (Finance, HR and IT) allocated to Algoma Power relative to other affiliates.

The total costs of $1,139,217 associated with shared IT and equipment in the 2017 Test Year have been included as revenue offsets within the RRWF for 2017. These costs relate to changes in the allocation of costs for shared assets, as detailed in Exhibit 2, Tab 1, Schedule 1.

Table 4.5.1.2 shown below details the variances from the 2015 actuals to the 2017 Test Year. There are no material changes in amounts allocated.

Table 4.5.1.2

Shared Services Cost Variances - 2017 Test Year to 2015 Actual					
Name of Company			Cost for the Service		
From	To	Service Offered	2015 Actual	2017 Test Year	Variance
FortisOntario	CNPI-Distribution	corporate services	$ 498,468	$ 536,686	$ 38,218
FortisOntario	CNPI-Distribution	building rent	$ 342,585	$ 342,503	-$ 82
CNPI-Distribution	Cornwall Electric	administrative services	$ 1,027,037	$ 998,396	-$ 28,641
CNPI-Distribution	FortisOntario	administrative services	$ 81,977	$ 100,069	$ 18,091
CNPI-Distribution	CNPI-Transmission	administrative services	$ 397,854	$ 441,904	$ 44,050
CNPI-Distribution	Algoma Power	administrative services	$ 1,426,761	$ 1,508,302	$ 81,542
Cornwall Electric	CNPI-Distribution	administrative services	$ 32,535	$ 25,946	-$ 6,589
Fortis Inc.	CNPI-Distribution	administrative services	$ 160,643	$ 197,140	$ 36,497

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Appendix 2-N
Shared Services/Corporate Cost Allocation - Canadian Niagara Power Inc.

Year: 2013 Board Approved

Name of Company		Service Offered	Pricing Methodology	Price for the Service	Cost for the Service	Percentage Allocation
From	To			$	$	%
FortisOntario	CNPI-Distribution	corporate services	cost based	506,044	506,044	24%
FortisOntario	CNPI-Distribution	building rent	market based	342,711	342,711	67%
CNPI-Distribution	Cornwall Electric	administrative services	cost based	954,583	954,583	20%
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Year: 2017 Test

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FortisOntario	CNPI-Distribution	building rent	market based	342,503	342,503	62%
CNPI-Distribution	Cornwall Electric	administrative services	cost based	998,396	998,396	16%
CNPI-Distribution	FortisOntario	administrative services	cost based	100,069	100,069	2%
CNPI-Distribution	CNPI-Transmission	administrative services	cost based	441,904	441,904	7%
CNPI-Distribution	Algoma Power	administrative services	cost based	1,508,302	1,508,302	25%
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CNPI-Distribution	Cornwall Electric	shared IT	cost based (Note 1)	404,139	404,139	24%
CNPI-Distribution	FortisOntario	shared IT	cost based (Note 1)	14,986	14,986	1%
CNPI-Distribution	CNPI-Transmission	shared IT	cost based (Note 1)	91,117	91,117	6%
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CNPI-Distribution	CNPI-Transmission	shared equipment	cost based (Note 1)	52,967	52,967	23%

Note 1: Price for the Service is the depreciation cost plus cost of capital based on average NBV

Appendix A
Shared Services Agreement

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SERVICES AGREEMENT

BETWEEN

Canadian Niagara Power Inc.,

Cornwall Street Railway, Light and Power Company Limited,

Algoma Power Inc., and

FortisOntario Inc.

MADE AS OF

September 15, 2015

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SCHEDULE "A"

SERVICES AGREEMENT

THIS AGREEMENT is made as of September 15, 2015.

BETWEEN:

Canadian Niagara Power Inc., a corporation incorporated under the laws of the Province of Ontario; ("CNPI"),

Cornwall Street Railway, Light and Power Company Limited a corporation incorporated under the laws of the Province of Ontario ("Cornwall"),

Algoma Power Inc., a corporation incorporated under the laws of the Province of Ontario ("Algoma"),and

FortisOntario Inc. a corporation incorporated under the laws of the Province of Ontario ("FortisOntario" and together with CNPI, Cornwall, Algoma, and FPC, the "Fortis Entities" and each a "Fortis Entity").

THIS AGREEMENT WITNESSES that, in consideration of the covenants and agreements herein contained, the parties hereto agree as follows:

ARTICLE 1 – GENERAL

1.01 Services

"Services" means:

a) building maintenance including security, janitorial services, snow plowing, lawn care, major and minor repairs;

b) purchasing including procurements, order tracking, delivery of operating and capital items, payment processing and vendor management;

c) stores management including maintaining stock levels, issuing and receiving, maintenance of SAP inventory management system and disposition of excess assets;

d) customer service and customer care services, including meter reading, (including verification, testing, approval, installation and removal systems) billing and collection services and related SAP systems;

e) health and safety monitoring including the development of policies and procedures, training (awareness and procedures), site inspections and field audits;

f) environmental compliance monitoring including the development of policies and procedures, training (awareness and procedures), regulatory reporting, government liaison and site inspections;

g) human resources administration including development of policies and procedures, union relations and negotiations, personnel file management, wholesale settlement services and management of employee benefit plans;

h) regulatory reporting and compliance services;

i) bookkeeping including the provision of statutory financial and regulatory reporting, management reporting and financial systems administration;

j) payroll including the maintenance of payroll records and payroll system, calculation of pay and payroll deductions, and facilitation of payroll payments;

k) financial management including cash administration, investments and debt management, treasury services, internal audit services, and development of financial and account policies and procedures;

l) executive, legal and secretarial services;

m) tax administration, filing and payment, including compliance, regulatory reporting and filing, planning, audit reviews, transfer of tax liabilities and the payments, filing of tax reports, and exposure management;

n) information technology including the provision and management of systems, system and hardware support services, major and minor repairs, development and policies and procedures, and monitoring of information technology developments;

o) monitoring the status of generating facilities using supervisory control and data acquisition (SCADA) technology;

p) such other services as may from time to time be agreed upon between the parties.

1.02 Capacities of Parties

Pursuant to the terms of this Agreement, each of the Fortis Entities shall both provide Services to the other Fortis Entities, as requested, and receive Services that they have requested from one or more of the other Fortis Entities. A Fortis Entity in the capacity as a provider of Services is referred to as a "Service Provider". A Fortis Entity in the capacity as a receiver of Services is referred to as a "Service Recipient". When reference is made to the provision of Services by "the Service Providers" or "each Service Provider" to "each Service Recipient" or "the Service Recipients", it shall be interpreted to exclude any provision of Services by any Fortis Entity to itself.

1.03 Services

Subject to the terms and conditions hereof, each Service Recipient will, from time to time, request that one or more of the Service Providers carry out one or more of the Services and each Service Provider will render the Services requested by the Service Recipient as requested.

1.04 Term of Agreement

The provision of Services by the Service Providers to the Service Recipients hereunder shall commence on September 15, 2015 and shall continue until September 15, 2020 or earlier if terminated by the parties hereto as set forth in Article 5 hereof.

ARTICLE 2 – REMUNERATION OF SERVICE PROVIDERS

2.01 Fee for Services and Cost Mechanism

In respect of fee for services, the Service Recipients shall each pay their respective Service Providers for the Services provided under the Agreement a fee reflecting cost plus a reasonable rate of return and shall be reviewed at the option of either the respective Service Recipient or Service Provider. For the purpose of this Agreement, reasonable rate of return shall mean a return on invested capital that is the higher of the utility's approved rate of return or the bank prime rate.

Where a utility provides a Service, resource or product to a generating affiliate, the utility shall ensure that the sale price is no less than the utility's fully loaded cost of the Service, resource or product. Where a utility receives Services from a generating affiliate, the utility shall ensure that the sale price for such Services is no more than the generator's fully loaded cost of the Service.

For greater certainty (i) each Service Recipient shall only be liable to pay for Services provided to it, and shall not be liable to pay for any Services provided to any other Service Recipient; and (ii) each Service Provider shall only be liable for its own acts or omissions and shall not be liable for the acts or omissions of any other Service Provider.

2.02 Expenses

The Service Provider shall be responsible for all day to day expenses incurred in connection with the Services provided pursuant to Section 1.03. However, each Service Recipient shall reimburse its respective Service Provider for all extraordinary expenses actually and properly incurred by the Service Provider in the performance of the Services to such Service Recipient hereunder provided that such expenses shall be paid in accordance with the normal practices of the Service Recipient in force from time to time.

2.03 Invoices

Payment shall be made to the Service Provider with respect to the fees and expenses referred to in Sections 2.01 and 2.02 within 10 days from receipt by the Service Recipient of proper invoices and vouchers, all of which shall be submitted by the respective Service Provider to the appropriate Service Recipient by the last day of the following month during the term of this Agreement. The Service Provider shall also provide a report to each Service Recipient to which it has provided Services, annually of all expenses incurred in connection with the provision of Services pursuant to Section 1.03 hereof.

2.04 Cost Allocation Methodology

In respect of shared costs, costs shall be allocated based upon an appropriate cost allocation methodology to be determined by the respective Service Provider and Service Recipient. The cost allocation methodology shall be reviewed by the respective Service

Provider and Service Recipient at the option of either party, or at least every five years. The allocation factors that comprise the methodology shall be reviewed and updated by the parties annually.

ARTICLE 3 – COVENANTS OF SERVICE PROVIDERS

3.01 Services

Each Service Provider shall render performance of the Services hereunder to the best of the Service Provider's ability and in a competent and professional manner.

3.02 Time of Services

Each Service Provider shall devote such of its time and attention to the business of its respective Service Recipients as may be agreed to by the Service Provider and its respective Service Recipient. The time of Services to be provided hereunder by the Service Providers shall be as agreed to from time to time by negotiations between each Service Recipient and its respective Service Provider. Subject to the obligations of the Service Providers hereunder, the Service Providers shall be free to offer such services to any other person.

3.03 Licences and Permits

The Service Provider shall be responsible for obtaining all necessary licences and permits and for complying with all applicable federal, provincial and municipal laws, codes and regulations in connection with its provision of the Services hereunder and the Service Provider shall, when requested, provide their respective Service Recipients with adequate evidence of its compliance with this Section 3.03.

3.04 Rules and Regulations

Each Service Provider shall (subject to applicable exemptions) comply, while on the premises used by the Service Recipients, with all the rules and regulations of the Service Recipients from time to time in force which are brought to its notice or of which it could reasonably be aware, and the applicable provision of the *Electricity Act, 1998* (Ontario) and the regulations thereunder, the *Ontario Energy Board Act*, 1998 (Ontario) and the regulations thereunder, applicable licences from the Ontario Energy Board, IESO market rules, the Affiliate Relationships Code, the Distribution System Code, the Transmission System Code, the Retail Settlement Code, and the Standard Service Supply Code and such other applicable codes, rules and regulations, which from time to time shall come into force.

3.05 Regulatory Compliance

Each Service Provider shall ensure that any order or measure made or taken by the Ontario Energy Board:

(i) that is brought to its attention or of which it becomes aware;

(ii) that is directed at or affects its respective Service Recipients; and

(iii) that, in order to be implemented or complied with, is dependent in whole or in part upon any Service or task that the Service Provider is obligated to perform hereunder;

shall be fully implemented or complied with to the extent of obligations hereunder. In connection with this section, each Service Recipient agrees that it will promptly notify its respective Service Providers of any order or measure of the Ontario Energy Board directed at or affecting such Service Recipient.

Nothing in this Agreement will prevent the Service Recipient(s) from taking any steps, including without limitation using the Service Recipient(s) own resources or those of a third party, that are necessary to implement or comply with the applicable Ontario Energy Board licence, or any other applicable provisions of the applicable legislation, regulations and market rules, or any order or measure made or taken by the Ontario Energy Board.

3.06 Insurance

Each Service Provider shall pay for and maintain for the benefit of the Service Provider and its respective Service Recipients, with insurers or through the appropriate government department and in an amount and in a form acceptable to the Service Recipients, appropriate insurance concerning the operations and liabilities of the Service Provider relevant to this Agreement including, without limiting the generality of the foregoing, workers' compensation and employment insurance in conformity with applicable statutory requirements in respect of any remuneration payable by the Service Provider to any employees of the Service Provider and public liability and property damage insurance.

3.07 Indemnity

The Service Provider shall indemnify and save its respective Service Recipients harmless from and against all claims, actions, losses, expenses, costs or damages of every nature and kind whatsoever which the Service Recipients or its officers, employees or agents may suffer as a result of the negligence of the Service Provider in the performance or non-performance of this Agreement.

3.08 Non-disclosure and Confidentiality

The Service Provider shall not (either during the term of this Agreement or at any time thereafter) disclose any information relating to the private or confidential affairs of any Service Recipient or relating to any secrets of any Service Recipient to any person other than with the consent of such Service Recipient. In the case of information supplied by a distribution facility to a generation facility, the information will be used solely for the purposes of efficiently operating the generation facility and shall not be shared with any other affiliate or any other party to which it may offer a competitive advantage.

3.09 Access to Confidential Information

All confidential information must be protected. Access to a utility's information services shall include appropriate computer data management and data access protocols. In the event that a utility shares employees with a generating affiliate, such employees shall be bound to maintain the confidentiality of information provided for herein, except as otherwise required by applicable law.

3.10 Monitoring Services

Each Service Provider shall provide to its respective Service Recipients all information that such Service Recipients require so that the Service Recipients can monitor the provision of its applicable licensed Services provided by the Service Provider. Each Service Provider will also provide information as requested by its respective Service Recipients which is required for such Service Recipients fulfillment of its applicable Ontario Energy Board licence.

ARTICLE 4 – TERMINATION

4.01 Termination by Service Recipients or Service Providers for Cause

Any Fortis Entity may terminate its relationship to provided or receive Services from any other Fortis Entity (the "Non-Compliant Entity") in the event of the failure of the Non-Compliant Entity to comply with any of the provisions hereunder upon such Non-Compliant Entity being notified in writing by the Fortis Entity alleging such failure and failing to remedy such failure within 30 days of receiving such notice.

4.02 Termination by Service Recipients or Service Providers on Notice

Any Fortis Entity may terminate any agreement to receive Services from, or provide Services to, any other Fortis Entity upon the giving of 60 days written notice to the other party. Notwithstanding the foregoing, any Service Recipient may terminate its obligations to receive Services from any Service Provider immediately upon paying to the Service Provider 60 days' fee for Services in lieu of such notice. Any termination effective between two Fortis Entities shall not effect any other obligation of such Fortis Entities to each other or to any other Fortis Entity.

4.03 Provisions which Operate Following Termination

Notwithstanding any termination of this Agreement for any reason whatsoever and with or without cause, the provisions of Sections 3.06, 3.07 and 3.08 and any other provisions of this Agreement necessary to give efficacy thereto shall continue in full force and effect following any such termination. Any termination effective between two Fortis Entities shall not effect any other obligation of such Fortis Entities to each other or to any other Fortis Entity.

4.04 Change of Control

To the extent that a Fortis Entity sells all or substantially all of its assets or there is a change of control of any Fortis Entity, either by way of change of the ownership structure of any of the Fortis Entities or otherwise, all obligations of any Fortis Entity to provide Services to, or receive Service from such changed Fortis Entity, pursuant to the terms of this Agreement, shall cease effective the date of such change of control. For greater certainty the immediately preceding sentence shall not effect Section 4.03.

ARTICLE 5 – ARBITRATION

5.01 Arbitration of Disputes

Any disputes arising between the parties relating to the interpretation of any provision of this Agreement or other matters which under the provisions of this Agreement are to be referred to arbitration shall be settled by arbitration in accordance with the provisions of Section 5.02.

5.02 Appointment of Arbitrator and Arbitration Procedures

a) In the event of disagreement, litigation or dispute with respect to the interpretation, application or execution of one or the other of the provisions of this Agreement the parties hereto renounce their right to institute legal proceedings and undertake to submit such disagreement, litigation or dispute to the final decision pursuant to Arbitration in accordance with Schedule "A" hereto.

b) The fees and disbursements of the arbitrator shall be shared equally by the Fortis Entities that are engaged in such dispute.

c) The arbitration provided for in this Agreement is subject to the provisions of the *Arbitration Act* (Ontario), to the extent that such provisions are not incompatible herewith.

ARTICLE 6 – INTERPRETATION AND ENFORCEMENT

6.01 Sections and Headings

The division of this Agreement into Articles and Sections and the insertion of headings are for the convenience of reference only and shall not affect the construction or interpretation of this Agreement. The terms "this Agreement", "hereof", "hereunder" and similar expressions refer to this Agreement and not to any particular Article, Section or other portion hereof and include any agreement or instrument supplemental or ancillary hereto. Unless something in the subject matter or context is inconsistent therewith, references herein to Articles and Sections are to Articles and Sections of this Agreement.

6.02 Extended Meanings

In this Agreement words importing the singular number only include the plural and *vice versa*, words importing any gender include all genders and words importing persons include individuals, partnerships, associations, trusts, unincorporated organizations and corporations and *vice versa*.

6.03 Benefit of Agreement

This Agreement shall enure to the benefit of and be binding upon successors and assigns of the Fortis Entities.

6.04 Entire Agreement

This Agreement constitutes the entire agreement between the parties with respect to the subject matter hereof and cancels and supersedes any prior understandings and agreements between the parties hereto with respect thereto. There are no representations, warranties, forms, conditions, undertakings or collateral agreements, express implied or statutory between the parties other than as expressly set forth in this Agreement.

6.05 Amendments and Waivers

No amendment to this Agreement shall be valid or binding unless set forth in writing and duly executed by both of the parties hereto. No waiver of any breach of any term or provision of this Agreement shall be effective or binding unless made in writing and signed by the party purporting to give the same and, unless otherwise provided in the written waiver, shall be limited to the specific breach waived.

6.06 Assignment

Except as may be expressly provided in this Agreement, no Fortis Entity may assign his or its rights or obligations under this Agreement without the prior written consent of each other Fortis Entity.

6.07 Severability

If any provision of this Agreement is determined to be invalid or unenforceable in whole or in part, such invalidity or unenforceability shall attach only to such provision or part thereof and the remaining part of such provision and all other provisions hereof shall continue in full force and effect.

6.08 Notices

Any demand, notice or other communication to be made or given in connection with this Agreement shall be made or given in writing and may be made or given by personal delivery or by registered mail addressed to the recipient as follows:

To CNPI:

Canadian Niagara Power Inc.
1130 Bertie Street
P.O. Box 1218
Fort Erie, Ontario L2A 5Y2
Attention: R. Scott Hawkes
Fax: (905) 994-2211

To Cornwall Electric:

Cornwall Street Railway, Light and Power Company Limited
1130 Bertie Street
P.O. Box 1218
Fort Erie, Ontario L2A 5Y2
Attention: R. Scott Hawkes
Fax: (905) 994-2211

To Algoma:

Algoma Power Inc.
1130 Bertie Street
P.O. Box 1218
Fort Erie, Ontario L2A 5Y2
Attention: R. Scott Hawkes
Fax: (905) 994-2211

To FortisOntario:

FortisOntario Inc.
1130 Bertie Street
P.O. Box 1218
Fort Erie, Ontario L2A 5Y2
Attention: William J. Daley
Fax: (905) 994-2202

or such other address or individual as may be designated by notice by either party to the other. Any demand, notice or other communication made or given by personal delivery shall be conclusively deemed to have been given on the day of actual delivery thereof and, if made or given by registered mail, on the 5th day, other than a Saturday, Sunday or statutory holiday in the province of the recipient Fortis Entity, following the deposit thereof in the mail. If the party giving any demand, notice or other communication knows or ought reasonably to know of any difficulties with the postal system which might affect the delivery of the mail, any such demand, notice or other communication shall not be mailed but shall be made or given by personal delivery.

6.09 Further Assurances

Each party must from time to time execute and deliver all such further documents and instruments and do all acts and things as the other party may reasonably require to effectively carry out or better evidence or perfect the full intent and meaning of this Agreement.

6.10 Governing Law

This Agreement shall be governed by and construed in accordance with the laws of the Province of Ontario, and the laws of Canada applicable therein.

6.11 Attornment

For the purpose of all legal proceedings this Agreement shall be deemed to have been performed in the Province of Ontario and, subject to Article 5 of this Agreement, the courts of the Province of Ontario shall have jurisdiction to entertain any action arising under this Agreement.

IN WITNESS WHEREOF the parties have executed this Agreement.

Canadian Niagara Power Inc.

Per: R. Scott Hawkes

Name: R. Scott Hawkes
Title: Vice President, Corporate Services and General Counsel

Cornwall Street Railway, Light and Power Company Limited

Per: ______________________________

Name: R. Scott Hawkes
Title: Vice President, Corporate Services and General Counsel

Algoma Power Inc.

Per: ______________________________

Name: R. Scott Hawkes
Title: Vice President, Corporate Services and General Counsel

FortisOntario Inc.

Per: ______________________________

Name: William J. Daley
Title: President and Chief Executive Officer

SCHEDULE "A"

ARBITRATION

Any dispute between the parties hereto, or any matter to be submitted to arbitration hereunder, whether arising during the period of this Agreement or at any time thereafter which touches upon the validity, construction, meaning, performance or effect of this Agreement or the rights and liabilities of the parties hereto or any matter arising out of or connected with this Agreement shall be subject to arbitration pursuant to the *Arbitration Act* (Ontario) and as provided in this Schedule A and the decision shall be final and binding as between the parties hereto and shall not be subject to appeal.

Any arbitration to be carried out under this Schedule A shall be subject to the following provisions, namely:

The party desiring arbitration shall nominate one (1) arbitrator and shall notify the other party hereto of such nomination. Such notice shall set forth a brief description of the matter submitted for arbitration and, if appropriate, the paragraph hereof pursuant to which such matter is so submitted. Such other party shall within thirty (30) days after receiving such notice nominate an arbitrator and the two (2) arbitrators shall select a chairman of the arbitral tribunal to act jointly with them. If the said arbitrators shall be unable to agree in the selection of such chairman, the chairman shall be designated by a Judge of the Superior Court of Justice or any successor thereto upon an application. The arbitration shall take place in the Town of Fort Erie, Regional Municipality of Niagara, and the chairman shall fix the time and place in the Town of Fort Erie for the purpose of hearing such evidence and representations as either of the parties may present and, subject to provisions hereto, the decision of the arbitrators and chairman or any of two (2) of them in writing shall be binding upon the parties both in respect of procedure and the conduct of the parties during the proceedings and the final determination of the issues herein. Said arbitrators and chairman shall, after hearing any evidence and representations that the parties may submit, make their decision and reduce the same to writing and deliver one (1) copy thereof to each of the parties hereto. The majority of the chairman and arbitrators may determine any matters of procedure for the arbitration not specified herein.

If the party hereto receiving the notice of the nomination of an arbitrator by the party desiring arbitration fails within the thirty (30) days to nominate an arbitrator, then the arbitrator nominated by the party desiring arbitration may proceed alone to determine the dispute in such manner and at such time as he shall think fit and his decision shall, subject to the provisions hereof, be binding upon the parties.

Notwithstanding the foregoing, any arbitration may be carried out by a single arbitrator if the parties hereto so agree, in which event the provisions of this paragraph shall apply, *mutatis mutandis*.

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Appendix B
BDR Report

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STUDY OF AFFILIATE SERVICE COSTS AND COST ALLOCATION

Prepared for
Canadian Niagara Power Inc.
April 11, 2016

BDR NorthAmerica Inc.
34 King Street East
Suite 600
Toronto, ON M5C 2X8
416-807-3332 phone

BDR

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1 SUMMARY OF STUDY AND FINDINGS

FortisOntario owns and operates four Ontario electricity distribution business units and a transmission business unit. Within the FortisOntario organization, management and specialist staff, and certain key systems and facilities are shared to maximize efficiencies of scale, avoid duplication, and provide the required skills and expertise to each business function. In order to prepare appropriate revenue requirements for the 2017 distribution rate application of its subsidiary, Canadian Niagara Power Inc., for rates in its service territories of Niagara and Gananoque, FortisOntario conducted a study to allocate the shared costs among its business units. If approved by the Ontario Energy Board ("OEB"), the costs allocated to the regulated distribution business units will become part of the revenue requirement for those business units in 2017.

CNPI requested BDR NorthAmerica Inc. ("BDR") to review the methodology in the study to allocate the shared costs, based on BDR's extensive experience in cost allocation for energy utilities.

Based on the information provided by CNPI, BDR has concluded that the approach is reasonable and consistent with acceptable methods of cost allocation for regulated utilities.

2 INTRODUCTION AND SCOPE

FortisOntario is a holding company which owns and operates electricity transmission and distribution business units as well as generation assets in Ontario. Its subsidiary CNPI has distribution territories located in Fort Erie and Port Colborne (together "Niagara") and Gananoque, and transmission assets located in Fort Erie, all of which are licensed and regulated as to rates by the OEB. Its electricity distribution subsidiary Algoma Power Inc. ("Algoma" or "API") is also licensed and regulated as to rates by the OEB. Another subsidiary, Cornwall Street Railway Light and Power Company Limited ("Cornwall Electric"), operates an electricity distribution system in the City of Cornwall. The Cornwall Electric distribution business is licensed by the OEB.

CNPI is required to obtain the approval of the OEB for the 2017 distribution rates in the Niagara business unit and the Gananoque business unit, and as part of the process, to establish and submit to the OEB cost information in support of the revenue requirements of each business unit.

Within the FortisOntario organization, staff, systems and certain facilities are shared to maximize efficiencies of scale, avoid duplication, and provide the required skills and expertise to each business function. Examples of these shared functions are executive management, administrative support functions (finance, human resources, health, safety and environment and information technology) and asset management. These activities support and provide benefits to all of FortisOntario's regulated business units and to its unregulated business activities. Where permitted by considerations of location, customer service, engineering and operations staff, systems and equipment are also shared. The costs are shared by the business units based on allocation.

In order to recover the allocated portion of shared costs through the rates of the rate-regulated transmission and distribution business units, approval is required from the OEB. The allocated portion of shared costs must be supported by documentation of the costs involved, the services performed, and the methodology used for the allocation.

To support its application to the OEB for approval of 2013 rates in CNPI's service territories (EB-2012-0112), FortisOntario retained the services of BDR to review the methodology of the cost allocations and to provide an opinion as to the reasonableness of the overall approach and the specific allocation treatment of each cost function. Computations and background data were provided for BDR's review. The work resulted in a report dated May 8, 2012, titled "Study of Affiliate Service Costs and Cost Allocation" that was prepared by BDR and filed with the OEB in CNPI's application as Exhibit 4, Tab 5, Schedule 2, Appendix E, in EB-2012-0112 (the "2012 BDR report").

On acquiring API, FortisOntario integrated the operations of API with those of CNPI, so that by the time CNPI's cost of service application was filed, the revenue requirements of CNPI's service territories reflected cost reductions as a result of allocations to API, as API was fully brought into the shared services structure. The cost allocation methodology and results reviewed in the 2012 BDR report therefore reflected the allocations of costs to CNPI, Cornwall Electric and also API.

On April 3, 2014, FortisOntario requested BDR to provide a letter for filing in API's cost of service application for 2015 rates (EB-2014-0055), providing an opinion on the cost allocation methodology as applied specifically to API. The resulting letter, dated May 2, 2014, was filed with the OEB as an exhibit in the proceeding.

To support its application to the OEB for approval of 2017 rates in CNPI's service territories, FortisOntario has once again retained the services of BDR to review the methodology of the updated cost allocations and to provide an opinion as to the reasonableness of the overall approach and the specific allocation treatment of each cost function. Computations and background data were provided for BDR's review. BDR was not requested to comment on the overall level of the costs or on the degree to which operational synergies are or will be achieved by this arrangement.

3 CONSULTANT QUALIFICATIONS

BDR NorthAmerica Inc. is a Toronto-based consultancy specializing in services to energy sector participants who include governments, regulators, public and investor-owned utilities, generators, prospective investors and consumers. Our areas of specialization include:

Regulatory and Tariffs: BDR advises clients who are regulated entities in all aspects of dealing with regulators. This includes studies in support of rates and revenue requirements, such as rate designs, cost of capital, cost allocation and working capital analysis, as well as supporting applications for capital projects, mergers and acquisitions. Services include analysis and expert testimony where required.

Mergers and Acquisitions: A changing industry requires basic reassessments and decisions to merge and/or acquire businesses and to expand some businesses and exit others. BDR has managed the process of merger, divestment and acquisition of "wires" facilities, and also of generation and other unregulated businesses in the electricity industry. Key in these assignments is the development of a valuation for the enterprise, which ultimately involves an assessment of the condition of the assets and liabilities involved.

Business and Strategic Planning: BDR staff has completed strategic business plans and options analyses for well over 100 clients in the electricity sector. These plans include consideration of the strengths and weaknesses of the client in a range of business options, all of which are assessed in the context of the business and regulatory climate and current government policy.

This assignment was carried out by Paula Zarnett, Vice President of BDR. She is a Certified Management Accountant, and has an MBA (Finance) from the University of Calgary. Ms. Zarnett's three decades of cost allocation experience include:

- Customer class cost allocation studies for natural gas utilities in Manitoba and Alberta;
- leading an in-house team in a one-year cross functional project to perform Toronto Hydro's first cost allocation study (pre-restructuring);
- a cost allocation and rate design study for Enwave District Energy;
- three cost allocation studies for Saint John Energy, a municipal utility in New Brunswick;
- advice to the municipal utilities of New Brunswick in their interventions in NB Power's current application to the NBEUB for approval of a cost allocation methodology[1]; and

[1] Matter 271. Hearings have concluded, with the EUB's decision pending.

- for Toronto Hydro-Electric System, a study to allocate costs to a proposed new class of customers who are individually metered suites in multi-unit residential buildings.

She participated on behalf of a client in the OEB's stakeholder processes regarding cost allocation for electricity distribution service, and was an instructor in cost allocation and rate design (advanced) at CAMPUT's annual utility regulation course in 2006, 2007 and 2008. She has testified before the regulators in Ontario, New Brunswick, Québec and British Columbia.

A former Toronto Hydro employee, Paula is knowledgeable in the typical business processes of distribution utilities and their affiliates. In addition to having prepared evidence in support of FortisOntario's shared cost allocation and transfer pricing approach in successive cost of service applications, she also provided evidence to the OEB on shared cost allocation for:

- EnWin Utilities
- Kingston Hydro
- Oakville Hydro
- Greater Sudbury Hydro, and
- Bluewater Power.

She recently concluded an assignment for Gazifère Inc., a natural gas distributor serving about 40,000 customers in the Province of Québec, to allocate shared costs between the company's regulated services and its various unregulated activities. The assignment included preparation of a report for filing with the Régie de l'énergie and oral testimony before the Régie[2].

4 APPROACH TO THE ASSIGNMENT

The purpose of this study was to allocate to CNPI's service territories of Niagara and Gananoque the costs of shared staff and facilities. The costs involved are costs that *cannot be directly attributed to a single business unit*, and therefore must be allocated based on some fair and reasonable methodology.

The essence of the methodology is, for each type of cost, to attempt to identify an objectively measurable variable (or a combination of variables) that is (a) causally related to the incurrence of the cost, and/or (b) related to the value that is created by the incurrence of the cost; such a variable is generally termed a "cost driver". Each type of cost is then allocated to each business unit based on its share of the identified cost driver.

[2] Requête 3924-2015.

The selection of cost drivers is the key area for professional judgment since, once the cost drivers are selected, the related computations are straightforward.

Late in 2015, management of FortisOntario undertook the work of identifying and quantifying the cost of functions that are shared among its affiliates and gathering cost driver data to support allocations. Except as specifically set out in this report, the selection of cost drivers follows the precedent of previous allocations of FortisOntario and CNPI costs. FortisOntario then computed the cost responsibility of each affiliate company and/or service territory as appropriate. The data and computations were provided to BDR in January, 2016 for review. BDR did not make any independent audit either of financial information or of the data related to cost drivers.

The review focuses on the types of costs for which FortisOntario is proposing to make an allocation to be recovered in the revenue requirements of its Niagara and Gananoque business units. All of the cost types involved are cost types for which FortisOntario's subsidiary, CNPI, has previously received approval to include an allocation for the revenue requirement of its distribution service territories. Because of this, BDR has treated the issue of the appropriateness of sharing and allocating such costs within the FortisOntario group of business units as already determined to be acceptable.

5 Overview of Shared Functions and Allocation Methodology

The regulated businesses of FortisOntario have requirements for the same business functions, but operate in non-contiguous service territories. There is therefore both an opportunity for sharing of functions and a requirement for some employees to be based locally in each of the communities served.

Over time, FortisOntario has taken steps to realize available synergies in the work assignments of its employees, subject to the constraints of location. The following corporate services are based in Fort Erie and are shared by the FortisOntario business units:

- Executive
- Regulatory
- Finance
- Safety
- Human Resources
- Information Technology.

As well, in each of the service territories, there are employees who perform services for other service territories and/or Fortis/Ontario's unregulated business units.

- In Algoma, as a result of its more remote location from the rest of the FortisOntario service territories, most of the employees perform services only for the Algoma service territory; however, employees in the areas of finance, human resources, safety and information technology have had their work integrated with the FortisOntario corporate functional groups and have therefore become a shared resource on the same basis as the members of these functional groups located in Fort Erie. One employee devotes a small percentage of effort at the FortisOntario level.
- All of the distribution business units receive the benefit of services from CNPI's Fort Erie-based customer service staff, although each individual is different in terms of which of the business units they serve.
- Some members of the Fort-Erie based engineering and operations staff perform services for other distribution business units, and the transmission business unit.
- Members of functional management based in Fort Erie perform services for the other distribution service territories and the transmission business unit.

As a result of this sharing of almost all types of resources among the business units of FortisOntario, the approach taken to the allocation was to:

- first allocate the efforts of each employee in all functions other than human resources, safety and information technology,
- then allocate human resources, safety and information technology based on the allocation of the employees served by these functions,
- and finally, to allocate supporting resources, such as space in the Fort Erie building on the basis of the employees working from that building.

This approach required FortisOntario to review, on an employee by employee basis, the sharing of its resources among the business units. This is the approach that has been used in allocating shared costs for several years. Note that except for the specific sharing arrangements noted above, employees in Algoma Power are fully utilized in the Algoma service territory and not shared. Similarly there are six employees in Gananoque. Of these, 4 FTEs are fully dedicated to duties in the Gananoque service territory. These employees are therefore not part of the allocations, except for purposes of allocation of Human Resources, Safety and Information Technology.

BDR reviewed the results of this analysis, in the form of a spreadsheet, and considered the reasonableness of the allocation approach applied. BDR did not otherwise confirm the information received from FortisOntario management.

6 Specific Allocations

6.1 *Customer Service and Billing*

Of the customer service employees based in Fort Erie, four individuals serve only the Niagara service territory. Others share their time with Gananoque, Cornwall Electric, and/or Algoma. These FTEs have been allocated in proportion to the number of customers in the territories they serve. Gananoque service territory receives customer service primarily out of Cornwall. The customer service FTEs located in Cornwall are allocated between Cornwall Electric and Gananoque on the basis of number of customers.

On review, BDR considers this approach reasonable and consistent with acceptable methods of distribution cost allocation. It is also consistent with the methodology previously applied by FortisOntario in its allocations.

6.2 *Operations Management and Field Staff*

Except for one person who has responsibilities for all of the business units, the employees based in Fort Erie are shared by the Niagara distribution business unit and the transmission business unit. Gananoque is served by Cornwall Electric staff. For these staff, time sheets are used to allocate the costs on an actual basis.

For purposes of the forecast test year, an allocation factor has been developed based on budgeted operations and field services plus capital expenditures where the employee is involved in both operations and maintenance work and capital work. A few staff have been identified as performing more than an average level of work for transmission, and they have been allocated in a higher proportion to transmission, based on management judgment.

On review, BDR considers the timesheet approach for sharing actual costs, and the estimation approach for purposes of forecasting the test year allocations, to be reasonable and consistent with acceptable methods of distribution cost allocation, as well as consistent with the methodology used in previous years.

6.3 *Engineering*

Of the 13 engineering staff based in Fort Erie, seven are shared only between the Niagara distribution unit and the transmission business unit. All others provide services to all of the business units.

Allocation of actual costs is based on the time sheets kept by the employees. For purposes of forecasting the allocated costs for the test year, capital expenditure levels were used as the allocation factor.

On review, BDR considers the timesheet approach for sharing actual costs, and the estimation approach for purposes of forecasting the test year allocations, to be reasonable and consistent with acceptable methods of distribution cost allocation, as well as consistent with the methodology used in previous years.

6.4 *Executive*

This function consists of four senior executives and an executive assistant. Each executive was interviewed to determine the percentage of time spent on each of the business units in a representative period. The resulting percentages were averaged and used to allocate the costs of the executive group including the executive assistant.

On review, BDR considers that time spent is a reasonable and appropriate cost driver, and that this approach is consistent with acceptable methods of cost allocation, and with the allocation methodology previously employed by FortisOntario for this function.

6.5 *Regulatory*

The allocation of the 2-FTE regulatory group is based on judgment. A small allocation is made to FortisOntario, as the holding company for the regulated businesses on a judgment basis. Each rate-regulated distribution service territory other than Cornwall Electric and CNPI Transmission has the same regulatory requirements, and has therefore received equal allocations. Cornwall Electric and CNPI transmission presently require a lower level of rate development and regulatory activity than a rate-regulated distribution business unit. They therefore received reduced allocations, as compared with the distribution service territories.

When BDR last reviewed these allocations, consideration was given to whether any synergies existed in the work of regulatory staff in providing services to the regulated distribution service territories. It was concluded that there are no appreciable synergies. Regulatory accounting matters such as PILs reconciliation, deferral and variance accounting continue to be maintained separately. In addition, the Regulatory function oversees separate monthly IESO and Hydro One cost of power true ups with form 1598, RRP true ups, and Global Adjustment settlements. A further consideration in the allocation is that FortisOntario's regulatory staff represents the regulated business units at regulatory stakeholder events and prepares required filings. This means that much of the effort applies to the benefit of all FortisOntario's regulated business units at once.

Therefore, each of the four service territories (Fort Erie, Port Colbourne, Gananoque, and Algoma) has therefore received an equal allocation.

On review, BDR considers this approach reasonable, consistent with acceptable methods of cost allocation, and consistent with the approach previously used by FortisOntario.

6.6 *Finance*

FortisOntario staff reviewed each of the sub-activities that comprise the finance function. The sub-activities are:

- Accounts Payable and Receivable;
- Payroll;
- Financial Reporting;
- Financial Analysis; and
- Supervision.

Each person's function was separately reviewed and allocated based on the work performed. While some of the functions such as regulatory accounting and financial reporting received a judgment-based allocation, others were based on measures of activity. For example, payroll was based on FTEs, and other accounting functions were allocated based on a combination of capital expenditure levels and operating expenses. This factor is a high-level proxy for the account activity in each of the business units.

BDR discussed with FortisOntario management the possibility of a time log system for finance employees to use as a basis of allocation, and was satisfied in this discussion that because of the corporate structure the same effort creates value that is shared, and cannot be specifically identified with one business unit.

BDR considers the approach used as reasonable and consistent with accepted methods of shared cost allocation, as well as with methods previously applied by FortisOntario.

6.7 *Fort Erie Warehousing and Procurement*

The warehousing and procurement function is carried out in Fort Erie on behalf of the Niagara distribution service territories and the transmission business unit, with some service also provided to the unregulated FortisOntario business unit. At present, some purchasing and warehousing is carried out in Cornwall for Cornwall and Gananoque. An inventory of parts for operations and maintenance purposes is maintained locally in each service territory. The costs are allocated based on capital expenditures, because the activity is concentrated on capital-related inventory.

On review, BDR considers the approach used as reasonable, and consistent with acceptable methods of shared cost allocation. The same method was applied in the previous cost allocation.

6.8 *Human Resources*

The approach taken to this shared cost is consistent with that taken for previous CNPI service territory revenue requirements. Human Resources is a function that supports employment, and the number of FTEs is therefore the most appropriate cost driver for allocation purposes.

To compute an allocation factor for Human Resources, the FTEs for all functions other than Human Resources, Information Technology and Safety were summed for each business unit. Included were the allocated portions of the FTEs in shared cost functions (such as executive, finance, etc.) plus the FTEs in functions that are 100% dedicated to that business unit. Information Technology and Safety were excluded to simplify the computation and avoid iteration, because the methodology uses FTEs for their allocation in a manner similar to Human Resources.

For each business unit, the allocation factor for Human resources was therefore the percentage which FTEs allocated to that business unit (excluding Human Resource, Safety and Information Technology) represent of all FTEs, including FTEs that are not shared resources (excluding Human Resources, Safety and Information Technology.

On review, BDR considers that this approach, as in previous reviews, is reasonable and consistent with acceptable methods of cost allocation.

6.9 *Employee Safety*

For allocation of this cost, the same approach was adopted as for Human Resources, making the FTE responsibility for the business unit the basis for its allocation of the Safety Function. Having reviewed the activities of the employees, management was of the view that no adjustments to the resulting allocations were appropriate.

On review, BDR considers that this approach is reasonable and consistent with acceptable methods of cost allocation. The approach and methodology are consistent with those used previously by FortisOntario.

6.10 *Information Technology*

Since the information technology ("IT") function supports the employees in their work, the allocation approach utilized by FortisOntario is based on use by the employees following the allocation of their efforts to the business units (i.e. allocated or direct FTEs), weighted to reflect usage of the various corporate systems.

A simple methodology was applied to reflect different levels of use in this shared cost allocation. Each employee's information technology use was assigned a weighting based on relative use of key corporate systems. Employees using primarily office suite and email services (word processing, spreadsheet, etc.), were assigned a weighting of 1. Employees making extensive use of the major corporate systems (such as call centre and billing staff using the customer information system, or finance staff generating reports from the financial system) were assigned a weighting of 2. Employees making some use of corporate systems, but not enough use to warrant a weight of 2, received a judgment-based weighting between 1 and 2.

For each shared function and non-shared function other than IT, the weighted number of FTEs was used to calculate a percentage allocation of IT services. The weighted allocator was used to allocate IT FTEs to each of the business units.

BDR considers that a weighting to reflect different levels of use of shared IT resources is reasonable, and represents an improvement over an unweighted allocation in reflecting the drivers of IT cost incurrence. BDR is aware that the weightings are judgment-based, but accepts Fortis management's concern that the value of improved accuracy in allocation of this cost does not justify incurring the expense of developing and analyzing system usage reports.

BDR therefore accepts the methodology used in allocation of IT resources as reasonable and consistent with accepted principles of cost allocation. This approach has been used by FortisOntario in the previous cost of service filing for CNPI and other business units.

6.11 *Service Centre Rent and Maintenance*

CNPI staff advised BDR that the Fort Erie service centre building is owned by FortisOntario and rented by CNPI Fort Erie. Appropriate total rent for the building was determined by an independent appraisal as an estimate of market value. Based on area utilized, the total rent was disaggregated into the office, warehouse and garage components. The warehouse and garage components serve the Niagara distribution and the CNPI transmission business units only, so only those business units received an allocation. The allocation was based on the combined capital and O&M budgets, since inventory in the warehouse and transportation equipment in the garage support capital construction, operating and maintenance activity.

Staff (FTEs) located in the office part of the Fort Erie service center, and their previously determined allocations (or direct assignment) to business units were used to allocate the related costs.

Maintenance costs were in proportion to the allocation of service centre rent.

On review, BDR considers this approach reasonable and consistent with acceptable methods of distribution cost allocation, and is the same methodology used previously by FortisOntario.

7 AUTHORSHIP AND USE

This report was written and submitted by me, Paula Zarnett, Vice President, BDR NorthAmerica Inc., following a review of information provided to me by FortisOntario, and is intended for use by FortisOntario's subsidiary CNPI in support of its application to the Ontario Energy Board for approval of 2017 rates and charges.

Dated at Toronto, Ontario, this 11th day of April, 2016.

Paula Zarnett

APPENDIX – ALLOCATION OF FULL-TIME EQUIVALENT STAFF TO BUSINESS UNITS

The following tables resulting from the application of the proposed cost allocation methodology were produced by CNPI and provided to BDR for purposes of this Study.

Department/Section	Business Unit - Full Time Equivalent Employee Distribution							
	FortisOntario	CNPI Niagara	CNPI Gananoque	Cornwall Electric	Algoma Power	CNPI Transmission	Total	CNPI Dx
Executive	0.91	0.93	0.28	1.15	1.09	0.63	5.00	1.21
Regulatory	0.05	0.75	0.38	0.20	0.38	0.25	2.00	1.13
Finance	0.49	2.93	0.78	2.79	4.36	0.66	12.00	3.70
Cornwall Region	0.00	0.00	7.38	39.62	0.00	0.00	47.00	7.38
Algoma Region	0.10	0.00	0.00	0.00	60.90	0.00	61.00	0.00
Gananoque	0.00	0.00	4.00	0.00	0.00	0.00	4.00	4.00
Engineering	0.00	8.59	0.43	1.32	1.34	1.31	13.00	9.02
T&D Operations	0.00	19.72	0.08	0.24	0.24	6.72	27.00	19.80
CNPI Stores and Property	0.06	4.10	0.00	0.00	0.00	0.84	5.00	4.10
Customer Service	0.00	8.91	0.65	0.46	0.49	0.00	10.50	9.55
Subtotal	1.61	45.92	13.97	45.78	68.80	10.41	186.50	59.89
Health & Safety	0.03	0.74	0.22	0.74	1.11	0.17	3.00	0.96
Information Technology	0.10	2.71	0.82	2.70	4.06	0.61	11.00	3.53
Human Resources	0.03	0.86	0.26	0.86	1.29	0.20	3.50	1.12
	1.76	50.23	15.28	50.08	75.26	11.39	204.00	65.51

Department/Section	Business Unit - Full Time Equivalent Employee Distribution							
	FortisOntario	CNPI Niagara	CNPI Gananoque	Cornwall Electric	Algoma Power	CNPI Transmission	Total	CNPI Dx
Executive	18.3%	18.6%	5.6%	23.1%	21.8%	12.7%	100.0%	24.3%
Regulatory	2.5%	37.5%	18.8%	10.0%	18.8%	12.5%	100.0%	56.3%
Finance	4.1%	24.4%	6.5%	23.2%	36.4%	5.5%	100.0%	30.9%
Cornwall Region	0.0%	0.0%	15.7%	84.3%	0.0%	0.0%	100.0%	15.7%
Algoma Region	0.2%	0.0%	0.0%	0.0%	99.8%	0.0%	100.0%	0.0%
Gananoque	0.0%	0.0%	100.0%	0.0%	0.0%	0.0%	100.0%	100.0%
Engineering	0.0%	66.1%	3.3%	10.2%	10.3%	10.1%	100.0%	69.4%
T&D Operations	0.0%	73.0%	0.3%	0.9%	0.9%	24.9%	100.0%	73.3%
CNPI Stores and Property	1.2%	81.9%	0.0%	0.0%	0.0%	16.9%	100.0%	81.9%
Customer Service	0.0%	84.8%	6.2%	4.4%	4.6%	0.0%	100.0%	91.0%
Health & Safety	0.9%	24.6%	7.5%	24.5%	36.9%	5.6%	100.0%	32.1%
Information Technology	0.9%	26.9%	7.3%	24.5%	34.8%	5.6%	100.0%	34.2%
Human Resources	0.9%	24.6%	7.5%	24.5%	36.9%	5.6%	100.0%	32.1%

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PURCHASE OF NON-AFFILIATE SERVICES

Summary

CNPI Policy MM100 (attached at Appendix 'A' to this schedule) allows for outsourcing of service expenses primarily through two means.

a) Competitive Bidding

Policy MM100 states that processes such as a Request for Quotations (“RFQ”), Request for Proposals (“RFP”) and Request for Information (“RFI”) are to be used for purchases over $10,000 (Contract A and Contract B scenario). Depending on the nature of the work and estimated expense, this could be a formal or informal process.

Contractors that have met CNPI’s Health, Safety and Environmental requirements are eligible to be included in the competitive bidding process. A bid document is sent to each of the qualified Contractors where they are asked to either provide a detailed proposal on the cost of the project or provide standard rates for labour and equipment to complete the work.

The responses are then evaluated by CNPI using a number of criteria which may include: price, health and safety, environment, return on investment, delivery schedule, quality, and methodology. Based upon this evaluation, the Contractor that offers the best value to CNPI is awarded the work.

b) Single Source

Policy MM100 allows for purchases over $10,000 to have a single source of supply provided they meet specific requirements of Section 5.2 of the Policy. CNPI has allowed that purchases with an annual spend under $10,000 can have a single source of supply in order to facilitate low dollar purchases.

As with Competitive Bidding, Contractors are selected through the pre-qualified list and are asked to submit a detailed proposal or rate sheet so all costs are fully understood.

Both selection methods are subject to the rules and controls that CNPI has built into their ERP system. The purpose being to provide visibility on the acquisition and to have an authorized approval for all goods and services purchased. Approval authorizations are tiered to specific positions within CNPI with specific dollar limitations. Purchases over the $30,000 limit become the responsibility of the CNPI Executives to review and approve. This is done both in the ERP system and by having the VP1A Executive Authorization form signed. The VP1A form again is tiered to specific dollar amounts to provide visibility and to ensure that all high dollar expenses are authorized by one or more of the Executives.

CNPI also employs a Corporate Buyer. The buyer is responsible to seek the optimal combination of logistics activities and their attributes such as price, quality, speed and security and to manage the resulting information and monetary flows. Additional responsibilities of the buyer include overseeing the acquisition, use and disposition of goods, materials and services to fulfill internal and external customer needs. The specific duties of the buyer include but are not limited to:

a) Administration of the CNPI Corporate Purchasing Policy MM100.

b) Prepare and administer competitive bidding documents and processes. This includes but is not limited to; issuing the bid, summarizing submissions, assisting with the review and selection process, finalizing and managing any contractual documents and the ongoing maintenance thereof.

c) Review and evaluate purchase orders submitted through the ERP system to ensure reasonableness, accuracy and policy compliance prior to Management approval.

d) Prepare and submit the VP1A form for Executive signoff.

e) Review and investigate invoices for any price, product or service discrepancies.

f) Develop new supply sources and stay abreast of new trends and innovations in routinely purchased supplies, materials, services and equipment.

g) Maintain price lists on assigned commodities and negotiate prices and terms.

h) Solicit labour and equipment rates for cost comparisons.

The following tables list CNPI's third party non-affiliated services that were purchased between 2012 and 2015 inclusive; a $50,000 materiality threshold was used.

2012

Account	Vendor	Nature of Service	Selection Process	Annual Expense
101513	PINERIDGE TREE SERVICE	Tree Trimming	Competitive Bid	$569,758.33
100460	GROUND AERIAL MAINTENANCE SERV	Line Construction	Single Source	$539,735.10
100202	WIENS UNDERGROUND ELECTRIC LTD	Underground/Trenching	Single Source	$ 499,294.16
102731	ELEMENT FLEET MANAGEMENT	Fleet Management	Annual Agreement	$ 369,903.14
100146	DAVIES, WARD PHILLIPS & VINEBE	Legal	Legal Services	$ 278,944.58
101633	CLOCKWORK	IT Consultant	Annual Agreement	$ 227,877.15
101978	MARK ROEST CONSULTING INC.	IT Consultant	Annual Agreement	$ 226,314.43
102986	THE ENERGY BOUTIQUE	Legal	Legal Services	$ 62,932.44
102850	PETERS EXCAVATING	Underground/Trenching	Single Source	$ 101,163.26
102388	SERIO CONSULTING CANADA INC.	Finance/IT Consultant	Annual Agreement	$ 80,731.32
103094	OLIVE CONSULTING INC.	Legal	Annual Agreement	$ 77,508.32
102894	POLECARE INTERNATIONAL INC.	Pole Inspections	Competitive Bid	$ 68,367.26

1 **2013**

Account	Vendor	Nature of Service	Selection Process	Annual Expense
100895	EPTCON LTD.	Design/Build Substation	Competitive Bid	$1,395,293.37
100460	GROUND AERIAL MAINTENANCE SERV	Line Construction	Single Source	$ 882,993.96
101513	PINERIDGE TREE SERVICE	Tree Trimming	Competitive Bid	$ 579,307.46
103764	MERIT CONTRACTORS NIAGARA	Design/Build Offices	Competitive Bid	$ 393,173.25
102731	ELEMENT FLEET MANAGEMENT	Fleet Management	Annual Agreement	$ 322,522.80
100055	AMEC FOSTER WHEELER ENVIRONMEN	Environmental Consultant	Competitive Bid	$ 211,574.59
101633	CLOCKWORK	IT Consultant	Annual Agreement	$ 181,001.14
102232	DUNDAS POWER LINE LTD.	Line Construction	Competitive Bid	$ 170,332.58
100202	WIENS UNDERGROUND ELECTRIC LTD	Underground/Trenching	Single Source	$ 135,023.70
102986	THE ENERGY BOUTIQUE	Legal	Legal Services	$ 125,609.67
102850	PETERS EXCAVATING	Underground/Trenching	Single Source	$ 113,627.27
101978	MARK ROEST CONSULTING INC.	IT Consultant	Annual Agreement	$ 95,065.50
103667	SUPER SUCKER HYDRO VAC SERVICE	Vac Truck Services	Competitive Bid	$ 79,891.00
103600	GILMORE DOCULINK	Invoice/Mail Services	Annual Agreement	$ 72,346.74
102388	SERIO CONSULTING CANADA INC.	Finance/IT Consultant	Annual Agreement	$ 68,276.19
102703	SAFELINE UTILITY SERVICES INC.	Line Construction	Competitive Bid	$ 60,329.62
100221	REGIONAL TRENCHING INC.	Underground/Trenching	Single Source	$ 57,488.75

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2014

Account	Vendor	Nature of Service	Selection Process	Annual Expense
100460	GROUND AERIAL MAINTENANCE SERV	Line Construction	Single Source	$1,532,884.71
101513	PINERIDGE TREE SERVICE	Tree Trimming	Competitive Bid	$ 605,488.73
102731	ELEMENT FLEET MANAGEMENT	Fleet Management	Annual Agreement	$ 387,761.35
100895	EPTCON LTD.	Design/Build Substation	Competitive Bid	$ 286,459.58
102850	PETERS EXCAVATING	Underground/Trenching	Single Source	$ 190,888.35
103754	ONE LINE ENGINEERING	Design/Build Substation	Competitive Bid	$ 145,466.24
103667	SUPER SUCKER HYDRO VAC SERVICE	Vac Truck Service	Annual Agreement	$ 129,644.90
100055	AMEC FOSTER WHEELER ENVIRONMEN	Environmental Consultant	Competitive Bid	$ 128,734.92
101633	CLOCKWORK	IT Consultant	Annual Agreement	$ 127,041.38
103764	MERIT CONTRACTORS NIAGARA	Design/Build Substation	Competitive Bid	$ 60,823.84
103781	COMMERCIAL CLEANING SERVICES	Janitorial Services	Annual Agreement	$ 54,383.01
102097	TIMBER TREE SERVICE	Tree Trimming	Annual Agreement	$ 53,245.60
100141	MCCARTHY TETRAULT LLP	Legal	Legal Services	$ 52,662.39

2015

Account	Vendor	Nature of Service	Selection Process	Annual Expense
100460	GROUND AERIAL MAINTENANCE SERV	Line Construction	Single Source	$1,472,892.24
101513	PINERIDGE TREE SERVICE	Tree Trimming	Single Source	$ 537,711.32
103881	ASCENT SOLUTIONS INC.	Line Construction	Competitive Bid	$ 456,590.53
103764	MERIT CONTRACTORS NIAGARA	Substation Construction	Competitive Bid	$ 437,326.88
102232	DUNDAS POWER LINE LTD.	Line Construction	Competitive Bid	$ 421,161.38
102731	ELEMENT FLEET MANAGEMENT	Fleet Management	Annual Agreement	$ 346,033.63
102850	PETERS EXCAVATING	Underground/Trenching	Single Source	$ 248,511.72
101633	CLOCKWORK	IT Consultant	Annual Agreement	$ 226,192.43
103667	SUPER SUCKER HYDRO VAC SERVICE	Vac Truck Service	Annual Agreement	$ 112,285.28
102332	PVS CONTRACTORS INC.	Underground Locates	Single Source	$ 108,069.19
103642	LinkLine Contractors Ltd.	Underground/Trenching	Annual Agreement	$ 94,559.47
100895	EPTCON LTD.	Substation Construction	Competitive Bid	$ 76,967.92
103600	GILMORE DOCULINK	Invoice/Mail Service	Annual Agreement	$ 61,718.55
102986	THE ENERGY BOUTIQUE	Legal	Legal Services	$ 52,838.81
103781	COMMERCIAL CLEANING SERVICES	Janitorial Service	Annual Agreement	$ 51,669.99

Notes:

a) Ground Aerial Maintenance has been identified as single source of supply for line construction in the Niagara Region. Annually CNPI issues an RFQ to other contactors to validate their rates and the continued prudence of using them as a single source.

b) For Underground/Trenching work there are limited resources in the Niagara Region. CNPI would consider this as single source since competitive bidding is not always possible.

c) Competitive bidding often turns into annual agreements for regular reoccurring services such as janitorial and vac truck services.

d) Prior to 2015, the contacting for tree trimming services went through a competitive bidding process, specifically a RFQ. Since 2011, Pineridge has been the successful Proponent of this competition. In 2015, Pineridge agreed to hold their previous pricing for the upcoming cycles of work should CNPI elect to extend their contract with them. After reviewing the previous award history and performance by Pineridge; CNPI felt that extending this contact offered value and single sourced this service by extending the contact with Pineridge. The 2019-2021 cycle though will be put through the competitive bidding to process to ensure CNPI is still receiving the best value.

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APPENDIX A

Purchasing Policies & Procedures

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Purchasing
Policies & Procedures

MM100

FORTISONTARIO

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PROCEDURE

1. Requisitions (REQ)

1.1 What is a Requisition?
Requisitions are a list of required materials or services needed by a department to complete their duties, tasks, assignments or projects.

1.2 Purchase Orders without Requisitions
Under no circumstances will a Purchase Order be created without an approved requisition.

1.3 Access of SAP Requisitioning System
The requisitioning system will be accessed through the company's SAP system.

1.4 Requisition Approval Process in SAP

If the total value of the requisition is >$10,000, the approver will be his Supervisor.

If the total value of the requisition is between $10,000 and $30,000, the approver will be his Manager. For Algoma Power Inc., this will be the Regional Manager. FTSO Supervisor Procurement and Facilities will also have rights to approve requisitions up to $30,000 for approved items.

If the total value of the requisition is over $30,000, the approver will be the Vice-President of Operations in most cases.

1.5 Required Material and Service Requisition Information
The following is a check list of the required information needed by the Procurement Department to properly source and process Material or Service requisitions:

- Full Description (Material Number or Short Text)
- Quantity
- Unit Measurement
- Account Assignment GL and Cost Centre or Order number
- Delivery Date
- Net Price

- Vendor
- Purchasing Group Code – ex – FLS (FE Line Services)

1.6 Requisition Flow

Once the requisition has been created and saved in SAP, the requester shall notify the next level of approval by way of e-mail.

1) < $10,000– Approver - Supervisor cc: Buyer for that plant
2) > $10,000 and < $30,000 – Approver Manager cc: Supervisor cc: Buyer for that plant.
3) > $30,000 – Approver – VP cc: Manager cc: Supervisor cc: Buyer for that plant. VP1A and affiliated documents to be completed and forwarded. See Section 6.3.5 below.

1.7 Purchasing Requisition Approver

The approver verifies the validity of the request and ensures cost center, internal order, GL account, etc. for correctness. He/she selects the line items to approve and releases the requisition for processing to the Procurement Department. The approver replies to the requester that the requisition is now approved cc buyer.

2. Request for Quotations (RFQ)

2.1 When RFQ's are Required

Request for Quotations are required for any purchases where the anticipated amount will be over $10,000, the scope and specifications are clearly identified and stated, and it does not meet the sole sourcing criteria.

2.2 How many quotations are Required?

It is desirable to have a minimum of three quotations, but no less than two.

2.3 Record of Quotations

All quotations will be filed in the Purchasing Department along with supporting documentation.

2.4 Analyzing Quotations

Quotations shall be analyzed by Materials Management and the requesting department. The lowest price quote shall be selected unless there are extenuating circumstances upon which this should not occur. e.g. –delivery date, quality factor, warranties, etc.

3. Request for Information (RFI)

3.1 What is a Request for Information (RFI)

Unlike a Request for Quotation (RFQ) or Request for Proposal (RFP), the Request for Information (RFI) does not bind the vendor to any information price given. The request is for informational purposes only.

3.2 When to use a RFI

A Request for Information could be used during the budgetary process or during job planning where estimated cost figures are required only. It should be clearly stated to the vendor that this is a Request for Information Only and any pricing supplied will not be binding or commit the company to this purchase or this vendor.

4. Request for Proposal (RFP)

4.1 When RFP's are Required

A Request for Proposal is required for any purchases where the anticipated amount will be over $10,000, you wish the vendor to supply the scope and specifications, and it does not meet the sole sourcing criteria.

4.2 How many Proposals are Required?

It is desirable to have a minimum of three proposals, but no less than two.

4.3 Record of Proposals

All proposals must be entered into the SAP system by the Materials Management personnel. Once entered, the vendor proposals will be filed in the Purchasing Department Open File along with the Requisition.

4.4 Analyzing Proposals

Proposals shall be analyzed by the Materials Management and the requesting department. The lowest price proposal shall be selected unless there is extenuating circumstances upon which this should not occur.
e.g. delivery date, quality factor, warranties, etc.

5. Sole Sourcing

Sole sourcing is where only one vendor is chosen to supply a quotation for goods or services. Sole sourcing should only be used where obtaining three quotations is not viable or reasonable. Therefore sole sourcing shall be looked upon as a "method of exception" rather than the "normal method" of procurement.

5.1 Limitations under $10,000

Sole Source Purchasing may be used for purchases where the anticipated price will be under $10,000. The quote from the sole source vendor maybe written or verbal.

Any approved method of procurement may be used for Sole Sourcing Purchasing.

5.2 Limitations over $10,000

The following is the criteria to be used when justifying a single source for procurement purposes:

a) The estimated amount of the requested materials, equipment or services total less than $10,000. This amount shall be considered a limit on an annual basis where the Requesting Department or Purchasing Department can reasonably approximate needs on an annual basis.

b) Only one source of supply has been identified for the requesting materials, equipment or services, and attempts to either identify additional sources or to modify the request to allow for alternate sources has not been successful.

c) The requested materials or equipment must be purchased from the original equipment manufacturer, in order to match or replace existing equipment.

d) The requested material, equipment, or services provide unique qualifications or technology.

e) The requested material and equipment has been approved as sole source by the Engineering Standards Group.

f) There is an urgent delivery requirement for the requested materials or service, and there is not sufficient time to solicit competitive bids.

g) Price quotations for the requested goods or services which definitely indicate a low cost provider are on file. Such quotations must be less than one year old, and in the professional judgment of the Buyer, reflect the current market for the requested materials.

6. Purchase Orders

6.1 Purchase Orders

The Purchase order is the most common method of procurement used in the company and can be used to procure both materials and services. The Purchase Order, in its entirety, is a binding contract between two parties.

When the company issues a Purchase Order to a vendor, the company is agreeing to purchase materials or services for the stipulated quantity, price, delivery, and any other terms specified in the document.

The company also agrees to pay to the vendor, in a time agreed to by both parties, the full amount owed to the vendor for delivery of the materials or services.

The vendor, in acknowledging the purchase order, also agrees to the quantity, price, delivery and all other terms within the document. The vendor has an obligation to the company to meet all these conditions. Failure to meet any or all conditions could result in the contract (the Purchase Order) to be terminated.

6.1.1 Who can create Purchase Orders?

The only employees in FortisOntario who can create Purchase Orders are the Supervisor, Procurement & Property/Facilities and the Buyer who belong to the Materials Management Department. All other employees shall be blocked within SAP from producing Purchase Orders.

6.1.2 Limitations of Storekeepers

Storekeepers within FortisOntario can only create Purchase Requisitions for Inventory materials.

6.2 Types of Purchase Orders

6.2.1 Standard Purchase Order for Material or Service

Standard Purchase Orders for material or Service are the most common of all Purchase Orders. Creating a Standard Purchase Order within the SAP system heavily supports the “three-way match”. A “three-way match” occurs when all three documents, the Purchase Order, the Receiving, and the Invoice concur with one another. If at least one document does not agree with any of the other two, the invoice will be blocked for payment.

It is essential, if possible, to indicate on the Purchase Order that all materials be delivered to the Stores Department in Fort Erie, Sault Ste. Marie or Cornwall so that proper receiving procedures can be done. If materials are delivered to a different site, all packing slips must immediately be forwarded on to the respective Stores Department for processing.

6.2.2 Contracts

Formal contracts, with a minimum value of $50,000.00 can be made for materials only, external labour & materials, or external labour only.

All contracts must be processed through the Procurement Department.

All multi-year contracts must be approved by the Vice President and President during the requisitioning stage regardless of any one singular annual amount i.e. VP1A approval

6.2.3 <u>Blanket Purchase Orders</u>

Blanket Orders are created for frequently used, minimal cost, materials and services with vendors who do not accept the company's procurement card.

Blanket Orders should never be used to purchase assets.

Blanket Orders are created with valid "from" and "to" dates. Each Blanket Order is created with a maximum expected value within the valid time period. Blanket Orders exceeding the maximum expected value before the time period expires, shall be re-assessed for future competitive bidding avenues.

6.3 Purchasing Authorization

6.3.1 Purchasing Groups

All departments within FortisOntario shall be identified by means of a Purchasing Group designation.

ACS	Customer Svs API	CMS	CE Metering Servic
AEL	Electrical API	COR	Corporate
AEN	Eng/Planning API	CPE	CE Planning & Engi
AFF	Fleet & Facility	CPP	CE Prop & Proc
AFN	Finance API	CRM	CE Regional Mgmt
AFS	Forestry Svs API	ECS	EOP Customer Servi
AHE	HSE API	ELS	EOP Line Services
AHR	HR API	FCR	FE Control Room
AIT	IT API	FCS	Fort Erie Customer
ALD	Desbarats Line Svs	FES	FE Electrical Serv
ALS	Sault Line Svs	FHR	Fort Erie Human Re
ALW	Wawa Line Svs	FIN	FE Finance
AMS	Metering Svs API	FIT	IT Fort Erie
APP	Purchasing API	FLS	FE Line Services
ARM	Regional Mgmnt API	FMS	FE Metering Servic
CCS	CE Customer Servic	FPE	FE Planning & Engi
CDV	Corp Devlopment	FPP	FE Prop & Proc
CLS	CE Line Services	REG	Regulatory Affairs

Alterations or changes to Purchasing Groups within SAP shall not be made unless authorized in writing at the executive level.

6.3.2 Purchasing Authorization Limits

All Purchasing Groups shall have the same Purchasing Authorization limits.
Supervisors will approve all direct report employee requisitions and their own, up to $10,000
Managers – up to $30,000
VP’s – over $30,000

Alterations or changes to Purchasing Authorization Limits within SAP shall not be made unless authorized in writing by the Vice President and President.

6.3.3 <u>Purchase Order Creation (see 1.7 under Requisition)</u>

The buyer lists the approved requisitions for his plant and uses the copy function in SAP to create the purchase order. The buyer will also verify that the vendor, GL account, cost center, internal order etc. are appropriate.

6.3.4 <u>Purchase Order Approver (Finance)</u>

The final purchase order approval will be in the Finance Department, where a Finance employee will verify the validity of the cost center, internal order, GL account etc, select line items to approve and save.
Only then, will the hard copy of the purchase order be printed to the Buyer for processing to the vendor.

6.3.5 <u>Executive Purchasing Authorization-Form VP1A</u>

All Purchase Requisitions created with a value over $30,000 require Executive Purchasing Authorization.

Purchase Requisitions created within the Operations Division, greater than $30,000 but less than $150,000 shall be authorized in writing and released by the VP of Operations before the final release of the Purchase Department.

Purchase Requisitions created outside the Operations Division, greater than $30,000 but less than $150,000 shall be authorized and released by the VP of Operations only after being authorized writing by the responsible VP through the means of a completed Form VP1A .The Purchasing Department will not release the Purchase Order until the VP of Operations has completed his release procedure, and, they are in receipt of the completed Form VP1A .

Purchase Requisitions created for any area, greater than $150,000 but less than $250,000 shall be authorized and released by the VP of Operations only after being authorized in writing by the responsible area VP and one additional VP through the means of a completed Form VP1A .The Purchasing Department will not release the Purchase Order until the VP of Operations has completed his release procedure, and, they are in receipt of the completed Form VP1A.

Purchase Orders created for any area, greater than $250,000 shall be authorized and released by the VP of Operations only after being authorized in writing by the responsible area VP and the CEO through the means of a completed Form VP1A .The Purchasing Department will not release the Purchase Order until the VP of Operations has completed his release procedure, and, they are in receipt of the completed Form VP1A .

The completed VP1A shall be filed along with the Requisition and Quotes in the Purchasing Department.

6.4 Distribution of Purchase Order

6.4.1 File Copy

Upon release and printing of the Purchase Order, Materials Management shall distribute a copy of the Purchase Order to the Purchasing Department which will be attached to the Requisition, Quotes and VP1A (if req'd).

6.4.2 Supplier Signed Original

Upon release and printing of the Purchase Order, Materials Management shall sign the original Purchase Order.

The signed original Purchase Order shall be emailed and/or faxed to the Supplier.

7. Receiving of Goods and Services

7.1 Receiving of Goods

7.1.1 Receiving of Goods by Stores

The preferred method of receiving goods ordered for the company is through the Regional Stores Department.

The Storekeeping shall inspect the shipment prior to unloading to assure that the shipment was not damaged during transit.

The storekeeper should then match the “Bill of Lading” or “Packing Slip” with what is being unloaded.

The Storekeeping shall, as soon as possible, create a goods receipt document in SAP against the Purchase Order.

7.1.2 Receiving of Goods by Others

At times goods are received by others in another site or location other than the Stores Department.

The same receiving procedure as for the storekeeper shall also hold true for other receiving goods.

The Receiver shall inspect the shipment prior to unloading to assure that the shipment was not damaged during transit.

The Receiver should then match the “Bill of Lading” or “Packing Slip” with what is being unloaded.

The Receiver shall sign the “Bill of Lading” or “Packing Slip” and forward it on to the Stores Department.

The Storekeeper shall, a.s.a.p. create goods receipts document in SAP against the Purchase Order

7.1.3 Receiving of Damaged Goods

Whenever possible, the Storekeeper or the Receiver should not receive or take possession of damaged goods.

The Storekeeper or Receiver shall indicate on the "Bill of Lading" why the goods were being rejected, sign it and keep a copy of it in the Stores Department.

If possible, a digital photograph of the damaged goods should be taken for future reference.

7.1.4 Bill of Lading or Packing Slips

All Bill of Ladings or Packing Slips shall be filed in the Purchasing Department along with the requisition, Quotes, VP1A (if req'd),and Purchase Order.

7.2 Receiving of Services

7.2.1 Receiving of Goods by Project Coordinator

The preferred method of receiving goods ordered for the company is by the Project Coordinator responsible for the contractor providing the services.

The Project Coordinator shall inspect and assure that the services provided by the contractor satisfy both the term and conditions of the contract, and quality of service provided.

The Project Coordinator should then match the Service Statement provided by the contractor with his own field records.

The Project Coordinator shall notify the Stores Department in writing that it is appropriate to receive said services against the exiting Purchase Order in SAP for processing.

7.2.2 Non-Receipt of Services or Sub-Standard Work

It is the responsibility of the Project Coordinator to ensure that the Services received match the Service Statement provided by the contractor. If there is a discrepancy, then it is the responsibility of the Project Coordinator to rectify it with the contractor.

The Project Coordinator is also responsible to ensure that the contractor remedies all sub-standard work provided.

7.2.3 Service Statements

All Service Statements shall be filed in the Operations Department's File for review if necessary.

8. Procurement Cards

8.1 Procurement Cards

8.1.1 Contacts

Financial Analyst
Manager of Financial Reporting
Manager of Customer Service
Manager of T&D
Manager of Engineering
Supervisor Procurement and Facilities
Manager of Cornwall Region
Regional Manager of Algoma Power

Scotia Bank Card Administration:

Scotia Bank VISA Purchasing Card Program
Scotia Plaza
40 King St.
Toronto, ON M5H 1H1

Scotia Bank Customer Service:

1-888-823-9657
(8:00 a.m. - 8:00 p.m., Mon. to Fri.)

8.1.2 Purpose

The purpose of the Scotia Bank Visa Purchasing Card is to establish a more efficient, cost-effective method for purchasing and processing small dollar transactions.

The program is NOT intended to avoid or bypass appropriate purchasing or pay procedures. Rather, the program complements the existing processes. The card can be used for in-store purchases as well as telephone, mail, or fax orders.

The Scotia Bank Visa Purchasing Card should be used whenever possible within the prescribed limits set for each cardholder.

8.1.3 <u>Duties & Responsibilities</u>

<u>Plan Administrator Duties & Responsibilities</u>

- Establish and maintain company-wide communication
- Assist in normal card usage procedures
- Serve as primary contact for cardholders and liaison between cardholders and Scotia Bank
- Assist in problem resolution
- Audit program compliance and receipt retention
- Distribute training, Purchasing Cards and policy manuals
- Set credit limits, single dollar transaction limits and SIC/MCC code blocking changes.
- Generate reports to monitor performance of the program
- Co-ordinate reconciled data to A/P

<u>Site Coordinator Duties & Responsibilities</u>:

- Initiate and approve card requests for the Purchasing Cards within their areas of the organization
- Ensure the cards issued under their authority are properly utilized.
- Review and sign reconciled Monthly Reconciliation statements to ensure that receipts and documentation are attached and appropriate accounting codes are indicated
- Ensure that reconciled monthly transactions are received and forwarded to the Program Administrator.
- Co-ordinate any changes between cardholders and Program Administrator

Cardholder Duties & Responsibilities:

- Maintain card security to prevent unauthorized charges against the account.
- Use it only for purchasing of items in accordance with company policies.
- Obtain a receipt at the point of purchase and verify it for accuracy. Retain receipts and Visa charge slips, and keep a monthly transaction log of card purchases.
- Reconcile receipts and monthly transaction log and forward to your Site Coordinator for review.
- Notify Program Administrator/Site Coordinator of name, telephone, address and division/department changes.
- Report any lost or stolen cards immediately to Program Administrator

8.1.4 Controls

Authorization controls are set by The Manager responsible for Materials Management and the Vice President of Operations only. Modifications shall not be done unless written authorization is provided to the Site Co-Coordinator in advance. The controls include:

- Monthly credit limits for cardholders
- Dollar limits per transaction
- Types of purchases that will be allowed (some vendors have been blocked from usage in the program)

For control purposes, the following transactions will be denied:

- Stock items available from stores or through approved ordering systems
- Prescription drugs
- Health care and medical services
- Capital Purchases exceeding $500.00
- Gas Purchases & Vehicle Maintenance (Canada Only) or any other services which fall under Fleet Services Card Program
- Any product or service considered to be inappropriate use of Company funds

Use of this card for personal purposes is prohibited.

All transaction details will be transmitted from the Scotia Bank and stored in a database on the computer system. Managers, supervisors and cardholders will be able to view or print various reports from their computers. Contact the Program Administrators or Site Coordinators for details on available reports.

8.1.5 Reconciliation, Payment and Merchandise Returns

Each cardholder will receive a monthly statement identifying each transaction made against the card during the previous billing period. The statement will be sent through e-mail.

Reconciliation:

1. The cardholder reconciles the credit card receipts to the transactions listed on their statement.
2. The cardholder verifies that the transactions are correct.
3. The cardholder must enter in the appropriate charge account numbers into the system.
4. Any discrepancies must be identified and the appropriate action taken to resolve the problem (see Dispute Process on next page).
5. Cardholder signs reconciled statement and forwards it with receipts attached to the next level of management for their review and approval.
6. Completed statements are forwarded to Program Administrator.

Payment:

1. All non-disputed transactions in the billing period are paid by the Company.
2. Disputed transactions remain outstanding and remain on the statement until they are resolved.

Merchandise Returns:

The merchandise returns process will depend on the suppliers policy, reason for the return, how the purchase was made, i.e. pick up or mail order. In any case, the cardholder contacts the supplier for return policy information. Credit transactions are applied against the cardholder's Visa card and should be reported in the same manner as stated in the Purchase Procedures.

8.1.7 Dispute Process

The following steps should be taken for any transactions in dispute:

1. Cardholder contacts supplier directly.
2. Supplier reviews information and either demonstrates the charge is legitimate, credits the account or continues the dispute.
3. If the dispute continues, contact the Site Co-ordinator with the details.
4. If dispute cannot be resolved at the Site Co-ordinator level, contact the Program Administrator who will work with the Scotia Bank to resolve the dispute.

8.1.8 Lost or Stolen Cards

The following steps must be taken if a card is lost or stolen:

1. The cardholder must notify the Scotia Bank immediately at 1-888-823-9657.
2. The cardholder notifies the Program Administrator.
3. The card will be cancelled and a replacement issued.

8.1.9 Allocation of Accounts for Meals

A Company can only claim 2.5% of the HST as a business meal as an expense. The remainder is classified as a non-deductible expense.

How to calculate: example: total HST is $7.21, multiply
$7.21 **x** (2.5/13) =$1.39

All meals are coded to Cost Element 7802.

8.2 Fleet Cards

8.2.1 Assignment of Fleet Cards

Each transportation unit or licensed equipment will be issued its own fleet card.

The Fleet Supervisor (Cornwall and Fort Erie) or the Supervisor Procurement and Facilities (Algoma Power) shall be responsible for issuing new, lost or stolen fleet cards.

Fleet cards are only to be used for the transportation unit or licensed equipment for which they were assigned.

The cost centre under which the transportation unit or licensed equipment is assigned shall be responsible for all costs associated with the use of the fleet card.

8.2.2 Fleet Card Goods & Services

Fleet cards are used to purchase either fuel and/or maintenance for the assigned transportation unit or licensed equipment at all participating fuel dispensing or auto and equipment maintenance shops in Canada Only.

The card shall not be used for any personal or sundry type items.

8.2.3 Lost or Stolen Fleet Cards

Lost or Stolen Fleet Cards shall be reported immediately to the respective Fleet Supervisor.

8.2.4 Fuel Receipts

Fuel Receipts must be retained and produced upon request for a period of one year by the responsible cost centre or individual.

9. Disposition of Scrap Metals

9.1.1 Disposition of Scrap Metals

FortisOntario has two types of metal materials that are sold to scrap dealers:

1. Mixed Metals
2. Copper (bare and jacketed)

9.1.2 Mixed Metals Disposition Procedure

- Metals collected and stored in large bin provided by vendor.
- Vendor picks up the bin when full.
- Vendor sorts and weighs metals.
- Bill of Lading is given to storekeeper at pickup by the vendor.
- Record of pickup is filed in the Stores Department.
- When payment is made to FortisOntario, record of payment is attached to the appropriate Bill of Lading.
- Purchasing Department follows up if payment is not made in a reasonable time frame.

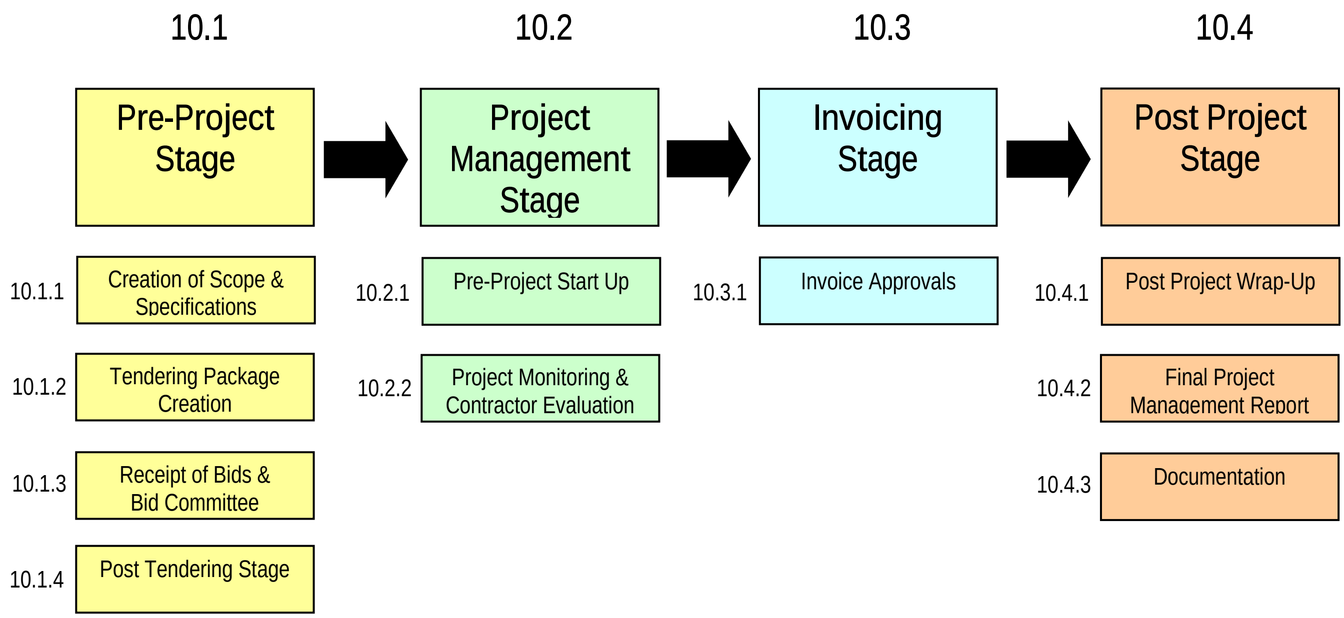
Copper Disposition Procedure

- Copper collected and stored in container provided by vendor.
- When bin is full, the bin is weighed by FortisOntario and arrangements are made for pick up.
- Bill of Lading is given to storekeeper at pickup by the vendor.
- Record of pickup is filed in the Stores Department.
- When payment is made to FortisOntario, record of payment is attached to the appropriate Bill of Lading.
- Purchasing Department follows up if payment is not made in a reasonable time frame.

10.0 Contracting for Goods or Services

When services or goods are required for a project with an estimated value of $50,000.00 or greater.

The Four Stages of Contracting listed below will be followed:



10.1 Pre-Project Stage

10.1.1 Creation of Scope and Specification

The project owner will define the Scope of the work, clearly defining the description, purpose, time frame, and responsibilities of all parties

The project owner will provide the Specifications and/or Drawings, representing what is required and how the project will be performed or constructed.

Both the Scope of the work and the Specifications will be forwarded to the Purchasing Dept.

10.1.2 Tendering Package Creation

The Purchasing Dept. will create the Tender Package with the information provided including the Scope, Specifications, and Drawings and send them out to pre-qualified vendors.

10.1.3 Receipt of Bids and Bid Committee

All bids must be received by the Purchasing Dept. before the closing time of the tender. Bids received after the closing time will not be accepted.

A Bid Committee set up by the Purchasing Dept. (typically comprised of the project owner requesting the work, a representative of the Purchasing Dept. and one other representative from the company with no direct relationship to the project) will open the bids and record the results on a bid analysis form. The bid committee will then determine who will be awarded the contract.

10.1.4 Post Tendering Stage

Before awarding the contract, the project owner requesting the contract shall forward a requisition to Purchasing, where the Purchasing Policies & Procedures will be followed:

Proper release procedures in SAP, followed by a Purchase Order and the completion of the VP1A by the Vice President of Operations. Once these steps are completed the successful bidder will provide all documentation required as described in the contract and both parties (company & contractor) will sign two copies of the Agreement part of the contract and the contractor will be given the Purchase Order to start work.

10.2 Project Management Stage

10.2.1 Pre-Project Start Up

The project owner is responsible to have a pre-job meeting with the contractor and shall document the meeting on the Pre-job Meeting Minute form. During the meeting the project owner will ensure that the contractor obtains all necessary permits according to the contract document. The Company's HSE policy #P-304 "Contractor Health, Safety and Environmental Protection" shall be communicated to the contractor as well as all applicable Health, Safety and Environmental compliance requirements.

10.2.2 Project Monitoring and Contractor Evaluation

The project owner shall monitor all aspects of the project, including site visits, progress of the project, invoice verification for interim progress billing and provide reference documentation. He will also conduct safety observations as per HS&E policies and evaluate the performance of the contractor.

10.3 Invoicing Stage

10.3.1 Invoice Approval

All invoices are initially received by Accounts Payable, the Accounts Payable Clerk will forward the invoice to the project owner for his review. After the invoice has been reviewed and meets with his approval, the project owner will sign the invoice, approving it for payment, and forward the invoice to Purchasing. The Purchasing Dept. will also review the invoice against the original Purchase Order and make SAP entry to create a document number. At this stage it is sent back to accounts payable for processing. (create the cheque for payment).

10.4 Post Project Stage

10.4.1 Post Project Wrap-Up

This is the last stage of the contracting process. The project (as well as the contractor's obligations) is finalized and evaluated. The project owner is responsible to ensure all invoices, including hold-backs, have reviewed and paid. He is also responsible to ensure that all excess materials are returned to the Stores Dept. to be credited back to the project.

He will also make sure that all deficiencies have been dealt with prior to closure of the project.

10.4.2 Final Project Management Report (Project Owner)

This report will include items like:

Cost savings, new procedures, explanation of cost over runs, timelines, final contract evaluation and general overview of how the project went.

10.4.3 Documentation

All documentation of any kind pertaining to this project will be included in the project file under the contract number in the Purchasing Department.

11.0 Contractor Pre-Qualification Form (PQF)

11.1 Purpose

The purpose of this form is to document the qualifications of contractors having NO PREVIOUS WORK HISTORY with FortisOntario, and who are being considered to do projects in the $50,000.00 range and up, and to gage their suitability to be on or off the Approved Contractors' List.

11.2 Roles & Responsibilities

All FortisOntario personnel entrusted with the hiring of Contractors will have the Contractor complete this form. The Health and Safety Department will either approve or conditionally approve the request and work with the vendor to ensure all necessary facets are completed. Based on certain criteria and vendor performance, the HSE Department may elect NOT to pre-qualify a vendor.

Record of Change

Date	Section	Description	Updated	Approved By
2016.03.15				

ONE-TIME COSTS

The one-time costs included in this Application are for the costs of the Application and they are spread over five years until the next rebasing. A summary of the costs is shown below:

Table: 4.7.1.1 One Time Cost Summary

One Time Cost Summary	
Intervenor Costs	$ 80,000
OEB Costs	25,000
Legal	105,000
Other Consultants	90,000
Total	$ 300,000
Cost per year over 5 years	$ 60,000

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REGULATORY COSTS

The Table 4.8.1.1 shown below (Appendix 2–M) summarizes the regulatory costs for CNPI.

Table 4.8.1.1: Appendix 2-M Regulatory Cost Schedule

Appendix 2-M
Regulatory Cost Schedule

	Regulatory Cost Category	USoA Account	USoA Account Balance	Ongoing or One-time Cost? [2]	Last Rebasing Year (2013 Board Approved)	Most Current Actuals Year 2015	2016 Bridge Year	Annual % Change	2017 Test Year	Annual % Change
	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H) = [(G)-(F)]/(F)	(I)	(J) = [(I)-(G)]/(G)
1	OEB Annual Assessment	5655		On-Going	$ 102,550	$ 107,180	$ 109,027	1.72%	$ 112,068	2.79%
2	OEB Section 30 Costs (Applicant-originated)	5655		On-Going	$ 2,100	$ -	$ -		$ -	
3	OEB Section 30 Costs (OEB-initiated)	5655		On-Going	$ 2,150	$ 9,403	$ 5,814	-38.16%	$ 9,834	69.14%
4	Expert Witness costs for regulatory matters									
5	Legal costs for regulatory matters	5655		On-Going	$ 34,272	$ 23,766	$ 23,700	-0.28%	$ 24,070	10.00%
6	Consultants' costs for regulatory matters	5655		On-Going	$ 24,973	$ 16,539	$ 18,597	12.44%	$ 21,457	15.38%
7	Operating expenses associated with staff resources allocated to regulatory matters	Multiple incl 5655		On-Going	$ 122,350	$ 91,496	$ 143,944	57.32%	$ 164,490	14.27%
8	Operating expenses associated with other resources allocated to regulatory matters [1]									
9	Other regulatory agency fees or assessments	5655		On-Going	$ 7,296	$ -	$ -		$ -	
10	Any other costs for regulatory matters (please define)									
11	Intervenor costs	5655		On-Going	$ 24,999	$ 18,386	$ 18,386	0.00%	$ 22,386	10.88%
12	Sub-total - Ongoing Costs [3]		$ -		$ 320,690	$ 266,769	$ 319,468	19.75%	$ 354,305	10.90%
13	Sub-total - One-time Costs [4]		$ -		$ -	$ -	$ -		$ -	
14	Total		$ -		$ 320,690	$ 266,769	$ 319,468	19.75%	$ 354,305	10.90%

Please fill out the following table for all one-time costs related to this cost of service application to be amortized over the test year plus the IRM period.

		Historical Year(s)	2016 Bridge Year	2017 Test Year
4	Expert Witness costs			
5	Legal costs			105,000
6	Consultants' costs			90,000
7	Incremental operating expenses associated with staff resources allocated to this application.			
8	Incremental operating expenses associated with other resources allocated to this application. [1]			
11	Intervenor costs			105,000

The OEB Annual Assessment, the OEB Hearing Assessments (Applicant initiated) and OEB Section 30 Costs (OEB initiated) have been forecast in the 2017 Test Year based on historic actuals. The operating expenses associated with staff resources allocated to regulatory matters are forecast based on intercompany administrative allocations. Costs related to the cost of service application including the following: legal costs for regulatory matters, consultants costs for regulatory matters, and anticipated intervenor costs. These 2017 Test Year costs have been forecast on the basis of 2013 EDR costs. These amounts will be amortized over the anticipated IRM term under 4th generation with a cycle of five years, and one fifth of the amount has been included in the 2017 Test Year column in the top portion of the schedule above.

Appendix 2-M
Regulatory Cost Schedule

	Regulatory Cost Category	USoA Account	USoA Account Balance	Ongoing or One-time Cost? [2]	Last Rebasing Year (2013 Board Approved)	Most Current Actuals Year 2015	2016 Bridge Year	Annual % Change	2017 Test Year	Annual % Change
	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H) = [(G)-(F)]/(F)	(I)	(J) = [(I)-(G)]/(G)
1	OEB Annual Assessment	5655		On-Going	$ 102,550	$ 107,180	$ 109,027	1.72%	$ 112,068	2.79%
2	OEB Section 30 Costs (Applicant-originated)	5655		On-Going	$ 2,100	$ -	$ -		$ -	
3	OEB Section 30 Costs (OEB-initiated)	5655		On-Going	$ 2,150	$ 9,403	$ 5,814	-38.16%	$ 9,834	69.14%
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5	Legal costs for regulatory matters	5655		On-Going	$ 34,272	$ 23,766	$ 23,700	-0.28%	$ 24,070	10.00%
6	Consultants' costs for regulatory matters	5655		On-Going	$ 24,973	$ 16,539	$ 18,597	12.44%	$ 21,457	15.38%
7	Operating expenses associated with staff resources allocated to regulatory matters	Multiple incl 5655		On-Going	$ 122,350	$ 91,496	$ 143,944	57.32%	$ 164,490	14.27%
8	Operating expenses associated with other resources allocated to regulatory matters [1]									
9	Other regulatory agency fees or assessments	5655		On-Going	$ 7,296	$ -	$ -		$ -	
10	Any other costs for regulatory matters (please define)									
11	Intervenor costs	5655		On-Going	$ 24,999	$ 18,386	$ 18,386	0.00%	$ 22,386	21.76%
12	Sub-total - Ongoing Costs [3]		$ -		$ 320,690	$ 266,769	$ 319,468	19.75%	$ 354,305	10.90%
13	Sub-total - One-time Costs [4]		$ -		$ -	$ -	$ -		$ -	
14	Total		$ -		$ 320,690	$ 266,769	$ 319,468	19.75%	$ 354,305	10.90%

Please fill out the following table for all one-time costs related to this cost of service application to be amortized over the test year plus the IRM period.

		Historical Year(s)	2016 Bridge Year	2017 Test Year
4	Expert Witness costs			
5	Legal costs			105,000
6	Consultants' costs			90,000
7	Incremental operating expenses associated with staff resources allocated to this application.			
8	Incremental operating expenses associated with other resources allocated to this application. [1]			
11	Intervenor costs			105,000

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LOW-INCOME ENERGY CONSUMER PROGRAMS

As set out in the March 2009, OEB issued *Report of the Board: Low Income Energy Assistance Program* (the LEAP Report), CNPI allocates 0.12% of its OEB-approved distribution revenue requirement to provide consumers assistance in response to affordability issues.

In Fort Erie, Port Colborne and Gananoque, the Low-Income Consumer Programs began in 2011 and expenses are included through to the 2017 Test Year. The annual expense of $22,759 has remained consistent since the last rebasing year through to the 2016 Bridge Year. The 2017 Test Year LEAP Funding budget has been increased to $23,900. The LEAP amount will be adjusted to account for changes resulting from the Board's decision on the final distribution revenue requirement. These expenses are recorded in OEB account 6205.

Year	**LEAP Funding (OEB Account # 6205)**
2013 – 2016 (Bridge Year)	$ 22,759
2017 (Test Year)	$ 23,900

CNPI has designated a local lead-social agency within each of its service territories. The Salvation Army (Fort Erie), Port Cares (Port Colborne) and the United Way of Leeds and Grenville (Gananoque) are CNPI's respective local lead-social agencies, responsible for the screening and distribution of financial assistance to low income customers.

The budgeted LEAP Funding for the 2017 Test Year is not inclusive of any amounts for legacy programs.

CNPI's LEAP program and funding for LEAP will continue in tandem with the Ontario Energy Support Program effective January 1, 2016.

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CHARITABLE AND POLITICAL DONATIONS

There are no charitable or political donations funded by CNPI. Donations are made by the shareholder; FortisOntario. The amounts included in OEB account 6205 are costs related to the Low-Income Energy Consumer Program (“LEAP”).

CNPI confirms that, other than LEAP contributions, it has not forecasted any charitable or political donations in the 2017 Test Year.

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DEPRECIATION, AMORTIZATION AND DEPLETION

In CNPI's 2013 Cost of Service application (EB-2012-0112), CNPI changed its useful lives of assets and depreciation rates effective January 1, 2013. The Board's Kinectrics Report had been used as guideline in updating the depreciation/amortization rates. The rates used within this Application are the depreciation rates that were approved within the 2013 application.

Depreciation/amortization on capital assets is calculated as follows:

- The amount is calculated on a straight line basis over the estimated remaining useful life of the assets at the end of the previous year; plus

- For depreciation/amortization on capital additions during the current year, depreciation commences in the month following the month the asset is capitalized and ends in the month the asset is taken out of service. This methodology ensures an accurate and precise calculation of depreciation in both the beginning and ending year of service. CNPI has historically used this methodology. The fixed asset module within SAP tracks and calculates depreciation.

- In the Bridge Year and Test Year the "half year rule" is applied, i.e., six months of depreciation expense. This is consistent with prior Cost of Service applications.

Exhibit 4, Tab 11, Schedule 2, details the depreciation expenses by OEB asset account and the amortization rate.

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Appendix 2-C
Depreciation and Amortization Expense

Year **2013** **MIFRS**

Account	Description	Opening NBV as at Jan 1, 2013 (a)	Additions (d)	Average Remaining Life of Opening NBV (i)	Years (new additions only) (f)	Depreciation Rate on New Additions (g) = 1 / (f)	Depreciation Expense on Opening NBV (j) = (a) / (i)	Adjustment for transfers between accounts and capitalization date	Depreciation Expense on Additions (h)=((d)*0.5)/(f)	2013 Depreciation Expense (k) = (j) + (h)+adj	2013 Depreciation Expense per Appendix 2-BA Fixed Assets (l)	Variance (m) = (k) - (l)	Depreciation Expense on 2013 Full Year Additions (n)=((d))/(f)	Less Depreciation Expense on Assets Fully Depreciated during the year (o)	Adjustment for transfers	2013 Full Year Depreciation (p) = (j) + (n) - (o)
1606	Organization & Rec	$ -	$ -		40.00	2.50%	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1608	Franchises & Consents	$ 120,941	$ -	31.00	40.00	2.50%	$ 3,901	$ -	$ -	$ 3,901	$ 3,901	$ -	$ -	$ -	$ -	$ 3,901
1610	Misc. Intangible Plant	$ 36,895	$ -	36.37	40.00	2.50%	$ 1,014	$ -	$ -	$ 1,014	$ 1,014	$ -	$ -	$ -	$ -	$ 1,014
1611	GA Comp Software	$ 2,945,958	$ 1,101,559	9.81	5.00	20.00%	$ 300,176	$ -	$ 110,156	$ 410,332	$ 410,332	$ -	$ 220,312	$ -	$ (465,467)	$ 55,021
1611A	GA Comp Software	$ -	$ 871,758	-	10.00	10.00%	$ -	$ 311,924	$ 43,588	$ 355,512	$ 355,512	$ 0	$ 87,176	$ -	$ 465,467	$ 552,643
1612	D Land Rights	$ 223,113	$ 8,934	34.78	40.00	2.50%	$ 6,415	$ -	$ 112	$ 6,527	$ 6,527	$ -	$ 223	$ -	$ -	$ 6,639
1805	D Land	$ 211,728	$ -		-	0.00%	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1808	D Bldgs & Fixtures	$ 3,093,521	$ 128	35.01	50.00	2.00%	$ 88,374	$ -	$ 1	$ 88,375	$ 88,375	$ -	$ 3	$ 9,041	$ -	$ 79,335
1820	D Station Equipment < 50KV	$ 8,735,275	$ 373,772	45.97	50.00	2.00%	$ 190,038	$ -	$ 3,738	$ 193,776	$ 193,776	$ -	$ 7,475	$ -	$ -	$ 197,514
1820A	D Station Equipment < 50KV	$ -	$ 58,085	-	40.00	2.50%	$ -	$ 38,415	$ 726	$ 39,141	$ 39,141	-$ 0	$ 1,452	$ -	$ 38,415	$ 39,867
1830	D Poles,Towers&Fixtures	$ 11,808,901	$ 1,288,276	24.72	45.00	2.22%	$ 477,757	$ -	$ 14,314	$ 492,071	$ 492,071	$ -	$ 28,628	$ -	$ -	$ 506,385
1835	D OH Cond & Devices	$ 17,899,087	$ 2,055,900	31.00	45.00	2.22%	$ 577,377	$ -	$ 22,843	$ 600,220	$ 600,220	$ -	$ 45,687	$ -	$ -	$ 623,063
1840	D UG Conduit & Manholes	$ 791,543	$ 2,208	11.94	50.00	2.00%	$ 66,277	$ -	$ 22	$ 66,299	$ 66,299	$ -	$ 44	$ -	$ -	$ 66,321
1845	D UG Cond & Devices	$ 6,090,863	$ 227,556	30.86	40.00	2.50%	$ 197,395	$ -	$ 2,844	$ 200,239	$ 200,239	$ -	$ 5,689	$ -	$ -	$ 203,083
1850	D Line Transformers	$ 8,413,428	$ 708,846	22.17	40.00	2.50%	$ 379,457	$ -	$ 8,861	$ 388,317	$ 388,317	$ -	$ 17,721	$ -	$ -	$ 397,178
1855	D Services	$ 6,630,164	$ 509,442	32.36	40.00	2.50%	$ 204,873	$ -	$ 6,368	$ 211,241	$ 211,241	$ -	$ 12,736	$ -	$ -	$ 217,609
1860	D Meters	$ 1,961,511	$ 4,854,305	2.12	30.00	3.33%	$ 923,376	$ -	$ 80,905	$ 1,004,281	$ 1,004,281	-$ 0	$ 161,810	$ 646,079	$ (408,049)	$ 31,058
1860A	D Meters	$ -	$ 101,144	-	15.00	6.67%	$ -	$ 385,674	$ 3,371	$ 389,045	$ 389,045	$ 0	$ 6,743	$ -	$ 389,325	$ 396,068
1860B	D Meters	$ -	$ 24,757	-	30.00	3.33%	$ -	$ 20,887	$ 413	$ 21,300	$ 21,299	$ 0	$ 825	$ -	$ 18,724	$ 19,549
1865	D Other Install on Cust Prem	$ 50,388	$ 69,554	1.94	10.00	10.00%	$ 26,016	$ -	$ 3,478	$ 29,493	$ 29,493	$ -	$ 6,955	$ 19,546	$ -	$ 13,425
1875	D St Lites & Signal Systems	$ -	$ -		20.00	5.00%	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1908	GA Bldgs & Fixtures	$ 832,174	$ 193,954	47.66	50.00	2.00%	$ 17,461	$ -	$ 1,940	$ 19,400	$ 19,400	$ -	$ 3,879	$ -	$ -	$ 21,340
1910	GA Leasehold Improvements	$ 283,376	$ 276,500	4.73	5.00	20.00%	$ 59,855	$ -	$ 27,650	$ 87,505	$ 87,505	$ -	$ 55,300	$ -	$ -	$ 115,155
1915	GA Office Furn & Equipment	$ 107,152	$ (1,485)	4.11	10.00	10.00%	$ 26,076	$ -	$ (74)	$ 26,002	$ 26,002	$ -	$ (149)	$ 4,458	$ -	$ 21,469
1920	GA Comp Hardware	$ 1,191,923	$ 198,011	2.97	5.00	20.00%	$ 401,585	$ -	$ 19,801	$ 421,386	$ 421,386	$ -	$ 39,602	$ 88,694	$ -	$ 352,493
1930	GA Transportation Equipment	$ 1,454,705	$ 479,487	23.55	5.00	20.00%	$ 61,768	$ -	$ 47,949	$ 109,717	$ 109,717	$ -	$ 95,897	$ 8,591	$ (76,596)	$ 72,479
1930A	GA Transportation Equipment	$ -	$ 31,527	-	10.00	10.00%	$ -	$ 240,864	$ 1,576	$ 242,440	$ 242,440	$ 0	$ 3,153	-$ 164,268	$ 76,596	$ 244,017
1935	GA Stores Equip	$ 11,989	$ -	2.59	10.00	10.00%	$ 4,628	$ -	$ -	$ 4,628	$ 4,628	$ -	$ -	$ -	$ -	$ 4,628
1940	GA tools,shop&garage equip	$ 102,657	$ 8,551	6.35	10.00	10.00%	$ 16,168	$ -	$ 428	$ 16,596	$ 16,596	$ -	$ 855	$ 553	$ -	$ 16,470
1945	GA measure&test equip	$ 58,925	$ -	3.22	10.00	10.00%	$ 18,300	$ -	$ -	$ 18,300	$ 18,300	$ -	$ -	$ 1,045	$ -	$ 17,255
1950	GA power op equip	$ 16,432	$ -	6.81	10.00	10.00%	$ 2,414	$ -	$ -	$ 2,414	$ 2,414	$ -	$ -	$ -	$ -	$ 2,414
1955	GA Comm Equipment	$ 549,002	$ (2,676)	5.74	10.00	10.00%	$ 95,697	$ -	$ (134)	$ 95,563	$ 95,563	$ 0	$ (268)	$ 12,042	$ -	$ 83,387
1960	GA Misc. Equip	$ 42,551	$ -	5.67	10.00	10.00%	$ 7,504	$ -	$ -	$ 7,504	$ 7,504	$ -	$ -	$ -	$ -	$ 7,504
1960A	GA Misc. Equip	$ -	$ -	-	5.00	20.00%	$ -	$ 5,455	$ -	$ 5,455	$ 5,455	-$ 0	$ -	$ -	$ 5,488	$ 5,488
1980	GA System Supv Equip	$ 85,705	$ 51,051	13.14	20.00	5.00%	$ 6,525	$ -	$ 1,276	$ 7,801	$ 7,801	$ -	$ 2,553	$ -	$ -	$ 9,077
1995	Contributions & Grants	$ (7,868,392)	$ (1,062,493)	37.07	40.00	2.50%	$ (212,273)	$ -	$ (13,281)	$ (225,554)	$ (225,554)	$ 0	$ (26,562)	$ -	$ -	$ (238,835)
						0.00%	$ -		$ -	$ -		$ -	$ -		$ -	$ -
						0.00%	$ -		$ -	$ -		$ -	$ -		$ -	$ -
etc.						0.00%	$ -		$ -	$ -		$ -	$ -		$ -	$ -
						0.00%	$ -		$ -	$ -		$ -	$ -		$ -	$ -
	Total	$ 65,881,516	$ 12,428,651				$ 3,948,152	$ 1,003,219	$ 388,870	$ 5,340,242	$ 5,340,241	$ 0	$ 777,741	$ 625,781	$ 43,903	$ 4,144,015
	Depreciation on asset allocations									$ (1,250,787)	$ (1,250,787)	see Exh 2				
	Vehicle depreciation									$ -	$ -	Credit reported within General and Admin in 2013, see Exh 4, Tab 2				
	Total depreciation for revenue requirement									$ 4,089,455	$ 4,089,455					

Appendix 2-C
Depreciation and Amortization Expense

2014 **MIFRS**

Account	Description	Additions (d)	Years (new additions only) (f)	Depreciation Rate on New Additions (g) = 1 / (f)	Adjustment for transfers between accounts and capitalization date	2014 Depreciation Expense (h)=2013 Full Year Deprecation + ((d)*0.5)/(f)	2014 Depreciation Expense per Apppendix 2-BA Fixed Assets (l)	Variance (m) = (h) - (l)	Depreciation Expense on 2014 Full Year Additions (n)=((d))/(f)	Less Depreciation Expense on Assets Fully Depreciated during the year (o)	2014 Full Year Depreciation (p) = 2013 Full Year Depreciation + (n) - (o)
1606	Organization & Rec	$ -	40.00	2.50%	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1608	Franchises & Consents	$ -	40.00	2.50%	$ -	$ 3,901	$ 3,901	$ -	$ -	$ -	$ 3,901
1610	Misc. Intangible Plant	$ -	40.00	2.50%	$ -	$ 1,014	$ 1,014	$ -	$ -	$ -	$ 1,014
1611	GA Comp Software	$ 325,866	5.00	20.00%	$ -	$ 87,607	$ 87,607	$ (0)	$ 65,173	$ -	$ 120,194
1611A	GA Comp Software	$ 597,678	10.00	10.00%	$ 18,420	$ 600,947	$ 600,946	$ 0	$ 59,768	$ -	$ 612,411
1612	D Land Rights	$ 3,463	40.00	2.50%	$ 44	$ 6,726	$ 6,726	$ (0)	$ 87	$ -	$ 6,725
1805	D Land	$ -	-	0.00%	$ -		$ -	$ -	$ -	$ -	$ -
1808	D Bldgs & Fixtures	$ -	50.00	2.00%	$ -	$ 79,335	$ 79,335	$ 0	$ -	$ 4,091	$ 75,244
1820	D Station Equipment < 50KV	$ 68,090	50.00	2.00%	$ 2,416	$ 200,611	$ 200,611	$ (0)	$ 1,362	$ -	$ 198,875
1820A	D Station Equipment < 50KV	$ 39,223	40.00	2.50%	$ 555	$ 40,912	$ 40,912	$ 0	$ 981	$ -	$ 40,848
1830	D Poles,Towers&Fixtures	$ 1,151,613	45.00	2.22%	$ 2,239	$ 521,420	$ 521,420	$ (0)	$ 25,591	$ -	$ 531,976
1835	D OH Cond & Devices	$ 1,860,392	45.00	2.22%	$ 602	$ 644,336	$ 644,337	$ (0)	$ 41,342	$ -	$ 664,405
1840	D UG Conduit & Manholes	$ 7,391	50.00	2.00%	$ (43)	$ 66,352	$ 66,352	$ 0	$ 148	$ -	$ 66,469
1845	D UG Cond & Devices	$ 514,085	40.00	2.50%	$ (5,946)	$ 203,564	$ 203,563	$ 0	$ 12,852	$ -	$ 215,936
1850	D Line Transformers	$ 597,714	40.00	2.50%	$ 1,206	$ 405,855	$ 405,855	$ 0	$ 14,943	$ -	$ 412,121
1855	D Services	$ 555,334	40.00	2.50%	$ (761)	$ 223,790	$ 223,790	$ 0	$ 13,883	$ -	$ 231,492
1860	D Meters	$ 47,380	30.00	3.33%	$ -	$ 31,848	$ 31,848	$ 0	$ 1,579	$ -	$ 32,638
1860A	D Meters	$ 115,924	15.00	6.67%	$ -	$ 399,932	$ 399,933	$ (0)	$ 7,728	$ -	$ 403,796
1860B	D Meters	$ 30,064	30.00	3.33%	$ -	$ 20,050	$ 20,050	$ (0)	$ 1,002	$ -	$ 20,551
1865	D Other Install on Cust Prem	$ 166	10.00	10.00%	$ -	$ 13,433	$ 13,433	$ 0	$ 17	$ -	$ 13,442
1875	D St Lites & Signal Systems	$ -	20.00	5.00%	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1908	GA Bldgs & Fixtures	$ 15,885	50.00	2.00%	$ (3,494)	$ 18,005	$ 18,004	$ 0	$ 318	$ -	$ 21,657
1910	GA Leasehold Improvements	$ 144,925	5.00	20.00%	$ 21,450	$ 151,098	$ 151,098	$ (0)	$ 28,985	$ -	$ 144,140
1915	GA Office Furn & Equipment	$ 66,160	10.00	10.00%	$ 3,101	$ 27,878	$ 27,878	$ 0	$ 6,616	$ 5,422	$ 22,663
1920	GA Comp Hardware	$ 272,714	5.00	20.00%	$ -	$ 379,764	$ 379,764	$ 0	$ 54,543	$ 30,792	$ 376,244
1930	GA Transportation Equipment	$ 137,344	5.00	20.00%	$ 8,591	$ 94,804	$ 94,804	$ (0)	$ 27,469	$ 7,156	$ 92,791
1930A	GA Transportation Equipment	$ 559,754	10.00	10.00%	$ 20,103	$ 292,107	$ 292,107	$ 0	$ 55,975	$ 11,500	$ 288,492
1935	GA Stores Equip	$ -	10.00	10.00%	$ -	$ 4,628	$ 4,628	$ -	$ -	$ 1,894	$ 2,734
1940	GA tools,shop&garage equip	$ 60,961	10.00	10.00%	$ (1,028)	$ 18,490	$ 18,491	$ (0)	$ 6,096	$ 1,919	$ 20,647
1945	GA measure&test equip	$ 30,926	10.00	10.00%	$ (1,740)	$ 17,061	$ 17,061	$ 0	$ 3,093	$ 1,922	$ 18,426
1950	GA power op equip	$ -	10.00	10.00%	$ -	$ 2,414	$ 2,414	$ 0	$ -	$ -	$ 2,414
1955	GA Comm Equipment	$ 43,239	10.00	10.00%	$ (2,189)	$ 83,360	$ 83,360	$ (0)	$ 4,324	$ 7,758	$ 79,953
1960	GA Misc. Equip	$ -	10.00	10.00%	$ -	$ 7,504	$ 7,504	$ -	$ -	$ -	$ 7,504
1960A	GA Misc. Equip	$ 20,900	5.00	20.00%	$ (2,123)	$ 5,455	$ 5,455	$ (0)	$ 4,180	$ -	$ 9,668
1980	GA System Supv Equip	$ 7,683	20.00	5.00%	$ 1,387	$ 10,657	$ 10,656	$ 0	$ 384	$ -	$ 9,462
1995	Contributions & Grants	$ (1,658,435)	40.00	2.50%	$ 19,105	$ (240,460)	$ (240,460)	$ (0)	$ (41,461)	$ -	$ (280,296)
				0.00%				$ -	$ -		$ -
				0.00%				$ -	$ -		$ -
				0.00%				$ -	$ -		$ -
	Total	**$ 5,616,436**			**$ 81,895**	**$ 4,424,399**	**$ 4,424,397**	**$ 2**	**$ 396,977**	**$ 72,454**	**$ 4,468,538**
	Depreciation on asset allocations					**$ (1,161,220)**	**$ (1,161,220)**	see Exh 2			
	Vehicle depreciation					**$ (386,911)**	**$ (386,911)**	included in burden rate			
	Total depreciation for revenue requirement					**$ 2,876,268**	**$ 2,876,266**				

Appendix 2-C
Depreciation and Amortization Expense

2015 **MIFRS**

Account	Description	Additions (d)	Years (new additions only) (f)	Depreciation Rate on New Additions (g) = 1 / (f)	Adjustment for transfers between accounts and capitalization date	2015 Depreciation Expense (h)=2014 Full Year Deprecation + ((d)*0.5)/(f)	2015 Depreciation Expense per Apppendix 2-BA Fixed Assets (l)	Variance (m) = (h) - (l)	Depreciation Expense on 2015 Full Year Additions (n)=((d))/(f)	Less Depreciation Expense on Assets Fully Depreciated during the year (o)	2015 Full Year Depreciation (p) = 2014 Full Year Depreciation + (n) - (o)
1606	Organization & Rec	$ -	40.00	2.50%	$ -	**$ -**	$ -	**$ -**	**$ -**	$ -	**$ -**
1608	Franchises & Consents	$ -	40.00	2.50%	$ -	**$ 3,901**	$ 3,901	**$ (0)**	**$ -**	$ -	**$ 3,901**
1610	Misc. Intangible Plant	$ -	40.00	2.50%	$ -	**$ 1,014**	$ 1,014	**$ (0)**	**$ -**	$ -	**$ 1,014**
1611	GA Comp Software	$ 166,492	5.00	20.00%	$ (356)	**$ 136,487**	$ 136,487	**$ 0**	**$ 33,298**	$ -	**$ 153,492**
1611A	GA Comp Software	$ 640,815	10.00	10.00%	$ (172)	**$ 644,279**	$ 644,279	**$ 0**	**$ 64,082**	$ 37,436	**$ 639,056**
1612	D Land Rights	$ 4,867	40.00	2.50%	$ 4	**$ 6,790**	$ 6,790	**$ 0**	**$ 122**	$ -	**$ 6,847**
1805	D Land	$ -	-	0.00%	$ -		$ -	**$ -**	**$ -**	$ -	**$ -**
1808	D Bldgs & Fixtures	$ -	50.00	2.00%	$ -	**$ 75,244**	$ 75,244	**$ 0**	**$ -**	$ 4,606	**$ 70,638**
1820	D Station Equipment < 50KV	$ 1,182,592	50.00	2.00%	$ (6,611)	**$ 204,090**	$ 204,091	**$ (0)**	**$ 23,652**	$ -	**$ 222,527**
1820A	D Station Equipment < 50KV	$ 514,319	40.00	2.50%	$ (4,288)	**$ 42,989**	$ 42,989	**$ (0)**	**$ 12,858**	$ -	**$ 53,706**
1830	D Poles,Towers&Fixtures	$ 2,578,593	45.00	2.22%	$ (6,599)	**$ 554,028**	$ 554,028	**$ 0**	**$ 57,302**	$ -	**$ 589,278**
1835	D OH Cond & Devices	$ 2,777,581	45.00	2.22%	$ (2,711)	**$ 692,556**	$ 692,556	**$ (0)**	**$ 61,724**	$ -	**$ 726,129**
1840	D UG Conduit & Manholes	$ 104,778	50.00	2.00%	$ (845)	**$ 66,672**	$ 66,672	**$ 0**	**$ 2,096**	$ 36,319	**$ 32,246**
1845	D UG Cond & Devices	$ 765,724	40.00	2.50%	$ (3,186)	**$ 222,321**	$ 222,321	**$ 0**	**$ 19,143**	$ 7,439	**$ 227,640**
1850	D Line Transformers	$ 590,514	40.00	2.50%	$ 1,729	**$ 421,231**	$ 421,231	**$ 0**	**$ 14,763**	$ -	**$ 426,884**
1855	D Services	$ 571,682	40.00	2.50%	$ 558	**$ 239,196**	$ 239,197	**$ (0)**	**$ 14,292**	$ -	**$ 245,785**
1860	D Meters	$ 105,091	30.00	3.33%	$ (6,465)	**$ 27,924**	$ 27,924	**$ 0**	**$ 3,503**	$ 16,326	**$ 19,815**
1860A	D Meters	$ 320,626	15.00	6.67%	$ (8,330)	**$ 406,154**	$ 406,153	**$ 0**	**$ 21,375**	$ -	**$ 425,171**
1860B	D Meters	$ 13,046	30.00	3.33%	$ (1,935)	**$ 18,834**	$ 18,834	**$ (0)**	**$ 435**	$ -	**$ 20,986**
1865	D Other Install on Cust Prem	$ -	10.00	10.00%	$ (3)	**$ 13,439**	$ 13,439	**$ 0**	**$ -**	$ 48	**$ 13,394**
1875	D St Lites & Signal Systems	$ -	20.00	5.00%	$ -	**$ -**	$ -	**$ -**	**$ -**	$ -	**$ -**
1908	GA Bldgs & Fixtures	$ 32,714	50.00	2.00%	$ (4,078)	**$ 17,907**	$ 17,906	**$ 0**	**$ 654**	$ 4,061	**$ 18,251**
1910	GA Leasehold Improvements	$ 44,967	5.00	20.00%	$ 23,841	**$ 172,478**	$ 172,478	**$ 0**	**$ 8,993**	$ 30,392	**$ 122,742**
1915	GA Office Furn & Equipment	$ 69,642	10.00	10.00%	$ (1,927)	**$ 24,218**	$ 24,219	**$ (0)**	**$ 6,964**	$ 4,454	**$ 25,174**
1920	GA Comp Hardware	$ 79,876	5.00	20.00%	$ (47,272)	**$ 336,959**	$ 336,959	**$ 0**	**$ 15,975**	$ 108,641	**$ 283,578**
1930	GA Transportation Equipment	$ -	5.00	20.00%	$ -	**$ 92,791**	$ 92,791	**$ 0**	**$ -**	$ 13,334	**$ 79,457**
1930A	GA Transportation Equipment	$ 125,741	10.00	10.00%	$ 7,711	**$ 302,490**	$ 302,490	**$ 0**	**$ 12,574**	$ 11,667	**$ 289,399**
1935	GA Stores Equip	$ -	10.00	10.00%	$ -	**$ 2,734**	$ 2,734	**$ (0)**	**$ -**	$ 2,734	**$ (0)**
1940	GA tools,shop&garage equip	$ 43,095	10.00	10.00%	$ (1,601)	**$ 21,201**	$ 21,201	**$ 0**	**$ 4,309**	$ 442	**$ 24,515**
1945	GA measure&test equip	$ 6,022	10.00	10.00%	$ (1,741)	**$ 16,986**	$ 16,986	**$ (0)**	**$ 602**	$ 6,901	**$ 12,127**
1950	GA power op equip	$ -	10.00	10.00%	$ -	**$ 2,414**	$ 2,414	**$ (0)**	**$ -**	$ -	**$ 2,414**
1955	GA Comm Equipment	$ 7,223	10.00	10.00%	$ (1,415)	**$ 78,899**	$ 78,899	**$ 0**	**$ 722**	$ 1,801	**$ 78,874**
1960	GA Misc. Equip	$ 9,995	10.00	10.00%	$ (1,466)	**$ 6,537**	$ 6,537	**$ 0**	**$ 999**	$ 4,145	**$ 4,358**
1960A	GA Misc. Equip	$ 2,974	5.00	20.00%	$ (2,952)	**$ 7,013**	$ 7,014	**$ (0)**	**$ 595**	$ 5,466	**$ 4,797**
1980	GA System Supv Equip	$ 211,954	20.00	5.00%	$ (4,023)	**$ 10,737**	$ 10,738	**$ (0)**	**$ 10,598**	-$ 1,337	**$ 21,396**
1995	Contributions & Grants	$(1,264,311)	40.00	2.50%	$ 19,649	**$ (276,451)**	$ (276,451)	**$ (0)**	**$ (31,608)**	$ -	**$ (311,904)**
				0.00%				**$ -**	**$ -**		**$ -**
				0.00%				**$ -**	**$ -**		**$ -**
				0.00%				**$ -**	**$ -**		**$ -**
	Total	**$ 9,706,611**			**$ (54,484)**	**$ 4,594,066**	**$ 4,594,065**	**$ 1**	**$ 360,023**	**$ 294,875**	**$ 4,533,687**
	Depreciation on asset allocations					**$ (807,781)**	**$ (807,781)**	see Exh 2			
	Vehicle depreciation					**$ (395,281)**	**$ (395,281)**	included in burden rate			
1	**Total depreciation for revenue requirement**					**$ 3,391,004**	**$ 3,391,003**				

Appendix 2-C
Depreciation and Amortization Expense

2016 **MIFRS**

Account	Description	Additions (d)	Years (new additions only) (f)	Depreciation Rate on New Additions (g) = 1 / (f)	Adjustment for transfers between accounts and capitalization date	2016 Depreciation Expense (h)=2015 Full Year Deprecation + ((d)*0.5)/(f)	2016 Depreciation Expense per Apppendix 2-BA Fixed Assets (l)	Variance (m) = (h) - (l)	Depreciation Expense on 2016 Full Year Additions (n)=((d))/(f)	Less Depreciation Expense on Assets Fully Depreciated during the year (o)	2016 Full Year Depreciation (p) = 2015 Full Year Depreciation + (n) - (o)
1606	Organization & Rec	$ -	40.00	2.50%	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1608	Franchises & Consents	$ -	40.00	2.50%	$ -	$ 3,901	$ 3,901	$ -	$ -	$ -	$ 3,901
1610	Misc. Intangible Plant	$ -	40.00	2.50%	$ -	$ 1,014	$ 1,014	$ -	$ -	$ -	$ 1,014
1611	GA Comp Software	$ 679,305	5.00	20.00%	$ 3,033	$ 224,456	$ 224,456	$ -	$ 135,861	$ -	$ 289,353
1611A	GA Comp Software	$ 889,891	10.00	10.00%	$ (10,155)	$ 673,395	$ 673,395	$ -	$ 88,989	$ -	$ 728,045
1612	D Land Rights	$ 20,377	40.00	2.50%	$ 44	$ 7,146	$ 7,146	$ -	$ 509	$ -	$ 7,356
1805	D Land	$ 4,862	-	0.00%	$ -		$ -	$ -	$ -	$ -	$ -
1808	D Bldgs & Fixtures	$ 233,975	50.00	2.00%	$ (1,121)	$ 71,857	$ 71,857	$ -	$ 4,679	$ -	$ 75,318
1820	D Station Equipment < 50KV	$ 342,800	50.00	2.00%	$ 2,588	$ 228,543	$ 228,543	$ -	$ 6,856	$ -	$ 229,383
1820A	D Station Equipment < 50KV	$ 1,705,161	40.00	2.50%	$ 1,045	$ 76,065	$ 76,065	$ -	$ 42,629	$ -	$ 96,335
1830	D Poles,Towers&Fixtures	$ 2,419,593	45.00	2.22%	$ 10,251	$ 626,414	$ 626,414	$ -	$ 53,769	$ -	$ 643,047
1835	D OH Cond & Devices	$ 1,386,266	45.00	2.22%	$ 13,449	$ 754,981	$ 754,981	$ -	$ 30,806	$ -	$ 756,935
1840	D UG Conduit & Manholes	$ 208,790	50.00	2.00%	$ (385)	$ 33,948	$ 33,948	$ -	$ 4,176	$ 12,249	$ 24,173
1845	D UG Cond & Devices	$ 212,827	40.00	2.50%	$ (994)	$ 229,306	$ 229,306	$ -	$ 5,321	$ 2,651	$ 230,309
1850	D Line Transformers	$ 1,914,937	40.00	2.50%	$ 4,415	$ 455,236	$ 455,236	$ -	$ 47,873	$ -	$ 474,757
1855	D Services	$ 724,666	40.00	2.50%	$ 3,285	$ 258,128	$ 258,128	$ -	$ 18,117	$ -	$ 263,901
1860	D Meters	$ -	30.00	3.33%	$ 0	$ 19,815	$ 19,815	$ (0)	$ -	$ 754	$ 19,060
1860A	D Meters	$ 228,500	15.00	6.67%	$ 161	$ 432,949	$ 432,949	$ (0)	$ 15,233	$ -	$ 440,405
1860B	D Meters	$ 79,807	30.00	3.33%	$ (2,957)	$ 19,359	$ 19,360	$ (0)	$ 2,660	$ -	$ 23,646
1865	D Other Install on Cust Prem	$ -	10.00	10.00%	$ -	$ 13,394	$ 13,394	$ -	$ -	$ -	$ 13,394
1875	D St Lites & Signal Systems	$ -	20.00	5.00%	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1908	GA Bldgs & Fixtures	$ 20,000	50.00	2.00%	$ (0)	$ 18,450	$ 18,450	$ -	$ 400	$ -	$ 18,651
1910	GA Leasehold Improvements	$ 49,746	5.00	20.00%	$ 3,459	$ 131,176	$ 131,176	$ -	$ 9,949	$ 30,392	$ 102,299
1915	GA Office Furn & Equipment	$ 23,000	10.00	10.00%	$ (1,604)	$ 24,719	$ 24,719	$ -	$ 2,300	$ 626	$ 26,848
1920	GA Comp Hardware	$ 522,768	5.00	20.00%	$ (32,513)	$ 303,342	$ 303,342	$ -	$ 104,554	$ 77,055	$ 311,077
1930	GA Transportation Equipment	$ 72,700	5.00	20.00%	$ (10,917)	$ 75,811	$ 75,811	$ -	$ 14,540	$ 30,566	$ 63,431
1930A	GA Transportation Equipment	$ 294,300	10.00	10.00%	$ (1,442)	$ 302,672	$ 302,672	$ -	$ 29,430	$ 22,951	$ 295,878
1935	GA Stores Equip	$ -	10.00	10.00%	$ 0	$ -	$ -	$ -	$ -	$ -	$ (0)
1940	GA tools,shop&garage equip	$ 50,000	10.00	10.00%	$ (1,620)	$ 25,395	$ 25,395	$ -	$ 5,000	$ -	$ 29,515
1945	GA measure&test equip	$ -	10.00	10.00%	$ 0	$ 12,127	$ 12,127	$ -	$ -	$ 6,845	$ 5,282
1950	GA power op equip	$ 18,000	10.00	10.00%	$ (0)	$ 3,314	$ 3,314	$ -	$ 1,800	$ -	$ 4,214
1955	GA Comm Equipment	$ 35,160	10.00	10.00%	$ (420)	$ 80,212	$ 80,212	$ -	$ 3,516	$ -	$ 82,390
1960	GA Misc. Equip	$ -	10.00	10.00%	$ (0)	$ 4,358	$ 4,358	$ -	$ -	$ 1,271	$ 3,088
1960A	GA Misc. Equip	$ -	5.00	20.00%	$ (0)	$ 4,797	$ 4,797	$ -	$ -	$ -	$ 4,797
1980	GA System Supv Equip	$ -	20.00	5.00%	$ (0)	$ 21,396	$ 21,396	$ -	$ -	$ -	$ 21,396
1995	Contributions & Grants	$ (1,470,207)	40.00	2.50%	$ 20,563	$ (309,718)	$ (309,718)	$ -	$ (36,755)	$ -	$ (348,659)
				0.00%				$ -	$ -		$ -
				0.00%				$ -	$ -		$ -
				0.00%				$ -	$ -		$ -
	Total	**$ 10,667,225**			**$ (1,835)**	**$ 4,827,958**	**$ 4,827,959**	**$ (1)**	**$ 592,212**	**$ 185,360**	**$ 4,940,539**
	Depreciation on asset allocations					$ -	$ -	see Exh 2			
	Vehicle depreciation					$ (378,483)	$ (378,483)	included in burden rate			
	Total depreciation for revenue requirement					**$ 4,449,476**	**$ 4,449,477**				

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Appendix 2-C
Depreciation and Amortization Expense

2017 **MIFRS**

Account	Description	Additions (d)	Years (new additions only) (f)	Depreciation Rate on New Additions (g) = 1 / (f)	Adjustment for transfers between accounts and capitalization date	2017 Depreciation Expense (h)=2016 Full Year Deprecation + ((d)*0.5)/(f)	2017 Depreciation Expense per Apppendix 2-BA Fixed Assets (l)	Variance (m) = (h) - (l)
1606	Organization & Rec	$ -	40.00	2.50%	$ -	$ -	$ -	$ -
1608	Franchises & Consents	$ -	40.00	2.50%	$ -	$ 3,901	$ 3,901	$ -
1610	Misc. Intangible Plant	$ -	40.00	2.50%	$ -	$ 1,014	$ 1,014	$ -
1611	GA Comp Software	$ 300,531	5.00	20.00%	$ 1,416	$ 320,823	$ 320,823	$ -
1611A	GA Comp Software	$ 973,496	10.00	10.00%	$ (28,967)	$ 747,753	$ 747,753	$ -
1612	D Land Rights	$ 20,517	40.00	2.50%	$ 44	$ 7,657	$ 7,657	$ -
1805	D Land	$ 123,387	-	0.00%	$ -		$ -	$ -
1808	D Bldgs & Fixtures	$ 32,472	50.00	2.00%	$ (1,121)	$ 74,521	$ 74,521	$ -
1820	D Station Equipment < 50KV	$ 118,700	50.00	2.00%	$ 2,588	$ 233,158	$ 233,158	$ -
1820A	D Station Equipment < 50KV	$ 1,350,963	40.00	2.50%	$ 1,045	$ 114,267	$ 114,267	$ -
1830	D Poles,Towers&Fixtures	$ 2,367,461	45.00	2.22%	$ 10,249	$ 679,601	$ 679,601	$ -
1835	D OH Cond & Devices	$ 1,347,941	45.00	2.22%	$ 12,881	$ 784,794	$ 784,794	$ -
1840	D UG Conduit & Manholes	$ 239,209	50.00	2.00%	$ (385)	$ 26,179	$ 26,179	$ -
1845	D UG Cond & Devices	$ 226,194	40.00	2.50%	$ (993)	$ 232,144	$ 232,144	$ -
1850	D Line Transformers	$ 1,636,697	40.00	2.50%	$ 4,415	$ 499,631	$ 499,631	$ -
1855	D Services	$ 512,630	40.00	2.50%	$ 3,285	$ 273,594	$ 273,594	$ -
1860	D Meters	$ -	30.00	3.33%	$ -	$ 19,060	$ 19,061	$ (0)
1860A	D Meters	$ 196,252	15.00	6.67%	$ 10,558	$ 457,504	$ 457,504	$ -
1860B	D Meters	$ 81,202	30.00	3.33%	$ (3,876)	$ 21,124	$ 21,123	$ 0
1865	D Other Install on Cust Prem	$ -	10.00	10.00%	$ 0	$ 13,394	$ 13,394	$ -
1875	D St Lites & Signal Systems	$ -	20.00	5.00%	$ -	$ -	$ -	$ -
1908	GA Bldgs & Fixtures	$ 20,000	50.00	2.00%	$ (0)	$ 18,850	$ 18,850	$ -
1910	GA Leasehold Improvements	$ 85,389	5.00	20.00%	$ 3,460	$ 114,298	$ 114,298	$ -
1915	GA Office Furn & Equipment	$ 23,500	10.00	10.00%	$ (3,059)	$ 24,964	$ 24,964	$ -
1920	GA Comp Hardware	$ 354,153	5.00	20.00%	$ (25,594)	$ 320,898	$ 320,898	$ -
1930	GA Transportation Equipment	$ 17,500	5.00	20.00%	$ (765)	$ 64,417	$ 64,417	$ -
1930A	GA Transportation Equipment	$ 157,500	10.00	10.00%	$ (2,183)	$ 301,571	$ 301,571	$ -
1935	GA Stores Equip	$ -	10.00	10.00%	$ 0	$ -	$ -	$ -
1940	GA tools,shop&garage equip	$ 60,000	10.00	10.00%	$ (1,815)	$ 30,700	$ 30,700	$ -
1945	GA measure&test equip	$ -	10.00	10.00%	$ (0)	$ 5,282	$ 5,282	$ -
1950	GA power op equip	$ 18,000	10.00	10.00%	$ -	$ 5,114	$ 5,114	$ -
1955	GA Comm Equipment	$ 43,463	10.00	10.00%	$ (2,361)	$ 82,203	$ 82,203	$ -
1960	GA Misc. Equip	$ -	10.00	10.00%	$ 0	$ 3,088	$ 3,088	$ -
1960A	GA Misc. Equip	$ -	5.00	20.00%	$ (0)	$ 4,797	$ 4,797	$ -
1980	GA System Supv Equip	$ -	20.00	5.00%	$ 5	$ 21,401	$ 21,401	$ -
1995	Contributions & Grants	$ (550,000)	40.00	2.50%	$ 22,662	$ (332,872)	$ (332,872)	$ -
				0.00%				$ -
				0.00%				$ -
				0.00%				$ -
	Total	**$ 9,757,158**			**$ 1,489**	**$ 5,174,827**	**$ 5,174,828**	**$ (0)**
	Depreciation on asset allocations					**$ -**	**$ -**	see Exh 2
	Vehicle depreciation					**$ (365,987)**	**$ (365,987)**	included in burden rate
	Total depreciation for revenue requirement					**$ 4,808,840**	**$ 4,808,841**	

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TAX OVERVIEW

Attached at Exhibit 4, Tab 12, Schedule 2 (Tax Calculations) is the tax model used to calculate 2017 income taxes. The income tax rates and capital cost allowance rates used to calculate the taxes are the rates proposed for the forecast period. Income taxes for CNPI are allocated between transmission and distribution, based on the same methodology used and approved in the 2013 Cost of Service application. The methodology is outlined below.

Schedule 2 summarizes CNPI's income tax for the period 2013 Actual to 2017 Test Year. The 2013 Actual and 2014 Actual highlights are based on the actual returns filed. The 2015 Actual is based on the expected income tax filing for 2015. The 2016 Bridge and 2017 Test Year highlights are forecasts. The 2013 Actual to 2015 Forecast calculations are segregated between transmission operations and distribution operations. The 2016 Bridge and 2017 Test Year distribution utility earnings are based on the requested return on equity and the calculated income tax amounts are grossed up.

Schedule 3, Capital Cost Allowance ("CCA") contains the capital cost allowance continuity schedules for the distribution operations of CNPI for the period 2013 Actual to 2017 Test Year.

Schedule 4 contains the CNPI's 2014 T2 Corporation Income Tax Return that was filed with Canada Revenue Agency in June 2015.

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CANADIAN NIAGARA POWER INC.
TAX CALCULATIONS

Description	TOTAL CNPI 2013 Actual	TRANSMISSION 2013 Actual	DISTRIBUTION 2013 Actual	TOTAL CNPI 2014 Actual	TRANSMISSION 2014 Actual	DISTRIBUTION 2014 Actual	TOTAL CNPI 2015 Regulatory	TRANSMISSION 2015 Forecast	DISTRIBUTION 2015 Forecast	DISTRIBUTION 2016 Regulatory	DISTRIBUTION 2017 Regulatory
Net income(loss) per financial statements	4,060,020	1,355,157	2,704,863	4,720,839	1,380,725	3,340,114	3,246,955	69,899	3,177,056	-	-
Utility income before taxes	-	-	-	-	-	-	-	-	-	3,099,596	3,305,624
Add:											
Provision for income taxes - current	1,448,451	-	1,448,451	996,410	289,881	706,529	644,310	5,368	638,942	-	-
Provision for income taxes - deferred	-	-	-	-	-	-	266,835	-	266,835	-	-
Amortization of assets	6,110,239	793,658	5,316,581	5,299,167	874,770	4,424,397	5,146,863	552,798	4,594,065	4,827,959	5,174,828
Loss on disposal of assets	19,692	-	19,692	-	-	-	-	-	-	-	-
Donations	-	-	-	22,759	-	22,759	22,759	-	22,759	23,000	19,593
Non-deductible meals and entertainment	17,225	2,260	14,965	26,598	3,490	23,108	23,543	3,089	20,454	20,851	20,445
Reserves from financial statements - EOY	1,101,438	144,530	956,908	4,970,962	652,287	4,318,675	856,216	112,352	743,864	590,468	558,990
Amortization of deferred financing	32,028	5,838	26,190	32,028	6,243	25,785	32,028	6,688	25,340	25,041	25,041
Ontario apprentice and co-op tax credits	41,553	5,453	36,100	20,644	2,709	17,935	15,800	2,073	13,727	13,727	13,460
Total Additions	8,770,626	951,739	7,818,887	11,368,568	1,829,380	9,539,188	7,008,354	682,368	6,325,986	5,501,046	5,812,357
Deduct:											
Gain on disposal of assets per financial statements	-	-	-	74,502	-	74,502	46,779	-	46,779	-	-
Capital cost allowance	6,285,716	659,250	5,626,466	6,704,477	784,943	5,919,534	6,919,189	1,101,641	5,817,548	6,458,746	7,072,459
Cumulative eligible capital deduction	7,393	-	7,393	6,875	-	6,875	6,394	-	6,394	5,946	5,530
Adjustment to reserves - BOY	-	-	-	-	-	-	(4,309,833)	(565,534)	(3,744,299)	-	-
Reserves from financial statements - BOY	1,406,979	184,623	1,222,356	5,411,271	710,064	4,701,207	4,970,962	652,287	4,318,675	743,864	578,986
Donations	-	-	-	22,759	-	22,759	-	-	-	-	-
Disallowed Ontario apprentice credit	-	-	-	3,863	-	3,863	-	-	-	-	-
Total Deductions	7,700,088	843,872	6,856,215	12,223,747	1,495,007	10,728,741	7,633,491	1,188,394	6,445,097	7,208,556	7,656,975
Taxable Income	5,130,558	1,463,024	3,667,535	3,865,660	1,715,098	2,150,561	2,621,818	(436,127)	3,057,945	1,392,086	1,461,007
Corporate tax rate	26.50%	26.50%	26.50%	26.50%	26.50%	26.50%	26.50%	26.50%	26.50%	26.50%	26.50%
Income Tax	1,359,598	387,701	971,897	1,024,400	454,501	569,899	694,782	(115,574)	810,355	368,903	387,167
Grossed Up Taxes										501,908	526,758
Calculation of total taxes											
Income Tax	1,359,598	387,701	971,897	1,024,400	454,501	569,899	694,782	(115,574)	810,355	368,903	387,167
Ontario apprentice and co-op tax credits	(41,553)	(5,453)	(36,100)	(20,644)	(2,709)	(17,935)	(15,800)	(2,073)	(13,727)	(13,727)	(13,460)
Total taxes	**1,318,045**	**382,249**	**935,796**	**1,003,756**	**451,792**	**551,964**	**678,982**	**(117,647)**	**796,629**	**355,176**	**373,707**
Tax Rates											
Federal Tax	15.00%	15.00%	15.00%	15.00%	15.00%	15.00%	15.00%	15.00%	15.00%	15.00%	15.00%
Provincial Tax	11.50%	11.50%	11.50%	11.50%	11.50%	11.50%	11.50%	11.50%	11.50%	11.50%	11.50%
Total Tax Rate	26.50%	26.50%	26.50%	26.50%	26.50%	26.50%	26.50%	26.50%	26.50%	26.50%	26.50%

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DISTRIBUTION 2013 CCA SCHEDULE

Class	Class Description	UCC 2013 Opening Balance	2013 Additions	2013 Disposals	UCC Before 1/2 Yr Adjustment	1/2 Year Rule {1/2 Additions Less Disposals}	Reduced UCC	Rate %	2013 CCA	UCC End of 2013
1	Distribution System - post 1987	22,492,917	0	0	22,492,917	0	22,492,917	4%	899,717	21,593,200
2	Distribution System - pre 1988	991,269	0	0	991,269	0	991,269	6%	59,476	931,793
3		61,384	0	0	61,384	0	61,384	5%	3,069	58,315
8	General Office/Stores Equip	374,376	58,117	0	432,493	29,059	403,435	20%	80,687	351,806
10	Computer Hardware/ Vehicles	1,176,399	508,338	23,000	1,661,737	242,669	1,419,068	30%	425,721	1,236,017
12	Computer Software	289,455	1,405,501	0	1,694,956	702,751	992,206	100%	992,206	702,751
13	Leasehold Improvements	220,015	0	0	220,015	0	220,015	NA	61,780	158,235
45	Computers & Systems Software acq'd post Mar 22/04	7,812	0	0	7,812	0	7,812	45%	3,515	4,297
46	System Supervisory processing	147	0	0	147	0	147	30%	44	103
47.0	New Distribution Assets	31,984,419	4,651,679	405,866	36,230,232	2,122,906	34,107,325	8%	2,728,586	33,501,646
1.3	Bldg after Mar 18/07	207,999	193,954	0	401,953	96,977	304,976	6%	18,299	383,654
50.0	Comp Equip after Mar 18/07	562,690	159,592	0	722,282	79,796	642,486	55%	353,367	368,915
	TOTAL	58,368,882	6,977,181	428,866	64,917,197	3,274,157	61,643,039		5,626,466	59,290,731

DISTRIBUTION 2014 CCA SCHEDULE

Class	Class Description	UCC 2014 Opening Balance	2014 Additions	2014 Disposals	UCC Before 1/2 Yr Adjustment	1/2 Year Rule {1/2 Additions Less Disposals}	Reduced UCC	Rate %	2014 CCA	UCC End of 2014
1	Distribution System - post 1987	21,593,200	0	0	21,593,200	0	21,593,200	4%	863,728	20,729,472
2	Distribution System - pre 1988	931,793	0	0	931,793	0	931,793	6%	55,908	875,885
3		58,315	0	0	58,315	0	58,315	5%	2,916	55,399
8	General Office/Stores Equip	351,806	214,282	0	566,088	107,141	458,947	20%	91,789	474,299
10	Computer Hardware/ Vehicles	1,236,017	818,068	0	2,054,085	409,034	1,645,051	30%	493,515	1,560,570
12	Computer Software	702,751	1,068,469	0	1,771,220	534,235	1,236,985	100%	1,236,985	534,235
13	Leasehold Improvements	158,235	0	0	158,235	0	158,235	NA	61,780	96,455
45	Computers & Systems Software acq'd post Mar 22/04	4,297	0	0	4,297	0	4,297	45%	1,933	2,363
46	System Supervisory processing	103	0	0	103	0	103	30%	31	72
47.0	New Distribution Assets	33,501,646	3,323,290	87,745	36,737,191	1,617,773	35,119,419	8%	2,809,553	33,927,638
1.3	Bldg after Mar 18/07	383,654	15,885	0	399,539	7,943	391,597	6%	23,496	376,043
50.0	Comp Equip after Mar 18/07	368,915	272,714	0	641,629	136,357	505,272	55%	277,899	363,729
	TOTAL	59,290,731	5,712,708	87,745	64,915,694	2,812,482	62,103,212		5,919,534	58,996,160

FC DISTRIBUTION 2015 CCA SCHEDULE

Class	Class Description	UCC 2015 Opening Balance	2015 Additions	2015 Disposals	UCC Before 1/2 Yr Adjustment	1/2 Year Rule {1/2 Additions Less Disposals}	Reduced UCC	Rate %	2015 CCA	UCC End of 2015
1	Distribution System - post 1987	20,729,472	0	0	20,729,472	0	20,729,472	4%	829,179	19,900,293
2	Distribution System - pre 1988	875,885	0	0	875,885	0	875,885	6%	52,553	823,332
3		55,399	0	0	55,399	0	55,399	5%	2,770	52,629
8	General Office/Stores Equip	474,299	533,599	0	1,007,898	266,799	741,098	20%	148,220	859,678
10	Computer Hardware/ Vehicles	1,560,570	138,986	0	1,699,555	69,493	1,630,062	30%	489,019	1,210,537
12	Computer Software	534,235	852,275	0	1,386,509	426,137	960,372	100%	960,372	426,137
13	Leasehold Improvements	96,455	0	0	96,455	0	96,455	NA	61,780	34,675
45	Computers & Systems Software acq'd post Mar 22/04	2,363	0	0	2,363	0	2,363	45%	1,063	1,300
46	System Supervisory processing	72	0	0	72	0	72	30%	22	50
47.0	New Distribution Assets	33,927,638	8,265,101	445,138	41,747,600	3,909,981	37,837,619	8%	3,027,010	38,720,591
1.3	Bldg after Mar 18/07	376,043	32,714	0	408,757	16,357	392,400	6%	23,544	385,213
50.0	Comp Equip after Mar 18/07	363,729	79,876	0	443,605	39,938	403,667	55%	222,017	221,588
	TOTAL	58,996,160	9,902,550	445,138	68,453,571	4,728,706	63,724,866		5,817,548	62,636,024

1

FC DISTRIBUTION 2016 CCA SCHEDULE

Class	Class Description	UCC 2016 Opening Balance	2016 Additions	2016 Disposals	UCC Before 1/2 Yr Adjustment	1/2 Year Rule {1/2 Additions Less Disposals}	Reduced UCC	Rate %	2016 CCA	UCC End of 2016
1	Distribution System - post 1987	19,900,293	0	0	19,900,293	0	19,900,293	4%	796,012	19,104,282
2	Distribution System - pre 1988	823,332	0	0	823,332	0	823,332	6%	49,400	773,932
3		52,629	0	0	52,629	0	52,629	5%	2,631	49,998
8	General Office/Stores Equip	859,678	73,000	0	932,678	36,500	896,178	20%	179,236	753,442
10	Computer Hardware/ Vehicles	1,210,537	420,160	0	1,630,697	210,080	1,420,617	30%	426,185	1,204,512
12	Computer Software	426,137	1,618,942	0	2,045,079	809,471	1,235,608	100%	1,235,608	809,471
13	Leasehold Improvements	34,675	0	0	34,675	0	34,675	NA	61,780	0
45	Computers & Systems Software acq'd post Mar 22/04	1,300	0	0	1,300	0	1,300	45%	585	715
46	System Supervisory processing	50	0	0	50	0	50	30%	15	35
47.0	New Distribution Assets	38,720,591	8,007,493	0	46,728,084	4,003,747	42,724,337	8%	3,417,947	43,310,137
1.3	Bldg after Mar 18/07	385,213	20,000	0	405,213	10,000	395,213	6%	23,713	381,500
50.0	Comp Equip after Mar 18/07	221,588	522,768	0	744,356	261,384	482,972	55%	265,634	478,721
	TOTAL	62,636,024	10,662,362	0	73,298,386	5,331,181	67,967,205		6,458,746	66,866,745

FC DISTRIBUTION 2017 CCA SCHEDULE

Class	Class Description	UCC 2017 Opening Balance	2017 Additions	2017 Disposals	UCC Before 1/2 Yr Adjustment	1/2 Year Rule {1/2 Additions Less Disposals}	Reduced UCC	Rate %	2017 CCA	UCC End of 2017
1	Distribution System - post 1987	19,104,282	0	0	19,104,282	0	19,104,282	4%	764,171	18,340,110
2	Distribution System - pre 1988	773,932	0	0	773,932	0	773,932	6%	46,436	727,496
3		49,998	0	0	49,998	0	49,998	5%	2,500	47,498
8	General Office/Stores Equip	753,442	83,500	0	836,943	41,750	795,193	20%	159,039	677,904
10	Computer Hardware/ Vehicles	1,204,512	236,463	0	1,440,975	118,232	1,322,743	30%	396,823	1,044,152
12	Computer Software	809,471	1,359,416	0	2,168,887	679,708	1,489,179	100%	1,489,179	679,708
13	Leasehold Improvements	0	0	0	0	0	0	NA	61,780	0
45	Computers & Systems Software acq'd post Mar 22/04	715	0	0	715	0	715	45%	322	393
46	System Supervisory processing	35	0	0	35	0	35	30%	11	25
47.0	New Distribution Assets	43,310,137	7,580,239	0	50,890,376	3,790,119	47,100,256	8%	3,768,021	47,122,355
1.3	Bldg after Mar 18/07	381,500	20,000	0	401,500	10,000	391,500	6%	23,490	378,010
50.0	Comp Equip after Mar 18/07	478,721	354,153	0	832,874	177,076	655,797	55%	360,689	472,185
	TOTAL	66,866,745	9,633,771	0	76,500,515	4,816,885	71,683,630		7,072,459	69,489,837

Copies of Income Tax Return - Historical Years

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Federal Tax Instalments

Federal tax instalments

For the taxation year ended 2015-12-31

Business number 87249 8225 RC0002

The following is a list of federal instalments payable for the current taxation year. The last column indicates the instalments payable to Canada Revenue Agency. The instalments are due no later than on the dates indicated, otherwise non-deductible interest will be charged. Payment may be made by cheque or money order payable to the Receiver General either at an authorized financial institution or filed with **the appropriate remittance voucher at the following address**:

Canada Revenue Agency
875 Heron Road
Ottawa ON K1A 1B1

Note that you may also be able to pay by telephone or Internet banking. For more information, consult the *Corporation Instalment Guide*.

Monthly instalment workchart

Date	Monthly tax instalments	Refund transferred to instalments	Instalments paid	Cumulative difference	Instalments payable
2015-01-31	83,647				83,647
2015-02-28	83,647				83,647
2015-03-31	83,647				83,647
2015-04-30	83,647				83,647
2015-05-31	83,647				83,647
2015-06-30	83,647				83,647
2015-07-31	83,647				83,647
2015-08-31	83,647				83,647
2015-09-30	83,647				83,647
2015-10-31	83,647				83,647
2015-11-30	83,647				83,647
2015-12-31	83,638				83,638
Totals	1,003,755				1,003,755

Quarterly instalment workchart

Date	Quarterly tax instalments	Refund transferred to instalments	Instalments paid	Cumulative difference	Instalments payable
2015-03-31					
2015-06-30					
2015-09-30					
2015-12-31					
Totals					

Instalment method

Indicate instalment method chosen [1-3] 1

1st Instalment base method

If payment of instalments other than quarterly instalments is delayed, indicate the MONTH in which you want them to begin (1=January, 2=February, etc.). 1

Select this box if you want the instalments to be calculated without taking the applicable threshold into account ☐

Quarterly instalments calculation

The corporation must meet requirements 1 to 5 to be eligible for quarterly instalments for a tax year.

		Yes	No
1 –	Is the corporation a Canadian-controlled private corporation (CCPC)?		X
2 –	Did the corporation claim any deduction under the section 125, during either the current or previous year?		X
3 –	Is the corporation's, or any of its associated corporations', taxable income for the current or previous year less than or equal to $500,000?		
4 –	Is the corporation and any associated corporations' taxable capital employed in Canada for the current or previous year less than or equal to $10,000,000?		
5 –	Does the corporation have a perfect compliance history in the last 12 months?		

If you do not want to use the quarterly instalments option, select this box to go back to monthly instalments. ☐

1 – 1st Instalment base method

1st Instalment base amount (amount N below)	1,003,755	÷	12	=	83,647
	Monthly instalments required				83,647
Quarterly tax instalments required	1,003,755	÷	4	=	

2 – Combined 1st and 2nd instalment base method

Select this box if you want the first 2 payments* to be calculated without taking the applicable threshold into account? ☐

2nd Monthly instalment base amount

Indicate: Part I tax		765,583					
Part VI, VI.1 and XIII.1 tax	+						
Federal adjustment for amalgamation, winding up or transfer	+						
Provincial tax, other than Alberta, Québec and Ontario	+						
Ontario tax	+	590,014					
Provincial adjustment for amalgamation, winding up or transfer	+						
Total	=	1,355,597	÷	12	=	112,967	A
1/12 of estimated current year credits (M below /12)					–	1,387	
Each of the first two instalment payments					=	111,580	B
Total tax from N below		1,003,755					
Amount B above x 2	–	223,160					
	=	780,595	÷	10	=	78,060	
Each of the remaining ten instalment payments					=	78,060	

2nd Quarterly instalment base amount

Indicate: Part I tax		765,583					
Part VI, VI.1 and XIII.1 tax	+						
Federal adjustment for amalgamation, winding up or transfer	+						
Provincial tax, other than Alberta, Québec and Ontario	+						
Ontario tax	+	590,014					
Provincial adjustment for amalgamation, winding up or transfer	+						
Total	=	1,355,597	÷	4	=	338,900	A
1/4 of estimated current year credits (M below /4)					–	4,161	
The first instalment payment					=		B
Total tax from N below		1,003,755					
Amount B above	–						
	=	1,003,755	÷	3	=	334,585	
Each of the remaining three instalment payments					=		

* It is the first payment if the quarterly instalments are applicable.

3 – Estimated tax method

Instalment base amount (amount N below)		÷	12	=	
	Monthly instalments required				
Quarterly tax instalments required		÷	4	=	

Instalment base calculation

Federal tax

		1st instalment base method		Estimated tax method	
Taxable income		3,865,658			
Calculation of tax payable					
Federal part I tax		1,468,950			
Recapture of investment tax credit	+		+		
Refundable tax on a CCPC's investment income	+		+		
Subtotal	=	1,468,950	=		A
Deduction					
Small business deduction					
Investment corporation deduction	+		+		
Federal tax abatement	+	386,566	+		
Manufacturing and processing profits deduction	+		+		
Non-business foreign tax credit	+		+		
Business foreign tax credit	+		+		
Tax reduction, general and accelerated	+	502,536	+		
Logging tax credit	+		+		
Investment tax credit per Schedule 31	+	4,000	+		
Eligible Canadian bank deduction	+		+		
Qualifying environmental trust tax credit	+		+		
Subtotal	=	893,102	=		B
Federal tax summary					
Total part I tax payable (A minus B)		575,848			C
Part VI tax	+		+		D
Part VI.1 tax	+		+		E1
Part XIII.1 tax	+		+		E2
Parts I, VI, VI.1 and XIII.1 **Total**	=	575,848	=		F
Federal adjustments					
Adjustment for short taxation years multiplied by 365 and divided by the number of days in the year if less than 365	x	365 / 365	x	365 / 365	
Subtotal	=	575,848	=		
Federal adjustment for amalgamation, winding up or transfer	+		+	N/A	
Total federal tax after adjustments	=	575,848	=		G

Provincial tax

				1st instalment base method		Estimated tax method	
Provincial/territorial tax other than Alberta, Québec and Ontario before provincial refundable tax credits			+		+		H
Ontario tax							
Income tax		444,551					
Corporate minimum tax paid (credited)	+						
Special additional tax on life insurance corporations	+						
Total Ontario tax	=	444,551	► +	444,551	+		I
Harmonized provincial tax (H + I) **Provincial/territorial tax other than Alberta and Québec before provincial refundable tax credits**			=	444,551	=		J
Provincial adjustments							
Adjustment for short taxation years multiplied by 365 and divided by the number of days in the year if less than 365			x	365 / 365	x	365 / 365	
Subtotal			=	444,551	=		
Provincial adjustment for amalgamation, winding up or transfer			+		+	N/A	
Total provincial tax after adjustments			=	444,551	=		K
Total of tax before refundable credits**			=	1,020,399	=		L

Instalment base calculation (continued)

Estimated current year credits

Investment tax credit refund					
Dividend refund	+		+		
Federal capital gains refund	+		+		
Provincial and territorial capital gains refund	+		+		
NRO allowable refund per Schedule 26	+		+		
Tax withheld at source	+		+		
Other estimated credits	+		+		
Provincial/territorial refundable tax credits other than Alberta, Québec and Ontario*	+		+		
Ontario refundable tax credits*	+	16,644	+		
Total estimated current year credits	=	16,644	=		**M**
Instalment base amount (L – M)		1,003,755			**N**

* For more details with regards to the impact of the refundable tax credits in the instalment base calculation, consult the Help.

** For instalments payable, the amount on line G will only be included in the amount of line L when it exceeds $3,000. The same rule applies to line K.

Canada Revenue Agency / Agence du revenu du Canada

T2 Corporation Income Tax Return

200

055 Do not use this area

This form serves as a federal, provincial, and territorial corporation income tax return, unless the corporation is located in Quebec or Alberta. If the corporation is located in one of these provinces, you have to file a separate provincial corporation return.

All legislative references on this return are to the federal *Income Tax Act* and *Income Tax Regulations*. This return may contain changes that had not yet become law at the time of publication.

Send one completed copy of this return, including schedules and the *General Index of Financial Information* (GIFI), to your tax centre or tax services office. You have to file the return within six months after the end of the corporation's tax year.

For more information see **www.cra.gc.ca** or Guide T4012, *T2 Corporation – Income Tax Guide*.

Identification

Business number (BN) 001 87249 8225 RC0002

Corporation's name
002 Canadian Niagara Power Inc.

Address of head office
Has this address changed since the last time we were notified? . . . . 010 1 Yes [ ] 2 No [X]
(If **yes**, complete lines 011 to 018.)
011 1130 Bertie Street
012
City: 015 Fort Erie
Province, territory, or state: 016 ON
Country (other than Canada): 017
Postal code/Zip code: 018 L2A 5Y2

Mailing address (if different from head office address)
Has this address changed since the last time we were notified? . . . . 020 1 Yes [ ] 2 No [X]
(If **yes**, complete lines 021 to 028.)
021 c/o
022 1130 Bertie Street
023 P.O. Box 1218
City: 025 Fort Erie
Province, territory, or state: 026 ON
Country (other than Canada): 027
Postal code/Zip code: 028 L2A 5Y2

Location of books and records (if different from head office address)
Has the location of books and records changed since the last time we were notified? . . . . 030 1 Yes [ ] 2 No [X]
(If **yes**, complete lines 031 to 038.)
031 1130 Bertie Street
032
City: 035 Fort Erie
Province,territory, or state: 036 ON
Country (other than Canada): 037
Postal code/Zip code: 038 L2A 5Y2

040 **Type of corporation at the end of the tax year**
1 [ ] Canadian-controlled private corporation (CCPC)
2 [ ] Other private corporation
3 [ ] Public corporation
4 [X] Corporation controlled by a public corporation
5 [ ] Other corporation (specify, below)

If the type of corporation changed during the tax year, provide the effective date of the change . . . . 043 ____ YYYY MM DD

To which tax year does this return apply?
Tax year start: 060 2014-01-01 (YYYY MM DD)
Tax year-end: 061 2014-12-31 (YYYY MM DD)

Has there been an acquisition of control to which subsection 249(4) applies since the tax year start on line 060? . . . . 063 1 Yes [ ] 2 No [X]
If **yes**, provide the date control was acquired . . . . 065 ____ YYYY MM DD

Is the date on line 061 a deemed tax year-end according to subsection 249(3.1)? . . . . 066 1 Yes [ ] 2 No [X]

Is the corporation a professional corporation that is a member of a partnership? . . . . 067 1 Yes [ ] 2 No [X]

Is this the first year of filing after:
Incorporation? . . . . 070 1 Yes [ ] 2 No [X]
Amalgamation? . . . . 071 1 Yes [ ] 2 No [X]
If **yes**, complete lines 030 to 038 and attach Schedule 24.

Has there been a wind-up of a subsidiary under section 88 during the current tax year? . . . . 072 1 Yes [ ] 2 No [X]
If **yes**, complete and attach Schedule 24.

Is this the final tax year before amalgamation? . . . . 076 1 Yes [ ] 2 No [X]

Is this the final return up to dissolution? . . . . 078 1 Yes [ ] 2 No [X]

If an election was made under section 261, state the functional currency used 079

Is the corporation a resident of Canada?
080 1 Yes [X] 2 No [ ] If **no**, give the country of residence on line 081 and complete and attach Schedule 97.
081

Is the non-resident corporation claiming an exemption under an income tax treaty? . . . . 082 1 Yes [ ] 2 No [X]
If **yes**, complete and attach Schedule 91.

If the corporation is exempt from tax under section 149, tick one of the following boxes:
085
1 [ ] Exempt under paragraph 149(1)(e) or (l)
2 [ ] Exempt under paragraph 149(1)(j)
3 [ ] Exempt under paragraph 149(1)(t)
4 [ ] Exempt under other paragraphs of section 149

Do not use this area
095 096

Attachments

Financial statement information: Use GIFI schedules 100, 125, and 141.

Schedules – Answer the following questions. For each **yes** response, **attach** the schedule to the T2 return, unless otherwise instructed.

		Yes	Schedule
Is the corporation related to any other corporations?	150	X	9
Is the corporation an associated CCPC?	160		23
Is the corporation an associated CCPC that is claiming the expenditure limit?	161		49
Does the corporation have any non-resident shareholders who own voting shares?	151		19
Has the corporation had any transactions, including section 85 transfers, with its shareholders, officers, or employees, other than transactions in the ordinary course of business? Exclude non-arm's length transactions with non-residents	162		11
If you answered **yes** to the above question, and the transaction was between corporations not dealing at arm's length, were all or substantially all of the assets of the transferor disposed of to the transferee?	163		44
Has the corporation paid any royalties, management fees, or other similar payments to residents of Canada?	164		14
Is the corporation claiming a deduction for payments to a type of employee benefit plan?	165		15
Is the corporation claiming a loss or deduction from a tax shelter?	166		T5004
Is the corporation a member of a partnership for which a partnership account number has been assigned?	167		T5013
Did the corporation, a foreign affiliate controlled by the corporation, or any other corporation or trust that did not deal at arm's length with the corporation have a beneficial interest in a non-resident discretionary trust (without reference to section 94)?	168		22
Did the corporation own any shares in one or more foreign affiliates in the tax year?	169		25
Has the corporation made any payments to non-residents of Canada under subsections 202(1) and/or 105(1) of the federal *Income Tax Regulations*?	170		29
Did the corporation have a total amount over $1 million of reportable transactions with non-arm's length non-residents?	171		T106
For private corporations: Does the corporation have any shareholders who own 10% or more of the corporation's common and/or preferred shares?	173		50
Has the corporation made payments to, or received amounts from, a retirement compensation plan arrangement during the year?	172		
Does the corporation earn income from one or more Internet webpages or websites?	180		88
Is the net income/loss shown on the financial statements different from the net income/loss for income tax purposes?	201	X	1
Has the corporation made any charitable donations; gifts to Canada, a province, or a territory; gifts of cultural or ecological property; or gifts of medicine?	202	X	2
Has the corporation received any dividends or paid any taxable dividends for purposes of the dividend refund?	203		3
Is the corporation claiming any type of losses?	204		4
Is the corporation claiming a provincial or territorial tax credit or does it have a permanent establishment in more than one jurisdiction?	205	X	5
Has the corporation realized any capital gains or incurred any capital losses during the tax year?	206		6
i) Is the corporation claiming the small business deduction and reporting income from: a) property (other than dividends deductible on line 320 of the T2 return), b) a partnership, c) a foreign business, or d) a personal services business; or ii) does the corporation have aggregate investment income at line 440?	207		7
Does the corporation have any property that is eligible for capital cost allowance?	208	X	8
Does the corporation have any property that is eligible capital property?	210	X	10
Does the corporation have any resource-related deductions?	212		12
Is the corporation claiming deductible reserves (other than transitional reserves under section 34.2)?	213		13
Is the corporation claiming a patronage dividend deduction?	216		16
Is the corporation a credit union claiming a deduction for allocations in proportion to borrowing or an additional deduction?	217		17
Is the corporation an investment corporation or a mutual fund corporation?	218		18
Is the corporation carrying on business in Canada as a non-resident corporation?	220		20
Is the corporation claiming any federal or provincial foreign tax credits, or any federal or provincial logging tax credits?	221		21
Does the corporation have any Canadian manufacturing and processing profits?	227		27
Is the corporation claiming an investment tax credit?	231	X	31
Is the corporation claiming any scientific research and experimental development (SR&ED) expenditures?	232		T661
Is the total taxable capital employed in Canada of the corporation and its related corporations over $10,000,000?	233	X	33/34/35
Is the total taxable capital employed in Canada of the corporation and its associated corporations over $10,000,000?	234	X	
Is the corporation claiming a surtax credit?	237		37
Is the corporation subject to gross Part VI tax on capital of financial institutions?	238		38
Is the corporation claiming a Part I tax credit?	242		42
Is the corporation subject to Part IV.1 tax on dividends received on taxable preferred shares or Part VI.1 tax on dividends paid?	243		43
Is the corporation agreeing to a transfer of the liability for Part VI.1 tax?	244		45
Is the corporation subject to Part II - Tobacco Manufacturers' surtax?	249		46
For financial institutions: Is the corporation a member of a related group of financial institutions with one or more members subject to gross Part VI tax?	250		39
Is the corporation claiming a Canadian film or video production tax credit refund?	253		T1131
Is the corporation claiming a film or video production services tax credit refund?	254		T1177
Is the corporation subject to Part XIII.1 tax? (Show your calculations on a sheet that you identify as Schedule 92.)	255		92

Attachments – continued from page 2

		Yes	Schedule
Did the corporation have any foreign affiliates in the tax year?	271		T1134
Did the corporation own specified foreign property in the year with a cost amount over $100,000?	259		T1135
Did the corporation transfer or loan property to a non-resident trust?	260		T1141
Did the corporation receive a distribution from or was it indebted to a non-resident trust in the year?	261		T1142
Has the corporation entered into an agreement to allocate assistance for SR&ED carried out in Canada?	262		T1145
Has the corporation entered into an agreement to transfer qualified expenditures incurred in respect of SR&ED contracts?	263		T1146
Has the corporation entered into an agreement with other associated corporations for salary or wages of specified employees for SR&ED?	264		T1174
Did the corporation pay taxable dividends (other than capital gains dividends) in the tax year?	265	X	55
Has the corporation made an election under subsection 89(11) not to be a CCPC?	266		T2002
Has the corporation revoked any previous election made under subsection 89(11)?	267		T2002
Did the corporation (CCPC or deposit insurance corporation (DIC)) pay eligible dividends, or did its general rate income pool (GRIP) change in the tax year?	268		53
Did the corporation (other than a CCPC or DIC) pay eligible dividends, or did its low rate income pool (LRIP) change in the tax year?	269	X	54

Additional information

		1 Yes	2 No
Did the corporation use the International Financial Reporting Standards (IFRS) when it prepared its financial statements?	270		X
Is the corporation inactive?	280		X

What is the corporation's main revenue-generating business activity? ..... 221122 Electric Power Distribution

Specify the principal product(s) mined, manufactured, sold, constructed, or services provided, giving the approximate percentage of the total revenue that each product or service represents.

284	Electrical Energy Distribution and Transmission	285	100.000 %
286		287	%
288		289	%

		1 Yes	2 No
Did the corporation immigrate to Canada during the tax year?	291		X
Did the corporation emigrate from Canada during the tax year?	292		X
Do you want to be considered as a quarterly instalment remitter if you are eligible?	293		

If the corporation was eligible to remit instalments on a quarterly basis for part of the tax year, provide the date the corporation ceased to be eligible ..... 294 ______ YYYY MM DD

		1 Yes	2 No
If the corporation's major business activity is construction, did you have any subcontractors during the tax year?	295		

Taxable income

Net income or (loss) for income tax purposes from Schedule 1, financial statements, or GIFI.			300	3,888,417	A
Deduct: Charitable donations from Schedule 2	311	22,759			
Gifts to Canada, a province, or a territory from Schedule 2	312				
Cultural gifts from Schedule 2	313				
Ecological gifts from Schedule 2	314				
Gifts of medicine from Schedule 2	315				
Taxable dividends deductible under section 112 or 113, or subsection 138(6) from Schedule 3	320				
Part VI.1 tax deduction*	325				
Non-capital losses of previous tax years from Schedule 4	331				
Net capital losses of previous tax years from Schedule 4	332				
Restricted farm losses of previous tax years from Schedule 4	333				
Farm losses of previous tax years from Schedule 4	334				
Limited partnership losses of previous tax years from Schedule 4	335				
Taxable capital gains or taxable dividends allocated from a central credit union	340				
Prospector's and grubstaker's shares	350				
Subtotal		22,759	►	22,759	B
Subtotal (amount A **minus** amount B) (if negative, enter "0")				3,865,658	C
Add: Section 110.5 additions or subparagraph 115(1)(a)(vii) additions			355		D
Taxable income (amount C **plus** amount D)			360	3,865,658	
Income exempt under paragraph 149(1)(t)			370		
Taxable income for a corporation with exempt income under paragraph 149(1)(t) (line 360 **minus** line 370)				3,865,658	Z

* This amount is equal to 3.5 times the Part VI.1 tax payable at line 724 on page 8.

Small business deduction

Canadian-controlled private corporations (CCPCs) throughout the tax year

Income from active business carried on in Canada from Schedule 7 . . . . **400** ______ A

Taxable income from line 360 on page 3, **minus** 100/28 3.57143 of the amount on line 632* on page 7, **minus** 4 times the amount on line 636** on page 7, and **minus** any amount that, because of federal law, is exempt from Part I tax . . . . **405** ______ B

Business limit (see notes 1 and 2 below) . . . . **410** ______ C

Notes:

1. For CCPCs that are not associated, enter $ 500,000 on line 410. However, if the corporation's tax year is less than 51 weeks, prorate this amount by the number of days in the tax year divided by 365, and enter the result on line 410.
2. For associated CCPCs, use Schedule 23 to calculate the amount to be entered on line 410.

Business limit reduction:

Amount C ______ x **415** *** ______ D / 11,250 = ... ______ E

Reduced business limit (amount C **minus** amount E) (if negative, enter "0") . . . . **425** ______ F

Small business deduction

Amount A, B, C, or F, whichever is the least ______ x 17 % = ... **430** ______ G

Enter amount G on line I on page 7.

* Calculate the amount of foreign non-business income tax credit deductible on line 632 without reference to the refundable tax on the CCPC's investment income (line 604) and without reference to the corporate tax reductions under section 123.4.

** Calculate the amount of foreign business income tax credit deductible on line 636 without reference to the corporation tax reductions under section 123.4.

***** Large corporations**

- If the corporation is not associated with any corporations in both the current and previous tax years, the amount to be entered on line 415 is: (total taxable capital employed in Canada for the **prior year** minus $10,000,000) x 0.225%.
- If the corporation is not associated with any corporations in the current tax year, but was associated in the previous tax year, the amount to be entered on line 415 is: (total taxable capital employed in Canada for the **current year** minus $10,000,000) x 0.225%.
- For corporations associated in the current tax year, see Schedule 23 for the special rules that apply.

General tax reduction for Canadian-controlled private corporations

Canadian-controlled private corporations throughout the tax year

Taxable income from page 3 (line 360 or amount Z, whichever applies)				A
Lesser of amounts V and Y (line Z1) from Part 9 of Schedule 27		B		
Amount QQ from Part 13 of Schedule 27		C		
Personal service business income **432**		D		
Amount used to calculate the credit union deduction (amount F from Schedule 17)		E		
Amount from line 400, 405, 410, or 425 on page 4, whichever is the least		F		
Aggregate investment income from line 440 on page 6*		G		
Subtotal (**add** amounts B to G)		►		H
Amount A **minus** amount H (if negative, enter "0")				I
General tax reduction for Canadian-controlled private corporations – Amount I **multiplied** by 13 %				J

Enter amount J on line 638 on page 7.

* Except for a corporation that is, throughout the year, a cooperative corporation (within the meaning assigned by subsection 136(2)) or a credit union.

General tax reduction

Do not complete this area if you are a Canadian-controlled private corporation, an investment corporation, a mortgage investment corporation, a mutual fund corporation, or any corporation with taxable income that is not subject to the corporation tax rate of 38%.

Taxable income from page 3 (line 360 or amount Z, whichever applies)			3,865,658	K
Lesser of amounts V and Y (line Z1) from Part 9 of Schedule 27		L		
Amount QQ from Part 13 of Schedule 27		M		
Personal service business income **434**		N		
Amount used to calculate the credit union deduction (amount F from Schedule 17)		O		
Subtotal (**add** amounts L to O)		►		P
Amount K **minus** amount P (if negative, enter "0")			3,865,658	Q
General tax reduction – Amount Q **multiplied** by 13 %			502,536	R

Enter amount R on line 639 on page 7.

Refundable portion of Part I tax

Canadian-controlled private corporations throughout the tax year

Aggregate investment income from Schedule 7 . . . . **440** ________ x 26 2 / 3 % = ... ________ A

Foreign non-business income tax credit from line 632 on page 7 . . . . ________ B

Deduct:
Foreign investment income from Schedule 7 . . . . **445** ________ x 9 1 / 3 % = ________ C
(if negative, enter "0") ________ ▶ ________ D

Amount A **minus** amount D (if negative, enter "0") . . . . ________ E

Taxable income from line 360 on page 3 . . . . ________ F

Deduct:
Amount from line 400, 405, 410, or 425 on page 4, whichever is the least . . . . ________ G

Foreign non-business income tax credit from line 632 on page 7 . . . ________ x 100 / 35 = ________ H

Foreign business income tax credit from line 636 on page 7 . . . . ________ x 4 = ________ I

Subtotal ________ ▶ ________ J

________ K

x 26 2 / 3 % = ________ L

Part I tax payable minus investment tax credit refund (line 700 **minus** line 780 from page 8) . . . . ________ M

Refundable portion of Part I tax – Amount E, L, or M, whichever is the least . . . . **450** ________ N

Refundable dividend tax on hand

Refundable dividend tax on hand at the end of the previous tax year . . . . **460** ________

Deduct: Dividend refund for the previous tax year . . . . **465** ________

________ ▶ ________ O

Add the total of:

Refundable portion of Part I tax from line 450 above . . . . ________ P

Total Part IV tax payable from Schedule 3 . . . . ________ Q

Net refundable dividend tax on hand transferred from a predecessor corporation on amalgamation, or from a wound-up subsidiary corporation . . . . **480** ________

________ ▶ ________ R

Refundable dividend tax on hand at the end of the tax year – Amount O **plus** amount R . . . . **485** ________

Dividend refund

Private and subject corporations at the time taxable dividends were paid in the tax year

Taxable dividends paid in the tax year from line 460 on page 2 of Schedule 3 . . . . ________ x 1 / 3 = ________ S

Refundable dividend tax on hand at the end of the tax year from line 485 above . . . . ________ T

Dividend refund – Amount S or T, whichever is less . . . . ________ U

Enter amount U on line 784 on page 8.

Part I tax

Base amount Part I tax – Taxable income from page 3 (line 360 or amount Z, whichever applies) **multiplied** by 38 %			550	1,468,950	A
Recapture of investment tax credit from Schedule 31			602		B

Calculation for the refundable tax on the Canadian-controlled private corporation's (CCPC) investment income
(if it was a CCPC throughout the tax year)

Aggregate investment income from line 440 on page 6				C
Taxable income from line 360 on page 3		D		
Deduct:				
Amount from line 400, 405, 410, or 425 on page 4, whichever is the least		E		
Net amount (amount D **minus** amount E)				F

Refundable tax on CCPC's investment income – 6 2/3 % of whichever is less: amount C or amount F	604		G
Subtotal (**add** amounts A, B, and G)		1,468,950	H

Deduct:

Small business deduction from line 430 on page 4			I	
Federal tax abatement	608	386,566		
Manufacturing and processing profits deduction from Schedule 27	616			
Investment corporation deduction	620			
Taxed capital gains 624				
Additional deduction – credit unions from Schedule 17	628			
Federal foreign non-business income tax credit from Schedule 21	632			
Federal foreign business income tax credit from Schedule 21	636			
General tax reduction for CCPCs from amount J on page 5	638			
General tax reduction from amount R on page 5	639	502,536		
Federal logging tax credit from Schedule 21	640			
Eligible Canadian bank deduction under section 125.21	641			
Federal qualifying environmental trust tax credit	648			
Investment tax credit from Schedule 31	652	4,000		
Subtotal		893,102	893,102	J

Part I tax payable – Amount H **minus** amount J	575,848	K

Enter amount K on line 700 on page 8.

Summary of tax and credits

Federal tax

Part I tax payable from amount K on page 7	700	575,848
Part II surtax payable from Schedule 46	708	
Part III.1 tax payable from Schedule 55	710	
Part IV tax payable from Schedule 3	712	
Part IV.1 tax payable from Schedule 43	716	
Part VI tax payable from Schedule 38	720	
Part VI.1 tax payable from Schedule 43	724	
Part XIII.1 tax payable from Schedule 92	727	
Part XIV tax payable from Schedule 20	728	
Total federal tax		575,848

Add provincial or territorial tax:

Provincial or territorial jurisdiction . . . 750 ON
(if more than one jurisdiction, enter "multiple" and complete Schedule 5)

Net provincial or territorial tax payable (except Quebec and Alberta)	760	427,907	
Provincial tax on large corporations (Nova Scotia Schedule 342)	765		
(The Nova Scotia tax on large corporations is eliminated effective July 1, 2012.)			
Total provincial or territorial tax		427,907 ▶	427,907
Total tax payable	770		1,003,755 A

Deduct other credits:

Investment tax credit refund from Schedule 31	780		
Dividend refund from amount U on page 6	784		
Federal capital gains refund from Schedule 18	788		
Federal qualifying environmental trust tax credit refund	792		
Canadian film or video production tax credit refund (Form T1131)	796		
Film or video production services tax credit refund (Form T1177)	797		
Tax withheld at source	800		
Total payments on which tax has been withheld 801			
Provincial and territorial capital gains refund from Schedule 18	808		
Provincial and territorial refundable tax credits from Schedule 5	812		
Tax instalments paid	840	1,013,000	
Total credits	890	1,013,000 ▶	1,013,000 B

Refund code 894 1 Overpayment 9,245

Balance (amount A **minus** amount B) -9,245

If the result is positive, you have a **balance unpaid**.
If the result is negative, you have an **overpayment**.
Enter the amount on whichever line applies.
Generally, we do not charge or refund a difference of $2 or less.

Balance unpaid . . . . . .

For information on how to make your payment, go to **www.cra-arc.gc.ca/payments**.

Enclosed payment 898

Direct deposit request

To have the corporation's refund deposited directly into the corporation's bank account at a financial institution in Canada, or to change banking information you already gave us, complete the information below:

☐ Start ☐ Change information

910 ______ Branch number

914 ______ Institution number

918 ______ Account number

If the corporation is a Canadian-controlled private corporation throughout the tax year, does it qualify for the one-month extension of the date the balance of tax is due? . . . 896 1 Yes ☐ 2 No ☐

If this return was prepared by a tax preparer for a fee, provide their EFILE number . . . 920

Certification

I, 950 KING (Last name (print)) 951 GLEN (First name (print)) 954 Chief Financial Officer (Position, office, or rank),

am an authorized signing officer of the corporation. I certify that I have examined this return, including accompanying schedules and statements, and that the information given on this return is, to the best of my knowledge, correct and complete. I also certify that the method of calculating income for this tax year is consistent with that of the previous tax year except as specifically disclosed in a statement attached to this return.

955 2015-06-30 — Date (yyyy/mm/dd)

Signature of the authorized signing officer of the corporation

956 (905) 871-0330 — Telephone number

Is the contact person the same as the authorized signing officer? If **no**, complete the information below . . . 957 1 Yes ☐ 2 No ☒

958 HARRY CLUTTERBUCK — Name (print)

959 (905) 871-0330 — Telephone number

Language of correspondence – Langue de correspondance

Indicate your language of correspondence by entering **1** for English or **2** for French.
Indiquez votre langue de correspondance en inscrivant **1** pour anglais ou **2** pour français.

990 1

Privacy Act, personal information bank number CRA PPU 047

Schedule of Instalment Remittances

Name of corporation contact: Harry Clutterbuck
Telephone number: (905) 871-0330

Effective interest date	Description (instalment remittance, split payment, assessed credit)	Amount of credit
2014-01-31	INSTALLMENT REMITTANCE	71,000
2014-02-28	INSTALLMENT REMITTANCE	71,000
2014-03-31	INSTALLMENT REMITTANCE	71,000
2014-04-30	INSTALLMENT REMITTANCE	100,000
2014-05-31	INSTALLMENT REMITTANCE	100,000
2014-06-30	INSTALLMENT REMITTANCE	100,000
2014-07-31	INSTALLMENT REMITTANCE	100,000
2014-08-31	INSTALLMENT REMITTANCE	100,000
2014-09-30	INSTALLMENT REMITTANCE	100,000
2014-10-31	INSTALLMENT REMITTANCE	100,000
2014-11-30	INSTALLMENT REMITTANCE	50,000
2014-12-31	INSTALLMENT REMITTANCE	50,000

Total amount of instalments claimed (carry the result to line 840 of the T2 Return) 1,013,000 **A**

Total instalments credited to the taxation year per T9 1,013,000 **B**

Transfer

	Account number	Taxation year end	Amount	Effective interest date	Description
From:					
To:					
From:					
To:					
From:					
To:					
From:					
To:					
From:					
To:					

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SCHEDULE 100

Form identifier 100

GENERAL INDEX OF FINANCIAL INFORMATION – GIFI

Name of corporation	Business Number	Tax year end Year Month Day
Canadian Niagara Power Inc.	87249 8225 RC0002	2014-12-31

Balance sheet information

Account	Description	GIFI		Current year	Prior year
	Assets				
	Total current assets	1599	+	19,104,457	18,329,142
	Total tangible capital assets	2008	+	158,479,859	148,798,015
	Total accumulated amortization of tangible capital assets	2009	–	60,117,068	55,781,077
	Total intangible capital assets	2178	+	25,507,253	24,588,339
	Total accumulated amortization of intangible capital assets	2179	–	9,491,446	8,629,731
	Total long-term assets	2589	+	3,810,726	3,893,612
	* Assets held in trust	2590	+		
	Total assets (mandatory field)	2599	=	137,293,781	131,198,300
	Liabilities				
	Total current liabilities	3139	+	18,327,400	17,808,061
	Total long-term liabilities	3450	+	71,370,560	68,015,256
	* Subordinated debt	3460	+		
	* Amounts held in trust	3470	+		
	Total liabilities (mandatory field)	3499	=	89,697,960	85,823,317
	Shareholder equity				
	Total shareholder equity (mandatory field)	3620	+	47,595,821	45,374,983
	Total liabilities and shareholder equity	3640	=	137,293,781	131,198,300
	Retained earnings				
	Retained earnings/deficit – end (mandatory field)	3849	=	23,695,821	21,474,983

***** Generic item

Canada Revenue Agency / Agence du revenu du Canada

SCHEDULE 125

Form identifier 125

GENERAL INDEX OF FINANCIAL INFORMATION – GIFI

Name of corporation	Business Number	Tax year end Year Month Day
Canadian Niagara Power Inc.	87249 8225 RC0002	2014-12-31

Income statement information

Description	GIFI	
Operating name	0001	
Description of the operation	0002	
Sequence number	0003	01

Account	Description	GIFI		Current year	Prior year
	Income statement information				
	Total sales of goods and services	8089	+	81,572,829	78,827,712
	Cost of sales	8518	–	65,248,331	62,678,971
	Gross profit/loss	8519	=	16,324,498	16,148,741
	Cost of sales	8518	+	65,248,331	62,678,971
	Total operating expenses	9367	+	10,702,730	10,422,532
	Total expenses (mandatory field)	9368	=	75,951,061	73,101,503
	Total revenue (mandatory field)	8299	+	81,668,309	78,609,974
	Total expenses (mandatory field)	9368	–	75,951,061	73,101,503
	Net non-farming income	9369	=	5,717,248	5,508,471
	Farming income statement information				
	Total farm revenue (mandatory field)	9659	+		
	Total farm expenses (mandatory field)	9898	–		
	Net farm income	9899	=		
	Net income/loss before taxes and extraordinary items	9970	=	5,717,248	5,508,471
	Total other comprehensive income	9998	=		
	Extraordinary items and income (linked to Schedule 140)				
	Extraordinary item(s)	9975	–		
	Legal settlements	9976	–		
	Unrealized gains/losses	9980	+		
	Unusual items	9985	–		
	Current income taxes	9990	–	996,410	1,448,451
	Future (deferred) income tax provision	9995	–		
	Total – Other comprehensive income	9998	+		
	Net income/loss after taxes and extraordinary items (mandatory field)	9999	=	4,720,838	4,060,020

Canada Revenue Agency / Agence du revenu du Canada

Schedule 141

Notes checklist

Corporation's name	Business number	Tax year-end Year Month Day
Canadian Niagara Power Inc.	87249 8225 RC0002	2014-12-31

- Parts 1, 2, and 3 of this schedule must be completed from the perspective of the person (referred to in these parts as the **accountant**) who prepared or reported on the financial statements. If the person preparing the tax return is not the accountant referred to above, they must still complete Parts 1, 2, 3, and 4, as applicable.
- For more information, see Guide RC4088, *General Index of Financial Information (GIFI)* and Guide T4012, *T2 Corporation – Income Tax Guide*.
- Complete this schedule and include it with your T2 return along with the other GIFI schedules.

Part 1 – Information on the accountant who prepared or reported on the financial statements

Does the accountant have a professional designation? . . . **095** 1 Yes [X] 2 No [ ]

Is the accountant connected* with the corporation? . . . **097** 1 Yes [ ] 2 No [X]

* A person connected with a corporation can be: (i) a shareholder of the corporation who owns more than 10% of the common shares; (ii) a director, an officer, or an employee of the corporation; or (iii) a person not dealing at arm's length with the corporation.

Note

If the accountant does not have a professional designation **or** is connected to the corporation, you do not have to complete Parts 2 and 3 of this schedule. However, you **do have** to complete Part 4, as applicable.

Part 2 – Type of involvement with the financial statements

Choose the option that represents the highest level of involvement of the accountant: . . . **198**

Completed an auditor's report . . . 1 [X]

Completed a review engagement report . . . 2 [ ]

Conducted a compilation engagement . . . 3 [ ]

Part 3 – Reservations

If you selected option **1** or **2** under **Type of involvement with the financial statements** above, answer the following question:

Has the accountant expressed a reservation? . . . **099** 1 Yes [ ] 2 No [X]

Part 4 – Other information

If you have a professional designation and are not the accountant associated with the financial statements in Part 1 above, choose one of the following options: . . . **110**

Prepared the tax return (financial statements prepared by client) . . . 1 [ ]

Prepared the tax return and the financial information contained therein (financial statements have not been prepared) . . . 2 [ ]

Were notes to the financial statements prepared? . . . **101** 1 Yes [X] 2 No [ ]

If **yes**, complete lines 104 to 107 below:

Are subsequent events mentioned in the notes? . . . **104** 1 Yes [ ] 2 No [X]

Is re-evaluation of asset information mentioned in the notes? . . . **105** 1 Yes [ ] 2 No [X]

Is contingent liability information mentioned in the notes? . . . **106** 1 Yes [X] 2 No [ ]

Is information regarding commitments mentioned in the notes? . . . **107** 1 Yes [X] 2 No [ ]

Does the corporation have investments in joint venture(s) or partnership(s)? . . . **108** 1 Yes [ ] 2 No [X]

Part 4 – Other information (continued)

Impairment and fair value changes

In any of the following assets, was an amount recognized in net income or other comprehensive income (OCI) as a result of an impairment loss in the tax year, a reversal of an impairment loss recognized in a previous tax year, or a change in fair value during the tax year? . . . . . **200** 1 Yes [ ] 2 No [X]

If **yes**, enter the amount recognized:

		In net income Increase (decrease)		In OCI Increase (decrease)
Property, plant, and equipment	210		211	
Intangible assets	215		216	
Investment property	220			
Biological assets	225			
Financial instruments	230		231	
Other	235		236	

Financial instruments

Did the corporation derecognize any financial instrument(s) during the tax year (other than trade receivables)? . . . . . **250** 1 Yes [ ] 2 No [X]

Did the corporation apply hedge accounting during the tax year? . . . . . **255** 1 Yes [ ] 2 No [X]

Did the corporation discontinue hedge accounting during the tax year? . . . . . **260** 1 Yes [ ] 2 No [X]

Adjustments to opening equity

Was an amount included in the opening balance of retained earnings or equity, in order to correct an error, to recognize a change in accounting policy, or to adopt a new accounting standard in the current tax year? . . . . . **265** 1 Yes [ ] 2 No [X]

If **yes**, you have to maintain a separate reconciliation.

Name: Canadian Niagara Power Inc.

BN: 87249 8225 RC 0002

Tax Year Start: 2014-01-01

Tax Year End: 2014-12-31

1. BASIS OF ACCOUNTING AND SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Incorporation

Canadian Niagara Power Inc. [the "Corporation" or "CNPI"], a wholly owned subsidiary of FortisOntario Inc. [the "parent company"] [formerly Canadian Niagara Power Company, Limited], was incorporated on February 17, 1999 to comply with the Electricity Act, 1998 (Ontario) [the "Act"]. The Act requires that the electric power transmission and distribution businesses, previously carried out by the parent company, be carried out by a separate legal entity. Effective March 31, 1999, the Corporation purchased the electric power transmission and distribution assets of its parent company and commenced operations. On January 1, 2004, the Corporation was amalgamated with Eastern Ontario Power Inc. and continued as Canadian Niagara Power Inc. The business of the Corporation is the transmission and distribution of electricity to customers within Ontario. The business is regulated by the Ontario Energy Board ["OEB"].

These financial statements include the operating results of the Fort Erie, Port Colborne and Eastern Ontario Power [Gananoque] distribution centres and the Fort Erie transmission centre.

A. BASIS OF ACCOUNTING

These financial statements have been prepared in accordance with the accounting standards for private enterprises ["ASPE"], as per Part II of the CPA Handbook - Accounting, which constitutes generally accepted accounting principles for non-publicly accountable enterprises in Canada.

B. SIGNIFICANT ACCOUNTING POLICIES

Regulation

CNPI distribution

The distribution rates of CNPI are based upon cost-of-service rate regulation by the OEB. Earnings are regulated on the basis of a rate of return on rate base plus a recovery of all allowable distribution costs of CNPI.

On May 11, 2012, CNPI filed a Cost of Service Application for electricity distribution rates effective January 1, 2013. The application included the integration of smart meter costs into rate base, the recovery of stranded assets related to conventional meters and a rate rider designed to capture additional smart meter expenditures forecast to the end of 2012. The application also proposed changes to the accounting policy and estimates for utility capital assets. Since the majority of distributors in Ontario are transitioning to International Financial Reporting Standards ["IFRS"], and the OEB is requiring consistency amongst distributors, CNPI updated amortization rates and its capitalization of overhead policy effective for 2013. The OEB commissioned an amortization study, which was used as a guideline in updating the amortization rates. Consistent with International Accounting Standard 16 under IFRS, CNPI proposed that indirect overhead costs not be capitalized.

The OEB issued its Final Decision and Order on December 20, 2012 for new rates effective January 1, 2013, which resulted in a 6.8% increase for the average residential consumer in Fort Erie, a 5.9% increase for the average residential consumer in Gananoque and a 7.4% increase for the average residential consumer in Port Colborne effective January 1, 2013. The Decision and Order approves a 2013 base revenue requirement of $18,966,180 and provides an 8.93% return on equity ["ROE"] with a 60%/40% debt equity structure.

On August 16, 2013, CNPI filed its 2014 4th Generation Incentive Rate-setting Application ["4GIRM"] for electricity distribution rates effective January 1, 2014. This application was based on the OEB's guidelines for 4th Generation Incentive Regulation Mechanism. On January 9, 2014, the OEB issued its Decision and Order for CNPI; the final 4th Generation Incentive Price Index was 1.25% comprising 1.7% inflation, a 0% productivity factor and a 0.45% stretch factor [i.e., 1.7% - (0% + 0.45%)]. Rates were effective January 1, 2014. The overall bill impact for the average residential consumer is a 0.9% increase in Fort Erie, a 0.8% increase for the average residential consumer in Gananoque, and a 0.2% increase for the average residential consumer in Port Colborne.

On August 13, 2014, CNPI submitted its 2015 4GIRM, for electricity distribution rates effective January 1, 2015. This application is a second in a series of rate applications to fully harmonize electricity distribution rates in Port Colborne with those of Fort Erie and Gananoque. The OEB issued its Decision and Order on December 4, 2014, and the net price cap index adjustment for 2015 is 1.15% [i.e. 1.6% - (0% + 0.45%)]. The overall bill impact for the average residential consumer in Fort Erie is a 1.4% decrease, a 1.5% decrease for the average residential consumer in Gananoque, and a 3.2% decrease for the average residential consumer in Port Colborne. These overall decreases are the result of the disposition of regulatory deferral and variance accounts.

CNPI transmission

The transmission rates of CNPI are based upon cost-of-service rate regulation by the OEB. Earnings are regulated on the basis of a rate of return on rate base plus a recovery of all allowable transmission costs of CNPI.

On November 17, 2014, CNPI submitted a Revenue Requirement Application for its Transmission business. This Application seeks approval of CNPI's 2015 and 2016 Transmission Revenue Requirement. It is anticipated that the OEB's review of this Application will occur in the first quarter of 2015.

Materials and supplies

Materials and supplies are recorded at average cost. Materials and supplies expensed to operating expenses in 2014 were $119 [2013 - $82].

Utility capital assets, capitalization policy and service life of utility capital assets

Nature of distribution and transmission assets

Distribution assets

Distribution assets are those used to distribute electricity at lower voltages [generally below 50 kilovolts]. These assets include poles, towers and fixtures, low-voltage wires, transformers, overhead and underground conductors, street lighting, meters, metering equipment and other related equipment.

Transmission assets

Transmission assets are those used to transmit electricity at higher voltages [generally at 50 kilovolts and above]. These assets include poles, wires and conductors, substations, support structures and other related equipment.

Utility capital assets are stated at cost less accumulated amortization. Amortization is provided over the estimated useful lives of the utility capital assets using the straight-line method at a composite rate of 3.2% [2013 - 3.2%].

Contributions in aid of construction represent funding of utility capital assets contributed by customers. These accounts are being reduced annually by an amount equal to the charge for amortization provided on the contributed portion of the assets involved.

Capitalization policy and service life of utility capital assets

General expenses capitalized ["GEC"] are capitalized overhead costs that are not directly attributable to specific utility capital assets, but relate to the Corporation's overall capital program. Prior to 2013, GEC was permitted to be capitalized by the OEB's Distribution Rate Handbook and Accounting Procedures Handbook. In 2012, CNPI filed a cost of service application with the OEB based on a 2013 Test Year. The OEB is currently using "modified IFRS" as an accounting basis. As discussed in "Regulation" above, CNPI had proposed changes to its capitalization policy in its last cost of service application. These changes encompass adjustments to the useful lives of utility capital assets, changes to labour rates and the elimination of GEC. The impact of these changes has resulted in higher operating expenses and lower amortization expense. CNPI had requested the recovery of these changes in distribution rates. The changes were approved by the OEB and were incorporated on January 1, 2013.

In 2013, these changes were accounted for prospectively for regulatory purposes, and due to the complex nature of assigning overhead costs to utility capital assets, the Corporation could not reasonably quantify the retrospective impact of these changes.

Intangible assets

Intangible assets are stated at cost less accumulated amortization. Amortization is provided over the estimated useful lives of the intangible assets using the straight-line method.

Asset retirement obligations

ASPE requires the recognition of an asset retirement obligation in the period during which a legal obligation associated with the retirement of a tangible long lived asset is incurred and when a reasonable estimate of this amount can be made.

The Corporation has determined that there are asset retirement obligations associated with some parts of its transmission and distribution systems; however, none of these are material or require recognition under section 3110 of CPA Handbook.

Goodwill

Goodwill represents the excess of the acquisition cost of the shares of the Corporation, and Eastern Ontario Power Inc. [amalgamated with the Corporation as at January 1, 2004] over the assigned value of identifiable net assets acquired, as well as the excess of the purchase price of the remaining utility capital assets of Port Colborne Hydro Inc. ["PCHI"] over the fair value of these assets.

ASPE requires that goodwill shall be tested for impairment whenever events or changes in circumstances indicate that the carrying amount of the reporting unit to which the goodwill is assigned may exceed the fair value of the reporting unit. Any impairment in value is charged to earnings during the year.

Other assets

Other assets are amortized over their useful lives.

Revenue recognition

Revenue from the sale, transmission and distribution of electricity is recognized on the accrual basis. Electricity is metered upon delivery to customers and is recognized as revenue using approved rates when consumed. Meters are read periodically and bills are issued to customers based on these readings. At the end of the year a certain amount of consumed electricity will not have been billed. Electricity that is consumed but not yet billed to the customers is estimated and accrued as revenue in the current year. Unbilled revenue included in accounts receivable as at December 31, 2014 is $6,574 [2013 - $6,383].

Foreign currency translation

Monetary assets and liabilities denominated in foreign currencies are translated into Canadian dollars at the exchange rate prevailing at the balance sheet date. Gains and losses on translation are included in the statement of earnings and retained earnings. Revenue and expenses are translated at the exchange rate prevailing on the transaction date.

Employee benefit plans and change in accounting policy

Effective January 1, 2014, the Corporation has adopted new CPA Handbook Section 3462, Employee Future Benefits, for its accounting of pension benefits and other retirement benefits. As allowed under new Section 3462, the Corporation has made an accounting policy choice to measure its defined benefit plan obligations using the funding valuation approach. This approach uses the most recent completed actuarial valuations prepared for funding purposes as the basis of measuring defined benefit plan obligations. Even though other retirement benefits are not funded, Section 3462 requires that such liabilities be measured on a basis consistent with funded plans. As well, the Corporation is using a roll-forward technique in the years between valuations to estimate the defined benefit obligations. Pension plan assets are valued at fair value as of the balance sheet date. As required, the adoption of this new ASPE standard has been applied retroactively and the 2013 comparatives reflect these changes.

As a result of adopting CPA Handbook Section 3462 as of January 1, 2014, previously recognized unamortized pension and other retirement benefit amounts as at December 31, 2013 have been retroactively charged to retained earnings.

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As well, prior years' pension and other retirement expenses have been restated upon adoption of Section 3462. As a result, an amount of $4,310 has been charged to retained earnings effective January 1, 2014, offset by a corresponding increase in recorded pension liabilities of $2,386 and other retirement benefit liabilities of $1,924. The Corporation made application to the OEB to allow recognition of regulatory assets related to unamortized amounts, and restatement of prior years' pension and other retirement benefit expenses that would otherwise be collected from customers through rates in subsequent years. In December 2013, the OEB issued a Decision and Order approving the establishment of specific deferral accounts to recognize these amounts as long-term regulatory assets, which will be disposed of in future cost of service proceedings, subject to the OEB's prudence review at that time. The Corporation has recorded a corresponding increase in retained earnings for the amount of $4,310 as of January 1, 2014 and has recognized $4,310 in long-term regulatory assets. As well, the Corporation has reversed previously recognized future income tax liabilities in the amount of $1,142 related to the changes in the pension and other retirement benefit liabilities as of January 1, 2014. The Corporation has recognized offsetting regulatory liabilities related to the future income taxes expected to be recovered from customers in future electricity rates as of January 1, 2014 in the amount of $1,142. Therefore, there is no retroactive change to retained earnings as a result of the adoption of Section 3462

The Corporation made an application to the OEB to continue to account for pension and other retirement benefits under the former Section 3461. In December 2013, the OEB issued a Decision and Order approving the establishment of specific variance accounts as of January 1, 2013 to recognize the difference in expense between Sections 3461 and 3462 as long-term regulatory assets or liabilities for 2013 and future years, which will be disposed of in future cost of service proceedings, subject to the OEB's prudence review at that time. For 2014, the difference in expense between former Section 3461 and the new Section 3462 using the funding valuation approach is a charge to income of $2,004 for pension expense, and a charge to income of $26 for other retirement benefits. Therefore, a total of $2,030 has been recognized as long -term regulatory liabilities in accordance with the OEB Decision and Order in 2014. As well, an amount of $538 related to future income taxes on these amounts has been recognized as long-term regulatory assets in 2014.

Income taxes

The Corporation follows the asset and liability method of accounting for income taxes. Under this method, future tax assets and liabilities are recognized for the temporary differences between the tax and accounting bases of assets and liabilities. Future tax assets and liabilities are measured using the enacted and substantively enacted tax rates and laws expected to apply to taxable income in the period in which the temporary differences are expected to be recovered or settled. Effective January 1, 2009, the Corporation recognizes regulatory assets related to future income tax liabilities in the amount of future income taxes expected to be recovered from customers in future electricity rates.

Use of estimates

The preparation of financial statements in conformity with ASPE requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenue and expenses during the reporting periods. Actual results may vary from the current estimates. These estimates are reviewed periodically and, as adjustments become necessary, they are reported in earnings in the period in which they become known.

2. UTILITY CAPITAL ASSETS

Utility capital assets consist of the following:

2014

	Cost	Accumulated amortization	Net book value
	$	$	$
Transmission	28,566	12,983	15,583
Distribution	114,068	37,170	76,898
Other	15,846	9,964	5,882
	158,480	60,117	98,363

2013

	Cost	Accumulated amortization	Net book value
	$	$	$

Transmission	26,223	12,251	13,972
Distribution	107,761	34,341	73,420
Other	14,814	9,189	5,625
	148,798	55,781	93,017

The amounts above include assets under construction of $7,035 [2013 - $4,206]

which are not subject to amortization.

?

3. INTANGIBLE ASSETS

Intangible assets consist of the following:

	2014		
		Accumulated	Net book
	Cost	amortization	value
	$	$	$
Software costs	11,002	6,649	4,353
Land and transmission rights	6,985	2,763	4,222
Other	287	79	208
	18,274	9,491	8,783

2013

Accumulated Net book

Cost amortization value

$ $ $

Software costs	10,080	5,968	4,112
Land and transmission rights	6,989	2,590	4,399
Other	287	72	215
	17,356	8,630	8,726

4. EMPLOYEE FUTURE BENEFITS

The Corporation is a participating employer with its parent company in a defined benefit pension plan and a defined benefit plan providing other retirement benefits. The Corporation also maintains a defined contribution pension plan providing pension benefits and makes contributions to the Ontario Municipal Employees' Retirement System ["OMERS"] plan on behalf of some of its employees. OMERS is a multi-employer defined benefit pension plan providing pension benefits and is accounted for as a defined contribution pension plan.

Information about the Corporation's defined benefit plans is as follows:

	Pension benefit plan		Other retirement plan	
	2014	2013	2014	2013
	$	$	$	$
		[restated]		[restated]
Accrued benefit obligation				
Balance, beginning of year	14,752	14,361	6,498	6,386
Current service cost	386	368	90	86
Finance cost	700	682	309	303
Benefits paid	(675)	(652)	(291)	(317)
Actuarial losses (gains)	(24)	(7)	46	40

Balance, end of year 15,139 14,752 6,652 6,498

Plan assets

Fair value, beginning of year 15,838 14,635 -- --

Interest income 747 683 -- --

Return on plan assets 1,807 46 -- --

Contributions 1,120 1,126 291 317

Benefits paid (675) (652) (291) (317)

Fair value, end of year 18,837 15,838 -- --

Funded status - plan surplus (deficit) 3,698 1,086 (6,652)
(6,498)

The measurement date for the plan assets and the accrued benefit obligation is December 31, 2014. The effective date of the most recent actuarial valuation was as at December 31, 2011 and the date of the next required valuation for funding purposes is December 31, 2014.

The defined benefit pension plan assets held at the measurement date are represented by the following categories:

%

Canadian equity funds 14

US equity funds 13

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EAFE equity funds 11

Canadian fixed income funds 60

Cash and short-term investments 2

	Pension benefit plans		Other retirement plans	
	2014	2013	2014	2013
	$	$	$	$
		[restated]		[restated]
Significant assumptions used				
Discount rate - beginning of year	4.75%	4.75%	4.75%	4.75%
Discount rate - end of year	4.75%	4.75%	4.75%	4.75%
Rate of compensation increase	4.00%	4.00%	-	-
Initial health care trend rate	-	-	5.93%	5.96%
Average remaining service life of active employees [years]	5	6	16	17
Net benefit expense for the year				
Current service cost	386	368	90	86
Finance cost	(47)	(1)	309	303
Remeasurement costs	(1,823)	(61)	46	40
Regulatory adjustments	2,004	312	26	23
Net benefit expense	520	618	471	452

The total expense for the Corporation's defined contribution pension plan for the year amounted to $255 [2013 - $243]. The pension cost associated with the OMERS plan was $156 [2013 - $151].

5. INCOME TAXES

The provision for (recovery of) income taxes consists of the following:

2014 2013
$ $

Current income taxes 996 1,448
Future income taxes
Future income taxes transferred to regulatory liabilities (assets) 1,029
(1,029) (22)
22
996 1,448

During the year, the Corporation recorded $1,029 in regulatory assets and a corresponding decrease to future income tax expense, for the amount of future income taxes expected to be recovered from customers in future electricity rates.

Future income taxes are provided for temporary differences. Future tax assets and liabilities consist of the following:

2014 2013

	$	$
		[restated]
Future tax liabilities (assets)		
Utility capital assets	5,074	4,684
Employee future benefits	(786)	(1,434)
Other assets	30	39
Net future tax liabilities	4,318	3,289

6. RELATED PARTY TRANSACTIONS

During the year, the Corporation entered into the following transactions with related parties:

	2014	2013
	$	$
Receipts		
Administrative services to:		
FortisOntario Inc.	101	156
Cornwall Street Railway, Light and Power Company Limited	1,394	1,354
Algoma Power Inc.	1,903	1,892
Reimbursement of expenses paid on behalf of and services provided to:		
FortisOntario Inc.	433	380
Fortis Properties Corporation	-	16
Fortis Generation East Limited Partnership	485	547
Algoma Power Inc.	255	34

Westario Power Holdings Inc.

Grimsby Power Inc.

Cornwall Street Railway, Light and Power Company Limited 367

98

318 210

93

194

CH Energy Group Inc. 19 -

Payments

Purchased power from Fortis Generation East Limited Partnership 1,679

1,483

Management fees paid to FortisOntario Inc. 744 675

Rent paid to FortisOntario Inc. 525 515

Dividends paid to FortisOntario Inc. 2,500 -

Interest expense paid to FortisOntario Inc. 899 945

Interest expense paid to Fortis Inc. 36 -

Reimbursement for expenses paid on behalf of and services

provided from:

FortisOntario Inc. 4,524 3,426

Cornwall Street Railway, Light and Power Company Limited 416 459

Westario Power Holdings Inc. - 3

These transactions are in the normal course of operations and are measured at the exchange amount, which is the amount of consideration established and agreed to by the related parties.

As at December 31, the amounts due to (from) related parties are as follows:

	2014	2013
	$	$
FortisOntario Inc.	10,350	5,825
Fortis Generation East Limited Partnership	73	125
Westario Power Holdings Inc.	(52)	(39)
Grimsby Power Inc.	(8)	(14)
CH Energy Group Inc.	(19)	-
	10,344	5,897
Promissory notes due to parent company	20,000	20,000

A promissory note of $20,000 due to the parent company bears interest at a rate of 4.03% and is payable on demand. There are no specific terms of repayment for this note.

Details of relationships with related parties are as follows:

" Fortis Inc. owns a 100% interest in the capital stock of FortisOntario Inc.

" FortisOntario Inc. owns a 100% interest in the capital stock of the Corporation

" Fortis Properties Corporation is a wholly owned subsidiary of Fortis Inc.

" Cornwall Street Railway, Light and Power Company Limited is a wholly owned subsidiary of FortisOntario Inc.

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" Algoma Power Inc. is a wholly owned subsidiary of FortisOntario Inc

" Westario Power Holdings Inc. is 10% owned by FortisOntario Inc.

" FortisOntario Inc. owns 10 Class B preferred shares of Niagara Power Incorporated.

" FortisOntario Inc. indirectly owns 10% of Grimsby Power Inc. through the ownership of the Class B preferred shares in Niagara Power Incorporated.

" Fortis Generation East Limited Partnership is a wholly owned subsidiary of Fortis Inc.

" CH Energy Group Inc. is a wholly owned subsidiary of Fortis Inc.

7. LONG-TERM DEBT

Long-term debt consists of the following:

	2014	2013
	$	$
7.092% senior unsecured notes due August 14, 2018	30,000	30,000
Unamortized debt issue costs	(115)	(147)
	29,885	29,853

The senior unsecured notes bear interest of 7.092% and are repayable at maturity on August 14, 2018. Interest expense on long-term debt for the year was $2,131 [2013 - $2,128].

The Corporation incurred costs of $480 that are being amortized over the term of the loan. As at December 31, 2014, the accumulated amortization was $365 [2013 - $333].

8. CAPITAL STOCK

The authorized and issued shares consist of 23,900,001 common shares without par value.

9. AMORTIZATION

Amortization consists of the following:

	2014	2013
	$	$
Amortization of utility capital assets	4,706	4,452
Amortization of contributions in aid of construction	(268)	(253)
Amortization of intangible assets	862	810
	5,300	5,009
Vehicle amortization allocated	(388)	(351)
	4,912	4,658

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10. STATEMENTS OF CASH FLOWS

The net change in non-cash working capital balances related to operations consists of the following:

	2014	2013
	$	$
Accounts receivable	(61)	(627)
Income taxes receivable	186	145
Materials and supplies	(63)	29
Prepaid expenses	27	71
Accounts payable and accrued liabilities	(956)	1,099
Regulatory assets/liabilities	1,484	(351)
Due to related parties	4,447	(3,158)
	5,064	(2,792)

Supplemental cash flow information:

	2014	2013
	$	$
Interest paid	3,132	3,130
Income taxes paid	1,013	1,525

11. FINANCIAL RISK MANAGEMENT

The Corporation is primarily exposed to credit risk, liquidity risk and market risk as a result of holding financial instruments in the normal course of business.

Credit risk: Risk that a third party to a financial instrument might fail to meet its obligations under the terms of the financial instrument.
Liquidity risk: Risk that an entity will encounter difficulty in raising funds to meet commitments associated with financial instruments.
Market risk: Risk that the fair value or future cash flows of a financial instrument will fluctuate due to changes in market prices.

Credit risk

For cash, trade and other accounts receivable due from customers, the Corporation's credit risk is limited to the carrying value on the balance sheet.

The Corporation is exposed to credit risk from its distribution customers but has various policies to minimize this risk. These policies include requiring customer deposits, performing disconnections and using third party collection agencies for overdue accounts. The Corporation has a large and diversified distribution customer base, which minimizes the concentration of this risk.

The aging of the Corporation's trade and other receivables due from customers is as follows:

	2014
	$
Not past due	11,213
Past due 0-30 days	381
Past due 31-60 days	86
Past due 61 days and over	170
	11,850
Less allowance for doubtful accounts	160
	11,690

Liquidity risk

Liquidity risk to the Corporation is minimized. Financing of regulated capital and other expenditures is done through internally generated funds. These funds are a result of allowable rate regulated returns and recoveries under the OEB rate regulation mechanism.

The Corporation's parent company is a wholly owned by Fortis Inc., a large, investor owned utility that has had the ability to raise sufficient and cost effective financing. However, the ability to arrange financing on a go forward basis is subject to numerous factors including the results of operations and financial position of Fortis Inc. and its subsidiaries, conditions in the capital and bank credit markets, ratings assigned by rating agencies and general economic conditions.

To mitigate any liquidity risk, the Corporation is a party to a committed revolving credit facility and letters of credit facilities totaling $30,000, of which $15,700 is unused. This credit agreement is shared among the subsidiaries of FortisOntario Inc. and is renewed on an annual basis.

The facility is guaranteed by the parent company and bears interest at the bankers' acceptance rate plus 1.20% in the case of bankers' acceptances and at the bank's prime lending rate plus 0.20% in the case of bank loans.

The following is an analysis of the contractual maturities of the Corporation's financial liabilities as at December 31, 2014:

< 1 year 1-3 years 4-5 years > 5 years Total

$ $ $ $ $

Accounts payable and

accrued liabilities 7,139 ? ? ? 7,139

Government remittances payable 209 ? ? ? 209

Customer deposits 251 125 230 ? 606

Promissory notes due to parent company

?

?

?

20,000

20,000

Long-term debt	?	?	30,000	?	30,000
	7,599	125	30,230	20,000	57,954

Interest rate risk

Long-term debt is at fixed interest rates thereby minimizing cash flow and interest rate fluctuation exposure. The Corporation is primarily subject to risks associated with fluctuating interest rates on its short-term borrowings. Short-term borrowings for 2014 is nil [2013 - $3,000].

12. CAPITAL MANAGEMENT

The Corporation manages its capital to approximate the deemed capital structure reflected in the utility's customer rates. Effective January 1, 2013, the distribution rates are based on a deemed capital structure of 60% debt and 40% equity. The Corporation's capital structure consists of third party debt, affiliated debt and common equity but excludes unamortized debt issue costs.

The managed capital is as follows:

	2014 Actual		2013 Actual	
	$	%	$	%
Debt	50,000	51	50,000	52
Equity	47,596	49	45,375	48
	97,596	100	95,375	100

The Corporation's long-term debt obligations and credit facility agreements have covenants that restrict the issuance of additional debt such that debt cannot exceed 75% of their capital structures as defined in the agreements. As at December 31, 2014, the Corporation was in compliance with its debt covenants.

13. REGULATORY ASSETS AND LIABILITIES

Regulatory assets and regulatory liabilities arise as a result of regulatory requirements.

The Corporation pays the cost of power on behalf of its customers and recovers these costs through retail billings to its customers. The cost of power includes charges for transmission, wholesale market operations and the power itself from Ontario's Independent Electricity System Operator. The balance of the retail settlement variance account represents the costs that have not been recovered from, or settled through, customers as of the balance sheet date. The OEB's Distribution Rate Handbook and Accounting Procedures Handbook allow these costs to be deferred and recovered through future rate adjustments, as discussed in note 1. In the absence of rate regulation, these costs would be expensed in the period that they are incurred.

The OEB has the general power to include or exclude costs, revenues, gains or losses in the rates of a specific period, resulting in the timing of revenue and expense recognition that may differ in the Corporation's regulated operations from those otherwise expected in non-regulated businesses. This change in timing gives rise to the recognition of regulatory assets and liabilities. The Corporation continually assesses the likelihood of recovery of its regulatory assets and believes that its regulatory assets and liabilities will be factored into the setting of future rates as discussed in note 1. If future recovery through rates is no longer considered probable, the appropriate carrying amount will be written off in the period that the assessment is made.

In 2013, upon approval by the OEB, the Corporation integrated smart meters into rate base from amounts previously held as regulatory assets of $4,365 as well as removed stranded meter assets of $1,238 from capital assets and recognized these amounts as regulatory assets.

In 2013 the smart meter revenue and expense balances previously held in regulatory assets were transferred to the statement of earnings and retained earnings per the guidance provided in the OEB Accounting Procedures Handbook. The net disposition costs were $237.

The following table provides the detailed revenue and costs associated with the smart meter disposition costs.

	2014	2013
	$	$
Billed revenue	?	2,049
Less: return on equity previously booked	?	(1,004)
	?	1,045

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Amortization ? (1,101)

Operating costs ? (51)

Reduction in regulatory interest income ? (130)

Net smart meter disposition costs ? (237)

Regulatory assets and liabilities are not subject to a regulatory return; however, the balances include an accrual for interest recovery/payable as permitted by the regulators.

2014 2013 Remaining

rebate

$ $ period

[restated]

Current regulatory assets

Amounts approved in current rates 260 1,742 1 year

Long-term regulatory assets

Retail settlement and other variance accounts 2,343 1,167 2 years

Amounts approved in current rates 84 167 2 years

Future taxes to be recovered from customers 4,318 3,289 life of

assets

Pension and other retirement benefits 2,293 4,310 EARSL

9,038 8,933

Current regulatory liabilities

Ontario Clean Energy benefits 629 631 1 month

Amounts approved in current rates 6 ? 1 year

Other 64 66

699 697

Long-term regulatory liabilities

Retail settlement and other variance accounts	2,928	1,704	2 years
Other	84	168	2 years
	3,012	1,872	

14. SEGMENTED INFORMATION

[a] Earnings

	2014		
	CNPI	CNPI	
	Distribution	Transmission	Total
	$	$	$
Revenue	76,463	4,854	81,317
Purchased power	56,490	-	56,490
Operating expenses	9,296	1,738	11,034
Amortization	4,014	898	4,912
Operating earnings	6,663	2,218	8,881
Interest expense	2,617	547	3,164
Income taxes	706	290	996
Net earnings	3,340	1,381	4,721

2013

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	CNPI Distribution	CNPI Transmission	Total
	$	$	$
Revenue	73,332	4,856	78,188
Purchased power	53,921	-	53,921
Operating expenses	9,012	1,698	10,710
Amortization	3,864	794	4,658
Operating earnings	6,535	2,364	8,899
Net smart meter disposition costs	237	-	237
Interest expense	2,623	531	3,154
Income taxes	970	478	1,448
Net earnings	2,705	1,355	4,060

[b] Utility capital assets

	2014		
	CNPI Distribution	CNPI Transmission	Total
	$	$	$
Cost	129,808	28,672	158,480
Accumulated amortization	47,133	12,984	60,117
	82,675	15,688	98,363

	2013		
	CNPI	CNPI	
	Distribution	Transmission	Total
	$	$	$
Cost	122,575	26,223	148,798
Accumulated amortization	43,530	12,251	55,781
	79,045	13,972	93,017

15. COMPARATIVE FINANCIAL STATEMENTS

The comparative financial statements have been reclassified from statements previously presented to conform to the presentation of the 2014 financial statements.

SCHEDULE 100

GENERAL INDEX OF FINANCIAL INFORMATION – GIFI

Form identifier 100

Name of corporation	Business Number	Tax year-end Year Month Day
Canadian Niagara Power Inc.	87249 8225 RC0002	2014-12-31

Assets – lines 1000 to 2599

1000	1,216,202	1060	11,689,664	1120	142,647
1480	5,587,078	1484	468,866	1599	19,104,457
1600	260,622	1740	158,219,237	1741	-60,117,068
2008	158,479,859	2009	-60,117,068	2010	18,274,763
2011	-9,491,446	2012	7,232,490	2178	25,507,253
2179	-9,491,446	2422	3,697,837	2424	112,889
2589	3,810,726	2599	137,293,781		

Liabilities – lines 2600 to 3499

2620	7,345,770	2680	31,153	2860	10,344,408
2961	606,069	3139	18,327,400	3140	30,000,000
3240	4,318,016	3300	20,000,000	3320	10,400,944
3321	6,651,600	3450	71,370,560	3499	89,697,960

Shareholder equity – lines 3500 to 3640

3500	23,900,000	3600	23,695,821	3620	47,595,821
3640	137,293,781				

Retained earnings – lines 3660 to 3849

3660	21,474,983	3680	4,720,838	3701	-2,500,000
3849	23,695,821				

SCHEDULE 125

GENERAL INDEX OF FINANCIAL INFORMATION – GIFI

Form identifier 125

Name of corporation	Business Number	Tax year-end Year Month Day
Canadian Niagara Power Inc.	87249 8225 RC0002	2014-12-31

Description

Sequence number **0003** 01

Revenue – lines 8000 to 8299

8000	81,572,829	**8089**	81,572,829	**8094**	32,724
8210	74,502	**8231**	-11,746	**8299**	81,668,309

Cost of sales – lines 8300 to 8519

8320	56,607,840	**8450**	8,640,491	**8518**	65,248,331
8519	16,324,498				

Operating expenses – lines 8520 to 9369

8520	32,619	**8523**	53,195	**8570**	861,715
8590	193,132	**8670**	4,437,452	**8690**	106,792
8710	3,164,109	**8860**	1,020,225	**9180**	204,854
9200	86,217	**9220**	542,420	**9367**	10,702,730
9368	75,951,061	**9369**	5,717,248		

Extraordinary items and taxes – lines 9970 to 9999

9970	5,717,248	**9990**	996,410	**9999**	4,720,838

Canada Revenue Agency / Agence du revenu du Canada

Net Income (Loss) for Income Tax Purposes

SCHEDULE 1

Corporation's name	Business Number	Tax year end Year Month Day
Canadian Niagara Power Inc.	87249 8225 RC0002	2014-12-31

- The purpose of this schedule is to provide a reconciliation between the corporation's net income (loss) as reported on the financial statements and its net income (loss) for tax purposes. For more information, see the T2 *Corporation Income Tax Guide*.
- All legislative references are to the *Income Tax Act*.

Amount calculated on line 9999 from Schedule 125				4,720,838	A
Add:					
Provision for income taxes – current		101	996,410		
Amortization of tangible assets		104	4,437,452		
Amortization of intangible assets		106	861,715		
Charitable donations and gifts from Schedule 2		112	22,759		
Non-deductible meals and entertainment expenses		121	26,598		
Reserves from financial statements – balance at the end of the year		126	4,970,962		
Subtotal of additions			11,315,896 ▶	11,315,896	
Other additions:					
Financing fees deducted in books		216	32,028		
Miscellaneous other additions:					
600 ITC from apprenticeship job creation		290	4,000		
602 Ontario Co-operative education tax credit		292	3,000		
603 Ontario Apprenticeship training tax credit	13,644				
Total	13,644	293	13,644		
604					
Total		294			
Subtotal of other additions		199	52,672 ▶	52,672	
Total additions		500	11,368,568 ▶	11,368,568	B
Amount A **plus** amount B				16,089,406	
Deduct:					
Gain on disposal of assets per financial statements		401	74,502		
Capital cost allowance from Schedule 8		403	6,704,478		
Cumulative eligible capital deduction from Schedule 10		405	6,875		
Reserves from financial statements – balance at the beginning of the year		414	5,411,271		
Subtotal of deductions			12,197,126 ▶	12,197,126	
Other deductions:					
Miscellaneous other deductions:					
700 overstatement of 2013 apprenticeship training tax credit		390	3,863		
704					
Total		394			
Subtotal of other deductions		499	3,863 ▶	3,863	
Total deductions		510	12,200,989 ▶	12,200,989	
Net income (loss) for income tax purposes – enter on line 300 of the T2 return				3,888,417	

T2 SCH 1 E (12)

Canada

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Schedule 2

Charitable Donations and Gifts

Corporation's name	Business number	Tax year-end Year Month Day
Canadian Niagara Power Inc.	87249 8225 RC0002	2014-12-31

- For use by corporations to claim any of the following:
  - the eligible amount of charitable donations to qualified donees;
  - the Ontario community food program donation tax credit for farmers;
  - the eligible amount of gifts to Canada, a province, or a territory;
  - the eligible amount of gifts of certified cultural property;
  - the eligible amount of gifts of certified ecologically sensitive land; or
  - the deduction for gifts of medicine.
- The eligible amount of a gift is the amount by which the fair market value of the gifted property exceeds the amount of an advantage, if any, for the gift.
- The donations and gifts are eligible for a 5-year carryforward except for gifts of certified ecologically sensitive land made after February 10, 2014, which are eligible for a 10-year carryforward.
- Use this schedule to show a transfer of unused amounts from previous years following an amalgamation or the wind-up of a subsidiary as described under subsections 87(1) and 88(1) of the federal *Income Tax Act*.
- Subsection 110.1(1.2) of the federal Act provides as follows:
  - Where a particular corporation has undergone an acquisition of control, for tax years that end on or after the acquisition of control, no corporation can claim a deduction for a gift made by the particular corporation to a qualified donee before the acquisition of control.
  - If a particular corporation makes a gift to a qualified donee pursuant to an arrangement under which both the gift and the acquisition of control is expected, no corporation can claim a deduction for the gift unless the person acquiring control of the particular corporation is the qualified donee.
- An eligible medical gift to a qualifying organization for activities outside of Canada may be eligible for a deduction. Calculate the deduction in Part 6.
- File one completed copy of this schedule with your *T2 Corporation Income Tax Return*.
- For more information, see the *T2 Corporation - Income Tax Guide*.

Part 1 – Charitable donations

Charity/Recipient		Amount ($100 or more only)
Port Cares		7,320
United Way of Leeds Grenville		2,867
The Salvation Army		12,572
	Subtotal	22,759
	Add: Total donations of less than $100 each	
	Total donations in current tax year	22,759

Part 1 – Charitable donations

	Line	Federal		Québec	Alberta
Charitable donations at the end of the previous tax year			A		
Deduct: Charitable donations expired after five tax years*	239				
Charitable donations at the beginning of the current tax year	240		B		
Add:					
Charitable donations transferred on an amalgamation or the wind-up of a subsidiary	250				
Total charitable donations made in the current year (enter this amount on line 112 of Schedule 1)	210	22,759		22,759	22,759
Subtotal (line 250 **plus** line 210)		22,759	C	22,759	22,759
Subtotal (amount B **plus** amount C)		22,759	D	22,759	22,759
Deduct: Adjustment for an acquisition of control	255				
Total charitable donations available (amount D **minus** amount on line 255)		22,759	E	22,759	22,759
Deduct: Amount applied in the current year against taxable income (cannot be more than amount O in Part 2) (enter this amount on line 311 of the T2 return)	260	22,759		22,759	22,759
Charitable donations closing balance (amount E **minus** amount on line 260)	280				
Ontario community food program donation for farmers included in the amount on line 260 (for donations made after December 31, 2013)	262				
Ontario community food program donation tax credit for farmers (amount on line 262 multiplied by 25 %)			1		

Enter the amount from line 1 on line 420 of Schedule 5, *Tax Calculation Supplementary – Corporations*. The maximum amount you can claim in the current year is whichever is less; the Ontario income tax otherwise payable or the amount on line 1. For more information, see section 103.1.2 of the *Taxation Act, 2007* (Ontario).

* For the federal and Alberta, the gifts expire after five tax years. For Québec, gifts made in a tax year that ended before March 24, 2006, expire after five tax years and gifts made in a tax year that ended after March 23, 2006, expire after twenty tax years.

Amounts carried forward – Charitable donations

Year of origin:		Federal	Québec	Alberta
1st prior year	2013-12-31			
2nd prior year	2012-12-31			
3rd prior year	2011-12-31			
4th prior year	2010-12-31			
5th prior year	2009-12-31			
6th prior year*	2008-12-31			
7th prior year	2007-12-31			
8th prior year	2006-12-31			
9th prior year	2005-12-31			
10th prior year	2004-12-31			
11th prior year	2003-12-31			
12th prior year	2002-12-31			
13th prior year	2001-12-31			
14th prior year	2000-12-31			
15th prior year	1999-12-31			
16th prior year				
17th prior year				
18th prior year				
19th prior year				
20th prior year				
21st prior year*				
Total (to line A)				

***** For the federal and Alberta, the 6th prior year gifts expire in the current year. For Québec, the 6th prior year gifts made in a tax year that ended before March 24, 2006, expire in the current year and the 21st prior year gifts made in a tax year that ended after March 23, 2006, expire in the current year.

Part 2 – Calculation of the maximum allowable deduction for charitable donations

Net income for tax purposes* **multiplied** by 75 %					2,916,313	F
Taxable capital gains arising in respect of gifts of capital property included in Part 1 **	225			G		
Taxable capital gain in respect of deemed gifts of non-qualifying securities per subsection 40(1.01), from the disposition of a property in the preceding tax year	227			H		
The amount of the recapture of capital cost allowance in respect of charitable donations	230					
Proceeds of disposition, less outlays and expenses**			I			
Capital cost**			J			
Amount I or J, whichever is less	235					
Amount on line 230 or 235, whichever is less				K		
Subtotal (**add** amounts G, H, and K)				L		
Amount L **multiplied** by 25 %						M
Subtotal (amount F **plus** amount M)					2,916,313	N
Maximum allowable deduction for charitable donations (enter amount E from Part 1, amount N, or net income for tax purposes, whichever is less)					22,759	O

* For credit unions, subsection 137(2) states that this amount is before the deduction of payments pursuant to allocations in proportion to borrowing and bonus interest.

** This amount must be prorated by the following calculation: eligible amount of the gift **divided by** the proceeds of disposition of the gift.

Part 3 – Gifts to Canada, a province, or a territory

Gifts to Canada, a province, or a territory at the end of the previous tax year					A
Deduct: Gifts to Canada, a province, or a territory expired after five tax years	339				
Gifts to Canada, a province, or a territory at the beginning of the current tax year	340				B
Add:					
Gifts to Canada, a province, or a territory transferred on an amalgamation or the windup of a subsidiary	350				
Total gifts made to Canada, a province, or a territory in the current year*	310				
Subtotal (line 350 **plus** line 310)			►		C
Subtotal (amount B **plus** amount C)					D
Deduct:					
Adjustment for an acquisition of control	355				
Amount applied in the current year against taxable income (enter this amount on line 312 of the T2 return)	360				
Subtotal (line 355 **plus** line 360)			►		E
Gifts to Canada, a province, or a territory closing balance (amount D **minus** amount E)	380				

* Not applicable for gifts made after February 18, 1997, unless a written agreement was made before this date. If no written agreement exists, enter the amount on line 210 and complete Part 2.

Part 4 – Gifts of certified cultural property

	Line	Federal		Québec	Alberta
Gifts of certified cultural property at the end of the previous tax year			F		
Deduct: Gifts of certified cultural property expired after five tax years*	439				
Gifts of certified cultural property at the beginning of the current tax year	440		G		
Add:					
Gifts of certified cultural property transferred on an amalgamation or the windup of a subsidiary	450				
Total gifts of certified cultural property in the current year	410				
Subtotal (line 450 **plus** line 410)			H		
Subtotal (amount G **plus** amount H)			I		
Deduct:					
Adjustment for an acquisition of control	455				
Amount applied in the current year against taxable income (enter this amount on line 313 of the T2 return)	460				
Subtotal (line 455 **plus** line 460)			J		
Gifts of certified cultural property closing balance (amount I **minus** amount J)	480				

* For the federal and Alberta, the gifts expire after five tax years. For Québec, gifts made in a tax year that ended before March 24, 2006, expire after five tax years and gifts made in a tax year that ended after March 23, 2006, expire after twenty tax years.

Amount carried forward – Gifts of certified cultural property

Year of origin:		Federal	Québec	Alberta
1st prior year	2013-12-31			
2nd prior year	2012-12-31			
3rd prior year	2011-12-31			
4th prior year	2010-12-31			
5th prior year	2009-12-31			
6th prior year*	2008-12-31			
7th prior year	2007-12-31			
8th prior year	2006-12-31			
9th prior year	2005-12-31			
10th prior year	2004-12-31			
11th prior year	2003-12-31			
12th prior year	2002-12-31			
13th prior year	2001-12-31			
14th prior year	2000-12-31			
15th prior year	1999-12-31			
16th prior year				
17th prior year				
18th prior year				
19th prior year				
20th prior year				
21st prior year*				
Total				

* For the federal and Alberta, the 6th prior year gifts expire in the current year. For Québec, the 6th prior year gifts made in a tax year that ended before March 24, 2006, expire in the current year and the 21st prior year gifts made in a tax year that ended after March 23, 2006, expire in the current year.

Part 5 – Gifts of certified ecologically sensitive land

	Line	Federal		Québec	Alberta
Gifts of certified ecologically sensitive land at the end of the previous tax year			K		
Deduct: Gifts of certified ecologically sensitive land expired after 5 tax years, or after 10 tax years for gifts made after February 10, 2014*	539				
Gifts of certified ecologically sensitive land at the beginning of the current tax year	540		L		
Add:					
Gifts of certified ecologically sensitive land transferred on an amalgamation or the windup of a subsidiary	550				
Total current-year gifts of certified ecologically sensitive land made before February 11, 2014	510				
Total current-year gifts of certified ecologically sensitive land made after February 10, 2014	520				
Subtotal (**add** lines 550, 510, and 520)			M		
Subtotal (amount L **plus** amount M)			N		
Deduct:					
Adjustment for an acquisition of control	555				
Amount applied in the current year against taxable income (enter this amount on line 314 of the T2 return)	560				
Subtotal (line 555 **plus** line 560)			O		
Gifts of certified ecologically sensitive land closing balance (amount N **minus** amount O)	580				

* For the federal and Alberta, gifts made before February 11, 2014 , expire after five tax years and gifts made after February 10, 2014, expire after ten tax years. For Québec, gifts made during a tax year that ended before March 24, 2006, expire after five tax years and gifts made during a tax year that ended after March 23, 2006 expire after twenty tax years.

Amounts carried forward – Gifts of certified ecologically sensitive land

Amount of carried forward gifts made on or after February 11, 2014, in the tax year including this date . . . .

Year of origin:		Federal	Québec	Alberta
1st prior year	2013-12-31			
2nd prior year	2012-12-31			
3rd prior year	2011-12-31			
4th prior year	2010-12-31			
5th prior year	2009-12-31			
6th prior year*	2008-12-31			
7th prior year	2007-12-31			
8th prior year	2006-12-31			
9th prior year	2005-12-31			
10th prior year	2004-12-31			
11th prior year*	2003-12-31			
12th prior year	2002-12-31			
13th prior year	2001-12-31			
14th prior year	2000-12-31			
15th prior year	1999-12-31			
16th prior year				
17th prior year				
18th prior year				
19th prior year				
20th prior year				
21st prior year*				
Total				

***** For the federal and Alberta, gifts made before February 11, 2014, expire after five tax years and gifts made after February 10, 2014, expire after ten tax years. The field "Amount of carried forward gifts made on or after February 11, 2014, in the tax year including this date" is used to determine the portion of the gifts made in the tax year straddling February 11, 2014, that expires after ten tax years.
For Québec, gifts made during a tax year that ended before March 24, 2006, expire after five tax years and gifts made in a tax year that ended after March 23, 2006, expire after twenty tax years.

Part 6 – Deduction for gifts of medicine

		Federal		Québec		Alberta	
Deduction for gifts of medicine at the end of the previous tax year			P				
Deduct: Deduction for gifts of medicine expired after five tax years	639						
Deduction for gifts of medicine at the beginning of the current tax year	640		Q				
Add:							
Deduction for gifts of medicine transferred on an amalgamation or the wind-up of a subsidiary	650						
Deduction for gifts of medicine for the current year:							
Proceeds of disposition	602		1		1		1
Cost of gifts of medicine	601		2		2		2
Subtotal (line 1 **minus** line 2)			3		3		3
Line 3 **multiplied** by 50 %			4		4		4
Eligible amount of gifts	600		5		5		5

Federal

a ______ x (b ______ / c) = Deduction for gifts of medicine for the current year **610** ______

Québec

a ______ x (b ______ / c) = Deduction for gifts of medicine for the current year ______

Alberta

a ______ x (b ______ / c) = Deduction for gifts of medicine for the current year ______

where:

a is the **lesser** of line 2 and line 4

b is the eligible amount of gifts (line 600)

c is the proceeds of disposition (line 602)

		Federal		Québec	Alberta
Subtotal (line 650 **plus** line 610)			R		
Subtotal (amount Q **plus** amount R)			S		
Deduct:					
Adjustment for an acquisition of control	655				
Amount applied in the current year against taxable income (enter this amount on line 315 of the T2 return)	660				
Subtotal (line 655 **plus** line 660)			T		
Deduction for gifts of medicine closing balance (amount S **minus** amount T)	680				

Amounts carried forward – Deduction for gifts of medicine

Year of origin:		Federal	Québec	Alberta
1st prior year	2013-12-31			
2nd prior year	2012-12-31			
3rd prior year	2011-12-31			
4th prior year	2010-12-31			
5th prior year	2009-12-31			
6th prior year*	2008-12-31			
Total				

***** These donations expired in the current year.

Québec – Gifts of musical instruments

Gifts of musical instruments at the end of the previous tax year		A
Deduct: Gifts of musical instruments expired after twenty tax years		B
Gifts of musical instruments at the beginning of the tax year		C
Add:		
Gifts of musical instruments transferred on an amalgamation or the wind-up of a subsidiary		D
Total current-year gifts of musical instruments		E
Subtotal (line D **plus** line E)		F
Deduct: Adjustment for an acquisition of control		G
Total gifts of musical instruments available		H
Deduct: Amount applied against taxable income		I
Gifts of musical instruments closing balance		J

Amounts carried forward – Gifts of musical instruments

Year of origin:		Québec
1st prior year	2013-12-31	
2nd prior year	2012-12-31	
3rd prior year	2011-12-31	
4th prior year	2010-12-31	
5th prior year	2009-12-31	
6th prior year*	2008-12-31	
7th prior year	2007-12-31	
8th prior year	2006-12-31	
9th prior year	2005-12-31	
10th prior year	2004-12-31	
11th prior year	2003-12-31	
12th prior year	2002-12-31	
13th prior year	2001-12-31	
14th prior year	2000-12-31	
15th prior year	1999-12-31	
16th prior year		
17th prior year		
18th prior year		
19th prior year		
20th prior year		
21st prior year*		
Total		

* These gifts expired in the current year.

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Tax Calculation Supplementary – Corporations

Schedule 5

Corporation's name	Business Number	Tax year-end Year Month Day
Canadian Niagara Power Inc.	87249 8225 RC0002	2014-12-31

- Use this schedule if, during the tax year, the corporation:
  - had a permanent establishment in more than one jurisdiction (corporations that have no taxable income should only complete columns A, B and D in Part 1);
  - is claiming provincial or territorial tax credits or rebates (see Part 2); or
  - has to pay taxes, other than income tax, for Newfoundland and Labrador, or Ontario (see Part 2).
- Regulations mentioned in this schedule are from the *Income Tax Regulations.*
- For more information, see the *T2 Corporation – Income Tax Guide.*
- Enter the regulation number in field 100 of Part 1.

Part 1 – Allocation of taxable income

100 ______ Enter the Regulation that applies (402 to 413).

A Jurisdiction Tick yes if the corporation had a permanent establishment in the jurisdiction during the tax year. *		B Total salaries and wages paid in jurisdiction	C (B x taxable income**) / G	D Gross revenue	E (D x taxable income**) / H	F Allocation of taxable income (C + E) x 1/2*** (where either G or H is nil, do not multiply by 1/2)
Newfoundland and Labrador	003 1 Yes	103		143		
Newfoundland and Labrador Offshore	004 1 Yes	104		144		
Prince Edward Island	005 1 Yes	105		145		
Nova Scotia	007 1 Yes	107		147		
Nova Scotia Offshore	008 1 Yes	108		148		
New Brunswick	009 1 Yes	109		149		
Quebec	011 1 Yes	111		151		
Ontario	013 1 Yes	113		153		
Manitoba	015 1 Yes	115		155		
Saskatchewan	017 1 Yes	117		157		
Alberta	019 1 Yes	119		159		
British Columbia	021 1 Yes	121		161		
Yukon	023 1 Yes	123		163		
Northwest Territories	025 1 Yes	125		165		
Nunavut	026 1 Yes	126		166		
Outside Canada	027 1 Yes	127		167		
Total		129 G		169 H		

* "Permanent establishment" is defined in Regulation 400(2).

** If the corporation has income or loss from an international banking centre: the taxable income is the amount on line 360 or line Z of the T2 return **plus** the total amount not required to be included, or **minus** the total amount not allowed to be deducted, in calculating the corporation's income under section 33.1 of the federal *Income Tax Act*. This does not apply to tax years starting after March 20, 2013.

*** For corporations other than those described under Regulation 402, use the appropriate calculation described in the Regulations to allocate taxable income.

Notes:

1. After determining the allocation of taxable income, you have to calculate the corporation's provincial or territorial tax payable. For more information on how to calculate the tax for each province or territory, see the instructions for Schedule 5 in the *T2 Corporation – Income Tax Guide*.
2. If the corporation has provincial or territorial tax payable, complete Part 2.

Part 2 – Ontario tax payable, tax credits, and rebates

Total taxable income	Income eligible for small business deduction	Provincial or territorial allocation of taxable income	Provincial or territorial tax payable before credits
3,865,658		3,865,658	444,551

Description	Line	Amount		Amount	Ref
Ontario basic income tax (from Schedule 500)	270	444,551			
Deduct: Ontario small business deduction (from Schedule 500)	402				
Subtotal		444,551	►	444,551	A6
Add:					
Ontario additional tax re Crown royalties (from Schedule 504)	274				
Ontario transitional tax debits (from Schedule 506)	276				
Recapture of Ontario research and development tax credit (from Schedule 508)	277				
Subtotal			►		B6
Subtotal (amount A6 **plus** amount B6)				444,551	C6
Deduct:					
Ontario resource tax credit (from Schedule 504)	404				
Ontario tax credit for manufacturing and processing (from Schedule 502)	406				
Ontario foreign tax credit (from Schedule 21)	408				
Ontario credit union tax reduction (from Schedule 500)	410				
Ontario transitional tax credits (from Schedule 506)	414				
Ontario political contributions tax credit (from Schedule 525)	415				
Subtotal			►		D6
Subtotal (amount C6 **minus** amount D6) (if negative, enter "0")				444,551	E6
Deduct: Ontario research and development tax credit (from Schedule 508)	416				
Ontario corporate income tax payable before Ontario corporate minimum tax credit and Ontario community food program donation tax credit for farmers (amount E6 **minus** amount on line 416) (if negative, enter "0")				444,551	F6
Deduct:					
Ontario corporate minimum tax credit (from Schedule 510)	418				
Ontario community food program donation tax credit for farmers (from Schedule 2)	420				
Ontario corporate income tax payable (amount F6 **minus** amounts on line 418 and line 420) (if negative, enter "0")				444,551	G6
Add:					
Ontario corporate minimum tax (from Schedule 510)	278				
Ontario special additional tax on life insurance corporations (from Schedule 512)	280				
Subtotal			►		H6
Total Ontario tax payable before refundable credits (amount G6 **plus** amount H6)				444,551	I6
Deduct:					
Ontario qualifying environmental trust tax credit	450				
Ontario co-operative education tax credit (from Schedule 550)	452	3,000			
Ontario apprenticeship training tax credit (from Schedule 552)	454	13,644			
Ontario computer animation and special effects tax credit (from Schedule 554)	456				
Ontario film and television tax credit (from Schedule 556)	458				
Ontario production services tax credit (from Schedule 558)	460				
Ontario interactive digital media tax credit (from Schedule 560)	462				
Ontario sound recording tax credit (from Schedule 562)	464				
Ontario book publishing tax credit (from Schedule 564)	466				
Ontario innovation tax credit (from Schedule 566)	468				
Ontario business-research institute tax credit (from Schedule 568)	470				
Subtotal		16,644	►	16,644	J6
Net Ontario tax payable or refundable credit (amount I6 **minus** amount J6) (if a credit, enter a negative amount) Include this amount on line 255.	290			427,907	K6

Summary

Enter the total net tax payable or refundable credits for all provinces and territories on line 255.

Net provincial and territorial tax payable or refundable credits	**255**	427,907

If the amount on line 255 is positive, enter the net provincial and territorial tax payable on line 760 of the T2 return.
If the amount on line 255 is negative, enter the net provincial and territorial refundable tax credits on line 812 of the T2 return.

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Schedule 8

Capital Cost Allowance (CCA)

Corporation's name	Business Number	Tax year end Year Month Day
Canadian Niagara Power Inc.	87249 8225 RC0002	2014-12-31

For more information, see the section called "Capital Cost Allowance" in the *T2 Corporation Income Tax Guide*.

Is the corporation electing under *Regulation* 1101(5q)? **101** 1 Yes [ ] 2 No [X]

	1 Class number (See Note) 200	Description	2 Undepreciated capital cost at the beginning of the year (amount from column 12 of last year's schedule 8) 201	3 Cost of acquisitions during the year (new property must be available for use)* 203	4 Adjustments and transfers** 205	5 Proceeds of dispositions during the year (amount not to exceed the capital cost) 207	6 50% rule (1/2 of the amount, if any, by which the net cost of acquisitions exceeds column 5)*** 211	7 Reduced undepreciated capital cost	8 CCA rate % **** 212	9 Recapture of capital cost allowance***** (line 107 of Schedule 1) 213	10 Terminal loss (line 404 of Schedule 1) 215	11 Capital cost allowance (for declining balance method, column 7 **multiplied** by column 8, or a lower amount) (line 403 of Schedule 1) ****** 217	12 Undepreciated capital cost at the end of the year (column 6 **plus** column 7 **minus** column 11) 220
1.	1		31,067,315			0		31,067,315	4	0	0	1,242,693	29,824,622
2.	1b	Building > Mar 18, 2007	383,653	15,885		0	7,943	391,595	6	0	0	23,496	376,042
3.	2		1,531,339			0		1,531,339	6	0	0	91,880	1,439,459
4.	3		58,314			0		58,314	5	0	0	2,916	55,398
5.	8		351,806	214,282		0	107,141	458,947	20	0	0	91,789	474,299
6.	10		1,237,715	818,068		0	409,034	1,646,749	30	0	0	494,025	1,561,758
7.	12		702,751	1,068,469		0	534,235	1,236,985	100	0	0	1,236,985	534,235
8.	13	Leasehold Improvements	158,235			0		158,235	NA	0	0	61,780	96,455
9.	45	Computers > 22-03-04 & < 19-(	4,297			0		4,297	45	0	0	1,934	2,363
10.	46	System Supervisory processing e	103			0		103	30	0	0	31	72
11.	47		37,676,421	4,211,121		87,745	2,061,688	39,738,109	8	0	0	3,179,049	38,620,748
12.	50	Computers > Mar 18, 2007	368,915	272,714		0	136,357	505,272	55	0	0	277,900	363,729
		Totals	73,540,864	6,600,539		87,745	3,256,398	76,797,260				6,704,478	73,349,180

Note: Class numbers followed by a letter indicate the basic rate of the class taking into account the additional deduction allowed.
Class 1a: 4% + 6% = 10% (class 1 to 10%), class 1b: 4% + 2% = 6% (class 1 to 6%).

* Include any property acquired in previous years that has now become available for use. This property would have been previously excluded from column 3. List separately any acquisitions that are not subject to the 50% rule, see *Regulation* 1100(2) and (2.2).

** Enter in column 4, "Adjustments and transfers", amounts that increase or reduce the undepreciated capital cost.
Items that **increase** the undepreciated capital cost include amounts transferred under section 85, or transferred on amalgamation or winding-up of a subsidiary. Items that **reduce** the undepreciated capital cost include government assistance received or entitled to be received in the year, or a reduction of capital cost after the application of section 80. See the *T2 Corporation Income Tax Guide* for other examples of adjustments and transfers to include in column 4.

*** The net cost of acquisitions is the cost of acquisitions (column 3) **plus** or **minus** certain adjustments and transfers from column 4. For exceptions to the 50% rule, see Interpretation Bulletin IT-285, *Capital Cost Allowance – General Comments*.

**** Enter a rate only if you are using the declining balance method. For any other method (for example the straight-line method, where calculations are always based on the cost of acquisitions), enter N/A. Then enter the amount you are claiming in column 11.

***** For every entry in column 9, the "Recapture of capital cost allowance" there must be a corresponding entry in column 5, "Proceeds of dispositions during the year". The recapture and terminal loss rules do not apply to passenger vehicles in Class 10.1.

****** If the tax year is shorter than 365 days, prorate the CCA claim. Some classes of property do not have to be prorated. See the *T2 Corporation Income Tax Guide* for more information.

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SCHEDULE 9

RELATED AND ASSOCIATED CORPORATIONS

Name of corporation	Business Number	Tax year end Year Month Day
Canadian Niagara Power Inc.	87249 8225 RC0002	2014-12-31

- Complete this schedule if the corporation is related to or associated with at least one other corporation.
- For more information, see the *T2 Corporation Income Tax Guide*.

	Name 100	Country of residence (other than Canada) 200	Business number (see note 1) 300	Relationship code (see note 2) 400	Number of common shares you own 500	% of common shares you own 550	Number of preferred shares you own 600	% of preferred shares you own 650	Book value of capital stock 700
1.	1228158 Ontario Limited		88706 8690 RC0001	3					
2.	1606059 Ontario Inc.		86184 9107 RC0001	3					
3.	52905 Newfoundland and Labrador		80392 9546 RC0001	3					
4.	630319 BC Ltd.		87011 0616 RC0001	3					
5.	Advanced Energy Technologies, Inc	US	NR	3					
6.	Algoma Power Inc.		82249 4290 RC0001	3					
7.	BC Gas (Argentina) S.A.	AR	NR	3					
8.	BC Gas (Malaysia) SDN. BHDS.A.	MY	NR	3					
9.	BC Gas International (Middle East)		89059 8022 RC0001	3					
10.	BC Gas International Projects Ltd.		86892 1644 RC0001	3					
11.	Belize Electric Company Limited	BZ	NR	3					
12.	Caribbean Utilities Company, Ltd.	KY	NR	3					
13.	Central Hudson Enterprise Corp.	US	NR	3					
14.	Central Hudson Gas & Electric Corp.	US	NR	3					
15.	CH Energy Group Inc.	US	NR	3					
16.	Color Acquisition Sub Inc.	US	NR	3					
17.	Cornwall Street Railway Light and P		12090 6839 RC0001	3					
18.	Escavada Company	US	NR	3					
19.	ESI Power-Walden Corporation		12628 4249 RC0001	3					
20.	Fortis Cayman Inc.	KY	NR	3					
21.	Fortis Energy (Bermuda) Ltd.	BM	NR	3					
22.	Fortis Energy (International) Belize	BZ	NR	3					
23.	Fortis Energy Cayman Inc.	KY	NR	3					
24.	Fortis Energy Corporation (NCLA)		10386 4443 RC0001	3					
25.	Fortis Generation East GP Inc		83966 8308 RC0001	3					
26.	Fortis Generation Inc		83967 1096 RC0001	3					
27.	Fortis Generation Similkameen GP I		83496 7838 RC0001	3					
28.	Fortis Hydro Corporation		NR	3					
29.	Fortis Inc.		10185 2416 RC0001	3					
30.	Fortis Properties Corporation		89693 2449 RC0001	3					
31.	Fortis US Energy Corporation	US	NR	3					
32.	Fortis West Inc.		87470 8209 RC0001	3					
33.	FortisAlberta Holdings Inc.		86921 0203 RC0001	3					
34.	FortisAlberta Inc.		86929 4520 RC0001	3					
35.	FortisBC Alternative Energy Services		81144 5873 RC0001	3					
36.	FortisBC Energy (Vancouver Island)		12174 3074 RC0001	3					
37.	FortisBC Energy (Whistler) Inc.		89138 9652 RC0001	3					
38.	FortisBC Energy Inc.		10043 1592 RC0004	3					
39.	FortisBC Holdings Inc.		10534 9740 RC0004	3					
40.	FortisBC Huntington Inc.		12974 2870 RC0001	3					
41.	FortisBC Inc.		10564 5642 RC0001	3					
42.	FortisBC Pacific Holdings Inc.		87170 9101 RC0001	3					
43.	FortisBC Storage Inc.		86014 6588 RC0001	3					

	Name 100	Country of residence (other than Canada) 200	Business number (see note 1) 300	Relationship code (see note 2) 400	Number of common shares you own 500	% of common shares you own 550	Number of preferred shares you own 600	% of preferred shares you own 650	Book value of capital stock 700
44.	FortisLUX Holdings Inc. (CBCA)		82293 1242 RC0001	3					
45.	FortisOntario District Heating Inc.		89329 1740 RC0001	3					
46.	FortisOntario Inc.		10076 8985 RC0003	1					
47.	FortisTCI Limited	TC	NR	3					
48.	FortisUS Holdings Nova Scotia Limit		82872 6091 RC0001	3					
49.	FortisUS Inc.	US	NR	3					
50.	Griffith Energy Services Inc.	US	NR	3					
51.	Inland Energy Corp.		11960 8529 RC0001	3					
52.	Inland Pacific Energy Services		10249 0554 RC0001	3					
53.	Maritime Electric Cayman Inc.	KY	NR	3					
54.	Maritime Electric Company, Limited		12111 9879 RC0001	3					
55.	MEH Equities Management, Inc.	US	NR	3					
56.	Millennium Energy Holdings, Inc.	US	NR	3					
57.	Mt. Hayes (GP) Ltd.		84888 3914 RC0001	3					
58.	Newfoundland Electric Company Lin		12748 1059 RC0001	3					
59.	Newfoundland Energy Cayman Inc.	KY	NR	3					
60.	Newfoundland Energy Luxembourg	LU	NR	3					
61.	Newfoundland Industries Limited		87536 2774 RC0001	3					
62.	Newfoundland Power Inc.		10386 4831 RC0001	3					
63.	Powertrusion Intarnational, Inc.	US	NR	3					
64.	San Carlos Resources Inc.	US	NR	3					
65.	Southwest Energy Solutions, Inc.	US	NR	3					
66.	Terasen Gas Holdings Inc.		86602 7832 RC0002	3					
67.	Terasen International Inc.		13237 5346 RC0001	3					
68.	The Gananoque Water Power Comp		10521 4068 RC0001	3					
69.	Tucson Electric Power Company	US	NR	3					
70.	Tucsonel Inc.	US	NR	3					
71.	Turks and Caicos Utilities Limited	TC	NR	3					
72.	Unisource Energy Development Con	US	NR	3					
73.	Unisource Energy Services, Inc.	US	NR	3					
74.	UNS Electric, Inc.	US	NR	3					
75.	UNS Energy Corporation	US	NR	3					
76.	UNS Gas, Inc.	US	NR	3					
77.	Waneta Expansion General Partner		84815 4001 RC0001	3					
78.	West Kootenay Power Ltd.		89427 8670 RC0001	3					

Note 1: Enter "NR" if the corporation is not registered or does not have a business number.

Note 2: Enter the code number of the relationship that applies from the following order: 1 - Parent 2 - Subsidiary 3 - Associated 4 - Related but not associated

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SCHEDULE 10

CUMULATIVE ELIGIBLE CAPITAL DEDUCTION

Name of corporation	Business Number	Tax year-end Year Month Day
Canadian Niagara Power Inc.	87249 8225 RC0002	2014-12-31

- For use by a corporation that has eligible capital property. For more information, see the *T2 Corporation Income Tax Guide*.
- A separate cumulative eligible capital account must be kept for each business.

Part 1 – Calculation of current year deduction and carry-forward

Cumulative eligible capital - Balance at the end of the preceding taxation year (if negative, enter "0")			200	98,218 A
Add: Cost of eligible capital property acquired during the taxation year	222			
Other adjustments	226			
Subtotal (line 222 plus line 226)		x 3 / 4 = B		
Non-taxable portion of a non-arm's length transferor's gain realized on the transfer of an eligible capital property to the corporation after December 20, 2002	228	x 1 / 2 = C		
amount B minus amount C (if negative, enter "0")		▶		D
Amount transferred on amalgamation or wind-up of subsidiary			224	E
Subtotal (add amounts A, D, and E)			230	98,218 F
Deduct: Proceeds of sale (less outlays and expenses not otherwise deductible) from the disposition of all eligible capital property during the taxation year	242	G		
The gross amount of a reduction in respect of a forgiven debt obligation as provided for in subsection 80(7)	244	H		
Other adjustments	246	I		
(add amounts G,H, and I)		x 3 / 4 =	248	J
Cumulative eligible capital balance (amount F minus amount J)				98,218 K
(if amount K is negative, enter "0" at line M and proceed to Part 2)				
Cumulative eligible capital for a property no longer owned after ceasing to carry on that business		249		
amount K	98,218			
less amount from line 249				
Current year deduction	98,218 x 7.00 % =	250	6,875 *	
(line 249 plus line 250) (enter this amount at line 405 of Schedule 1)			6,875 ▶	6,875 L
Cumulative eligible capital – Closing balance (amount K minus amount L) (if negative, enter "0")			300	91,343 M

* You can claim any amount up to the maximum deduction of 7%. The deduction may not exceed the maximum amount prorated by the number of days in the taxation year divided by 365.

Part 2 – Amount to be included in income arising from disposition

(complete this part only if the amount at line K is negative)

Amount from line K (show as positive amount)						N
Total of cumulative eligible capital (CEC) deductions from income for taxation years beginning after June 30, 1988			**400**		1	
Total of all amounts which reduced CEC in the current or prior years under subsection 80(7)			**401**		2	
Total of CEC deductions claimed for taxation years beginning before July 1, 1988	**402**		3			
Negative balances in the CEC account that were included in income for taxation years beginning before July 1, 1988	**408**		4			
Line 3 minus line 4 (if negative, enter "0")			▶		5	
Total of lines 1, 2 and 5					6	
Amounts included in income under paragraph 14(1)(b), as that paragraph applied to taxation years ending after June 30, 1988 and before February 28, 2000, to the extent that it is for an amount described at line 400			7			
Amounts at line T from Schedule 10 of previous taxation years ending after February 27, 2000			8			
Subtotal (line 7 plus line 8)	**409**		▶		9	
Line 6 minus line 9 (if negative, enter "0")					▶	O
Line N minus line O (if negative, enter "0")						P
			Line 5		x 1 / 2 =	Q
Line P minus line Q (if negative, enter "0")						R
			Amount R		x 2 / 3 =	S
Amount N or amount O, whichever is less						T
Amount to be included in income (amount S plus amount T) (enter this amount on line 108 of Schedule 1)					**410**	

Continuity of financial statement reserves (not deductible)

Financial statement reserves (not deductible)

	Description	Balance at the beginning of the year	Transfer on an amalgamation or the wind-up of a subsidiary	Add	Deduct	Balance at the end of the year
1	Deferred Pension Asset GL 150(	-1,086,029		-1,140,936	-519,506	-1,707,459
2	Deferred Post Retirement Bene	6,497,300		470,600	289,479	6,678,421
3						
	Reserves from Part 2 of Schedule 13					
	Totals	5,411,271		-670,336	-230,027	4,970,962

The total opening balance plus the total transfers should be entered on line 414 of Schedule 1 as a deduction.
The total closing balance should be entered on line 126 of Schedule 1 as an addition.

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Schedule 31

Investment Tax Credit – Corporations

General information

- Use this schedule:
  - to calculate an investment tax credit (ITC) earned during the tax year;
  - to claim a deduction against Part I tax payable;
  - to claim a refund of credit earned during the current tax year;
  - to claim a carryforward of credit from previous tax years;
  - to transfer a credit following an amalgamation or wind-up of a subsidiary, as described under subsections 87(1) and 88(1) of the federal *Income Tax Act*;
  - to request a credit carryback to one or more previous years; or
  - if you are subject to a recapture of ITC.
- The ITC is eligible for a three-year carryback (if not deductible in the year earned). It is also eligible for a twenty-year carryforward.
- All legislative references are to the federal *Income Tax Act* and *Income Tax Regulations*.
- Investments or expenditures, described in subsection 127(9) of the Act and Part XLVI of the Regulations, that earn an ITC are:
  - qualified property and qualified resource property (Parts 4 to 7 of this schedule);
  - expenditures that are part of the SR&ED qualified expenditure pool (Parts 8 to 17). File Form T661, *Scientific Research and Experimental Development (SR&ED) Expenditures Claim;*
  - pre-production mining expenditures (Parts 18 to 20);
  - apprenticeship job creation expenditures (Parts 21 to 23); and
  - child care spaces expenditures (Parts 24 to 28).
- Include a completed copy of this schedule with the *T2 Corporation Income Tax Return*. If you need more space, attach additional schedules.
- For more information on ITCs, see "Investment Tax Credit" in Guide T4012, *T2 Corporation – Income Tax Guide*, Information Circular IC 78-4, *Investment Tax Credit Rates*, and its related Special Release.
- For more information on SR&ED, see Brochure RC4472, *Overview of the Scientific Research and Experimental Development Program (SR&ED) Tax Incentive Program*; Brochure RC4467, *Support for your R&D in Canada*, and T4088, *Guide to Form T661 – Scientific Research and Experimental Development (SR&ED) Expenditures Claim*. Also see the *Eligibility of Work for SR&ED Investment Tax Credits Policy* at **www.cra.gc.ca/txcrdt/sred-rsde/clmng/lgbltywrkfrsrdnvstmnttxcrdts-eng.html**.

Detailed information

- For the purpose of this schedule, **investment** means the capital cost of the property (excluding amounts added by an election under section 21 of the Act), determined without reference to subsections 13(7.1) and 13(7.4), minus the amount of any government or non-government assistance that the corporation has received, is entitled to receive, or can reasonably be expected to receive for that property when it files the income tax return for the year in which the property was acquired.
- An ITC deducted or refunded in a tax year for a depreciable property, other than a depreciable property deductible under paragraph 37(1)(b), reduces the capital cost of that property in the next tax year. It also reduces the undepreciated capital cost of that class in the next tax year. An ITC for SR&ED deducted or refunded in a tax year will reduce the balance in the pool of deductible SR&ED expenditures and the adjusted cost base (ACB) of an interest in a partnership in the next tax year. An ITC from pre-production mining expenditures deducted in a tax year reduces the balance in the pool of deductible cumulative Canadian exploration expenses in the next tax year.
- Property acquired has to be **available for use** before a claim for an ITC can be made. See subsections 127(11.2) and 248(19) for more information.
- Expenditures for SR&ED and capital costs for a property qualifying for an ITC must be identified by the claimant on Form T661 and Schedule 31 no later than 12 months after the claimant's income tax return is due for the tax year in which it incurred the expenditures or capital costs.
- Partnership allocations – Subsection 127(8) provides for the allocation of the amount that may reasonably be considered to be a partner's share of the ITCs of the partnership at the end of the fiscal period of the partnership. An allocation of ITCs is generally considered to be the partner's reasonable share of the ITCs if it is made in the same proportion in which the partners have agreed to share any income or loss and if section 103 is not applicable for the agreement to share any income or loss. Special rules apply to specified and limited partners. For more information, see Guide T4068, *Guide for the Partnership Information Return*.
- For SR&ED expenditures, the expression **in Canada** includes the "exclusive economic zone" (as defined in the *Oceans Act* to generally consist of an area that is within 200 nautical miles from the Canadian coastline), including the airspace, seabed and subsoil for that zone.
- For the purpose of this schedule, the expression **Atlantic Canada** includes the Gaspé Peninsula and the provinces of Newfoundland and Labrador, Prince Edward Island, Nova Scotia, and New Brunswick, as well as their respective offshore regions (prescribed in Regulation 4609).
- For the purpose of this schedule, **qualified property** means property in Atlantic Canada that is used primarily for manufacturing and processing, farming or fishing, logging, storing grain, or harvesting peat. Property in Atlantic Canada that is used primarily for oil and gas, and mining activities is considered qualified property only if acquired by the taxpayer **before** March 29, 2012. Qualified property includes new buildings and new machinery and equipment (prescribed in Regulation 4600), and if acquired by the taxpayer **after** March 28, 2012, new energy generation and conservation property (prescribed in Regulation 4600). Qualified property can also be used primarily to produce or process electrical energy or steam in a prescribed area (as described in Regulation 4610). See the definition of **qualified property** in subsection 127(9) of the Act for more information.
- For the purpose of this schedule, **qualified resource property** means property in Atlantic Canada that is used primarily for oil and gas, and mining activities, if acquired by the taxpayer **after** March 28, 2012, and **before** January 1, 2016. Qualified resource property includes new buildings and new machinery and equipment (prescribed in Regulation 4600). See the definition of **qualified resource property** in subsection 127(9) of the Act for more information.

Detailed information (continued)

- For the purpose of this schedule, **pre-production mining exploration expenditures** are pre-production mining expenditures incurred **after** March 28, 2012, by the taxpayer to determine the existence, location, extent, or quality of certain mineral resources in Canada, excluding expenses incurred in the exploration of an oil or gas well. See subparagraph (a)(i) of the definition of **pre-production mining expenditure** in subsection 127(9) for more information.
- For the purpose of this schedule, **pre-production mining development expenditures** are pre-production mining expenditures incurred **after** March 28, 2012, by the taxpayer to bring a new mineral resource mine in Canada into production, excluding expenses in the development of a bituminous sands deposit or an oil shale deposit. See subparagraph (a)(ii) of the definition of **pre-production mining expenditure** in subsection 127(9) for more information.

Part 1 – Investments, expenditures, and percentages

Investments	**Specified percentage**
Qualified property acquired primarily for use in Atlantic Canada	10 %
Qualified resource property acquired primarily for use in Atlantic Canada and acquired:	
– after March 28, 2012, and before 2014	10 %
– after 2013 and before 2016	5 %
– after 2015*	0 %
Expenditures	
If you are a Canadian-controlled private corporation (CCPC), this percentage may apply to the portion that you claim of the SR&ED qualified expenditure pool that does not exceed your expenditure limit (see Part 10)	35 %
Note: If your current year's qualified expenditures are more than the corporation's expenditure limit (see Part 10), the excess is eligible for an ITC calculated at the 20 % rate**.	
If you are a corporation that is not a CCPC and have incurred qualified expenditures for SR&ED in any area in Canada:	
– before 2014**	20 %
– after 2013**	15 %
If you are a taxable Canadian corporation that incurred pre-production mining expenditures before March 29, 2012	10 %
If you are a taxable Canadian corporation that incurred pre-production mining exploration expenditures***:	
– after March 28, 2012, and before 2013	10 %
– in 2013	5 %
– after 2013***	0 %
If you are a taxable Canadian corporation that incurred pre-production mining development expenditures****:	
– after March 28, 2012, and before 2014****	10 %
– in 2014	7 %
– in 2015	4 %
– after 2015****	0 %
If you paid salary and wages to apprentices in the first 24 months of their apprenticeship contract for employment	10 %
If you incurred eligible expenditures after March 18, 2007, for the creation of licensed child care spaces for the children of your employees and, potentially, for other children	25 %

* A transitional relief rate of 10% may apply to property acquired after 2013 and before 2017, if the property is acquired under a written agreement entered into before March 29, 2012, or the property is acquired as part of a **phase** of a project where the construction or the engineering and design work for the construction started before March 29, 2012. See paragraph (a.1) of the definition of **specified percentage** in subsection 127(9) for more information.

** The reduction of the rate from 20% to 15% applies to 2014 and later tax years, except that, for 2014 tax years that start before 2014, the reduction is pro-rated based on the number of days in the tax year that are after 2013.

*** Pre-production mining exploration expenditures are described in subparagraph (a)(i) of the definition of **pre-production mining expenditure** in subsection 127(9).

**** A transitional relief rate of 10% may apply to expenditures incurred after 2013 and before 2016, if the expenditure is incurred under a written agreement entered into before March 29, 2012, or the expenditure is incurred as part of the development of a new mine where the construction or the engineering and design work for the construction of the new mine started before March 29, 2012. See subparagraph (k)(ii) of the definition of **specified percentage** in subsection 127(9) for more information. Pre-production mining development expenditures are described in subparagraph (a)(ii) of the definition of **pre-production mining expenditure** in subsection 127(9).

Corporation's name	Business number	Tax year-end Year Month Day
Canadian Niagara Power Inc.	87249 8225 RC0002	2014-12-31

Part 2 – Determination of a qualifying corporation

Is the corporation a qualifying corporation? . . . . **101** 1 Yes [ ] 2 No [X]

For the purpose of a refundable ITC, a **qualifying corporation** is defined under subsection 127.1(2). The corporation has to be a CCPC and its taxable income (before any loss carrybacks) for its previous tax year cannot be more than its **qualifying income limit** for the particular tax year. If the corporation is associated with any other corporations during the tax year, the total of the taxable incomes of the corporation and the associated corporations (before any loss carrybacks), for their last tax year ending in the previous calendar year, cannot be more than their qualifying income limit for the particular tax year.

Note: A CCPC calculating a refundable ITC is considered to be associated with another corporation if it meets any of the conditions in subsection 256(1), except where:

- one corporation is associated with another corporation solely because one or more persons own shares of the capital stock of both corporations; and
- one of the corporations has at least one shareholder who is not common to both corporations.

If you are a **qualifying** corporation, you will earn a **100%** refund on your share of any ITCs earned at the 35% rate on qualified **current** expenditures for SR&ED, up to the allocated expenditure limit. The 100% refund does not apply to qualified **capital** expenditures eligible for the 35% credit rate. They are only eligible for the **40%** refund*.

Some CCPCs that are **not qualifying** corporations may also earn a **100%** refund on their share of any ITCs earned at the 35% rate on qualified **current** expenditures for SR&ED, up to the allocated expenditure limit. The expenditure limit can be determined in Part 10. The 100% refund does not apply to qualified **capital** expenditures eligible for the 35% credit rate. They are only eligible for the **40%** refund*.

The 100% refund will not be available to a corporation that is an **excluded corporation** as defined under subsection 127.1(2). A corporation is an excluded corporation if, at any time during the year, it is a corporation that is either controlled by (directly or indirectly, in any manner whatever) or is related to:

a) one or more persons exempt from Part I tax under section 149;

b) Her Majesty in right of a province, a Canadian municipality, or any other public authority; or

c) any combination of persons referred to in a) or b) above.

* Capital expenditures incurred after December 31, 2013, including lease payments for property that would have been a capital expenditure if purchased directly, are **not** qualified SR&ED expenditures and are **not** eligible for an ITC on SR&ED expenditures.

Part 3 – Corporations in the farming industry

Complete this area if the corporation is making SR&ED contributions.

Is the corporation claiming a contribution in the current year to an agricultural organization whose goal is to finance SR&ED work (for example, check-off dues)? . . . . **102** 1 Yes [ ] 2 No [X]

Contributions to agricultural organizations for SR&ED* . . . . **103** ______

If **yes**, complete Schedule 125, *Income Statement Information*, to identify the type of farming industry the corporation is involved in. For more information on Schedule 125, see Guide RC4088, *General Index of Financial Information (GIFI)*. Enter contributions on line 350 of Part 8.

* Enter only contributions not already included on Form T661. Include all of the contributions made before 2013 and 80% of the contributions made after 2012.

Qualified Property and Qualified Resource Property

Part 4 – Eligible investments for qualified property and qualified resource property from the current tax year

CCA* class number **105**	Description of investment **110**	Date available for use **115**	Location used (province or territory) **120**	Amount of investment **125**
			Total of investments for qualified property and qualified resource property	A

* CCA: capital cost allowance

Part 5 – Current-year credit and account balances – ITC from investments in qualified property and qualified resource property

ITC at the end of the previous tax year				B
Deduct:				
Credit deemed as a remittance of co-op corporations	210			
Credit expired	215			
Subtotal (line 210 **plus** line 215)			▶	C
ITC at the beginning of the tax year (amount B **minus** amount C)			220	
Add:				
Credit transferred on amalgamation or wind-up of subsidiary	230			
ITC from repayment of assistance	235			
Qualified property; and qualified resource property acquired after March 28, 2012, and before January 1, 2014* (applicable part of amount A from Part 4) ______ x 10 % =	240			
Qualified resource property acquired after December 31, 2013, and before January 1, 2016 (applicable part of amount A from Part 4) ______ x 5 % =	242			
Credit allocated from a partnership	250			
Subtotal (total of lines 230 to 250)			▶	D
Total credit available (line 220 **plus** amount D)				E
Deduct:				
Credit deducted from Part I tax (enter at amount D in Part 30)	260			
Credit carried back to the previous year(s) (amount H from Part 6)		a		
Credit transferred to offset Part VII tax liability	280			
Subtotal (total of line 260, amount a, and line 280)			▶	F
Credit balance before refund (amount E **minus** amount F)				G
Deduct:				
Refund of credit claimed on investments from qualified property and qualified resource property (from Part 7)			310	
ITC closing balance of investments from qualified property and qualified resource property (amount G **minus** line 310)			320	

* Include investments acquired after 2013 and before 2017 that are eligible for transitional relief.

Part 6 – Request for carryback of credit from investments in qualified property and qualified resource property

	Year	Month	Day			
1st previous tax year				Credit to be applied	901	
2nd previous tax year				Credit to be applied	902	
3rd previous tax year				Credit to be applied	903	
				Total (enter at amount a in Part 5)		H

Part 7 – Refund of ITC for qualifying corporations on investments from qualified property and qualified resource property

Current-year ITCs (total of lines 240, 242, and 250 from Part 5)		I
Credit balance before refund (amount G from Part 5)		J
Refund (40 % of amount I or J, whichever is less)		K

Enter amount K or a lesser amount on line 310 in Part 5 (also enter it on line 780 of the T2 return if the corporation does not claim an SR&ED ITC refund).

SR&ED

Part 8 – Qualified SR&ED expenditures

Current expenditures

Current expenditures (from line 557 on Form T661) . . . . ______

Contributions to agricultural organizations for SR&ED . . . . ______

Deduct:

Government assistance, non-government assistance, or contract payment . . . . ______

Contributions to agricultural organizations for SR&ED for the federal ITC (this amount is updated to line 103 of Part 3. For more details, consult the Help.)* . . . . ______ ► + ______

Current expenditures (line 557 on Form T661 **plus** line 103 from Part 3)* . . . . ______ ► **350** ______

Capital expenditures incurred **before** 2014 (from line 558 on Form T661)** . . . . **360** ______

Repayments made in the year (from line 560 on Form T661) . . . . **370** ______

Qualified SR&ED expenditures (total of lines 350 to 370) . . . . **380** ______

* If you are claiming only contributions made to agricultural organizations for SR&ED, line 350 should equal line 103 in Part 3. Do not file Form T661.

** Capital expenditures incurred after December 31, 2013, are not qualified SR&ED expenditures.

Part 9 – Components of the SR&ED expenditure limit calculation

Part 9 only applies if the corporation is a CCPC.

Note: A CCPC that calculates an SR&ED expenditure limit is considered to be associated with another corporation if it meets any of the conditions in subsection 256(1), except where:

- one corporation is associated with another corporation solely because one or more persons own shares of the capital stock of the corporation; and
- one of the corporations has at least one shareholder who is not common to both corporations.

Is the corporation associated with another CCPC for the purpose of calculating the SR&ED expenditure limit? . . . . **385** 1 Yes ☐ 2 No ☐

Complete lines 390 and 398 if you answered **no** to the question at line 385 above or if the corporation is not associated with any other corporations (the amounts for associated corporations will be determined on Schedule 49).

Enter your taxable income for the previous tax year* (prior to any loss carry-backs applied) . . . . **390** ______

Enter your taxable capital employed in Canada for the previous tax year minus $10 million. If this amount is nil or negative, enter "0". If this amount is over $40 million, enter $40 million . . . . **398** ______

* If either of the tax years referred to at line 390 is less than 51 weeks, **multiply** the taxable income by the following result: 365 **divided** by the number of days in these tax years.

Part 10 – SR&ED expenditure limit for a CCPC

For a stand-alone corporation: $ **8,000,000**

Deduct:

Taxable income for the previous tax year (line 390 from Part 9) or $500,000, whichever is more ______ x 10 = ______ A

Excess ($8,000,000 **minus** amount A; if negative, enter "0") . . . . ______ B

$ 40,000,000 **minus** line 398 from Part 9 . . . . ______ a

Amount a **divided** by $ 40,000,000 . . . . ______ C

Expenditure limit for the stand-alone corporation (amount B **multiplied** by amount C) . . . . ______ D*

For an associated corporation:

If associated, the allocation of the SR&ED expenditure limit as provided on Schedule 49 . . . . **400** ______ E*

Where the tax year of the corporation is less than 51 weeks, calculate the amount of the expenditure limit as follows:

Amount D or E ______ x $\frac{\text{Number of days in the tax year}}{365}$ 365 = ... ______ F

Your SR&ED expenditure limit for the year (enter the amount from line D, E, or F, whichever applies) . . . . **410** ______

* Amount D or E cannot be more than $3,000,000.

Part 11 – Investment tax credits on SR&ED expenditures

Current expenditures (line 350 from Part 8) or the expenditure limit (line 410 from Part 10), whichever is less*	420		x	35 %	=	G
Line 350 **minus** line 410 (if negative, enter "0")**	430		x	15 %	=	H
Line 410 **minus** line 350 (if negative, enter "0")			b			
Capital expenditures (line 360 from Part 8) or amount b above, whichever is less*	440		x	35 %	=	I
Line 360 **minus** amount b above (if negative, enter "0")**	450		x	15 %	=	J

Repayments (amount from line 370 in Part 8)

If a corporation makes a repayment of any government or non-government assistance, or contract payments that reduced the amount of qualified expenditures for ITC purposes, the amount of the repayment is eligible for a credit at the rate that would have applied to the repaid amount. Enter the amount of the repayment on the line that corresponds to the appropriate rate.**

460		x	35 %	=	c
480		x	15 %	=	d

Subtotal (amount c **plus** amount d) ▶ K

Current-year SR&ED ITC (total of amounts G to K; enter on line 540 in Part 12) L

* For corporations that are not CCPCs, enter "0" for amounts G and I.

** For tax years that end after 2013, the general SR&ED rate is reduced from 20% to 15%, except that, for 2014 tax years that start before 2014, the reduction is pro-rated based on the number of days in the tax year that are after 2013.

Part 12 – Current-year credit and account balances – ITC from SR&ED expenditures

ITC at the end of the previous tax year M

Deduct:

Credit deemed as a remittance of co-op corporations 510

Credit expired 515

Subtotal (line 510 **plus** line 515) ▶ N

ITC at the beginning of the tax year (amount M **minus** amount N) 520

Add:

Credit transferred on amalgamation or wind-up of subsidiary 530

Total current-year credit (from amount L in Part 11) 540

Credit allocated from a partnership 550

Subtotal (total of lines 530 to 550) ▶ O

Total credit available (line 520 **plus** amount O) P

Deduct:

Credit deducted from Part I tax (enter at amount E in Part 30) 560

Credit carried back to the previous year(s) (amount S from Part 13) e

Credit transferred to offset Part VII tax liability 580

Subtotal (total of line 560, amount e, and line 580) ▶ Q

Credit balance before refund (amount P **minus** amount Q) R

Deduct:

Refund of credit claimed on SR&ED expenditures (from Part 14 or 15, whichever applies) 610

ITC closing balance on SR&ED (amount R **minus** line 610) 620

Part 13 – Request for carryback of credit from SR&ED expenditures

	Year	Month	Day			
1st previous tax year				Credit to be applied	911	
2nd previous tax year				Credit to be applied	912	
3rd previous tax year				Credit to be applied	913	
				Total (enter at amount e in Part 12)		S

Part 14 – Refund of ITC for qualifying corporations – SR&ED

Complete this part only if you are a qualifying corporation as determined at line 101 in Part 2.

Is the corporation an excluded corporation as defined under subsection 127.1(2)? . . . . . 650 1 Yes [ ] 2 No [X]

Current-year ITC (lines 540 **plus** 550 from Part 12 **minus** amount K from Part 11) . . . . . f

Refundable credits (amount f above or amount R from Part 12, whichever is less)* . . . . . T

Deduct:

Amount T or amount G from Part 11, whichever is less . . . . . U

Net amount (amount T **minus** amount U; if negative, enter "0") V

Amount V **multiplied** by 40 % . . . . . W

Add:

Amount U X

Refund of ITC (amount W **plus** amount X – enter this, or a lesser amount, on line 610 in Part 12) . . . . . Y

Enter the total of lines 310 from Part 5 and 610 from Part 12 on line 780 of the T2 return.

* If you are also an excluded corporation [as defined in subsection 127.1(2)], this amount must be multiplied by 40%. Claim this, or a lesser amount, as your refund of ITC for amount Y.

Part 15 – Refund of ITC for CCPCs that are not qualifying or excluded corporations – SR&ED

Complete this box only if you are a CCPC that is not a qualifying or excluded corporation as determined at line 101 in Part 2.

Credit balance before refund (amount R from Part 12) . . . . . Z

Deduct:

Amount Z or amount G from Part 11, whichever is less . . . . . AA

Net amount (amount Z **minus** amount AA; if negative, enter "0") . . . . . BB

Amount BB or amount I from Part 11, whichever is less CC

Amount CC **multiplied** by 40 % . . . . . DD

Add :

Amount AA . . . . . EE

Refund of ITC (amount DD **plus** amount EE) . . . . . FF

Enter FF, or a lesser amount, on line 610 in Part 12 and also on line 780 of the T2 return.

Recapture – SR&ED

Part 16 – Recapture of ITC for corporations and corporate partnerships – SR&ED

You will have a recapture of ITC in a year when **all** of the following conditions are met:

- you acquired a particular property in the current year or in any of the 20 previous tax years, if the credit was earned in a tax year ending after 1997 and did not expire before 2008;
- you claimed the cost of the property as a qualified expenditure for SR&ED on Form T661;
- the cost of the property was included in calculating your ITC or was the subject of an agreement made under subsection 127(13) to transfer qualified expenditures; and
- you disposed of the property or converted it to commercial use after February 23, 1998. This condition is also met if you disposed of or converted to commercial use a property that incorporates the particular property previously referred to.

Note:

The recapture **does not apply** if you disposed of the property to a non-arm's-length purchaser who intended to use it all or substantially all for SR&ED. When the non-arm's-length purchaser later sells or converts the property to commercial use, the recapture rules will apply to the purchaser based on the historical ITC rate of the original user.

You will report a recapture on the T2 return for the year in which you disposed of the property or converted it to commercial use. In the following tax year, add the amount of the ITC recapture to the SR&ED expenditure pool.

If you have more than one disposition for calculations 1 and 2, complete the columns for each disposition for which a recapture applies, using the calculation formats below.

Calculation 1 – If you meet all of the above conditions

Amount of ITC you originally calculated for the property you acquired, or the original user's ITC where you acquired the property from a non-arm's length party, as described in the note above **700**	Amount calculated using ITC rate at the date of acquisition (or the original user's date of acquisition) on either the proceeds of disposition (if sold in an arm's length transaction) or the fair market value of the property (in any other case) **710**	Amount from column 700 or 710, whichever is less

Subtotal (enter this amount at amount C in Part 17) ______ A

Calculation 2 – Only if you transferred all or a part of the qualified expenditure to another person under an agreement described in subsection 127(13); otherwise, enter nil in amount B in Part 16 on page 9.

A Rate that the transferee used in determining its ITC for qualified expenditures under a subsection 127(13) agreement **720**	B Proceeds of disposition of the property if you dispose of it to an arm's length person; or, in any other case, enter the fair market value of the property at conversion or disposition **730**	C Amount, if any, already provided for in Calculation 1 (This allows for the situation where only part of the cost of a property is transferred under a subsection 127(13) agreement.) **740**

Calculation 2 (continued) – Only if you transferred all or a part of the qualified expenditure to another person under an agreement described in subsection 127(13); otherwise, enter nil in amount B below.

D Amount determined by the formula (A x B) – C	E ITC earned by the transferee for the qualified expenditures that were transferred **750**	F Amount from column D or E, whichever is less

Subtotal (enter this amount at amount D in Part 17) ______ B

Calculation 3

As a member of the partnership, you will report your share of the SR&ED ITC of the partnership after the SR&ED ITC has been reduced by the amount of the recapture. If this amount is a positive amount, you will report it on line 550 in Part 12. However, if the partnership does not have enough ITC otherwise available to offset the recapture, then the amount by which reductions to ITC exceed additions (the excess) will be determined and reported on line 760 below.

Corporate partner's share of the excess of SR&ED ITC (amount to be reported at amount E in Part 17) **760** ______

Part 17 – Total recapture of SR&ED investment tax credit

Recaptured ITC for calculation 1 from amount A in Part 16		C
Recaptured ITC for calculation 2 from amount B in Part 16		D
Recaptured ITC for calculation 3 from line 760 in Part 16		E
Total recapture of SR&ED investment tax credit – total of amounts C to E		F

Enter amount F at amount A in Part 29.

Pre-Production Mining

Part 18 – Pre-production mining expenditures

Exploration information

A mineral resource that qualifies for the credit means a mineral deposit from which the principal mineral to be extracted is diamond, a base or precious metal deposit, or a mineral deposit from which the principal mineral to be extracted is an industrial mineral that, when refined, results in a base or precious metal.

In column 800, list all minerals for which pre-production mining expenditures have taken place in the tax year.

For each of the minerals reported in column 800, identify each project (in column 805), mineral title (in column 806), and mining division (in column 807) where title is registered. If there is no mineral title, identify only the project and mining division.

List of minerals 800	Project name 805

Mineral title 806	Mining division 807

Pre-production mining expenditures*

Exploration:

Pre-production mining expenditures that the corporation incurred in the tax year for the purpose of determining the existence, location, extent, or quality of a mineral resource in Canada:

Prospecting	810	
Geological, geophysical, or geochemical surveys	811	
Drilling by rotary, diamond, percussion, or other methods	812	
Trenching, digging test pits, and preliminary sampling	813	

Development:

Pre-production mining expenditures incurred in the tax year for bringing a new mine in a mineral resource in Canada into production in reasonable commercial quantities and incurred before the new mine comes into production in such quantities:

Clearing, removing overburden, and stripping	820	
Sinking a mine shaft, constructing an adit, or other underground entry	821	

Other pre-production mining expenditures incurred in the tax year:

Description 825	Amount 826

Add amounts in column 826		▶	A
Total pre-production mining expenditures (total of lines 810 to 821 and amount A)	830		

Deduct:

Total of all assistance (grants, subsidies, rebates, and forgivable loans) or reimbursements that the corporation has received or is entitled to receive in respect of the amounts referred to at line 830 above	832		
Excess (line 830 **minus** line 832) (if negative, enter "0")			B

Add:

Repayments of government and non-government assistance	835		
Pre-production mining expenditures (amount B **plus** line 835)			C

* A pre-production mining expenditure is defined under subsection 127(9).

Part 19 – Current-year credit and account balances – ITC from pre-production mining expenditures

ITC at the end of the previous tax year					D
Deduct:					
Credit deemed as a remittance of co-op corporations	841				
Credit expired	845				
Subtotal (line 841 **plus** line 845)			▶		E
ITC at the beginning of the tax year (amount D **minus** amount E)			850		
Add:					
Credit transferred on amalgamation or wind-up of subsidiary			860		
Pre-production mining expenditures* incurred before January 1, 2013 (applicable part of amount C from Part 18)	870	x 10 % =			a
Pre-production mining exploration expenditures incurred in 2013 (applicable part of amount C from Part 18)	872	x 5 % =			b
Pre-production mining development expenditures incurred in 2014 (applicable part of amount C from Part 18)	874	x 7 % =			c
Pre-production mining development expenditures incurred in 2015 (applicable part of amount C from Part 18)	876	x 4 % =			d
Current year credit (total of amounts a to d)	880		▶		F
Total credit available (total of lines 850, 860, and amount F)					G
Deduct:					
Credit deducted from Part I tax (enter at amount F in Part 30)	885				
Credit carried back to the previous year(s) (amount I from Part 20)					e
Subtotal (line 885 **plus** amount e)			▶		H
ITC closing balance from pre-production mining expenditures (amount G **minus** amount H)			890		

* Also include pre-production mining development expenditures incurred before 2014 and pre-production mining development expenditures incurred after 2013 and before 2016 that are eligible for transitional relief.

Part 20 – Request for carryback of credit from pre-production mining expenditures

	Year	Month	Day			
1st previous tax year				Credit to be applied	921	
2nd previous tax year				Credit to be applied	922	
3rd previous tax year				Credit to be applied	923	
				Total (enter at amount e in Part 19)		I

Apprenticeship Job Creation

Part 21 – Total current-year credit – ITC from apprenticeship job creation expenditures

If you are a related person as defined under subsection 251(2), has it been agreed in writing that you are the only employer who will be claiming the apprenticeship job creation tax credit for this tax year for each apprentice whose contract number (or social insurance number or name) appears below? (If not, you cannot claim the tax credit.) . . . . 611 1 Yes ☐ 2 No ☐

For each apprentice in their first 24 months of the apprenticeship, enter the apprenticeship contract number registered with Canada, or a province or territory, under an apprenticeship program designed to certify or license individuals in the trade. For the province, the trade must be a Red Seal trade. If there is no contract number, enter the social insurance number (SIN) or the name of the eligible apprentice.

	A Contract number (SIN or name of apprentice) 601	B Name of eligible trade 602	C Eligible salary and wages* 603	D Column C x 10 % 604	E Lesser of column D or $ 2,000 605
1.	PF2485	Powerline Technician	77,613	7,761	2,000

	A Contract number (SIN or name of apprentice) 601	B Name of eligible trade 602	C Eligible salary and wages* 603	D Column C x 10 % 604	E Lesser of column D or $ 2,000 605
2.	BA8018	Powerline Technician	39,630	3,963	2,000

Total current-year credit (enter at line 640 in Part 22) 4,000 A

* Net of any other government or non-government assistance received or to be received.

Part 22 – Current-year credit and account balances – ITC from apprenticeship job creation expenditures

ITC at the end of the previous tax year . . . . B

Deduct:

Credit deemed as a remittance of co-op corporations 612

Credit expired after 20 tax years 615

Subtotal (line 612 **plus** line 615) ▶ C

ITC at the beginning of the tax year (amount B **minus** amount C) 625

Add:

Credit transferred on amalgamation or wind-up of subsidiary 630

ITC from repayment of assistance 635

Total current-year credit (amount A from Part 21) 640 4,000

Credit allocated from a partnership 655

Subtotal (total of lines 630 to 655) 4,000 ▶ 4,000 D

Total credit available (line 625 **plus** amount D) . . . . . 4,000 E

Deduct:

Credit deducted from Part I tax (enter at amount G in Part 30) 660 4,000

Credit carried back to the previous year(s) (amount G from Part 23) . . . . . a

Subtotal (line 660 **plus** amount a) 4,000 ▶ 4,000 F

ITC closing balance from apprenticeship job creation expenditures (amount E **minus** amount F) 690

Part 23 – Request for carryback of credit from apprenticeship job creation expenditures

	Year	Month	Day			
1st previous tax year				Credit to be applied	931	
2nd previous tax year				Credit to be applied	932	
3rd previous tax year				Credit to be applied	933	

Total (enter at amount a in Part 22) G

Child Care Spaces

Part 24 – Eligible child care spaces expenditures

Enter the eligible expenditures that the corporation incurred to create licensed child care spaces for the children of the employees and, potentially, for other children. The corporation cannot be carrying on a child care services business. The eligible expenditures include:

- the cost of depreciable property (other than specified property); and
- the specified child care start-up expenditures;

acquired or incurred only to create new child care spaces at a licensed child care facility.

Cost of depreciable property from the current tax year

	CCA* class number 665	Description of investment 675	Date available for use 685	Amount of investment 695
1.				

Total cost of depreciable property from the current tax year **715** ______

Add:

Specified child care start-up expenditures from the current tax year . . . . . **705** ______

Total gross eligible expenditures for child care spaces (line 715 **plus** line 705) . . . . . ______ A

Deduct:

Total of all assistance (including grants, subsidies, rebates, and forgivable loans) or reimbursements that the corporation has received or is entitled to receive in respect of the amounts referred to at line A . . . . . **725** ______

Excess (amount A **minus** line 725) (if negative, enter "0") . . . . . ______ B

Add:

Repayments by the corporation of government and non-government assistance . . . . . **735** ______

Total eligible expenditures for child care spaces (amount B **plus** line 735) . . . . . **745** ______

* CCA: capital cost allowance

Part 25 – Current-year credit – ITC from child care spaces expenditures

The credit is equal to 25% of eligible child care spaces expenditures incurred to a maximum of $10,000 per child care space created in a licensed child care facility.

Eligible expenditures (from line 745) . . . . . ______ x 25 % = ______ C

Number of child care spaces . . . . . **755** ______ x $ 10,000 = ______ D

ITC from child care spaces expenditures (amount C or D, whichever is less) . . . . . ______ E

Part 26 – Current-year credit and account balances – ITC from child care spaces expenditures

ITC at the end of the previous tax year				F
Deduct:				
Credit deemed as a remittance of co-op corporations	765			
Credit expired after 20 tax years	770			
Subtotal (line 765 **plus** line 770)			▶	G
ITC at the beginning of the tax year (amount F **minus** amount G)			775	
Add:				
Credit transferred on amalgamation or wind-up of subsidiary	777			
Total current-year credit (amount E from Part 25)	780			
Credit allocated from a partnership	782			
Subtotal (total of lines 777 to 782)			▶	H
Total credit available (line 775 **plus** amount H)				I
Deduct:				
Credit deducted from Part I tax (enter at amount H in Part 30)	785			
Credit carried back to the previous year(s) (amount K from Part 27)			a	
Subtotal (line 785 **plus** amount a)			▶	J
ITC closing balance from child care spaces expenditures (amount I **minus** amount J)			790	

Part 27 – Request for carryback of credit from child care space expenditures

	Year Month Day			
1st previous tax year	2013-12-31	Credit to be applied	941	
2nd previous tax year	2012-12-31	Credit to be applied	942	
3rd previous tax year	2011-12-31	Credit to be applied	943	
		Total (enter at amount a in Part 26)		K

Recapture – Child Care Spaces

Part 28 – Recapture of ITC for corporations and corporate partnerships – Child care spaces

The ITC will be recovered against the taxpayer's tax otherwise payable under Part I of the Act if, at any time within 60 months of the day on which the taxpayer acquired the property:

- the new child care space is no longer available; or
- property that was an eligible expenditure for the child care space is:
  - disposed of or leased to a lessee; or
  - converted to another use.

If the property disposed of is a child care space, the amount that can reasonably be considered to have been included in the original ITC (paragraph 127(27.12)(a)) . . . . **792** ____________

In the case of eligible expenditures (paragraph 127(27.12)(b)), the lesser of:

The amount that can reasonably be considered to have been included in the original ITC . . . . **795** ____________

25% of either the proceeds of disposition (if sold in an arm's length transaction) or the fair market value (in any other case) of the property . . . . **797** ____________

Amount from line 795 or line 797, whichever is less . . . . ____________ A

Corporate partnerships

As a member of the partnership, you will report your share of the child care spaces ITC of the partnership after the child care spaces ITC has been reduced by the amount of the recapture. If this amount is a positive amount, you will report it on line 782 in Part 26. However, if the partnership does not have enough ITC otherwise available to offset the recapture, then the amount by which reductions to ITC exceed additions (the excess) will be determined and reported on line 799 below.

Corporate partner's share of the excess of ITC **799** ____________

Total recapture of child care spaces investment tax credit (total of line 792, amount A, and line 799) . . . . ____________ B

Enter amount B at amount B in Part 29.

Summary of Investment Tax Credits

Part 29 – Total recapture of investment tax credit

Recaptured SR&ED ITC (from amount F in Part 17)		A
Recaptured child care spaces ITC (from amount B in Part 28)		B
Total recapture of investment tax credit (amount A **plus** amount B)		C

Enter amount C on line 602 of the T2 return.

Part 30 – Total ITC deducted from Part I tax

ITC from investments in qualified property deducted from Part I tax (from line 260 in Part 5)		D
ITC from SR&ED expenditures deducted from Part I tax (from line 560 in Part 12)		E
ITC from pre-production mining expenditures deducted from Part I tax (from line 885 in Part 19)		F
ITC from apprenticeship job creation expenditures deducted from Part I tax (from line 660 in Part 22)	4,000	G
ITC from child care space expenditures deducted from Part I tax (from line 785 in Part 26)		H
Total ITC deducted from Part I tax (total of amounts D to H)	4,000	I

Enter amount I at line 652 of the T2 return.

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Summary of Investment Tax Credit Carryovers

Continuity of investment tax credit carryovers

CCA class number 97 Apprenticeship job creation ITC

Current year

Addition current year (A)	Applied current year (B)	Claimed as a refund (C)	Carried back (D)	ITC end of year (A-B-C-D)
4,000	4,000			

Prior years

Taxation year	ITC beginning of year (E)	Adjustments (F)	Applied current year (G)	ITC end of year (E-F-G)
2013-12-31				
2012-12-31				
2011-12-31				
2010-12-31				
2009-12-31				
2008-12-31				
2007-12-31				
2006-12-31				
2005-12-31				
2004-12-31				*
2003-12-31				
2002-12-31				
2001-12-31				
2000-12-31				
1999-12-31				
				*
Total				

B+C+D+G **Total ITC utilized** 4,000

* The **ITC end of year** includes the amount of ITC expired from the 10th preceding year if it is before January 1, 1998, or the amount of ITC expired from the 20th preceding year if it is after December 31, 1997. Note that this credit expires at the end of the tax year and any expired credit will be posted to line 215, 515, 615, 770 or 845, as applicable, in Schedule 31 the following year.

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Schedule 33

Taxable Capital Employed in Canada – Large Corporations

Corporation's name	Business number	Tax year-end Year Month Day
Canadian Niagara Power Inc.	87249 8225 RC0002	2014-12-31

- Use this schedule in determining if the total taxable capital employed in Canada of the corporation (other than a financial institution or an insurance corporation) and its related corporations is greater than $10,000,000.
- If the total taxable capital employed in Canada of the corporation and its related corporations is greater than $10,000,000, file a completed Schedule 33 with your T2 Corporation Income Tax Return no later than six months from the end of the tax year.
- Unless otherwise noted, all legislative references are to the *Income Tax Act* and the *Income Tax Regulations*.
- Subsection 181(1) defines the terms **financial institution**, **long-term debt**, and **reserves**.
- Subsection 181(3) provides the basis to determine the carrying value of a corporation's assets or any other amount under Part I.3 for its capital, investment allowance, taxable capital, or taxable capital employed in Canada, or for a partnership in which it has an interest.
- If the corporation was a non-resident of Canada throughout the year and carried on a business through a permanent establishment in Canada, go to Part 4, **Taxable capital employed in Canada**.

Part 1 – Capital

Add the following amounts at the end of the year:

	Line	Amount		
Reserves that have not been deducted in computing income for the year under Part I	101			
Capital stock (or members' contributions if incorporated without share capital)	103	23,900,000		
Retained earnings	104	23,695,821		
Contributed surplus	105			
Any other surpluses	106			
Deferred unrealized foreign exchange gains	107			
All loans and advances to the corporation	108			
All indebtedness of the corporation represented by bonds, debentures, notes, mortgages, hypothecary claims, bankers' acceptances, or similar obligations	109			
Any dividends declared but not paid by the corporation before the end of the year	110			
All other indebtedness of the corporation (other than any indebtedness for a lease) that has been outstanding for more than 365 days before the end of the year	111			
The total of all amounts, each of which is an amount (see note below) for a partnership in which the corporation held a membership interest at the end of the year, either directly or indirectly through another partnership	112			
Subtotal		47,595,821	47,595,821	A

Deduct the following amounts:

	Line	Amount		
Deferred tax debit balance at the end of the year	121			
Any deficit deducted in computing its shareholders' equity (including, for this purpose, the amount of any provision for the redemption of preferred shares) at the end of the year	122			
Any amount deducted under subsection 135(1) in computing income under Part I for the year, as long as the amount may reasonably be regarded as being included in any of lines 101 to 112 above	123			
The amount of deferred unrealized foreign exchange losses at the end of the year	124			
Subtotal				B
Capital for the year (amount A **minus** amount B) (if negative, enter "0")	190		47,595,821	

Note: Line 112 is determined as follows:

- An amount for the partnership is the amount, if any, by which the total of those amounts—for the partnership's last fiscal period that ends at or before the tax year-end of the corporation—that would be determined for lines 101, 107, 108, 109, and 111 as if they apply to the partnership in the same way that they apply to corporations exceed the partnership's deferred unrealized foreign exchange losses at the end of the fiscal period.
- Do not include amounts owing to any corporation that held a membership interest in the partnership either directly or indirectly through another partnership.
- Do not include amounts owning to any partnership in which a corporation described above held a membership interest either directly or indirectly through another partnership.
- The proportion of the amount is determined by the amount that the corporation's share of the partnership's income or loss for the fiscal period—to which the corporation is entitled either directly or indirectly through another partnership—is of the partnership's income or loss for the period.

Part 2 – Investment allowance

Add the carrying value at the end of the year of the following assets of the corporation:

A share of another corporation	401	
A loan or advance to another corporation (other than a financial institution)	402	
A bond, debenture, note, mortgage, hypothecary claim, or similar obligation of another corporation (other than a financial institution)	403	
Long-term debt of a financial institution	404	
A dividend receivable on a share of the capital stock of another corporation	405	
A loan or advance to, or a bond, debenture, note, mortgage, hypothecary claim, or similar obligation of, a partnership all of the members of which, throughout the year, were other partnership or other corporations (other than financial institutions) that were not exempt from tax under Part I.3 [other than by reason of paragraph 181.1(3)(d)]	406	
An interest in a partnership (see note 1 below)	407	
Investment allowance for the year (add lines 401 to 407)	490	

Notes:

1. Where the corporation has an interest in a partnership or in tiered partnerships, consider the following:
   – the investment allowance of a partnership is deemed to be the amount calculated at line 490 above, at the end of its fiscal period, as if it was a corporation;
   – the total of the carrying value of each asset of the partnership described in the above lines is for its last fiscal period ending at or before the end of the corporation's tax year; and
   – the carrying value of a partnership member's interest at the end of the year is its specified proportion [as defined in subsection 248(1)] of the partnership's investment allowance.
2. Lines 401 to 405 should not include the carrying value of a share of the capital stock of, a dividend payable by, or indebtedness of a corporation that is exempt from tax under Part I.3 [other than by reason of paragraph 181.1(3)(d)].
3. Where a trust is used as a conduit for loaning money from a corporation to another related corporation (other than a financial institution), the loan will be considered to have been made directly from the lending corporation to the borrowing corporation, according to subsection 181.2(6).

Part 3 – Taxable capital

Capital for the year (line 190)		47,595,821	C
Deduct: Investment allowance for the year (line 490)			D
Taxable capital for the year (amount C **minus** amount D) (if negative, enter "0")	500	47,595,821	

Part 4 – Taxable capital employed in Canada

To be completed by a corporation that was resident in Canada at any time in the year

Taxable capital for the year (line 500) 47,595,821 x $\frac{\text{Taxable income earned in Canada}}{\text{Taxable income}}$ **610** $\frac{3,865,658}{3,865,658}$ = **Taxable capital employed in Canada** **690** 47,595,821

Notes:
1. Regulation 8601 gives details on calculating the amount of taxable income earned in Canada.
2. Where a corporation's taxable income for a tax year is "0," it shall, for the purposes of the above calculation, be deemed to have a taxable income for that year of $1,000.
3. In the case of an airline corporation, Regulation 8601 should be considered when completing the above calculation.

To be completed by a corporation that was a non-resident of Canada throughout the year and carried on a business through a permanent establishment in Canada

Total of all amounts each of which is the carrying value at the end of the year of an asset of the corporation used in the year or held in the year, in the course of carrying on any business during the year through a permanent establishment in Canada			701	
Deduct the following amounts:				
Corporation's indebtedness at the end of the year [other than indebtedness described in any of paragraphs 181.2(3)(c) to (f)] that may reasonably be regarded as relating to a business it carried on during the year through a permanent establishment in Canada	711			
Total of all amounts each of which is the carrying value at the end of year of an asset described in subsection 181.2(4) of the corporation that it used in the year, or held in the year, in the course of carrying on any business during the year through a permanent establishment in Canada	712			
Total of all amounts each of which is the carrying value at the end of year of an asset of the corporation that is a ship or aircraft the corporation operated in international traffic, or personal or movable property used or held by the corporation in carrying on any business during the year through a permanent establishment in Canada (see note below)	713			
Total deductions (**add** lines 711, 712, and 713)			►	E
Taxable capital employed in Canada (line 701 **minus** amount E) (if negative, enter "0")			790	

Note: Complete line 713 only if the country in which the corporation is resident did not impose a capital tax for the year on similar assets, or a tax for the year on the income from the operation of a ship or aircraft in international traffic, of any corporation resident in Canada during the year.

Part 5 – Calculation for purposes of the small business deduction

This part is applicable to corporations that are not associated in the current year, but were associated in the prior year.

Taxable capital employed in Canada (line 690 or 790, whichever applies)		F
Deduct:	10,000,000	G
Excess (amount F **minus** amount G) (if negative, enter "0")		H
Calculation for purposes of the small business deduction (amount H x 0.00225)		I

Enter this amount at line 415 of the T2 return.

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SCHEDULE 54

LOW RATE INCOME POOL (LRIP) CALCULATION

Name of corporation	Business Number	Tax year-end Year Month Day
Canadian Niagara Power Inc.	87249 8225 RC0002	2014-12-31

On: 2014-12-31

- Use this schedule to calculate the balance of the low rate income pool (LRIP) at any time in the tax year if you are a corporation resident in Canada that is:
  - a corporation **other** than a Canadian-controlled private corporation (CCPC) or a deposit insurance corporation (DIC); or
  - a corporation that elects under subsection 89(11) not to be a CCPC.
- When an eligible dividend was paid or there was a change in the LRIP balance in the tax year, file a completed copy of this schedule with your *T2 Corporation Income Tax Return*. Do not send your worksheets with your return, but keep them in your records in case we ask to see them later.
- Sections and subsections referred to in this schedule are from the *Income Tax Act*.
- Subsection 89(1) defines the terms eligible dividend, excessive eligible dividend designation, general rate income pool, and low rate income pool.

Did the corporation elect not to be a CCPC under subsection 89(11) ITA for the current year or a prior year or did it revoke this election in the current year*? . . . . . [ ] Yes [X] No

* If the corporation revoked its election in the current year when filing Form T2002, this election will still be valid for the current year, but will cease to apply as of the end of the year.

Eligibility for the various additions

Answer the following questions to determine the corporation's eligibility for the various additions:

Change in the type of corporation

1. Was the corporation a CCPC during its preceding taxation year? . . . . . [ ] Yes [X] No
2. Corporations that ceased to be a CCPC or a DIC . . . . . [ ] Yes [X] No
   If the answer to question 2 is yes, complete Part 4.

Amalgamation (first year of filing after amalgamation)

3. Corporations that were formed as a result of an amalgamation . . . . . [ ] Yes [X] No
   If the answer to question 3 is yes, answer questions 4 and 5. If the answer is no, go to question 6.
4. Was one or several of the predecessor corporations a CCPC or a DIC during the taxation year that ended immediately before the amalgamation? . . . . . [ ] Yes [ ] No
   If the answer to question 4 is yes, complete Part 5.
5. Was one or several of the predecessor corporations neither a CCPC nor a DIC? . . . . . [ ] Yes [ ] No
   If the answer to question 5 is yes, complete Part 5 (line R).

Winding-up

6. Corporations that wound-up a subsidiary . . . . . [ ] Yes [X] No
   If the answer to question 6 is yes, answer questions 7 and 8. If the answer is no, go to Part 1.
7. Was the subsidiary a CCPC or a DIC during its last taxation year? . . . . . [ ] Yes [ ] No
   If the answer to question 7 is yes, complete Part 6.
8. Was the subsidiary neither a CCPC nor a DIC during its last taxation year? . . . . . [ ] Yes [ ] No
   If the answer to question 8 is yes, complete Part 6 (line R).

Part 1 – Calculation of low rate income pool (LRIP)

LRIP at the end of the immediately previous tax year (enter "0" for the first tax year ending in 2006) . . . . . **100** ______

Income for the credit union deduction (amount E in Part 3 of Schedule 17 of the previous year if the corporation was **not** a CCPC in the previous tax year, otherwise enter "0") . . . . . **120** ______

Aggregate investment income of a corporation that has elected under subsection 89(11) not to be a CCPC (line 440 of the T2 return of the previous tax year) . . . . . **140** ______

Subtotal (**add** lines 120 and 140) ______ x 80 % = **150** ______

Investment corporation deduction (line 620 of the T2 return of the previous tax year) . . . . . ______ x 4 = **160** ______

Subtotal (**add** lines 100, 150, and 160) **190** ______

Part 2 – Calculation of LRIP and excessive eligible dividend designations during the tax year

Complete this part if you paid an eligible dividend in the tax year.

	200 Date* (yyyy/mm/dd)	210 Total dividends** receivable in the year up to but not including the date on line 200 that are deductible under section 112	220 Total adjustments for amalgamations, wind-ups, or on ceasing to be a CCPC***	230 Subtotal (**add** lines 190, 210, and 220)	240 Total dividends**** payable in the year up to but not including the date on line 200	250 Total of excessive eligible dividend designations made up to, but not including the date on line 200
1.	2014-12-09					
2.						

	260 LRIP as of the date on line 200 (line 230 **minus** the total of line 240 and line 250)	270 Total eligible dividends paid on the date on line 200	280 Excessive eligible dividend designation (**lesser** of lines 260 and 270)
1.		2,500,000	
2.			

Total excessive eligible dividend designations in the tax year (total of all amounts in column 280) . . ______ A
Enter this amount on line B on Schedule 55.

* Enter on line 200 each date where:
- an eligible dividend was paid in the year; or
- an adjustment was made as a result of an amalgamation or the wind-up of a subsidiary or on ceasing to be a CCPC (by an election or otherwise).

** taxable dividends from a corporation resident in Canada (other than eligible dividends)

*** Complete the worksheets in Parts 4 to 6 separately for each predecessor, each subsidiary involved in the wind-up, and when the corporation ceases to be a CCPC or DIC. Total the adjustments for this date and enter on line 220.

**** includes taxable dividends (other than an eligible dividend, a capital gains dividend within the meaning assigned by subsection 130.1(4) or 131(1), or a dividend deductible under subsection 130.1(1)).

Part 3 – LRIP closing balance calculation

Amount on line 190 of Part 1 . . . . A

Dividends** receivable in the tax year that are deductible under section 112 (Amount on line 210 in the last row (last date) of the chart in Part 2) . . . .

If an eligible dividend has been paid in the tax year, enter all dividends other than eligible dividends receivable in the year that are deductible under section 112 (hereinafter: “dividends other than eligible dividends receivable”) on the date in the last row, or after (last date), from column 200 in Part 2. If no eligible dividend was paid in the tax year, enter all dividends receivable other than eligible dividends receivable. . . . .

Total dividends** receivable in the tax year that are deductible under section 112 . . . . **510**

Adjustments for amalgamations, wind-ups, or ceasing to be a CCPC*** (Amount on line 220 in the last row (last date) of the chart in Part 2) . . . .

Adjustments for amalgamations, wind-ups, or ceasing to be a CCPC*** if no eligible dividend has been paid in the tax year . . . .

Total adjustments for amalgamations, wind-ups, or on ceasing to be a CCPC*** **520**

Subtotal (**add** lines 510 and 520) ▶ B

Subtotal (**add** lines A and B) C

Total dividends**** payable in the tax year (Amount on line 240 in the last row (last date) of the chart in Part 2) . . .

If an eligible dividend has been paid in the tax year, enter all dividends other than eligible dividends payable in the year (hereinafter: “dividends other that eligible dividends payable”) on the date in the last row, or after (last date), from column 200 in Part 2. If no eligible dividend was paid in the tax year, enter all dividends paid other than eligible dividends paid. . . . .

Total dividends**** payable in the tax year **540**

Total excessive eligible dividend designations in the tax year (line A from Part 2) . . . . D

Subtotal (**add** lines 540 and D) ▶ E

LRIP at the end of the tax year (line C **minus** line E) (if negative enter "0") **590**

** Taxable dividends from a corporation resident in Canada (other than eligible dividends).

*** Complete the worksheets in Parts 4 to 6 separately for each predecessor, each subsidiary involved in the wind-up, and when the corporation ceases to be a CCPC or DIC.

**** Includes taxable dividends (other than an eligible dividend, a capital gains dividend within the meaning assigned by subsection 130.1(4) or 131(1), or a dividend deductible under subsection 130.1(1)).

Part 4 – Worksheet for adjustment when a corporation ceases to be a CCPC or DIC

Adjustment date . . . . ______

Complete this part if the corporation is neither a CCPC nor a DIC in this tax year but was a CCPC or a DIC in the previous tax year.
This adjustment to the LRIP can be made at any time in the tax year.
Keep a copy of this calculation for your records in case we ask to see it later.

Cost amount to the corporation of all property immediately before the end of the previous tax year . . . . . . ______ D
The corporation's cash on hand immediately before the end of the previous tax year . . . . . . ______ E

Unused and unexpired losses at the end of the corporation's previous tax year:

Non-capital losses . . . . . . ______
Net capital losses . . . . . . ______
Farm losses . . . . . . ______
Restricted farm losses . . . . . . ______
Limited partnership losses . . . . . . ______
Subtotal ______ ► ______ F

Subtotal (**add** lines D, E, and F) ______ G

All of the corporation's debts and other obligations to pay that were outstanding immediately before the end of its previous tax year . . . . . . ______ H
Paid up capital of all of the corporation's issued and outstanding shares of capital stock immediately before the end of its previous tax year . . . . . . ______ I

All of the corporation's reserves deducted in its previous tax year . . . . . . ______ J

Is the corporation a private corporation? . . . . . . ☐ Yes ☒ No
The corporation's capital dividend account immediately before the end of its previous tax year if the corporation is **not** a private corporation in the current tax year . . . . . . ______ K
The corporation's general rate income pool (GRIP) at the end of its previous tax year . . . . . . ______ L
Eligible dividends paid in the previous tax year . . . . . . ______ 3
Excessive eligible dividend designations made in the previous tax year . . . . . . ______ 4
Subtotal (line 3 **minus** line 4) (if negative, enter "0") . . . . . . ______ ► ______ M

Subtotal (line L **minus** line M) ______ ► ______ N

Subtotal (**add** lines H, I, J, K, and N) ______ ► ______ O

Adjustment for a corporation that ceases to be a CCPC or DIC (line G **minus** line O) (if negative, enter "0") . . . . . . ______ T

Part 5 – Worksheet for adjustment when a corporation is formed as a result of an amalgamation

nb. 1

Adjustment date . . . . ______

Complete this part if the corporation was formed as a result of an amalgamation or merger of two or more corporations, one of which is a taxable Canadian corporation. Complete a separate worksheet for **each** predecessor.

This adjustment to the LRIP can be made at any time in the tax year.

The last tax year was its tax year that ended immediately before the amalgamation.

Keep a copy of this calculation for your records, in case we ask to see it later.

For a predecessor corporation that was a CCPC or a DIC in its tax year that ended immediately before the amalgamation

Cost amount to the predecessor of all property immediately before the end of its last tax year . . . . ______ D

The predecessor's cash on hand immediately before the end of its last tax year . . . . ______ E

Unused and unexpired losses at the end of the corporation's previous tax year:

Non-capital losses . . . . ______

Net capital losses . . . . ______

Farm losses . . . . ______

Restricted farm losses . . . . ______

Limited partnership losses . . . . ______

Subtotal ______ ► ______ F

Subtotal (**add** lines D, E, and F) ______ G

All of the predecessor's debts and other obligations to pay that were outstanding immediately before the end of its last tax year . . . . ______ H

Paid up capital of all the predecessor's issued and outstanding shares of capital stock immediately before the end of its last tax year . . . . ______ I

All of the predecessor's reserves deducted in its last tax year . . . . ______ J

The predecessor's capital dividend account immediately before the end of its last tax year if the new corporation is **not** a private corporation . . . . ______ K

The predecessor's general rate income pool (GRIP) at the end of its last tax year . . . . ______ L

Eligible dividends paid in its last tax year . . . ______ 3

Excessive eligible dividend designations made in its last tax year . . . . ______ 4

Subtotal (line 3 **minus** line 4) (if negative, enter "0") . . . . ______ ► ______ M

Subtotal (line L **minus** line M) ______ ► ______ N

Subtotal (**add** lines H, I, J, K, and N) ______ ► ______ O

Adjustment for a CCPC or DIC predecessor corporation (line G **minus** line O) (if negative, enter "0") . . . . ______ P

For a predecessor corporation that was neither a CCPC nor a DIC in its tax year that ended immediately before the amalgamation

LRIP at the end of its last tax year . . . . ______ Q

Adjustment for a predecessor corporation involved in an amalgamation (**add** lines P and Q) . . . . ______ T

Calculate amount T for **each** predecessor.

Part 6 – Worksheet for adjustment when a corporation has wound-up a subsidiary

nb. 1

Adjustment date . . . . ______

Complete this part if the corporation is the parent corporation and has, in the year, received all or substantially all of the assets on dissolution or wind-up of a subsidiary. Complete a separate worksheet for **each** subsidiary involved in the wind-up.

This adjustment to the LRIP can be made at any time in the tax year that is on or after the end of the subsidiary's last tax year.

The last tax year for the subsidiary was its tax year during which its assets were distributed to the parent on the wind-up.

Keep a copy of this calculation for your records in case we ask to see it later.

For a subsidiary corporation that was a CCPC or a DIC in its last tax year

Cost amount to the subsidiary of all property immediately before the end of its last tax year . . . . ______ D

The subsidiary's cash on hand immediately before the end of its last tax year . . . . ______ E

Unused and unexpired losses at the end of the corporation's previous tax year:

Non-capital losses . . . . ______

Net capital losses . . . . ______

Farm losses . . . . ______

Restricted farm losses . . . . ______

Limited partnership losses . . . . ______

Subtotal ______ ► ______ F

Subtotal (**add** lines D, E, and F) ______ G

All of the subsidiary's debts and other obligations to pay that were outstanding immediately before the end of its last tax year . . . . ______ H

Paid up capital of all the subsidiary's issued and outstanding shares of capital stock immediately before the end of its last tax year . . . . ______ I

All the subsidiary's reserves deducted in its last tax year . . . . ______ J

The subsidiary's capital dividend account immediately before the end of its last tax year if the parent is **not** a private corporation . . . . ______ K

The subsidiary's general rate income pool (GRIP) at the end of its last tax year . . . . ______ L

Eligible dividends paid in its last tax year . . . ______ 3

Excessive eligible dividend designations made in its last tax year . . . . ______ 4

Subtotal (line 3 **minus** line 4) (if negative, enter "0") . . . . ______ ► ______ M

Subtotal (line L **minus** line M) ______ ► ______ N

Subtotal (**add** lines H, I, J, K, and N) ______ ► ______ O

Adjustment for a CCPC or DIC subsidiary (line G **minus** line O) (if negative, enter "0") . . . . ______ P

For a subsidiary corporation that was neither a CCPC nor a DIC in its last tax year

LRIP at the end of its last tax year . . . . ______ Q

Adjustment for a subsidiary involved in a wind-up (**add** lines P and Q) . . . . ______ T

Calculate amount T for **each** subsidiary.

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SCHEDULE 55

PART III.1 TAX ON EXCESSIVE ELIGIBLE DIVIDEND DESIGNATIONS

Name of corporation	Business Number	Tax year-end Year Month Day
Canadian Niagara Power Inc.	87249 8225 RC0002	2014-12-31

- Every corporation resident in Canada that pays a taxable dividend (other than a capital gains dividend within the meaning assigned by subsection 130.1(4) or 131(1)) in the tax year must file this schedule.
- Canadian-controlled private corporations (CCPC) and deposit insurance corporations (DIC) must complete Part 1 of this schedule. All other corporations must complete Part 2.
- Every corporation that has paid an eligible dividend must also file Schedule 53, *General Rate Income Pool (GRIP) Calculation*, or Schedule 54, *Low Rate Income Pool (LRIP) Calculation*, whichever is applicable.
- File the completed schedules with your *T2 Corporation Income Tax Return* no later than six months from the end of the tax year.
- All legislative references on this schedule are to the federal *Income Tax Act*.
- Subsection 89(1) defines the terms eligible dividend, excessive eligible dividend designation, general rate income pool (GRIP), and low rate income pool (LRIP).
- The calculations in Part 1 and Part 2 do not apply if the excessive eligible dividend designation arises from the application of paragraph (c) of the definition of excessive eligible dividend designation in subsection 89(1). This paragraph applies when an eligible dividend is paid to artificially maintain or increase the GRIP or to artificially maintain or decrease the LRIP.

Do not use this area

Part 1 – Canadian-controlled private corporations and deposit insurance corporations

Taxable dividends paid in the tax year **not included** in Schedule 3			
Taxable dividends paid in the tax year **included** in Schedule 3			
Total taxable dividends paid in the tax year	100		
Total eligible dividends paid in the tax year	150		A
GRIP at the end of the tax year (line 590 on Schedule 53) (if negative, enter "0")	160		B
Excessive eligible dividend designation (line 150 **minus** line 160)			C
Deduct:			
Excessive eligible dividend designations elected under subsection 185.1(2) to be treated as ordinary dividends*	180		D
Subtotal (amount C **minus** amount D)			E
Part III.1 tax on excessive eligible dividend designations – CCPC or DIC (amount E **multiplied** by 20 %)	190		F

Enter the amount from line 190 on line 710 of the T2 return.

Part 2 – Other corporations

Taxable dividends paid in the tax year **not included** in Schedule 3		2,500,000	
Taxable dividends paid in the tax year **included** in Schedule 3			
Total taxable dividends paid in the tax year	200	2,500,000	
Total excessive eligible dividend designations in the tax year (amount from line A of Schedule 54)			G
Deduct:			
Excessive eligible dividend designations elected under subsection 185.1(2) to be treated as ordinary dividends*	280		H
Subtotal (amount G **minus** amount H)			I
Part III.1 tax on excessive eligible dividend designations – Other corporations (amount I **multiplied** by 20 %)	290		J

Enter the amount from line 290 on line 710 of the T2 return.

* You can elect to treat all or part of your excessive eligible dividend designation as a separate taxable dividend in order to eliminate or reduce the Part III.1 tax otherwise payable. You must file the election on or before the day that is 90 days **after** the day the notice of assessment for Part III.1 tax was sent. We will accept an election before the assessment of the tax. For more information on how to make this election, go to **www.cra.gc.ca/eligibledividends**.

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Schedule 500

Ontario Corporation Tax Calculation

Corporation's name	Business number	Tax year-end Year Month Day
Canadian Niagara Power Inc.	87249 8225 RC0002	2014-12-31

- Use this schedule if the corporation had a permanent establishment (as defined in section 400 of the federal *Income Tax Regulations*) in Ontario at any time in the tax year and had Ontario taxable income in the year.
- All legislative references are to the federal *Income Tax Act* and *Income Tax Regulations*.
- This schedule is a worksheet only. You do not have to file it with your *T2 Corporation Income Tax Return*.

Part 1 – Calculation of Ontario basic rate of tax for the year

Number of days in the tax year before July 1, 2011 / Number of days in the tax year	/ 365	x	12.00 %	=	%	A1	
Number of days in the tax year after June 30, 2011 / Number of days in the tax year	365 / 365	x	11.50 %	=	11.50000 %	A2	
Ontario basic rate of tax for the year (rate A1 **plus** A2)					11.50000 ►	11.50000 %	A3

Part 2 – Calculation of Ontario basic income tax

Ontario taxable income *	3,865,658	B
Ontario basic income tax: amount B **multiplied** by Ontario basic rate of tax for the year (rate A3 from Part 1)	444,551	C

If the corporation has a permanent establishment in more than one jurisdiction, or is claiming an Ontario tax credit in addition to Ontario basic income tax, or has Ontario corporate minimum tax or Ontario special additional tax on life insurance corporations payable, enter amount C on line 270 of Schedule 5, *Tax Calculation Supplementary – Corporations*. Otherwise, enter it on line 760 of the T2 return.

* If the corporation has a permanent establishment only in Ontario, enter the amount from line 360 or line Z, whichever applies, of the T2 return. Otherwise, enter the taxable income allocated to Ontario from column F in Part 1 of Schedule 5.

Part 3 – Ontario small business deduction (OSBD)

Complete this part if the corporation claimed the federal small business deduction under subsection 125(1) or would have claimed it if subsection 125(5.1) had not been applicable in the tax year.

Income from active business carried on in Canada (amount from line 400 of the T2 return)		1
Federal taxable income, less adjustment for foreign tax credit (amount from line 405 of the T2 return)		2
Federal business limit before the application of subsection 125(5.1) (amount from line 410 of the T2 return)		3
Business limit reduction (amount from line E of the T2 return) ______ x (Number of days in the tax year after May 1, 2014 / Number of days in the tax year) 244 / 365 =		4
Amount from line 3 **minus** amount from line 4 (if negative, enter "0") =		5
Enter the least of amounts 1, 2, 3 and 5		D
Ontario domestic factor: Ontario taxable income * / Taxable income earned in all provinces and territories ** — 3,865,658.00 / 3,865,658 =	1.00000	E

Amount D x factor E		a
Ontario taxable income (amount B from Part 2)	3,865,658	b

Ontario small business income (lesser of amount a and amount b)		F

Number of days in the tax year before July 1, 2011 / Number of days in the tax year	/ 365	x	7.50 %	= %	G1
Number of days in the tax year after June 30, 2011 / Number of days in the tax year	365 / 365	x	7.00 %	= 7.00000 %	G2

OSBD rate for the year (rate G1 **plus** G2)	7.00000 %	G3
Ontario small business deduction: amount F **multiplied** by OSBD rate for the year (rate G3)		H

Enter amount H on line 402 of Schedule 5.

* Enter amount B from Part 2.

** Includes the offshore jurisdictions for Nova Scotia and Newfoundland and Labrador.

Part 4 – Ontario adjusted small business income

Complete this part if the corporation was a Canadian-controlled private corporation throughout the tax year and is claiming the Ontario tax credit for manufacturing and processing or the Ontario credit union tax reduction.

Ontario adjusted small business income (lesser of amount D and amount b from Part 3)		I

Enter amount I on line K in Part 5 of this schedule or on line B in Part 2 of Schedule 502, *Ontario Tax Credit for Manufacturing and Processing*, whichever applies.

Part 5 – Calculation of credit union tax reduction

Complete this part and Schedule 17, *Credit Union Deductions*, if the corporation was a credit union throughout the tax year.

Amount D from Part 3 of Schedule 17			J
Deduct:			
Ontario adjusted small business income (amount I from Part 4)			K
Subtotal (amount J **minus** amount K) (if negative, enter "0")			L
OSBD rate for the year (rate G3 from Part 3)	7.00000 %		
Amount L **multiplied** by the OSBD rate for the year			M
Ontario domestic factor (factor E from Part 3)		1.00000	N
Ontario credit union tax reduction (amount M **multiplied** by factor N)			O

Enter amount O on line 410 of Schedule 5.

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Schedule 510

Ontario Corporate Minimum Tax

Corporation's name	Business number	Tax year-end Year Month Day
Canadian Niagara Power Inc.	87249 8225 RC0002	2014-12-31

- File this schedule if the corporation is subject to Ontario corporate minimum tax (CMT). CMT is levied under section 55 of the *Taxation Act, 2007* (Ontario), referred to as the "Ontario Act".
- Complete Part 1 to determine if the corporation is subject to CMT for the tax year.
- A corporation not subject to CMT in the tax year is still required to file this schedule if it is deducting a CMT credit, has a CMT credit carryforward, or has a CMT loss carryforward or a current year CMT loss.
- A corporation that has Ontario special additional tax on life insurance corporations (SAT) payable in the tax year must complete Part 4 of this schedule even if it is not subject to CMT for the tax year.
- A corporation is exempt from CMT if, throughout the tax year, it was one of the following:
  1) a corporation exempt from income tax under section 149 of the federal *Income Tax Act*;
  2) a mortgage investment corporation under subsection 130.1(6) of the federal Act;
  3) a deposit insurance corporation under subsection 137.1(5) of the federal Act;
  4) a congregation or business agency to which section 143 of the federal Act applies;
  5) an investment corporation as referred to in subsection 130(3) of the federal Act; or
  6) a mutual fund corporation under subsection 131(8) of the federal Act.
- File this schedule with the *T2 Corporation Income Tax Return*.

Part 1 – Determination of CMT applicability

Total assets of the corporation at the end of the tax year *	112	137,293,781
Share of total assets from partnership(s) and joint venture(s) *	114	
Total assets of associated corporations (amount from line 450 on Schedule 511)	116	247,767,486
Total assets (total of lines 112 to 116)		385,061,267
Total revenue of the corporation for the tax year **	142	81,668,309
Share of total revenue from partnership(s) and joint venture(s) **	144	
Total revenue of associated corporations (amount from line 550 on Schedule 511)	146	113,733,480
Total revenue (total of lines 142 to 146)		195,401,789

The corporation is subject to CMT if:
- for tax years ending before July 1, 2010, the total assets at the end of the year of the corporation or the associated group of corporations are more than $5,000,000, or the total revenue for the year of the corporation or the associated group of corporations is more than $10,000,000.
- for tax years ending after June 30, 2010, the total assets at the end of the year of the corporation or the associated group of corporations are equal to or more than $50,000,000, and the total revenue for the year of the corporation or the associated group of corporations is equal to or more than $100,000,000.

If the corporation is not subject to CMT, do not complete the remaining parts unless the corporation is deducting a CMT credit, or has a CMT credit carryforward, a CMT loss carryforward, a current year CMT loss, or SAT payable in the year.

* **Rules for total assets**
- Report total assets according to generally accepted accounting principles, adjusted so that consolidation and equity methods are not used.
- Do not include unrealized gains and losses on assets and foreign currency gains and losses on assets that are included in net income for accounting purposes but not in income for corporate income tax purposes.
- The amount on line 114 is determined at the end of the last fiscal period of the partnership or joint venture that ends in the tax year of the corporation. Add the proportionate share of the assets of the partnership(s) and joint venture(s), and deduct the recorded asset(s) for the investment in partnerships and joint ventures.
- A corporation's share in a partnership or joint venture is determined under paragraph 54(5)(b) of the Ontario Act and, if the partnership or joint venture had no income or loss, is calculated as if the partnership's or joint venture's income were $1 million. For a corporation with an indirect interest in a partnership or joint venture, determine the corporation's share according to paragraph 54(5)(c) of the Ontario Act.

** **Rules for total revenue**
- Report total revenue in accordance with generally accepted accounting principles, adjusted so that consolidation and equity methods are not used.
- If the tax year is less than 51 weeks, **multiply** the total revenue of the corporation or the partnership, whichever applies, by 365 and **divide** by the number of days in the tax year.
- The amount on line 144 is determined for the partnership or joint venture fiscal period that ends in the tax year of the corporation. If the partnership or joint venture has 2 or more fiscal periods ending in the filing corporation's tax year, **multiply** the sum of the total revenue for each of the fiscal periods by 365 and **divide** by the total number of days in all the fiscal periods.
- A corporation's share in a partnership or joint venture is determined under paragraph 54(5)(b) of the Ontario Act and, if the partnership or joint venture had no income or loss, is calculated as if the partnership's or joint venture's income were $1 million. For a corporation with an indirect interest in a partnership or joint venture, determine the corporation's share according to paragraph 54(5)(c) of the Ontario Act.

Part 2 – Adjusted net income/loss for CMT purposes

Net income/loss per financial statements *			210	4,720,838
Add (to the extent reflected in income/loss):				
Provision for current income taxes/cost of current income taxes	220	996,410		
Provision for deferred income taxes (debits)/cost of future income taxes	222			
Equity losses from corporations	224			
Financial statement loss from partnerships and joint ventures	226			
Dividends deducted on financial statements (subsection 57(2) of the Ontario Act), excluding dividends paid by credit unions under subsection 137(4.1) of the federal Act	230			
Other additions (see note below):				
Share of adjusted net income of partnerships and joint ventures **	228			
Total patronage dividends received, not already included in net income/loss	232			
281	282			
283	284			
Subtotal		996,410 ▶		996,410 A
Deduct (to the extent reflected in income/loss):				
Provision for recovery of current income taxes/benefit of current income taxes	320			
Provision for deferred income taxes (credits)/benefit of future income taxes	322			
Equity income from corporations	324			
Financial statement income from partnerships and joint ventures	326			
Dividends deductible under section 112, section 113, or subsection 138(6) of the federal Act	330			
Dividends not taxable under section 83 of the federal Act (from Schedule 3)	332			
Gain on donation of listed security or ecological gift	340			
Accounting gain on transfer of property to a corporation under section 85 or 85.1 of the federal Act ***	342			
Accounting gain on transfer of property to/from a partnership under section 85 or 97 of the federal Act ****	344			
Accounting gain on disposition of property under subsection 13(4), subsection 14(6), or section 44 of the federal Act *****	346			
Accounting gain on a windup under subsection 88(1) of the federal Act or an amalgamation under section 87 of the federal Act	348			
Other deductions (see note below):				
Share of adjusted net loss of partnerships and joint ventures **	328			
Tax payable on dividends under subsection 191.1(1) of the federal Act **multiplied** by 3	334			
Interest deducted/deductible under paragraph 20(1)(c) or (d) of the federal Act, not already included in net income/loss	336			
Patronage dividends paid (from Schedule 16) not already included in net income/loss	338			
381	382			
383	384			
385	386			
387	388			
389	390			
Subtotal		▶		B
Adjusted net income/loss for CMT purposes (line 210 **plus** amount A **minus** amount B)			490	5,717,248

If the amount on line 490 is positive and the corporation is subject to CMT as determined in Part 1, enter the amount on line 515 in Part 3.

If the amount on line 490 is negative, enter the amount on line 760 in Part 7 (enter as a positive amount).

Note

In accordance with *Ontario Regulation 37/09*, when calculating net income for CMT purposes, accounting income should be adjusted to:

– exclude unrealized gains and losses due to mark-to-market changes or foreign currency changes on specified mark-to-market property (assets only);
– include realized gains and losses on the disposition of specified mark-to-market property not already included in the accounting income, if the property is not a capital property or is a capital property disposed in the year or in a previous tax year ended after March 22, 2007.

"Specified mark-to-market property" is defined in subsection 54(1) of the Ontario Act.

These rules also apply to partnerships. A corporate partner's share of a partnership's adjusted income flows through on a proportionate basis to the corporate partner.

* **Rules for net income/loss**

– Banks must report net income/loss as per the report accepted by the Superintendent of Financial Institutions under the federal *Bank Act*, adjusted so consolidation and equity methods are not used.

Part 2 – Calculation of adjusted net income/loss for CMT purposes (continued)

– Life insurance corporations must report net income/loss as per the report accepted by the federal Superintendent of Financial Institutions or equivalent provincial insurance regulator, before SAT and adjusted so consolidation and equity methods are not used. If the life insurance corporation is resident in Canada and carries on business in and outside of Canada, **multiply** the net income/loss by the ratio of the Canadian reserve liabilities **divided** by the total reserve liability. The reserve liabilities are calculated in accordance with Regulation 2405(3) of the federal Act.

– Other corporations must report net income/loss in accordance with generally accepted accounting principles, except that consolidation and equity methods must not be used. When the equity method has been used for accounting purposes, equity losses and equity income are removed from book income/loss on lines 224 and 324 respectively.

– Corporations, other than insurance corporations, should report net income from line 9999 of the GIFI (Schedule 125) on line 210.

** The share of the adjusted net income of a partnership or joint venture is calculated as if the partnership or joint venture were a corporation and the tax year of the partnership or joint venture were its fiscal period. For a corporation with an indirect interest in a partnership through one or more partnerships, determine the corporation's share according to clause 54(5)(c) of the Ontario Act.

*** A joint election will be considered made under subsection 60(1) of the Ontario Act if there is an entry on line 342, and an election has been made for transfer of property to a corporation under subsection 85(1) of the federal Act.

**** A joint election will be considered made under subsection 60(2) of the Ontario Act if there is an entry on line 344, and an election has been made under subsection 85(2) or 97(2) of the federal Act.

***** A joint election will be considered made under subsection 61(1) of the Ontario Act if there is an entry on line 346, and an election has been made under subsection 13(4) or 14(6) and/or section 44 of the federal Act.

For more information on how to complete this part, see the *T2 Corporation – Income Tax Guide*.

Part 3 – CMT payable

Adjusted net income for CMT purposes (line 490 in Part 2, if positive)		515	5,717,248	
Deduct:				
CMT loss available (amount R from Part 7)				
Minus: Adjustment for an acquisition of control *	518			
Adjusted CMT loss available		▶		C
Net income subject to CMT calculation (if negative, enter "0")		520	5,717,248	

Amount from line 520		Number of days in the tax year before July 1, 2010 / Number of days in the tax year				
Amount from line 520	5,717,248 x	Number of days in the tax year before July 1, 2010 / Number of days in the tax year	/ 365	x 4 % =		1
Amount from line 520	5,717,248 x	Number of days in the tax year after June 30, 2010 / Number of days in the tax year	365 / 365	x 2.7 % =	154,366	2

Subtotal (amount 1 **plus** amount 2) 154,366 3

Gross CMT: amount on line 3 above x OAF **	540	154,366	
Deduct:			
Foreign tax credit for CMT purposes ***	550		
CMT after foreign tax credit deduction (line 540 **minus** line 550) (if negative, enter "0")		154,366	D
Deduct:			
Ontario corporate income tax payable before CMT credit (amount F6 from Schedule 5)		444,551	
Net CMT payable (if negative, enter "0")			E

Enter amount E on line 278 of Schedule 5, *Tax Calculation Supplementary – Corporations*, and complete Part 4.

* Enter the portion of CMT loss available that exceeds the adjusted net income for the tax year from carrying on a business before the acquisition of control. See subsection 58(3) of the Ontario Act.

*** Enter "0" on line 550 for life insurance corporations as they are not eligible for this deduction. For all other corporations, enter the cumulative total of amount J for the province of Ontario from Part 9 of Schedule 21 on line 550.

** **Calculation of the Ontario allocation factor (OAF):**

If the provincial or territorial jurisdiction entered on line 750 of the T2 return is "Ontario," enter "1" on line F.

If the provincial or territorial jurisdiction entered on line 750 of the T2 return is "multiple," complete the following calculation, and enter the result on line F:

Ontario taxable income **** / Taxable income ***** =

Ontario allocation factor .... 1.00000 F

**** Enter the amount allocated to Ontario from column F in Part 1 of Schedule 5. If the taxable income is nil, calculate the amount in column F as if the taxable income were $1,000.

***** Enter the taxable income amount from line 360 or amount Z of the T2 return, whichever applies. If the taxable income is nil, enter "1,000".

Part 4 – Calculation of CMT credit carryforward

CMT credit carryforward at the end of the previous tax year *			G		
Deduct:					
CMT credit expired *	600				
CMT credit carryforward at the beginning of the current tax year * (see note below)			▶	620	
Add:					
CMT credit carryforward balances transferred on an amalgamation or the windup of a subsidiary (see note below)				650	
CMT credit available for the tax year (amount on line 620 **plus** amount on line 650)					H
Deduct:					
CMT credit deducted in the current tax year (amount P from Part 5)					I
Subtotal (amount H **minus** amount I)					J
Add:					
Net CMT payable (amount E from Part 3)					
SAT payable (amount O from Part 6 of Schedule 512)					
Subtotal			▶		K
CMT credit carryforward at the end of the tax year (amount J **plus** amount K)				670	L

* For the first harmonized T2 return filed with a tax year that includes days in 2009:

– do not enter an amount on line G or line 600;

– for line 620, enter the amount from line 2336 of Ontario CT23 Schedule 101, *Corporate Minimum Tax (CMT)*, for the last tax year that ended in 2008.

For other tax years, enter on line G the amount from line 670 of Schedule 510 from the previous tax year.

Note: If you entered an amount on line 620 or line 650, complete Part 6.

Part 5 – Calculation of CMT credit deducted from Ontario corporate income tax payable

CMT credit available for the tax year (amount H from Part 4)				M
Ontario corporate income tax payable before CMT credit (amount F6 from Schedule 5)		444,551 1		
For a corporation that is not a life insurance corporation:				
CMT after foreign tax credit deduction (amount D from Part 3)	154,366 2			
For a life insurance corporation:				
Gross CMT (line 540 from Part 3)	3			
Gross SAT (line 460 from Part 6 of Schedule 512)	4			
The **greater** of amounts 3 and 4	5			
Deduct: line 2 or line 5, whichever applies:		154,366 6		
Subtotal (if negative, enter "0")		290,185 ▶	290,185	N
Ontario corporate income tax payable before CMT credit (amount F6 from Schedule 5)		444,551		
Deduct:				
Total refundable tax credits excluding Ontario qualifying environmental trust tax credit (amount J6 **minus** line 450 from Schedule 5)		16,644		
Subtotal (if negative, enter "0")		427,907 ▶	427,907	O
CMT credit deducted in the current tax year (least of amounts M, N, and O)				P

Enter amount P on line 418 of Schedule 5 and on line I in Part 4 of this schedule.

Is the corporation claiming a CMT credit earned before an acquisition of control? 675 1 Yes ☐ 2 No ☒

If you answered **yes** to the question at line 675, the CMT credit deducted in the current tax year may be restricted. For information on how the deduction may be restricted, see subsections 53(6) and (7) of the Ontario Act.

Part 6 – Analysis of CMT credit available for carryforward by year of origin

Complete this part if:
- the tax year includes January 1, 2009; or
- the previous tax year-end is deemed to be December 31, 2008, under subsection 249(3) of the federal Act.

Year of origin	CMT credit balance *
10th previous tax year	680
9th previous tax year	681
8th previous tax year	682
7th previous tax year	683
6th previous tax year	684
5th previous tax year	685
4th previous tax year	686
3rd previous tax year	687
2nd previous tax year	688
1st previous tax year	689
Total **	

* CMT credit that was earned (by the corporation, predecessors of the corporation, and subsidiaries wound up into the corporation) in each of the previous 10 tax years and has not been deducted.

** Must equal the total of the amounts entered on lines 620 and 650 in Part 4.

Part 7 – Calculation of CMT loss carryforward

CMT loss carryforward at the end of the previous tax year * . . . . _______ Q

Deduct:

CMT loss expired * . . . . 700 _______

CMT loss carryforward at the beginning of the tax year * (see note below) . . . . _______ ▶ 720 _______

Add:

CMT loss transferred on an amalgamation under section 87 of the federal Act ** (see note below) . . . . 750 _______

CMT loss available (line 720 **plus** line 750) . . . . _______ R

Deduct:

CMT loss deducted against adjusted net income for the tax year (lesser of line 490 (if positive) and line C in Part 3) . . . . _______

Subtotal (if negative, enter "0") _______ S

Add:

Adjusted net loss for CMT purposes (amount from line 490 in Part 2, if **negative**) (enter as a positive amount) . . . . 760 _______

CMT loss carryforward balance at the end of the tax year (amount S **plus** line 760) . . . . 770 _______ T

* For the first harmonized T2 return filed with a tax year that includes days in 2009:
- do not enter an amount on line Q or line 700;
- for line 720, enter the amount from line 2214 of Ontario CT23 Schedule 101, *Corporate Minimum Tax (CMT)*, for the last tax year that ended in 2008.

For other tax years, enter on line Q the amount from line 770 of Schedule 510 from the previous tax year.

** Do not include an amount from a predecessor corporation if it was controlled at any time before the amalgamation by any of the other predecessor corporations.

Note: If you entered an amount on line 720 or line 750, complete Part 8.

Part 8 – Analysis of CMT loss available for carryforward by year of origin

Complete this part if:

- the tax year includes January 1, 2009; or
- the previous tax year-end is deemed to be December 31, 2008, under subsection 249(3) of the federal Act.

Year of origin	Balance earned in a tax year ending before March 23, 2007 *	Balance earned in a tax year ending after March 22, 2007 **
10th previous tax year	810	820
9th previous tax year	811	821
8th previous tax year	812	822
7th previous tax year	813	823
6th previous tax year	814	824
5th previous tax year	815	825
4th previous tax year	816	826
3rd previous tax year	817	827
2nd previous tax year	818	828
1st previous tax year		829
Total ***		

* Adjusted net loss for CMT purposes that was earned (by the corporation, by subsidiaries wound up into or amalgamated with the corporation before March 22, 2007, and by other predecessors of the corporation) in each of the previous 10 tax years that ended before March 23, 2007, and has not been deducted.

** Adjusted net loss for CMT purposes that was earned (by the corporation and its predecessors, but not by a subsidiary predecessor) in each of the previous 20 tax years that ended after March 22, 2007, and has not been deducted.

*** The total of these two columns must equal the total of the amounts entered on lines 720 and 750.

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SCHEDULE 511

ONTARIO CORPORATE MINIMUM TAX – TOTAL ASSETS AND REVENUE FOR ASSOCIATED CORPORATIONS

Name of corporation	Business Number	Tax year-end Year Month Day
Canadian Niagara Power Inc.	87249 8225 RC0002	2014-12-31

- For use by corporations to report the total assets and total revenue of all the Canadian or foreign corporations with which the filing corporation was associated at any time during the tax year. These amounts are required to determine if the filing corporation is subject to corporate minimum tax.
- Total assets and total revenue include the associated corporation's share of any partnership(s)/joint venture(s) total assets and total revenue.
- Attach additional schedules if more space is required.
- File this schedule with the *T2 Corporation Income Tax Return.*

	Names of associated corporations 200	Business number (Canadian corporation only) (see Note 1) 300	Total assets* (see Note 2) 400	Total revenue** (see Note 2) 500
1	1228158 Ontario Limited	88706 8690 RC0001	1	0
2	1606059 Ontario Inc.	86184 9107 RC0001	0	0
3	52905 Newfoundland and Labrador	80392 9546 RC0001	0	0
4	630319 BC Ltd.	87011 0616 RC0001	0	0
5	Advanced Energy Technologies, Inc.	NR	0	0
6	Algoma Power Inc.	82249 4290 RC0001	106,931,960	42,028,684
7	BC Gas (Argentina) S.A.	NR	0	0
8	BC Gas (Malaysia) SDN. BHDS.A.	NR	0	0
9	BC Gas International (Middle East)	89059 8022 RC0001	0	0
10	BC Gas International Projects Ltd.	86892 1644 RC0001	0	0
11	Belize Electric Company Limited	NR	0	0
12	Caribbean Utilities Company, Ltd.	NR	0	0
13	Central Hudson Enterprise Corp.	NR	0	0
14	Central Hudson Gas & Electric Corp.	NR	0	0
15	CH Energy Group Inc.	NR	0	0
16	Color Acquisition Sub Inc.	NR	0	0
17	Cornwall Street Railway Light and Power Company Li	12090 6839 RC0001	64,800,720	67,604,357
18	Escavada Company	NR	0	0
19	ESI Power-Walden Corporation	12628 4249 RC0001	0	0
20	Fortis Cayman Inc.	NR	0	0
21	Fortis Energy (Bermuda) Ltd.	NR	0	0
22	Fortis Energy (International) Belize	NR	0	0
23	Fortis Energy Cayman Inc.	NR	0	0
24	Fortis Energy Corporation (NCLA)	10386 4443 RC0001	0	0
25	Fortis Generation East GP Inc	83966 8308 RC0001	0	0
26	Fortis Generation Inc	83967 1096 RC0001	0	0
27	Fortis Generation Similkameen GP I	83496 7838 RC0001	0	0
28	Fortis Hydro Corporation	NR	0	0

	Names of associated corporations 200	Business number (Canadian corporation only) (see Note 1) 300	Total assets* (see Note 2) 400	Total revenue** (see Note 2) 500
29	Fortis Inc.	10185 2416 RC0001	0	0
30	Fortis Properties Corporation	89693 2449 RC0001	0	0
31	Fortis US Energy Corporation	NR	0	0
32	Fortis West Inc.	87470 8209 RC0001	0	0
33	FortisAlberta Holdings Inc.	86921 0203 RC0001	0	0
34	FortisAlberta Inc.	86929 4520 RC0001	0	0
35	FortisBC Alternative Energy Services Inc.	81144 5873 RC0001	0	0
36	FortisBC Energy (Vancouver Island) Inc.	12174 3074 RC0001	0	0
37	FortisBC Energy (Whistler) Inc.	89138 9652 RC0001	0	0
38	FortisBC Energy Inc.	10043 1592 RC0004	0	0
39	FortisBC Holdings Inc.	10534 9740 RC0004	0	0
40	FortisBC Huntington Inc.	12974 2870 RC0001	0	0
41	FortisBC Inc.	10564 5642 RC0001	0	0
42	FortisBC Pacific Holdings Inc.	87170 9101 RC0001	0	0
43	FortisBC Storage Inc.	86014 6588 RC0001	0	0
44	FortisLUX Holdings Inc. (CBCA)	82293 1242 RC0001	0	0
45	FortisOntario District Heating Inc.	89329 1740 RC0001	21,558	0
46	FortisOntario Inc.	10076 8985 RC0003	75,958,358	4,100,439
47	FortisTCI Limited	NR	0	0
48	FortisUS Holdings Nova Scotia Limited	82872 6091 RC0001	0	0
49	FortisUS Inc.	NR	0	0
50	Griffith Energy Services Inc.	NR	0	0
51	Inland Energy Corp.	11960 8529 RC0001	0	0
52	Inland Pacific Energy Services	10249 0554 RC0001	0	0
53	Maritime Electric Cayman Inc.	NR	0	0
54	Maritime Electric Company, Limited	12111 9879 RC0001	0	0
55	MEH Equities Management, Inc.	NR	0	0
56	Millennium Energy Holdings, Inc.	NR	0	0
57	Mt. Hayes (GP) Ltd.	84888 3914 RC0001	0	0
58	Newfoundland Electric Company Limited	12748 1059 RC0001	0	0
59	Newfoundland Energy Cayman Inc.	NR	0	0
60	Newfoundland Energy Luxembourg	NR	0	0
61	Newfoundland Industries Limited	87536 2774 RC0001	0	0
62	Newfoundland Power Inc.	10386 4831 RC0001	0	0
63	Powertrusion Intarnational, Inc.	NR	0	0
64	San Carlos Resources Inc.	NR	0	0
65	Southwest Energy Solutions, Inc.	NR	0	0

	Names of associated corporations 200	Business number (Canadian corporation only) (see Note 1) 300	Total assets* (see Note 2) 400	Total revenue** (see Note 2) 500
66	Terasen Gas Holdings Inc.	86602 7832 RC0002	0	0
67	Terasen International Inc.	13237 5346 RC0001	0	0
68	The Gananoque Water Power Company	10521 4068 RC0001	54,889	0
69	Tucson Electric Power Company	NR	0	0
70	Tucsonel Inc.	NR	0	0
71	Turks and Caicos Utilities Limited	NR	0	0
72	Unisource Energy Development Company	NR	0	0
73	Unisource Energy Services, Inc.	NR	0	0
74	UNS Electric, Inc.	NR	0	0
75	UNS Energy Corporation	NR	0	0
76	UNS Gas, Inc.	NR	0	0
77	Waneta Expansion General Partner	84815 4001 RC0001	0	0
78	West Kootenay Power Ltd.	89427 8670 RC0001	0	0
		Total	450 247,767,486	550 113,733,480

Enter the total assets from line 450 on line 116 in Part 1 of Schedule 510, *Ontario Corporate Minimum Tax*.
Enter the total revenue from line 550 on line 146 in Part 1 of Schedule 510.

Note 1: Enter ¨NR¨ if a corporation is not registered.

Note 2: If the associated corporation does not have a tax year that ends in the filing corporation's current tax year but was associated with the filing corporation in the previous tax year of the filing corporation, enter the total revenue and total assets from the tax year of the associated corporation that ends in the previous tax year of the filing corporation.

*** Rules for total assets**

- Report total assets in accordance with generally accepted accounting principles, adjusted so that consolidation and equity methods are not used.
- Include the associated corporation's share of the total assets of partnership(s) and joint venture(s) but exclude the recorded asset(s) for the investment in partnerships and joint ventures.
- Exclude unrealized gains and losses on assets that are included in net income for accounting purposes but not in income for corporate income tax purposes.

**** Rules for total revenue**

- Report total revenue in accordance with generally accepted accounting principles, adjusted so that consolidation and equity methods are not used.
- If the associated corporation has 2 or more tax years ending in the filing corporation's tax year, **multiply** the sum of the total revenue for each of those tax years by 365 and **divide** by the total number of days in all of those tax years.
- If the associated corporation's tax year is less than 51 weeks and is the only tax year of the associated corporation that ends in the filing corporation's tax year, **multiply** the associated corporation's total revenue by 365 and **divide** by the number of days in the associated corporation's tax year.
- Include the associated corporation's share of the total revenue of partnerships and joint ventures.
- If the partnership or joint venture has 2 or more fiscal periods ending in the associated corporation's tax year, **multiply** the sum of the total revenue for each of the fiscal periods by 365 and **divide** by the total number of days in all the fiscal periods.

Canada Revenue Agency / Agence du revenu du Canada

SCHEDULE 546

CORPORATIONS INFORMATION ACT ANNUAL RETURN FOR ONTARIO CORPORATIONS

Name of corporation	Business Number	Tax year-end Year Month Day
Canadian Niagara Power Inc.	87249 8225 RC0002	2014-12-31

- This schedule should be completed by a corporation that is incorporated, continued, or amalgamated in Ontario and subject to the Ontario *Business Corporations Act* (BCA) or Ontario *Corporations Act* (CA), except for registered charities under the federal *Income Tax Act*. This completed schedule serves as a *Corporations Information Act* Annual Return under the *Ontario Corporations Information Act*.
- Complete parts 1 to 4. Complete parts 5 to 7 only to report change(s) in the information recorded on the Ontario Ministry of Government Services (MGS) public record.
- This schedule must set out the required information for the corporation as of the date of delivery of this schedule.
- A completed Ontario *Corporations Information Act* Annual Return must be delivered within six months after the end of the corporation's tax year-end. The MGS considers this return to be delivered on the date that it is filed with the Canada Revenue Agency (CRA) together with the corporation's income tax return.
- It is the corporation's responsibility to ensure that the information shown on the MGS public record is accurate and up-to-date. To review the information shown for the corporation on the public record maintained by the MGS, obtain a Corporation Profile Report. Visit **www.ServiceOntario.ca** for more information.
- This schedule contains non-tax information collected under the authority of the Ontario *Corporations Information Act*. This information will be sent to the MGS for the purposes of recording the information on the public record maintained by the MGS.

Part 1 – Identification

100 Corporation's name (exactly as shown on the MGS public record)
Canadian Niagara Power Inc.

Jurisdiction incorporated, continued, or amalgamated, whichever is the most recent	**110** Date of incorporation or amalgamation, whichever is the most recent (Year Month Day)	**120** Ontario Corporation No.
Ontario	2004-01-01	1601365

Part 2 – Head or registered office address (P.O. box not acceptable as stand-alone address)

200 Care of (if applicable)

210 Street number	**220** Street name/Rural route/Lot and Concession number	**230** Suite number
1130	Bertie Street	

240 Additional address information if applicable (line 220 must be completed first)

250 Municipality (e.g., city, town)	**260** Province/state	**270** Country	**280** Postal/zip code
Fort Erie	ON	CA	L2A 5Y2

Part 3 – Change identifier

Have there been any changes in any of the information most recently filed for the public record maintained by the MGS for the corporation with respect to names, addresses for service, and the date elected/appointed and, if applicable, the date the election/appointment ceased of the directors and five most senior officers, or with respect to the corporation's mailing address or language of preference? To review the information shown for the corporation on the public record maintained by the MGS, obtain a Corporation Profile Report. For more information, visit **www.ServiceOntario.ca**.

300 1 If there have been no changes, enter **1** in this box and then go to "Part 4 – Certification."
If there are changes, enter **2** in this box and complete the applicable parts on the next page, and then go to "Part 4 – Certification."

Part 4 – Certification

I certify that all information given in this *Corporations Information Act* Annual Return is true, correct, and complete.

450 KING (Last name) **451** GLEN (First name)

454 ______, (Middle name(s))

460 2 Please enter one of the following numbers in this box for the above-named person: **1** for director, **2** for officer, or **3** for other individual having knowledge of the affairs of the corporation. If you are a director and officer, enter **1** or **2**.

Note: Sections 13 and 14 of the Ontario *Corporations Information Act* provide penalties for making false or misleading statements or omissions.

Complete the applicable parts to report changes in the information recorded on the MGS public record.

Part 5 – Mailing address

500 [ ] Please enter one of the following numbers in this box:
1 - Show no mailing address on the MGS public record.
2 - The corporation's mailing address is the same as the head or registered office address in Part 2 of this schedule.
3 - The corporation's complete mailing address is as follows:

510 Care of (if applicable)

520 Street number

530 Street name/Rural route/Lot and Concession number

540 Suite number

550 Additional address information if applicable (line 530 must be completed first)

560 Municipality (e.g., city, town)

570 Province/state

580 Country

590 Postal/zip code

Part 6 – Language of preference

600 [ ] Indicate your language of preference by entering **1** for English or **2** for French. This is the language of preference recorded on the MGS public record for communications with the corporation. It may be different from line 990 on the T2 return.

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SCHEDULE 550

ONTARIO CO-OPERATIVE EDUCATION TAX CREDIT

Name of corporation	Business Number	Tax year-end Year Month Day
Canadian Niagara Power Inc.	87249 8225 RC0002	2014-12-31

- Use this schedule to claim an Ontario co-operative education tax credit (CETC) under section 88 of the *Taxation Act, 2007* (Ontario).
- The CETC is a refundable tax credit that is equal to an eligible percentage (10% to 30%) of the eligible expenditures incurred by a corporation for a qualifying work placement. The maximum credit amount is $1,000 for each qualifying work placement ending before March 27, 2009, and $3,000 for each qualifying work placement beginning after March 26, 2009. For a qualifying work placement that straddles March 26, 2009, the maximum credit amount is prorated.
- Eligible expenditures are salaries and wages (including taxable benefits) paid or payable to a student in a qualifying work placement, or fees paid or payable to an employment agency for services performed by the student in a qualifying work placement. These expenditures must be paid on account of employment or services, as applicable, at a permanent establishment of the corporation in Ontario. Expenditures for a work placement (WP) are not eligible expenditures if they are greater than the amounts that would be paid to an arm's length employee.
- A WP must meet all of the following conditions to be a qualifying work placement:
  - the student performs employment duties for a corporation under a qualifying co-operative education program (QCEP);
  - the WP has been developed or approved by an eligible educational institution as a suitable learning situation;
  - the terms of the WP require the student to engage in productive work;
  - the WP is for a period of at least 10 consecutive weeks or, in the case of an internship program, not less than 8 consecutive months and not more than 16 consecutive months;
  - the student is paid for the work performed in the WP;
  - the corporation is required to supervise and evaluate the job performance of the student in the WP;
  - the institution monitors the student's performance in the WP; and
  - the institution has certified the WP as a qualifying work placement.
- Make sure you keep a copy of the letter of certification from the Ontario eligible educational institution containing the name of the student, the employer, the institution, the term of the WP, and the name/discipline of the QCEP to support the claim. Do not submit the letter of certification with the *T2 Corporation Income Tax Return*.
- File this schedule with the *T2 Corporation Income Tax Return*.

Part 1 – Corporate information

110 Name of person to contact for more information	120 Telephone number including area code
HARRY CLUTTERBUCK	(905) 871-0330

Is the claim filed for a CETC earned through a partnership?* . . . . **150** 1 Yes [ ] 2 No [X]

If you answered **yes** to the question at line 150, what is the name of the partnership? . . . . **160** ____________

Enter the percentage of the partnership's CETC allocated to the corporation . . . . **170** ______ %

* When a corporate member of a partnership is claiming an amount for eligible expenditures incurred by a partnership, complete a Schedule 550 for the partnership as if the partnership were a corporation. Each corporate partner, other than a limited partner, should file a separate Schedule 550 to claim the partner's share of the partnership's CETC. The allocated amounts can not exceed the amount of the partnership's CETC.

Part 2 – Eligibility

1. Did the corporation have a permanent establishment in Ontario in the tax year? . . . . **200** 1 Yes [X] 2 No [ ]
2. Was the corporation exempt from tax under Part III of the *Taxation Act*, 2007 (Ontario)? . . . . **210** 1 Yes [ ] 2 No [X]

If you answered **no** to question 1 or **yes** to question 2, then the corporation is **not eligible** for the CETC.

Part 3 – Eligible percentage for determining the eligible amount

Corporation's salaries and wages paid in the previous tax year * **300** 10,869,635

For eligible expenditures incurred before March 27, 2009:

– If line 300 is $400,000 or less, enter 15% on line 310.
– If line 300 is $600,000 or more, enter 10% on line 310.
– If line 300 is more than $400,000 and less than $600,000, enter the percentage on line 310 using the following formula:

$$\text{Eligible percentage} = 15\,\% - \left[5\,\% \times \left(\frac{\text{amount on line 300} \quad \textbf{minus} \quad \$ \quad 400{,}000}{\$ \quad 200{,}000} \right) \right]$$

Eligible percentage for determining the eligible amount . . . . **310** 10.000 %

For eligible expenditures incurred after March 26, 2009:

– If line 300 is $400,000 or less, enter 30% on line 312.
– If line 300 is $600,000 or more, enter 25% on line 312.
– If line 300 is more than $400,000 and less than $600,000, enter the percentage on line 312 using the following formula:

$$\text{Eligible percentage} = 30\,\% - \left[5\,\% \times \left(\frac{\text{amount on line 300} \quad \textbf{minus} \quad \$ \quad 400{,}000}{\$ \quad 200{,}000} \right) \right]$$

Eligible percentage for determining the eligible amount . . . . **312** 25.000 %

* If this is the first tax year of an amalgamated corporation and subsection 88(9) of the *Taxation Act, 2007* (Ontario) applies, enter the salaries and wages paid in the previous tax year by the predecessor corporations.

Part 4 – Calculation of the Ontario co-operative education tax credit

Complete a separate entry for each student for each qualifying work placement that ended in the corporation's tax year. If a qualifying work placement would otherwise exceed four consecutive months, divide the WP into periods of four consecutive months and enter each full period of four consecutive months as a separate WP. If the WP does not divide equally into four-month periods and if the period that is less than 4 months is 10 or more consecutive weeks, then enter that period as a separate WP. If that period is less than 10 consecutive weeks, then include it with the WP for the last period of 4 consecutive months. Consecutive WPs with two or more associated corporations are deemed to be with only one corporation, as designated by the corporations.

	A Name of university, college, or other eligible educational institution **400**	**B** Name of qualifying co-operative education program **405**
1.	McMaster University	Electrical Engineering
2.		

	C Name of student **410**	**D** Start date of WP (see note 1 below) **430**	**E** End date of WP (see note 2 below) **435**
1.	Michael (Li) Wang	2014-05-01	2014-08-31
2.			

Note 1: When the WP has been divided into separate periods because it exceeds four consecutive months, enter the start date for the separate WP.

Note 2: When the WP has been divided into separate periods because it exceeds four consecutive months, enter the end date for the separate WP.

Part 4 – Calculation of the Ontario co-operative education tax credit (continued)

	F1 Eligible expenditures before March 27, 2009 (see note 1 below) 450	Eligible percentage before March 27, 2009 (from line 310 in Part 3)	F2 Eligible expenditures after March 26, 2009 (see note 1 below) 452	Eligible percentage after March 26, 2009 (from line 310a in Part 3)	X Number of consecutive weeks of the WP completed by the student before March 27, 2009 (see note 3 below)	Y Total number of consecutive weeks of the student's WP (see note 3 below)
1.		10.000 %	16,244	25.000 %		17
2.		10.000 %		25.000 %		

	G Eligible amount (eligible expenditures **multiplied** by eligible percentage) (see note 2 below) 460	H Maximum CETC per WP (see note 3 below) 462	I CETC on eligible expenditures (column G or H, whichever is less) 470	J CETC on repayment of government assistance (see note 4 below) 480	K CETC for each WP (column I or column J) 490
1.	4,061	3,000	3,000		3,000
2.					

Ontario co-operative education tax credit (total of amounts in column K) **500** 3,000 **L**

or, if the corporation answered **yes** at line 150 in Part 1, determine the partner's share of amount L:

Amount L ____________ x percentage on line 170 in Part 1 ________ % = ... ____________ **M**

Enter amount L or M, whichever applies, on line 452 of Schedule 5, *Tax Calculation Supplementary – Corporations*. If you are filing more than one Schedule 550, add the amounts from line L or M, whichever applies, on all the schedules and enter the total amount on line 452 of Schedule 5.

Note 1: Reduce eligible expenditures by all government assistance, as defined under subsection 88(21) of the *Taxation Act, 2007* (Ontario), that the corporation has received, is entitled to receive, or may reasonably expect to receive, for the eligible expenditures, on or before the filing due date of the *T2 Corporation Income Tax Return* for the tax year.

Note 2: Calculate the eligible amount (Column G) using the following formula:

Column G = (column F1 x percentage on line 310) + (column F2 x percentage on line 312)

Note 3: If the WP ends before March 27, 2009, the maximum credit amount for the WP is $1,000.
If the WP begins after March 26, 2009, the maximum credit amount for the WP is $3,000.
If the WP begins before March 27, 2009, and ends after March 26, 2009, calculate the maximum credit amount using the following formula:

($1,000 x X/Y) + [$3,000 x (Y – X)/Y]

where "X" is the number of consecutive weeks of the WP completed by the student before March 27, 2009, and "Y" is the total number of consecutive weeks of the student's WP.

Note 4: When claiming a CETC for repayment of government assistance, complete a **separate entry** for each repayment and complete columns A to E and J and K with the details for the previous year WP in which the government assistance was received. Include the amount of government assistance repaid in the tax year multiplied by the eligible percentage for the tax year in which the government assistance was received, to the extent that the government assistance reduced the CETC in that tax year.

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SCHEDULE 552

ONTARIO APPRENTICESHIP TRAINING TAX CREDIT

Name of corporation	Business Number	Tax year-end Year Month Day
Canadian Niagara Power Inc.	87249 8225 RC0002	2014-12-31

- Use this schedule to claim an Ontario apprenticeship training tax credit (ATTC) under section 89 of the *Taxation Act, 2007* (Ontario).
- The ATTC is a refundable tax credit that is equal to a specified percentage (25% to 45%) of the eligible expenditures incurred by a corporation for a qualifying apprenticeship. Before March 27, 2009, the maximum credit for each apprentice is $5,000 per year to a maximum credit of $15,000 over the first 36-month period of the qualifying apprenticeship. After March 26, 2009, the maximum credit for each apprentice is $10,000 per year to a maximum credit of $40,000 over the first 48-month period of the qualifying apprenticeship. The maximum credit amount is prorated for an employment period of an apprentice that straddles March 26, 2009.
- Eligible expenditures are salaries and wages (including taxable benefits) paid to an apprentice in a qualifying apprenticeship or fees paid to an employment agency for the provision of services performed by the apprentice in a qualifying apprenticeship. These expenditures must be:
  - paid on account of employment or services, as applicable, at a permanent establishment of the corporation in Ontario;
  - for services provided by the apprentice during the first 36 months of the apprenticeship program, if incurred before March 27, 2009; and
  - for services provided by the apprentice during the first 48 months of the apprenticeship program, if incurred after March 26, 2009.
- An expenditure is not eligible for an ATTC if:
  - the same expenditure was used, or will be used, to claim a co-operative education tax credit; or
  - it is more than an amount that would be paid to an arm's length apprentice.
- An apprenticeship must meet the following conditions to be a qualifying apprenticeship:
  - the apprenticeship is in a qualifying skilled trade approved by the Ministry of Training, Colleges and Universities (Ontario); and
  - the corporation and the apprentice must be participating in an apprenticeship program in which the training agreement has been registered under the *Ontario College of Trades and Apprenticeship Act, 2009 or* the *Apprenticeship and Certification Act, 1998* or in which the contract of apprenticeship has been registered under the *Trades Qualification and Apprenticeship Act*.
- Make sure you keep a copy of the training agreement or contract of apprenticeship to support your claim. Do not submit the training agreement or contract of apprenticeship with your *T2 Corporation Income Tax Return*.
- File this schedule with your *T2 Corporation Income Tax Return*.

Part 1 – Corporate information (please print)

110 Name of person to contact for more information	120 Telephone number including area code
HARRY CLUTTERBUCK	(905) 871-0330

Is the claim filed for an ATTC earned through a partnership? * . . . . . **150** 1 Yes [ ] 2 No [X]

If **yes** to the question at line 150, what is the name of the partnership? . . . . . **160** ____

Enter the percentage of the partnership's ATTC allocated to the corporation . . . . . **170** ____ %

* When a corporate member of a partnership is claiming an amount for eligible expenditures incurred by a partnership, complete a Schedule 552 for the partnership as if the partnership were a corporation. Each corporate partner, other than a limited partner, should file a separate Schedule 552 to claim the partner's share of the partnership's ATTC. The total of the partners' allocated amounts can never exceed the amount of the partnership's ATTC.

Part 2 – Eligibility

1. Did the corporation have a permanent establishment in Ontario in the tax year? . . . . . **200** 1 Yes [X] 2 No [ ]
2. Was the corporation exempt from tax under Part III of the *Taxation Act, 2007* (Ontario)? . . . . . **210** 1 Yes [ ] 2 No [X]

If you answered **no** to question 1 or **yes** to question 2, then you are **not eligible** for the ATTC.

Part 3 – Specified percentage

Corporation's salaries and wages paid in the previous tax year * **300** 10,869,635

For eligible expenditures incurred before March 27, 2009:
- If line 300 is $400,000 or less, enter 30% on line 310.
- If line 300 is $600,000 or more, enter 25% on line 310.
- If line 300 is more than $400,000 and less than $600,000, enter the percentage on line 310 using the following formula:

$$\text{Specified percentage} = 30\,\% - \left[5\,\% \times \left(\frac{\text{amount on line 300} \;\; \textbf{minus} \;\; 400{,}000}{200{,}000} \right) \right]$$

Specified percentage . . . . **310** 25.000 %

For eligible expenditures incurred after March 26, 2009:
- If line 300 is $400,000 or less, enter 45% on line 312.
- If line 300 is $600,000 or more, enter 35% on line 312.
- If line 300 is more than $400,000 and less than $600,000, enter the percentage on line 312 using the following formula:

$$\text{Specified percentage} = 45\,\% - \left[10\,\% \times \left(\frac{\text{amount on line 300} \;\; \textbf{minus} \;\; 400{,}000}{200{,}000} \right) \right]$$

Specified percentage . . . . **312** 35.000 %

* If this is the first tax year of an amalgamated corporation and subsection 89(6) of the *Taxation Act, 2007* (Ontario) applies, enter salaries and wages paid in the previous tax year by the predecessor corporations.

Part 4 – Calculation of the Ontario apprenticeship training tax credit

Complete a **separate entry** for each apprentice that is in a qualifying apprenticeship with the corporation. When claiming an ATTC for repayment of government assistance, complete a **separate entry** for each repayment, and complete columns A to G and M and N with the details for the employment period in the previous tax year in which the government assistance was received.

	A Trade code 400	B Apprenticeship program/ trade name 405	C Name of apprentice 410
1.	434a	Powerline Technician	Curtis Cadott
2.	434a	Powerline Technician	Tim Lapp

	D Original contract or training agreement number 420	E Original registration date of apprenticeship contract or training agreement (see note 1 below) 425	F Start date of employment as an apprentice in the tax year (see note 2 below) 430	G End date of employment as an apprentice in the tax year (see note 3 below) 435
1.	PF2485	2013-01-09	2014-01-01	2014-12-31
2.	BA8018	2013-05-14	2014-01-01	2014-05-14

Note 1: Enter the original registration date of the apprenticeship contract or training agreement in all cases, even when multiple employers employed the apprentice.

Note 2: When there are multiple employment periods as an apprentice in the tax year with the corporation, enter the date that is the first day of employment as an apprentice in the tax year with the corporation. When claiming an ATTC for repayment of government assistance, enter the start date of employment as an apprentice for the tax year in which the government assistance was received.

Note 3: When there are multiple employment periods as an apprentice in the tax year with the corporation, enter the date that is the last day of employment as an apprentice in the tax year with the corporation. When claiming an ATTC for repayment of government assistance, enter the end date of employment as an apprentice for the tax year in which the government assistance was received.

Part 4 – Calculation of the Ontario apprenticeship training tax credit (continued)

	H1 Number of days employed as an apprentice in the tax year before March 27, 2009 (see note 1 below) 441	H2 Number of days employed as an apprentice in the tax year after March 26, 2009 (see note 1 below) 442	H3 Number of days employed as an apprentice in the tax year (column H1 **plus** column H2) 440	I Maximum credit amount for the tax year (see note 2 below) 445
1.		365	365	10,000
2.		133	133	3,644

	J1 Eligible expenditures before March 27, 2009 (see note 3 below) 451	J2 Eligible expenditures after March 26, 2009 (see note 3 below) 452	J3 Eligible expenditures for the tax year (column J1 **plus** column J2) 450	K Eligible expenditures **multiplied** by specified percentage (see note 4 below) 460
1.		77,613	77,613	27,165
2.		39,630	39,630	13,871

	L ATTC on eligible expenditures (lesser of columns I and K) 470	M ATTC on repayment of government assistance (see note 5 below) 480	N ATTC for each apprentice (column L or column M, whichever applies) 490
1.	10,000		10,000
2.	3,644		3,644

Ontario apprenticeship training tax credit (total of amounts in column N) **500** 13,644 **O**

or, if the corporation answered **yes** at line 150 in Part 1, determine the partner's share of amount O:

Amount O ________ x percentage on line 170 in Part 1 ________ % = ... ________ **P**

Enter amount O or P, whichever applies, on line 454 of Schedule 5, *Tax Calculation Supplementary – Corporations*. If you are filing more than one Schedule 552, add the amounts from line O or P, whichever applies, on all the schedules, and enter the total amount on line 454 of Schedule 5.

Note 1: When there are multiple employment periods as an apprentice in the tax year with the corporation, do not include days in which the individual was not employed as an apprentice.
For H1: The days employed as an apprentice must be within 36 months of the registration date provided in column E.
For H2: The days employed as an apprentice must be within 48 months of the registration date provided in column E.

Note 2: Maximum credit = ($5,000 x H1/365*) + ($10,000 x H2/365*)
* 366 days, if the tax year includes February 29

Note 3: Reduce eligible expenditures by all government assistance, as defined under subsection 89(19) of the *Taxation Act, 2007* (Ontario), that the corporation has received, is entitled to receive, or may reasonably expect to receive, in respect of the eligible expenditures, on or before the filing due date of the *T2 Corporation Income Tax Return* for the tax year.
For J1: Eligible expenditures before March 27, 2009, must be for services provided by the apprentice during the first 36 months of the apprenticeship program.
For J2: Eligible expenditures after March 26, 2009, must be for services provided by the apprentice during the first 48 months of the apprenticeship program.

Note 4: Calculate the amount in column K as follows:
Column K = (J1 x line 310) + (J2 x line 312)

Note 5: Include the amount of government assistance repaid in the tax year multiplied by the specified percentage for the tax year in which the government assistance was received, to the extent that the government assistance reduced the ATTC in that tax year.
Complete a **separate entry** for each repayment of government assistance.

Corporate Taxpayer Summary

Corporate information

Corporation's name . . . . Canadian Niagara Power Inc.

Taxation Year . . . . 2014-01-01 to 2014-12-31

Jurisdiction . . . . Ontario

BC	AB	SK	MB	ON	QC	NB	NS	NO	PE	NL	XO	YT	NT	NU	OC
				X											

Corporation is associated . . . . Y

Corporation is related . . . . Y

Number of associated corporations . . . 78

Type of corporation . . . . Corporation Controlled by a Public Corporation

Total amount due (refund) federal and provincial* . . . . -9,245

* The amounts displayed on lines "Total amount due (refund) federal and provincial" are all listed in the help. Press F1 to consult the context-sensative help.

Summary of federal information

Net income		3,888,417
Taxable income		3,865,658
Donations		22,759
Calculation of income from an active business carried on in Canada		3,888,417
Dividends paid		2,500,000
Dividends paid – Regular	2,500,000	
Dividends paid – Eligible		
Balance of the low rate income pool at the end of the previous year		
Balance of the low rate income pool at the end of the year		
Balance of the general rate income pool at the end of the previous year		
Balance of the general rate income pool at the end of the year		
Part I tax (base amount)		1,468,950

Credits against part I tax		Summary of tax		Refunds/credits	
Small business deduction		Part I	575,848	ITC refund	
M&P deduction		Part IV		Dividends refund	
Foreign tax credit		Part III.1		Instalments	1,013,000
Investment tax credits	4,000	Other*		Surtax credit	
Abatement/Other*	889,102	Provincial or territorial tax	427,907	Other*	

Balance due/refund (–) -9,245

* The amounts displayed on lines "Other" are all listed in the Help. Press F1 to consult the context-sensitive help.

Summary of federal carryforward/carryback information

Carryforward balances

Cumulative eligible capital	91,343
Financial statement reserve	4,970,962

Summary of provincial information – provincial income tax payable

	Ontario	Québec (CO-17)	Alberta (AT1)
Net income	3,888,417		
Taxable income	3,865,658		
% Allocation	100.00		
Attributed taxable income	3,865,658		
Tax payable before deduction*	444,551		
Deductions and credits			
Net tax payable	444,551		
Attributed taxable capital	N/A		N/A
Capital tax payable**	N/A		N/A
Total tax payable***	444,551		
Instalments and refundable credits	16,644		
Balance due/Refund (-)	427,907		
Logging tax payable (COZ-1179)			
Tax payable	N/A		N/A

* For Québec, this includes special taxes.

** For Québec, this includes compensation tax and registration fee.

*** For Ontario, this includes the corporate minimum tax, the Crown royalties' additional tax, the transitional tax debit, the recaptured research and development tax credit and the special additional tax debit on life insurance corporations. The Balance due/Refund is included in the federal Balance due/refund.

Summary – taxable capital

Federal

Corporate name	Taxable capital used to calculate the business limit reduction (T2, line 415)	Taxable capital used to calculate the SR&ED expenditure limit for a CCPC (Schedules 31 and 49)	Taxable capital used to calculate line 233 of the T2 return	Taxable capital used to calculate line 234 of the T2 return
Canadian Niagara Power Inc.			47,595,821	47,595,821
1228158 Ontario Limited	1		1	1
1606059 Ontario Inc.				
52905 Newfoundland and Labrador				
630319 BC Ltd.				
Advanced Energy Technologies, Inc.				
Algoma Power Inc.	41,683,727		42,460,469	42,460,469
BC Gas (Argentina) S.A.				
BC Gas (Malaysia) SDN. BHDS.A.				
BC Gas International (Middle East)				
BC Gas International Projects Ltd.				
Belize Electric Company Limited				
Caribbean Utilities Company, Ltd.				
Central Hudson Enterprise Corp.				
Central Hudson Gas & Electric Corp.				
CH Energy Group Inc.				
Color Acquisition Sub Inc.				
Cornwall Street Railway Light and Power Company Limited	22,072,035		23,218,403	23,218,403
Escavada Company				
ESI Power-Walden Corporation				
Fortis Cayman Inc.				
Fortis Energy (Bermuda) Ltd.				
Fortis Energy (International) Belize				
Fortis Energy Cayman Inc.				
Fortis Energy Corporation (NCLA)				

Federal

Corporate name	Taxable capital used to calculate the business limit reduction (T2, line 415)	Taxable capital used to calculate the SR&ED expenditure limit for a CCPC (Schedules 31 and 49)	Taxable capital used to calculate line 233 of the T2 return	Taxable capital used to calculate line 234 of the T2 return
Fortis Generation East GP Inc				
Fortis Generation Inc				
Fortis Generation Similkameen GP I				
Fortis Hydro Corporation				
Fortis Inc.				
Fortis Properties Corporation				
Fortis US Energy Corporation				
Fortis West Inc.				
FortisAlberta Holdings Inc.				
FortisAlberta Inc.				
FortisBC Alternative Energy Services Inc.				
FortisBC Energy (Vancouver Island) Inc.				
FortisBC Energy (Whistler) Inc.				
FortisBC Energy Inc.				
FortisBC Holdings Inc.				
FortisBC Huntington Inc.				
FortisBC Inc.				
FortisBC Pacific Holdings Inc.				
FortisBC Storage Inc.				
FortisLUX Holdings Inc. (CBCA)				
FortisOntario District Heating Inc.	2,871		2,871	2,871
FortisOntario Inc.	179,251,714		184,077,336	184,077,336
FortisTCI Limited				
FortisUS Holdings Nova Scotia Limited				
FortisUS Inc.				
Griffith Energy Services Inc.				
Inland Energy Corp.				
Inland Pacific Energy Services				
Maritime Electric Cayman Inc.				
Maritime Electric Company, Limited				
MEH Equities Management, Inc.				
Millennium Energy Holdings, Inc.				
Mt. Hayes (GP) Ltd.				
Newfoundland Electric Company Limited				
Newfoundland Energy Cayman Inc.				
Newfoundland Energy Luxembourg				
Newfoundland Industries Limited				
Newfoundland Power Inc.				
Powertrusion Intarnational, Inc.				
San Carlos Resources Inc.				
Southwest Energy Solutions, Inc.				
Terasen Gas Holdings Inc.				
Terasen International Inc.				
The Gananoque Water Power Company	54,889		54,889	54,889
Tucson Electric Power Company				
Tucsonel Inc.				
Turks and Caicos Utilities Limited				
Unisource Energy Development Company				
Unisource Energy Services, Inc.				
UNS Electric, Inc.				
UNS Energy Corporation				
UNS Gas, Inc.				
Waneta Expansion General Partner				

Federal

Corporate name	Taxable capital used to calculate the business limit reduction (T2, line 415)	Taxable capital used to calculate the SR&ED expenditure limit for a CCPC (Schedules 31 and 49)	Taxable capital used to calculate line 233 of the T2 return	Taxable capital used to calculate line 234 of the T2 return
West Kootenay Power Ltd.				
Total	243,065,237		297,409,790	297,409,790

Québec

Corporate name	Paid-up capital used to calculate the Québec business limit reduction (CO-771 and CO-771.1.3)	Paid-up capital used to calculate the tax credit for investment (CO-1029.8.36.IN)	Paid-up capital used to calculate the 1 million deduction (CO-1137.A and CO-1137.E)
Total			

Ontario

Corporate name	Specified capital used to calculate the expenditure limit – Ontario innovation tax credit (Schedule 566)
Total	

Other provinces

Corporate name	Capital used to calculate the Newfoundland and Labrador capital deduction on financial institutions (Schedule 306)	Taxable capital used to calculate the Nova Scotia capital deduction on large corporations (Schedule 343)
Total		

Five-Year Comparative Summary

Federal information (T2)

	Current year	1st prior year	2nd prior year	3rd prior year	4th prior year
Taxation year end	**2014-12-31**	**2013-12-31**	**2012-12-31**	**2011-12-31**	**2010-12-31**
Net income	3,888,417	5,130,559	1,972,544	867,866	1,745,091
Taxable income	3,865,658	5,130,559	1,951,446	867,866	1,745,091
Active business income	3,888,417	5,130,559	1,972,544	867,866	1,745,091
Dividends paid	2,500,000				
Dividends paid – Regular	2,500,000				
Dividends paid – Eligible					
LRIP – end of the previous year					
LRIP – end of the year					
GRIP – end of the previous year					
GRIP – end of the year					
Donations	22,759		21,098		
Balance due/refund (-)	-9,245	-206,956	-220,868	-40,570	-455,450

Loss carrybacks requested in prior years

Taxation year end	**2014-12-31**	**2013-12-31**	**2012-12-31**	**2011-12-31**	**2010-12-31**
Taxable income before loss carrybacks	N/A	N/A	1,951,446	867,866	1,745,091
Non-capital losses	N/A	N/A			
Net capital losses (50%)	N/A	N/A			
Restricted farm losses	N/A	N/A			
Farm losses	N/A	N/A			
Listed personal property losses (50%)	N/A	N/A			
Total loss carried back to prior years	N/A	N/A			
Adjusted taxable income after loss carrybacks	N/A	N/A	1,951,446	867,866	1,745,091

Losses in the current year carried back to previous years (according to Schedule 4)

Taxation year end	**2014-12-31**	**2013-12-31**	**2012-12-31**	**2011-12-31**	**2010-12-31**
Adjusted taxable income before current year loss carrybacks*	N/A	5,130,559	1,951,446	867,866	N/A
Non-capital losses	N/A				N/A
Net capital losses (50%)	N/A				N/A
Restricted farm losses	N/A				N/A
Farm losses	N/A				N/A
Listed personal property losses (50%)	N/A				N/A
Total current year losses carried back to prior years	N/A				N/A
Adjusted taxable income after loss carrybacks	N/A	5,130,559	1,951,446	867,866	N/A

* The adjusted taxable income before current year loss carryback takes into account loss carrybacks that were made in prior taxation years.

Federal taxes

Taxation year end	**2014-12-31**	**2013-12-31**	**2012-12-31**	**2011-12-31**	**2010-12-31**
Part I	575,848	765,583	292,716	143,197	314,117
Part IV					
Part III.1					
Other*					

* The amounts displayed on lines "Other" are all listed in the help. Press F1 to consult the context-sensative help.

Credits against part I tax

Taxation year end	2014-12-31	2013-12-31	2012-12-31	2011-12-31	2010-12-31
Small business deduction					
M&P deduction					
Foreign tax credit					
Political contribution					
Investment tax credit	4,000	4,000			
Abatement/other*	889,102	1,180,029	448,833	186,592	349,018

* The amounts displayed on lines "Other" are all listed in the help. Press F1 to consult the context-sensative help.

Refunds/credits

Taxation year end	2014-12-31	2013-12-31	2012-12-31	2011-12-31	2010-12-31
ITC refund					
Dividend refund					
Instalments	1,013,000	1,525,000	738,000	271,000	1,056,000
Surtax credit					
Other*					

* The amounts displayed on lines "Other" are all listed in the help. Press F1 to consult the context-sensative help.

Ontario

Taxation year end	2014-12-31	2013-12-31	2012-12-31	2011-12-31	2010-12-31
Net income	3,888,417	5,130,559	1,972,544	867,866	1,745,091
Taxable income	3,865,658	5,130,559	1,951,446	867,866	1,745,091
% Allocation	100.00	100.00	100.00	100.00	100.00
Attributed taxable income	3,865,658	5,130,559	1,951,446	867,866	1,745,091
Surtax					
Income tax payable before deduction	444,551	590,014	224,416	101,956	226,719
Income tax deductions /credits					
Net income tax payable	444,551	590,014	224,416	101,956	226,719
Taxable capital					95,514,739
Capital tax payable					68,988
Total tax payable*	444,551	590,014	224,416	101,956	295,707
Instalments and refundable credits	16,644	37,553		14,723	9,274
Balance due/refund**	427,907	552,461	224,416	87,233	286,433

* For taxation years ending before January 1, 2009, this includes the corporate minimum tax and the premium tax. For taxation years ending after December 31, 2008, this includes the corporate minimum tax, the Crown royalties' additional tax, the transitional tax debit, the recaptured research and development tax credit and the special additional tax debit on life insurance corporations.

** For taxation years ending after December 31, 2008, the Balance due/Refund is included in the federal Balance due/refund.

Name: Canadian Niagara Power Inc.

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Tax Year Start: 2014-01-01

Tax Year End: 2014-12-31

1. BASIS OF ACCOUNTING AND SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Incorporation

Canadian Niagara Power Inc. [the "Corporation" or "CNPI"], a wholly owned subsidiary of FortisOntario Inc. [the "parent company"] [formerly Canadian Niagara Power Company, Limited], was incorporated on February 17, 1999 to comply with the Electricity Act, 1998 (Ontario) [the "Act"]. The Act requires that the electric power transmission and distribution businesses, previously carried out by the parent company, be carried out by a separate legal entity. Effective March 31, 1999, the Corporation purchased the electric power transmission and distribution assets of its parent company and commenced operations. On January 1, 2004, the Corporation was amalgamated with Eastern Ontario Power Inc. and continued as Canadian Niagara Power Inc. The business of the Corporation is the transmission and distribution of electricity to customers within Ontario. The business is regulated by the Ontario Energy Board ["OEB"].

These financial statements include the operating results of the Fort Erie, Port Colborne and Eastern Ontario Power [Gananoque] distribution centres and the Fort Erie transmission centre.

A. BASIS OF ACCOUNTING

These financial statements have been prepared in accordance with the accounting standards for private enterprises ["ASPE"], as per Part II of the CPA Handbook - Accounting, which constitutes generally accepted accounting principles for non-publicly accountable enterprises in Canada.

B. SIGNIFICANT ACCOUNTING POLICIES

Regulation

CNPI distribution

The distribution rates of CNPI are based upon cost-of-service rate regulation by the OEB. Earnings are regulated on the basis of a rate of return on rate base plus a recovery of all allowable distribution costs of CNPI.

On May 11, 2012, CNPI filed a Cost of Service Application for electricity distribution rates effective January 1, 2013. The application included the integration of smart meter costs into rate base, the recovery of stranded assets related to conventional meters and a rate rider designed to capture additional smart meter expenditures forecast to the end of 2012. The application also proposed changes to the accounting policy and estimates for utility capital assets. Since the majority of distributors in Ontario are transitioning to International Financial Reporting Standards ["IFRS"], and the OEB is requiring consistency amongst distributors, CNPI updated amortization rates and its capitalization of overhead policy effective for 2013. The OEB commissioned an amortization study, which was used as a guideline in updating the amortization rates. Consistent with International Accounting Standard 16 under IFRS, CNPI proposed that indirect overhead costs not be capitalized.

The OEB issued its Final Decision and Order on December 20, 2012 for new rates effective January 1, 2013, which resulted in a 6.8% increase for the average residential consumer in Fort Erie, a 5.9% increase for the average residential consumer in Gananoque and a 7.4% increase for the average residential consumer in Port Colborne effective January 1, 2013. The Decision and Order approves a 2013 base revenue requirement of $18,966,180 and provides an 8.93% return on equity ["ROE"] with a 60%/40% debt equity structure.

On August 16, 2013, CNPI filed its 2014 4th Generation Incentive Rate-setting Application ["4GIRM"] for electricity distribution rates effective January 1, 2014. This application was based on the OEB's guidelines for 4th Generation Incentive Regulation Mechanism. On January 9, 2014, the OEB issued its Decision and Order for CNPI; the final 4th Generation Incentive Price Index was 1.25% comprising 1.7% inflation, a 0% productivity factor and a 0.45% stretch factor [i.e., 1.7% - (0% + 0.45%)]. Rates were effective January 1, 2014. The overall bill impact for the average residential consumer is a 0.9% increase in Fort Erie, a 0.8% increase for the average residential consumer in Gananoque, and a 0.2% increase for the average residential consumer in Port Colborne.

On August 13, 2014, CNPI submitted its 2015 4GIRM, for electricity distribution rates effective January 1, 2015. This application is a second in a series of rate applications to fully harmonize electricity distribution rates in Port Colborne with those of Fort Erie and Gananoque. The OEB issued its Decision and Order on December 4, 2014, and the net price cap index adjustment for 2015 is 1.15% [i.e. 1.6% - (0% + 0.45%)]. The overall bill impact for the average residential consumer in Fort Erie is a 1.4% decrease, a 1.5% decrease for the average residential consumer in Gananoque, and a 3.2% decrease for the average residential consumer in Port Colborne. These overall decreases are the result of the disposition of regulatory deferral and variance accounts.

CNPI transmission

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The transmission rates of CNPI are based upon cost-of-service rate regulation by the OEB. Earnings are regulated on the basis of a rate of return on rate base plus a recovery of all allowable transmission costs of CNPI.

On November 17, 2014, CNPI submitted a Revenue Requirement Application for its Transmission business. This Application seeks approval of CNPI's 2015 and 2016 Transmission Revenue Requirement. It is anticipated that the OEB's review of this Application will occur in the first quarter of 2015.

Materials and supplies

Materials and supplies are recorded at average cost. Materials and supplies expensed to operating expenses in 2014 were $119 [2013 - $82].

Utility capital assets, capitalization policy and service life of utility capital assets

Nature of distribution and transmission assets

Distribution assets

Distribution assets are those used to distribute electricity at lower voltages [generally below 50 kilovolts]. These assets include poles, towers and fixtures, low-voltage wires, transformers, overhead and underground conductors, street lighting, meters, metering equipment and other related equipment.

Transmission assets

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Transmission assets are those used to transmit electricity at higher voltages [generally at 50 kilovolts and above]. These assets include poles, wires and conductors, substations, support structures and other related equipment.

Utility capital assets are stated at cost less accumulated amortization. Amortization is provided over the estimated useful lives of the utility capital assets using the straight-line method at a composite rate of 3.2% [2013 - 3.2%].

Contributions in aid of construction represent funding of utility capital assets contributed by customers. These accounts are being reduced annually by an amount equal to the charge for amortization provided on the contributed portion of the assets involved.

Capitalization policy and service life of utility capital assets

General expenses capitalized ["GEC"] are capitalized overhead costs that are not directly attributable to specific utility capital assets, but relate to the Corporation's overall capital program. Prior to 2013, GEC was permitted to be capitalized by the OEB's Distribution Rate Handbook and Accounting Procedures Handbook. In 2012, CNPI filed a cost of service application with the OEB based on a 2013 Test Year. The OEB is currently using "modified IFRS" as an accounting basis. As discussed in "Regulation" above, CNPI had proposed changes to its capitalization policy in its last cost of service application. These changes encompass adjustments to the useful lives of utility capital assets, changes to labour rates and the elimination of GEC. The impact of these changes has resulted in higher operating expenses and lower amortization expense. CNPI had requested the recovery of these changes in distribution rates. The changes were approved by the OEB and were incorporated on January 1, 2013.

In 2013, these changes were accounted for prospectively for regulatory purposes, and due to the complex nature of assigning overhead costs to utility capital assets, the Corporation could not reasonably quantify the retrospective impact of these changes.

Intangible assets

Intangible assets are stated at cost less accumulated amortization. Amortization is provided over the estimated useful lives of the intangible assets using the straight-line method.

Asset retirement obligations

ASPE requires the recognition of an asset retirement obligation in the period during which a legal obligation associated with the retirement of a tangible long lived asset is incurred and when a reasonable estimate of this amount can be made.

The Corporation has determined that there are asset retirement obligations associated with some parts of its transmission and distribution systems; however, none of these are material or require recognition under section 3110 of CPA Handbook.

Goodwill

Goodwill represents the excess of the acquisition cost of the shares of the Corporation, and Eastern Ontario Power Inc. [amalgamated with the Corporation as at January 1, 2004] over the assigned value of identifiable net assets acquired, as well as the excess of the purchase price of the remaining utility capital assets of Port Colborne Hydro Inc. ["PCHI"] over the fair value of these assets.

ASPE requires that goodwill shall be tested for impairment whenever events or changes in circumstances indicate that the carrying amount of the reporting unit to which the goodwill is assigned may exceed the fair value of the reporting unit. Any impairment in value is charged to earnings during the year.

Other assets

Other assets are amortized over their useful lives.

Revenue recognition

Revenue from the sale, transmission and distribution of electricity is recognized on the accrual basis. Electricity is metered upon delivery to customers and is recognized as revenue using approved rates when consumed. Meters are read periodically and bills are issued to customers based on these readings. At the end of the year a certain amount of consumed electricity will not have been billed. Electricity that is consumed but not yet billed to the customers is estimated and accrued as revenue in the current year. Unbilled revenue included in accounts receivable as at December 31, 2014 is $6,574 [2013 - $6,383].

Foreign currency translation

Monetary assets and liabilities denominated in foreign currencies are translated into Canadian dollars at the exchange rate prevailing at the balance sheet date. Gains and losses on translation are included in the statement of earnings and retained earnings. Revenue and expenses are translated at the exchange rate prevailing on the transaction date.

Employee benefit plans and change in accounting policy

Effective January 1, 2014, the Corporation has adopted new CPA Handbook Section 3462, Employee Future Benefits, for its accounting of pension benefits and other retirement benefits. As allowed under new Section 3462, the Corporation has made an accounting policy choice to measure its defined benefit plan obligations using the funding valuation approach. This approach uses the most recent completed actuarial valuations prepared for funding purposes as the basis of measuring defined benefit plan obligations. Even though other retirement benefits are not funded, Section 3462 requires that such liabilities be measured on a basis consistent with funded plans. As well, the Corporation is using a roll-forward technique in the years between valuations to estimate the defined benefit obligations. Pension plan assets are valued at fair value as of the balance sheet date. As required, the adoption of this new ASPE standard has been applied retroactively and the 2013 comparatives reflect these changes.

As a result of adopting CPA Handbook Section 3462 as of January 1, 2014, previously recognized unamortized pension and other retirement benefit amounts as at December 31, 2013 have been retroactively charged to retained earnings.

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As well, prior years' pension and other retirement expenses have been restated upon adoption of Section 3462. As a result, an amount of $4,310 has been charged to retained earnings effective January 1, 2014, offset by a corresponding increase in recorded pension liabilities of $2,386 and other retirement benefit liabilities of $1,924. The Corporation made application to the OEB to allow recognition of regulatory assets related to unamortized amounts, and restatement of prior years' pension and other retirement benefit expenses that would otherwise be collected from customers through rates in subsequent years. In December 2013, the OEB issued a Decision and Order approving the establishment of specific deferral accounts to recognize these amounts as long-term regulatory assets, which will be disposed of in future cost of service proceedings, subject to the OEB's prudence review at that time. The Corporation has recorded a corresponding increase in retained earnings for the amount of $4,310 as of January 1, 2014 and has recognized $4,310 in long-term regulatory assets. As well, the Corporation has reversed previously recognized future income tax liabilities in the amount of $1,142 related to the changes in the pension and other retirement benefit liabilities as of January 1, 2014. The Corporation has recognized offsetting regulatory liabilities related to the future income taxes expected to be recovered from customers in future electricity rates as of January 1, 2014 in the amount of $1,142. Therefore, there is no retroactive change to retained earnings as a result of the adoption of Section 3462

The Corporation made an application to the OEB to continue to account for pension and other retirement benefits under the former Section 3461. In December 2013, the OEB issued a Decision and Order approving the establishment of specific variance accounts as of January 1, 2013 to recognize the difference in expense between Sections 3461 and 3462 as long-term regulatory assets or liabilities for 2013 and future years, which will be disposed of in future cost of service proceedings, subject to the OEB's prudence review at that time. For 2014, the difference in expense between former Section 3461 and the new Section 3462 using the funding valuation approach is a charge to income of $2,004 for pension expense, and a charge to income of $26 for other retirement benefits. Therefore, a total of $2,030 has been recognized as long -term regulatory liabilities in accordance with the OEB Decision and Order in 2014. As well, an amount of $538 related to future income taxes on these amounts has been recognized as long-term regulatory assets in 2014.

Income taxes

The Corporation follows the asset and liability method of accounting for income taxes. Under this method, future tax assets and liabilities are recognized for the temporary differences between the tax and accounting bases of assets and liabilities. Future tax assets and liabilities are measured using the enacted and substantively enacted tax rates and laws expected to apply to taxable income in the period in which the temporary differences are expected to be recovered or settled. Effective January 1, 2009, the Corporation recognizes regulatory assets related to future income tax liabilities in the amount of future income taxes expected to be recovered from customers in future electricity rates.

Use of estimates

The preparation of financial statements in conformity with ASPE requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenue and expenses during the reporting periods. Actual results may vary from the current estimates. These estimates are reviewed periodically and, as adjustments become necessary, they are reported in earnings in the period in which they become known.

2. UTILITY CAPITAL ASSETS

Utility capital assets consist of the following:

2014

	Cost	Accumulated amortization	Net book value
	$	$	$
Transmission	28,566	12,983	15,583
Distribution	114,068	37,170	76,898
Other	15,846	9,964	5,882
	158,480	60,117	98,363

2013

	Cost	Accumulated amortization	Net book value
	$	$	$

Transmission	26,223	12,251	13,972
Distribution	107,761	34,341	73,420
Other	14,814	9,189	5,625
	148,798	55,781	93,017

The amounts above include assets under construction of $7,035 [2013 - $4,206]

which are not subject to amortization.

?

3. INTANGIBLE ASSETS

Intangible assets consist of the following:

	2014		
		Accumulated	Net book
	Cost	amortization	value
	$	$	$
Software costs	11,002	6,649	4,353
Land and transmission rights	6,985	2,763	4,222
Other	287	79	208
	18,274	9,491	8,783

	2013		
		Accumulated	Net book
	Cost	amortization	value
	$	$	$

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Software costs 10,080 5,968 4,112

Land and transmission rights 6,989 2,590 4,399

Other 287 72 215

17,356 8,630 8,726

4. EMPLOYEE FUTURE BENEFITS

The Corporation is a participating employer with its parent company in a defined benefit pension plan and a defined benefit plan providing other retirement benefits. The Corporation also maintains a defined contribution pension plan providing pension benefits and makes contributions to the Ontario Municipal Employees' Retirement System ["OMERS"] plan on behalf of some of its employees. OMERS is a multi-employer defined benefit pension plan providing pension benefits and is accounted for as a defined contribution pension plan.

Information about the Corporation's defined benefit plans is as follows:

Pension benefit plan Other retirement plan

2014 2013 2014 2013

$ $ $ $

[restated] [restated]

Accrued benefit obligation

Balance, beginning of year 14,752 14,361 6,498 6,386

Current service cost 386 368 90 86

Finance cost 700 682 309 303

Benefits paid (675) (652) (291) (317)

Actuarial losses (gains) (24) (7) 46 40

Balance, end of year 15,139 14,752 6,652 6,498

Plan assets

Fair value, beginning of year 15,838 14,635 -- --

Interest income 747 683 -- --

Return on plan assets 1,807 46 -- --

Contributions 1,120 1,126 291 317

Benefits paid (675) (652) (291) (317)

Fair value, end of year 18,837 15,838 -- --

Funded status - plan surplus (deficit) 3,698 1,086 (6,652)
(6,498)

The measurement date for the plan assets and the accrued benefit obligation is December 31, 2014. The effective date of the most recent actuarial valuation was as at December 31, 2011 and the date of the next required valuation for funding purposes is December 31, 2014.

The defined benefit pension plan assets held at the measurement date are represented by the following categories:

%

Canadian equity funds 14

US equity funds 13

EAFE equity funds 11

Canadian fixed income funds 60

Cash and short-term investments 2

	Pension benefit plans		Other retirement plans	
	2014	2013	2014	2013
	$	$	$	$
		[restated]		[restated]
Significant assumptions used				
Discount rate - beginning of year	4.75%	4.75%	4.75%	4.75%
Discount rate - end of year	4.75%	4.75%	4.75%	4.75%
Rate of compensation increase	4.00%	4.00%	-	-
Initial health care trend rate	-	-	5.93%	5.96%
Average remaining service life of active employees [years]	5	6	16	17

Net benefit expense for the year				
Current service cost	386	368	90	86
Finance cost	(47)	(1)	309	303
Remeasurement costs	(1,823)	(61)	46	40
Regulatory adjustments	2,004	312	26	23
Net benefit expense	520	618	471	452

The total expense for the Corporation's defined contribution pension plan for the year amounted to $255 [2013 - $243]. The pension cost associated with the OMERS plan was $156 [2013 - $151].

5. INCOME TAXES

The provision for (recovery of) income taxes consists of the following:

2014 2013
$ $

Current income taxes 996 1,448
Future income taxes
Future income taxes transferred to regulatory liabilities (assets) 1,029
(1,029) (22)
22
996 1,448

During the year, the Corporation recorded $1,029 in regulatory assets and a corresponding decrease to future income tax expense, for the amount of future income taxes expected to be recovered from customers in future electricity rates.

Future income taxes are provided for temporary differences. Future tax assets and liabilities consist of the following:

2014 2013

	$	$
		[restated]
Future tax liabilities (assets)		
Utility capital assets	5,074	4,684
Employee future benefits	(786)	(1,434)
Other assets	30	39
Net future tax liabilities	4,318	3,289

6. RELATED PARTY TRANSACTIONS

During the year, the Corporation entered into the following transactions with related parties:

	2014	2013
	$	$
Receipts		
Administrative services to:		
FortisOntario Inc.	101	156
Cornwall Street Railway, Light and Power Company Limited	1,394	1,354
Algoma Power Inc.	1,903	1,892
Reimbursement of expenses paid on behalf of and services provided to:		
FortisOntario Inc.	433	380
Fortis Properties Corporation	-	16
Fortis Generation East Limited Partnership	485	547
Algoma Power Inc.	255	34

Westario Power Holdings Inc.

Grimsby Power Inc.

Cornwall Street Railway, Light and Power Company Limited 367

98

318 210

93

194

CH Energy Group Inc. 19 -

Payments

Purchased power from Fortis Generation East Limited Partnership 1,679

1,483

Management fees paid to FortisOntario Inc. 744 675

Rent paid to FortisOntario Inc. 525 515

Dividends paid to FortisOntario Inc. 2,500 -

Interest expense paid to FortisOntario Inc. 899 945

Interest expense paid to Fortis Inc. 36 -

Reimbursement for expenses paid on behalf of and services

provided from:

FortisOntario Inc. 4,524 3,426

Cornwall Street Railway, Light and Power Company Limited 416 459

Westario Power Holdings Inc. - 3

These transactions are in the normal course of operations and are measured at the exchange amount, which is the amount of consideration established and agreed to by the related parties.

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As at December 31, the amounts due to (from) related parties are as follows:

	2014	2013
	$	$
FortisOntario Inc.	10,350	5,825
Fortis Generation East Limited Partnership	73	125
Westario Power Holdings Inc.	(52)	(39)
Grimsby Power Inc.	(8)	(14)
CH Energy Group Inc.	(19)	-
	10,344	5,897
Promissory notes due to parent company	20,000	20,000

A promissory note of $20,000 due to the parent company bears interest at a rate of 4.03% and is payable on demand. There are no specific terms of repayment for this note.

Details of relationships with related parties are as follows:

" Fortis Inc. owns a 100% interest in the capital stock of FortisOntario Inc.

" FortisOntario Inc. owns a 100% interest in the capital stock of the Corporation

" Fortis Properties Corporation is a wholly owned subsidiary of Fortis Inc.

" Cornwall Street Railway, Light and Power Company Limited is a wholly owned subsidiary of FortisOntario Inc.

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" Algoma Power Inc. is a wholly owned subsidiary of FortisOntario Inc

" Westario Power Holdings Inc. is 10% owned by FortisOntario Inc.

" FortisOntario Inc. owns 10 Class B preferred shares of Niagara Power Incorporated.

" FortisOntario Inc. indirectly owns 10% of Grimsby Power Inc. through the ownership of the Class B preferred shares in Niagara Power Incorporated.

" Fortis Generation East Limited Partnership is a wholly owned subsidiary of Fortis Inc.

" CH Energy Group Inc. is a wholly owned subsidiary of Fortis Inc.

7. LONG-TERM DEBT

Long-term debt consists of the following:

	2014	2013
	$	$
7.092% senior unsecured notes due August 14, 2018	30,000	30,000
Unamortized debt issue costs	(115)	(147)
	29,885	29,853

The senior unsecured notes bear interest of 7.092% and are repayable at maturity on August 14, 2018. Interest expense on long-term debt for the year was $2,131 [2013 - $2,128].

The Corporation incurred costs of $480 that are being amortized over the term of the loan. As at December 31, 2014, the accumulated amortization was $365 [2013 - $333].

8. CAPITAL STOCK

The authorized and issued shares consist of 23,900,001 common shares without par value.

9. AMORTIZATION

Amortization consists of the following:

	2014	2013
	$	$
Amortization of utility capital assets	4,706	4,452
Amortization of contributions in aid of construction	(268)	(253)
Amortization of intangible assets	862	810
	5,300	5,009
Vehicle amortization allocated	(388)	(351)
	4,912	4,658

10. STATEMENTS OF CASH FLOWS

The net change in non-cash working capital balances related to operations consists of the following:

	2014	2013
	$	$
Accounts receivable	(61)	(627)
Income taxes receivable	186	145
Materials and supplies	(63)	29
Prepaid expenses	27	71
Accounts payable and accrued liabilities	(956)	1,099
Regulatory assets/liabilities	1,484	(351)
Due to related parties	4,447	(3,158)
	5,064	(2,792)

Supplemental cash flow information:

	2014	2013
	$	$
Interest paid	3,132	3,130
Income taxes paid	1,013	1,525

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11. FINANCIAL RISK MANAGEMENT

The Corporation is primarily exposed to credit risk, liquidity risk and market risk as a result of holding financial instruments in the normal course of business.

Credit risk: Risk that a third party to a financial instrument might fail to meet its obligations under the terms of the financial instrument.
Liquidity risk: Risk that an entity will encounter difficulty in raising funds to meet commitments associated with financial instruments.
Market risk: Risk that the fair value or future cash flows of a financial instrument will fluctuate due to changes in market prices.

Credit risk

For cash, trade and other accounts receivable due from customers, the Corporation's credit risk is limited to the carrying value on the balance sheet.

The Corporation is exposed to credit risk from its distribution customers but has various policies to minimize this risk. These policies include requiring customer deposits, performing disconnections and using third party collection agencies for overdue accounts. The Corporation has a large and diversified distribution customer base, which minimizes the concentration of this risk.

The aging of the Corporation's trade and other receivables due from customers is as follows:

	2014 $
Not past due	11,213
Past due 0-30 days	381
Past due 31-60 days	86
Past due 61 days and over	170
	11,850
Less allowance for doubtful accounts	160
	11,690

Liquidity risk

Liquidity risk to the Corporation is minimized. Financing of regulated capital and other expenditures is done through internally generated funds. These funds are a result of allowable rate regulated returns and recoveries under the OEB rate regulation mechanism.

The Corporation's parent company is a wholly owned by Fortis Inc., a large, investor owned utility that has had the ability to raise sufficient and cost effective financing. However, the ability to arrange financing on a go forward basis is subject to numerous factors including the results of operations and financial position of Fortis Inc. and its subsidiaries, conditions in the capital and bank credit markets, ratings assigned by rating agencies and general economic conditions.

To mitigate any liquidity risk, the Corporation is a party to a committed revolving credit facility and letters of credit facilities totaling $30,000, of which $15,700 is unused. This credit agreement is shared among the subsidiaries of FortisOntario Inc. and is renewed on an annual basis.

The facility is guaranteed by the parent company and bears interest at the bankers' acceptance rate plus 1.20% in the case of bankers' acceptances and at the bank's prime lending rate plus 0.20% in the case of bank loans.

The following is an analysis of the contractual maturities of the Corporation's financial liabilities as at December 31, 2014:

< 1 year 1-3 years 4-5 years > 5 years Total
$ $ $ $ $

Accounts payable and
accrued liabilities 7,139 ? ? ? 7,139
Government remittances payable 209 ? ? ? 209
Customer deposits 251 125 230 ? 606
Promissory notes due to parent company
?
?
?
20,000
20,000

Long-term debt ? ? 30,000 ? 30,000

7,599 125 30,230 20,000 57,954

Interest rate risk

Long-term debt is at fixed interest rates thereby minimizing cash flow and interest rate fluctuation exposure. The Corporation is primarily subject to risks associated with fluctuating interest rates on its short-term borrowings. Short-term borrowings for 2014 is nil [2013 - $3,000].

12. CAPITAL MANAGEMENT

The Corporation manages its capital to approximate the deemed capital structure reflected in the utility's customer rates. Effective January 1, 2013, the distribution rates are based on a deemed capital structure of 60% debt and 40% equity. The Corporation's capital structure consists of third party debt, affiliated debt and common equity but excludes unamortized debt issue costs.

The managed capital is as follows:

	2014 Actual		2013 Actual	
	$	%	$	%
Debt	50,000	51	50,000	52
Equity	47,596	49	45,375	48
	97,596	100	95,375	100

The Corporation's long-term debt obligations and credit facility agreements have covenants that restrict the issuance of additional debt such that debt cannot exceed 75% of their capital structures as defined in the agreements. As at December 31, 2014, the Corporation was in compliance with its debt covenants.

13. REGULATORY ASSETS AND LIABILITIES

Regulatory assets and regulatory liabilities arise as a result of regulatory requirements.

The Corporation pays the cost of power on behalf of its customers and recovers these costs through retail billings to its customers. The cost of power includes charges for transmission, wholesale market operations and the power itself from Ontario's Independent Electricity System Operator. The balance of the retail settlement variance account represents the costs that have not been recovered from, or settled through, customers as of the balance sheet date. The OEB's Distribution Rate Handbook and Accounting Procedures Handbook allow these costs to be deferred and recovered through future rate adjustments, as discussed in note 1. In the absence of rate regulation, these costs would be expensed in the period that they are incurred.

The OEB has the general power to include or exclude costs, revenues, gains or losses in the rates of a specific period, resulting in the timing of revenue and expense recognition that may differ in the Corporation's regulated operations from those otherwise expected in non-regulated businesses. This change in timing gives rise to the recognition of regulatory assets and liabilities. The Corporation continually assesses the likelihood of recovery of its regulatory assets and believes that its regulatory assets and liabilities will be factored into the setting of future rates as discussed in note 1. If future recovery through rates is no longer considered probable, the appropriate carrying amount will be written off in the period that the assessment is made.

In 2013, upon approval by the OEB, the Corporation integrated smart meters into rate base from amounts previously held as regulatory assets of $4,365 as well as removed stranded meter assets of $1,238 from capital assets and recognized these amounts as regulatory assets.

In 2013 the smart meter revenue and expense balances previously held in regulatory assets were transferred to the statement of earnings and retained earnings per the guidance provided in the OEB Accounting Procedures Handbook. The net disposition costs were $237.

The following table provides the detailed revenue and costs associated with the smart meter disposition costs.

	2014	2013
	$	$
Billed revenue	?	2,049
Less: return on equity previously booked	?	(1,004)
	?	1,045

Name: Canadian Niagara Power Inc.

BN: 87249 8225 RC 0002
Tax Year Start: 2014-01-01
Tax Year End: 2014-12-31

Amortization ? (1,101)

Operating costs ? (51)

Reduction in regulatory interest income ? (130)

Net smart meter disposition costs ? (237)

Regulatory assets and liabilities are not subject to a regulatory return; however, the balances include an accrual for interest recovery/payable as permitted by the regulators.

2014 2013 Remaining

rebate

$ $ period

[restated]

Current regulatory assets

Amounts approved in current rates 260 1,742 1 year

Long-term regulatory assets

Retail settlement and other variance accounts 2,343 1,167 2 years

Amounts approved in current rates 84 167 2 years

Future taxes to be recovered from customers 4,318 3,289 life of

assets

Pension and other retirement benefits 2,293 4,310 EARSL

9,038 8,933

Current regulatory liabilities

Ontario Clean Energy benefits 629 631 1 month

Amounts approved in current rates 6 ? 1 year

Other 64 66

699 697

Long-term regulatory liabilities

Retail settlement and other variance accounts	2,928	1,704	2 years
Other	84	168	2 years
	3,012	1,872	

14. SEGMENTED INFORMATION

[a] Earnings

	2014		
	CNPI	CNPI	
	Distribution	Transmission	Total
	$	$	$
Revenue	76,463	4,854	81,317
Purchased power	56,490	-	56,490
Operating expenses	9,296	1,738	11,034
Amortization	4,014	898	4,912
Operating earnings	6,663	2,218	8,881
Interest expense	2,617	547	3,164
Income taxes	706	290	996
Net earnings	3,340	1,381	4,721

2013

	CNPI Distribution $	CNPI Transmission $	Total $
Revenue	73,332	4,856	78,188
Purchased power	53,921	-	53,921
Operating expenses	9,012	1,698	10,710
Amortization	3,864	794	4,658
Operating earnings	6,535	2,364	8,899
Net smart meter disposition costs	237	-	237
Interest expense	2,623	531	3,154
Income taxes	970	478	1,448
Net earnings	2,705	1,355	4,060

[b] Utility capital assets

	2014		
	CNPI Distribution $	CNPI Transmission $	Total $
Cost	129,808	28,672	158,480
Accumulated amortization	47,133	12,984	60,117
	82,675	15,688	98,363

	2013		
	CNPI	CNPI	
	Distribution	Transmission	Total
	$	$	$
Cost	122,575	26,223	148,798
Accumulated amortization	43,530	12,251	55,781
	79,045	13,972	93,017

15. COMPARATIVE FINANCIAL STATEMENTS

The comparative financial statements have been reclassified from statements previously presented to conform to the presentation of the 2014 financial statements.

CANADIAN NIAGARA POWER INC.
PROPERTY TAXES

OEB Account	Description	2013 Board Approved	2013 Actual	Variance from 2013 Board Approved	2014 Actual	Variance from 2013 Actual	2015 Actual	Variance from 2014 Actual	2016 Bridge	Variance from 2015 Actual	2017 Test	Variance from 2016 Bridge
6105	Taxes Other Than Income Taxes	116,700	102,475	(14,225)	99,008	(3,468)	101,233	2,225	103,000	1,767	103,000	-

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NON-RECOVERABLE AND DISALLOWED EXPENSES

CNPI does not have non-recoverable or disallowed expenses in its revenue requirement.

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INTEGRITY CHECKS

CNPI confirms that the following integrity checks have been completed with respect to this Application:

- The depreciation and amortization added back in the tax model agree with the numbers disclosed in the rate base section of this Application with the exception of 2013 Actuals where a classification difference between Transmission and Distribution columns totaling $24,000 was noted. The difference is not material, has no impact on the proposed 2017 Revenue Requirement, and therefore has not been adjusted;
- With the exception of the following items, the capital additions in the UCC/CCA Schedule 8 agree with the rate base section for historical, Bridge and Test years:
    - 2013 additions per UCC/CCA Schedule 8 as compared to rate base continuity schedule differ due to the timing of smart meter additions.
    - 2014 and 2015 additions per UCC/CCA Schedule 8 and the rate base continuity schedules differ. A corresponding adjustment to the UCC/CCA Schedule 8 would result in an increase of approximately $8,000 to the 2017 Test Year Revenue Requirement as a result in increase to the Income Tax expense. As a result of the immaterial impact, changes were not made to either the UCC/CCA Schedule 8 or to the as-filed tax model in Exhibit 4, Tab 2, Schedule 12. The adjustment will be incorporated into any subsequent and final models filed during the interrogatory and hearing process.
    - Additions in OEB 1805 Distribution Land in the rate base continuity schedules in 2016 Bridge and 2017 Test are not included in the UCC/CCA Schedule 8 as CCA does not apply to this account.
- The capital deductions due to disposals in the UCC/CCA Schedule 8 do not agree with the rate base section for historical, Bridge and Test years due to differences between accounting treatment and tax treatment. These differences would not result in a material change in 2017 Test Year calculated Income Taxes;
- Schedule 8 of the most recent federal T2 tax return (2014) is filed on a CNPI consolidated basis, and includes both the Transmission and Distribution business

units. CNPI confirms that the most recent federal T2 tax return filed with the Application has a closing December 31 historical year UCC that reconciles to the consolidated CNPI total (see Table 4.14.1.1 on the following page). Schedule 8 amounts related to the Distribution business unit reconcile to the opening (January 1) 2015 Year UCC used within this Application;

- The CCA deductions in this Application's tax model for historical, Bridge and Test years agree with the numbers in the UCC schedules for the same years filed in this Application;
- There are no loss carry-forwards;
- CCA is maximized;
- Accounting OPEB and pension amounts added back on Schedule 1 to reconcile accounting income to net income for tax purposes, agree with the OM&A analysis for compensation; and
- The income tax rate used to calculate the tax expense is consistent with the CNPI's actual tax facts and evidence filed in the Application.

Table 4.14.1.1 Tie-out of CCA Schedule

DISTRIBUTION + TRANSMISSION 2014 CCA SCHEDULE

Class	Class Description	UCC 2014 Opening Balance	2014 Additions	2014 Disposals	UCC Before 1/2 Yr Adjustment	1/2 Year Rule {1/2 Additions Less Disposals}	Reduced UCC	Rate %	2014 CCA	UCC End of 2014
1	Distribution System - post 1987	31,067,315	0	0	31,067,315	0	31,067,315	4%	1,242,693	29,824,622
2	Distribution System - pre 1988	1,531,339	0	0	1,531,339	0	1,531,339	6%	91,880	1,439,459
3		58,314	0	0	58,314	0	58,314	5%	2,916	55,398
8	General Office/Stores Equip	351,806	214,282	0	566,088	107,141	458,947	20%	91,789	474,299
10	Computer Hardware/ Vehicles	1,237,715	818,068	0	2,055,783	409,034	1,646,749	30%	494,025	1,561,758
12	Computer Software	702,752	1,068,469	0	1,771,221	534,235	1,236,986	100%	1,236,985	534,236
13	Leasehold Improvements	158,235	0		158,235	0	158,235	NA	61,780	96,455
45	Computers & Systems Software acq'd post Mar 22/04	4,297	0	0	4,297	0	4,297	45%	1,934	2,362
46	System Supervisory processing	103	0	0	103	0	103	30%	31	72
47.0	New Distribution Assets	37,676,421	4,211,121	87,745	41,799,797	2,061,688	39,738,109	8%	3,179,049	38,620,748
1.3	Bldg after Mar 18/07	383,653	15,885	0	399,538	7,943	391,596	6%	23,496	376,042
50.0	Comp Equip after Mar 18/07	368,915	272,714	0	641,629	136,357	505,272	55%	277,900	363,730
	TOTAL	**73,540,864**	**6,600,539**	**87,745**	**80,053,658**	**3,256,397**	**76,797,261**		**6,704,477**	**73,349,180** A

A agrees to Schedule 8 of 2014 tax return in E4 T12 S4 of Application

DISTRIBUTION 2014 CCA SCHEDULE

Class	Class Description	UCC 2014 Opening Balance	2014 Additions	2014 Disposals	UCC Before 1/2 Yr Adjustment	1/2 Year Rule {1/2 Additions Less Disposals}	Reduced UCC	Rate %	2014 CCA	UCC End of 2014
1	Distribution System - post 1987	21,593,200	0	0	21,593,200	0	21,593,200	4%	863,728	20,729,472
2	Distribution System - pre 1988	931,793	0	0	931,793	0	931,793	6%	55,908	875,885
3		58,315	0	0	58,315	0	58,315	5%	2,916	55,399
8	General Office/Stores Equip	351,806	214,282	0	566,088	107,141	458,947	20%	91,789	474,299
10	Computer Hardware/ Vehicles	1,236,017	818,068	0	2,054,085	409,034	1,645,051	30%	493,515	1,560,570
12	Computer Software	702,751	1,068,469	0	1,771,220	534,235	1,236,985	100%	1,236,985	534,235
13	Leasehold Improvements	158,235	0	0	158,235	0	158,235	NA	61,780	96,455
45	Computers & Systems Software acq'd post Mar 22/04	4,297	0	0	4,297	0	4,297	45%	1,933	2,363
46	System Supervisory processing	103	0	0	103	0	103	30%	31	72
47.0	New Distribution Assets	33,501,646	3,323,290	87,745	36,737,191	1,617,773	35,119,419	8%	2,809,553	33,927,638
1.3	Bldg after Mar 18/07	383,654	15,885	0	399,539	7,943	391,597	6%	23,496	376,043
50.0	Comp Equip after Mar 18/07	368,915	272,714	0	641,629	136,357	505,272	55%	277,899	363,729
	TOTAL	**59,290,731**	**5,712,708**	**87,745**	**64,915,694**	**2,812,482**	**62,103,212**		**5,919,534**	**58,996,160** B

B agrees to 2014 CCA Schedule 8 in E4 T12 S3 of Application

TRANSMISSION 2014 CCA SCHEDULE

Class	Class Description	UCC 2014 Opening Balance	2014 Additions	2014 Disposals	UCC Before 1/2 Yr Adjustment	1/2 Year Rule {1/2 Additions Less Disposals}	Reduced UCC	Rate %	2014 CCA	UCC End of 2014
1	Distribution System - post 1987	9,474,114	-	-	9,474,114	-	9,474,114	4%	378,965	9,095,150
2	Distribution System - pre 1988	599,546	-	-	599,546	-	599,546	6%	35,973	563,573
3		0	-	-	0	-	0	5%	0	0
8	General Office/Stores Equip	(0)	-	-	(0)	-	(0)	20%	0	0
10	Computer Hardware/ Vehicles	1,698	-	-	1,698	-	1,698	30%	509	1,188
12	Computer Software	-	-	-	-	-	-	100%	0	0
13	Leasehold Improvements	-	-	-	-	-	-	NA	0	0
45	Computers & Systems Software acq'd post Mar 22/04	-	-	-	-	-	-	45%	0	0
46	System Supervisory processing	-	-	-	-	-	-	30%	0	0
47.0	New Distribution Assets	4,174,775	887,831	-	5,062,606	443,915	4,618,690	8%	369,495	4,693,111
1.3	Bldg after Mar 18/07	(0)	-	-	(0)	-	(0)	6%	0	0
50.0	Comp Equip after Mar 18/07	0	-	-	0	-	0	55%	0	0
	TOTAL	**14,250,133**	**887,831**	**0**	**15,137,964**	**443,915**	**14,694,048**		**784,942**	**14,353,022**

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CONSERVATION AND DEMAND MANAGEMENT COSTS

All conservation and demand management ("CDM") costs related to CNPI are funded either through the IESO-contracted Province-Wide CDM Programs or through OEB-approved CDM programs. Costs directly attributable to CDM programs are not included in the distribution rates.

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LOST REVENUE ADJUSTMENT MECHANISM

On March 31, 2011, the Minister of Energy and Infrastructure issued a directive (the "Directive") to the OEB regarding electricity CDM targets to be met by licensed electricity distributors. The Directive required that the Board amend the licenses of distributors to add, as a condition of license, the requirement for distributors to achieve reductions in electricity demand and consumption through the delivery of CDM programs over a four-year period beginning January 1, 2011. Section 12 of the Directive required that the OEB have regard to the objective that lost revenues that result from CDM Programs should not act as a disincentive to a distributor.

On April 26, 2012, the OEB issued Guidelines for Electricity Distributor Conservation and Demand Management (EB-2012-0003 – the "CDM Guidelines"). In keeping with the Directive, the OEB adopted a mechanism to capture the difference between the results of actual, verified impacts of authorized CDM activities undertaken by distributors between 2011 and 2014, and the level of activities embedded into rates through the distributors load forecast in an LRAM variance account.

LRAM for pre-2011 CDM Activities

CNPI is not requesting recovery of lost revenue resulting from any pre-2011 CDM activities or legacy programs completed in 2011.

Background

The Conservation and Demand Management Code for Electricity Distributors ("the CDM Code") sets out the obligations and requirements with which electricity distributors must comply in relation to the CDM targets set out in their licenses. The CDM Code also sets out the conditions and rules that licensed electricity distributors are required to follow if they choose to apply for OEB-Approved CDM programs to meet the CDM targets. The CDM Code applies to the four year period January 1, 2011 to December 31, 2014. In its April 26, 2012

CDM Guidelines, the OEB provided additional guidance on certain provisions in the CDM Code and details on the Lost Revenue Adjustment Mechanism ("LRAM") related to CDM programs implemented under the CDM Code. The CDM Guidelines are applicable to this same timeframe.

In the Guidelines, the OEB authorized the establishment of LRAMVA Account 1568 (LRAMVA) to capture, at the customer rate class level, the difference between:

- The results of actual, verified impacts of authorized CDM activities undertaken by distributors between 2011 and 2014 for both OEB-Approved CDM programs and OPA Contracted Province-Wide CDM programs in relation to activities undertaken by the distributor and/or delivered for the distributor by a third party under contract (in the distributor's franchise area);and

- The level of CDM program activities included in the distributor's load forecast (i.e. the level embedded in rates).

The OEB stated that distributors are generally expected to include a CDM component in their load forecast in Cost of Service proceedings to ensure that customers are realizing the true effects of conservation at the earliest date possible and to mitigate the variance between forecasted revenue losses and actual revenue losses. Further, if a distributor has included a CDM load reduction forecast in its distribution rates, the amount of the forecast that was adjusted for CDM at the rate class level would be compared to the actual CDM results verified by an independent third party for each year of the CDM program in accordance with the OPA's (now the Independent Electricity System Operator "IESO") EM&V Protocols as set out in the CDM Code. The calculated variance results in a credit or debit payable or receivable to the ratepayers. This account will continue on a going-forward basis.

In its CDM Guidelines, the OEB stated that the LRAMVA will attract carrying charges.

Further, the OEB stated that it expected distributors to apply for disposition of the balance in the LRAMVA in their next Cost of Service Rate Application.

CNPI has been successfully running IESO energy conservation and efficiency programs within its service territory since 2005. The IESO legacy programs ran, for the most part, until the end of 2010 (although there was some carry-over into 2011). New IESO programs began in 2011 following the creation of mandatory CDM targets and requirements of LDCs to attain the targets as a condition of their licence.

CNPI is not currently running any OEB-approved CDM programs.

Information related to the disposition of CNPI's LRAMVA account in the amount of $255,421, can be found at Exhibit 9, Tab 6, Schedule 1 of this application.

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CAPITAL STRUCTURE AND COST OF CAPITAL

OVERVIEW

This evidence summarizes the capital structure, method and cost of financing CNPI's capital requirements for the 2017 Test Year.

CAPITAL STRUCTURE

CNPI's current OEB-approved capital structure for rate making purposes is 4.0% short-term debt, 56.0% long-term debt and 40.0% equity. The Applicant proposes to maintain the same capital structure in the 2017 Test Year. This capital structure was confirmed by the OEB in the *Report of the Board on Cost of Capital for Ontario's Regulated Utilities* dated December 11, 2009 (the "Board Report").

CNPI's capital structure consists of third-party debt, affiliated debt and common equity. The actual capital structure is managed to approximate the Board approved deemed capital structure.

CNPI Capital Structure

($'000)	**2015 Actual**	
Debt	65,157	56.2%
Common equity	50,843	43.8%

RETURN ON EQUITY

CNPI has used a return on equity ("ROE") of 9.19% in the 2017 Test Year as established by the Board's Cost of Capital parameters letter dated October 15, 2015. The Applicant recognizes that the ROE will be updated in accordance with Board guidelines at the time of the Board's decision.

COST OF DEBT

CNPI has embedded third party long-term debt of $30 million. These 15-year senior unsecured notes were issued on August 14, 2003 and bear interest of 7.092%. The Board has confirmed in the Board Report (page 52), "the Board will primarily rely on the embedded or actual cost for existing long-term debt instruments." The Board approved this third-party debt and interest rate in CNPI's 2013 cost of service application (EB-2012-0112). CNPI has used in the 2017 Test Year this embedded debt rate of 7.092% plus the debt issue costs which are amortized over the term of the debt.

CNPI also utilizes affiliated debt to support its capital program spending requirements until the balance is sufficient to replace it with the issuance of third party long-term debt. In January 2013, CNPI issued a promissory note to FortisOntario in the amount $20 million, which bears interest at 4.03%. CNPI has used a deemed long-term debt rate of 4.54% for 2017 Test Year as established by the Board's Cost of Capital parameters letter dated October 15, 2015. The Applicant recognizes that the affiliated debt rate will be updated in accordance with Board guidelines at the time of the Board's decision.

CNPI has used a deemed short-term debt rate of 1.65% for the 2017 Test Year as established by the Board's Cost of Capital parameters letter dated October 15, 2015. The Applicant recognizes that the short-term debt rate will be updated in accordance with Board guidelines at the time of the Board's decision.

CNPI has not forecasted an issuance of additional debt in the 2016 Bridge Year and the 2017 Test Year.

Appendix 2-OB Debt Instruments is attached and provides details of outstanding long-term debt from the 2013 Board Approved to the 2017 Test Year.

A copy of the Trust Debenture providing for the issue of the Senior Unsecured Notes is attached (Appendix A). A copy of the Promissory Note payable to FortisOntario is attached (Appendix B).

COST OF CAPITAL

CNPI's 2017 Test Year cost of capital rate is 7.18%, which results in a return on capital of $6,456,937.

Appendix 2-OA Capital Structure and Cost of Capital is attached and provides details of the capital structure and cost of capital for the 2013 Board Approved and the 2017 Test Year.

Appendix A

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CANADIAN NIAGARA POWER INC.

$30,000,000 7.092% Senior Unsecured Notes due August 14, 2018

MASTER NOTE PURCHASE AGREEMENT

August 14, 2003

TORYS LLP

NEW YORK TORONTO

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Compliance with Covenants **2**

MASTER NOTE PURCHASE AGREEMENT

This Master Note Purchase Agreement (this "Agreement") is made as of the 14th day of August, 2003 among Canadian Niagara Power Inc., a corporation incorporated in Ontario, as issuer (the "Company"), Sun Life Assurance Company of Canada ("Sun Life"), Canada Life Financial Corporation ("Canada Life") and the Maritime Life Assurance Company ("Maritime Life"), as purchasers (collectively, the "Purchasers" and each a "Purchaser");

WITNESSETH:

WHEREAS the Company wishes to sell and the Purchasers wish to purchase the aggregate amount of $30,000,000 of the Company's 7.092% Senior Unsecured Notes due August 14, 2018 on the terms and conditions set forth herein and in the form of Note provided for in Exhibit 1 hereto;

NOW THEREFORE in consideration of their mutual covenants herein contained, the parties hereto, intending to be legally bound, hereby mutually covenant and agree as follows:

Article 1
Interpretation

1.1 **Definitions**

For the purposes of this Agreement:

1.1.1 **"Affiliate"** means, in respect of the Company or any Subsidiary, any Person which, directly or indirectly, controls or is controlled by or is under common control with the Company or any Subsidiary; and for the purpose of this definition, **"control"** (including, with correlative meanings, the terms **"controlled by"** and **"under common control with"**) means the power to direct, or cause to be directed, the management and policies of or by a Person whether through the ownership of voting shares or by contract or otherwise;

1.1.2 **"Affiliate Relationships Code"** means the Affiliate Relationships Code for Electricity Distributors and Transmitters originally issued by the OEB on April 1, 1999 as revised on February 1, 2001, as amended, restated or replaced from time to time;

1.1.3 **"Agreement"** means this note purchase agreement and all exhibits and schedules attached to this agreement, in each case as they may be amended or supplemented from time to time; the expressions **"hereof"**, **"herein"**, **"hereto"**, **"hereunder"**, **"hereby"** and similar expressions refer to this Agreement as a whole and not to any particular article, section, schedule or other portion hereof, and the expression **"article"** and **"section"** followed by a number, and **"schedule"** or **"exhibit"** followed by a number, mean and refer to the specified article or section of or schedule to or exhibit to this Agreement, except as otherwise specifically provided herein;

1.1.4 **"Applicable Law"** means, in respect of any Person, property, transaction, event or course of conduct, all applicable laws (including, without limitation, Environmental Laws), statutes, rules, by-laws and regulations, regulatory policies and all applicable official directives, orders, rulings, notices, judgments and decrees of Governmental Bodies (whether or not having the force of law);

1.1.5 **"Asset Sale"** means in respect of any Person, the sale, lease, securitization, conveyance or other disposition of any assets of such Person (including without limitation a sale by way of shares) other than the sale of current assets in the ordinary course of business of such Person or a Sale and Leaseback Transaction. Notwithstanding the foregoing, sales of property or equipment that become worn-out, obsolete or damaged or are otherwise unsuitable for use in the business of the Company or the Subsidiary and transfers by the Company or a Subsidiary to another Subsidiary or to the Company, as the case may be, will not be deemed to be an "Asset Sale" for the purposes of this definition;

1.1.6 **"Asset Sale Report"** means a written report of the Company summarizing (i) the Asset Sales made during the relevant fiscal quarter, the net proceeds of which are greater than $2,000,000 and (ii) with respect to the last fiscal quarter only, a summary of the use of the proceeds of all Assets Sales exceeding $1,000,000 made during the relevant Fiscal Year;

1.1.7 **"Benefit Plans"** has the meaning attributed to such term in Section 1.1.31.3;

1.1.8 **"Business"** means, with respect to the Company and its Subsidiaries, the transmission and distribution of electricity in the Province of Ontario as regulated by the Regulators;

1.1.9 **"Business Assets"** means all of the property, assets and undertaking of the Company and its Subsidiaries of every nature and kind, both present and future, real and personal, tangible and intangible, including all proceeds of disposition of any such property, assets or undertaking;

1.1.10 **"Business Day"** means a day, other than a Saturday or Sunday, on which banks are generally open for business in Toronto, Ontario;

1.1.11 **"Canada Yield Price"** means a price equal to the net present value of all scheduled payments of interest (other than accrued and unpaid interest) and principal on the Notes, using as a discount rate the sum of the Government of Canada Yield, calculated at 10:00 a.m. (Toronto time) on the third Business Day preceding the Redemption Date or the purchase date, or on the date of demand, as applicable, plus 47.5 basis points;

1.1.12 **"Capital Lease"** means any lease of any property that would be classified and accounted for as a capital lease on the balance sheet of the lessee in accordance with generally accepted accounting principles;

1.1.13 **"Capital Lease Obligations"** means all obligations pursuant to a Capital Lease, provided that such Capital Lease is incurred or assumed within 18 months after the acquisition of real property or fixtures or the completion of construction, installation or improvement, as the case may be, and includes any extension, renewal or refunding of any such Capital Lease, so long as the principal amount thereof outstanding on the date of extension, renewal or refunding is not increased;

1.1.14 **"City Guarantee"** means the guarantee dated as of July 19, 2001 of The Corporation of the City of Port Colborne guaranteeing the obligations of Port Colborne Hydro Inc. pursuant to the transactions contemplated by the Master Implementation Agreement;

1.1.15 **"Company's Counsel"** means Gowling Lafleur Henderson LLP, or such other counsel as the Company may designate;

1.1.16 **"Consolidated EBITDAR"** means, as at any date, the consolidated EBITDAR of the Company and its Subsidiaries as at such date, with such consolidation determined in accordance with generally accepted accounting principles;

1.1.17 **"Consolidated Indebtedness"** means, as at any date, the aggregate amount of Consolidated Senior Indebtedness and Consolidated Subordinated Indebtedness;

1.1.18 **"Consolidated Interest Expense"** means, as at any date, the consolidated Interest Expense of the Company and its Subsidiaries as at such date determined in accordance with generally accepted accounting principles;

1.1.19 **"Consolidated Net Worth"** means, as at any date, the consolidated Net Worth of the Company and its Subsidiaries as at such date determined in accordance with generally accepted accounting principles;

1.1.20 **"Consolidated Senior Indebtedness"** means the consolidated Senior Indebtedness of the Company and its Subsidiaries, with such consolidation determined in accordance with generally accepted accounting principles;

1.1.21 **"Consolidated Senior Interest Expense"** means Consolidated Interest Expense of the Company and its Subsidiaries on all Indebtedness, other than Subordinated Indebtedness, calculated for the most recent four fiscal quarters in accordance with generally accepted accounting principles;

1.1.22 **"Consolidated Subordinated Indebtedness"** means the consolidated Subordinated Indebtedness of the Company and its Subsidiaries, with such consolidation determined in accordance with generally accepted accounting principles;

1.1.23 **"Closing"** has the meaning ascribed thereto in Section 4.1;

1.1.24 **"Closing Date"** means August 14, 2003;

1.1.25 **"Default"** means any event which, but for the lapse of time, giving of notice or both, would constitute an Event of Default;

1.1.26 **"Distribution"** means:

(a) any dividend on (or declaration thereof or any setting aside payment thereof), purchase, redemption or other acquisition for value of, or reduction of capital or other distribution in respect of the shares of the Company;

(b) any payment of principal or interest on any Subordinated Indebtedness owed by the Company or any Subsidiary to the shareholders of the Company or any Affiliates of the Company; and

(c) any payment of Management Fees, in aggregate, in excess of $1,000,000 per year, to an Affiliate of the Company other than to a Subsidiary;

1.1.27 **"EBITDAR"** means, for the Company on a consolidated basis for any period of computation thereof, its net income, increased, to the extent deducted in calculating the net income for such period, by the sum of (i) Interest Expense (ii) all income tax expense (other than income taxes attributable to extraordinary, unusual or non-recurring gains or losses or taxes attributable to sales or dispositions outside the normal course of business), (iii) depreciation and amortization expense, (iv) Rent; and (v) unusual or non-recurring non-cash charges and decreased, to the extent included in calculating the net income for such period, by the sum of all cash payments during such period relating to non-cash charges which were added back under (v) in determining EBITDAR in any prior period, all as determined in accordance with generally accepted accounting principles;

1.1.28 **"Electricity Act"** means the Electricity Act, 1998, S.O., Chp.15, Sch.A, as amended from time to time, or any successor or replacement thereof, and, to the extent they have the force of law, all regulations, rules, policies and guidelines from time to time made thereunder;

1.1.29 **"Electricity Distribution Licence"** means the Company's electricity distribution licence with the OEB pursuant to which the Company is authorized to own and operate the distribution system within Fort Erie, Ontario and to operate the distribution system in Port Colborne, subject to the conditions set out therein, together with all amendments thereto;

1.1.30 **"Electricity Supplier"** means any Person who, whether in the ordinary course of business or otherwise, sells, offers to sell, transmits, distributes or otherwise supplies electricity or ancillary services through the IMO-administered markets or directly to another Person;

1.1.31 **"Employee Plans"** means all oral or written plans, arrangements, agreements, programs, policies, practices or undertakings of or relating to the Company or any of its Subsidiaries with respect to some or all of the current or former directors, officers, employees, independent contractors or agents of the Company or any of its Subsidiaries which provide for or relate to:

1.1.31.1 bonus, profit sharing or deferred profit sharing, performance compensation, deferred or incentive compensation, share compensation, share purchase or share option purchase, share appreciation rights, phantom stock, vacation or vacation pay, sick pay, employee loans, or any other compensation in addition to salary granted or payable by the Company or any of its Subsidiaries;

1.1.31.2 retirement or retirement savings, including, without limitation, registered or unregistered pension plans, pensions, supplemental pensions, registered retirement savings plans and retirement compensation arrangements established by the Company or any of its Subsidiaries ("Pension Plans"); or

1.1.31.3 insured or self-insured benefits for or relating to income continuation or other benefits during absence from work (including short term disability, long term disability and workers compensation), hospitalization, health, welfare, legal costs or expenses, medical or dental treatments or expenses, life insurance, accident, death or survivor's benefits, supplementary employment insurance, day care, tuition or professional commitments or expenses or similar employment benefits established by the Company or any of its Subsidiaries ("Benefit Plans");

but for greater certainty, the foregoing definition expressly excludes any such oral or written plans, arrangements, agreements, programs, policies, practices or undertakings that have been established by or that are otherwise controlled by or related to the Ontario Municipal Employees Retirement System ("**OMERS**");

1.1.32 **"Environment"** means the ambient air, all layers of the atmosphere, surface water, underground water, all land, all living organisms and the interacting natural systems that include components of air, land, water, organic and inorganic matter and living organisms, and includes indoor spaces;

1.1.33 **"Environmental Laws"** mean all Applicable Laws, notices and Environmental Permits in effect as at the date hereof and as may be brought into effect at a future date, with respect to environmental matters;

1.1.34 **"Environmental Permits"** means all permits, licences, approvals, consents, authorizations, registrations and certificates issued by or provided to, as the case may be, any government, governmental or regulatory body or agency pursuant to an Environmental Law;

1.1.35 **"Event of Default"** has the meaning attributed to such term in Section 12.1;

1.1.36 **"Finance Documents"** means this Agreement and the Notes;;

1.1.37 **"Financial Instrument Obligations"** means, with respect to any Person, obligations arising under:

(a) interest rate swap agreements, forward rate agreements, floor, cap or collar agreements, futures or options, insurance or other similar agreements or arrangements, or any combination thereof, entered into or guaranteed by the Person where the subject matter thereof is interest rates or the price, value or amount payable thereunder is dependent or based upon interest rates or fluctuations in interest rates in effect from time to time (but excluding conventional floating rate indebtedness);

(b) currency swap agreements, cross-currency agreements, forward agreements, floor, cap or collar agreements, futures or options, insurance or other similar agreements or arrangements, or any combination thereof, entered into or guaranteed by the person where the subject matter thereof is currency exchange rates or the price, value or amount payable thereunder is dependent or based upon currency exchange rates or fluctuations in currency exchange rates in effect from time to time; and

(c) any agreement for the making or taking of any commodity (including, without limitation, electricity), swap agreement, floor, cap or collar agreement or commodity future or option or other similar agreement or arrangement, or any combination thereof, entered into or guaranteed by the person where the subject matter thereof is any commodity or the price, value or amount payable thereunder is dependent or based upon the price or fluctuations in the price of any commodity; or any other similar transaction, including any option to enter into any of the foregoing, or any combination of the foregoing, in each case to the extent of the net amount due or accruing due by the person under the obligations determined by marking the obligations to market in accordance with their terms;

1.1.38 **"Fiscal Year"** means the fiscal year of the Company, being January 1 to December 31;

1.1.39 **"Government of Canada Yield"**, means on any date, with respect to any Notes, the yield to maturity on such date, compounded semi-annually, which an assumed new issue of non-callable Government of Canada bonds denominated in Canada dollars would carry if issued in Canada at 100% of its principal amount on such date, with a term to maturity as nearly as possible equal to the remaining term to maturity of such Notes. The Government of Canada

Yield will be the average (rounded to four decimal points) of the bid-side yields provided by the Investment Dealers;

1.1.40 **"Governmental Body"** means any government, parliament, legislature, or any regulatory authority, agency, commission or board of any government, parliament or legislature, or any court or (without limitation to the foregoing) any other law, regulation or rule-making entity (including, without limitation, any central bank, fiscal or monetary authority or authority regulating banks), having or purporting to have jurisdiction in the relevant circumstances, or any Person acting or purporting to act under the authority of any of the foregoing (including, without limitation, any arbitrator), including, without limitation, the IMO and OEB;

1.1.41 **"Governmental Charges"** means all Taxes, levies, assessments, reassessments and other charges together with all related penalties, interest and fines, due and payable to any Governmental Body having jurisdiction in relevant circumstances;

1.1.42 **"IMO"** means the Independent Electricity Market Operator for Ontario, a not-for-profit corporation without share capital established under the Electricity Act, and its successors and assigns;

1.1.43 **"Indebtedness"** means:

(i) all obligations for borrowed money including obligations with respect to bankers' acceptances and contingent reimbursement obligations relating to letters of credit and other financial instruments;

(ii) all obligations created or arising under any conditional sale or other title retention agreement with respect to property acquired;

(iii) all guarantees of obligations of entities other than the Company or its wholly-owned Subsidiaries; and

(iv) all Capital Leases and Purchase Money Obligations.

but in any event shall not include accounts payable, income taxes payable, accrued liabilities, deferred revenue, deferred income taxes and non-controlling interests (or letters of credit or other financial instruments in support of any of these items);

1.1.44 **"Interest Expense"** of any Person for any period means the aggregate amount of interest accrued, whether paid or not, by the Person and its Subsidiaries during such period, determined on a consolidated basis in accordance with generally accepted accounting principles including, without limitation, interest payable hereunder and on other Indebtedness;

1.1.45 **"Interest Payment Date"** means, for any Note, each August 14th and February 14th on or prior to the Maturity Date, commencing on February ●, 2004;

1.1.46 **"Interest Period"** means, for any Note, each period from and including one Interest Payment Date to but excluding the next following Interest Payment Date, except that (a) the initial Interest Period for any Note will commence on and include the date hereof and (b) the final Interest Period for any Note will end on but exclude the Maturity Date for such Note;

1.1.47 **"Interest Rate"** applicable to any Interest Period for any Note means the rate specified as such in such Note;

1.1.48 **"Investment Dealers"** means any two major Canadian investment dealers (or their successors) elected by the Company from the following list:

(a) CIBC World Markets Inc.;

(b) Scotia Capital Inc.;

(c) BMO Nesbitt Burns Inc.;

(d) TD Securities Inc.;

(e) RBC Dominion Securities Inc.;

(f) Merrill Lynch; or

(g) National Bank Financial.

1.1.49 **"Lien"** means, with respect to any person, any mortgage, lien, pledge, adverse claim, charge, deed of trust, lis pendens, security interest, hypothec or other encumbrance, or any interest or title of any vendor, lessor, lender or other secured party to or of such person under any conditional sale or other title retention agreement or Capital Lease or any similar type of agreement, upon or with respect to any property or asset of such person, or the signing or filing of a financing statement that names such person as debtor, or the signing of any security agreement by such person authorizing any other person as the secured party to file any financing statement;

1.1.50 **"Majority Noteholders"** means holders of at least 66 2/3% of the principal amount of outstanding Notes issued under this Agreement excluding any Notes held by or on behalf of the Company, the Subsidiaries or their Affiliates;

1.1.51 **"Management Fees"** means management, advisory or other similar fees, whether paid pursuant to the Affiliate Relationships Code or otherwise (but excludes ordinary course commercially reasonable payments for Non-Management Services);

1.1.52 **"Master Implementation Agreement"** means the master implementation agreement dated as of July 19, 2001 among Port Colborne Hydro Inc., as Lessor, Canadian Niagara Power Inc. as Lessee, The Corporation of the City of Port Colborne, as Shareholder of the Lessor and Canadian Niagara Power Company Limited as Lessee Guarantor;

1.1.53 **"Material Adverse Effect"** means, when used with reference to any event or circumstance, an event or circumstance which has had or could reasonably be expected to have: (a) a material adverse effect on the business, assets (including the Power System), property, capital, operations, condition (financial or otherwise) of the Company and its Subsidiaries, taken as a whole, or (b) a material adverse effect on the ability of the Company or any Subsidiary to perform the obligations under any Material Authorization, Material Contract or any Finance Document to which it is a party, or (c) material adverse effect on the validity or enforceability or effectiveness of this Agreement or the rights and remedies of the Noteholders under this Agreement not attributable solely to the fault or neglect of any or all of the Noteholders;

1.1.54 **"Material Authorization"** means any Permit required by the Company or any of its Subsidiaries to own its property and assets or to carry on its Business in each jurisdiction in which it does so or is contemplated to do so, where the failure to have such Permit, would have a Material Adverse Effect;

1.1.55 **"Material Contracts"** means:

(a) this Agreement and the Notes;

(b) the Port Colborne Lease;

(c) the Electricity Distribution Licence;

(d) the Master Implementation Agreement;

(e) the City Guarantee; and

(f) any other agreements which are material to the ongoing operation or funding of the Power System entered into by the Company or any of its Subsidiaries from time to time.

and when used in relation to any Person, the term "Material Contracts" shall mean and refer to the Material Contracts executed and delivered by such Person.

1.1.56 **"Maturity Date"** means August 14^{th}, 2018;

1.1.57 **"Net Worth"** means, with respect to any Person, as of any date on which the amount thereof is to be determined, shareholders' equity, including the amount of any minority equity interests, as determined in accordance with generally accepted accounting principles;

1.1.58 **"Non-Disclosure Agreement"** means the non-disclosure agreement to be entered into by each Purchaser and any transferee of a Noteholder substantially in the form attached hereto as **Schedule 1.1.58;**

1.1.59 **Non-Management Services"** means:

(i) rental of facilities;

(ii) insurance;

(iii) electric utility operation services, including transmission and distribution;

(iv) building maintenance including security, janitorial services, snow plowing, lawn care, major and minor repairs;

(v) purchasing including procurements, order tracking, delivery of operating and capital items, payment processing and vendor management;

(vi) stores management including maintaining stock levels, issuing and receiving, maintenance of SAP inventory management system and disposition of excess assets;

(vii) customer service, including meter reading, billing services and related SAP systems;

(viii) safety monitoring including the development of policies and procedures, training (awareness and procedures), site inspections and field audits;

(ix) environmental compliance monitoring including the development of policies and procedures, training (awareness and procedures), regulatory reporting, government liaison and site inspections;

(x) human resources administration including development of policies and procedures, union relations and negotiations, personnel file management and management of employee benefit plans;

(xi) bookkeeping including the provision of statutory financial and regulatory reporting, management reporting and financial systems administration;

(xii) payroll including the maintenance of payroll records and payroll system, calculation of pay and payroll deductions, and facilitation of payroll payments;

(xiii) fleet management including the maintenance of all vehicles in working condition, major and minor repairs, regulatory reporting, expense tracking and fleet management system administration;

(xiv) financial management including cash administration, investments and debt management, treasury services, internal audit services, and development of financial and account policies and procedures;

(xv) legal and secretarial services;

(xvi) tax administration, filing and payment, including compliance, regulatory reporting and filing, planning, audit reviews, transfer of tax liabilities and the payments, filing of tax reports, and exposure management;

(xvii) information technology including the provision and management of systems, system and hardware support services, major and minor repairs, development and policies and procedures, and monitoring of information technology developments; and,

(xviii) such other services as may from time to time be agreed upon by the Company and an affiliate excluding management, advisory or other similar services.

1.1.60 **"Non-Speculative Financial Instrument Obligations"** means, with respect to any Person, Financial Instrument Obligations of the Person entered into by the Person in the ordinary course of business for risk management purposes and not for speculative or capital raising purposes;

1.1.61 **"Noteholders"** or **"holders of Notes"** means, at any given time, any Person whose names are then entered in the register of the Company for recording the holders of the Notes;

1.1.62 **"Noteholders' Counsel"** means Torys LLP, or such other counsel as the Noteholders may designate;

1.1.63 **"Notes"** has the meaning ascribed thereto in Section 2.1;

1.1.64 **"Obligations"** means all indebtedness, liabilities and other obligations of the Company to the Noteholders, or any of them, hereunder or under any Notes issued by the Company pursuant hereto, whether actual or contingent, direct or indirect, matured or not, now existing or arising hereafter;

1.1.65 **"OEB"** means the Ontario Energy Board, and its successors;

1.1.66 **"Officers' Certificate"** means a certificate signed by any two of the Chairman of the Board, any Vice-Chairman of the Board, the President, any Vice-President, the Treasurer or the Secretary of the Company;

1.1.67 **"OMERS"** means the Ontario Municipal Employees Retirement System;

1.1.68 **"OMERS Plans"** means any oral or written plans, arrangements, agreements, programs, policies, practices or undertakings that have been established by or that are otherwise controlled by or related to OMERS and which are applicable to some or all of the current or former directors, officers, employees, independent contractors or agents of the Company or any of its Subsidiaries;

1.1.69 **"Ontario Hydro Property"** means the property leased from Port Colborne Hydro Inc. under the Port Colborne Lease which was previously owned by Ontario Hydro for which an easement is required and which is the subject of the unexecuted draft agreement between Ontario Hydro and the Port Colborne Hydro-Electric Commission dated January 1, 1980;

1.1.70 **"Permits"** means all permits, consents, waivers, licences, certificates, approvals authorizations, arrangements, registrations, franchises, rights, privileges and exemptions or any item with a similar effect as the foregoing issued or granted by any Governmental Body;

1.1.71 **"Permitted Encumbrances"** means:

1.1.71.1 any Lien granted by the Company or a Subsidiary to secure the Notes;

1.1.71.2 any Lien granted by the Company or a Subsidiary to secure any Purchase Money Obligations or Capital Lease Obligations of the Company or a Subsidiary for assets acquired after the date hereof and incurred in compliance with this Agreement provided such Lien is not applicable to the Company or any other Subsidiary or the properties or assets of the Company or any Subsidiary except for such property so acquired or leased unless otherwise permitted hereunder;

1.1.71.3 any Lien on a property or asset acquired by the Company or a Subsidiary that secures the obligations of a Person (whether or not such obligation is assumed by the acquiring person) which Lien exists at the time such property or asset is acquired and which (i) is not incurred in contemplation of such property or asset being acquired and (ii) is not applicable to the Company or any other Subsidiary or the properties or assets of the Company or any Subsidiary;

1.1.71.4 any Lien granted by a Subsidiary in favour of the Company or a wholly-owned Subsidiary;

1.1.71.5 any Lien on or against cash or marketable debt securities pledged to secure Non-Speculative Financial Instrument Obligations which hedges Indebtedness of the Company or a Subsidiary;

1.1.71.6 any Lien for taxes, payments in lieu of taxes, assessments, government charges or claims that are being contested in good faith and in respect of which appropriate provision is made in the consolidated financial statements of the Corporation in accordance with generally accepted accounting principles;

1.1.71.7 Liens securing appeal bonds or other similar Liens arising in connection with contracts, bids, tenders or court proceedings (including, without limitation, surety bonds, security for costs of litigation where required by law and letters of credit) or any other instruments serving a similar purpose;

1.1.71.8 a Lien or deposit under workers' compensation, social security or similar legislation or good faith deposits in connection with bids, tenders, leases or contracts entered into in the ordinary course of business, or expropriation proceedings, or deposits to secure public or statutory obligations or deposits of cash or obligations to secure surety and appeal bonds;

1.1.71.9 a Lien or privilege imposed by law, such as builders', carriers', warehousemen's, landlords', mechanics', and material men's Liens and privileges, and any Lien or privilege arising out of judgements or awards with respect to which the Company or a Subsidiary at the time is prosecuting in good faith an appeal or proceedings for review and with respect to which it has secured a stay of execution pending such appeal or proceedings for review; or Liens for taxes, assessments or Governmental Charges or levies not at the time due and delinquent or the validity of which is being contested at the time by the Company or a Subsidiary in good faith; or undetermined or inchoate Liens, privileges and charges incidental to current operations which have not at such time been filed pursuant to law against the Company or a Subsidiary or which relate to obligations not due or delinquent;

1.1.71.10 deposits or pledges of cash or securities in connection with any Lien or privilege referred in this Section 1.1.71;

1.1.71.11 any defect or irregularity in title or minor encumbrance, including, without limitation, easements, rights-of-way, servitudes or other similar rights in land granted to or reserved by other persons, rights-of-way for sewers, electric lines, telegraph and telephone lines and oil and natural gas pipelines and other similar purposes, or zoning or other restrictions as to the use of real properties, which encumbrances, easements, servitudes, rights-of-way or other similar rights and restrictions do not in the aggregate materially detract from the value of such properties or materially impair their use in the operation of the business of the Company or a Subsidiary;

1.1.71.12 any right reserved to or vested in any municipality or governmental or other public authority by the terms of any lease, license, franchise, grantor permit acquired by the Company or a Subsidiary, or by any statutory provision, to terminate any such lease, license, franchise, grant or permit or to purchase assets used in connection therewith or to acquire annual or other periodic payments as a condition to the continuance thereof;

1.1.71.13 a Lien or right of distress reserved in or exerciseable under any lease for rent and for compliance with the terms of such lease;

1.1.71.14 any Lien granted by the Company or a Subsidiary to a public utility or any municipality or governmental or other public authority when required by such utility, municipality or other authority in connection with the operations of the Company or such Subsidiary;

1.1.71.15 any reservation, limitation, proviso or condition, if any, expressed in any original grants to the Company or a Subsidiary from the Crown;

1.1.71.16 any extension, renewal, alteration, substitution or replacement, in whole or in part, of a Lien referred to in the foregoing clauses 1.1.71.1 to 1.1.71.15, provided the extension, renewal, alteration, substitution or replacement of such Lien is limited to all or any part of the same property that secured the Lien extended, renewed, altered, substituted or replaced the principal amount of the obligations secured thereby is not thereby increased, the terms of the Indebtedness secured thereby is not changed and the terms and conditions thereof are no more restrictive in any material respect than the Lien so extended;

1.1.71.17 any encumbrance provided in support of letters of credit issued in favour of (i) any Electricity Supplier in connection with a non-speculative electricity forward contract entered into for hedging purposes or in connection with the Company's obligations to supply electricity to customers in the ordinary course of business of the Company or its Subsidiaries, or (ii) any Regulator to meet prescribed prudential requirements in the wholesale and retail market for electricity administration by such Regulator;

1.1.71.18 the encumbrances listed on Schedule 1.1.71 hereto; and

1.1.71.19 any other encumbrances that are not otherwise referred to in this section 1.1.71, that secures indebtedness that does not exceed, in the aggregate a cap equal to the greater of (i) \$4,000,000 and (ii) 10% of the sum of Consolidated Net Worth and Consolidated Subordinated Indebtedness.

1.1.72 **"Permitted Indebtedness"** means (i) short term credit facilities not exceeding 10% of the sum of Consolidated Net Worth and Consolidated Subordinated Indebtedness, in aggregate, (ii) Indebtedness up to \$1,000,000 in each calendar year for expenditures directed by any Regulator, (iii) any Indebtedness incurred to extend, renew, refund or refinance any Indebtedness at maturity so long as the principal amount thereof outstanding and any other amount on the date of extension, renewal, refunding or refinancing is not increased; (iv) Non-Speculative Financial

Investment Obligations; (v) contingent reimbursement obligations relating to letters of credit and other financial instruments issued to any Electricity Supplier in the ordinary course of business or to meet prescribed prudential requirements in wholesale market for electricity administered by any Regulator; and (vi) Subordinated Indebtedness owing to Affiliates;

1.1.73 **"Person"** means any individual, partnership, limited partnership, joint venture, syndicate, sole proprietorship, company or corporation with or without share capital, unincorporated association, trust, trustee, executor, administrator or other legal personal representative or Governmental Body;

1.1.74 **"Power System"** means, the electric transmission and distribution system operated by the Company from time-to-time;

1.1.75 **"Port Colborne Lease"** means the long term operating lease with Port Colborne Hydro Inc. in respect of that part of the Power System located in Port Colborne and which expires in April, 2012;

1.1.76 **"Premises"** means all real property, equipment relating to the Power System, buildings and facilities, including any part of any such property, equipment relating to the Power System, building or facility, owned, leased, used or operated by the Company and each of its Subsidiaries in connection with its Business;

1.1.77 **"Premium"** means at any time with respect to any Note, an amount equal to the greater of:

(a) the Canada Yield Price for such Note less the outstanding principal amount of such Note at such time; and

(b) zero;

1.1.78 **"Purchase Money Obligations"** means indebtedness of the Company or a Subsidiary incurred or assumed to finance the purchase price, in whole or in part, of any property (except any indebtedness which constitutes Indebtedness and which was incurred or assumed to finance the purchase price, in whole or in part, of any shares, bonds or other securities) or incurred to finance the cost, in whole or in part, of construction or installation of or improvements to any real property or fixtures provided that such indebtedness is incurred or assumed within 18 months after the purchase of such real property or fixtures or the completion of such construction, installation or improvements, as the case may be, and includes any extension, renewal or refunding of any such indebtedness, so long as the principal amount thereof outstanding on the date of extension, renewal or refunding is not increased;

1.1.79 **"Redemption Date"** has the meaning ascribed thereto in Section 5.2;

1.1.80 **"Redemption Price"** has the meaning ascribed thereto in Section 5.1;

1.1.81 **"Regulators"** means the IMO, the OEB and any other Governmental Body that from time to time is entitled to regulate the Business in addition to or in replacement of the IMO or the OEB;

1.1.82 **"Rent"** means all amounts payable pursuant to operating leases or similar agreements for the use of electrical systems including the Port Colborne Lease, but excluding rent for office space, office equipment and similar fungible items;

1.1.83 **"Required Noteholders"** means (i) each Purchaser, provided that each such Purchaser holds a minimum of 10% of the principal amount of outstanding Notes; and (ii) any Noteholder which holds at least 25% of the principal amount of outstanding Notes issued under this Agreement excluding any Notes held by or on behalf of the Company, the Subsidiaries and their Affiliates.

1.1.84 **"Sale and Leaseback Transaction"** means an arrangement with a Person by the Company or a Subsidiary providing for the leasing by the Company or a Subsidiary of personal property from such Person that has been previously sold or transferred to such Person by the Company or such Subsidiary, as applicable;

1.1.85 **"Sale and Leaseback Report"** means a written report of the Company summarizing (i) the Sale and Leaseback Transactions made during the relevant fiscal quarter, the net proceeds of which are greater than $500,000 and (ii) with respect to the last fiscal quarter only, a summary of the use of the proceeds of all Sale and Leaseback Transactions exceeding $500,000 made during the relevant Fiscal Year;

1.1.86 **"Sales Taxes"** means sales, transfer, turnover or value added taxes of any nature or kind, including Canadian goods and services taxes and provincial sales taxes;

1.1.87 **"Secured Property"** has the meaning ascribed thereto in Section 10.1.12;

1.1.88 **"Senior Indebtedness"** means all Indebtedness except Subordinated Indebtedness;

1.1.89 **"Senior Management"** means all Persons who perform a policy-making function in respect of the Company or any Subsidiary, including any corporation which receives fees or other remuneration in respect of services performed by such Persons;

1.1.90 **"Subordinated Indebtedness"** means Indebtedness which (i) is subordinated in all rights to the Notes, (ii) has no rights of acceleration until 180 days following an event of default under such subordinated indebtedness, (iii) has no rights to initiate remedies unless the Noteholders fail to initiate remedies within 120 days of the Noteholders being permitted to do so, and (iv) does not permit any payments to be made in respect thereof at any time when monies are due and payable with respect to the Notes;

1.1.91 **"Subsidiary"** means, at any time, as to the Company, any other Person, if at such time the Company owns, directly or indirectly, securities or other ownership interests in such other Person, having ordinary voting power to elect a majority of the board of directors of such other Person, or if such other Person is not a corporation, such persons performing similar functions as a board of directors for such other Person, and shall include any other Person in like relationship to a Subsidiary of the Company or any Subsidiary;

1.1.92 **"Substance"** means any substance or material which under any Environmental Law is defined to be "hazardous", "toxic", "deleterious", "caustic", "dangerous", a "contaminant", a "pollutant", a "dangerous good", a "waste", a "source of contamination" or a source of a "pollutant".

1.1.93 **"Taxes"** means all taxes of any kind or nature whatsoever including Federal large corporation taxes, provincial capital taxes, realty taxes (including utility charges which are collectible like realty taxes), business taxes, property transfer taxes, income taxes, Sales Taxes, stamp taxes, royalties, duties and all fees, deductions or compulsory loans and withholdings imposed, levied, collected, withheld or assessed as of the date hereof or at any time in the future, by any Governmental Body of or within Canada or any other jurisdiction whatsoever having power to tax, together with penalties, fines, additions to tax and interest thereon; and

1.1.94 **"Total Consolidated Capitalization"** means at any time and from time to time, and in respect of any Person, without duplication, the sum of (a) Consolidated Net Worth, (b) the principal amount of Consolidated Senior Indebtedness outstanding, (c) the principal amount of

Consolidated Subordinated Indebtedness outstanding, (d) the accumulated provision for deferred income taxes, and (e) the amount of any minority equity interest in such Person;

1.2 **Gender and Number**

Words importing the singular include the plural and vice versa and words importing gender include all genders.

1.3 **Invalidity, etc.**

Each of the provisions contained in any Finance Document is distinct and severable and a declaration of invalidity, illegality or unenforceability of any such provision or part thereof by a court of competent jurisdiction shall not affect the validity or enforceability of any other provision of such Finance Document or of any other Finance Document. To the extent permitted by Applicable Law, the parties waive any provision of Applicable Law which renders any provision of any Finance Document invalid or unenforceable in any respect. The parties shall engage in good faith negotiations to replace any provision which is declared invalid or unenforceable with a valid and enforceable provision, the economic effect of which comes as close as possible to that of the invalid or unenforceable provision which it replaces. Without limiting the generality of the foregoing, if any amounts on account of interest or fees or otherwise payable by the Company to the Noteholder hereunder exceed the maximum amount recoverable under Applicable Law, the amounts so payable hereunder shall be reduced to the maximum amount recoverable under Applicable Law.

1.4 **Headings, etc.**

The division of a Finance Document into articles and sections, the inclusion of a table of contents and the insertion of headings are for convenience of reference only and shall not affect the construction or interpretation of such Finance Document.

1.5 **Governing Law**

Except as otherwise specifically provided, the Finance Document shall be governed by and construed in accordance with the laws of the Province of Ontario and the laws of Canada applicable therein.

1.6 **Attornment**

The parties hereto irrevocably submit and attorn to the non-exclusive jurisdiction of the courts of the Province of Ontario for all matters arising out of or in connection with this Agreement and the other Finance Documents.

1.7 **References**

Except as otherwise specifically provided, reference in any Finance Document to any contract, agreement or any other instrument shall be deemed to include references to the same as varied, amended, supplemented or replaced from time to time and reference in any Finance Document to any enactment, including without limitation, any statute, law, by-law, regulation, ordinance or order, shall be deemed to include references to such enactment as re-enacted, amended or extended from time to time.

1.8 **Currency**

Except as otherwise specifically provided herein, all monetary amounts in this Agreement are stated in Canadian dollars.

1.9 **This Agreement to Govern**

If there is any inconsistency between the terms of this Agreement and the terms of any other Finance Document, the provisions hereof shall prevail to the extent of the inconsistency.

1.10 **Generally Accepted Accounting Principles**

Except as otherwise specifically provided herein and except as specifically required by the Accounting Procedures Handbook issued by the OEB, as amended, or other similar accounting rules, policies or procedures imposed by the Regulators from time to time, all accounting terms shall be applied and construed in accordance with generally accepted accounting principles consistently applied. References herein to "generally accepted accounting principles" mean, for all principles stated from time to time in the Handbook of the Canadian Institute of Chartered Accountants, such principles so stated. For the purpose of determining compliance with the negative covenants set forth in Section 10.2, unless expressly provided to the contrary or unless the Majority Noteholders otherwise agree, all computations shall be calculated on a consolidated basis, and shall be adjusted to eliminate the effect of any discretionary change by the Company in the application of generally accepted accounting principles since the date of its most recent audited consolidated financial statements prior to the date hereof.

1.11 **Computation of Time Periods**

Except as otherwise specifically provided herein, in the computation of a period of time from a specified date to a later specified date, the word "from" means "from and including" and the words "to" and "until" each mean "to but excluding".

1.12 **Actions on Days Other Than Business Days**

Except as otherwise specifically provided herein, where any payment is required to be made or any other action is required to be taken on a particular day and such day is not a Business Day and, as a result, such payment cannot be made or action cannot be taken on such day, then this Agreement shall be deemed to provide that such payment shall be made or such action shall be taken on the first Business Day after such day.

1.13 **Incorporation of Schedules**

The following schedules annexed hereto shall, for all purposes hereof, form part of this Agreement:

Exhibit 1	-	Form of Note
Exhibit 2	-	Information relating to the Purchasers
Schedule 1.1.58	-	Form of Non-Disclosure Agreement
Schedule 1.1.71	-	Permitted Encumbrances
Schedule 5.2	-	Redemption Notification Form
Schedule 8.1.9	-	Litigation
Schedule 8.1.14	-	Environmental
Schedule 8.1.16	-	Governmental Charges
Schedule 8.1.17	-	Existing Indebtedness
Schedule 8.1.18	-	Corporate Structure of Company and Subsidiaries
Schedule 10.1.16	-	Officers' Certificate
Schedule 13.3	-	Assignment Form

Article 2
Authorization of Notes

2.1 **Authorization of Notes**

The Company has authorized the issue and sale of $30,000,000 aggregate principal amount of its 7.092% Senior Unsecured Notes due August 14, 2018 (the "**Notes**"). The Notes shall be substantially in the form set out in Exhibit 1, with such changes therefrom, if any, as may be approved by the Noteholders and the Company and shall be issued under this Agreement entered into by the Company and such other Person agreeing to purchase Notes.

Article 3
Sale and Purchase of Notes

3.1 **Sale and Purchase of Notes**

Subject to the terms and conditions of this Agreement, the Company hereby agrees to issue and sell to each of the Purchasers, and each of the Purchasers hereby agrees to purchase from the Company, at the Closing provided for in Section 4.1, Notes in a principal amount to be agreed to between the Company and each Purchaser at the time of such purchase, and at the purchase price of 100% of the principal amount thereof, provided that each such Purchaser is satisfied that the conditions in Article 11 have been met.

3.2 **Principal**

The principal amount of each Note, together with any accrued and unpaid interest thereon and all other amounts owing thereon, will be payable on the Maturity Date or the Redemption Date for such Note, as applicable.

3.3 **Interest**

3.3.1 The Notes shall be dated August 14th, 2003, become due and payable on the Maturity Date and shall bear interest from the date hereof at 7.092% per annum calculated and payable semi annually in arrears (after as well as before default or judgment, with interest on amounts in default at the same rate), until such time as the Notes are paid in full, on August 14th and February 14th, with the first such interest payment to be made on February 14, 2004 all as set forth in the appendix to the form of Note set out in Exhibit 1.

3.3.2 The principal amount of the Notes and interest thereon, or the Redemption Price applicable to the Notes payable on redemption (including any Premium, if applicable), shall be paid in lawful money of Canada.

3.4 **Payments**

3.4.1 All payments of, or in respect of, principal, interest and other amounts owing on the Notes shall be made in such coin or currency of Canada as at the time of payment is legal for payment of public and private debts by wire transfer of immediately available funds to an account designated by each of the Noteholders.

3.4.2 All payments of, or in respect of, principal, interest and other amounts owing on the Notes made by the Company hereunder will be made without withholding or deduction for, or on account of, any present or future Taxes.

3.5 Use of Proceeds.

The Company shall use the net proceeds from the Notes to repay inter-company Indebtedness and for general corporate purposes.

3.6 Ranking.

The payment obligations of the Company under the Notes will at all times rank at least pari passu in right of payment with all existing and future unsecured Senior Indebtedness and senior in ranking to all existing and future Subordinated Indebtedness.

Article 4
Closing

4.1 Closing

The sale and purchase of the Notes to be purchased by the Purchasers shall occur at the offices of Torys LLP, Suite 3000, Maritime Life Tower, Toronto-Dominion Centre, Toronto, Ontario, M5K 1N2 at 9:00 a.m. Toronto time, at a closing (the "Closing") on August 14th, 2003. At the Closing the Company will deliver to each Purchaser the Notes to be purchased by it in the form of a single Note (or such greater number of Notes in denominations of at least $1,000,000 as each Purchaser may request) dated the date of the Closing and registered in the name of such Purchaser (or in the name of a nominee of such Purchaser), against delivery by such Purchaser to the Company or its order of immediately available funds in the amount of the purchase price therefor by wire transfer of immediately available funds for the benefit of the Company according to payment instructions provided to the Company by each such Purchaser.

Article 5
Redemption and Purchase

5.1 Redemption by Company

Upon compliance with Section 5.2, the Company shall have the right, at any time and from time to time, to redeem the outstanding Notes on any Business Day, either in whole or in part, upon payment of a redemption price in respect of each Note equal to the greater of: (i) the Canada Yield Price of the principal amount thereof to be redeemed; and (ii) the principal amount thereof to be redeemed; together in each case with accrued but unpaid interest to but excluding the date fixed for redemption and any other amount owing thereon (the amount so payable in either case being the **"Redemption Price"**). All partial redemptions pursuant to this Section 5.1 shall be applied on all outstanding Notes on a pro rata basis in accordance with the unpaid principal amounts thereof.

5.2 **Notice of Redemption**

Notice of redemption by the Company of any Note shall be irrevocable and shall be given to the holders of the Notes so to be redeemed on a date not more than 60 days nor less than 30 days prior to the Business Day set for redemption (the **"Redemption Date"**). Every such notice shall be sent via facsimile and also by registered mail and shall specify: (i) the aggregate principal amount of the Notes called for redemption; (ii) the Redemption Date; (iii) the places of payment thereof; (iv) the estimated Redemption Price for the Notes, showing in reasonable detail the computation of such estimated Redemption Price and the assumptions used in such computation; and (v) shall state that interest upon the principal amount of Notes called for redemption shall cease to be payable from and after the Redemption Date provided that the Redemption Price is paid in full on the Redemption Date. In addition, unless all the outstanding Notes are to be redeemed, the notice of redemption shall specify the aggregate principal amount of such Notes to be redeemed and the aggregate principal amount of the Notes which will be outstanding after such partial redemption. On the date that is 3 Business Days before the Redemption Date, the Company shall give to the holders of the Notes so to be redeemed notice via facsimile and also by registered mail of the actual Redemption Price showing in reasonable detail the computation of the Redemption Price for the Notes.

5.3 **Notes Due on Redemption Dates**

Provided that Notice has been given in accordance with Section 5.2, all the Notes so called for redemption shall thereupon be and become due and payable at the Redemption Price therefor, on the Redemption Date specified in such notice, in the same manner and with the same effect as if it were the Maturity Date specified in such Notes, anything therein or herein to the contrary notwithstanding, and from and after such Redemption Date, if the Redemption Price for such Notes has been paid as provided in Section 5.4 of this Agreement, such Notes shall not be considered as outstanding hereunder and interest upon such Notes shall cease.

5.4 **Payment of Redemption Price**

On the Redemption Date, the Company shall pay or cause to be paid to the Noteholders, upon surrender of such Notes, the Redemption Price to which they are respectively entitled on such redemption.

5.5 **Failure to Surrender Note Called for Redemption**

If any Noteholder fails on or before the Redemption Date to surrender such Noteholder's Note called for redemption pursuant hereto, or does not accept payment of the Redemption Price payable in respect thereof or give such receipt therefor, if any, as the Company may require, the applicable Redemption Price may be set aside in trust at such rate of interest as the depository may allow, in an account of or for the benefit of such Noteholder and such setting aside shall for all purposes be deemed a payment to such Noteholder of the Redemption Price so set aside and, to that extent, such Note shall thereafter not be considered as outstanding hereunder and such Noteholder shall have no other right hereunder other than to receive out of the money so paid or deposited, upon surrender of such Noteholder's Note, payment of the Redemption Price for such Note. Any interest accrued on any such Redemption Price so paid and deposited shall be the property of the Noteholder and shall be paid to such Noteholder upon demand.

5.6 **Purchase for Cancellation**

At any time and from time to time, provided that at such time no Default or Event of Default has occurred and is continuing, the Company may purchase all or any of the outstanding Notes in the open market or by invitation for tenders or by private contract at a price not to exceed the Redemption Price, together with accrued but unpaid interest. Any Notes so purchased by the Company shall be cancelled in accordance with the provisions of Section 5.7 and shall not be reissued.

5.7 **Cancellation**

All Notes which are redeemed, purchased or otherwise held by the Company will forthwith be delivered to the holder of said Notes and cancelled and may not be reissued or resold. In the case of partial redemption of Notes, replacement certificates representing the outstanding principal amount of Notes not redeemed shall be executed by the Company and forthwith delivered to the applicable Noteholders, all at the expense of the Company.

5.8 **Pro Rata Payment**

Unless otherwise provided herein, all payments in respect of the Notes shall be made on a pro rata basis in accordance with the unpaid principal amount thereof.

Article 6
Registration; Exchange; Substitution of Notes

6.1 Registration of Notes

The Company shall keep at its principal executive office a register for the registration, and registration of transfers, of Notes. The name and address of each Noteholder, each transfer thereof and the name and address of each transferee of one or more Notes shall be registered in such register. Prior to due presentment for registration of transfer, the Person in whose name any Note shall be registered shall be deemed and treated as the owner and holder thereof for all purposes hereof, and the Company shall not be affected by any notice or knowledge to the contrary and payment of or on account of the principal of, and interest on, or Redemption Price in respect of, such Note shall be made only to, or upon the order in writing of, such Person. Any such payment to another Person upon the order in writing of such holder shall be a complete discharge to the Company to the extent of the amount so paid to such Person. The Company shall give to any Noteholder, promptly upon request therefor and at the expense of such Noteholder, a complete and correct copy of the names, addresses and other contact information of all registered Noteholders.

6.2 Transfer and Exchange of Notes

Any Noteholder may transfer all or any part of a Note to one or more transferees (i) at any time upon the occurrence and continuation of a Default or Event of Default, and (ii) at any time prior to the occurrence of a Default or Event of Default, provided that such transfer is made in accordance with Applicable Law, including without limitation, applicable securities legislation and, in the case of (ii) only, the transferee of any Note has executed and delivered to the Company a Non-Disclosure Agreement.

Upon surrender of any Note at the principal executive office of the Company for registration of transfer or exchange pursuant to Section 6.1 above (and in the case of a surrender for registration of transfer, duly endorsed or accompanied by a written instrument of transfer duly executed by the registered holder of such Note or its attorney duly authorized in writing and accompanied by the address for notice of each transferee of such Note or part thereof), the Company shall execute and deliver, at the Noteholder's expense, one or more new Notes (as requested by the holder thereof) in exchange therefor, in an aggregate principal amount equal to the unpaid principal amount of the surrendered Note. Each such new Note shall be payable to such Person as such Noteholder may request and shall be substantially in the form of Exhibit 1. Each such new Note shall be dated and bear interest from the date to which interest shall have been paid on the surrendered Note. Except as otherwise provided herein, and except upon the occurrence of and during the continuation of a Default or Event of Default (in which case the following expenses will be for the Company's account), upon any exchange of Notes of any denomination for Notes of any other authorized denominations requested by a Noteholder and upon any transfer of Notes requested by a Noteholder, the Company will be entitled to reimbursement for any stamp tax, security transfer tax or other governmental charge required to be paid, and in addition a reasonable charge for its services for each Note exchanged or transferred.

6.3 **Replacement of Notes**

Upon receipt by the Company of evidence reasonably satisfactory to it of the ownership of and the loss, theft, destruction or mutilation of any Note, the Company shall execute and deliver to the applicable Noteholder, at the Noteholder's expense, a replacement Note in lieu thereof, subject to the prior receipt by the Company of such evidence of such loss, theft or destruction as shall be satisfactory to the Company, acting reasonably, and an affidavit of loss and indemnity in form satisfactory to the Company, acting reasonably.

Article 7
Payments and Notes

7.1 **Place of Payment**

Payments of principal, interest and Redemption Price, if any, becoming due and payable and any other amounts owing on the Notes shall be made in Toronto, Ontario pursuant to the terms of the Note. The Company shall, by notice to each Noteholder, designate the place of payment of the Notes so long as such place of payment shall be either the principal office of the Company in such jurisdiction or the principal office of a bank or trust company in such jurisdiction.

7.2 **Home Office Payment**

So long as any Purchaser or a nominee thereof is a Noteholder, and notwithstanding anything contained in Section 7.1 or in such Note to the contrary, the Company will pay all sums becoming due on such Note for principal, interest, Redemption Price, if any, and any other amounts owing on the Notes by the method and at the address specified in Section 13.7 hereof, or by such other method or at such other address in Canada as such Purchaser shall have from time to time specified to the Company in writing for such purpose, without the presentation or surrender of such Note or the making of any notation thereon, except that upon written request of the Company made concurrently with or reasonably promptly after payment or prepayment in full of any Note, such Purchaser shall surrender such Note for cancellation, reasonably promptly after any such request, to the Company at its principal executive office or at the place of payment most recently designated by the Company pursuant to Section

7.1. Prior to any sale or other disposition of any Note held by such Purchaser or its nominee, such Purchaser will, at that Purchaser's election, either endorse thereon the amount of principal paid thereon and the last date to which interest has been paid thereon or surrender such Note to the Company in exchange for a new Note or Notes pursuant to Section 6.2. The Company will afford the benefits of this Section 7.2 to direct or indirect transferees of any Note purchased by any Purchaser under this Agreement and that has made the same agreement relating to such Note as such Purchaser has made in this Section 7.2.

Article 8
Representations and Warranties

8.1 **Representations and Warranties**

The Company represents and warrants to each of the Purchasers that as of the date hereof:

8.1.1 **Incorporation and Status.** Each of the Company and the Subsidiaries is duly incorporated and validly existing under the laws of its jurisdiction of incorporation and has the corporate power and capacity to own its properties and assets and to carry on its Business as presently carried on by it or as contemplated hereunder to be carried on by it.

8.1.2 **Power and Capacity.** The Company has the corporate power and capacity to enter into this Agreement and each of the other Finance Documents and to do all acts and things as are required or contemplated hereunder or thereunder to be done, observed and performed by it.

8.1.3 **Due Authorization.** The Company has taken all necessary corporate action, including any shareholder approval which may be required, to authorize the execution, delivery and performance of this Agreement and each of the other Finance Documents.

8.1.4 **No Contravention.** The execution and delivery of this Agreement and the other Finance Documents and the performance by the Company of its obligations thereunder (i) does not and will not contravene, breach or result in any default under any Material Contract or under the articles, by-laws, constating documents or other organizational documents of the Company or under any mortgage, lease, agreement or other legally binding instrument, Permit or Applicable Law to which the Company or any of its Subsidiaries is a party or by which the Company or any of its Subsidiaries or any of their respective properties or assets may be bound, (ii) will not oblige the Company or any of its Subsidiaries to grant any Lien to any Person, and (iii) will not result in or permit the acceleration of the maturity of any indebtedness, liability or obligation of the

Company or any of its Subsidiaries under any mortgage, lease, agreement or other legally binding instrument of or affecting the Company or any of its Subsidiaries.

8.1.5 **No Consents Required** No authorization, consent or approval of, or filing with or notice to, any Person (including any Governmental Body) is required that has not been given or received, as applicable, in connection with the execution, delivery or performance of this Agreement or any of the other Finance Documents by the Company.

8.1.6 **Enforceability.** Each of the Finance Documents constitutes, or upon execution and delivery will constitute, a valid and binding obligation of the Company enforceable against it in accordance with its terms and each of the Material Contracts constitutes a valid and binding obligation of the parties thereto enforceable against such Person in accordance with its terms.

8.1.7 **Title.** The Company and each of its Subsidiaries has good and marketable title to all of its real and personal property free from material defects to title which would prevent them from conducting their business, and, except for Permitted Encumbrances, such real and personal property and the revenues of the Company and its Subsidiaries are free and clear of any Lien.

8.1.8 **Financial Statements.** The audited consolidated financial statements of the Company for the fiscal year-ended December 31, 2002 have been prepared in accordance with generally accepted accounting principles, and fairly and accurately present the financial condition of the Company and the financial information presented therein for the period and as at the date thereof. Since the date of the last financial statements delivered to the Purchasers there has been no development which has had or will have a Material Adverse Effect.

8.1.9 **Litigation and Other Proceedings.** Except as set out in Schedule 8.1.9, (A) there is no court, administrative, regulatory or similar proceeding (whether civil, quasi-criminal, or criminal), arbitration or other dispute settlement procedure; investigation or enquiry by any Governmental Body, or any similar matter or proceeding (collectively "proceedings") against or involving the Company or any of its Subsidiaries (whether in progress or threatened) which, if determined adversely to the Company or any such Subsidiary would, in each case, (i) materially adversely affect its Business, financial condition or prospects or (ii) have a Material Adverse Effect; and (B) there is no judgment, decree, injunction, rule, award or order of any Governmental body outstanding against the Company or any of its Subsidiaries which would, in each case, (i) materially adversely affect its Business, financial condition or prospects or (ii) have a Material Adverse Effect.

8.1.10 <u>No Default</u>. No Default or Event of Default has occurred and is continuing. To the Company's knowledge, after due inquiry, neither the Company nor any of its Subsidiaries is in default or breach in any material respect under any material commitment or obligation, including, without limitation, any Material Contract.

8.1.11 <u>Location of Property</u>. The Company does not have property or assets located in any jurisdiction other than the province of Ontario which in the aggregate are material to the Business.

8.1.12 <u>Employee Plans and OMERS Plans</u>.

8.1.12.1 Except as may be disclosed in writing to the Purchasers prior to the date hereof, neither the Company nor any of its Subsidiaries is a party to, is bound by, or has any actual or contingent liability in respect of, any Employee Plan which is material to the Business.

8.1.12.2 Except as may be disclosed in writing to the Purchasers prior to the date hereof:

8.1.12.2.1 each Pension Plan is and has been registered, and each Employee Plan has been established and administered and, if applicable, invested and funded in accordance in all material respects with: (i) all Applicable Law; (ii) the terms of the plan and all employee plan summaries and booklets; and (iii) all understandings, written or oral, between the Company and/or its Subsidiaries and plan participants;

8.1.12.2.2 all material obligations to be performed respecting each Employee Plan (including, without limitation, those respecting the making or payment of contributions or premiums, as applicable) have been, are being performed in all material respects in accordance with the relevant terms of each plan and all Applicable Law, and no Governmental Charges are owing or exigible under any Employee Plan;

8.1.12.2.3 all Employee Plans which are required to be funded are fully funded in all material respects and the funds in such plans are and have been invested in accordance with the relevant terms of each plan and all Applicable Law, and, in the case of Pension Plans, are fully funded on a going concern basis and solvency basis in accordance with generally accepted actuarial principles and actuarial methods and assumptions contained in the most recent actuarial report of the plan;

8.1.12.2.4 to the best of the Company's knowledge, the Company and each of its Subsidiaries are in compliance with its obligations under the OMERS Plans in all material respects; and

8.1.12.2.5 to the best of the Company's knowledge, all employer and employee contributions required to be remitted to or in respect of any OMERS Plan have been remitted in accordance with the terms of such OMERS Plan;

8.1.12.2.6 no condition exists and no event or transaction has occurred with respect to any Pension Plan which is reasonably likely to result in the Company or any of its Subsidiaries incurring any material liability, fine or penalty, whether related to a deficit with respect to a Pension Plan or otherwise.

8.1.13 **Insurance.** The Company and each of its Subsidiaries maintains with insurers of recognized standing, over all of its Business Assets which are insurable, coverage against risks of loss of or damage to such Business Assets and Business (including fire and extended perils, public liability and damage to property of third parties) of such types and amounts as are customary in the case of companies with established reputation engaged in the same or similar businesses.

8.1.14 **Environmental Matters.**

8.1.14.1 Except as disclosed in Schedule 8.1.14,

8.1.14.1.1 none of the Company or any of its Subsidiaries has in any material respect emitted, discharged, deposited or released or caused or permitted to be emitted, discharged, deposited or released, any Substances on or to the Premises, or in connection with the operation of the Business of the Company or any of its Subsidiaries, except in compliance in all material respects with Environmental Law;

8.1.14.1.2 to the best of the Company's knowledge, information and belief, the soil and subsoil, and the surface and ground water in, on or under the Premises in any material respect do not contain any Substances, nor do the Premises contain any underground storage tanks; all Substances which have been or are being treated, handled or stored on the Premises by the Company and its Subsidiaries have been generated, treated and stored in compliance in all material respects with Environmental Law; and

8.1.14.1.3 neither the Company nor any of its Subsidiaries has permitted the Premises to be used for the disposal of any Substance or as a coal gasification site.

8.1.14.2 All Environmental Permits obtained by the Company and its Subsidiaries in connection with the Business (including any applicable expiry dates) are in all material respects valid and in full force and effect, and all Environmental Permits are listed in Schedule 8.1.14.

8.1.14.3 There are no proceedings (as defined in Section 8.1.9) against or involving the Company or any of its Subsidiaries, either in progress, pending, or threatened which allege the violation of, or non-compliance with, any Environmental Law.

8.1.15 **Claims**. The Company and each of its Subsidiaries have:

8.1.15.1 paid and discharged when due all lawful claims for labour, material and supplies; and

8.1.15.2 paid and discharged when due all obligations incidental to any trust imposed upon it by statute which, if unpaid, might become a Lien upon any of the Business Assets;

except for any amounts which are in the aggregate not material to the Business or in respect of which an appeal or claim is being asserted or processed with respect to such claim or obligations and, in each case, for which adequate reserves (if appropriate) have been established in accordance with generally accepted accounting principles;

8.1.16 **Governmental Charges.** Except as otherwise disclosed on Schedule 8.1.16 hereto, the Company and each of its Subsidiaries have filed all tax returns required to be filed by them in all applicable jurisdictions and have paid all Governmental Charges, except where failure to do so would not be reasonably likely to have a Material Adverse Effect. Adequate provision has been made in the audited consolidated financial statements of the Company for all Governmental Charges, and all professional fees related thereto, payable in respect of the Business or Business Assets for all periods up to the date of the balance sheet comprising part of the audited consolidated financial statements, except where failure to do so would not be reasonably likely to have a Material Adverse Effect. There are no proceedings (as defined in Section 8.1.9) in progress, pending or threatened against the Company or any of its Subsidiaries in respect of any Governmental Charges and, in particular, there are no currently outstanding reassessments or written enquiries which have been issued or raised by any Governmental Authority relating to any such Governmental Charges that, if adversely determined, would be reasonably likely to have a Material Adverse Effect. The Company and its Subsidiaries have withheld or collected and remitted all amounts required to be withheld or collected and remitted by them in respect of any Governmental Charges except where failure to do so would not be reasonably likely to have a Material Adverse Effect.

8.1.17 **Indebtedness.** The Company does not have any Indebtedness owing to any one creditor in excess of $100,000 other than the Indebtedness listed in Schedule 8.1.17 or in another Schedule attached hereto.

8.1.18 **Corporate Structure.** The corporate structure of the Company and its Subsidiaries is set out in Schedule 8.1.18.

8.1.19 **Compliance with Laws.** Except as set out in Schedule 8.1.19 or in any other Schedule attached hereto, the Company and each of its Subsidiaries are in compliance with all Applicable Law and have all necessary Permits and have made all necessary filings with all applicable federal, provincial and territorial authorities in Canada, except in such cases of non-compliance which singly and in the aggregate are not material to the Company and where the Company or each relevant Subsidiary is aware of such non-compliance, it is using efforts to remedy such non-compliance or obtain such necessary Permits in a timely manner;

8.1.20 **Ontario Hydro Property.** The Ontario Hydro Property

8.1.20.1 services no more than 2,000 customers of the Company;

8.1.20.2 accounts for no more than $500,000 of the net revenues of the Company and no more than $2,000,000 of the gross revenues of the Company on an annual basis for the fiscal year ended December 31, 2002;

8.1.20.3 does not include any assets material to the operation of the Company or its Subsidiaries individually or in the aggregate except for such assets for which title has been validly assigned to the Company;

8.1.20.4 has, to the best of the Company's knowledge, when the opportunity has arisen, been subject to Port Colborne Hydro Inc.'s program of registering or obtaining legal easements in favour of Port Colborne Hydro Inc. as appropriate; and

8.1.20.5 was paid for by Port Colborne Hydro Inc.

8.1.21 <u>**Property Leased from Port Colborne Hydro Inc.**</u> All legal easements (other than those in respect of the Ontario Hydro Property) in favour of Port Colborne Hydro Inc. in connection with the Property leased from Port Colborne Hydro Inc. subsequent to 1980 under the Port Colborne Hydro Lease have, to the best of the Company's knowledge, been either registered or obtained.

Article 9
Representations of the Purchasers

9.1 <u>**Representations and Warranties of the Purchaser**</u>

9.1.1 Each of Sun Life and Canada Life represents and warrants to the Company, as of the date hereof and as of the date of each Note that:

9.1.1.1 it is purchasing the Notes as principal and not as agent and is purchasing for investment only and not with a view to resale or distribution; and

9.1.1.2 it is a resident in the Province of Ontario and, by virtue of being a company licensed to do business as an insurance company in any Canadian jurisdiction, is an accredited investor within the meaning of Ontario Securities laws.

9.1.2 Maritime Life represents and warrants to the Company, as of the date hereof and as of the date of each Note that:

9.1.2.1 it is purchasing the Notes as principal and not as agent and is purchasing for investment only and not with a view to resale or distribution; and

9.1.2.2 it is a resident in the Province of Nova Scotia and, by virtue of being a Canadian financial institution, is an accredited investor within the meaning of *Multilateral Instrument 45-103 – Capital Raising Exemptions* as implemented under Nova Scotia Securities laws.

Article 10
Covenants

10.1 **Affirmative Covenants**

The Company covenants and agrees that so long as any of the Notes are outstanding:

10.1.1 **Punctual Payment.** The Company shall pay or cause to be paid, without deduction or any right of set-off, all Obligations when due hereunder on the dates and in the manner specified herein including, without limitation, in respect of payments of principal, interest or Redemption Price or any other amounts owing on the Notes;

10.1.2 **Conduct of Business.** The Company shall do or cause to be done, and shall cause each Subsidiary to do or cause to be done, all things necessary or desirable to maintain its corporate existence in its present jurisdiction of incorporation, to maintain its corporate power and capacity to own its properties and assets, and to carry on its Business in a commercially reasonable manner in accordance with normal industry standards;

10.1.3 **Preservation of Material Authorizations.** The Company shall, and shall cause each of its Subsidiaries to, preserve and maintain all Material Authorizations;

10.1.4 **Compliance with Applicable Law and Contracts.** The Company will, and will cause its Subsidiaries to, comply with all Material Contracts and Applicable Laws except where failure to do so would not be reasonably likely to have a Material Adverse Effect;

10.1.5 **Interim Financial Statements.** The Company shall, as soon as practicable and in any event within 60 days after the end of each quarter of each Fiscal Year, deliver to the Noteholders (i) the Asset Sale Report for such quarter, (ii) the Sale and Leaseback Report for such quarter and (iii) the interim unaudited consolidated financial statements of the Company and the interim unaudited unconsolidated financial statements of the Company and each Subsidiary for such quarter, including in each case a balance sheet, statement of profit and loss and a statement of changes in financial position, together with comparative figures for the corresponding period in the previous Fiscal Year;

10.1.6 **Annual Financial Statements.** The Company shall, as soon as practicable and in any event within 120 days after the end of each Fiscal Year, deliver to each Noteholder the audited consolidated financial statements of the Company and the annual unconsolidated financial statements of the Company and each Subsidiary for such Fiscal Year, including in each case a balance sheet, statement of profit and loss, a statement of changes in financial position and a statement of retained earnings, together with comparative figures for the previous Fiscal Year;

10.1.7 **Accounting Methods and Financial Records.** The Company shall, and shall cause each of its Subsidiaries to, maintain a system of accounting which is established and administered in accordance with generally accepted accounting principles, keep adequate records and books of account in which accurate and complete entries shall be made in accordance with such accounting principles reflecting all transactions required to be reflected by such accounting principles and keep accurate and complete records of any property owned by it;

10.1.8 **Payment of Governmental Charges and Claims.** Except in such cases where a failure to do so would not reasonably be expected to have a Material Adverse Effect and except for any amounts the payment of which is being contested in good faith by appropriate proceedings and for which reserves (if appropriate) have been established in accordance with generally accepted accounting principles, the Company shall, and shall cause each of its Subsidiaries to:

10.1.8.1pay and discharge when due all lawful claims for labour, material and supplies;

10.1.8.2pay and discharge when due all Governmental Charges payable by it;

10.1.8.3withhold and collect all Governmental Charges required to be withheld and collected by it and remit such Governmental Charges to the appropriate Governmental Body at the time and in the manner required;

10.1.8.4pay and discharge when due all obligations incidental to any trust imposed upon it by statute which, if unpaid, might become a Lien upon any of the Business Assets;

10.1.9 **Energy Distribution Business.** The Company and its Subsidiaries will operate only in the electricity transmission and distribution business in Ontario regulated by the Regulators, provided that the Company and its Subsidiaries may also operate in businesses ancillary to the Business, which in the aggregate are not material. For greater certainty, the Company and its Subsidiaries will not engage in the electricity generation or energy marketing businesses unless it is immaterial and ancillary to the Business.

10.1.10 **Insurance.** The Company and its Subsidiaries shall maintain or cause to be maintained with reputable insurers, coverage against risk of loss or damage to the properties and operations of the Company and its Subsidiaries of such types as is customary for and would be maintained by a corporation with an established reputation engaged in the same or similar business in similar locations and provide to each Noteholder, upon reasonable request, evidence of such coverage.

10.1.11 **Damage to Business Assets.** In the Event that any of the Business Assets are materially damaged, destroyed, impaired or otherwise materially harmed as a result of fire or other hazard, including, without limitation, flood, earthquake, ice storm, tornado, hurricane or other environmental or natural causes, and such Business Assets are material to the operation of the Power System, the Company shall use its best commercial efforts to repair, restore, reconstruct or replace such Business Assets in a timely manner, acting reasonably.

10.1.12 **Springing Lien.** Upon a breach of Section 10.1.11 hereof having occurred and while such breach is continuing, the Company shall, upon the request of the Required Noteholders, within a commercially reasonable period thereafter, pledge and grant to the Noteholders, or an agent thereof, a second ranking continuing security interest in all of the right, title and interest of the Company in, to and under all accounts receivable or other rights of payment of any monetary obligation of or owing to the Company (the "Secured Property") pursuant to a security agreement on terms and conditions satisfactory to the Noteholders. Notwithstanding the foregoing and without derogating from the obligations of the Company referred to above, the Noteholders acknowledge that they may be required to enter into an inter-creditor agreement on terms and conditions satisfactory to the Noteholders with each other Person that the Company has granted a security interest to in respect of and over such Secured Property and agree to use reasonable best efforts to enter into the same provided that the Company uses commercially reasonable efforts to induce such Persons to enter into such inter-creditor agreement within a commercially reasonable timeframe. For clarity, no other secured party (other than existing and future Noteholders) shall have a second ranking secured charge over the Secured Property ranking pari passu with the charge granted to the Noteholders as referred to above. The Noteholders shall take such actions as necessary to release the charge on the Secured Property when the breach of Section 10.1.11 has been cured or waived.

10.1.13 <u>Employee Plans</u>. The Company shall, and shall cause each of the Subsidiaries to perform all material obligations under each Employee Plan and OMERS Plan (including without limitation), those respecting the making or payment of contributions or premiums, as applicable) in all material respects in accordance with the relevant terms of each plan and all Applicable Law.

10.1.14 <u>Inspections.</u> At any time upon the occurrence and continuation of an Event of Default, the Company shall, and shall cause each of its Subsidiaries to, permit each Noteholder and its authorized employees, representatives and agents, upon giving at least 24 hours' prior notice to the Company, to (i) visit and inspect its assets or properties, (ii) inspect and make extracts from and copies of its books and records, and (iii) discuss with appropriate representatives of Senior Management of the Company or any of its Subsidiaries, its Businesses, property, financial condition and prospects;

10.1.15 <u>Notice of Litigation and Other Matters.</u> The Company shall, and shall cause each of its Subsidiaries to, as soon as practicable after it shall become aware of the same, give notice to each Noteholder of the following events:

10.1.15.1 the commencement of any action, proceeding, arbitration or investigation against or in any other way relating adversely to the Company or any of its Subsidiaries or any of their respective properties, assets or Businesses which, if adversely determined, could, singly or when aggregated with all other such actions, proceedings, arbitrations and investigations, reasonably be expected to have a Material Adverse Effect;

10.1.15.2 any material amendment of its articles, by-laws, constating documents or other organizational documents;

10.1.15.3 any change in its Fiscal Year;

10.1.15.4 any development which has had or will have a Material Adverse Effect; and

10.1.15.5 any Default or Event of Default, or the occurrence or non-occurrence of any event which constitutes, or which with the passage of time or giving of notice or both would constitute, a material default under any other material agreement to which the

Company or any of its Subsidiaries is a party or by which it or any of its properties may be bound, giving in each case the details thereof and specifying the action proposed to be taken with respect thereto;

10.1.16 **Officers' Certificate.** The Company shall deliver to each Noteholder, together with the consolidated financial statements in Sections 10.1.5 and 10.1.6, an Officers' Certificate in the form attached as Schedule 10.1.16 certifying (i) that such financial statements were prepared in accordance with generally accepted accounting principles (subject to normal year-end adjustments in the case of interim unaudited financial statements) and fairly and accurately present the financial condition of the Company and the financial information presented therein for the period and as at the date thereof, (ii) that no Default or Event of Default has occurred hereunder or, if any Default or Event of Default has occurred, specifying the relevant particulars and the period of existence thereof and the action taken or proposed to be taken by the Company with respect thereto, and (iii) demonstrating in reasonable detail compliance (or, as the case may be, non-compliance) at the end of the relevant fiscal quarter or Fiscal Year with the covenants contained in Sections 10.2.4, 10.2.5, 10.2.6 and 10.2.7.

10.1.17 **Property Leased from Port Colborne Hydro Inc.** The Company will, and will cause its Subsidiaries as appropriate to, use reasonable commercial efforts, consistent with those of a Person with an established reputation engaged in a business that is the same as or similar to the Business in similar locations, to register in the name of the Port Colborne Hydro Inc., or the Company, as the case may be, legal easements that are used solely in respect of the Ontario Hydro Property subject to the receipt of all third party consents.

10.2 Negative Covenants

The Company covenants and agrees that it shall not, nor shall it permit any of its Subsidiaries to:

10.2.1 **Encumber Property.** create, grant, assume or suffer to exist any Lien upon any of its properties or assets unless (a) at the same time as that Lien is created, granted, assumed or suffered to exist, the Company shall secure or cause to be secured equally and rateably therewith all the Notes then outstanding to the satisfaction of the Majority Noteholders; or (b) such Lien is a Permitted Encumbrance;

10.2.2 **Non-Arm's Length Transactions.** engage in any transaction with any Affiliate on terms that are not in compliance with the Affiliate Relationships Code;

10.2.3 **Amalgamations, Sales etc.** merge, consolidate or amalgamate with another Person unless:

10.2.3.1 the successor entity is a corporation incorporated under the laws of Canada or one of its provinces;

10.2.3.2 the successor corporation executes, prior to or contemporaneously with the consummation of such transaction, such instruments, if any, as are in the opinion of Noteholders' Counsel necessary or advisable to evidence the assumption by the successor corporation of liability for the due and punctual payment of all liabilities under this Agreement and the other Finance Documents (as applicable) and the covenant of the successor corporation or purchaser, as applicable, to observe and perform all of the covenants and obligations of the predecessor corporation under this Agreement and the Finance Documents to which the predecessor corporation is a party;

10.2.3.3 such transaction is on such terms that are sufficient to preserve or enforce the rights and powers of the Noteholders under this Agreement and the Notes;

10.2.3.4 the Company is entitled under this Agreement to incur or issue Indebtedness in the principal amount of at least $1.00;

10.2.3.5 the Noteholders have received, to the reasonable satisfaction of Noteholders' Counsel, customary documentation and legal opinions in respect of the transaction;

10.2.3.6 no condition or event exists in respect of the successor corporation at the time of such transaction or after giving full effect thereto which constitutes or would constitute a Default or Event of Default hereunder;

but for greater certainty, the amalgamation of Eastern Ontario Power Inc. and the Company is hereby approved by the Noteholders.

10.2.4 **Distributions.** make any Distribution unless (i) no Default or Event of Default has occurred and is continuing or will occur and be continuing as a result of such Distribution being made, (ii) the aggregate principal amount of Consolidated Senior Indebtedness does not exceed 65% of its Total Consolidated Capitalization, calculated on a pro forma basis and (iii) such Distribution does not contravene the Affiliate Relationships Code, if applicable.

10.2.5 **Further Indebtedness.** directly or indirectly incur, issue, assume, guarantee or otherwise become liable for or in respect of any Indebtedness, other than Permitted Indebtedness, or enter into any material operating lease unless after giving effect to such guarantee, incurrence, issuance or liability (including the application or use of the net proceeds therefrom) calculated on a pro forma basis: (i) the aggregate principal amount of its Consolidated Indebtedness (which for the purposes of this clause 10.2.5 (i) excludes Subordinated Indebtedness owing to Affiliates) does not exceed 70% of its Total Consolidated Capitalization, (ii) Consolidated EBITDAR is not less than 2.0 times the sum of Consolidated Senior Interest Expense plus Rent, and (iii) no Default or Event of Default shall have occurred and be continuing at the time of, or as a consequence of, such additional Indebtedness having been incurred or such operating lease having been entered into;

10.2.6 **Disposition of Assets.** enter into, or agree to enter into any Asset Sale, unless, after giving effect to any such sale, no Default or Event of Default has occurred or is continuing or would occur as a result of such Asset Sale, subject to the following:

10.2.6.1 **Single Asset Sale Restrictions.**

If the net proceeds of a single Asset Sale are equal to or greater than $2,000,000 then the Company shall, subject to the provisions which follow, reinvest the entire amount of the net proceeds of such Asset Sale (for the purposes of this Section 10.2.6.1, such entire amount being the "Total Single Asset Proceeds") in the Business within 270 days of such sale, provided that if a portion of the Total Single Asset Proceeds are not reinvested in the Business within 270 days of such Asset Sale (such un-invested amount hereinafter referred to in this section 10.2.6.1 as the "Un-invested Single Sale Amount"), the following provisions shall apply:

10.2.6.1.1 if the Un-invested Single Sale Amount is equal to or less than $2 million then the Un-invested Single Sale Amount shall be applied to redeem or prepay any Senior Indebtedness selected by the Company. If the Company elects to redeem or prepay the Notes, redemption of the Notes will be at a purchase price per Note equal to the Redemption Price and shall be made on a pro-rata basis amongst Noteholders;

10.2.6.1.2 if the Un-invested Single Sale Amount is greater than $2 million then (i) a maximum of $2,000,000 of the Un-invested Single Sale Amount shall be applied to redeem or prepay any Senior Indebtedness selected by the Company and (ii) the remainder of the Un-invested Single Sale Amount after such payment referred to in (i) of this Section 10.2.6.1.2 above (for the purposes of this Section 10.2.6.1, such remainder being the "Remaining Amount") shall be applied to redeem or prepay the Notes and the other Senior Indebtedness. The portion of the Remaining Amount to be applied to redeem the Notes shall be equal to the Remaining Amount multiplied by the percentage that the Notes represent of the Consolidated Senior Indebtedness at the date of Redemption. Redemption of the Notes under (i) and (ii) above will be at a purchase price per Note equal to the Redemption Price and shall be made on a pro rata basis amongst Noteholders.

10.2.6.2 **Multiple Asset Sale Restrictions.**

10.2.6.2.1 If the aggregate net proceeds for all single Asset Sales ("Total Multiple Sale Proceeds") total less than $2,000,000 for any fiscal year period as determined on the last Business Day of the relevant fiscal year (the "Calculation Date") then the Company shall use those net proceeds at the Company's discretion;

10.2.6.2.2 if for the applicable fiscal year the Total Multiple Sale Proceeds are calculated as being greater than or equal to $2,000,000 as of the Calculation Date, then the Company shall, subject to the provisions which follow, reinvest an amount equal to the Total Multiple Sale Proceeds in the Business within 270 days of the Calculation Date provided that, if a portion of the Total Multiple Sale Proceeds (or an amount equal thereto) is not reinvested in the Business within 270 days of the Calculation Date (such un-invested amount hereinafter referred to in this section 10.2.6.2 as the "Un-invested Multiple Sale Amount"), the following provisions shall apply:

(a) in the event that the Total Multiple Sale Proceeds are less than $8,000,000, the Company shall (i) use up to a maximum of $2,000,000 of the Un-invested Multiple Sale Amount at the Company's discretion, (ii) apply the remainder of the Un-invested Multiple Sale Amount, if any, up to a maximum of $2,000,000, to redeem or prepay any Senior Indebtedness selected by the Company and (iii) apply any portion of the

Un-invested Multiple Sale Amount remaining after deducting the amounts referred to in (i) and (ii) above of this Section 10.2.6.2.2(a) (for the purposes of this Section 10.2.6.2.2(a), such remainder being the "Remaining Amount") to redeem or prepay the Notes and the other Senior Indebtedness provided that the portion of that amount to be applied to redeem the Notes shall be equal to the Remaining Amount multiplied by the percentage that the Notes represent of the Consolidated Senior Indebtedness at the date of Redemption. Redemption of the Notes under (i), (ii) or (iii) of this Section 10.2.6.2.2.(a) above will be at a purchase price per Note equal to the Redemption Price and shall be made on a pro rata basis amongst Noteholders.

(b) in the event that the Total Multiple Sale Proceeds are greater than $8,000,000, the Company shall (i) apply the first $2,000,000 of the Un-invested Multiple Sale Amount to redeem or prepay any Senior Indebtedness selected by the Company and (ii) apply the portion of the Un-invested Multiple Sale Amount remaining after deducting the amount referred to in (i) of this Section 10.2.6.2.2(b) above (for the purposes of this Section 10.2.6.2.2(b), such remainder being the "Remaining Amount") to redeem or prepay the Notes and the other Senior Indebtedness provided that that portion of the Remaining Amount to be applied to redeem the Notes shall be equal to the Remaining Amount multiplied by the percentage that the Notes represent of the Consolidated Senior Indebtedness at the date of redemption. Redemption of the Notes under (i) or (ii) above will be at a purchase price per Note equal to the Redemption Price and shall be made on a pro rata basis amongst Noteholders.

10.2.7 **Sale and Leaseback Transactions.** enter into, or agree to enter into any Sale and Leaseback Transaction, unless, after giving effect to any such Sale and Leaseback Transaction, no Default or Event of Default has occurred or is continuing or would occur as a result of such Sale and Leaseback Transaction, subject to the following:

10.2.7.1 **Single Transaction Restrictions.**

If the net proceeds of a single Sale and Leaseback Transaction are equal to or greater than $500,000 then the Company shall, subject to the provisions which follow, reinvest the entire amount of the net proceeds of such Sale and Leaseback Transaction (for the purposes of this Section 10.2.7.1, such entire amount being the "Total Single Transaction Proceeds") in the Business within 270 days of such sale, provided that if a portion of the Total Single Transaction Proceeds are not reinvested in the Business within 270 days of such Sale and Leaseback Transaction (for the purposes of this Section 10.2.7.1, such un-invested amount hereinafter referred to as the "Un-invested Single Transaction Amount"), the following provisions shall apply:

10.2.7.1.1 if the Un-invested Single Transaction Amount is equal to or less than $500,000 then the Un-invested Single Transaction Amount shall be applied to redeem or prepay any Senior Indebtedness selected by the Company; if the Company elects to redeem or prepay the Notes, redemption of the Notes will be at a purchase price per Note equal to the Redemption Price and shall be made on a pro-rata basis amongst Noteholders;

10.2.7.1.2 if the Un-invested Single Transaction Amount is greater than $500,000 then (i) a maximum of $500,000 of the Un-invested Single Transaction Amount shall be applied to redeem or prepay any Senior Indebtedness selected by the Company and (ii) the remainder of the Un-invested Single Transaction Amount after such payment referred to in (i) above (for the purposes hereof, the "Remaining Amount") shall be applied to redeem or prepay the Notes and the other Senior Indebtedness. The portion of the Remaining Amount to be applied to redeem the Notes shall be equal to the Remaining Amount multiplied by the percentage that the Notes represent of the Consolidated Senior Indebtedness at the date of redemption. Redemption of the Notes under (i) and (ii) of this Section 10.2.6.2.1 above will be at a purchase price per Note equal to the Redemption Price and shall be made on a pro rata basis amongst Noteholders.

10.2.7.2 **Multiple Transaction Restrictions.**

10.2.7.2.1 If the aggregate net proceeds for all single Sale and Leaseback Transactions ("Total Multiple Transaction Proceeds") total less than $500,000 in the aggregate for any fiscal year period as determined on the Calculation Date then the Company shall use those net proceeds at the Company's discretion:

10.2.7.2.2 if for the applicable fiscal year the Total Multiple Transaction Proceeds are calculated as being greater than or equal to $500,000 as of the Calculation Date, then the Company shall, subject to the provisions which follow, reinvest an amount equal to the Total Multiple Transaction Proceeds in the Business within 270 days of the Calculation Date provided that, if a portion of the Total Multiple Transaction Proceeds are not reinvested in the Business within 270 days of the Calculation Date (for the purposes of this Section 10.2.7.2, such un-invested amount (or an amount equal thereto) hereinafter referred to as the "Un-invested Multiple Transaction Amount"), the following provisions shall apply:

(a) the Company shall (i) use up to a maximum of $500,000 of the Un-invested Multiple Transaction Amount at the Company's discretion, (ii) apply the remainder of the Un-invested Multiple Transaction Amount, if any, up to a maximum of $500,000 to redeem or prepay any Senior Indebtedness selected by the Company and (iii) apply any portion of the Un-invested Multiple Transaction Amount remaining after deducting the amounts referred to in (i) and (ii) of this Section 10.2.7.2.2(a) above (for the purposes hereof, such remainder being the "Remaining Amount") to redeem or prepay the Notes and the other Senior Indebtedness provided that the portion of that amount to be applied to redeem the Notes shall be equal to the Remaining Amount multiplied by the percentage that the Notes represent of the Consolidated Senior Indebtedness at the date of redemption. Redemption of the Notes under (i), (ii) or (iii) of this Section 10.2.7.2.2(a) will be at a purchase price per Note equal to the Redemption Price and shall be made on a pro rata basis amongst Noteholders.

10.3 **<u>Environmental Compliance</u>**

10.3.1 The Company shall, and shall cause its Subsidiaries to, operate its Business in compliance with applicable Environmental Laws and Environmental Permits and operate all assets owned, leased, used or otherwise occupied by it such that no obligation, including a clean-up or remedial obligation, shall arise in respect of the Company or any of its Subsidiaries under any Environmental Law or Environmental Permit, provided however, that if any such obligation arises, the Company, or such Subsidiary, as the case may be, shall promptly satisfy or contest such obligation at its own cost and expense. It shall promptly notify the Noteholders, to the extent not disclosed as of the date hereof, upon (i) learning of the existence of any Substance located on, above or below the surface of any land which it owns, leases, operates, occupies, uses or controls (except those being stored, transported, used, treated or otherwise handled in compliance with applicable Environmental Law), or contained in the soil or water constituting such land and (ii) the occurrence of any lawfully reportable release, spill, leak, emission, discharge, leaching, dumping or disposal of Substances that has occurred on or from such land which, in either case, is likely to result in liability under Environmental Law.

10.3.2 The Company shall indemnify each Noteholder and its officers, directors, employees, agents and shareholders and shall hold each of them harmless from and against any and all losses, liabilities, damages, costs, expenses and claims (including legal fees on a solicitor and his own client basis) in respect of (a) any Environmental Law including the assertion of any Lien thereunder, (b) the presence of any Substance affecting the Premises or any adjacent real estate, or (c) the release of any Substance into the Environment. The Company's obligations and indemnification under this Section 10.3.2. shall survive the payment and satisfaction of all Obligations and the termination of this Agreement. Each Noteholder shall hold the benefit of this indemnity in trust for those indemnified parties who are not parties to this Agreement.

Article 11
Conditions Precedent

11.1 Conditions Precedent

The obligations of each Purchaser to purchase and pay for the Notes to be sold to it at the Closing is subject to the fulfilment, to the satisfaction of the Purchaser, prior to or at the Closing, of the following Conditions Precedent:

11.1.1 the representations and warranties set out in Article 8 shall be true and correct at Closing as if made on and as of such date;

11.1.2 no Default or Event of Default shall have occurred and be continuing nor shall there be any Default or Event of Default after giving effect to the proposed purchase of the Notes on Closing; and

11.1.3 the Purchaser shall have received the following in form and substance satisfactory to it:

11.1.3.1an Officers' Certificate dated as of the Closing Date certifying that attached thereto are true and correct copies of the following documents, and that such documents are in full force and effect, unamended:

11.1.3.1.1 the articles or constating documents of the Company and each Subsidiary;

11.1.3.1.2 the by-laws or other organizational documents of the Company and each Subsidiary;

11.1.3.1.3 a certificate of incumbency including sample signatures of officers and directors of the Company who have executed any of the Finance Documents or any other document delivered to the Purchaser under this Article 11;

11.1.3.1.4 the resolutions or other documentation evidencing that all necessary action, corporate or otherwise, has been taken by the Company to authorize the execution, delivery and performance of the Finance Documents to which it is a party; and

11.1.3.1.5 confirming Sections 11.1.1 and 11.1.2;

11.1.3.2 a certificate of status, certificate of good standing or similar certificate with respect to the jurisdiction of incorporation of the Company and each Subsidiary and for each jurisdiction where any of them carries on its Business;

11.1.3.3 an opinion of Company's Counsel dated the Closing Date reasonably acceptable to Noteholders' Counsel; and

11.1.3.4such other documentation or information as the Purchaser shall have reasonably requested; and

11.1.4 the Purchasers' Counsel shall have received payment of its fees and expenses owing at the Closing.

Article 12
Events of Default and Remedies

12.1 **Events of Default**

The occurrence of any of the following events shall constitute an Event of Default:

12.1.1 default by the Company in payment in respect of principal or Redemption Price when the same becomes due at the Maturity Date or at the Redemption Date, as the case may be, if such failure continues for a period of 2 Business Days;

12.1.2 default by the Company in payment in respect of any interest or other amount owing on the Notes when due (except as provided in Section 12.1.1) and any such failure continues for a period of 5 Business Days;

12.1.3 default by the Company of the negative covenant in Section 10.2.3;

12.1.4 default by the Company in the performance or observance of any covenant, condition or obligation contained in any Finance Document to which it is a party not referred to in Section 12.1.1 to 12.1.3 above unless such default is remedied within 30 Business Days of notice thereof to the Company by the Required Noteholders or the Company otherwise becoming aware of such default, except that a breach of Section 10.1.11 shall not be a default by the Company if the Company has complied, or is complying, with Section 10.1.12;

12.1.5 any representation or warranty made by the Company hereunder or in any Finance Document or other document delivered to the Purchasers pursuant hereto or in connection with any Finance Document is found to be false or incorrect in any way so as to make it materially misleading when made or deemed to have been made;

12.1.6 the Company or any Subsidiary (whether as primary obligor or guarantor or surety) fails to make any payment of principal, premium, if any, or interest on any Indebtedness, the outstanding principal amount of which exceeds, in the aggregate, 5% of Consolidated Net Worth, beyond any period of grace provided with respect thereto or fails to perform or observe any other term or condition contained in any agreement under which any such Indebtedness is created, and the effect of such default or failure is to cause an amount in excess of 5% of Consolidated Net Worth to become due or to be required to be repurchased prior to any stated maturity;

12.1.7 the Company or a Subsidiary institutes any proceeding or takes any corporate action or executes any agreement to authorize its participation in or commencement of any proceeding:

12.1.7.1seeking to adjudicate it a bankrupt or insolvent, or

12.1.7.2seeking liquidation, dissolution, winding up, reorganization, arrangement, protection, relief or composition of it or any of its property or debt or making a proposal with respect to it under any law relating to bankruptcy, insolvency, reorganization or compromise of debts or other similar laws (including, without limitation, any application under the Companies' Creditors Arrangement Act (Canada) or any reorganization, arrangement or compromise of debt under the laws of its jurisdiction of incorporation);

12.1.8 the Company or a Subsidiary admits its inability to pay its debts generally as they become due or otherwise acknowledges its insolvency;

12.1.9 any proceeding is commenced against or affecting the Company or a Subsidiary:

12.1.9.1 seeking to adjudicate it a bankrupt or insolvent;

12.1.9.2 seeking liquidation, dissolution, winding up, reorganization, arrangement, protection, relief or composition of it or any of its property or debt or making a proposal with respect to it under any law relating to bankruptcy, insolvency, reorganization or compromise of debts or other similar laws (including, without limitation, any reorganization, arrangement or compromise of debt under the laws of its jurisdiction of incorporation); or

12.1.9.3 seeking appointment of a receiver, trustee, agent, custodian or other similar official for it or for any substantial part of its properties and assets, including the Mortgaged Property or any part thereof;

and such proceeding is not being contested in good faith by appropriate proceedings or, if so contested remains outstanding, undismissed and unstayed more than 60 days from the institution of such first mentioned proceeding, provided however that notwithstanding any such 60 day period shall not have elapsed, an Event of Default shall be deemed to have occurred if such proceeding remains outstanding and, after the date of commencement of such proceeding, the Company does not satisfy a payroll obligation.

12.1.10 any creditor of the Company or any other Person shall privately appoint a receiver, trustee or similar official for any substantial part of the Company's properties and assets, having a book value greater than 5% of Consolidated Net Worth and such appointment is not being contested in good faith and by appropriate proceedings or, if so contested, such appointment continues for more than 60 days, provided however that notwithstanding any such 60 day period shall not have elapsed, an Event of Default shall be deemed to have occurred if such appointment remains outstanding and, after the date of the making of such appointment, the Company does not satisfy a payroll obligation;

12.1.11 any execution, distress or other enforcement process, whether by court order or otherwise, in an amount exceeding 5% of Consolidated Net Worth becomes enforceable againsr any property of the Company or a Subsidiary and such event is not being contested in good faith and by appropriate proceedings or, if so contested, such appointment continues for more than 60 days, provided however that notwithstanding any such 60 day period shall not have elapsed, an Event of Default shall be deemed to have occurred if such appointment remains outstanding and, after the date of the making of such appointment, the Company does not satisfy a payroll obligation;

12.1.12 any judgment or order for the payment of money in excess of 5% of Consolidated Net Worth shall be rendered against the Company or any Subsidiary and either (i) enforcement proceedings shall have been commenced by any creditor upon such judgment or order or (ii) there shall be any period during which a stay of enforcement of such judgment or order, by reason of a pending appeal or otherwise, shall not be in effect; and

12.1.13 at any time after execution and delivery thereof, any Finance Document ceases to be in full force and effect (unless within five Business Days of notice of the same being given by any Purchaser to the Company such Finance Document again has full force and effect as if it had always had full force and effect) or if any Finance Document is declared by a court or tribunal of competent jurisdiction to be null and void or the validity or enforceability thereof is contested by the Company or any of its Subsidiaries, or the Company or any of its Subsidiaries denies in writing that it has any or further liability or obligations under any Finance Document.

12.2 **Remedies Upon Default**

Upon the occurrence of any Event of Default, but subject to Section 13.1, the parties hereto agree that the Required Noteholders may:

12.2.1 declare all Obligations to be immediately due and payable to each of the Noteholders, on a pro rata basis; and

12.2.2 take such actions and commence such proceedings as may be permitted at law or in equity (whether or not provided for herein) at such times and in such manner as the Required Noteholders may consider expedient,

all without, except as may be required by Applicable Law, any additional notice, presentment, demand, protest, notice of protest, dishonour or any other action. The parties hereto acknowledge and agree that the rights and remedies of the Noteholders are cumulative and are in addition to and not in substitution for any other rights or remedies provided by Applicable Law.

12.3 **Proceeds of Realization**

All amounts realized by any Noteholder upon exercise of the remedies hereunder or under any Note shall be distributed to each other Noteholder on a pro rata basis on account of the obligations of the Company to each Noteholder without prejudice to any claim by each Noteholder on a pro rata basis for any deficiency after such proceeds are received by the Noteholders, and the Company shall remain liable for any such deficiency.

12.4 **Defeasance**

The Company shall be deemed to have fully paid, satisfied and discharged the outstanding Notes and the Noteholders shall execute and deliver proper instruments acknowledging the full payment, satisfaction and discharge of the Notes, when, with respect to all outstanding Notes:

12.4.1 the Company has deposited or caused to be deposited with a trustee satisfactory to the Majority Noteholders, acting reasonably, as trust funds in trust for the purpose of making payment on the Notes, an amount of cash sufficient to pay, satisfy and discharge the entire amount of principal, Redemption Price, interest and other amounts owing hereunder or under any other Finance Document, if any, to maturity or any repayment date or Redemption Date, as the case may be, of the outstanding Notes; and in such case, the Company has delivered to the Noteholders an Officers' Certificate stating that all conditions precedent herein provided relating to the payment, satisfaction and discharge of the outstanding Notes have been satisfied.

12.4.2 Any deposits with a trustee pursuant to this Section 12.4 shall be made under the terms of an escrow and/or trust agreement in form and substance satisfactory to the Majority Noteholders and which provides for the due and punctual payment of the principal, interest, Redemption Price or any other amounts that may be owing hereunder or under any other Finance Document, as applicable, on the Notes being satisfied.

12.4.3 Any funds or obligations deposited with the trustee pursuant to this Section 12.4 shall be denominated in the currency of denomination of the Notes in respect of which such deposit is made.

12.4.4 The account in respect of which any funds or obligations are to be deposited with the trustee pursuant to this Section 12.4, and the funds and all proceeds thereof, shall be subject to a first ranking security interest perfected in favour of the Noteholders and the Noteholders will have received an opinion of Company's Counsel satisfactory to the Noteholders regarding such security interest;

12.4.5 Upon the satisfaction of the conditions set forth in this Section 12.4 with respect to all the outstanding Notes, the terms and conditions of this Agreement (other than Section 10.3) and the Notes shall no longer be binding upon or applicable to the Company.

Article 13
General

13.1 Amendment and Waiver

This Agreement and the Notes may be amended, and the observance of any term hereof or of the Notes may be waived (either retroactively or prospectively), with (and only with) the written consent of the Company and the Majority Noteholders, except that no such amendment or waiver may, without the written consent of the holder of each Note at the time outstanding affected thereby, (i) subject to the provisions of Section 12.1 relating to acceleration or rescission, change the amount or time of any prepayment or payment of principal of, or reduce the rate or change the time of payment or method of computation of interest on the Notes or in respect of the Redemption Price or (ii) change the percentage of the principal amount of the Notes the holders of which are required to consent to any such amendment or waiver.

13.2 Substitution of Purchaser

Each Purchaser shall have the right to substitute any one of its Affiliates as the purchaser of the Notes that such Purchaser has agreed to purchase hereunder, by written notice to the Company, which notice shall be signed by both that Purchaser and such Affiliate, shall contain such Affiliate's agreement to be bound by this Agreement and shall contain a confirmation by such Affiliate of the accuracy with respect to it of the representations set forth in Section 9.1. Upon receipt of such notice, wherever the words "Purchasers" or "Purchaser" are used in this Agreement (other than in this Section 13.2), such word shall be deemed to include such Affiliate or refer to such Affiliate in lieu of such Purchaser, as the case may be. In the event that such Affiliate is so substituted as a purchaser hereunder and such Affiliate thereafter transfers to the relevant Purchaser all of the Notes then held by such Affiliate, upon receipt by the Company of notice of such transfer, wherever the words "the Purchaser" is used in this Agreement (other than in this Section 13.2), such words shall no longer be deemed to refer to such Affiliate, but shall refer to the relevant Purchaser, and the relevant Purchaser shall have all the rights of an original holder of the Notes under this Agreement.

13.3 **Assignment**

13.3.1 This Agreement and the other Finance Documents shall enure to the benefit of and be binding on the parties hereto and thereto, their respective successors and any assignee or transferee of some or all of the parties' rights or obligations under this Agreement and the other Finance Documents as permitted under this section 13.3.

13.3.2 The Company shall not assign or transfer all or any part of its rights or obligations under this Agreement or any of the other Finance Documents without the prior written consent of all of the Noteholders, which consent may be arbitrarily withheld.

13.3.3 Any Noteholder (an "Assignor") may assign or transfer all or part of its rights in respect of any Notes and this Agreement to, and may have its corresponding obligations in respect thereof assumed by, any other Person at such times and upon such terms as it may deem fit, without any obligation to obtain any consent of the Company, provided in each case that:

(a) such Assignor complies with the provisions of Article 6 hereof;

(b) any such assignment or transfer shall be at least the lesser of:

(i) $1,000,000; and

(ii) the outstanding amount held by such Noteholder;

(c) the Assignor and the assignee or transferee (the "Assignee") shall enter into an assignment and assumption agreement (the "Assignment Agreement") substantially in the form of Schedule 13.3, whereby *inter alia* the Assignee agrees to be bound by this Agreement, and all Finance Documents relating to the obligations of a

Noteholder in the place and stead of the Assignor to the extent that the rights and obligations of the Assignor shall have been assigned to and assumed by the Assignee, and shall deliver a copy of the Assignment Agreement so executed to the Company;

(d) The Company shall execute and deliver such other assurances as may be requested by the Assignor to confirm the release and discharge provided for in clause (e) below;

(e) upon execution of the Assignment Agreement by the Assignor and the Assignee, the assignment or transfer to the Assignee shall be effective upon the date provided in the Assignment Agreement, and the Assignee shall thereafter be and be treated as a Noteholder for all purposes of this Agreement and the other Finance Documents and shall be entitled to the full benefit hereof and thereof to the extent such benefits are transferred to it by the Assignor and subject to the obligations of the Assignor; and

(f) all expenses incurred by or on behalf of the Company and its Subsidiaries and Affiliates shall be paid in full by such Assignee as a condition precedent to the validity of such assignment.

13.4 **Severability**

Any provision of this Agreement that is prohibited or unenforceable in any jurisdiction shall, as to such jurisdiction, be ineffective to the extent of such prohibition or unenforceability without invalidating the remaining provisions hereof, and any such prohibition or unenforceability in any jurisdiction shall (to the full extent permitted by law) not invalidate or render unenforceable such provision in any other jurisdiction.

13.5 **Construction**

Each covenant contained herein shall be construed (absent express provision to the contrary) as being independent of each other covenant contained herein, so that compliance with any one covenant shall not (absent such an express contrary provision) be deemed to excuse compliance with any other covenant. Where any provision herein refers to action to be taken by any Person, or which such Person is prohibited from taking, such provision shall be applicable whether such action is taken directly or indirectly by such Person.

13.6 **Counterparts**

This Agreement may be executed in any number of counterparts, each of which shall be an original but all of which together shall constitute one instrument. Each counterpart may consist of a number of copies hereof, each signed by fewer than all, but together signed by all, of the parties hereto.

13.7 **Notices**

Any notice or other communication required or permitted to be given hereunder shall be in writing and shall be given by prepaid first-class mail, by telecopier or other means of electronic communication or by hand-delivery as hereinafter provided. Any such notice, if mailed by prepaid first-class mail at any time other than during or within three Business Days prior to a general discontinuance of postal service due to strike, lock-out or otherwise, shall be deemed to have been received on the fourth Business Day after the post-marked date thereof, or if sent by telecopier or other means of electronic communication, shall be deemed to have been received on the Business Day following the sending, or if delivered by hand shall be deemed to have been received at the time it is delivered to the applicable address noted below either to the individual designated below or to a senior employee of the addressee at such address (and, in the case of each Noteholder, at the same department within the Company) with responsibility for matters to which the information relates. Notice of change of address shall also be governed by this section. In the event of a general discontinuance of postal service due to strike, lock-out or otherwise, notices or other communications shall be delivered by hand or sent by facsimile or other means of electronic communication and shall be deemed to have been received in accordance with this section. Notices and other communications shall be addressed as follows:

(a) if to the Company:

Canadian Niagara Power Inc.
PO BOX 1218
1130 Bertie Street, Fort Erie Ontario
L2A 5Y2

Attention: Chief Financial Officer
Fax number: (905) 994-2203

(b) if to the Purchasers:

The Canada Life Assurance Company
330 University Avenue
Toronto, Ontario
M5G 1R8

Attention:	Canadian Private Placements, SP-11
Fax number:	(416) 597-9678

Sun Life Assurance Company of Canada
225 King Street West, 11th Floor
Toronto, Ontario
M5V 3C5

Attention:	Structured Finance, Investments
Fax number:	(416) 595-0131

The Maritime Life Assurance Company
7 Maritime Place
P.O. Box 1030
Halifax, Nova Scotia
B3J 2X5

Attention:	Vice President, Private Placements
Fax number:	(902) 453-7181

13.8 **Time**

Time is of the essence of the Finance Documents.

13.9 **Further Assurances**

Whether before or after the happening of an Event of Default, the Company shall at its own expense (except where otherwise expressly indicated herein) do, make, execute or deliver, or cause to be done, made, executed or delivered by its Subsidiaries or other Persons, all such further acts, documents and things in connection with the Finance Documents as the Noteholders may reasonably require from time to time for the purpose of giving effect to the Finance Documents, all immediately upon the request of such Noteholder.

13.10 **Facsimile Copies**

Delivery of an executed signature page to this Agreement by any party to this Agreement by facsimile transmission shall be as effective as delivery of a manually executed copy of this Agreement by such party.

IN WITNESS WHEREOF this Agreement has been executed by the parties hereto as of the date first written above.

CANADIAN NIAGARA POWER INC.

by: [signature]
Name: Timothy B. Curtis
Title: VP Finance CFO

by: William J. Daley
Name: WILLIAM J. DALEY
Title: PRESIDENT & CEO

SUN LIFE ASSURANCE COMPANY OF CANADA

by:____________________
Name:
Title:

by:____________________
Name:
Title:

CANADA LIFE FINANCIAL CORPORATION

by:____________________
Name:
Title:

by:____________________
Name:
Title:

MARITIME LIFE ASSURANCE COMPANY

by:____________________
Name:
Title:

by:____________________
Name:
Title:

IN WITNESS WHEREOF this Agreement has been executed by the parties hereto as of the date first written above.

CANADIAN NIAGARA POWER INC.

by:______________________________
Name:
Title:

by:______________________________
Name:
Title:

SUN LIFE ASSURANCE COMPANY OF CANADA

by:______________________________
Name: Paul C. Sinclair
Title: AVP, Structured Finance

by:______________________________
Name: Steve Theofanis
Title: Director, Structured Finance

CANADA LIFE FINANCIAL CORPORATION

by:______________________________
Name:
Title:

by:______________________________
Name:
Title:

MARITIME LIFE ASSURANCE COMPANY

by:______________________________
Name:
Title:

by:______________________________
Name:
Title:

IN WITNESS WHEREOF this Agreement has been executed by the parties hereto as of the date first written above.

CANADIAN NIAGARA POWER INC.

by:______________________________
Name:
Title:

by:______________________________
Name:
Title:

SUN LIFE ASSURANCE COMPANY OF CANADA

by:______________________________
Name:
Title:

by:______________________________
Name:
Title:

CANADA LIFE FINANCIAL CORPORATION

by:______________________________
Name: Kelly Kwan
Title: Senior Investment Analyst

by:______________________________
Name:
Title:

MARITIME LIFE ASSURANCE COMPANY

by:______________________________
Name:
Title:

by:______________________________
Name:
Title:

IN WITNESS WHEREOF this Agreement has been executed by the parties hereto as of the date first written above.

CANADIAN NIAGARA POWER INC.

by:____________________________
Name:
Title:

by:____________________________
Name:
Title:

SUN LIFE ASSURANCE COMPANY OF CANADA

by:____________________________
Name:
Title:

by:____________________________
Name:
Title:

CANADA LIFE FINANCIAL CORPORATION

by:____________________________
Name:
Title:

by:____________________________
Name:
Title:

AUTH FOR EXECUTION

ES.

MLAC PRIVATE PLACEMENTS

MARITIME LIFE ASSURANCE COMPANY

by:____________________________
Name: LAURIE A. HARDING
Title: Vice President, Private Placements

by:____________________________
Name: PETER A. STUART
Title: Senior Vice President
Chief Investment Officer

EXHIBIT 1

[FORM OF NOTE]

CANADIAN NIAGARA POWER INC.

7.092 % Senior Unsecured Note Due August 14, 2018

No. [________] [Date]

$[__________] PPN ________

FOR VALUE RECEIVED, the undersigned, Canadian Niagara Power Inc. (herein called the "Company"), a corporation incorporated and existing under the laws of Ontario, hereby promises to pay to [______________], or registered assigns, the principal sum of [______________] DOLLARS on August 14, 2018 (the "Maturity Date") with interest at a rate per annum of 7.092% calculated and payable semi-annually. Interest will be payable after as well as before the Maturity Date, default and judgment semi-annually on August 14 and February 14 in each year commencing on February 14, 2004 in accordance with the payment schedule set forth in Annex A hereto; provided that in the event of any redemption, the amounts payable pursuant to Annex A shall be reduced proportionately based on the amount redeemed and the original face amount of the Note.

Payments of principal, interest, any Redemption Price and other amounts owing with respect to this Note are to be made in lawful money of Canada at ______________, Toronto, Ontario, or at such other place as the Company shall have designated by written notice to the holder of this Note as provided in the Note Purchase Agreement referred to below.

This Note is one of a series of Senior Unsecured Notes (herein called the "Notes") issued pursuant to the Master Note Purchase Agreement dated as of August 14, 2003 (as from time to time amended, the "Note Purchase Agreement"), among the Company, the Purchaser, [■] and [■] and is entitled to the benefits thereof. The holder of this Note will be deemed, by its acceptance hereof, to have made the representation set forth in Section 9.1 of the Note Purchase Agreement.

This Note is a registered Note and, as provided in the Note Purchase Agreement, upon surrender of this Note for registration of transfer, duly endorsed, or accompanied by a written instrument of transfer duly executed, by the registered holder hereof or counsel to such holder's attorney duly authorized in writing, a new Note for a like principal amount will be issued to, and registered in the name of, the transferee. Prior to due presentment for registration of transfer, the Company may treat the person in whose name this Note is registered as the owner hereof for the purpose of receiving payment and for all other purposes, and the Company will not be affected by any notice to the contrary.

This Note is subject to optional prepayment, in whole or from time to time in part, at the times and on the terms specified in the Note Purchase Agreement, but not otherwise.

If an Event of Default, as defined in the Note Purchase Agreement, occurs and is continuing, the principal of this Note may be declared or otherwise become due and payable in the manner, at the price (including any applicable Redemption Price) and with the effect provided in the Note Purchase Agreement.

This Note shall be construed and enforced in accordance with, and the rights of the parties shall be governed by, the laws of Ontario excluding choice-of-law principles of the law of such province that would require the application of the laws of a jurisdiction other than such province.

CANADIAN NIAGARA POWER INC.

by:____________________________
Name:
Title:

by:____________________________
Name:
Title:

ANNEX A

Date	Dollars per $1,000,000 in principal amount
February 15, 2004	$35,460
August 14, 2004	$35,460
February 14, 2005	$35,460
August 14, 2005	$35,460
February 14, 2006	$35,460
August 14, 2006	$35,460
February 14, 2007	$35,460
August 14, 2007	$35,460
February 14, 2008	$35,460
August 14, 2008	$35,460
February 14, 2009	$35,460
August 14, 2009	$35,460
February 14, 2010	$35,460
August 14, 2010	$35,460
February 14, 2011	$35,460
August 14, 2011	$35,460
February 14, 2012	$35,460
August 14, 2012	$35,460
February 14, 2013	$35,460
August 14, 2013	$35,460
February 14, 2014	$35,460
August 14, 2014	$35,460
February 14, 2015	$35,460

August 14, 2015	$35,460
February 14, 2016	$35,460
August 14, 2016	$35,460
February 14, 2017	$35,460
August 14, 2017	$35,460
February 14, 2018	$35,460
August 14, 2018	$35,460

EXHIBIT 2

INFORMATION RELATING TO PURCHASER

Name and Address of Purchaser	Principal Amount of Notes to be Purchased
[■]	$[■]

Payments

All payments on or in respect of the Notes to be by bank wire transfer of Cdn$ or other immediately available funds (identified each payment as "Canadian Niagara Power Inc." Notes due August 14, 2018, principal, premium or interest") to:

[■]

Notices

All notices and communications, including notices with respect to payments and written confirmation of each such payment, to be addressed as first provided above, with a copy to:

[■]

Name of Nominee in which Notes are to be issued: [■]

SCHEDULE 1.1.58

FORM OF NON-DISCLOSURE AGREEMENT

THIS AGREEMENT made and entered into as of this ● day of ●, ●.

BY:

●, having its place of business at ●

(hereinafter referred to as the "Recipient")

in favour of

CANADIAN NIAGARA POWER INC. (the "Company") ●

WHEREAS the Recipient is considering an investment (the "Investment") in a private placement debt offering of 7.092% senior unsecured notes due August 14th, 2018 (the "Notes") issued by the Company pursuant to a master note purchase agreement dated as of August 14th, 2003 between the Company, as issuer, SunLife Assurance Company of Canada, Canada Life Financial Corporation and Maritime Life Assurance Company, as purchasers (the "Note Purchase Agreement");

AND WHEREAS it is a condition pursuant to the terms of the Note Purchase Agreement that the Recipient shall have entered into this Agreement and provided a copy thereof to the Company;

NOW THEREFORE, IN CONSIDERATION of the premises and mutual covenants herein set forth, the Company and the Recipient agree as follows:

1. Use of Confidential Information

The Recipient agrees that either during the currency of this Agreement or at any time thereafter:

(a) it will keep confidential and not disclose to any third party all Confidential Information disclosed to the Recipient by the Company or by any of the Company' agents in writing, orally or by any other means, provided that (i) prior to making the Investment, the Recipient may disclose Confidential Information to other potential investors provided further that prior to such disclosure the receiver of such Confidential Information has executed a non-disclosure agreement in favour of the Company in a form substantially the same this Agreement and (ii) after making the Investment, so long as the Recipient is a holder of Notes, the Recipient may disclose Confidential Information to other holders of Notes;

(b) it will use its best efforts to protect the confidentiality of the Confidential Information, using a standard of care no less than the degree of care that Recipient employs for its own similar confidential information. In particular Recipient shall not directly or indirectly disclose, allow access to, transmit or transfer the Confidential Information to a third party other than a potential investor without the Company's prior written consent. Recipient shall disclose the Confidential Information only to those of its employees, advisors or to those employees of any consultant of Recipient, who have a need to know the Confidential Information for the purpose of making an Investment in the Notes (the "Purpose"), and to its regulatory authorities. Recipient shall, prior to disclosing the Confidential Information to such employees, advisors and consultants, issue appropriate instructions to them to satisfy its obligations herein and obtain their agreement to receive and use the Confidential Information on a confidential basis on the same conditions as contained in this Agreement;

(c) it will not use such Confidential Information, or any portion or copy thereof, for any purpose other than the Purpose;

(d) the Confidential Information shall not be copied, reproduced in any form or stored in a retrieval system or data base by Recipient without the prior written consent of the Company, except for such copies and storage as may reasonably be required internally by Recipient for the Purpose; and

(e) in the event that the Recipient chooses not to make the Investment, it will return all Confidential Information furnished to it by the Company and any photocopies thereof, to the Company, upon their request, provided that the Recipient may retain all material prepared by it subject to its confidentiality obligations under this Agreement.

2. Confidential Information Defined

The Confidential Information to which the obligations of non-use, confidence and secrecy imposed upon the Recipient by this Agreement comprises the following:

(a) any document or drawing provided to the Recipient by the Company, any Subsidiary or Affiliate thereof, or any agent or any Subsidiary thereof with respect to the Investment or the Company;

(b) any information obtained through discussions with the Company or any agent of the Company or any Subsidiary thereof with respect to the Investment or the Company;

(c) any information learned through visits by the Recipient to facilities of the Company, any Subsidiary or Affiliate thereof, or any agent of the Company or any Subsidiary thereof with respect to the Investment or the Company and its Subsidiaries and Affiliates; and

(d) such further and other information with respect to the Investment or the Company that might reasonably be considered to be confidential including, without limitation, financial statements and other disclosure documents, corporate strategies and plans, brand share and tracking data, brand strategies and plans, sales information, new product information, technical information and third party contractual terms and conditions.

3. Non-Applicability

The Recipient's obligations hereunder shall not extend to information which:

(a) was in the Recipient's possession prior to disclosure by the Company, any Subsidiary or Affiliate thereof, or any agent of the Company or its Subsidiaries and Affiliates, not already subject to a confidentiality agreement;

(b) was or subsequently becomes generally available to the public other than by acts or omissions by the Recipient;

(c) is subsequently communicated to the Recipient by a third party who did not receive such information under obligations of confidentiality, either directly or indirectly from the Company or any Subsidiary or Affiliate;

(d) is required to be disclosed pursuant Applicable Law, provided the Company is given timely notice of the issuance of such order by the Recipient to enable the Company to contest compliance therewith; or

(e) was independently developed by Recipient, other than by a breach of this Agreement.

4. Consequence of Breach

The parties hereto specifically agree that money damages may not be a sufficient remedy for any breach of this agreement and that, in addition to all other remedies available, the Company and its Subsidiaries and Affiliates shall be entitled to specific performance, injunctive or other equitable relief as a remedy for such breach.

5. Term

The obligations of non-use, confidence and secrecy hereunder shall, subject to sub-sections 3(a) through (e) above, survive the termination of this agreement for a period of two (2) years.

6. Entire Agreement

This Agreement constitutes the entire agreement between the parties hereto with respect to the subject matter hereof and cancels and supersedes any prior understandings and agreements between the parties hereto with respect thereto. There are no representations, warranties, terms, conditions, undertakings or collateral agreements, express, implied or statutory, between the parties other than as expressly set forth in this Agreement.

7. No Assignment

This Agreement may not be assigned by either party without the prior written consent of the other party.

8. Binding Effect

This Agreement shall inure to the benefit of and be binding upon the parties hereto, their successors and assigns.

9. Applicable Law

This Agreement shall be construed in accordance with the laws of the Province of Ontario, and the parties hereto submit to the jurisdiction of the courts of the Province of Ontario.

IN WITNESS WHEREOF, the parties have caused this Agreement to be executed as of the date first above written.

[■]

by:______________________________
Name:
Title:

by:______________________________
Name:
Title:

SCHEDULE 1.1.71

PERMITTED ENCUMBRANCES

LIENS UNDER THE *PERSONAL PROPERTY SECURITY ACT* (ONTARIO)

PERMITTED ENCUMBRANCES

LIENS UNDER THE *PERSONAL PROPERTY SECURITY ACT* (ONTARIO)

SECURED PARTY	FILE NUMBER	REGISTRATION NUMBER AND TIME PERIOD	COLLATERAL	COMMENTS
De Lage Landen Financial Services Canada Inc.	868533183	20001221 1049 7029 3840 (3 years)	Equipment, Other	Up to a maximum of $________

SCHEDULE 8.1.9

Litigation

NIL

SCHEDULE 8.1.14

Environmental

CNPI:
Registration - PCB Storage Site 20391A009

Acknowledgement of Subject Waste Registration ON2593800

Acknowledgement of Subject Waste Registration ON0603800

Acknowledgement of Subject Waste Registration ON0562401

Certificate of Approval (Air) 1195-5HWMLF

Eastern Ontario Power:

PCB Waste Storage Site 403-89-A0480

Acknowledgement of Subject Waste Registration ON1033000

MOE Approval for Septic System LG-248-91

SCHEDULE 8.1.16

Governmental Charges

NIL

SCHEDULE 8.1.17

Existing Indebtedness

Letter of Credit SBGT721815 issued by CIBC to FortisOntario Inc. on behalf of Canadian Niagara Power Inc. for $2,107,567.00. Beneficiary is the Independent Electricity Market Operator. Expiry April 9, 2004.

Letter of Credit SBGT721813 issued by CIBC to FortisOntario Inc. on behalf of Canadian Niagara Power Inc. for $1,393,434.00. Beneficiary is the Independent Electricity Market Operator. Expiry April 9, 2004.

SCHEDULE 8.1.18

Corporate Structure of Company and Subsidiaries

See Attached

SCHEDULE 10.1.16

Officers' Certificate

Date:

[■]

Attention: [■]

Dear Sirs:

I, ______________________________, of ________________________, in the Province of Ontario, as ______________________ of [■] (the "Company") hereby certify on behalf of the Company and without personal liability as follows:

(i) This Certificate applies to the fiscal quarter ending ______________________________;

(ii) I am familiar with and have examined the provisions of the Note Purchase Agreement dated as of [■] (the "Note Purchase Agreement", the terms defined therein being used herein as therein defined) among the Company and [■], and have made reasonable investigations for purposes of this Certificate;

(iii) Based on the foregoing:

(a) the consolidated financial statements attached as Exhibit "A" were prepared in accordance with generally accepted accounting principles (subject to normal year-end adjustments in the case of interim unaudited financial statements) and fairly, completely and accurately present the financial condition of the Company and the financial information presented therein for the period and as of the date referred to in clause (ii) above;

(b) the Company was not, as of the date referred to in clause (ii) above, in breach of the covenants contained in Sections 10.2.4, 10.2.5, 10.2.6 and 10.2.7 of the Note Purchase Agreement, evidence of compliance with which is set out in Exhibit B;

(c) no event has occurred and is continuing which would constitute a Default or an Event of Default; and

(d) the officer has authority to bind the Company.

[■]

Per:______________________________
Name:
Title:

EXHIBIT A to SCHEDULE 10.1.16

Consolidated Financial Statements

EXHIBIT B to SCHEDULE 10.1.16

Compliance with Covenants

[Company to describe calculation of:

1) EBITDAR

2) Consolidated Senior Indebtedness

3) Total Consolidated Capitalization

4) Consolidated Senior Interest Expense plus Rent

5) Compliance with Sections 10.2.4 to 10.2.7

and to confirm compliance with covenants]

SCHEDULE 13.3

Form of Assignment and Assumption Agreement

ASSIGNMENT AND ASSUMPTION AGREEMENT

■

as Assignor

- and -

■

as Assignee

- and -

- and -

CANADIAN NIAGARA POWER INC.

as Company

ASSIGNMENT AND ASSUMPTION AGREEMENT

Dated as of ■, ■

ASSIGNMENT AND ASSUMPTION AGREEMENT

This Assignment and Assumption Agreement is made as of ■, ■ (the "Assignment Date") among ■ (the "Assignor"), a Noteholder under the Master Note Purchase Agreement referred to and defined hereafter, ■ (the "Assignee") and Canadian Niagara Power Inc. (the "Company").

RECITALS:

A. Pursuant to a master note purchase agreement dated as of August 14th, 2003 (as amended, supplemented and restated from time to time, the "Master Note Purchase Agreement") among the Company and the financial institutions specified therein as Noteholders (collectively, the "Noteholders"), the Noteholders have purchased certain notes from the Company;

B. The Assignor has agreed to assign and sell to the Assignee $■ of principal of its right, title and interest in and to the **[specify Note]**, (the "Assigned Interest"), and the Assignee has agreed to accept and purchase the Assigned Interest and to assume all liabilities and obligations of the Assignor in respect of the Assigned Interest, all effective as of the Assignment Date;

C. The Company has requested that the Assignee enter into an agreement pursuant to section 13.3.3 of the Master Note Purchase Agreement and the Company has agreed to acknowledge the release and assumption of the Assigned Interest hereunder.

NOW THEREFORE, for valuable consideration, the receipt and sufficiency of which are hereby acknowledged, the parties hereto agree as follows:

1. **Definitions.** All terms defined in the Master Note Purchase Agreement which appear herein without definition shall have the meanings attributed thereto in the Master Note Purchase Agreement.

2. **Conveyance of Assigned Interest.** The Assignor hereby assigns, sells, conveys and transfers to the Assignee all of its undivided interest in and to the Assigned Interest, effective as of the Assignment Date, without recourse, representation or warranty of any kind except as expressly set forth in section 4.1 hereof.

3. **Assumption.** The Assignee hereby accepts and purchases the Assigned Interest, effective as of the Assignment Date, and the Assignee hereby agrees to be bound by the terms and conditions of the Master Note Purchase Agreement and the other Finance Documents as if it were an original Noteholder and acknowledges and expressly assumes in the name, place and stead of the Assignor all obligations and liabilities attaching to the Assigned Interest and agrees to perform the terms, conditions and agreements on its part to be performed as a Lender in respect thereof under the Master Note Purchase Agreement and the other Finance Documents.

4. **Representations of Assignor.**

4.1 The Assignor hereby represents and warrants to the Assignee that:

(a) the Assignor has full power and authority and has taken all action necessary to execute and deliver, to perform its obligations under and to consummate the transactions contemplated by this assignment and assumption agreement and any and all other documents and instruments to be delivered by it in connection with this assignment and assumption agreement; and

(b) the Assignor is the sole legal and beneficial owner of the Assigned Interest, and the Assigned Interest is free and clear of any Liens created by the Assignor in respect of the Assigned Interest.

4.2 It is understood and agreed that, except for the representations and warranties set forth herein, the assignment and assumption made hereunder are without recourse to the Assignor and the Assignor makes no further representations or warranties whatsoever, express or implied.

5. **Representation of Company.** The Company hereby represents and warrants that, as of the Assignment Date, no Default or Event of Default has occurred and is continuing.

6. **Release by the Company.** The Company hereby releases the Assignor from all obligations and liabilities relating to the Assigned Interest in respect of the period from and after the Assignment Date and acknowledges the assumption of all such liabilities and obligations by the Assignee, effective as of the Assignment Date.

7. **Assignee's Acknowledgement.** The Assignee hereby acknowledges that it has received a copy of the Master Note Purchase Agreement, the other Finance Documents and such other documents and information as it has deemed appropriate to make its own credit analysis and determination to enter into this assignment and assumption agreement.

8. **Recognition as Noteholder.** The parties hereto acknowledge that the Assignee is, by virtue of compliance with the provisions of section 13.2 of the Master Note Purchase Agreement, as of and from the Assignment Date, a Noteholder under and as defined in the Master Note Purchase Agreement for the purposes thereof and for the purposes of all other Finance Documents.

9. **Notice.** The Assignee's address for notice is as follows: ■.

10. **Governing Law.** This assignment and assumption agreement shall be governed by and construed in accordance with the laws of the Province of Ontario and the laws of Canada applicable therein.

11. **Enurement.** This assignment and assumption agreement shall enure to the benefit of and be binding upon the parties hereto and their respective successors and permitted assigns.

12. **Counterparts**. This assignment and assumption agreement may be signed in any number of counterparts, each of which shall be deemed an original, but all such separate counterparts shall constitute one and the same instrument.

IN WITNESS WHEREOF the parties have executed this assignment and assumption agreement under the hands of their proper officers duly authorized in that behalf as of the date first above written.

[ASSIGNOR], as Assignor

Per: ______________________________
Authorized Signing Officer

Per: ______________________________
Authorized Signing Officer

[ASSIGNEE], as Assignee

Per: ______________________________
Authorized Signing Officer

Per: ______________________________
Authorized Signing Officer

CANADIAN NIAGARA POWER INC.

Per: ______________________________
Authorized Signing Officer

quarter, including in each case a balance sheet, statement of profit and loss and a statement of changes in financial position, together with comparative figures for the corresponding period in the previous Fiscal Year;

10.1.6 **Annual Financial Statements.** The Company shall, as soon as practicable and in any event within 120 days after the end of each Fiscal Year, deliver to each Noteholder the audited consolidated financial statements of the Company and the annual unconsolidated financial statements of the Company and each Subsidiary for such Fiscal Year, including in each case a balance sheet, statement of profit and loss, a statement of changes in financial position and a statement of retained earnings, together with comparative figures for the previous Fiscal Year;

10.1.7 **Accounting Methods and Financial Records.** The Company shall, and shall cause each of its Subsidiaries to, maintain a system of accounting which is established and administered in accordance with generally accepted accounting principles, keep adequate records and books of account in which accurate and complete entries shall be made in accordance with such accounting principles reflecting all transactions required to be reflected by such accounting principles and keep accurate and complete records of any property owned by it;

10.1.8 **Payment of Governmental Charges and Claims.** Except in such cases where a failure to do so would not reasonably be expected to have a Material Adverse Effect and except for any amounts the payment of which is being contested in good faith by appropriate proceedings and for which reserves (if appropriate) have been established in accordance with generally accepted accounting principles, the Company shall, and shall cause each of its Subsidiaries to:

10.1.8.1pay and discharge when due all lawful claims for labour, material and supplies;

10.1.8.2pay and discharge when due all Governmental Charges payable by it;

10.1.8.3withhold and collect all Governmental Charges required to be withheld and collected by it and remit such Governmental Charges to the appropriate Governmental Body at the time and in the manner required;

10.1.8.4pay and discharge when due all obligations incidental to any trust imposed upon it by statute which, if unpaid, might become a Lien upon any of the Business Assets;

10.1.9 **Energy Distribution Business.** The Company and its Subsidiaries will operate only in the electricity transmission and distribution business in Ontario regulated by the Regulators, provided that the Company and its Subsidiaries may also operate in businesses ancillary to the Business, which in the aggregate are not material. For greater certainty, the Company and its Subsidiaries will not engage in the electricity generation or energy marketing businesses unless it is immaterial and ancillary to the Business.

10.1.10 **Insurance.** The Company and its Subsidiaries shall maintain or cause to be maintained with reputable insurers, coverage against risk of loss or damage to the properties and operations of the Company and its Subsidiaries of such types as is customary for and would be maintained by a corporation with an established reputation engaged in the same or similar business in similar locations and provide to each Noteholder, upon reasonable request, evidence of such coverage.

10.1.11 **Damage to Business Assets.** In the Event that any of the Business Assets are materially damaged, destroyed, impaired or otherwise materially harmed as a result of fire or other hazard, including, without limitation, flood, earthquake, ice storm, tornado, hurricane or other environmental or natural causes, and such Business Assets are material to the operation of the Power System, the Company shall use its best commercial efforts to repair, restore, reconstruct or replace such Business Assets in a timely manner, acting reasonably.

10.1.12 **Springing Lien.** Upon a breach of Section 10.1.11 hereof having occurred and while such breach is continuing, the Company shall, upon the request of the Required Noteholders, within a commercially reasonable period thereafter, pledge and grant to the Noteholders, or an agent thereof, a second ranking continuing security interest in all of the right, title and interest of the Company in, to and under all accounts receivable or other rights of payment of any monetary obligation of or owing to the Company (the "Secured Property") pursuant to a security agreement on terms and conditions satisfactory to the Noteholders. Notwithstanding the foregoing and without derogating from the obligations of the Company referred to above, the Noteholders acknowledge that they may be required to enter into an inter-creditor agreement on terms and conditions satisfactory to the Noteholders with each other Person that the Company has granted a security interest to in respect of and over such Secured Property and agree to use reasonable best efforts to enter into the same provided that the Company uses commercially reasonable efforts to induce such Persons to enter into such inter-creditor agreement within a commercially reasonable timeframe. For clarity, no other secured party (other than existing and future Noteholders) shall have a second ranking secured charge over the Secured Property ranking pari passu with the charge granted to the Noteholders as referred to above. The Noteholders shall take such actions as necessary to release the charge on the Secured Property when the breach of Section 10.1.11 has been cured or waived.

10.1.13 <u>Employee Plans</u>. The Company shall, and shall cause each of the Subsidiaries to perform all material obligations under each Employee Plan and OMERS Plan (including without limitation), those respecting the making or payment of contributions or premiums, as applicable) in all material respects in accordance with the relevant terms of each plan and all Applicable Law.

10.1.14 <u>Inspections.</u> At any time upon the occurrence and continuation of an Event of Default, the Company shall, and shall cause each of its Subsidiaries to, permit each Noteholder and its authorized employees, representatives and agents, upon giving at least 24 hours' prior notice to the Company, to (i) visit and inspect its assets or properties, (ii) inspect and make extracts from and copies of its books and records, and (iii) discuss with appropriate representatives of Senior Management of the Company or any of its Subsidiaries, its Businesses, property, financial condition and prospects;

10.1.15 <u>Notice of Litigation and Other Matters</u>. The Company shall, and shall cause each of its Subsidiaries to, as soon as practicable after it shall become aware of the same, give notice to each Noteholder of the following events:

10.1.15.1 the commencement of any action, proceeding, arbitration or investigation against or in any other way relating adversely to the Company or any of its Subsidiaries or any of their respective properties, assets or Businesses which, if adversely determined, could, singly or when aggregated with all other such actions, proceedings, arbitrations and investigations, reasonably be expected to have a Material Adverse Effect;

10.1.15.2 any material amendment of its articles, by-laws, constating documents or other organizational documents;

10.1.15.3 any change in its Fiscal Year;

10.1.15.4 any development which has had or will have a Material Adverse Effect; and

10.1.15.5 any Default or Event of Default, or the occurrence or non-occurrence of any event which constitutes, or which with the passage of time or giving of notice or both would constitute, a material default under any other material agreement to which the

Company or any of its Subsidiaries is a party or by which it or any of its properties may be bound, giving in each case the details thereof and specifying the action proposed to be taken with respect thereto;

10.1.16 **Officers' Certificate.** The Company shall deliver to each Noteholder, together with the consolidated financial statements in Sections 10.1.5 and 10.1.6, an Officers' Certificate in the form attached as Schedule 10.1.16 certifying (i) that such financial statements were prepared in accordance with generally accepted accounting principles (subject to normal year-end adjustments in the case of interim unaudited financial statements) and fairly and accurately present the financial condition of the Company and the financial information presented therein for the period and as at the date thereof, (ii) that no Default or Event of Default has occurred hereunder or, if any Default or Event of Default has occurred, specifying the relevant particulars and the period of existence thereof and the action taken or proposed to be taken by the Company with respect thereto, and (iii) demonstrating in reasonable detail compliance (or, as the case may be, non-compliance) at the end of the relevant fiscal quarter or Fiscal Year with the covenants contained in Sections 10.2.4, 10.2.5, 10.2.6 and 10.2.7.

10.1.17 **Property Leased from Port Colborne Hydro Inc.** The Company will, and will cause its Subsidiaries as appropriate to, use reasonable commercial efforts, consistent with those of a Person with an established reputation engaged in a business that is the same as or similar to the Business in similar locations, to register in the name of the Port Colborne Hydro Inc., or the Company, as the case may be, legal easements that are used solely in respect of the Ontario Hydro Property subject to the receipt of all third party consents.

10.2 Negative Covenants

The Company covenants and agrees that it shall not, nor shall it permit any of its Subsidiaries to:

10.2.1 **Encumber Property.** create, grant, assume or suffer to exist any Lien upon any of its properties or assets unless (a) at the same time as that Lien is created, granted, assumed or suffered to exist, the Company shall secure or cause to be secured equally and rateably therewith all the Notes then outstanding to the satisfaction of the Majority Noteholders; or (b) such Lien is a Permitted Encumbrance;

10.2.2 **Non-Arm's Length Transactions.** engage in any transaction with any Affiliate on terms that are not in compliance with the Affiliate Relationships Code;

10.2.3 **Amalgamations, Sales etc.** merge, consolidate or amalgamate with another Person unless:

10.2.3.1 the successor entity is a corporation incorporated under the laws of Canada or one of its provinces;

10.2.3.2 the successor corporation executes, prior to or contemporaneously with the consummation of such transaction, such instruments, if any, as are in the opinion of Noteholders' Counsel necessary or advisable to evidence the assumption by the successor corporation of liability for the due and punctual payment of all liabilities under this Agreement and the other Finance Documents (as applicable) and the covenant of the successor corporation or purchaser, as applicable, to observe and perform all of the covenants and obligations of the predecessor corporation under this Agreement and the Finance Documents to which the predecessor corporation is a party;

10.2.3.3 such transaction is on such terms that are sufficient to preserve or enforce the rights and powers of the Noteholders under this Agreement and the Notes;

10.2.3.4 the Company is entitled under this Agreement to incur or issue Indebtedness in the principal amount of at least $1.00;

10.2.3.5 the Noteholders have received, to the reasonable satisfaction of Noteholders' Counsel, customary documentation and legal opinions in respect of the transaction;

10.2.3.6 no condition or event exists in respect of the successor corporation at the time of such transaction or after giving full effect thereto which constitutes or would constitute a Default or Event of Default hereunder;

but for greater certainty, the amalgamation of Eastern Ontario Power Inc. and the Company is hereby approved by the Noteholders.

10.2.4 **Distributions.** make any Distribution unless (i) no Default or Event of Default has occurred and is continuing or will occur and be continuing as a result of such Distribution being made, (ii) the aggregate principal amount of Consolidated Senior Indebtedness does not exceed 65% of its Total Consolidated Capitalization, calculated on a pro forma basis and (iii) such Distribution does not contravene the Affiliate Relationships Code, if applicable.

10.2.5 **Further Indebtedness.** directly or indirectly incur, issue, assume, guarantee or otherwise become liable for or in respect of any Indebtedness, other than Permitted Indebtedness, or enter into any material operating lease unless after giving effect to such guarantee, incurrence, issuance or liability (including the application or use of the net proceeds therefrom) calculated on a pro forma basis: (i) the aggregate principal amount of its Consolidated Indebtedness (which for the purposes of this clause 10.2.5 (i) excludes Subordinated Indebtedness owing to Affiliates) does not exceed 70% of its Total Consolidated Capitalization, (ii) Consolidated EBITDAR is not less than 2.0 times the sum of Consolidated Senior Interest Expense plus Rent, and (iii) no Default or Event of Default shall have occurred and be continuing at the time of, or as a consequence of, such additional Indebtedness having been incurred or such operating lease having been entered into;

10.2.6 **Disposition of Assets.** enter into, or agree to enter into any Asset Sale, unless, after giving effect to any such sale, no Default or Event of Default has occurred or is continuing or would occur as a result of such Asset Sale, subject to the following:

10.2.6.1 **Single Asset Sale Restrictions.**

If the net proceeds of a single Asset Sale are equal to or greater than $2,000,000 then the Company shall, subject to the provisions which follow, reinvest the entire amount of the net proceeds of such Asset Sale (for the purposes of this Section 10.2.6.1, such entire amount being the "Total Single Asset Proceeds") in the Business within 270 days of such sale, provided that if a portion of the Total Single Asset Proceeds are not reinvested in the Business within 270 days of such Asset Sale (such un-invested amount hereinafter referred to in this section 10.2.6.1 as the "Un-invested Single Sale Amount"), the following provisions shall apply:

10.2.6.1.1 if the Un-invested Single Sale Amount is equal to or less than $2 million then the Un-invested Single Sale Amount shall be applied to redeem or prepay any Senior Indebtedness selected by the Company. If the Company elects to redeem or prepay the Notes, redemption of the Notes will be at a purchase price per Note equal to the Redemption Price and shall be made on a pro-rata basis amongst Noteholders;

10.2.6.1.2 if the Un-invested Single Sale Amount is greater than $2 million then (i) a maximum of $2,000,000 of the Un-invested Single Sale Amount shall be applied to redeem or prepay any Senior Indebtedness selected by the Company and (ii) the remainder of the Un-invested Single Sale Amount after such payment referred to in (i) of this Section 10.2.6.1.2 above (for the purposes of this Section 10.2.6.1, such remainder being the "Remaining Amount") shall be applied to redeem or prepay the Notes and the other Senior Indebtedness. The portion of the Remaining Amount to be applied to redeem the Notes shall be equal to the Remaining Amount multiplied by the percentage that the Notes represent of the Consolidated Senior Indebtedness at the date of Redemption. Redemption of the Notes under (i) and (ii) above will be at a purchase price per Note equal to the Redemption Price and shall be made on a pro rata basis amongst Noteholders.

10.2.6.2 **Multiple Asset Sale Restrictions.**

10.2.6.2.1 If the aggregate net proceeds for all single Asset Sales ("Total Multiple Sale Proceeds") total less than $2,000,000 for any fiscal year period as determined on the last Business Day of the relevant fiscal year (the "Calculation Date") then the Company shall use those net proceeds at the Company's discretion;

10.2.6.2.2 if for the applicable fiscal year the Total Multiple Sale Proceeds are calculated as being greater than or equal to $2,000,000 as of the Calculation Date, then the Company shall, subject to the provisions which follow, reinvest an amount equal to the Total Multiple Sale Proceeds in the Business within 270 days of the Calculation Date provided that, if a portion of the Total Multiple Sale Proceeds (or an amount equal thereto) is not reinvested in the Business within 270 days of the Calculation Date (such un-invested amount hereinafter referred to in this section 10.2.6.2 as the "Un-invested Multiple Sale Amount"), the following provisions shall apply:

(a) in the event that the Total Multiple Sale Proceeds are less than $8,000,000, the Company shall (i) use up to a maximum of $2,000,000 of the Un-invested Multiple Sale Amount at the Company's discretion, (ii) apply the remainder of the Un-invested Multiple Sale Amount, if any, up to a maximum of $2,000,000, to redeem or prepay any Senior Indebtedness selected by the Company and (iii) apply any portion of the

Un-invested Multiple Sale Amount remaining after deducting the amounts referred to in (i) and (ii) above of this Section 10.2.6.2.2(a) (for the purposes of this Section 10.2.6.2.2(a), such remainder being the "Remaining Amount") to redeem or prepay the Notes and the other Senior Indebtedness provided that the portion of that amount to be applied to redeem the Notes shall be equal to the Remaining Amount multiplied by the percentage that the Notes represent of the Consolidated Senior Indebtedness at the date of Redemption. Redemption of the Notes under (i), (ii) or (iii) of this Section 10.2.6.2.2.(a) above will be at a purchase price per Note equal to the Redemption Price and shall be made on a pro rata basis amongst Noteholders.

(b) in the event that the Total Multiple Sale Proceeds are greater than $8,000,000, the Company shall (i) apply the first $2,000,000 of the Un-invested Multiple Sale Amount to redeem or prepay any Senior Indebtedness selected by the Company and (ii) apply the portion of the Un-invested Multiple Sale Amount remaining after deducting the amount referred to in (i) of this Section 10.2.6.2.2(b) above (for the purposes of this Section 10.2.6.2.2(b), such remainder being the "Remaining Amount") to redeem or prepay the Notes and the other Senior Indebtedness provided that that portion of the Remaining Amount to be applied to redeem the Notes shall be equal to the Remaining Amount multiplied by the percentage that the Notes represent of the Consolidated Senior Indebtedness at the date of redemption. Redemption of the Notes under (i) or (ii) above will be at a purchase price per Note equal to the Redemption Price and shall be made on a pro rata basis amongst Noteholders.

10.2.7 **Sale and Leaseback Transactions.** enter into, or agree to enter into any Sale and Leaseback Transaction, unless, after giving effect to any such Sale and Leaseback Transaction, no Default or Event of Default has occurred or is continuing or would occur as a result of such Sale and Leaseback Transaction, subject to the following:

10.2.7.1 **Single Transaction Restrictions.**

If the net proceeds of a single Sale and Leaseback Transaction are equal to or greater than \$500,000 then the Company shall, subject to the provisions which follow, reinvest the entire amount of the net proceeds of such Sale and Leaseback Transaction (for the purposes of this Section 10.2.7.1, such entire amount being the "Total Single Transaction Proceeds") in the Business within 270 days of such sale, provided that if a portion of the Total Single Transaction Proceeds are not reinvested in the Business within 270 days of such Sale and Leaseback Transaction (for the purposes of this Section 10.2.7.1, such un-invested amount hereinafter referred to as the "Un-invested Single Transaction Amount"), the following provisions shall apply:

10.2.7.1.1 if the Un-invested Single Transaction Amount is equal to or less than \$500,000 then the Un-invested Single Transaction Amount shall be applied to redeem or prepay any Senior Indebtedness selected by the Company; if the Company elects to redeem or prepay the Notes, redemption of the Notes will be at a purchase price per Note equal to the Redemption Price and shall be made on a pro-rata basis amongst Noteholders;

10.2.7.1.2 if the Un-invested Single Transaction Amount is greater than \$500,000 then (i) a maximum of \$500,000 of the Un-invested Single Transaction Amount shall be applied to redeem or prepay any Senior Indebtedness selected by the Company and (ii) the remainder of the Un-invested Single Transaction Amount after such payment referred to in (i) above (for the purposes hereof, the "Remaining Amount") shall be applied to redeem or prepay the Notes and the other Senior Indebtedness. The portion of the Remaining Amount to be applied to redeem the Notes shall be equal to the Remaining Amount multiplied by the percentage that the Notes represent of the Consolidated Senior Indebtedness at the date of redemption. Redemption of the Notes under (i) and (ii) of this Section 10.2.6.2.1 above will be at a purchase price per Note equal to the Redemption Price and shall be made on a pro rata basis amongst Noteholders.

10.2.7.2 <u>**Multiple Transaction Restrictions.**</u>

10.2.7.2.1 If the aggregate net proceeds for all single Sale and Leaseback Transactions ("Total Multiple Transaction Proceeds") total less than \$500,000 in the aggregate for any fiscal year period as determined on the Calculation Date then the Company shall use those net proceeds at the Company's discretion:

10.2.7.2.2 if for the applicable fiscal year the Total Multiple Transaction Proceeds are calculated as being greater than or equal to $500,000 as of the Calculation Date, then the Company shall, subject to the provisions which follow, reinvest an amount equal to the Total Multiple Transaction Proceeds in the Business within 270 days of the Calculation Date provided that, if a portion of the Total Multiple Transaction Proceeds are not reinvested in the Business within 270 days of the Calculation Date (for the purposes of this Section 10.2.7.2, such un-invested amount (or an amount equal thereto) hereinafter referred to as the "Un-invested Multiple Transaction Amount"), the following provisions shall apply:

(a) the Company shall (i) use up to a maximum of $500,000 of the Un-invested Multiple Transaction Amount at the Company's discretion, (ii) apply the remainder of the Un-invested Multiple Transaction Amount, if any, up to a maximum of $500,000 to redeem or prepay any Senior Indebtedness selected by the Company and (iii) apply any portion of the Un-invested Multiple Transaction Amount remaining after deducting the amounts referred to in (i) and (ii) of this Section 10.2.7.2.2(a) above (for the purposes hereof, such remainder being the "Remaining Amount") to redeem or prepay the Notes and the other Senior Indebtedness provided that the portion of that amount to be applied to redeem the Notes shall be equal to the Remaining Amount multiplied by the percentage that the Notes represent of the Consolidated Senior Indebtedness at the date of redemption. Redemption of the Notes under (i), (ii) or (iii) of this Section 10.2.7.2.2(a) will be at a purchase price per Note equal to the Redemption Price and shall be made on a pro rata basis amongst Noteholders.

10.3 **<u>Environmental Compliance</u>**

10.3.1 The Company shall, and shall cause its Subsidiaries to, operate its Business in compliance with applicable Environmental Laws and Environmental Permits and operate all assets owned, leased, used or otherwise occupied by it such that no obligation, including a clean-up or remedial obligation, shall arise in respect of the Company or any of its Subsidiaries under any Environmental Law or Environmental Permit, provided however, that if any such obligation arises, the Company, or such Subsidiary, as the case may be, shall promptly satisfy or contest such obligation at its own cost and expense. It shall promptly notify the Noteholders, to the extent not disclosed as of the date hereof, upon (i) learning of the existence of any Substance located on, above or below the surface of any land which it owns, leases, operates, occupies, uses or controls (except those being stored, transported, used, treated or otherwise handled in compliance with applicable Environmental Law), or contained in the soil or water constituting such land and (ii) the occurrence of any lawfully reportable release, spill, leak, emission, discharge, leaching, dumping or disposal of Substances that has occurred on or from such land which, in either case, is likely to result in liability under Environmental Law.

10.3.2 The Company shall indemnify each Noteholder and its officers, directors, employees, agents and shareholders and shall hold each of them harmless from and against any and all losses, liabilities, damages, costs, expenses and claims (including legal fees on a solicitor and his own client basis) in respect of (a) any Environmental Law including the assertion of any Lien thereunder, (b) the presence of any Substance affecting the Premises or any adjacent real estate, or (c) the release of any Substance into the Environment. The Company's obligations and indemnification under this Section 10.3.2. shall survive the payment and satisfaction of all Obligations and the termination of this Agreement. Each Noteholder shall hold the benefit of this indemnity in trust for those indemnified parties who are not parties to this Agreement.

Article 11
Conditions Precedent

11.1 <u>Conditions Precedent</u>

The obligations of each Purchaser to purchase and pay for the Notes to be sold to it at the Closing is subject to the fulfilment, to the satisfaction of the Purchaser, prior to or at the Closing, of the following Conditions Precedent:

11.1.1 the representations and warranties set out in Article 8 shall be true and correct at Closing as if made on and as of such date;

11.1.2 no Default or Event of Default shall have occurred and be continuing nor shall there be any Default or Event of Default after giving effect to the proposed purchase of the Notes on Closing; and

11.1.3 the Purchaser shall have received the following in form and substance satisfactory to it:

11.1.3.1 an Officers' Certificate dated as of the Closing Date certifying that attached thereto are true and correct copies of the following documents, and that such documents are in full force and effect, unamended:

11.1.3.1.1 the articles or constating documents of the Company and each Subsidiary;

11.1.3.1.2 the by-laws or other organizational documents of the Company and each Subsidiary;

11.1.3.1.3 a certificate of incumbency including sample signatures of officers and directors of the Company who have executed any of the Finance Documents or any other document delivered to the Purchaser under this Article 11;

11.1.3.1.4 the resolutions or other documentation evidencing that all necessary action, corporate or otherwise, has been taken by the Company to authorize the execution, delivery and performance of the Finance Documents to which it is a party; and

11.1.3.1.5 confirming Sections 11.1.1 and 11.1.2;

11.1.3.2 a certificate of status, certificate of good standing or similar certificate with respect to the jurisdiction of incorporation of the Company and each Subsidiary and for each jurisdiction where any of them carries on its Business;

11.1.3.3 an opinion of Company's Counsel dated the Closing Date reasonably acceptable to Noteholders' Counsel; and

11.1.3.4 such other documentation or information as the Purchaser shall have reasonably requested; and

11.1.4 the Purchasers' Counsel shall have received payment of its fees and expenses owing at the Closing.

Article 12
Events of Default and Remedies

12.1 **Events of Default**

The occurrence of any of the following events shall constitute an Event of Default:

12.1.1 default by the Company in payment in respect of principal or Redemption Price when the same becomes due at the Maturity Date or at the Redemption Date, as the case may be, if such failure continues for a period of 2 Business Days;

12.1.2 default by the Company in payment in respect of any interest or other amount owing on the Notes when due (except as provided in Section 12.1.1) and any such failure continues for a period of 5 Business Days;

12.1.3 default by the Company of the negative covenant in Section 10.2.3;

12.1.4 default by the Company in the performance or observance of any covenant, condition or obligation contained in any Finance Document to which it is a party not referred to in Section 12.1.1 to 12.1.3 above unless such default is remedied within 30 Business Days of notice thereof to the Company by the Required Noteholders or the Company otherwise becoming aware of such default, except that a breach of Section 10.1.11 shall not be a default by the Company if the Company has complied, or is complying, with Section 10.1.12;

12.1.5 any representation or warranty made by the Company hereunder or in any Finance Document or other document delivered to the Purchasers pursuant hereto or in connection with any Finance Document is found to be false or incorrect in any way so as to make it materially misleading when made or deemed to have been made;

12.1.6 the Company or any Subsidiary (whether as primary obligor or guarantor or surety) fails to make any payment of principal, premium, if any, or interest on any Indebtedness, the outstanding principal amount of which exceeds, in the aggregate, 5% of Consolidated Net Worth, beyond any period of grace provided with respect thereto or fails to perform or observe any other term or condition contained in any agreement under which any such Indebtedness is created, and the effect of such default or failure is to cause an amount in excess of 5% of Consolidated Net Worth to become due or to be required to be repurchased prior to any stated maturity;

12.1.7 the Company or a Subsidiary institutes any proceeding or takes any corporate action or executes any agreement to authorize its participation in or commencement of any proceeding:

12.1.7.1seeking to adjudicate it a bankrupt or insolvent, or

12.1.7.2seeking liquidation, dissolution, winding up, reorganization, arrangement, protection, relief or composition of it or any of its property or debt or making a proposal with respect to it under any law relating to bankruptcy, insolvency, reorganization or compromise of debts or other similar laws (including, without limitation, any application under the Companies' Creditors Arrangement Act (Canada) or any reorganization, arrangement or compromise of debt under the laws of its jurisdiction of incorporation);

12.1.8 the Company or a Subsidiary admits its inability to pay its debts generally as they become due or otherwise acknowledges its insolvency;

12.1.9 any proceeding is commenced against or affecting the Company or a Subsidiary:

12.1.9.1 seeking to adjudicate it a bankrupt or insolvent;

12.1.9.2 seeking liquidation, dissolution, winding up, reorganization, arrangement, protection, relief or composition of it or any of its property or debt or making a proposal with respect to it under any law relating to bankruptcy, insolvency, reorganization or compromise of debts or other similar laws (including, without limitation, any reorganization, arrangement or compromise of debt under the laws of its jurisdiction of incorporation); or

12.1.9.3 seeking appointment of a receiver, trustee, agent, custodian or other similar official for it or for any substantial part of its properties and assets, including the Mortgaged Property or any part thereof;

and such proceeding is not being contested in good faith by appropriate proceedings or, if so contested remains outstanding, undismissed and unstayed more than 60 days from the institution of such first mentioned proceeding, provided however that notwithstanding any such 60 day period shall not have elapsed, an Event of Default shall be deemed to have occurred if such proceeding remains outstanding and, after the date of commencement of such proceeding, the Company does not satisfy a payroll obligation.

12.1.10 any creditor of the Company or any other Person shall privately appoint a receiver, trustee or similar official for any substantial part of the Company's properties and assets, having a book value greater than 5% of Consolidated Net Worth and such appointment is not being contested in good faith and by appropriate proceedings or, if so contested, such appointment continues for more than 60 days, provided however that notwithstanding any such 60 day period shall not have elapsed, an Event of Default shall be deemed to have occurred if such appointment remains outstanding and, after the date of the making of such appointment, the Company does not satisfy a payroll obligation;

12.1.11 any execution, distress or other enforcement process, whether by court order or otherwise, in an amount exceeding 5% of Consolidated Net Worth becomes enforceable againsr any property of the Company or a Subsidiary and such event is not being contested in good faith and by appropriate proceedings or, if so contested, such appointment continues for more than 60 days, provided however that notwithstanding any such 60 day period shall not have elapsed, an Event of Default shall be deemed to have occurred if such appointment remains outstanding and, after the date of the making of such appointment, the Company does not satisfy a payroll obligation;

12.1.12 any judgment or order for the payment of money in excess of 5% of Consolidated Net Worth shall be rendered against the Company or any Subsidiary and either (i) enforcement proceedings shall have been commenced by any creditor upon such judgment or order or (ii) there shall be any period during which a stay of enforcement of such judgment or order, by reason of a pending appeal or otherwise, shall not be in effect; and

12.1.13 at any time after execution and delivery thereof, any Finance Document ceases to be in full force and effect (unless within five Business Days of notice of the same being given by any Purchaser to the Company such Finance Document again has full force and effect as if it had always had full force and effect) or if any Finance Document is declared by a court or tribunal of competent jurisdiction to be null and void or the validity or enforceability thereof is contested by the Company or any of its Subsidiaries, or the Company or any of its Subsidiaries denies in writing that it has any or further liability or obligations under any Finance Document.

12.2 **<u>Remedies Upon Default</u>**

Upon the occurrence of any Event of Default, but subject to Section 13.1, the parties hereto agree that the Required Noteholders may:

12.2.1 declare all Obligations to be immediately due and payable to each of the Noteholders, on a pro rata basis; and

12.2.2 take such actions and commence such proceedings as may be permitted at law or in equity (whether or not provided for herein) at such times and in such manner as the Required Noteholders may consider expedient,

all without, except as may be required by Applicable Law, any additional notice, presentment, demand, protest, notice of protest, dishonour or any other action. The parties hereto acknowledge and agree that the rights and remedies of the Noteholders are cumulative and are in addition to and not in substitution for any other rights or remedies provided by Applicable Law.

12.3 **Proceeds of Realization**

All amounts realized by any Noteholder upon exercise of the remedies hereunder or under any Note shall be distributed to each other Noteholder on a pro rata basis on account of the obligations of the Company to each Noteholder without prejudice to any claim by each Noteholder on a pro rata basis for any deficiency after such proceeds are received by the Noteholders, and the Company shall remain liable for any such deficiency.

12.4 **Defeasance**

The Company shall be deemed to have fully paid, satisfied and discharged the outstanding Notes and the Noteholders shall execute and deliver proper instruments acknowledging the full payment, satisfaction and discharge of the Notes, when, with respect to all outstanding Notes:

12.4.1 the Company has deposited or caused to be deposited with a trustee satisfactory to the Majority Noteholders, acting reasonably, as trust funds in trust for the purpose of making payment on the Notes, an amount of cash sufficient to pay, satisfy and discharge the entire amount of principal, Redemption Price, interest and other amounts owing hereunder or under any other Finance Document, if any, to maturity or any repayment date or Redemption Date, as the case may be, of the outstanding Notes; and in such case, the Company has delivered to the Noteholders an Officers' Certificate stating that all conditions precedent herein provided relating to the payment, satisfaction and discharge of the outstanding Notes have been satisfied.

12.4.2 Any deposits with a trustee pursuant to this Section 12.4 shall be made under the terms of an escrow and/or trust agreement in form and substance satisfactory to the Majority Noteholders and which provides for the due and punctual payment of the principal, interest, Redemption Price or any other amounts that may be owing hereunder or under any other Finance Document, as applicable, on the Notes being satisfied.

12.4.3 Any funds or obligations deposited with the trustee pursuant to this Section 12.4 shall be denominated in the currency of denomination of the Notes in respect of which such deposit is made.

12.4.4 The account in respect of which any funds or obligations are to be deposited with the trustee pursuant to this Section 12.4, and the funds and all proceeds thereof, shall be subject to a first ranking security interest perfected in favour of the Noteholders and the Noteholders will have received an opinion of Company's Counsel satisfactory to the Noteholders regarding such security interest;

12.4.5 Upon the satisfaction of the conditions set forth in this Section 12.4 with respect to all the outstanding Notes, the terms and conditions of this Agreement (other than Section 10.3) and the Notes shall no longer be binding upon or applicable to the Company.

Article 13
General

13.1 Amendment and Waiver

This Agreement and the Notes may be amended, and the observance of any term hereof or of the Notes may be waived (either retroactively or prospectively), with (and only with) the written consent of the Company and the Majority Noteholders, except that no such amendment or waiver may, without the written consent of the holder of each Note at the time outstanding affected thereby, (i) subject to the provisions of Section 12.1 relating to acceleration or rescission, change the amount or time of any prepayment or payment of principal of, or reduce the rate or change the time of payment or method of computation of interest on the Notes or in respect of the Redemption Price or (ii) change the percentage of the principal amount of the Notes the holders of which are required to consent to any such amendment or waiver.

13.2 Substitution of Purchaser

Each Purchaser shall have the right to substitute any one of its Affiliates as the purchaser of the Notes that such Purchaser has agreed to purchase hereunder, by written notice to the Company, which notice shall be signed by both that Purchaser and such Affiliate, shall contain such Affiliate's agreement to be bound by this Agreement and shall contain a confirmation by such Affiliate of the accuracy with respect to it of the representations set forth in Section 9.1. Upon receipt of such notice, wherever the words "Purchasers" or "Purchaser" are used in this Agreement (other than in this Section 13.2), such word shall be deemed to include such Affiliate or refer to such Affiliate in lieu of such Purchaser, as the case may be. In the event that such Affiliate is so substituted as a purchaser hereunder and such Affiliate thereafter transfers to the relevant Purchaser all of the Notes then held by such Affiliate, upon receipt by the Company of notice of such transfer, wherever the words "the Purchaser" is used in this Agreement (other than in this Section 13.2), such words shall no longer be deemed to refer to such Affiliate, but shall refer to the relevant Purchaser, and the relevant Purchaser shall have all the rights of an original holder of the Notes under this Agreement.

13.3 **Assignment**

13.3.1 This Agreement and the other Finance Documents shall enure to the benefit of and be binding on the parties hereto and thereto, their respective successors and any assignee or transferee of some or all of the parties' rights or obligations under this Agreement and the other Finance Documents as permitted under this section 13.3.

13.3.2 The Company shall not assign or transfer all or any part of its rights or obligations under this Agreement or any of the other Finance Documents without the prior written consent of all of the Noteholders, which consent may be arbitrarily withheld.

13.3.3 Any Noteholder (an "Assignor") may assign or transfer all or part of its rights in respect of any Notes and this Agreement to, and may have its corresponding obligations in respect thereof assumed by, any other Person at such times and upon such terms as it may deem fit, without any obligation to obtain any consent of the Company, provided in each case that:

(a) such Assignor complies with the provisions of Article 6 hereof;

(b) any such assignment or transfer shall be at least the lesser of:

(i) $1,000,000; and

(ii) the outstanding amount held by such Noteholder;

(c) the Assignor and the assignee or transferee (the "Assignee") shall enter into an assignment and assumption agreement (the "Assignment Agreement") substantially in the form of Schedule 13.3, whereby *inter alia* the Assignee agrees to be bound by this Agreement, and all Finance Documents relating to the obligations of a

Noteholder in the place and stead of the Assignor to the extent that the rights and obligations of the Assignor shall have been assigned to and assumed by the Assignee, and shall deliver a copy of the Assignment Agreement so executed to the Company;

(d) The Company shall execute and deliver such other assurances as may be requested by the Assignor to confirm the release and discharge provided for in clause (e) below;

(e) upon execution of the Assignment Agreement by the Assignor and the Assignee, the assignment or transfer to the Assignee shall be effective upon the date provided in the Assignment Agreement, and the Assignee shall thereafter be and be treated as a Noteholder for all purposes of this Agreement and the other Finance Documents and shall be entitled to the full benefit hereof and thereof to the extent such benefits are transferred to it by the Assignor and subject to the obligations of the Assignor; and

(f) all expenses incurred by or on behalf of the Company and its Subsidiaries and Affiliates shall be paid in full by such Assignee as a condition precedent to the validity of such assignment.

13.4 **Severability**

Any provision of this Agreement that is prohibited or unenforceable in any jurisdiction shall, as to such jurisdiction, be ineffective to the extent of such prohibition or unenforceability without invalidating the remaining provisions hereof, and any such prohibition or unenforceability in any jurisdiction shall (to the full extent permitted by law) not invalidate or render unenforceable such provision in any other jurisdiction.

13.5 **Construction**

Each covenant contained herein shall be construed (absent express provision to the contrary) as being independent of each other covenant contained herein, so that compliance with any one covenant shall not (absent such an express contrary provision) be deemed to excuse compliance with any other covenant. Where any provision herein refers to action to be taken by any Person, or which such Person is prohibited from taking, such provision shall be applicable whether such action is taken directly or indirectly by such Person.

13.6 **Counterparts**

This Agreement may be executed in any number of counterparts, each of which shall be an original but all of which together shall constitute one instrument. Each counterpart may consist of a number of copies hereof, each signed by fewer than all, but together signed by all, of the parties hereto.

13.7 **Notices**

Any notice or other communication required or permitted to be given hereunder shall be in writing and shall be given by prepaid first-class mail, by telecopier or other means of electronic communication or by hand-delivery as hereinafter provided. Any such notice, if mailed by prepaid first-class mail at any time other than during or within three Business Days prior to a general discontinuance of postal service due to strike, lock-out or otherwise, shall be deemed to have been received on the fourth Business Day after the post-marked date thereof, or if sent by telecopier or other means of electronic communication, shall be deemed to have been received on the Business Day following the sending, or if delivered by hand shall be deemed to have been received at the time it is delivered to the applicable address noted below either to the individual designated below or to a senior employee of the addressee at such address (and, in the case of each Noteholder, at the same department within the Company) with responsibility for matters to which the information relates. Notice of change of address shall also be governed by this section. In the event of a general discontinuance of postal service due to strike, lock-out or otherwise, notices or other communications shall be delivered by hand or sent by facsimile or other means of electronic communication and shall be deemed to have been received in accordance with this section. Notices and other communications shall be addressed as follows:

(a) if to the Company:

Canadian Niagara Power Inc.
PO BOX 1218
1130 Bertie Street, Fort Erie Ontario
L2A 5Y2

Attention: Chief Financial Officer
Fax number: (905) 994-2203

(b) if to the Purchasers:

The Canada Life Assurance Company
330 University Avenue
Toronto, Ontario
M5G 1R8

Attention: Canadian Private Placements, SP-11
Fax number: (416) 597-9678

Sun Life Assurance Company of Canada
225 King Street West, 11th Floor
Toronto, Ontario
M5V 3C5

Attention: Structured Finance, Investments
Fax number: (416) 595-0131

The Maritime Life Assurance Company
7 Maritime Place
P.O. Box 1030
Halifax, Nova Scotia
B3J 2X5

Attention: Vice President, Private Placements
Fax number: (902) 453-7181

13.8 **Time**

Time is of the essence of the Finance Documents.

13.9 **Further Assurances**

Whether before or after the happening of an Event of Default, the Company shall at its own expense (except where otherwise expressly indicated herein) do, make, execute or deliver, or cause to be done, made, executed or delivered by its Subsidiaries or other Persons, all such further acts, documents and things in connection with the Finance Documents as the Noteholders may reasonably require from time to time for the purpose of giving effect to the Finance Documents, all immediately upon the request of such Noteholder.

13.10 **Facsimile Copies**

Delivery of an executed signature page to this Agreement by any party to this Agreement by facsimile transmission shall be as effective as delivery of a manually executed copy of this Agreement by such party.

IN WITNESS WHEREOF this Agreement has been executed by the parties hereto as of the date first written above.

CANADIAN NIAGARA POWER INC.

by:
Name: Timothy B. Curtis
Title: VP Finance CFO

by:
Name: WILLIAM J. DALEY
Title: PRESIDENT & CEO

SUN LIFE ASSURANCE COMPANY OF CANADA

by:
Name:
Title:

by:
Name:
Title:

CANADA LIFE FINANCIAL CORPORATION

by:
Name:
Title:

by:
Name:
Title:

MARITIME LIFE ASSURANCE COMPANY

by:
Name:
Title:

by:
Name:
Title:

IN WITNESS WHEREOF this Agreement has been executed by the parties hereto as of the date first written above.

CANADIAN NIAGARA POWER INC.

by:________________________________
Name:
Title:

by:________________________________
Name:
Title:

SUN LIFE ASSURANCE COMPANY OF CANADA

by:________________________________
Name: Paul C. Sinclair
Title: AVP, Structured Finance

by:________________________________
Name: Steve Theofanis
Title: Director, Structured Finance

CANADA LIFE FINANCIAL CORPORATION

by:________________________________
Name:
Title:

by:________________________________
Name:
Title:

MARITIME LIFE ASSURANCE COMPANY

by:________________________________
Name:
Title:

by:________________________________
Name:
Title:

IN WITNESS WHEREOF this Agreement has been executed by the parties hereto as of the date first written above.

CANADIAN NIAGARA POWER INC.

by:____________________________
Name:
Title:

by:____________________________
Name:
Title:

SUN LIFE ASSURANCE COMPANY OF CANADA

by:____________________________
Name:
Title:

by:____________________________
Name:
Title:

CANADA LIFE FINANCIAL CORPORATION

by:____________________________
Name: Kelly Kwan
Title: Senior Investment Analyst

by:____________________________
Name:
Title:

MARITIME LIFE ASSURANCE COMPANY

by:____________________________
Name:
Title:

by:____________________________
Name:
Title:

IN WITNESS WHEREOF this Agreement has been executed by the parties hereto as of the date first written above.

CANADIAN NIAGARA POWER INC.

by:______________________________
Name:
Title:

by:______________________________
Name:
Title:

SUN LIFE ASSURANCE COMPANY OF CANADA

by:______________________________
Name:
Title:

by:______________________________
Name:
Title:

CANADA LIFE FINANCIAL CORPORATION

by:______________________________
Name:
Title:

by:______________________________
Name:
Title:

AUTH FOR EXECUTION
ES.
MLAC PRIVATE PLACEMENTS

MARITIME LIFE ASSURANCE COMPANY

by:______________________________
Name: LAURIE A. HARDING
Title: Vice President, Private Placements

by:______________________________
Name: PETER A. STUART
Title: Senior Vice President
Chief Investment Officer

EXHIBIT 1

[FORM OF NOTE]

CANADIAN NIAGARA POWER INC.

7.092 % Senior Unsecured Note Due August 14, 2018

No. [_________] [Date]

$[___________] PPN _________

FOR VALUE RECEIVED, the undersigned, Canadian Niagara Power Inc. (herein called the "Company"), a corporation incorporated and existing under the laws of Ontario, hereby promises to pay to [______________], or registered assigns, the principal sum of [______________] DOLLARS on August 14, 2018 (the "Maturity Date") with interest at a rate per annum of 7.092% calculated and payable semi-annually. Interest will be payable after as well as before the Maturity Date, default and judgment semi-annually on August 14 and February 14 in each year commencing on February 14, 2004 in accordance with the payment schedule set forth in Annex A hereto; provided that in the event of any redemption, the amounts payable pursuant to Annex A shall be reduced proportionately based on the amount redeemed and the original face amount of the Note.

Payments of principal, interest, any Redemption Price and other amounts owing with respect to this Note are to be made in lawful money of Canada at ______________, Toronto, Ontario, or at such other place as the Company shall have designated by written notice to the holder of this Note as provided in the Note Purchase Agreement referred to below.

This Note is one of a series of Senior Unsecured Notes (herein called the "Notes") issued pursuant to the Master Note Purchase Agreement dated as of August 14, 2003 (as from time to time amended, the "Note Purchase Agreement"), among the Company, the Purchaser, [■] and [■] and is entitled to the benefits thereof. The holder of this Note will be deemed, by its acceptance hereof, to have made the representation set forth in Section 9.1 of the Note Purchase Agreement.

This Note is a registered Note and, as provided in the Note Purchase Agreement, upon surrender of this Note for registration of transfer, duly endorsed, or accompanied by a written instrument of transfer duly executed, by the registered holder hereof or counsel to such holder's attorney duly authorized in writing, a new Note for a like principal amount will be issued to, and registered in the name of, the transferee. Prior to due presentment for registration of transfer, the Company may treat the person in whose name this Note is registered as the owner hereof for the purpose of receiving payment and for all other purposes, and the Company will not be affected by any notice to the contrary.

This Note is subject to optional prepayment, in whole or from time to time in part, at the times and on the terms specified in the Note Purchase Agreement, but not otherwise.

If an Event of Default, as defined in the Note Purchase Agreement, occurs and is continuing, the principal of this Note may be declared or otherwise become due and payable in the manner, at the price (including any applicable Redemption Price) and with the effect provided in the Note Purchase Agreement.

This Note shall be construed and enforced in accordance with, and the rights of the parties shall be governed by, the laws of Ontario excluding choice-of-law principles of the law of such province that would require the application of the laws of a jurisdiction other than such province.

CANADIAN NIAGARA POWER INC.

by:______________________________
Name:
Title:

by:______________________________
Name:
Title:

ANNEX A

Date	Dollars per $1,000,000 in principal amount
February 15, 2004	$35,460
August 14, 2004	$35,460
February 14, 2005	$35,460
August 14, 2005	$35,460
February 14, 2006	$35,460
August 14, 2006	$35,460
February 14, 2007	$35,460
August 14, 2007	$35,460
February 14, 2008	$35,460
August 14, 2008	$35,460
February 14, 2009	$35,460
August 14, 2009	$35,460
February 14, 2010	$35,460
August 14, 2010	$35,460
February 14, 2011	$35,460
August 14, 2011	$35,460
February 14, 2012	$35,460
August 14, 2012	$35,460
February 14, 2013	$35,460
August 14, 2013	$35,460
February 14, 2014	$35,460
August 14, 2014	$35,460
February 14, 2015	$35,460

August 14, 2015	$35,460
February 14, 2016	$35,460
August 14, 2016	$35,460
February 14, 2017	$35,460
August 14, 2017	$35,460
February 14, 2018	$35,460
August 14, 2018	$35,460

EXHIBIT 2

INFORMATION RELATING TO PURCHASER

Name and Address of Purchaser	Principal Amount of Notes to be Purchased
[■]	$[■]

Payments

All payments on or in respect of the Notes to be by bank wire transfer of Cdn$ or other immediately available funds (identified each payment as "Canadian Niagara Power Inc." Notes due August 14, 2018, principal, premium or interest") to:

[■]

Notices

All notices and communications, including notices with respect to payments and written confirmation of each such payment, to be addressed as first provided above, with a copy to:

[■]

Name of Nominee in which Notes are to be issued: [■]

SCHEDULE 1.1.58

FORM OF NON-DISCLOSURE AGREEMENT

THIS AGREEMENT made and entered into as of this ● day of ●, ●.

BY:

●, having its place of business at ●

(hereinafter referred to as the "Recipient")

in favour of

CANADIAN NIAGARA POWER INC. (the "Company") ●

WHEREAS the Recipient is considering an investment (the "Investment") in a private placement debt offering of 7.092% senior unsecured notes due August 14th, 2018 (the "Notes") issued by the Company pursuant to a master note purchase agreement dated as of August 14th, 2003 between the Company, as issuer, SunLife Assurance Company of Canada, Canada Life Financial Corporation and Maritime Life Assurance Company, as purchasers (the "Note Purchase Agreement");

AND WHEREAS it is a condition pursuant to the terms of the Note Purchase Agreement that the Recipient shall have entered into this Agreement and provided a copy thereof to the Company;

NOW THEREFORE, IN CONSIDERATION of the premises and mutual covenants herein set forth, the Company and the Recipient agree as follows:

1. <u>Use of Confidential Information</u>

The Recipient agrees that either during the currency of this Agreement or at any time thereafter:

(a) it will keep confidential and not disclose to any third party all Confidential Information disclosed to the Recipient by the Company or by any of the Company' agents in writing, orally or by any other means, provided that (i) prior to making the Investment, the Recipient may disclose Confidential Information to other potential investors provided further that prior to such disclosure the receiver of such Confidential Information has executed a non-disclosure agreement in favour of the Company in a form substantially the same this Agreement and (ii) after making the Investment, so long as the Recipient is a holder of Notes, the Recipient may disclose Confidential Information to other holders of Notes;

(b) it will use its best efforts to protect the confidentiality of the Confidential Information, using a standard of care no less than the degree of care that Recipient employs for its own similar confidential information. In particular Recipient shall not directly or indirectly disclose, allow access to, transmit or transfer the Confidential Information to a third party other than a potential investor without the Company's prior written consent. Recipient shall disclose the Confidential Information only to those of its employees, advisors or to those employees of any consultant of Recipient, who have a need to know the Confidential Information for the purpose of making an Investment in the Notes (the "Purpose"), and to its regulatory authorities. Recipient shall, prior to disclosing the Confidential Information to such employees, advisors and consultants, issue appropriate instructions to them to satisfy its obligations herein and obtain their agreement to receive and use the Confidential Information on a confidential basis on the same conditions as contained in this Agreement;

(c) it will not use such Confidential Information, or any portion or copy thereof, for any purpose other than the Purpose;

(d) the Confidential Information shall not be copied, reproduced in any form or stored in a retrieval system or data base by Recipient without the prior written consent of the Company, except for such copies and storage as may reasonably be required internally by Recipient for the Purpose; and

(e) in the event that the Recipient chooses not to make the Investment, it will return all Confidential Information furnished to it by the Company and any photocopies thereof, to the Company, upon their request, provided that the Recipient may retain all material prepared by it subject to its confidentiality obligations under this Agreement.

2. Confidential Information Defined

The Confidential Information to which the obligations of non-use, confidence and secrecy imposed upon the Recipient by this Agreement comprises the following:

(a) any document or drawing provided to the Recipient by the Company, any Subsidiary or Affiliate thereof, or any agent or any Subsidiary thereof with respect to the Investment or the Company;

(b) any information obtained through discussions with the Company or any agent of the Company or any Subsidiary thereof with respect to the Investment or the Company;

(c) any information learned through visits by the Recipient to facilities of the Company, any Subsidiary or Affiliate thereof, or any agent of the Company or any Subsidiary thereof with respect to the Investment or the Company and its Subsidiaries and Affiliates; and

(d) such further and other information with respect to the Investment or the Company that might reasonably be considered to be confidential including, without limitation, financial statements and other disclosure documents, corporate strategies and plans, brand share and tracking data, brand strategies and plans, sales information, new product information, technical information and third party contractual terms and conditions.

3. Non-Applicability

The Recipient's obligations hereunder shall not extend to information which:

(a) was in the Recipient's possession prior to disclosure by the Company, any Subsidiary or Affiliate thereof, or any agent of the Company or its Subsidiaries and Affiliates, not already subject to a confidentiality agreement;

(b) was or subsequently becomes generally available to the public other than by acts or omissions by the Recipient;

(c) is subsequently communicated to the Recipient by a third party who did not receive such information under obligations of confidentiality, either directly or indirectly from the Company or any Subsidiary or Affiliate;

(d) is required to be disclosed pursuant Applicable Law, provided the Company is given timely notice of the issuance of such order by the Recipient to enable the Company to contest compliance therewith; or

(e) was independently developed by Recipient, other than by a breach of this Agreement.

4. Consequence of Breach

The parties hereto specifically agree that money damages may not be a sufficient remedy for any breach of this agreement and that, in addition to all other remedies available, the Company and its Subsidiaries and Affiliates shall be entitled to specific performance, injunctive or other equitable relief as a remedy for such breach.

5. Term

The obligations of non-use, confidence and secrecy hereunder shall, subject to sub-sections 3(a) through (e) above, survive the termination of this agreement for a period of two (2) years.

6. Entire Agreement

This Agreement constitutes the entire agreement between the parties hereto with respect to the subject matter hereof and cancels and supersedes any prior understandings and agreements between the parties hereto with respect thereto. There are no representations, warranties, terms, conditions, undertakings or collateral agreements, express, implied or statutory, between the parties other than as expressly set forth in this Agreement.

7. No Assignment

This Agreement may not be assigned by either party without the prior written consent of the other party.

8. Binding Effect

This Agreement shall inure to the benefit of and be binding upon the parties hereto, their successors and assigns.

9. Applicable Law

This Agreement shall be construed in accordance with the laws of the Province of Ontario, and the parties hereto submit to the jurisdiction of the courts of the Province of Ontario.

IN WITNESS WHEREOF, the parties have caused this Agreement to be executed as of the date first above written.

[■]

by:______________________________
Name:
Title:

by:______________________________
Name:
Title:

SCHEDULE 1.1.71

PERMITTED ENCUMBRANCES

LIENS UNDER THE *PERSONAL PROPERTY SECURITY ACT* (ONTARIO)

PERMITTED ENCUMBRANCES

LIENS UNDER THE *PERSONAL PROPERTY SECURITY ACT* (ONTARIO)

SECURED PARTY	FILE NUMBER	REGISTRATION NUMBER AND TIME PERIOD	COLLATERAL	COMMENTS
De Lage Landen Financial Services Canada Inc.	868533183	20001221 1049 7029 3840 (3 years)	Equipment, Other	Up to a maximum of $____________

SCHEDULE 8.1.9

Litigation

NIL

SCHEDULE 8.1.14

Environmental

CNPI:
Registration - PCB Storage Site 20391A009

Acknowledgement of Subject Waste Registration ON2593800

Acknowledgement of Subject Waste Registration ON0603800

Acknowledgement of Subject Waste Registration ON0562401

Certificate of Approval (Air) 1195-5HWMLF

Eastern Ontario Power:

PCB Waste Storage Site 403-89-A0480

Acknowledgement of Subject Waste Registration ON1033000

MOE Approval for Septic System LG-248-91

SCHEDULE 8.1.16

Governmental Charges

NIL

SCHEDULE 8.1.17

Existing Indebtedness

Letter of Credit SBGT721815 issued by CIBC to FortisOntario Inc. on behalf of Canadian Niagara Power Inc. for $2,107,567.00. Beneficiary is the Independent Electricity Market Operator. Expiry April 9, 2004.

Letter of Credit SBGT721813 issued by CIBC to FortisOntario Inc. on behalf of Canadian Niagara Power Inc. for $1,393,434.00. Beneficiary is the Independent Electricity Market Operator. Expiry April 9, 2004.

SCHEDULE 8.1.18

Corporate Structure of Company and Subsidiaries

See Attached

SCHEDULE 10.1.16

Officers' Certificate

Date:

[■]

Attention: [■]

Dear Sirs:

I, ______________________________, of __________________________, in the Province of Ontario, as of [■] (the "Company") hereby certify on behalf of the Company and without personal liability as follows:

(i) This Certificate applies to the fiscal quarter ending ______________________________;

(ii) I am familiar with and have examined the provisions of the Note Purchase Agreement dated as of [■] (the "Note Purchase Agreement", the terms defined therein being used herein as therein defined) among the Company and [■], and have made reasonable investigations for purposes of this Certificate;

(iii) Based on the foregoing:

(a) the consolidated financial statements attached as Exhibit "A" were prepared in accordance with generally accepted accounting principles (subject to normal year-end adjustments in the case of interim unaudited financial statements) and fairly, completely and accurately present the financial condition of the Company and the financial information presented therein for the period and as of the date referred to in clause (ii) above;

(b) the Company was not, as of the date referred to in clause (ii) above, in breach of the covenants contained in Sections 10.2.4, 10.2.5, 10.2.6 and 10.2.7 of the Note Purchase Agreement, evidence of compliance with which is set out in Exhibit B;

(c) no event has occurred and is continuing which would constitute a Default or an Event of Default; and

(d) the officer has authority to bind the Company.

[■]

Per: ______________________________

Name:

Title:

EXHIBIT A to SCHEDULE 10.1.16

Consolidated Financial Statements

EXHIBIT B to SCHEDULE 10.1.16

Compliance with Covenants

[Company to describe calculation of:

1) EBITDAR

2) Consolidated Senior Indebtedness

3) Total Consolidated Capitalization

4) Consolidated Senior Interest Expense plus Rent

5) Compliance with Sections 10.2.4 to 10.2.7

and to confirm compliance with covenants]

SCHEDULE 13.3

Form of Assignment and Assumption Agreement

ASSIGNMENT AND ASSUMPTION AGREEMENT

■

as Assignor

- and -

■

as Assignee

- and -

- and -

CANADIAN NIAGARA POWER INC.

as Company

ASSIGNMENT AND ASSUMPTION AGREEMENT

Dated as of ■, ■

ASSIGNMENT AND ASSUMPTION AGREEMENT

This Assignment and Assumption Agreement is made as of ■, ■ (the "Assignment Date") among ■ (the "Assignor"), a Noteholder under the Master Note Purchase Agreement referred to and defined hereafter, ■ (the "Assignee") and Canadian Niagara Power Inc. (the "Company").

RECITALS:

A. Pursuant to a master note purchase agreement dated as of August 14th, 2003 (as amended, supplemented and restated from time to time, the "Master Note Purchase Agreement") among the Company and the financial institutions specified therein as Noteholders (collectively, the "Noteholders"), the Noteholders have purchased certain notes from the Company;

B. The Assignor has agreed to assign and sell to the Assignee \$■ of principal of its right, title and interest in and to the **[specify Note]**, (the "Assigned Interest"), and the Assignee has agreed to accept and purchase the Assigned Interest and to assume all liabilities and obligations of the Assignor in respect of the Assigned Interest, all effective as of the Assignment Date;

C. The Company has requested that the Assignee enter into an agreement pursuant to section 13.3.3 of the Master Note Purchase Agreement and the Company has agreed to acknowledge the release and assumption of the Assigned Interest hereunder.

NOW THEREFORE, for valuable consideration, the receipt and sufficiency of which are hereby acknowledged, the parties hereto agree as follows:

1. Definitions. All terms defined in the Master Note Purchase Agreement which appear herein without definition shall have the meanings attributed thereto in the Master Note Purchase Agreement.

2. Conveyance of Assigned Interest. The Assignor hereby assigns, sells, conveys and transfers to the Assignee all of its undivided interest in and to the Assigned Interest, effective as of the Assignment Date, without recourse, representation or warranty of any kind except as expressly set forth in section 4.1 hereof.

3. Assumption. The Assignee hereby accepts and purchases the Assigned Interest, effective as of the Assignment Date, and the Assignee hereby agrees to be bound by the terms and conditions of the Master Note Purchase Agreement and the other Finance Documents as if it were an original Noteholder and acknowledges and expressly assumes in the name, place and stead of the Assignor all obligations and liabilities attaching to the Assigned Interest and agrees to perform the terms, conditions and agreements on its part to be performed as a Lender in respect thereof under the Master Note Purchase Agreement and the other Finance Documents.

4. Representations of Assignor.

4.1 The Assignor hereby represents and warrants to the Assignee that:

(a) the Assignor has full power and authority and has taken all action necessary to execute and deliver, to perform its obligations under and to consummate the transactions contemplated by this assignment and assumption agreement and any and all other documents and instruments to be delivered by it in connection with this assignment and assumption agreement; and

(b) the Assignor is the sole legal and beneficial owner of the Assigned Interest, and the Assigned Interest is free and clear of any Liens created by the Assignor in respect of the Assigned Interest.

4.2 It is understood and agreed that, except for the representations and warranties set forth herein, the assignment and assumption made hereunder are without recourse to the Assignor and the Assignor makes no further representations or warranties whatsoever, express or implied.

5. **Representation of Company.** The Company hereby represents and warrants that, as of the Assignment Date, no Default or Event of Default has occurred and is continuing.

6. **Release by the Company**. The Company hereby releases the Assignor from all obligations and liabilities relating to the Assigned Interest in respect of the period from and after the Assignment Date and acknowledges the assumption of all such liabilities and obligations by the Assignee, effective as of the Assignment Date.

7. **Assignee's Acknowledgement.** The Assignee hereby acknowledges that it has received a copy of the Master Note Purchase Agreement, the other Finance Documents and such other documents and information as it has deemed appropriate to make its own credit analysis and determination to enter into this assignment and assumption agreement.

8. **Recognition as Noteholder**. The parties hereto acknowledge that the Assignee is, by virtue of compliance with the provisions of section 13.2 of the Master Note Purchase Agreement, as of and from the Assignment Date, a Noteholder under and as defined in the Master Note Purchase Agreement for the purposes thereof and for the purposes of all other Finance Documents.

9. **Notice.** The Assignee's address for notice is as follows: ■.

10. **Governing Law**. This assignment and assumption agreement shall be governed by and construed in accordance with the laws of the Province of Ontario and the laws of Canada applicable therein.

11. **Enurement**. This assignment and assumption agreement shall enure to the benefit of and be binding upon the parties hereto and their respective successors and permitted assigns.

12. **Counterparts**. This assignment and assumption agreement may be signed in any number of counterparts, each of which shall be deemed an original, but all such separate counterparts shall constitute one and the same instrument.

IN WITNESS WHEREOF the parties have executed this assignment and assumption agreement under the hands of their proper officers duly authorized in that behalf as of the date first above written.

[ASSIGNOR], as Assignor

Per: ______________________________
Authorized Signing Officer

Per: ______________________________
Authorized Signing Officer

[ASSIGNEE], as Assignee

Per: ______________________________
Authorized Signing Officer

Per: ______________________________
Authorized Signing Officer

CANADIAN NIAGARA POWER INC.

Per: ______________________________
Authorized Signing Officer

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Appendix B

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SCHEDULE A

PROMISSORY NOTE

$20,000,000 **DUE: ON DEMAND**

FOR VALUE RECEIVED Canadian Niagara Power Inc. ("CNPI") hereby promises to pay on demand to or to the order of FortisOntario Inc. ("FON") at 1130 Bertie Street, Fort Erie, Ontario, the principal amount of $20,000,000 in lawful money of Canada and to pay interest both before and after demand, default and judgement at the rate of 4.03% per annum, which interest rate will be automatically amended from time to time to be consistent with any interest rate approved by the Ontario Energy Board ("OEB") in connection with the then current decision and order issued by the OEB approving the electricity distribution rates that the Corporation is permitted to recover. The interest rate will be calculated monthly not in advance on the principal amount, said interest to be payable monthly in each year, commencing on the 1st day of January 2013.

The principal amount outstanding under this promissory note from time to time and all accrued interest thereon shall become due and be paid in full upon demand being made by FON therefore.

CNPI hereby waives demand and presentment for payment, notice of non-payment, protest, notice of protest, notice of dishonour, bringing of suit and diligence in taking any action.

DATED at Fort Erie, Ontario, as of this 1st day of January 2013.

CANADIAN NIAGARA POWER INC.

W. J. Daley

William J. Daley
President and Chief Executive Officer

Glen King
Vice President, Finance and Chief Financial Officer

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CAPITAL STRUCTURE

Appendix 2-OA
Capital Structure and Cost of Capital

This table must be completed for the last Board approved year and the test year.

Year: 2013

Line No.	Particulars	Capitalization Ratio (%)		Capitalization Ratio ($)	Cost Rate (%)	Return ($)
	Debt					
1	Long-term Debt	56.00%		$41,158,761	5.67%	$2,333,702
2	Short-term Debt	4.00%	(1)	$2,939,912	2.08%	$61,150
3	**Total Debt**	60.0%		$44,098,673	5.43%	$2,394,852
	Equity					
4	Common Equity	40.00%		$29,399,115	8.93%	$2,625,341
5	Preferred Shares			$ -		$ -
6	**Total Equity**	40.0%		$29,399,115	8.93%	$2,625,341
7	**Total**	100.0%		$73,497,788	6.83%	$5,020,193

Year: 2017TY

Line No.	Particulars	Capitalization Ratio (%)		Capitalization Ratio ($)	Cost Rate (%)	Return ($)
	Debt					
1	Long-term Debt	56.00%		$50,357,709	6.14%	$3,091,963
2	Short-term Debt	4.00%	(1)	$3,596,979	1.65%	$59,350
3	**Total Debt**	60.0%		$53,954,689	5.84%	$3,151,314
	Equity					
4	Common Equity	40.00%		$35,969,792	9.19%	$3,305,624
5	Preferred Shares			$ -		$ -
6	**Total Equity**	40.0%		$35,969,792	9.19%	$3,305,624
7	**Total**	100.0%		$89,924,481	7.18%	$6,456,937

Notes

(1) 4.0% unless an applicant has proposed or been approved for a different amount.

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DEBT INSTRUMENTS

Please see tables below.

Appendix 2-OB
Debt Instruments

This table must be completed for all required historical years, the bridge year and the test year.

Year 2013

Row	Description	Lender	Affiliated or Third-Party Debt?	Fixed or Variable-Rate?	Start Date	Term (years)	Principal ($)	%	Interest ($) [1]	Additional Comments, if any
1	Senior Unsecured Notes	Life insurance companies	Third-Party	Fixed Rate	14-Aug-03	15	$ 30,000,000	7.092%	$ 2,127,600	
2	Senior Unsecured Notes	n/a	Third-Party	Fixed Rate	14-Aug-03	15			$ 32,028	Debt issue costs amort.
3	Promissory Note	FortisOntario Inc.	Affiliated	Fixed Rate	1-Jan-13	Demand	$ 20,000,000	4.03%	$ 806,000	
4									$ -	
5									$ -	
6									$ -	
7									$ -	
8									$ -	
9									$ -	
10									$ -	
11									$ -	
12									$ -	
Total							$ 50,000,000	5.93%	$ 2,965,628.00	

Year 2014

Row	Description	Lender	Affiliated or Third-Party Debt?	Fixed or Variable-Rate?	Start Date	Term (years)	Principal ($)	Rate (%) [2]	Interest ($) [1]	Additional Comments, if any
1	Senior Unsecured Notes	Life insurance companies	Third-Party	Fixed Rate	14-Aug-03	15	$ 30,000,000	7.092%	$ 2,127,600	
2	Senior Unsecured Notes	n/a	Third-Party	Fixed Rate	14-Aug-03	15			$ 32,028	Debt issue costs amort.
3	Promissory Note	FortisOntario Inc.	Affiliated	Fixed Rate	1-Jan-13	Demand	$ 20,000,000	4.03%	$ 806,000	
4									$ -	
5									$ -	
6									$ -	
7									$ -	
8									$ -	
9									$ -	
10									$ -	
11									$ -	
12									$ -	
Total							$ 50,000,000	5.93%	$ 2,965,628.00	

Year 2015

Row	Description	Lender	Affiliated or Third-Party Debt?	Fixed or Variable-Rate?	Start Date	Term (years)	Principal ($)	Rate (%) [2]	Interest ($) [1]	Additional Comments, if any
1	Senior Unsecured Notes	Life insurance companies	Third-Party	Fixed Rate	14-Aug-03	15	$ 30,000,000	7.092%	$ 2,127,600	
2	Senior Unsecured Notes	n/a	Third-Party	Fixed Rate	14-Aug-03	15			$ 32,028	Debt issue costs amort.
3	Promissory Note	FortisOntario Inc.	Affiliated	Fixed Rate	1-Jan-13	Demand	$ 20,000,000	4.03%	$ 806,000	
4									$ -	
5									$ -	
6									$ -	
7									$ -	
8									$ -	
9									$ -	
10									$ -	
11									$ -	
12									$ -	
Total							$ 50,000,000	5.93%	$ 2,965,628.00	

Year 2016BY

Row	Description	Lender	Affiliated or Third-Party Debt?	Fixed or Variable-Rate?	Start Date	Term (years)	Principal ($)	Rate (%) [2]	Interest ($) [1]	Additional Comments, if any
1	Senior Unsecured Notes	Life insurance companies	Third-Party	Fixed Rate	14-Aug-03	15	$ 30,000,000	7.092%	$ 2,127,600	
2	Senior Unsecured Notes	n/a	Third-Party	Fixed Rate	14-Aug-03	15			$ 32,028	Debt issue costs amort.
3	Promissory Note	FortisOntario Inc.	Affiliated	Fixed Rate	1-Jan-13	Demand	$ 20,000,000	4.03%	$ 806,000	
4									$ -	
5									$ -	
6									$ -	
7									$ -	
8									$ -	
9									$ -	
10									$ -	
11									$ -	
12									$ -	
Total							$ 50,000,000	5.93%	$ 2,965,628.00	

			Year	2017TY						
Row	Description	Lender	Affiliated or Third-Party Debt?	Fixed or Variable-Rate?	Start Date	Term (years)	Principal ($)	Rate (%) [2]	Interest ($) [1]	Additional Comments, if any
1	Third Party Debt	Life insurance companies	Third-Party	Fixed Rate	14-Aug-03	15	$ 30,000,000	7.092%	$ 2,127,600	
2	Affiliated debt	FortisOntario Inc.	Affiliated	Fixed Rate	14-Aug-03	15			$ 32,028	Debt issue costs amort.
3	Affiliated debt	FortisOntario Inc.	Affiliated	Fixed Rate	1-Jan-17	Demand	$ 20,000,000	4.54%	$ 908,000	Updated deemed
4									$ -	interest rate
5									$ -	
6									$ -	
7									$ -	
8									$ -	
9									$ -	
10									$ -	
11									$ -	
12									$ -	
Total							$ 50,000,000	6.14%	$ 3,067,628.00	

REVENUE DEFICIENCY OVERVIEW

This Exhibit 6 provides a summary of the revenue required by CNPI in the 2017 Test Year in order to continue distributing electricity safely and reliably, while earning a fair return. The Total Service Revenue Requirement is offset by revenues obtained by sources other than distribution rates, i.e., other revenue. The calculation of the revenue deficiency/sufficiency does not include the recovery of Regulatory Assets (Exhibit 9). As directed in the Filing Requirements, costs and revenues related to the cost of power are kept separate from the determination of the distribution revenue deficiency/sufficiency.

The revenue deficiency/sufficiency for the 2017 Test Year was calculated using the following inputs:

- 2016 approved rates; and
- 2017 load forecast and forecast of customers and connections, as developed using the methodology described in Exhibit 3 (Operating Revenue).

CNPI's net revenue deficiency is $1,702,499 and when grossed up for income taxes, CNPI's revenue deficiency is $2,316,325. The revenue requirement work form can be found in Exhibit 6, Tab 1, Schedule 3, Appendix A.

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DRIVERS OF REVENUE REQUIREMENT CHANGES

CNPI's revenue requirement increase of $3,328,567 for the 2017 Test Year as compared to 2013 Board Approved, results primarily from higher OM&A expenses, higher Amortization/Depreciation, higher deemed interest and return on deemed equity, offset by lower property and income taxes.

The following table is taken from the approved revenue requirement work form for 2013 Board Approved and the submitted revenue requirement work form for 2017 Test Year (see Exhibit 6, Tab 1, Schedule 3, Appendix A) and provides the drivers of the change.

Table 6.1.2.1 Revenue Requirement Change from 2013 to 2017

Line No.	Particulars	Board Approved	Requested 2017	Change	%
1	OM&A Expenses	$ 9,719,261	$ 10,441,723	$ 722,462	7.4%
2	Amortization/Depreciation	$ 3,497,412	$ 4,766,329	$ 1,268,917	36.3%
3	Property Taxes	$ 116,700	$ 103,000	$ (13,700)	-11.7%
4	Capital Taxes	$ -	$ -	$ -	
5	Income Taxes (Grossed up)	$ 612,615	$ 526,758	$ (85,857)	-14.0%
6	Other Expenses	$ -	$ -	$ -	
7	Return				
	Deemed Interest Expense	$ 2,394,852	$ 3,151,314	$ 756,462	31.6%
	Return on Deemed Equity	$ 2,625,341	$ 3,305,624	$ 680,283	25.9%
8	Distribution Revenue Requirement before Revenues	$ 18,966,181	$ 22,294,747	$ 3,328,567	17.6%
9	Distribution revenue	$ 17,562,996	$ 19,870,302	$ 2,307,306	13.1%
10	Other revenue	$ 1,403,185	$ 2,424,445	$ 1,021,260	72.8%
11	**Total revenue requirement**	$ 18,966,181	$ 22,294,747	$ 3,328,567	17.6%

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CAUSES OF REVENUE REQUIREMENT CHANGES

The causes of CNPI's base revenue requirement increase of $2,307,306 for the 2017 Test Year as compared to 2013 Board Approved are highlighted in Table 6.1.3.1 below. There were no accounting changes introduced between 2013 Board Approved and 2017 Test Year.

Table 6.1.3.1 Causes of Change in Revenue Requirement

Description	2013 Board Approved	2017 Test	Difference	Reference Exhibit	Reference Tab	Reference Schedule
Long Term Debt	5.67%	6.14%	0.47%			
Short Term Debt	2.08%	1.65%	-0.43%			
Return on Equity	8.93%	9.19%	0.26%			
Weighted Debt Rate	5.43%	5.84%	0.41%			
Regulated Rate of Return	**6.83%**	**7.18%**	**0.35%**	**5**	**1**	**1**
Recoverable OM&A	$ 9,835,961	$ 10,544,723	$ 708,762			
Power Supply Costs	$ 52,454,045	$ 62,242,349	$ 9,788,304			
Working Capital	$ 62,290,005	$ 72,787,072	$ 10,497,067			
Working Capital Allowance Rate	13%	7.5%	-5.50%			
Total Working Capital Allowance	**$ 8,097,701**	**$ 5,459,030**	**$ (2,638,670)**	**2**	**1**	**6**
Closing NBV 2016		$ 82,153,030	$ 82,153,030			
Closing NBV 2017		$ 86,777,871	$ 86,777,871			
Average NBV	$ 65,400,087	$ 84,465,451	$ 19,065,364			
Working Capital Allowance	$ 8,097,701	$ 5,459,030	$ (2,638,670)			
Rate Base	**$ 73,497,788**	**$ 89,924,481**	**$ 16,426,694**	**2**	**1**	**1**
Regulated Rate of Return	6.83%	7.18%	0.35%			
Reguated Return on Capital	**$ 5,020,193**	**$ 6,456,937**	**$ 1,436,745**	**5**	**1**	**1**
Demed Interest Expense	$ 2,394,852	$ 3,151,314	$ 756,462			
Deemed Return on Equity	$ 2,625,341	$ 3,305,624	$ 680,283			
OM&A	$ 9,719,261	$ 10,441,723	$ 722,462	**4**	**2**	**1**
Depreciation Expense	$ 3,497,412	$ 4,766,329	$ 1,268,917	**4**	**11**	**2**
Property Taxes	$ 116,700	$ 103,000	$ (13,700)	**4**	**12**	**1**
Income Taxes	$ 612,615	$ 526,758	$ (85,857)	**4**	**12**	**2**
Revenue Offset	$ 1,403,185	$ 2,424,445	$ 1,021,260	**3**	**4**	**3**
Base Revenue Requirement	**$ 17,562,996**	**$ 19,870,302**	**$ 2,307,306**			

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Appendix A
Revenue Requirement Workform

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Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2016 Filers

Version 6.00

Utility Name	Canadian Niagara Power Inc.
Service Territory	
Assigned EB Number	EB-2016-0061
Name and Title	Brian Vander Vloet, Manager Regulatory Accountin
Phone Number	905-871-0330
Email Address	brian.vandervloet@cnpower.com

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2016 Filers

1. Info

2. Table of Contents

3. Data_Input_Sheet

4. Rate_Base

5. Utility Income

6. Taxes_PILs

7. Cost_of_Capital

8. Rev_Def_Suff

9. Rev_Reqt

10. Tracking Sheet

Notes:

(1) Pale green cells represent inputs

(2) Pale green boxes at the bottom of each page are for additional notes

(3) Pale yellow cells represent drop-down lists

(4) ***Please note that this model uses MACROS. Before starting, please ensure that macros have been enabled.***

(5) ***Completed versions of the Revenue Requirement Work Form are required to be filed in working Microsoft Excel***

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2016 Filers

Data Input (1)

		Initial Application	(2)		(6)	Per Board Decision	
1	**Rate Base**						
	Gross Fixed Assets (average)	$147,209,031		$ 147,209,031		$147,209,031	
	Accumulated Depreciation (average)	($62,743,580)	(5)	($62,743,580)		($62,743,580)	
	Allowance for Working Capital:						
	Controllable Expenses	$10,544,723		$ 10,544,723		$10,544,723	
	Cost of Power	$62,242,349		$ 62,242,349		$62,242,349	
	Working Capital Rate (%)	7.50%	(9)	7.50%	(9)	7.50%	(9)
2	**Utility Income**						
	Operating Revenues:						
	Distribution Revenue at Current Rates	$17,535,614					
	Distribution Revenue at Proposed Rates	$19,870,307					
	Other Revenue:						
	Specific Service Charges	$158,264					
	Late Payment Charges	$354,100					
	Other Distribution Revenue	$449,635					
	Other Income and Deductions	$1,462,446					
	Total Revenue Offsets	$2,424,445	(7)				
	Operating Expenses:						
	OM+A Expenses	$10,441,723		$ 10,441,723		$10,441,723	
	Depreciation/Amortization	$4,766,329		$ 4,766,329		$4,766,329	
	Property taxes	$103,000		$ 103,000		$103,000	
	Other expenses						
3	**Taxes/PILs**						
	Taxable Income:						
	Adjustments required to arrive at taxable income	($1,844,756)	(3)				
	Utility Income Taxes and Rates:						
	Income taxes (not grossed up)	$387,167					
	Income taxes (grossed up)	$526,758					
	Federal tax (%)	15.00%					
	Provincial tax (%)	11.50%					
	Income Tax Credits	($13,460)					
4	**Capitalization/Cost of Capital**						
	Capital Structure:						
	Long-term debt Capitalization Ratio (%)	56.0%					
	Short-term debt Capitalization Ratio (%)	4.0%	(8)		(8)		(8)
	Common Equity Capitalization Ratio (%)	40.0%					
	Prefered Shares Capitalization Ratio (%)						
		100.0%					
	Cost of Capital						
	Long-term debt Cost Rate (%)	6.14%					
	Short-term debt Cost Rate (%)	1.65%					
	Common Equity Cost Rate (%)	9.19%					
	Prefered Shares Cost Rate (%)						

Notes:

General Data inputs are required on Sheets 3. Data from Sheet 3 will automatically complete calculations on sheets 4 through 9 (Rate Base through Revenue Requirement). Sheets 4 through 9 do not require any inputs except for notes that the Applicant may wish to enter to support the results. Pale green cells are available on sheets 4 through 9 to enter both footnotes beside key cells and the related text for the notes at the bottom of each sheet.

(1) All inputs are in dollars ($) except where inputs are individually identified as percentages (%)

(2) Data in column E is for Application as originally filed. For updated revenue requirement as a result of interrogatory responses, technical or settlement conferences, etc., use colimn M and Adjustments in column I

(3) Net of addbacks and deductions to arrive at taxable income.

(4) Average of Gross Fixed Assets at beginning and end of the Test Year

(5) Average of Accumulated Depreciation at the beginning and end of the Test Year. Enter as a negative amount.

(6) Select option from drop-down list by clicking on cell M10. This column allows for the application update reflecting the end of discovery or Argument-in-Chief. Also, the outcome of any Settlement Process can be reflected.

(7) Input total revenue offsets for deriving the base revenue requirement from the service revenue requirement

(8) 4.0% unless an Applicant has proposed or been approved for another amount.

(9) The default Working Capital Allowance factor is 7.5% (of Cost of Power plus controllable expenses), per the letter issued by the Board on June 3, 2015. Alternatively, WCA factor based on lead-lag study or approved WCA factor for another distributor, with supporting rationale.

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2016 Filers

Rate Base and Working Capital

Rate Base

Line No.	Particulars		Initial Application				Per Board Decision
1	Gross Fixed Assets (average)	(3)	$147,209,031	$ -	$147,209,031	$ -	$147,209,031
2	Accumulated Depreciation (average)	(3)	($62,743,580)	$ -	($62,743,580)	$ -	($62,743,580)
3	Net Fixed Assets (average)	(3)	$84,465,451	$ -	$84,465,451	$ -	$84,465,451
4	Allowance for Working Capital	(1)	$5,459,030	$ -	$5,459,030	$ -	$5,459,030
5	**Total Rate Base**		$89,924,481	$ -	$89,924,481	$ -	$89,924,481

(1) **Allowance for Working Capital - Derivation**

Line No.	Particulars		Initial Application				Per Board Decision
6	Controllable Expenses		$10,544,723	$ -	$10,544,723	$ -	$10,544,723
7	Cost of Power		$62,242,349	$ -	$62,242,349	$ -	$62,242,349
8	Working Capital Base		$72,787,072	$ -	$72,787,072	$ -	$72,787,072
9	Working Capital Rate %	(2)	7.50%	0.00%	7.50%	0.00%	7.50%
10	Working Capital Allowance		$5,459,030	$ -	$5,459,030	$ -	$5,459,030

Notes

(2) Some Applicants may have a unique rate as a result of a lead-lag study. The default rate for 2016 cost of service applications is 7.5%, per the letter issued by the Board on June 3, 2015. Alternatively, a utility could conduct and file its own lead-lag study.

(3) Average of opening and closing balances for the year.

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2016 Filers

Utility Income

Line No.	Particulars		Initial Application				Per Board Decision
	Operating Revenues:						
1	Distribution Revenue (at Proposed Rates)		$19,870,307	($19,870,307)	$ -	$ -	$ -
2	Other Revenue	(1)	$2,424,445	($2,424,445)	$ -	$ -	$ -
3	Total Operating Revenues		$22,294,752	($22,294,752)	$ -	$ -	$ -
	Operating Expenses:						
4	OM+A Expenses		$10,441,723	$ -	$10,441,723	$ -	$10,441,723
5	Depreciation/Amortization		$4,766,329	$ -	$4,766,329	$ -	$4,766,329
6	Property taxes		$103,000	$ -	$103,000	$ -	$103,000
7	Capital taxes		$ -	$ -	$ -	$ -	$ -
8	Other expense		$ -	$ -		$ -	
9	Subtotal (lines 4 to 8)		$15,311,052	$ -	$15,311,052	$ -	$15,311,052
10	Deemed Interest Expense		$3,151,314	($3,151,314)	$ -	$ -	$ -
11	Total Expenses (lines 9 to 10)		$18,462,366	($3,151,314)	$15,311,052	$ -	$15,311,052
12	**Utility income before income taxes**		$3,832,386	($19,143,438)	($15,311,052)	$ -	($15,311,052)
13	Income taxes (grossed-up)		$526,758	$ -	$526,758	$ -	$526,758
14	**Utility net income**		$3,305,629	($19,143,438)	($15,837,810)	$ -	($15,837,810)

Notes

Other Revenues / Revenue Offsets

Note	Item	Initial Application				Per Board Decision
(1)	Specific Service Charges	$158,264		$ -		$ -
	Late Payment Charges	$354,100		$ -		$ -
	Other Distribution Revenue	$449,635		$ -		$ -
	Other Income and Deductions	$1,462,446		$ -		$ -
	Total Revenue Offsets	$2,424,445	$ -	$ -	$ -	$ -

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2016 Filers

Taxes/PILs

Line No.	Particulars	Application		Per Board Decision
	Determination of Taxable Income			
1	Utility net income before taxes	$3,305,624	$ -	$ -
2	Adjustments required to arrive at taxable utility income	($1,844,756)	$ -	($1,844,756)
3	Taxable income	$1,460,868	$ -	($1,844,756)
	Calculation of Utility income Taxes			
4	Income taxes	$387,167	$387,167	$387,167
6	Total taxes	$387,167	$387,167	$387,167
7	Gross-up of Income Taxes	$139,591	$139,591	$139,591
8	Grossed-up Income Taxes	$526,758	$526,758	$526,758
9	PILs / tax Allowance (Grossed-up Income taxes + Capital taxes)	$526,758	$526,758	$526,758
10	Other tax Credits	($13,460)	($13,460)	($13,460)
	Tax Rates			
11	Federal tax (%)	15.00%	15.00%	15.00%
12	Provincial tax (%)	11.50%	11.50%	11.50%
13	Total tax rate (%)	26.50%	26.50%	26.50%

Notes

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2016 Filers

Capitalization/Cost of Capital

Line No.	Particulars	Capitalization Ratio		Cost Rate	Return
		Initial Application			
		(%)	($)	(%)	($)
	Debt				
1	Long-term Debt	56.00%	$50,357,710	6.14%	$3,091,963
2	Short-term Debt	4.00%	$3,596,979	1.65%	$59,350
3	**Total Debt**	60.00%	$53,954,689	5.84%	$3,151,314
	Equity				
4	Common Equity	40.00%	$35,969,793	9.19%	$3,305,624
5	Preferred Shares	0.00%	$ -	0.00%	$ -
6	**Total Equity**	40.00%	$35,969,793	9.19%	$3,305,624
7	**Total**	100.00%	$89,924,481	7.18%	$6,456,937

Line No.	Particulars	Capitalization Ratio		Cost Rate	Return
		(%)	($)	(%)	($)
	Debt				
1	Long-term Debt	0.00%	$ -	0.00%	$ -
2	Short-term Debt	0.00%	$ -	0.00%	$ -
3	**Total Debt**	0.00%	$ -	0.00%	$ -
	Equity				
4	Common Equity	0.00%	$ -	0.00%	$ -
5	Preferred Shares	0.00%	$ -	0.00%	$ -
6	**Total Equity**	0.00%	$ -	0.00%	$ -
7	**Total**	0.00%	$89,924,481	0.00%	$ -

Line No.	Particulars	Capitalization Ratio		Cost Rate	Return
		Per Board Decision			
		(%)	($)	(%)	($)
	Debt				
8	Long-term Debt	0.00%	$ -	6.14%	$ -
9	Short-term Debt	0.00%	$ -	1.65%	$ -
10	**Total Debt**	0.00%	$ -	0.00%	$ -
	Equity				
11	Common Equity	0.00%	$ -	9.19%	$ -
12	Preferred Shares	0.00%	$ -	0.00%	$ -
13	**Total Equity**	0.00%	$ -	0.00%	$ -
14	**Total**	0.00%	$89,924,481	0.00%	$ -

Notes

(1) Data in column E is for Application as originally filed. For updated revenue requirement as a result of interrogatory responses, technical or settlement conferences, etc., use colimn M and Adjustments in column I

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2016 Filers

Revenue Deficiency/Sufficiency

		Initial Application				Per Board Decision	
Line No.	Particulars	At Current Approved Rates	At Proposed Rates	At Current Approved Rates	At Proposed Rates	At Current Approved Rates	At Proposed Rates
1	Revenue Deficiency from Below		$2,316,325		($2,907,991)		$15,311,052
2	Distribution Revenue	$17,535,614	$17,553,982	$17,535,614	$22,778,298	$ -	($15,311,052)
3	Other Operating Revenue Offsets - net	$2,424,445	$2,424,445	$ -	$ -	$ -	$ -
4	**Total Revenue**	$19,960,059	$22,294,752	$17,535,614	$19,870,307	$ -	$ -
5	Operating Expenses	$15,311,052	$15,311,052	$15,311,052	$15,311,052	$15,311,052	$15,311,052
6	Deemed Interest Expense	$3,151,314	$3,151,314	$ -	$ -	$ -	$ -
8	**Total Cost and Expenses**	$18,462,366	$18,462,366	$15,311,052	$15,311,052	$15,311,052	$15,311,052
9	**Utility Income Before Income Taxes**	$1,497,693	$3,832,386	$2,224,562	$4,559,255	($15,311,052)	($15,311,052)
10	Tax Adjustments to Accounting Income per 2013 PILs model	($1,844,756)	($1,844,756)	($1,844,756)	($1,844,756)	$ -	$ -
11	**Taxable Income**	($347,063)	$1,987,630	$379,806	$2,714,499	($15,311,052)	($15,311,052)
12	Income Tax Rate	26.50%	26.50%	26.50%	26.50%	26.50%	26.50%
13	**Income Tax on Taxable Income**	($91,972)	$526,722	$100,649	$719,342	($4,057,429)	($4,057,429)
14	**Income Tax Credits**	($13,460)	($13,460)	($13,460)	($13,460)	$ -	$ -
15	**Utility Net Income**	$1,603,125	$3,305,629	$2,137,373	($15,837,810)	($11,253,623)	($15,837,810)
16	**Utility Rate Base**	$89,924,481	$89,924,481	$89,924,481	$89,924,481	$89,924,481	$89,924,481
17	Deemed Equity Portion of Rate Base	$35,969,793	$35,969,793	$ -	$ -	$ -	$ -
18	Income/(Equity Portion of Rate Base)	4.46%	9.19%	0.00%	0.00%	0.00%	0.00%
19	Target Return - Equity on Rate Base	9.19%	9.19%	0.00%	0.00%	0.00%	0.00%
20	Deficiency/Sufficiency in Return on Equity	-4.73%	0.00%	0.00%	0.00%	0.00%	0.00%
21	Indicated Rate of Return	5.29%	7.18%	2.38%	0.00%	-12.51%	0.00%
22	Requested Rate of Return on Rate Base	7.18%	7.18%	0.00%	0.00%	0.00%	0.00%
23	Deficiency/Sufficiency in Rate of Return	-1.89%	0.00%	2.38%	0.00%	-12.51%	0.00%
24	Target Return on Equity	$3,305,624	$3,305,624	$ -	$ -	$ -	$ -
25	Revenue Deficiency/(Sufficiency)	$1,702,499	$5	($2,137,373)	$ -	$11,253,623	$ -
26	**Gross Revenue Deficiency/(Sufficiency)**	$2,316,325 **(1)**		($2,907,991) **(1)**		$15,311,052 **(1)**	

Notes:

(1) Revenue Deficiency/Sufficiency divided by (1 - Tax Rate)

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2016 Filers

Revenue Requirement

Line No.	Particulars	Application				Per Board Decision	
1	OM&A Expenses	$10,441,723		$10,441,723		$10,441,723	
2	Amortization/Depreciation	$4,766,329		$4,766,329		$4,766,329	
3	Property Taxes	$103,000		$103,000		$103,000	
5	Income Taxes (Grossed up)	$526,758		$526,758		$526,758	
6	Other Expenses	$ -					
7	Return						
	Deemed Interest Expense	$3,151,314		$ -		$ -	
	Return on Deemed Equity	$3,305,624		$ -		$ -	
8	**Service Revenue Requirement (before Revenues)**	$22,294,747		$15,837,810		$15,837,810	
9	Revenue Offsets	$2,424,445		$ -		$ -	
10	**Base Revenue Requirement (excluding Tranformer Owership Allowance credit adjustment)**	$19,870,302		$15,837,810		$15,837,810	
11	Distribution revenue	$19,870,307		$ -		$ -	
12	Other revenue	$2,424,445		$ -		$ -	
13	**Total revenue**	$22,294,752		$ -		$ -	
14	**Difference (Total Revenue Less Distribution Revenue Requirement before Revenues)**	$5	**(1)**	($15,837,810)	**(1)**	($15,837,810)	**(1)**

Notes

(1) Line 11 - Line 8

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2016 Filers

Tracking Form

The last row shown is the most current estimate of the cost of service data reflecting the original application and any updates provided by the applicant distributor (for updated evidence, responses to interrogatories, undertakings, etc.)
Please ensure a Reference (Column B) and/or Item Description (Column C) is entered. Please note that unused rows will automatically be hidden and the PRINT AREA set when the PRINT BUTTON on Sheet 1 is activated.
(1) Short reference to evidence material (interrogatory response, undertaking, exhibit number, Board Decision, Code, Guideline, Report of the Board, etc.)
(2) Short description of change, issue, etc.

60 Tracking Rows have been provided below. If you require more, please contact Industry Relations @ IndustryRelations@ontarioenergyboard.ca.

Summary of Proposed Changes

			Cost of Capital		Rate Base and Capital Expenditures			Operating Expenses			Revenue Requirement			
	Reference [1]	Item / Description [2]	Regulated Return on Capital	Regulated Rate of Return	Rate Base	Working Capital	Working Capital Allowance ($)	Amortization / Depreciation	Taxes/PILs	OM&A	Service Revenue Requirement	Other Revenues	Base Revenue Requirement	Grossed up Revenue Deficiency / Sufficiency
		Original Application	$ 6,456,937	7.18%	$ 89,924,481	$ 72,787,072	$ 5,459,030	$ 4,766,329	$ 526,758	$ 10,441,723	$ 22,294,747	$ 2,424,445	$ 19,870,302	$ 2,316,325
1														

CURRENT STATUS OF COST ALLOCATION

CNPI filed its most recent cost of service application on the basis of a 2013 Test Year; EB-2012-0112. In that application, CNPI filed separate Cost Allocation Studies for its Fort Erie / Gananoque and Port Colborne service areas.

The Proposed Settlement Agreement approved by the Board in EB-2012-0112 accepted that the harmonized revenue requirement for CNPI would serve as the basis for 2013 distribution rates. The Proposed Settlement Agreement also accepted that changes would be made in the 2014-2016 IRM period to adjust the revenue to cost ratios of USL and Sentinel lighting classes to the nearest boundaries of the Board's policy range. Further, the Proposed Settlement Agreement also accepted that in the 2014-2016 IRM period, CNPI would adjust the fixed to variable ratios of distribution rates in Fort Erie/EOP and Port Colborne to achieve harmonized rates on or before 2016.

Effective January 1, 2016, CNPI has achieved full harmonization of its Monthly Service Charges and Distribution Volumetric Rates as a result of the Board's decision in relation to CNPI's 2016 IRM Application; EB-2015-0058. CNPI has therefore filed a single harmonized Cost Allocation Study in relation this Application.

The table below summarizes the current status of CNPI's customer class revenue to cost ratios.

Current Status of Revenue to Cost Ratios				
Class	2016 Approved	Status Quo Ratios	Proposed Ratios	Policy Range
	%	%	%	%
Residential	91.42	94.62	95.37	85 - 115
GS < 50 kW	109.34	109.22	109.22	80 - 120
GS 50 to 4,999 kW	119.94	106.96	106.96	80 - 120
Street Lighting	96.28	162.22	120.00	80 - 120
Sentinel Lighting	91.42	105.08	105.08	80 - 120
Unmetered Scattered Load (USL)	120.00	72.95	95.37	80 - 120
Embedded Distributor		84.57	95.37	

THE 2017 COST ALLOCATION STUDY

CNPI's 2017 Cost Allocation Study follows the policies outlined in the Board's reports of November 28, 2007 Application of Cost Allocation for Electricity Distributors, and March 31, 2011 Review of Electricity Distribution Cost Allocation Policy (EB-2010-0219) (the "Cost Allocation Reports").

On June 12, 2015, the Board issued a letter outlining a new cost allocation policy for the Street Lighting rate class, and narrowing the revenue to cost ratio policy range for this class to 80%-120%. Subsequently, the Board issued version 3.3 of its Cost Allocation Model on July 16, 2015, incorporating this new cost allocation policy. CNPI has used version 3.3 of the Cost Allocation Model in preparing this Application. A completed model has been filed in live Microsoft Excel format in conjunction with this Application.

To perform the 2017 Cost Allocation Study, CNPI retained the services of Elenchus Research Associates Inc. ("Elenchus"); all distribution system attributes, financial, load and customer information was provided to Elenchus by CNPI. The various weighting allocators such as weighting for services, metering and billing and collection were also provided by CNPI. With the exception of meter reading cost ratios, these factors are identical to those used in CNPI's 2013 Cost Allocation Study, and were reviewed to ensure continued applicability, as outlined below. Details of other inputs and assumptions are presented in a report prepared by Elenchus Research Associates (the "Elenchus Report"), which can be found at Exhibit 7, Tab 1, Schedule 2, Appendix A.

Weighting Factors

<u>Meter Reading – Tab I7.2</u>

Following completion of the MIST metering implementation in Q1 2016, virtually all meter reading activities fall into 2 categories, namely Smart Meters and MIST/Interval meters. Both types of meters are automatically read wirelessly, whether via the Sensus AMI network (for

Smart Meters), or through the use of dedicated communications (for MIST/Interval meters). When either type of meter fails to read automatically as expected, a CNPI meter tech is issued a "Check Read" work order. The meter technician then attends on site and completes a basic read and restarts/re-activates for the affected meter communication devices, which involves roughly the same effort regardless of meter type. In rare cases where the effort extends beyond this initial attempt (e.g. replacing meters or modems), then the technician's time is charged to orders that settle to other OEB accounts (e.g. maintenance of meters). Interval meters are now rarely, if ever, read manually. Consequently, a relative factor of 1 has been assigned to all meter types. This is in-line with revised information found in the "Instructions" tab of the OEB Cost Allocation Model, which read in part:

> "To the extent that these factors are now more nearly uniform due to automated meter reading, the distributor may find that the appropriate weights are close to 1.0 for all classes."

<u>Weighting Factor for Services, Billing and Collecting – Tab I5.2</u>

CNPI determined that there have been no substantive changes in relative costs allocated to Account 1855 – Services since these costs were analyzed in preparing its 2013 Cost Allocation Study. With respect to billing costs, CNPI has been billing all customer classes on a monthly basis since prior to the 2013 Cost Allocation study. As a result, inflationary increases to items such as postage, stationary and labour rates would be expected to impact all classes equally, and the ratios remain unchanged. The following table outlines the weighting factors used on Tab I5.2.

	1	2	3	7	8	9	10
	Residential	**GS <50**	**GS>50-Regular**	**Street Light**	**Sentinel**	**Unmetered Scattered Load**	**Embedded Distributor**
Insert Weighting Factor for Services Account 1855	1.0	1.4	4.4	0.4	0.7	0.9	4.4
Insert Weighting Factor for Billing and Collecting	1.0	1.0	5.0	1.8	0.9	1.3	5.0

Establishment of Embedded Distributor Rate Class

In accordance with the Chapter 2 Filing Requirements updated on July 16, 2015, CNPI consulted with its single Embedded Distributor customer – Hydro One Networks Inc. ("HONI") with regards to CNPI's approach to allocation of costs. In reply to CNPI's proposal to continue as a GS 50 to 4999 kW customer, HONI requested that "a separate embedded distributor rate be developed that appropriately reflects the cost of serving Hydro One". This correspondence is attached as Appendix C to this Schedule. CNPI therefore proceeded with its Cost Allocation Study on the basis of establishing a distinct Embedded Distributor Rate Class and the subsequent allocation of costs to that class in accordance with Board Policy. The actual hourly load profile for the Hydro One embedded supply point was provided to Elenchus for use in the cost allocation study. Based on the physical characteristics of the embedded supply point, it was assigned to both the bulk and primary customer cost bases, but was excluded from the line transformer and secondary cost bases.

THE 2017 COST ALLOCATION STUDY RESULTS

The results of the 2017 Cost Allocation Study are presented the Elenchus Report, which can be found at Exhibit 7, Tab 1, Schedule 2, Appendix A. This report provides descriptions of inputs and assumptions, methodology used to complete the model, and results for class revenue requirements and revenue to cost ratios.

Hard copies of input sheets I-6 and I-8, and output sheets O-1 and O-2 from the OEB-issued Cost Allocation Model can be found at Exhibit 7, Tab 1, Schedule 2, Appendix B.

A summary of allocated costs, calculated revenues, and revenue to cost ratios by class can be found in the hard copy of Appendix 2-P filed as Exhibit 7, Tab 1, Schedule 3.

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APPENDIX A

2017 Cost Allocation Study

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Toronto, Ontario, M5C 2X8
elenchus.ca

Canadian Niagara Power Inc.

2017 Cost Allocation – Cost of Service

A Report Prepared by
Elenchus Research Associates Inc.

On Behalf of
Canadian
Niagara Power

05/04/2016

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1 INTRODUCTION

Canadian Niagara Power Inc. ("Canadian Niagara Power") has prepared its 2017 EDR Application as a cost of service rate application based on a forward test year. The relevant filing requirements for this Application are set out in Chapter 2 of the July 16, 2015 update to the document entitled *Ontario Energy Board, Filing Requirements for Electricity Distribution Rate Applications* ("Filing Requirements").

Section 2.7 of the Filing Requirements sets out the expectations of the Board with respect to Exhibit 7: Cost Allocation. The Filing Requirements on page 48 state:

> *A completed cost allocation study using the OEB-approved methodology or a comparable model must be filed. This filing must reflect future loads and costs and be supported by appropriate explanations and live Microsoft Excel spreadsheets. The most current update of the model (version 3.2) is available on the Board's web site. Appendix 2-P must also be completed.* [1]

Canadian Niagara Power asked Elenchus Research Associated (Elenchus)[2] to assist it by preparing an appropriate cost allocation study for its 2017 cost of service rate application.

In addressing the cost allocation issues, Elenchus was guided by the Filing Requirements, the November 28, 2007 *Report of the Board, Application of Cost Allocation for Electricity Distributors* (EB-2007-0667) ("CA Application Report") which "sets out the Board's policies in relation to specific cost allocation matters for electricity distributors"[3] and the March 31, 2011 *Report of the Board, Review of Electricity Distribution Cost Allocation Policy* (EB-2010-0219) ("CA Review Report") in which the Board narrowed some revenue to cost ratio ranges, and committed to further consultations on unmetered and standby loads, as well as the Board's decisions in various electricity distributor cost of service proceedings that addressed relevant issues.

1.1 PURPOSE OF THE COST ALLOCATION STUDY

In the context of a cost of service rate application based on 2017 forward test years, the primary purpose of the cost allocation study ("CA Study") is to determine the proportions

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1 Ontario Energy Board, *Filing Requirements for Electricity Distribution Rate Applications* (July 16, 2015), p. 51.

2 John Todd, President of Elenchus Research Associates, was the lead consultant for the development and implementation of the methodology used by Canadian Niagara Power and documented in this report. John Todd's curriculum vitae is available at www.elenchus.ca.

3 Ontario Energy Board, *Report of the Board, Application of Cost Allocation for Electricity Distributors* (EB-2007-0667), November 28, 2007, page 1.

of a distributor's total revenue requirement that are the "responsibility" of each rate class.

In addition, cost allocation studies provide revenue to cost ratios for each customer class that can be examined to ensure that they generally fall within the Board-specified ranges (or move toward those ranges where appropriate to mitigate rate impacts) and generally are not moving away from 100%.

Conceptually, Canadian Niagara Power's prospective year CA Study for the 2017 test years is based on an allocation of the 2017 test year costs (i.e., the 2017 forecast revenue requirement) to the various customer classes using allocators that are based on the forecast class loads (kW and kWh) by class, customer counts, etc. By definition, this approach will result in a total revenue to cost ratio at proposed rates of 100%. Given a revenue deficiency for the test year, the total revenue to cost ratio at current rates will be somewhat below 100%.

1.2 CANADIAN NIAGARA POWER'S 2013 COST ALLOCATION

The last cost allocation study filed by Canadian Niagara Power was in 2013 in Proceeding EB-2012-0112, was based on the v 2.0 Cost Allocation Model. In that proceeding Canadian Niagara Power filed a Cost Allocation model on a consolidated basis for the first time, and produced harmonized rates. The 2017 model was prepared only on a consolidated basis, and performed in accordance with the internal documentation in the v 3.3a Cost Allocation Model (CA Model).

Canadian Niagara Power's 2013 CA Study was prepared in accordance with the Filing Requirements, the November 28, 2007 *Report of the Board, Application of Cost Allocation for Electricity Distributors* (EB-2007-0667) ("CA Application Report") which "sets out the Board's policies in relation to specific cost allocation matters for electricity distributors"[4] and the March 31, 2011 *Report of the Board, Review of Electricity Distribution Cost Allocation Policy* (EB-2010-0219) ("CA Review Report").

1.3 STRUCTURE OF THE REPORT

The remainder of this report is divided into four additional sections. Section 2 provides an overview of the Canadian Niagara Power CA Study, explaining the model run included in the study, as well as the load and cost information used for the run. Section 3 explains the methodology used to develop the 2017 Canadian Niagara Power model by documenting each step taken in completing the model. Section 4 summarizes the

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4 Ontario Energy Board, *Report of the Board, Application of Cost Allocation for Electricity Distributors* (EB-2007-0667), November 28, 2007, page 1.

results of the Canadian Niagara Power CA Study, showing the class revenue requirements and revenue to cost ratios generated by the CA model. Section 5 shows the fixed charge unit costs per month and the fixed charge boundary values as calculated in the cost allocation.

2 OVERVIEW OF THE CANADIAN NIAGARA POWER 2017 CA STUDY

2.1 MODEL RUN INCLUDED IN THE CANADIAN NIAGARA POWER COST ALLOCATION STUDY

Section 2.7.3 of the updated Filing Requirements specifies that the third table in Appendix 2-P, "...includes the following information for each class" that should be provided based on:

- *The previously approved ratios most recently implemented by the distributor;*
- *The ratios that would result from the most recent approved distribution rates and the distributor's forecast of billing quantities in the test year, prorated upwards or downwards (as applicable) to match the revenue requirement, expressed as a ratio with the class revenue requirements derived in the updated cost allocation model*
- *The ratios that are proposed for the Test Year*

For clarity, the following designations are used.

- CNPI-2013: The Consolidated Canadian Niagara Power 2013 revenue to cost ratios.
- CNPI-2017: The version 3.3a CA Model with 2017 loads, costs, and revenues.

2.2 LOAD AND CUSTOMER INFORMATION

The updated Filing Requirements specify that "This filing must reflect future loads and costs..." and "For any customer class for which updated load profiles are not available, the load profiles provided by Hydro One for use in the Informational Filing may be used - scaled to match the load forecast as it relates to the respective rate classes", (Section 2.7.1, p. 51)

The Canadian Niagara Power 2017 models have been prepared using the following load and load profile information:

- Annual Loads (kW and kWh, as appropriate) and customer counts: The 2017 load forecast and customer counts by class being used by Canadian Niagara Power in its application were also used for the 2017 CA models.

- Hourly load profile: The hourly load profiles prepared by Hydro One and as consolidated for the 2013 Cost of Service were used for all classes except for the Embedded Distributor class. The Embedded distributor is a new customer since the Hydro One load profiles were established, and was not included in the profile for GS > 50 class. Canadian Niagara Power has used the actual 2015 hourly load profile for the embedded distributor. All load profiles were scaled to be consistent with the 2017 load forecast, and peak allocators were determined in a methodology consistent with the Hydro One methodology.

The hourly load profiles provided by Hydro One for all of the classes for the 2006 model were considered to be appropriate for use in the 2017 models for the following reasons.

1. Elenchus has previously explored alternatives for updating the hourly load profiles by rate class comparable to the estimated load profiles that Hydro One prepared for the LDCs for their 2006 CA Models. Hydro One advised that they no longer have the capacity to produce a significant number of LDC-specific hourly load profiles. As far as Elenchus is aware, no other entity has the necessary information and models to produce comparable quality hourly load profiles for Ontario LDCs. It therefore was not practical for distributors to update their hourly load profiles by class except in exceptional circumstances.
2. It is Elenchus' opinion that there would be little point in investing in updated load profiles without also investing in updated saturation surveys for the residential class in each service area. These are expensive and time consuming to undertake as they involve a survey of a statistically significant sample of customers.
3. With the widespread rollout of smart meters and the collection of smart meter data, Ontario distributors will have better hourly load profile by class data than the Hydro One estimates. Unless there is evidence of a significant change in circumstances, investing in new hourly load profile by class estimates would be a questionable use of ratepayer funds when superior hourly load profile information may be available in the future.
4. Both time-of-use commodity pricing and changes to the design of distribution rates are influencing the hourly load profiles of the affected classes; however, it will not be practical to use smart meter data to update the load profiles of the weather sensitive classes until a sufficient number of years of data have been collected to determine demand on a weather normalized basis.

2.3 COST INFORMATION

As noted earlier, the Filing Requirements mandate that the cost allocation models be prepared on the basis of prospective test year information. In the case of Canadian

Niagara Power, the financial information for the forecast years has been prepared at the USoA level.

3 CANADIAN NIAGARA POWER COST ALLOCATION STUDY METHODOLOGY

This section documents Elenchus' methodology for the Canadian Niagara Power Cost Allocation Study, the 2017 CA Models.

3.1 2017 CANADIAN NIAGARA POWER CA MODELS

3.1.1 HOURLY LOAD PROFILE (HONI FILE)

For the Canadian Niagara Power CAIF, HONI provided data files with three worksheets that were to be used as input to the 2006 CAIF:

- Data Summary: actual and weather normalized monthly kWh by class, disaggregated by weather sensitive and non-weather sensitive load for relevant classes.
- Hourly Load Shape by Class: GWh by class for each hour in 2004.
- Input to Cost Allocation Model: The 1CP, 4CP, 12CP, 1NCP, 4NCP, 12NCP allocators are derived from the hourly load profiles.

For all classes except the Embedded Distributor class, the Canadian Niagara Power hourly load shapes derived by Hydro One for the 2006 CAIF and combined for 2013 consolidated Cost of Service were not updated. However, the demand allocators derived by Hydro One for the 2006 CAIF were revised to reflect changes in the relative loads for the classes from 2004 to 2017. This was done by scaling the hourly load profiles of each class on the Hourly Load Shape by Class worksheet of the HONI file to levels consistent with the 2017 load forecast years while maintaining the hourly load shapes.

For the Embedded Distributor customer class, 2015 actual interval hourly data was used, scaled to levels consistent with the 2017 load forecast years while maintaining the hourly load shapes.

3.1.2 DEMAND ALLOCATORS (HONI FILE)

The demand allocators used in the Canadian Niagara Power-2017 CA models were derived using the same methodology as Hydro One used for the 2006 file; however, they were re-determined using the forecast 2017 hourly load profiles resulting from the preceding step. Using the 2017 hourly load profiles by class, the 12 monthly coincident and non-coincident peaks for the rate classes were determined on the Hourly Load Shape by Rate Class worksheet. The allocators were then derived as follows.

- The 1, 4 and 12 NCP values for each class were calculated by selecting the peak in the year (1 NCP), summing the four highest monthly peaks (4 NCP) and summing the 12 monthly peaks for each class (12 NCP), respectively.
- The total 1, 4 and 12 NCP values are the totals of the corresponding class NCP values.
- The 1, 4 and 12 CP values for each class were derived by identifying the hour in each month when the coincident peak occurred and then selecting the peak in the year (1 CP), adding the demands during the four highest coincident peak hours (4 CP) and summing the demand for each class during the 12 monthly coincident peak hours (12 CP), respectively.
- The total 1, 4 and 12 CP values are the totals of the corresponding class CP values, which are the values used to identify the relevant coincident peak hours.

3.1.3 2017 Demand Data (Canadian Niagara Power-2017 Models)

The demand allocators derived in the updated Hydro One file as described in the preceding section were input at the appropriate cells at sheet I8 Demand Data of the 2017 Canadian Niagara Power CA Models. However, the Primary, Line Transformer and Secondary 1NCP, 4NCP and 12NCP values for GS > 50 and Embedded Distributor customer classes are not equal to the full class NCP values since not all customers in these customer classes use these facilities. The Line Transformer and Secondary 1NCP, 4NCP and 12NCP values were therefore determined from the full load data NCP values using the ratio of values in the 2013 consolidated CA Model.

4 SUMMARY OF REVENUE TO COST RATIOS

The class revenue-to-cost ratios as determined in the Canadian Niagara Power cost allocation models are shown in Table 7, below.

Table 7: Revenue to Cost Ratios

Customer Class	CNPI-2013	CNPI-2017 Status Quo Rates	Board Target Range
Residential	91.06	94.62	85-115
GS < 50 kW	109.34	109.22	80-120
GS > 50 Regular	119.94	106.96	80-120
Street Light	96.28	162.22	80-120
Sentinel	79.68	105.08	80-120
USL	261.19	72.95	80-120
Embedded Distributor	-	84.57	80-120
Total	100.00	100.00	

The CNPI-2017 ratios (at Status Quo rates) reflect the impact of changes in throughput by class as well as changes in costs from 2013 through the 2017 forecast test years, and the separation of the Embedded Distributor into its own rate class.

Table 8 presents the revenue responsibility (i.e., allocation of the total revenue requirement to the rate classes) in each of the models. This revenue responsibility is presented in both dollar and percentage terms.

Table 8: Revenue Responsibility by Rate Class

Customer Class	CNPI-2013		CNPI-2017	
	$	%	$	%
Residential	11,876,815	62.6	14,073,081	63.1
GS < 50 kW	2,376,032	12.5	2,764,150	12.4
GS > 50 Regular	4,090,319	21.6	4,860,556	21.8
Street Light	503,635	2.7	322,994	1.4
Sentinel	82,426	0.4	64,083	0.3
USL	36,954	0.2	71,426	0.3
Embedded Distributor	-	-	138,462	0.6
Total	18,966,182	100.0	22,294,752	100.0

5 FIXED CHARGE RATES

The Canadian Niagara Power cost allocation model produced the following customer unit cost per month values:

Table 9: 2017 Customer Unit Cost per Month

Customer Class	Avoided Cost	Directly Related	Minimum System with PLCC[5] Adjustment
Residential	5.30	8.78	27.42
GS < 50 kW	11.95	19.14	39.53
GS > 50 Regular	103.12	177.31	233.75
Street Light	(0.02)	0.02	5.55
Sentinel	0.09	0.29	16.66
USL	0.17	.064	15.15
Embedded Distributor	584.79	870.69	613.58

In accordance with Board policy,[6] the following boundary values would apply for the fixed monthly service charge:

Table 10: 2017 Fixed Charge Boundary Values

Customer Class	Cost Allocation		Existing Rate	Boundary Values	
	Low	High		Minimum	Maximum
Residential	5.30	27.42	23.44	5.30	27.42
GS < 50 kW	11.95	39.53	28.26	11.95	39.53
GS > 50 Regular	103.12	233.75	151.83	103.12	233.75
Street Light	(0.02)	5.55	4.96	(0.02)	5.55
Sentinel	0.09	16.66	5.09	0.09	16.66
USL	0.17	15.15	32.96	0.17	32.96
Embedded Distributor	584.79	870.69	151.83	584.79	870.69

However, the new policy for rate design, calls for a fixed charge only for Residential rates. "Electricity distributors will structure residential rates so that all the costs for residential distribution service are collected through a fixed monthly charge."[7] This indicates that the upper boundaries of this guideline should no longer apply to the Residential rate class.

Further, the Board expects to roll this out to other rate classes. "Next, we intend to review the rate design for low-volume general service customers (generally small

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5 PLCC: 'Peak Load Carrying Capacity'

6 Ontario Energy Board, *Report of the Board, Application of Cost Allocation for Electricity Distributors* (EB-2007-0667), November 28, 2007, pages 12-13

7 Ontario Energy Board, *A New Distribution Rate Design for Residential Electricity Customers* (April 2, 2015), p. 2.

businesses) and coordinate that Rate Design with changes in the larger general service categories, following the same policy reasons." [8] In the interest of rate stability, it seems prudent to not allow the fixed percentage to fall any lower than it currently is for all rate classes – regardless of the maximum boundaries.

8 Ibid.

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APPENDIX B

Input and Output Sheets

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Ontario Energy Board

2016 Cost Allocation Model

EB-2015-XXXX

Sheet I6.1 Revenue Worksheet -

Total kWhs from Load Forecast	460,932,117
Total kWs from Load Forecast	617,607
Deficiency/sufficiency (RRWF 8. cell F51)	- 2,334,693
Miscellaneous Revenue (RRWF 5. cell F48)	2,424,445

			1	2	3	7	8	9	10
	ID	**Total**	**Residential**	**GS <50**	**GS>50-Regular**	**Street Light**	**Sentinel**	**Unmetered Scattered Load**	**Embedded Distributor**
Billing Data									
Forecast kWh	**CEN**	460,932,117	198,077,803	67,907,332	184,944,203	2,781,556	629,014	1,462,761	5,129,448
Forecast kW	**CDEM**	617,607			593,383	8,591	1,916		13,717
Forecast kW, included in CDEM, of customers receiving line transformer allowance		332,788			332,788				
Optional - Forecast kWh, included in CEN, from customers that receive a line transformation allowance on a kWh basis. In most cases this will not be applicable and will be left blank.		-							
KWh excluding KWh from Wholesale Market Participants	**CEN EWMP**	460,932,117	198,077,803	67,907,332	184,944,203	2,781,556	629,014	1,462,761	5,129,448

Existing Monthly Charge			$23.44	$28.26	$151.83	$4.96	$5.09	$32.96	$151.83
Existing Distribution kWh Rate			$0.0152	$0.0230				$0.0179	
Existing Distribution kW Rate					$6.6887	$10.7965	$5.9010		$6.6887
Existing TOA Rate					$0.60				$0.60
Additional Charges									
Distribution Revenue from Rates		$17,735,287	$10,344,877	$2,405,938	$4,364,326	$432,790	$53,757	$40,027	$93,571
Transformer Ownership Allowance		$199,673	$0	$0	$199,673	$0	$0	$0	$0
Net Class Revenue	**CREV**	$17,535,614	$10,344,877	$2,405,938	$4,164,653	$432,790	$53,757	$40,027	$93,571

Ontario Energy Board

2016 Cost Allocation Model

EB-2015-XXXX

Sheet I6.2 Customer Data Worksheet -

	ID	Total	Residential	GS <50	GS>50-Regular	Street Light	Sentinel	Unmetered Scattered Load	Embedded Distributor
			1	2	3	7	8	9	10
Billing Data									
Bad Debt 3 Year Historical Average	**BDHA**	$204,865	$175,741	$14,016	$15,108	$0	$0	$0	$0
Late Payment 3 Year Historical Average	**LPHA**	$349,237	$176,093	$52,960	$116,113	$2,690	$568	$813	
Number of Bills	**CNB**	346,800	312,888	29,868	2,604	552	456	420	12
Number of Devices	**CDEV**					5,713	695	175	
Number of Connections (Unmetered)	**CCON**	4,230				3,742	313	175	
Total Number of Customers	**CCA**	28,900	26,074	2,489	217	46	38	35	1
Bulk Customer Base	**CCB**	28,900	26,074	2,489	217	46	38	35	1
Primary Customer Base	**CCP**	29,304	26,074	2,489	217	450	38	35	1
Line Transformer Customer Base	**CCLT**	29,262	26,074	2,489	176	450	38	35	-
Secondary Customer Base	**CCS**	28,419	25,625	2,489	186	46	38	35	-
Weighted - Services	**CWCS**	31,801	25,625	3,485	818	1,497	219	158	-
Weighted Meter -Capital	**CWMC**	5,082,700	3,004,078	990,414	1,067,308	-	-	-	20,900
Weighted Meter Reading	**CWMR**	28,777	26,074	2,489	213	-	-	-	1
Weighted Bills	**CWNB**	357,765	312,888	29,868	13,020	994	410	525	60

Bad Debt Data

		Total	Residential	GS <50	GS>50-Regular	Street Light	Sentinel	Unmetered Scattered Load	Embedded Distributor
Historic Year:	2012	208,128	178,541	14,239	15,348				
Historic Year:	2013	188,228	161,469	12,878	13,881				
Historic Year:	2014	218,239	187,214	14,931	16,094				
Three-year average		**204,865**	**175,741**	**14,016**	**15,108**	**-**	**-**	**-**	**-**

Ontario Energy Board

2016 Cost Allocation Model

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Sheet I8 Demand Data Worksheet -

This is an input sheet for demand allocators.

CP TEST RESULTS	12 CP
NCP TEST RESULTS	4 NCP

Co-incident Peak	Indicator
1 CP	CP 1
4 CP	CP 4
12 CP	CP 12

Non-co-incident Peak	Indicator
1 NCP	NCP 1
4 NCP	NCP 4
12 NCP	NCP 12

Customer Classes		Total	1 Residential	2 GS <50	3 GS>50-Regular	7 Street Light	8 Sentinel	9 Unmetered Scattered Load	10 Embedded Distributor
CO-INCIDENT PEAK									
1 CP									
Transformation CP	TCP1	78,002	35,109	10,128	31,523	-	70	61	1,111
Bulk Delivery CP	BCP1	78,002	35,109	10,128	31,523	-	70	61	1,111
Total Sytem CP	DCP1	78,002	35,109	10,128	31,523	-	70	61	1,111
4 CP									
Transformation CP	TCP4	307,705	151,901	37,489	113,508	531	274	402	3,600
Bulk Delivery CP	BCP4	307,705	151,901	37,489	113,508	531	274	402	3,600
Total Sytem CP	DCP4	307,705	151,901	37,489	113,508	531	274	402	3,600
12 CP									
Transformation CP	TCP12	849,752	400,549	109,238	325,770	2,832	859	1,687	8,816
Bulk Delivery CP	BCP12	849,752	400,549	109,238	325,770	2,832	859	1,687	8,816
Total Sytem CP	DCP12	849,752	400,549	109,238	325,770	2,832	859	1,687	8,816
NON CO_INCIDENT PEAK									
1 NCP									
Classification NCP from Load Data Provider	DNCP1	90,253	42,748	12,365	32,537	711	81	310	1,501
Primary NCP	PNCP1	90,101	42,748	12,365	32,385	711	81	310	1,501
Line Transformer NCP	LTNCP1	83,775	42,748	12,365	27,560	711	81	310	
Secondary NCP	SNCP1	83,775	42,748	12,365	27,560	711	81	310	
4 NCP									
Classification NCP from Load Data Provider	DNCP4	346,968	164,394	45,841	126,836	2,835	320	1,234	5,508
Primary NCP	PNCP4	346,379	164,394	45,841	126,247	2,835	320	1,234	5,508
Line Transformer NCP	LTNCP4	322,105	164,394	45,841	107,482	2,835	320	1,234	
Secondary NCP	SNCP4	322,105	164,394	45,841	107,482	2,835	320	1,234	
12 NCP									
Classification NCP from Load Data Provider	DNCP12	957,276	436,700	127,390	366,925	8,500	913	3,609	13,240
Primary NCP	PNCP12	955,517	436,700	127,390	365,166	8,500	913	3,609	13,240
Line Transformer NCP	LTNCP12	886,734	436,700	127,390	309,622	8,500	913	3,609	
Secondary NCP	SNCP12	886,734	436,700	127,390	309,622	8,500	913	3,609	

Ontario Energy Board

2016 Cost Allocation Model

EB-2015-XXXX

Sheet O1 Revenue to Cost Summary Worksheet -

Instructions:
Please see the first tab in this workbook for detailed instructions

Class Revenue, Cost Analysis, and Return on Rate Base

			1	2	3	7	8	9	10
Rate Base Assets		**Total**	**Residential**	**GS <50**	**GS>50-Regular**	**Street Light**	**Sentinel**	**Unmetered Scattered Load**	**Embedded Distributor**
crev	Distribution Revenue at Existing Rates	$17,535,614	$10,344,877	$2,405,938	$4,164,653	$432,790	$53,757	$40,027	$93,571
mi	Miscellaneous Revenue (mi)	$2,424,445	$1,594,010	$292,795	$479,860	$33,537	$6,427	$6,753	$11,062
		Miscellaneous Revenue Input equals Output							
	Total Revenue at Existing Rates	$19,960,059	$11,938,887	$2,698,733	$4,644,514	$466,327	$60,184	$46,780	$104,633
	Factor required to recover deficiency (1 + D)	1.1331							
	Distribution Revenue at Status Quo Rates	$19,870,307	$11,722,195	$2,726,265	$4,719,136	$490,412	$60,914	$45,356	$106,029
	Miscellaneous Revenue (mi)	$2,424,445	$1,594,010	$292,795	$479,860	$33,537	$6,427	$6,753	$11,062
	Total Revenue at Status Quo Rates	$22,294,752	$13,316,205	$3,019,060	$5,198,996	$523,949	$67,341	$52,109	$117,091
	Expenses								
di	Distribution Costs (di)	$3,193,783	$1,893,037	$386,147	$799,532	$64,686	$12,143	$13,028	$25,210
cu	Customer Related Costs (cu)	$2,873,189	$2,252,256	$337,886	$270,334	$4,473	$1,848	$2,363	$4,028
ad	General and Administration (ad)	$4,477,753	$3,042,107	$535,507	$803,751	$52,179	$10,529	$11,601	$22,079
dep	Depreciation and Amortization (dep)	$4,766,331	$2,811,901	$623,839	$1,185,392	$78,827	$15,679	$17,330	$33,363
INPUT	PILs (INPUT)	$526,758	$307,272	$66,434	$135,885	$9,265	$1,802	$2,044	$4,057
INT	Interest	$3,151,314	$1,838,247	$397,438	$812,928	$55,425	$10,778	$12,230	$24,268
	Total Expenses	$18,989,128	$12,144,820	$2,347,251	$4,007,822	$264,855	$52,778	$58,597	$113,005
	Direct Allocation	$0	$0	$0	$0	$0	$0	$0	$0
NI	Allocated Net Income (NI)	$3,305,624	$1,928,260	$416,899	$852,734	$58,139	$11,306	$12,829	$25,457
	Revenue Requirement (includes NI)	$22,294,752	$14,073,081	$2,764,150	$4,860,556	$322,994	$64,083	$71,426	$138,462
		Revenue Requirement Input equals Output							
			63.1%	12.4%	21.8%	1.4%	0.3%	0.3%	0.6%
	Rate Base Calculation								
	Net Assets								
dp	Distribution Plant - Gross	$131,626,626	$77,617,591	$16,568,568	$33,121,310	$2,372,415	$466,211	$514,302	$966,229
gp	General Plant - Gross	$31,035,395	$18,213,576	$3,887,357	$7,901,890	$565,409	$109,344	$122,116	$235,704
accum dep	Accumulated Depreciation	($62,743,578)	($37,117,045)	($7,956,907)	($15,656,989)	($1,103,024)	($221,473)	($242,244)	($445,896)
co	Capital Contribution	($15,452,989)	($9,409,662)	($1,854,556)	($3,608,853)	($343,265)	($64,224)	($65,855)	($106,574)
	Total Net Plant	$84,465,454	$49,304,461	$10,644,461	$21,757,358	$1,491,535	$289,858	$328,318	$649,463
	Directly Allocated Net Fixed Assets	$0	$0	$0	$0	$0	$0	$0	$0
COP	Cost of Power (COP)	$62,242,349	$26,844,540	$9,150,749	$24,866,995	$405,124	$87,173	$198,123	$689,646
	OM&A Expenses	$10,544,725	$7,187,400	$1,259,541	$1,873,618	$121,338	$24,519	$26,992	$51,317
	Directly Allocated Expenses	$0	$0	$0	$0	$0	$0	$0	$0
	Subtotal	*$72,787,074*	*$34,031,939*	*$10,410,289*	*$26,740,612*	*$526,463*	*$111,693*	*$225,115*	*$740,963*
	Working Capital	$5,459,031	$2,552,395	$780,772	$2,005,546	$39,485	$8,377	$16,884	$55,572
	Total Rate Base	$89,924,485	$51,856,856	$11,425,233	$23,762,904	$1,531,019	$298,235	$345,202	$705,036
		Rate Base Input equals Output							
	Equity Component of Rate Base	$35,969,794	$20,742,742	$4,570,093	$9,505,161	$612,408	$119,294	$138,081	$282,014
	Net Income on Allocated Assets	$3,305,624	$1,171,384	$671,809	$1,191,174	$259,094	$14,564	($6,488)	$4,086
	Net Income on Direct Allocation Assets	$0	$0	$0	$0	$0	$0	$0	$0
	Net Income	$3,305,624	$1,171,384	$671,809	$1,191,174	$259,094	$14,564	($6,488)	$4,086
	RATIOS ANALYSIS								
	REVENUE TO EXPENSES STATUS QUO%	100.00%	94.62%	109.22%	106.96%	162.22%	105.08%	72.95%	84.57%
	EXISTING REVENUE MINUS ALLOCATED COSTS	($2,334,693)	($2,134,194)	($65,416)	($216,042)	$143,333	($3,899)	($24,647)	($33,828)

Ontario Energy Board

2016 Cost Allocation Model

EB-2015-XXXX

Sheet O1 Revenue to Cost Summary Worksheet -

Instructions:
Please see the first tab in this workbook for detailed instructions

Class Revenue, Cost Analysis, and Return on Rate Base

		1	2	3	7	8	9	10
Rate Base Assets	**Total**	**Residential**	**GS <50**	**GS>50-Regular**	**Street Light**	**Sentinel**	**Unmetered Scattered Load**	**Embedded Distributor**
	Deficiency Input equals Output							
STATUS QUO REVENUE MINUS ALLOCATED COSTS	**($0)**	($756,876)	$254,910	$338,440	$200,955	$3,258	($19,318)	($21,370)
RETURN ON EQUITY COMPONENT OF RATE BASE	9.19%	5.65%	14.70%	12.53%	42.31%	12.21%	-4.70%	1.45%

Ontario Energy Board

2016 Cost Allocation Model

EB-2015-XXXX

Sheet O2 Monthly Fixed Charge Min. & Max. Worksheet -

Output sheet showing minimum and maximum level for Monthly Fixed Charge

	1	2	3	7	8	9	10
Summary	**Residential**	**GS <50**	**GS>50-Regular**	**Street Light**	**Sentinel**	**Unmetered Scattered Load**	**Embedded Distributor**
Customer Unit Cost per month - Avoided Cost	$5.30	$11.96	$103.12	-$0.02	$0.09	$0.17	$584.79
Customer Unit Cost per month - Directly Related	$8.78	$19.14	$177.31	$0.02	$0.29	$0.64	$870.69
Customer Unit Cost per month - Minimum System with PLCC Adjustment	$27.42	$39.53	$233.75	$5.55	$16.66	$15.15	$613.58
Existing Approved Fixed Charge	$23.44	$28.26	$151.83	$4.96	$5.09	$32.96	$151.83

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APPENDIX C

HONI Correspondence

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From: henry.andre@HydroOne.com [mailto:henry.andre@HydroOne.com]
Sent: September-16-15 9:07 AM
To: Bradbury, Doug
Subject: RE: Canadian Niagara Power 2017 Distribution Rate Application

Doug,

My understanding is that Hydro One is embedded in CNPI though the use of the 27.6kV circuit M11 out of Port Colborne TS. As such, Hydro One is making only a limited use of CNPI's "high voltage" distribution facilities and no use of the primary or secondary distribution systems or any transformation facilities. I have not seen CNPI's cost allocation model, but I expect that the GS>50 class which you have been historically billing us under includes recovery of costs associated with your primary distribution facilities and transformation facilities.

It is not appropriate that Hydro One's distribution customers pay for any share of asset and maintenance costs associated CNPI's primary distribution system or transformation facilities and so I cannot support the continued use of CNPI's GS>50 rate for charging Hydro One. I would ask that a separate embedded distributor rate be developed that appropriately reflects the cost of serving Hydro One.

Henry Andre
Manager, Regulatory Affairs - Pricing, TCT07
Hydro One Networks Inc.
Tel: (416) 345-5124
Cell: (647) 409-3198
Email: henry.andre@hydroone.com

From: Bradbury, Doug [mailto:Doug.Bradbury@FortisOntario.com]
Sent: Wednesday, September 09, 2015 12:07 PM
To: HENDERSON Erin
Subject: Canadian Niagara Power 2017 Distribution Rate Application

Erin,

CNPI is preparing for its 2017 Distribution Rate Application, Section 2.7.1 of the Filing Requirements requires us to consult with our embedded distributors. Hydro One has an embedded distribution connection located in Port Colborne which services HONI's customers in the Wainfleet area; Account # 1095059. CNPI has historically billed HONI using our General Service 40 to 4,999 kW rate. CNPI would prefer to maintain this arrangement since this is the sole embedded point in our distribution system. The load on your system is typically at 1500 kW with energy consumption ranging from 325,000 kWh to 520,000 kWh; not atypical of the GS > 50 rate class.

Before I proceed further with our Cost Allocation evidence, I would like to know if HONI supports this arrangement on a go forward basis? I can be reached by email or at (905) 994 3634.

Thanks,

Douglas Bradbury P. Eng.
Director Regulatory Affairs
FortisOntario

This e-mail (including any attachments) may contain confidential, proprietary and privileged information, and unauthorized disclosure or use is prohibited. If you received this e-mail in error, please notify the sender and delete this e-mail from your system

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Appendix 2-P
Cost Allocation

A) Allocated Costs

Classes	Costs Allocated from Previous Study	%	Costs Allocated in Test Year Study (Column 7A)	%
Residential	$ 11,876,815	62.62%	$ 14,073,081	63.12%
GS < 50 kW	$ 2,376,032	12.53%	$ 2,764,150	12.40%
GS > 50 kW (or 50 kW < GS < xxx kW, if applicable)	$ 4,090,319	21.57%	$ 4,860,556	21.80%
GS > xxx kW, if applicable		0.00%		0.00%
Large User, if applicable		0.00%		0.00%
Street Lighting	$ 503,635	2.66%	$ 322,994	1.45%
Sentinel Lighting	$ 82,426	0.43%	$ 64,083	0.29%
Unmetered Scattered Load (USL)	$ 36,954	0.19%	$ 71,426	0.32%
Other class, if applicable		0.00%		0.00%
		0.00%		0.00%
Embedded distributor class		0.00%	$ 138,462	0.62%
Total	$ 18,966,181	100.00%	$ 22,294,752	100.00%

B) Calculated Class Revenues

Classes (same as previous table)	Column 7B	Column 7C	Column 7D	Column 7E
	Load Forecast (LF) X current approved rates	L.F. X current approved rates X (1 + d)	LF X proposed rates	Miscellaneous Revenue
Residential	$ 10,344,877	$ 11,722,195	$ 11,827,584	$ 1,594,010
GS < 50 kW	$ 2,405,938	$ 2,726,265	$ 2,726,265	$ 292,795
GS > 50 kW (or 50 kW < GS < xxx kW, if applicable)	$ 4,164,653	$ 4,719,136	$ 4,719,136	$ 479,860
GS > xxx kW, if applicable				
Large User, if applicable				
Street Lighting	$ 432,790	$ 490,412	$ 354,056	$ 33,537
Sentinel Lighting	$ 53,757	$ 60,914	$ 60,914	$ 6,427
Unmetered Scattered Load (USL)	$ 40,027	$ 45,356	$ 61,365	$ 6,753
Other class, if applicable				
Embedded distributor class	$ 93,571	$ 106,029	$ 120,987	$ 11,062
Total	$ 17,535,614	$ 19,870,307	$ 19,870,307	$ 2,424,445

In order to achieve revenue to cost ratios that fall within the Board's Policy Range, CNPI proposes to make the following adjustments:

1. Decrease the revenue to be collected from the Street Lighting class by $136,356.45 to achieve a revenue to cost ratio of 120% for that class.
2. Increase the revenue to be collected from both the USL and Embedded Distributor classes to achieve revenue to cost ratios of 94.62% (i.e. match the next lowest revenue to class ratio of the Residential class)
3. Increase the revenue to be collected from all three of the USL, Embedded Distributor and Residential classes, in proportion to their respective allocated costs, until the total adjusted revenue from all classes matches the 2017 proposed Base Revenue Requirement of $19,870,307.

The revenue-to-cost ratios resulting from the above adjustments are shown in table C) of Appendix 2-P below.

C) Rebalancing Revenue-to-Cost (R/C) Ratios

Class	Previously Approved Ratios	Status Quo Ratios	Proposed Ratios	Policy Range
	Most Recent Year: 2016	(7C + 7E) / (7A)	(7D + 7E) / (7A)	
	%	%	%	%
Residential	91.42	94.62	95.37	85 - 115
GS < 50 kW	109.34	109.22	109.22	80 - 120
GS > 50 kW (or 50 kW < GS < xxx kW, if applicable)	119.94	106.96	106.96	80 - 120
GS > xxx kW, if applicable				80 - 120
Large User, if applicable				85 - 115
Street Lighting	96.28	162.22	120.00	80 - 120
Sentinel Lighting	91.42	105.08	105.08	80 - 120
Unmetered Scattered Load (USL)	120.00	72.95	95.37	80 - 120
Other class, if applicable				
Embedded distributor class		84.57	95.37	

Note: Table D) of Appendix 2-P was not completed as the revenue to cost ratios proposed in this Application are within the Board's policy range. Consequently, no revenue to cost ratio adjustments are contemplated in upcoming IRM years.

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RATE DESIGN OVERVIEW

CNPI filed its most recent cost of service application on the basis of a 2013 Test Year; EB-2012-0112. In that application, CNPI filed separate rate design scenarios for its Fort Erie / Gananoque and its Port Colborne service areas.

The Proposed Settlement Agreement accepted by the Board in EB-2012-0112, described how, during the 2014-2016 IRM period, CNPI would adjust the fixed to variable ratios of distribution rates in Fort Erie/EOP and Port Colborne to achieve harmonized rates on or before 2016.

Effective January 1, 2016, CNPI achieved full harmonization of its Monthly Service Charges and Distribution Volumetric Rates as a result of the Board's decision in relation to CNPI's 2016 IRM Application; EB-2015-0058. CNPI has therefore continued on the basis of a single harmonized rate design for the 2017 Test Year in this Application. The proposed harmonization of existing rate riders across all service territories is presented at Exhibit 9, Tab 5, Schedule 1 of the current Application.

A live MS-Excel model of the Rate Design process presented in this Schedule has been filed in conjunction with the Application.

REVENUE REQUIREMENT ALLOCATION BY CLASS

CNPI has determined its total 2017 Test Year Service Revenue Requirement to be $22,294,752. The total Revenue Offsets in the amount of $2,424,445 reduces CNPI's total Service Revenue Requirement to a Base Revenue Requirement of $19,870,307 which is used to determine the proposed distribution rates. The Base Revenue Requirement is derived from CNPI's 2016 Test Year capital and operating forecasts, weather normalized usage, forecasted customer counts, and regulated return on rate base. The revenue requirement is summarized in the following table.

Description	Amount
OM&A Expenses	$ 10,544,725
Amortization Expenses	$ 4,766,331
Regulated Return on Capital	$ 6,456,938
Taxes	$ 526,758
Service Revenue Requirement	*$ 22,294,752*
Less: Revenue Offsets	-$ 2,424,445
Base Revenue Requirement	**$ 19,870,307**

The Base Revenue Requirement is allocated to the various rate classes as presented in Exhibit 7, Cost Allocation. The following table outlines the proposed allocation of the Base Revenue Requirement to each rate class:

Rate Class	2017 Test Year Proposed Base Revenue Requirement
Residential	$ 12,479,071
GS Less Than 50 kW	$ 2,471,355
GS 50 to 4,999 kW	$ 4,380,696
Embedded Distributor	$ 127,400
USL	$ 64,673
Sentinel Lighting	$ 57,656
Street Lighting	$ 289,457
Base Revenue Requirement	**$ 19,870,307**

REVENUE FORECAST AND FIXED / VARIABLE SPLIT - EXISTING RATES

The existing distribution rates, effective January 1, 2016 (EB-2015-0058), and forecasted loads and volumes from the Customer and Load Forecast presented in Exhibit 3, Tab 1 are shown in the following Table.

Existing Distribution Rates and Forecasted Loads & Volumes						
	Fixed Charge	Volumetric Charge	UOM	Average Customer (Connection) Count	Forecast kWh	Forecast kW
Residential	$ 23.44	$ 0.0152	kWh	26,074	198,077,803	
GS Less Than 50 kW	$ 28.26	$ 0.0230	kWh	2,489	67,907,332	
GS 50 to 4,999 kW	$ 151.83	$ 6.6887	kW	217	184,944,203	593,383
Embedded Distributor	$ 151.83	$ 6.6887	kW	1	5,129,448	13,717
USL	$ 32.96	$ 0.0179	kWh	35	1,462,761	
Sentinel Lighting	$ 5.09	$ 5.9010	kW	695	629,014	1,916
Street Lighting	$ 4.96	$ 10.7965	kW	5,713	2,781,556	8,591
Transformer Allowance		$ 0.60	kW			332,788

On the basis of the existing distribution rates and forecasted loads and volumes, CNPI has determined the expected distribution revenue, as well as the split between fixed and variable revenue, for the 2017 Test Year at current distribution rates. This is presented in the following Tables.

Revenue from Existing Rates at Forecasted Loads and Volumes						
Customer Class	Fixed Component	Variable Component	Distribution Revenue from Rates	Transformer Allowance	Net Class Revenue	Revenue Share per Class
Residential	7,334,095	3,010,783	10,344,877		10,344,877	59.0%
GS Less Than 50 kW	844,070	1,561,869	2,405,938		2,405,938	13.7%
GS 50 to 4,999 kW	395,365	3,968,961	4,364,326	199,673	4,164,653	23.7%
Embedded Distributor	1,822	91,749	93,571		93,571	0.5%
USL	13,843	26,183	40,027		40,027	0.2%
Sentinel Lighting	42,451	11,306	53,757		53,757	0.3%
Street Lighting	340,038	92,753	432,790		432,790	2.5%
Total	$8,971,683	$ 8,763,603	$17,735,287	$ 199,673	$17,535,614	100.0%

Fixed and Variable Proportions at Existing Rates					
Customer Class	Fixed Component	Variable Component[1]	Net Class Revenue	Fixed Component	Variable Component
	$	$	$	%	%
Residential	7,334,095	3,010,783	10,344,877	70.9%	29.1%
GS Less Than 50 kW	844,070	1,561,869	2,405,938	35.1%	64.9%
GS 50 to 4,999 kW	395,365	3,769,288	4,164,653	9.5%	90.5%
Embedded Distributor	1,822	91,749	93,571	1.9%	98.1%
USL	13,843	26,183	40,027	34.6%	65.4%
Sentinel Lighting	42,451	11,306	53,757	79.0%	21.0%
Street Lighting	340,038	92,753	432,790	78.6%	21.4%
Total	$8,971,683	$ 8,563,931	$17,535,614	51.2%	48.8%

Notes:

1. Exclusive of transformer ownership credit

REVENUE TO COST RATIO ADJUSTMENTS

From Output Sheet O1 of the Cost Allocation Model, the allocation of revenue requirement including net income by rate classification is compared to the net class revenue adjusted by the Deficiency Factor, 1.13314, as determined in the Cost Allocation Model. The ratio of the adjusted net class revenue to the allocation of revenue requirement including net income by classification is the class revenue to cost ratio. The class specific revenue to cost ratios arising from the 2017 Cost Allocation Study is presented in the following Table:

Derivation of the Test Year Revenue to Cost Ratios as Determined in the Cost Allocation Study

Customer Class	Allocation of Revenue Requirment including Net Income	Deficiency Factor	Distribution Revenue at Status Quo Rates	Misc. Revenue	Revenue to Cost Ratio	Board's Policy Range
Residential	14,073,081	1.13314	11,722,195	1,594,010	94.62%	85% - 115%
GS Less Than 50 kW	2,764,150	1.13314	2,726,265	292,795	109.22%	80% - 120%
GS 50 to 4,999 kW	4,860,556	1.13314	4,719,136	479,860	106.96%	80% - 120%
Embedded Distributor	138,462	1.13314	106,029	11,062	84.57%	80% - 120%
USL	71,426	1.13314	45,356	6,753	72.95%	80% - 120%
Sentinel Lighting	64,083	1.13314	60,914	6,427	105.08%	80% - 120%
Street Lighting	322,994	1.13314	490,412	33,537	162.22%	80% - 120%
Total	$ 22,294,752		$ 19,870,307	$ 2,424,445		

As highlighted in yellow in the preceding Table, there are two customer classifications which have revenue to cost ratios that are outside the Board's Policy Range. The Unmetered Scattered Load classification has a calculated revenue to cost ratio of 72.95% and the Street Lighting classification has a calculated revenue to cost ratio of 162.22%. All other customer classifications are within the Board's 2011 Policy Range.

In order to achieve revenue to cost ratios that fall within the Board's Policy Range, CNPI proposes to make the following adjustments:

1. Decrease the revenue to be collected from the Street Lighting class by $136,356.45 to achieve a revenue to cost ratio of 120% for that class.
2. Increase the revenue to be collected from both the USL and Embedded Distributor classes to achieve revenue to cost ratios of 94.62% (i.e. match the next lowest revenue to class ratio of the Residential class)
3. Increase the revenue to be collected from all three of the USL, Embedded Distributor and Residential classes, in proportion to their respective allocated costs, until the total adjusted revenue from all classes matches the 2017 proposed Base Revenue Requirement of $19,870,307.

The adjusted distribution revenue to be collected from each class, and the resulting revenue to cost ratios are outlined in the following table.

Revenue to Cost Ratio Adjustment					
Customer Class	Allocation of Revenue Requirment including Net Income	Misc. Revenue	Distribution Revenue at Status Quo Rates	Adjusted Revenue to Cost Ratio	Adjusted Distribution Revenue
Residential	14,073,081	1,594,010	11,722,195	95.37%	11,827,584
GS Less Than 50 kW	2,764,150	292,795	2,726,265	109.22%	2,726,265
GS 50 to 4,999 kW	4,860,556	479,860	4,719,136	106.96%	4,719,136
Embedded Distributor	138,462	11,062	106,029	95.37%	120,987
USL	71,426	6,753	45,356	95.37%	61,365
Sentinel Lighting	64,083	6,427	60,914	105.08%	60,914
Street Lighting	322,994	33,537	490,412	120.00%	354,056
Total	$ 22,294,752	$ 2,424,445	$ 19,870,307		$ 19,870,307

DETERMINATION OF 2017 DISTRIBUTION RATES

The next step in the proposed rate design is to divide the adjusted revenue requirement from rates into its fixed and variable components and add back the transformer ownership allowance forecasted amount. The percentage of revenue to be collected through fixed and variable rates are as calculated in the Table titled “Fixed and Variable Proportions at Existing Rates” shown on page 4 of this Schedule.

The calculation of fixed and variable revenues and resulting rates, including the transformer allowance add back is shown in the following Tables.

Determination of 2017 Base Distribution Rates					
Customer Class	Revenue Requirement from Rates	Fixed Component at Existing F/V Split	Variable Component at Existing F/V Split	Fixed Component	Variable Component
Residential	11,827,584	8,385,273	3,442,311	$ 26.80	$ 0.0174
GS Less Than 50 kW	2,726,265	956,449	1,769,816	$ 32.02	$ 0.0261
GS 50 to 4,999 kW	4,719,136	448,004	4,271,131	$ 172.04	$ 7.1979
Embedded Distributor	120,987	2,356	118,631	$ 196.32	$ 8.6485
USL	61,365	21,223	40,142	$ 50.53	$ 0.0274
Sentinel Lighting	60,914	48,102	12,812	$ 5.77	$ 6.6867
Street Lighting	354,056	278,177	75,879	$ 4.06	$ 8.8324
Total	$ 19,870,307	$ 10,139,585	$ 9,730,722		

Transformer Allowance Addback $ 199,673 (Allocated to GS > 50 to 4,999 kW)

2017 Distribution Rates with Transformer Allowance Addback					
Customer Class	Revenue Requirement from Rates with Addback	Fixed Component at Existing F/V Split	Variable Component at Existing F/V Split	Fixed Component	Variable Component
Residential	11,827,584	8,385,273	3,442,311	$ 26.80	$ 0.0174
GS Less Than 50 kW	2,726,265	956,449	1,769,816	$ 32.02	$ 0.0261
GS 50 to 4,999 kW	4,918,809	448,004	4,470,804	$ 172.04	$ 7.5344
Embedded Distributor	120,987	2,356	118,631	$ 196.32	$ 8.6485
USL	61,365	21,223	40,142	$ 50.53	$ 0.0274
Sentinel Lighting	60,914	48,102	12,812	$ 5.77	$ 6.6867
Street Lighting	354,056	278,177	75,879	$ 4.06	$ 8.8324
Total	$ 20,069,980	$ 10,139,585	$ 9,930,395		

At this point it is necessary to review the Monthly Service Charge (Fixed Component) for each customer classification to determine whether or not it meets the criteria established by the Board. To meet the Board's criteria, the Monthly Service Charge should be greater than the "Customer Unit Cost per Month – Avoided Costs" and less than the "Customer Unit Cost per Month – Minimum System with PLCC Adjustment" as determined by the Cost Allocation Study; Output Sheet O2.

The following Table presents the results of a test to determine adherence to the Board's criteria.

Test of 2017 Calculated Monthly Service Charge				
Customer Class	Customer Unit Cost per Month Avoided Cost	Customer Unit Cost per Month Min. System with PLCC Adj.	Rate Design at Existing F/V Split	Is Rate Design Within Bounds?
	Floor	Ceiling		
Residential	$ 5.30	$ 27.42	$ 26.80	TRUE
GS Less Than 50 kW	$ 11.96	$ 39.53	$ 32.02	TRUE
GS 50 to 4,999 kW	$ 103.12	$ 233.75	$ 172.04	TRUE
Embedded Distributor	$ 584.79	$ 613.58	$ 196.32	FALSE
USL	$ 0.17	$ 15.15	$ 50.53	FALSE
Sentinel Lighting	$ 0.09	$ 16.66	$ 5.77	TRUE
Street Lighting	$ (0.02)	$ 5.55	$ 4.06	TRUE

As evidenced in the preceding table, the Monthly Service Charge for the Embedded Distributor and the Unmetered Scattered Load ("USL") classes are not within the bounds of the Board's criteria. In this rate design, CNPI will adjust the Monthly Service Charge for the Embedded Distributor class, to $584.79, representing the lower bound of the Board's criteria. CNPI bills the Unmetered Scattered Load classification on a per customer basis and as such proposes to maintain the Monthly Service Charge as calculated here. This proposal is consistent with both CNPI past practice regarding rate design for the USL class, and the direction provided in Section 2.8.1 of the Filing Requirements.

The adjustment to the Monthly Service Charge or fixed component is accomplished by changing the fixed/variable split; this is presented in the following Table.

Adjustment to the Fixed and Variable Allocations

Customer Class	Revenue Requirement from Rates with Addback	Fixed Component at Existing F/V Split	Fixed Component at Adjusted F/V Split	Adjusted Fixed Component Percentage	Variable Component at Existing F/V Split	Variable Component at Adjusted F/V Split	Adjusted Variable Component Percentage	Adjusted Fixed Component	Adjusted Variable Component
Residential	11,827,584	8,385,273	8,385,273	70.90%	3,442,311	3,442,311	29.10%	$ 26.80	$ 0.0174
GS Less Than 50 kW	2,726,265	956,449	956,449	35.08%	1,769,816	1,769,816	64.92%	$ 32.02	$ 0.0261
GS 50 to 4,999 kW	4,918,809	448,004	448,004	9.11%	4,470,804	4,470,804	90.89%	$ 172.04	$ 7.5344
Embedded Distributor	120,987	2,356	7,017	5.80%	118,631	113,970	94.20%	$ 584.79	$ 8.3087
USL	61,365	21,223	21,223	34.58%	40,142	40,142	65.42%	$ 50.53	$ 0.0274
Sentinel Lighting	60,914	48,102	48,102	78.97%	12,812	12,812	21.03%	$ 5.77	$ 6.6867
Street Lighting	354,056	278,177	278,177	78.57%	75,879	75,879	21.43%	$ 4.06	$ 8.8324
Total	$20,069,980	$10,139,585	$ 10,144,246		$9,930,395	$ 9,925,733			

NEW RATE DESIGN POLICY FOR RESIDENTIAL CUSTOMERS

On April 2, 2015, the OEB released its Board Policy: A New Distribution Rate Design for Residential Electricity Customers (EB-2014-0210), which stated that electricity distributors will transition to a fully fixed monthly distribution service charge for residential customers. This will be implemented over a period of four years, beginning in 2016. CNPI made the first of four annual adjustments as part of its 2016 IRM application (EB-2015-0058). In order to calculate the required adjustment to the fixed and variable components for the current Application, CNPI completed Appendix 2-PA – New Rate Design Policy for Residential Customers. A copy of the inputs and calculations from Appendix 2-PA is provided on the following page and the live MS-Excel version has been filed in conjunction with the Application.

The resulting increase to the monthly fixed charge is $3.67, which is below the $4.00 maximum and therefore does not require mitigation.

A) Data Inputs

Test Year Billing Determinants for Residential Class	
Customers	26,074
kWh	198,077,803

Proposed Residential Class Specific Revenue Requirement[1]	$ 11,827,583.73

Residential Base Rates on Current Tariff	
Monthly Fixed Charge ($)	23.44
Distribution Volumetric Rate ($/kWh)	0.0152

B) Current Fixed/Variable Split

	Base Rates	Billing Determinants	Revenue	% of Total Revenue
Fixed	23.44	26,074	$ 7,334,094.72	70.90%
Variable	0.0152	198,077,803	$ 3,010,782.61	29.10%
TOTAL	-	-	$ 10,344,877.33	-

C) Calculating Test Year Base Rates

Number of Required Rate Design Policy Transition Years[2]	3

	Test Year Revenue @ Current F/V Split	Test Year Base Rates @ Current F/V Split	Reconciliation - Test Year Base Rates @ Current F/V Split
Fixed	$ 8,385,272.89	26.8	$ 8,385,398.40
Variable	$ 3,442,310.84	0.0174	$ 3,446,553.77
TOTAL	$ 11,827,583.73	-	$ 11,831,952.17

	New F/V Split	Revenue @ new F/V Split	Final Adjusted Base Rates	Reconciliation @ Adjusted Rates
Fixed	80.60%	$ 9,532,709.84	30.47	$ 9,533,697.36
Variable	19.40%	$ 2,294,873.89	0.0116	$ 2,297,702.51
TOTAL	-	$ 11,827,583.73	-	$ 11,831,399.87

Checks[3]	
Change in Fixed Rate	$ 3.67
Difference Between Revenues @ Proposed Rates and Class Specific Revenue Requirement	$ 3,816.14
	0.03%

COMPARISON OF CURRENT AND PROPOSED RATES

The following table provides the percentage change of the proposed fixed and variable distribution rates as compared to the most recent rates approved by the Board (EB-2015-0058) and effective January 1, 2016.

Comparison of Current Rates to Final Rate Design

Customer Class	Existing Rates		Proposed Rates		Percent Change	
	Fixed Charge	Volumetric Charge	Fixed Charge	Volumetric Charge	Fixed Charge	Volumetric Charge
Residential	$ 23.44	$ 0.0152	$ 30.47	$ 0.0116	30.0%	-23.8%
GS Less Than 50 kW	$ 28.26	$ 0.0230	$ 32.02	$ 0.0261	13.3%	13.3%
GS 50 to 4,999 kW	$ 151.83	$ 6.6887	$ 172.04	$ 7.5344	13.3%	12.6%
Embedded Distributor	$ 151.83	$ 6.6887	$ 584.79	$ 8.3087	285.2%	24.2%
USL	$ 32.96	$ 0.0179	$ 50.53	$ 0.0274	53.3%	53.3%
Sentinel Lighting	$ 5.09	$ 5.9010	$ 5.77	$ 6.6867	13.3%	13.3%
Street Lighting	$ 4.96	$ 10.7965	$ 4.06	$ 8.8324	-18.2%	-18.2%

ADJUSTMENTS FOR RESIDENTIAL RATE MITIGATION

In accordance with Section 2.8.13 of the Filing Requirements, CNPI reviewed the total bill impact for the Residential class, at the 10th consumption percentile of 210 kWh per month. This review determined that total bill impacts at this consumption level exceeded 10% for specific subsets of the Residential class (namely RPP-TOU customers in the Gananoque service area and customers on Retail contracts in the Fort Erie and Port Colborne service areas). Total bill impacts ranged from 10.3% to 11.5% for these subsets of the Residential class.

Further details on bill impacts can be found at Exhibit 8, Tab 1, Schedule 11, while details regarding mitigation can be found at Exhibit 8, Tab 1, Schedule 12.

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Appendix A
Rate Design Model

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Existing Distribution Rates and Forecasted Loads & Volumes						
	Fixed Charge	Volumetric Charge	UOM	Average Customer (Connection) Count	Forecast kWh	Forecast kW
Residential	$ 23.44	$ 0.0152	kWh	26,074	198,077,803	
GS Less Than 50 kW	$ 28.26	$ 0.0230	kWh	2,489	67,907,332	
GS 50 to 4,999 kW	$ 151.83	$ 6.6887	kW	217	184,944,203	593,383
Embedded Distributor	$ 151.83	$ 6.6887	kW	1	5,129,448	13,717
USL	$ 32.96	$ 0.0179	kWh	35	1,462,761	
Sentinel Lighting	$ 5.09	$ 5.9010	kW	695	629,014	1,916
Street Lighting	$ 4.96	$ 10.7965	kW	5,713	2,781,556	8,591
Transformer Allowance		$ 0.60	kW			332,788

Revenue from Existing Rates at Forecasted Loads and Volumes						
Customer Class	Fixed Component	Variable Component	Distribution Revenue from Rates	Transformer Allowance	Net Class Revenue	Revenue Share per Class
Residential	7,334,095	3,010,783	10,344,877		10,344,877	59.0%
GS Less Than 50 kW	844,070	1,561,869	2,405,938		2,405,938	13.7%
GS 50 to 4,999 kW	395,365	3,968,961	4,364,326	199,673	4,164,653	23.7%
Embedded Distributor	1,822	91,749	93,571		93,571	0.5%
USL	13,843	26,183	40,027		40,027	0.2%
Sentinel Lighting	42,451	11,306	53,757		53,757	0.3%
Street Lighting	340,038	92,753	432,790		432,790	2.5%
Total	$8,971,683	$ 8,763,603	$17,735,287	$ 199,673	$17,535,614	100.0%

Fixed and Variable Proportions at Existing Rates					
Customer Class	Fixed Component	Variable Component[1]	Net Class Revenue	Fixed Component	Variable Component
	$	$	$	%	%
Residential	7,334,095	3,010,783	10,344,877	70.9%	29.1%
GS Less Than 50 kW	844,070	1,561,869	2,405,938	35.1%	64.9%
GS 50 to 4,999 kW	395,365	3,769,288	4,164,653	9.5%	90.5%
Embedded Distributor	1,822	91,749	93,571	1.9%	98.1%
USL	13,843	26,183	40,027	34.6%	65.4%
Sentinel Lighting	42,451	11,306	53,757	79.0%	21.0%
Street Lighting	340,038	92,753	432,790	78.6%	21.4%
Total	$8,971,683	$ 8,563,931	$17,535,614	51.2%	48.8%

Notes:
1. Exclusive of transformer ownership credit

Derivation of the Test Year Revenue to Cost Ratios as Determined in the Cost Allocation Study							
Customer Class	Allocation of Revenue Requirment including Net Income	Deficiency Factor	Distribution Revenue at Status Quo Rates	Misc. Revenue	Revenue to Cost Ratio		Board's Policy Range
Residential	14,073,081	1.13314	11,722,195	1,594,010	94.62%		85% - 115%
GS Less Than 50 kW	2,764,150	1.13314	2,726,265	292,795	109.22%		80% - 120%
GS 50 to 4,999 kW	4,860,556	1.13314	4,719,136	479,860	106.96%		80% - 120%
Embedded Distributor	138,462	1.13314	106,029	11,062	84.57%		80% - 120%
USL	71,426	1.13314	45,356	6,753	72.95%		80% - 120%
Sentinel Lighting	64,083	1.13314	60,914	6,427	105.08%		80% - 120%
Street Lighting	322,994	1.13314	490,412	33,537	162.22%		80% - 120%
Total	$ 22,294,752		$ 19,870,307	$ 2,424,445			

Revenue to Cost Ratio Adjustment					
Customer Class	Allocation of Revenue Requirment including Net Income	Misc. Revenue	Distribution Revenue at Status Quo Rates	Adjusted Revenue to Cost Ratio	Adjusted Distribution Revenue
Residential	14,073,081	1,594,010	11,722,195	95.37%	11,827,584
GS Less Than 50 kW	2,764,150	292,795	2,726,265	109.22%	2,726,265
GS 50 to 4,999 kW	4,860,556	479,860	4,719,136	106.96%	4,719,136
Embedded Distributor	138,462	11,062	106,029	95.37%	120,987
USL	71,426	6,753	45,356	95.37%	61,365
Sentinel Lighting	64,083	6,427	60,914	105.08%	60,914
Street Lighting	322,994	33,537	490,412	120.00%	354,056
Total	$ 22,294,752	$ 2,424,445	$19,870,307		$ 19,870,307

Balanced? YES

Revenue to Cost Ratio Adjustment:

1. Reduce Street Lighting to 120% (-$136,356.45)
2. Increase USL and Embedded Distributor Revenue to match Residential R/C of 94.62%
3. Increase Residential, Embedded Distributor and USL in proportion until revenue balances

Determination of 2017 Base Distribution Rates					
Customer Class	Revenue Requirement from Rates	Fixed Component at Existing F/V Split	Variable Component at Existing F/V Split	Fixed Component	Variable Component
Residential	11,827,584	8,385,273	3,442,311	$ 26.80	$ 0.0174
GS Less Than 50 kW	2,726,265	956,449	1,769,816	$ 32.02	$ 0.0261
GS 50 to 4,999 kW	4,719,136	448,004	4,271,131	$ 172.04	$ 7.1979
Embedded Distributor	120,987	2,356	118,631	$ 196.32	$ 8.6485
USL	61,365	21,223	40,142	$ 50.53	$ 0.0274
Sentinel Lighting	60,914	48,102	12,812	$ 5.77	$ 6.6867
Street Lighting	354,056	278,177	75,879	$ 4.06	$ 8.8324
Total	$ 19,870,307	$ 10,139,585	$ 9,730,722		

Transformer Allowance Addback $ 199,673 (Allocated to GS > 50 to 4,999 kW)

2017 Distribution Rates with Transformer Allowance Addback					
Customer Class	Revenue Requirement from Rates with Addback	Fixed Component at Existing F/V Split	Variable Component at Existing F/V Split	Fixed Component	Variable Component
Residential	11,827,584	8,385,273	3,442,311	$ 26.80	$ 0.0174
GS Less Than 50 kW	2,726,265	956,449	1,769,816	$ 32.02	$ 0.0261
GS 50 to 4,999 kW	4,918,809	448,004	4,470,804	$ 172.04	$ 7.5344
Embedded Distributor	120,987	2,356	118,631	$ 196.32	$ 8.6485
USL	61,365	21,223	40,142	$ 50.53	$ 0.0274
Sentinel Lighting	60,914	48,102	12,812	$ 5.77	$ 6.6867
Street Lighting	354,056	278,177	75,879	$ 4.06	$ 8.8324
Total	$ 20,069,980	$ 10,139,585	$ 9,930,395		

Test of 2017 Calculated Monthly Service Charge					
Customer Class	Customer Unit Cost per Month Avoided Cost	Customer Unit Cost per Month Min. System with PLCC Adj.		Rate Design at Existing F/V Split	Is Rate Design Within Bounds?
	Floor	Ceiling			
Residential	$ 5.30	$ 27.42		$ 26.80	TRUE
GS Less Than 50 kW	$ 11.96	$ 39.53		$ 32.02	TRUE
GS 50 to 4,999 kW	$ 103.12	$ 233.75		$ 172.04	TRUE
Embedded Distributor	$ 584.79	$ 613.58		$ 196.32	FALSE
USL	$ 0.17	$ 15.15		$ 50.53	FALSE
Sentinel Lighting	$ 0.09	$ 16.66		$ 5.77	TRUE
Street Lighting	$ (0.02)	$ 5.55		$ 4.06	TRUE

Adjustment to the Fixed and Variable Allocations									
Customer Class	Revenue Requirement from Rates with Addback	Fixed Component at Existing F/V Split	Fixed Component at Adjusted F/V Split	Adjusted Fixed Component Percentage	Variable Component at Existing F/V Split	Variable Component at Adjusted F/V Split	Adjusted Variable Component Percentage	Adjusted Fixed Component	Adjusted Variable Component
Residential	11,827,584	8,385,273	8,385,273	70.90%	3,442,311	3,442,311	29.10%	$ 26.80	$ 0.0174
GS Less Than 50 kW	2,726,265	956,449	956,449	35.08%	1,769,816	1,769,816	64.92%	$ 32.02	$ 0.0261
GS 50 to 4,999 kW	4,918,809	448,004	448,004	9.11%	4,470,804	4,470,804	90.89%	$ 172.04	$ 7.5344
Embedded Distributor	120,987	2,356	7,017	5.80%	118,631	113,970	94.20%	$ 584.79	$ 8.3087
USL	61,365	21,223	21,223	34.58%	40,142	40,142	65.42%	$ 50.53	$ 0.0274
Sentinel Lighting	60,914	48,102	48,102	78.97%	12,812	12,812	21.03%	$ 5.77	$ 6.6867
Street Lighting	354,056	278,177	278,177	78.57%	75,879	75,879	21.43%	$ 4.06	$ 8.8324
Total	$20,069,980	$10,139,585	$ 10,144,246		$9,930,395	$ 9,925,733			

Balance **YES**

Revenue Decoupling for the Residential Rate Class - 2^{nd} Increment
EB-2016-0061

Rate Class	Customers/ Connections		Test Year Consumption		Proposed Rates			Proposed Revenues			Proposed Split	
		Average for 2017	kWh	kW	Monthly Service Charge	Volumetric		Fixed	Variable	Total	Fixed	Variable
						kWh	kW	$	$	$		
Residential	Customers	26,074	198,077,803		$ 26.80	$ 0.0174		8,385,273	3,442,311	11,827,584	70.9%	29.1%
GS Less Than 50 kW	Customers	2,489	67,907,332		$ 32.02	$ 0.0261		956,449	1,769,816	2,726,265	35.1%	64.9%
GS 50 to 4,999 kW	Customers	217	184,944,203	593,383	$ 172.04		$ 7.5344	448,004	4,470,804	4,918,809	9.1%	90.9%
Embedded Distributor	Customers	1	5,129,448	13,717	$ 584.79		$ 8.3087	7,017	113,970	120,987	5.8%	94.2%
USL	Customers	35	1,462,761		$ 50.53	$ 0.0274		21,223	40,142	61,365	34.6%	65.4%
Sentinel Lighting	Connections	695	629,014	1,916	$ 5.77		$ 6.6867	48,102	12,812	60,914	79.0%	21.0%
Street Lighting	Connections	5,713	2,781,556	8,591	$ 4.06		$ 8.8324	278,177	75,879	354,056	78.6%	21.4%
Total		35,224	460,932,117	617,607				10,144,246	9,925,733	20,069,980	50.5%	49.5%

Residential Decoupling

Current Monthly Service Charge (post 2017 COS adjustment)	$	26.80
Monthly Service Charge to Achieve 100% Recovery	$	37.80
Annual Increment Required (3 Increments Remaining)	$	3.67
Cap Applied to the Annual Increment	$	4.00
Proposed Residential Monthly Service Charge (2nd increment)	$	30.47

Decoupled Residential Rates

Rate Class	Customers/ Connections		Test Year Consumption		Proposed Rates			Proposed Revenues			Existing Split	
		Average for 2017	kWh	kW	Monthly Service Charge	Volumetric		Fixed	Variable	Total	Fixed	Variable
						kWh	kW	$	$	$		
Residential	Customers	26,074	198,077,803		**$ 30.47**	**$ 0.0116**		9,533,697	2,293,886	11,827,584	80.6%	19.4%

Balance Check -

Comparison of Current Rates to Final Rate Design

Customer Class	Existing Rates		Proposed Rates		Percent Change	
	Fixed Charge	Volumetric Charge	Fixed Charge	Volumetric Charge	Fixed Charge	Volumetric Charge
Residential	$ 23.44	$ 0.0152	$ 30.47	$ 0.0116	30.0%	-23.8%
GS Less Than 50 kW	$ 28.26	$ 0.0230	$ 32.02	$ 0.0261	13.3%	13.3%
GS 50 to 4,999 kW	$ 151.83	$ 6.6887	$ 172.04	$ 7.5344	13.3%	12.6%
Embedded Distributor	$ 151.83	$ 6.6887	$ 584.79	$ 8.3087	285.2%	24.2%
USL	$ 32.96	$ 0.0179	$ 50.53	$ 0.0274	53.3%	53.3%
Sentinel Lighting	$ 5.09	$ 5.9010	$ 5.77	$ 6.6867	13.3%	13.3%
Street Lighting	$ 4.96	$ 10.7965	$ 4.06	$ 8.8324	-18.2%	-18.2%

Appendix 2-V
Revenue Reconciliation

Rate Class	Customers/ Connections		Test Year Consumption		Proposed Rates			Revenues at Proposed Rates	Service Revenue Requirement	Transformer Allowance Credit	Total	Difference
		Average for 2017	kWh	kW	Monthly Service Charge	Volumetric						
						kWh	kW					
Residential	Customers	26,074	198,077,803		$ 30.47	$ 0.0116		$ 11,827,584	$ 11,827,584		$ 11,827,584	$ -
GS Less Than 50 kW	Customers	2,489	67,907,332		$ 32.02	$ 0.0261		$ 2,726,265	$ 2,726,265		$ 2,726,265	$ -
GS 50 to 4,999 kW	Customers	217	184,944,203	593,383	$ 172.04		$ 7.5344	$ 4,918,809	$ 4,719,136	$ 199,673	$ 4,918,809	$ -
Embedded Distributor	Customers	1	5,129,448	13,717	$ 584.79		$ 8.3087	$ 120,987	$ 120,987		$ 120,987	$ -
USL	Customers	35	1,462,761		$ 50.53	$ 0.0274		$ 61,365	$ 61,365		$ 61,365	$ -
Sentinel Lighting	Connections	695	629,014	1,916	$ 5.77		$ 6.6867	$ 60,914	$ 60,914		$ 60,914	$ -
Street Lighting	Connections	5,713	2,781,556	8,591	$ 4.06		$ 8.8324	$ 354,056	$ 354,056		$ 354,056	$ -
Total		35,224	460,932,117	617,607				$ 20,069,980	$ 19,870,307	$ 199,673	$ 20,069,980	$ -

RETAIL TRANSMISSION SERVICE RATES

Overview

In Fort Erie and the majority of the Port Colborne service territories, the distribution system load is supplied from the IESO-controlled grid and as such is billed for transmission service by the IESO at the prevailing Uniform Transmission Rate. In Gananoque and a portion of the Port Colborne service territories, the distribution system load is supplied from the Hydro One distribution system and as such is billed for retail transmission service by Hydro One at the prevailing Sub-Transmission Rate. Deferral accounts capture timing and rate differences between the rates paid at the wholesale level and the Retail Transmission Service Rates ("RTSRs") billed to CNPI's distribution customers.

CNPI has completed the 2016 RTSR Adjustment Workform (Exhibit 8, Tab 1, Schedule 2, Appendix A) and a live EXCEL Version of the Work Form accompanies this Application. Tables 8.1.2.1 and 8.1.2.2, following, compare CNPI's existing RTSRs with the RTSRs produced by the 2016 RTSR Adjustment Workform and proposed in this Application.

Table 8.1.2.1 Existing and Proposed RTSR – Network Charges

Rate Class	Rate Description	Unit	Adjusted RTSR-Network	Loss Adjusted Billed kWh	Billed kW	Billed Amount	Billed Amount %	Current Wholesale Billing	Proposed RTSR-Network
Residential	RTSR - Network	kWh	0.0071	208,813,620		1,478,399	42.4%	1,433,310	**0.0069**
General Service Less Than 50 kW	RTSR - Network	kWh	0.0060	71,587,909		429,408	12.3%	416,311	**0.0058**
General Service 50 to 4,999 kW	RTSR - Network	kW	2.5533		593,383	1,515,098	43.4%	1,468,889	**2.4754**
Embedded Distributor	RTSR - Network	kW	2.5533		13,717	35,024	1.0%	33,956	**2.4754**
Unmetered Scattered Load	RTSR - Network	kWh	0.0063	1,542,043		9,705	0.3%	9,409	**0.0061**
Sentinel Lighting	RTSR - Network	kW	2.1760		1,916	4,169	0.1%	4,042	**2.1097**
Street Lighting	RTSR - Network	kW	1.8899		8,591	16,236	0.5%	15,741	**1.8322**

Table 8.1.2.2 Existing and Proposed RTSR – Connection Charges

Rate Class	Rate Description	Unit	Adjusted RTSR-Connection	Loss Adjusted Billed kWh	Billed kW	Billed Amount	Billed Amount %	Current Wholesale Billing	Proposed RTSR-Connection
Residential	RTSR - Connection	kWh	0.0058	208,813,620		1,213,675	42.4%	1,222,614	**0.0059**
General Service Less Than 50 kW	RTSR - Connection	kWh	0.0050	71,587,909		358,695	12.5%	361,337	**0.0050**
General Service 50 to 4,999 kW	RTSR - Connection	kW	2.0847		593,383	1,237,020	43.2%	1,246,131	**2.1000**
Embedded Distributor	RTSR - Connection	kW	2.0847		13,717	28,596	1.0%	28,806	**2.1000**
Unmetered Scattered Load	RTSR - Connection	kWh	0.0051	1,542,043		7,881	0.3%	7,939	**0.0051**
Sentinel Lighting	RTSR - Connection	kW	1.7013		1,916	3,260	0.1%	3,284	**1.7138**
Street Lighting	RTSR - Connection	kW	1.5906		8,591	13,665	0.5%	13,766	**1.6024**

These Retail Transmission Service Rates are included in CNPI's proposed Tariff of Rates and Charges detailed in Exhibit 8, Tab 1, Schedule 9.

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Appendix A
Copy of RTSR

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2016 RTSR Workform for Electricity Distributors

Drop-down lists are shaded blue; Input cells are shaded green.

Utility Name	Canadian Niagara Power Inc.
Service Territory	Fort Erie, Port Colborne, Gananoque
Assigned EB Number	EB-2016-0061
Name and Title	Brian Vander Vloet, Manager Regulatory Accounting
Phone Number	905-871-0330
Email Address	brian.vandervloet@cnpower.com
Date	29-Apr-16
Last COS Re-based Year	**2013**

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2016 RTSR Workform for Electricity Distributors

1. Info

2. Table of Contents

3. Rate Classes

4. RRR Data

5. UTRs and Sub-Transmission

6. Historical Wholesale

7. Current Wholesale

8. Forecast Wholesale

9. RTSR Rates to Forecast

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2016 RTSR Workform for Electricity Distributors

1. Select the appropriate rate classes that appear on your most recent Board-Approved Tariff of Rates and Charges.
2. Enter the RTS Network and Connection Rate as it appears on the Tariff of Rates and Charges

Rate Class	Unit	RTSR-Network	RTSR-Connection
Residential	kWh	0.0072	0.0058
General Service Less Than 50 kW	kWh	0.0061	0.0050
General Service 50 to 4,999 kW	kW	2.5966	2.0803
Embedded Distributor	kW	2.5966	2.0803
Unmetered Scattered Load	kWh	0.0064	0.0051
Sentinel Lighting	kW	2.2129	1.6977
Street Lighting	kW	1.9219	1.5873
Choose Rate Class			
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2016 RTSR Workform for Electricity Distributors

Rate Class	Rate Description	Unit	Rate	Non-Loss Adjusted Metered kWh	Non-Loss Adjusted Metered kW	Applicable Loss Factor *eg: (1.0325)*	Loss Adjusted Billed kWh
Residential	RTSR - Network	kWh	0.0072	198,077,803		1.0542	208,813,620
Residential	RTSR - Connection	kWh	0.0058	198,077,803		1.0542	208,813,620
General Service Less Than 50 kW	RTSR - Network	kWh	0.0061	67,907,332		1.0542	71,587,909
General Service Less Than 50 kW	RTSR - Connection	kWh	0.0050	67,907,332		1.0542	71,587,909
General Service 50 to 4,999 kW	RTSR - Network	kW	2.5966		593,383		
General Service 50 to 4,999 kW	RTSR - Connection	kW	2.0803		593,383		
Embedded Distributor	RTSR - Network	kW	2.5966		13,717		
Embedded Distributor	RTSR - Connection	kW	2.0803		13,717		
Unmetered Scattered Load	RTSR - Network	kWh	0.0064	1,462,761		1.0542	1,542,043
Unmetered Scattered Load	RTSR - Connection	kWh	0.0051	1,462,761		1.0542	1,542,043
Sentinel Lighting	RTSR - Network	kW	2.2129		1,916		
Sentinel Lighting	RTSR - Connection	kW	1.6977		1,916		
Street Lighting	RTSR - Network	kW	1.9219		8,591		
Street Lighting	RTSR - Connection	kW	1.5873		8,591		

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2016 RTSR Workform for Electricity Distributors

Uniform Transmission Rates	Unit	Effective January 1, 2014	Effective January 1, 2015	Effective January 1, 2016
Rate Description		**Rate**	**Rate**	**Rate**
Network Service Rate	kW	$ 3.82	$ 3.78	$ 3.66
Line Connection Service Rate	kW	$ 0.82	$ 0.86	$ 0.87
Transformation Connection Service Rate	kW	$ 1.98	$ 2.00	$ 2.02

Hydro One Sub-Transmission Rates	Unit	Effective January 1, 2014 to April 30, 2015	Effective May 1, 2015	Effective January 1, 2016
Rate Description		**Rate**	**Rate**	**Rate**
Network Service Rate	kW	$ 3.23	$ 3.41	$ 3.34
Line Connection Service Rate	kW	$ 0.65	$ 0.79	$ 0.78
Transformation Connection Service Rate	kW	$ 1.62	$ 1.80	$ 1.77
Both Line and Transformation Connection Service Rate	kW	$ 2.27	$ 2.59	$ 2.55

If needed, add extra host here. (I)	Unit	Effective January 1, 2014	Effective January 1, 2015	Effective January 1, 2016
Rate Description		**Rate**	**Rate**	**Rate**
Network Service Rate	kW			
Line Connection Service Rate	kW			
Transformation Connection Service Rate	kW			
Both Line and Transformation Connection Service Rate	kW	$ -	$ -	$ -

If needed, add extra host here. (II)	Unit	Effective January 1, 2014	Effective January 1, 2015	Effective January 1, 2016
Rate Description		**Rate**	**Rate**	**Rate**
Network Service Rate	kW			
Line Connection Service Rate	kW			
Transformation Connection Service Rate	kW			
Both Line and Transformation Connection Service Rate	kW	$ -	$ -	$ -

Hydro One Sub-Transmission Rate Rider 9A	Unit	Effective January 1, 2014	Effective January 1, 2015	Effective January 1, 2016
Rate Description		**Rate**	**Rate**	**Rate**
RSVA Transmission network – 4714 – which affects 1584	kW	$ 0.1465	$ -	$ -
RSVA Transmission connection – 4716 – which affects 1586	kW	$ 0.0667	$ -	$ -
RSVA LV – 4750 – which affects 1550	kW	$ 0.0475	$ -	$ -
RARA 1 – 2252 – which affects 1590	kW	$ 0.0419	$ -	$ -
RARA 1 – 2252 – which affects 1590 (2008)	kW	-$ 0.0270	$ -	$ -
RARA 1 – 2252 – which affects 1590 (2009)	kW	-$ 0.0006	$ -	$ -
Hydro One Sub-Transmission Rate Rider 9A	kW	$ 0.2750	$ -	$ -

		Historical 2014	Current 2015	Forecast 2016
Low Voltage Switchgear Credit (if applicable, enter as a negative value)	$			

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2016 RTSR Workform for Electricity Distributors

In the green shaded cells, enter billing detail for wholesale transmission for the same reporting period as the billing determinants on Sheet "4. RRR Data". For Hydro One Sub-transmission Rates, if you are charged a *combined* Line and Transformer connection rate, please ensure that both the line connection and transformer connection columns are completed.

IESO	Network			Line Connection			Transformation Connection			Total Line
Month	Units Billed	Rate	Amount	Units Billed	Rate	Amount	Units Billed	Rate	Amount	Amount
January	75,385	$3.78	284,955	78,885	$0.86	67,841	78,885	$2.00	157,770	$ 225,611
February	76,554	$3.78	289,374	82,243	$0.86	70,729	82,243	$2.00	164,486	$ 235,215
March	67,929	$3.78	256,772	72,206	$0.86	62,097	72,206	$2.00	144,412	$ 206,509
April	57,919	$3.78	218,934	61,222	$0.86	52,651	61,222	$2.00	122,444	$ 175,095
May	54,658	$3.78	206,607	59,887	$0.86	51,503	59,887	$2.00	119,774	$ 171,277
June	60,378	$3.78	228,229	66,787	$0.86	57,437	66,787	$2.00	133,574	$ 191,011
July	78,327	$3.78	296,076	82,324	$0.86	70,799	82,324	$2.00	164,648	$ 235,447
August	79,920	$3.78	302,098	81,579	$0.86	70,158	81,579	$2.00	163,158	$ 233,316
September	83,543	$3.78	315,793	90,457	$0.86	77,793	90,457	$2.00	180,914	$ 258,707
October	54,983	$3.78	207,836	60,384	$0.86	51,930	60,384	$2.00	120,768	$ 172,698
November	57,036	$3.78	215,596	74,993	$0.86	64,494	74,993	$2.00	149,986	$ 214,480
December	66,524	$3.78	251,461	68,173	$0.86	58,629	68,173	$2.00	136,346	$ 194,975
Total	813,156	$ 3.78	$ 3,073,730	879,140	$ 0.86	$ 756,060	879,140	$ 2.00	$ 1,758,280	$ 2,514,340

Hydro One	Network			Line Connection			Transformation Connection			Total Line
Month	Units Billed	Rate	Amount	Units Billed	Rate	Amount	Units Billed	Rate	Amount	Amount
January	10,338	$3.23	33,391	10,338	$0.65	6,719	10,338	$1.62	16,747	$ 23,466
February	14,480	$3.23	46,772	17,349	$0.65	11,277	17,349	$1.62	28,106	$ 39,383
March	9,358	$3.23	30,225	9,621	$0.65	6,254	9,621	$1.62	15,586	$ 21,839
April	8,024	$3.23	25,918	8,067	$0.65	5,244	8,067	$1.62	13,069	$ 18,312
May	11,927	$3.41	40,698	12,308	$0.79	9,697	12,308	$1.80	22,176	$ 31,874
June	7,555	$3.41	25,778	7,642	$0.79	6,021	7,642	$1.80	13,769	$ 19,790
July	10,934	$3.41	37,307	11,036	$0.79	8,695	11,036	$1.80	19,884	$ 28,579
August	11,354	$3.41	38,740	20,011	$0.79	15,766	20,011	$1.80	36,055	$ 51,821
September	9,817	$3.41	33,496	10,313	$0.79	8,126	10,313	$1.80	18,582	$ 26,708
October	8,501	$3.41	29,005	8,732	$0.79	6,880	8,732	$1.80	15,734	$ 22,614
November	9,759	$3.41	33,298	9,759	$0.79	7,689	9,759	$1.80	17,583	$ 25,272
December	9,378	$3.41	32,018	9,378	$0.79	7,389	9,378	$1.80	16,897	$ 24,286
Total	121,423	$ 3.35	$ 406,644	134,552	$ 0.74	$ 99,757	134,552	$ 1.74	$ 234,187	$ 333,944

Add Extra Host Here (I) (if needed)	Network			Line Connection			Transformation Connection			Total Line
Month	Units Billed	Rate	Amount	Units Billed	Rate	Amount	Units Billed	Rate	Amount	Amount
January		$0.00			$0.00			$0.00		$ -
February		$0.00			$0.00			$0.00		$ -
March		$0.00			$0.00			$0.00		$ -
April		$0.00			$0.00			$0.00		$ -
May		$0.00			$0.00			$0.00		$ -
June		$0.00			$0.00			$0.00		$ -
July		$0.00			$0.00			$0.00		$ -
August		$0.00			$0.00			$0.00		$ -
September		$0.00			$0.00			$0.00		$ -
October		$0.00			$0.00			$0.00		$ -
November		$0.00			$0.00			$0.00		$ -
December		$0.00			$0.00			$0.00		$ -
Total	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -

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In the green shaded cells, enter billing detail for wholesale transmission for the same reporting period as the billing determinants on Sheet "4. RRR Data". For Hydro One Sub-transmission Rates, if you are charged a *combined* Line and Transformer connection rate, please ensure that both the line connection and transformer connection columns are completed.

Add Extra Host Here (II) (if needed)	Network			Line Connection			Transformation Connection			Total Line
Month	**Units Billed**	**Rate**	**Amount**	**Units Billed**	**Rate**	**Amount**	**Units Billed**	**Rate**	**Amount**	**Amount**
January		$0.00			$0.00			$0.00		$ -
February		$0.00			$0.00			$0.00		$ -
March		$0.00			$0.00			$0.00		$ -
April		$0.00			$0.00			$0.00		$ -
May		$0.00			$0.00			$0.00		$ -
June		$0.00			$0.00			$0.00		$ -
July		$0.00			$0.00			$0.00		$ -
August		$0.00			$0.00			$0.00		$ -
September		$0.00			$0.00			$0.00		$ -
October		$0.00			$0.00			$0.00		$ -
November		$0.00			$0.00			$0.00		$ -
December		$0.00			$0.00			$0.00		$ -
Total	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -

Total	Network			Line Connection			Transformation Connection			Total Line
Month	**Units Billed**	**Rate**	**Amount**	**Units Billed**	**Rate**	**Amount**	**Units Billed**	**Rate**	**Amount**	**Amount**
January	85,723	$3.71	$ 318,346	89,223	$0.84	$ 74,561	89,223	$1.96	$ 174,517	$ 249,078
February	91,034	$3.69	$ 336,146	99,592	$0.82	$ 82,006	99,592	$1.93	$ 192,592	$ 274,598
March	77,287	$3.71	$ 286,996	81,827	$0.84	$ 68,351	81,827	$1.96	$ 159,998	$ 228,348
April	65,943	$3.71	$ 244,851	69,289	$0.84	$ 57,895	69,289	$1.96	$ 135,513	$ 193,407
May	66,585	$3.71	$ 247,305	72,195	$0.85	$ 61,200	72,195	$1.97	$ 141,950	$ 203,151
June	67,933	$3.74	$ 254,007	74,429	$0.85	$ 63,458	74,429	$1.98	$ 147,343	$ 210,801
July	89,261	$3.73	$ 333,383	93,360	$0.85	$ 79,494	93,360	$1.98	$ 184,532	$ 264,026
August	91,274	$3.73	$ 340,838	101,590	$0.85	$ 85,924	101,590	$1.96	$ 199,213	$ 285,137
September	93,360	$3.74	$ 349,288	100,770	$0.85	$ 85,919	100,770	$1.98	$ 199,496	$ 285,415
October	63,484	$3.73	$ 236,841	69,116	$0.85	$ 58,810	69,116	$1.97	$ 136,502	$ 195,312
November	66,795	$3.73	$ 248,894	84,752	$0.85	$ 72,183	84,752	$1.98	$ 167,569	$ 239,752
December	75,902	$3.73	$ 283,479	77,551	$0.85	$ 66,018	77,551	$1.98	$ 153,243	$ 219,260
Total	934,579	$ 3.72	$ 3,480,374	1,013,692	$ 0.84	$ 855,817	1,013,692	$ 1.97	$ 1,992,467	$ 2,848,285

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2016 RTSR Workform for Electricity Distributors

The purpose of this sheet is to calculate the expected billing when current 2015 Uniform Transmission Rates are applied against historical 2014 transmission units.

IESO	Network			Line Connection			Transformation Connection			Total Line
Month	Units Billed	Rate	Amount	Units Billed	Rate	Amount	Units Billed	Rate	Amount	Amount
January	75,385	$ 3.7800	$ 284,955	78,885	$ 0.8600	$ 67,841	78,885	$ 2.0000	$ 157,770	$ 225,611
February	76,554	$ 3.7800	$ 289,374	82,243	$ 0.8600	$ 70,729	82,243	$ 2.0000	$ 164,486	$ 235,215
March	67,929	$ 3.7800	$ 256,772	72,206	$ 0.8600	$ 62,097	72,206	$ 2.0000	$ 144,412	$ 206,509
April	57,919	$ 3.7800	$ 218,934	61,222	$ 0.8600	$ 52,651	61,222	$ 2.0000	$ 122,444	$ 175,095
May	54,658	$ 3.7800	$ 206,607	59,887	$ 0.8600	$ 51,503	59,887	$ 2.0000	$ 119,774	$ 171,277
June	60,378	$ 3.7800	$ 228,229	66,787	$ 0.8600	$ 57,437	66,787	$ 2.0000	$ 133,574	$ 191,011
July	78,327	$ 3.7800	$ 296,076	82,324	$ 0.8600	$ 70,799	82,324	$ 2.0000	$ 164,648	$ 235,447
August	79,920	$ 3.7800	$ 302,098	81,579	$ 0.8600	$ 70,158	81,579	$ 2.0000	$ 163,158	$ 233,316
September	83,543	$ 3.7800	$ 315,793	90,457	$ 0.8600	$ 77,793	90,457	$ 2.0000	$ 180,914	$ 258,707
October	54,983	$ 3.7800	$ 207,836	60,384	$ 0.8600	$ 51,930	60,384	$ 2.0000	$ 120,768	$ 172,698
November	57,036	$ 3.7800	$ 215,596	74,993	$ 0.8600	$ 64,494	74,993	$ 2.0000	$ 149,986	$ 214,480
December	66,524	$ 3.7800	$ 251,461	68,173	$ 0.8600	$ 58,629	68,173	$ 2.0000	$ 136,346	$ 194,975
Total	813,156	$ 3.78	$ 3,073,730	879,140	$ 0.86	$ 756,060	879,140	$ 2.00	$ 1,758,280	$ 2,514,340

Hydro One	Network			Line Connection			Transformation Connection			Total Line
Month	Units Billed	Rate	Amount	Units Billed	Rate	Amount	Units Billed	Rate	Amount	Amount
January	10,338	$ 3.4121	$ 35,273	10,338	$ 0.7879	$ 8,145	10,338	$ 1.8018	$ 18,626	$ 26,771
February	14,480	$ 3.4121	$ 49,409	17,349	$ 0.7879	$ 13,669	17,349	$ 1.8018	$ 31,260	$ 44,929
March	9,358	$ 3.4121	$ 31,929	9,621	$ 0.7879	$ 7,580	9,621	$ 1.8018	$ 17,335	$ 24,915
April	8,024	$ 3.4121	$ 27,379	8,067	$ 0.7879	$ 6,356	8,067	$ 1.8018	$ 14,535	$ 20,891
May	11,927	$ 3.4121	$ 40,698	12,308	$ 0.7879	$ 9,697	12,308	$ 1.8018	$ 22,176	$ 31,874
June	7,555	$ 3.4121	$ 25,778	7,642	$ 0.7879	$ 6,021	7,642	$ 1.8018	$ 13,769	$ 19,790
July	10,934	$ 3.4121	$ 37,307	11,036	$ 0.7879	$ 8,695	11,036	$ 1.8018	$ 19,884	$ 28,579
August	11,354	$ 3.4121	$ 38,740	20,011	$ 0.7879	$ 15,766	20,011	$ 1.8018	$ 36,055	$ 51,821
September	9,817	$ 3.4121	$ 33,496	10,313	$ 0.7879	$ 8,126	10,313	$ 1.8018	$ 18,582	$ 26,708
October	8,501	$ 3.4121	$ 29,005	8,732	$ 0.7879	$ 6,880	8,732	$ 1.8018	$ 15,734	$ 22,614
November	9,759	$ 3.4121	$ 33,298	9,759	$ 0.7879	$ 7,689	9,759	$ 1.8018	$ 17,583	$ 25,272
December	9,378	$ 3.4121	$ 31,998	9,378	$ 0.7879	$ 7,389	9,378	$ 1.8018	$ 16,897	$ 24,286
Total	121,423	$ 3.41	$ 414,309	134,552	$ 0.79	$ 106,014	134,552	$ 1.80	$ 242,437	$ 348,450

Add Extra Host Here (I)	Network			Line Connection			Transformation Connection			Total Line
Month	Units Billed	Rate	Amount	Units Billed	Rate	Amount	Units Billed	Rate	Amount	Amount
January	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
February	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
March	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
April	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
May	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
June	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
July	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
August	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
September	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
October	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
November	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
December	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
Total	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -

Add Extra Host Here (II)	Network			Line Connection			Transformation Connection			Total Line
Month	Units Billed	Rate	Amount	Units Billed	Rate	Amount	Units Billed	Rate	Amount	Amount
January	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
February	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
March	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
April	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
May	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
June	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
July	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
August	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
September	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
October	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
November	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
December	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
Total	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -

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2016 RTSR Workform for Electricity Distributors

The purpose of this sheet is to calculate the expected billing when current 2015 Uniform Transmission Rates are applied against historical 2014 transmission units.

Total	Network			Line Connection			Transformation Connection			Total Line
Month	Units Billed	Rate	Amount	Units Billed	Rate	Amount	Units Billed	Rate	Amount	Amount
January	85,723	$3.74	$ 320,228	89,223	$0.85	$ 75,986	89,223	$1.98	$ 176,396	$ 252,382
February	91,034	$3.72	$ 338,783	99,592	$0.85	$ 84,398	99,592	$1.97	$ 195,746	$ 280,144
March	77,287	$3.74	$ 288,700	81,827	$0.85	$ 69,677	81,827	$1.98	$ 161,747	$ 231,424
April	65,943	$3.74	$ 246,313	69,289	$0.85	$ 59,007	69,289	$1.98	$ 136,979	$ 195,986
May	66,585	$3.71	$ 247,305	72,195	$0.85	$ 61,200	72,195	$1.97	$ 141,950	$ 203,151
June	67,933	$3.74	$ 254,007	74,429	$0.85	$ 63,458	74,429	$1.98	$ 147,343	$ 210,801
July	89,261	$3.73	$ 333,383	93,360	$0.85	$ 79,494	93,360	$1.98	$ 184,532	$ 264,026
August	91,274	$3.73	$ 340,838	101,590	$0.85	$ 85,924	101,590	$1.96	$ 199,213	$ 285,137
September	93,360	$3.74	$ 349,288	100,770	$0.85	$ 85,919	100,770	$1.98	$ 199,496	$ 285,415
October	63,484	$3.73	$ 236,841	69,116	$0.85	$ 58,810	69,116	$1.97	$ 136,502	$ 195,312
November	66,795	$3.73	$ 248,894	84,752	$0.85	$ 72,183	84,752	$1.98	$ 167,569	$ 239,752
December	75,902	$3.73	$ 283,459	77,551	$0.85	$ 66,018	77,551	$1.98	$ 153,243	$ 219,260
Total	934,579	$ 3.73	$ 3,488,039	1,013,692	$ 0.85	$ 862,074	1,013,692	$ 1.97	$ 2,000,717	$ 2,862,791

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2016 RTSR Workform for Electricity Distributors

The purpose of this sheet is to calculate the expected billing when forecasted 2016 Uniform Transmission Rates are applied against historical 2014 transmission units.

IESO	Network			Line Connection			Transformation Connection			Total Line
Month	Units Billed	Rate	Amount	Units Billed	Rate	Amount	Units Billed	Rate	Amount	Amount
January	75,385	$ 3.6600	$ 275,909	78,885	$ 0.8700	$ 68,630	78,885	$ 2.0200	$ 159,348	$ 227,978
February	76,554	$ 3.6600	$ 280,188	82,243	$ 0.8700	$ 71,551	82,243	$ 2.0200	$ 166,131	$ 237,682
March	67,929	$ 3.6600	$ 248,620	72,206	$ 0.8700	$ 62,819	72,206	$ 2.0200	$ 145,856	$ 208,675
April	57,919	$ 3.6600	$ 211,984	61,222	$ 0.8700	$ 53,263	61,222	$ 2.0200	$ 123,668	$ 176,932
May	54,658	$ 3.6600	$ 200,048	59,887	$ 0.8700	$ 52,102	59,887	$ 2.0200	$ 120,972	$ 173,073
June	60,378	$ 3.6600	$ 220,983	66,787	$ 0.8700	$ 58,105	66,787	$ 2.0200	$ 134,910	$ 193,014
July	78,327	$ 3.6600	$ 286,677	82,324	$ 0.8700	$ 71,622	82,324	$ 2.0200	$ 166,294	$ 237,916
August	79,920	$ 3.6600	$ 292,507	81,579	$ 0.8700	$ 70,974	81,579	$ 2.0200	$ 164,790	$ 235,763
September	83,543	$ 3.6600	$ 305,767	90,457	$ 0.8700	$ 78,698	90,457	$ 2.0200	$ 182,723	$ 261,421
October	54,983	$ 3.6600	$ 201,238	60,384	$ 0.8700	$ 52,534	60,384	$ 2.0200	$ 121,976	$ 174,510
November	57,036	$ 3.6600	$ 208,752	74,993	$ 0.8700	$ 65,244	74,993	$ 2.0200	$ 151,486	$ 216,730
December	66,524	$ 3.6600	$ 243,478	68,173	$ 0.8700	$ 59,311	68,173	$ 2.0200	$ 137,709	$ 197,020
Total	813,156	$ 3.66	$ 2,976,151	879,140	$ 0.87	$ 764,852	879,140	$ 2.02	$ 1,775,863	$ 2,540,715

Hydro One	Network			Line Connection			Transformation Connection			Total Line
Month	Units Billed	Rate	Amount	Units Billed	Rate	Amount	Units Billed	Rate	Amount	Amount
January	10,338	$ 3.3396	$ 34,524	10,338	$ 0.7791	$ 8,054	10,338	$ 1.7713	$ 18,311	$ 26,365
February	14,480	$ 3.3396	$ 48,359	17,349	$ 0.7791	$ 13,517	17,349	$ 1.7713	$ 30,731	$ 44,247
March	9,358	$ 3.3396	$ 31,250	9,621	$ 0.7791	$ 7,496	9,621	$ 1.7713	$ 17,041	$ 24,537
April	8,024	$ 3.3396	$ 26,797	8,067	$ 0.7791	$ 6,285	8,067	$ 1.7713	$ 14,289	$ 20,574
May	11,927	$ 3.3396	$ 39,833	12,308	$ 0.7791	$ 9,589	12,308	$ 1.7713	$ 21,801	$ 31,390
June	7,555	$ 3.3396	$ 25,231	7,642	$ 0.7791	$ 5,954	7,642	$ 1.7713	$ 13,536	$ 19,490
July	10,934	$ 3.3396	$ 36,514	11,036	$ 0.7791	$ 8,598	11,036	$ 1.7713	$ 19,548	$ 28,145
August	11,354	$ 3.3396	$ 37,917	20,011	$ 0.7791	$ 15,590	20,011	$ 1.7713	$ 35,445	$ 51,035
September	9,817	$ 3.3396	$ 32,784	10,313	$ 0.7791	$ 8,035	10,313	$ 1.7713	$ 18,267	$ 26,302
October	8,501	$ 3.3396	$ 28,389	8,732	$ 0.7791	$ 6,803	8,732	$ 1.7713	$ 15,468	$ 22,271
November	9,759	$ 3.3396	$ 32,590	9,759	$ 0.7791	$ 7,603	9,759	$ 1.7713	$ 17,286	$ 24,889
December	9,378	$ 3.3396	$ 31,318	9,378	$ 0.7791	$ 7,306	9,378	$ 1.7713	$ 16,611	$ 23,917
Total	121,423	$ 3.34	$ 405,506	134,552	$ 0.78	$ 104,830	134,552	$ 1.77	$ 238,333	$ 343,163

Add Extra Host Here (I)	Network			Line Connection			Transformation Connection			Total Line
Month	Units Billed	Rate	Amount	Units Billed	Rate	Amount	Units Billed	Rate	Amount	Amount
January	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
February	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
March	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
April	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
May	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
June	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
July	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
August	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
September	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
October	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
November	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
December	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
Total	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -

Add Extra Host Here (II)	Network			Line Connection			Transformation Connection			Total Line
Month	Units Billed	Rate	Amount	Units Billed	Rate	Amount	Units Billed	Rate	Amount	Amount
January	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
February	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
March	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
April	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
May	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
June	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
July	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
August	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
September	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
October	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
November	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
December	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
Total	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -

Ontario Energy Board

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2016 RTSR Workform for Electricity Distributors

The purpose of this sheet is to calculate the expected billing when forecasted 2016 Uniform Transmission Rates are applied against historical 2014 transmission units.

Total	Network			Line Connection			Transformation Connection			Total Line
Month	**Units Billed**	**Rate**	**Amount**	**Units Billed**	**Rate**	**Amount**	**Units Billed**	**Rate**	**Amount**	**Amount**
January	85,723	$ 3.62	310,433	89,223	$ 0.86	76,684	89,223	$ 1.99	177,659	$ 254,343
February	91,034	$ 3.61	328,547	99,592	$ 0.85	85,068	99,592	$ 1.98	196,862	$ 281,930
March	77,287	$ 3.62	279,870	81,827	$ 0.86	70,315	81,827	$ 1.99	162,897	$ 233,212
April	65,943	$ 3.62	238,781	69,289	$ 0.86	59,548	69,289	$ 1.99	137,958	$ 197,506
May	66,585	$ 3.60	239,881	72,195	$ 0.85	61,691	72,195	$ 1.98	142,773	$ 204,464
June	67,933	$ 3.62	246,214	74,429	$ 0.86	64,058	74,429	$ 1.99	148,446	$ 212,504
July	89,261	$ 3.62	323,191	93,360	$ 0.86	80,220	93,360	$ 1.99	185,842	$ 266,062
August	91,274	$ 3.62	330,424	101,590	$ 0.85	86,564	101,590	$ 1.97	200,234	$ 286,798
September	93,360	$ 3.63	338,551	100,770	$ 0.86	86,732	100,770	$ 1.99	200,991	$ 287,723
October	63,484	$ 3.62	229,627	69,116	$ 0.86	59,337	69,116	$ 1.99	137,443	$ 196,781
November	66,795	$ 3.61	241,342	84,752	$ 0.86	72,847	84,752	$ 1.99	168,771	$ 241,618
December	75,902	$ 3.62	274,796	77,551	$ 0.86	66,617	77,551	$ 1.99	154,320	$ 220,937
Total	934,579	$ 3.62	$ 3,381,657	1,013,692	$ 0.86	$ 869,682	1,013,692	$ 1.99	$ 2,014,196	$ 2,883,877

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2016 RTSR Workform for Electricity Distributors

The purpose of this sheet is to re-align the current RTS Network Rates to recover current wholesale network costs.

Rate Class	Rate Description	Unit	Current RTSR-Network	Loss Adjusted Billed kWh	Billed kW	Billed Amount	Billed Amount %	Current Wholesale Billing	Adjusted RTSR Network
Residential	RTSR - Network	kWh	0.0072	208,813,620		1,503,458	42.4%	1,478,399	0.0071
General Service Less Than 50 kW	RTSR - Network	kWh	0.0061	71,587,909		436,686	12.3%	429,408	0.0060
General Service 50 to 4,999 kW	RTSR - Network	kW	2.5966		593,383	1,540,778	43.4%	1,515,098	2.5533
Embedded Distributor	RTSR - Network	kW	2.5966		13,717	35,618	1.0%	35,024	2.5533
Unmetered Scattered Load	RTSR - Network	kWh	0.0064	1,542,043		9,869	0.3%	9,705	0.0063
Sentinel Lighting	RTSR - Network	kW	2.2129		1,916	4,240	0.1%	4,169	2.1760
Street Lighting	RTSR - Network	kW	1.9219		8,591	16,511	0.5%	16,236	1.8899

The purpose of this table is to re-align the current RTS Connection Rates to recover current wholesale connection costs.

Rate Class	Rate Description	Unit	Current RTSR-Connection	Loss Adjusted Billed kWh	Billed kW	Billed Amount	Billed Amount %	Current Wholesale Billing	Adjusted RTSR-Connection
Residential	RTSR - Connection	kWh	0.0058	208,813,620		1,211,119	42.4%	1,213,675	0.0058
General Service Less Than 50 kW	RTSR - Connection	kWh	0.0050	71,587,909		357,940	12.5%	358,695	0.0050
General Service 50 to 4,999 kW	RTSR - Connection	kW	2.0803		593,383	1,234,415	43.2%	1,237,020	2.0847
Embedded Distributor	RTSR - Connection	kW	2.0803		13,717	28,535	1.0%	28,596	2.0847
Unmetered Scattered Load	RTSR - Connection	kWh	0.0051	1,542,043		7,864	0.3%	7,881	0.0051
Sentinel Lighting	RTSR - Connection	kW	1.6977		1,916	3,253	0.1%	3,260	1.7013
Street Lighting	RTSR - Connection	kW	1.5873		8,591	13,636	0.5%	13,665	1.5906

The purpose of this table is to update the re-aligned RTS Network Rates to recover future wholesale network costs.

Rate Class	Rate Description	Unit	Adjusted RTSR-Network	Loss Adjusted Billed kWh	Billed kW	Billed Amount	Billed Amount %	Current Wholesale Billing	Proposed RTSR-Network
Residential	RTSR - Network	kWh	0.0071	208,813,620		1,478,399	42.4%	1,433,310	**0.0069**
General Service Less Than 50 kW	RTSR - Network	kWh	0.0060	71,587,909		429,408	12.3%	416,311	**0.0058**
General Service 50 to 4,999 kW	RTSR - Network	kW	2.5533		593,383	1,515,098	43.4%	1,468,889	**2.4754**
Embedded Distributor	RTSR - Network	kW	2.5533		13,717	35,024	1.0%	33,956	**2.4754**
Unmetered Scattered Load	RTSR - Network	kWh	0.0063	1,542,043		9,705	0.3%	9,409	**0.0061**
Sentinel Lighting	RTSR - Network	kW	2.1760		1,916	4,169	0.1%	4,042	**2.1097**
Street Lighting	RTSR - Network	kW	1.8899		8,591	16,236	0.5%	15,741	**1.8322**

The purpose of this table is to update the re-aligned RTS Connection Rates to recover future wholesale connection costs.

Rate Class	Rate Description	Unit	Adjusted RTSR-Connection	Loss Adjusted Billed kWh	Billed kW	Billed Amount	Billed Amount %	Current Wholesale Billing	Proposed RTSR-Connection
Residential	RTSR - Connection	kWh	0.0058	208,813,620		1,213,675	42.4%	1,222,614	**0.0059**
General Service Less Than 50 kW	RTSR - Connection	kWh	0.0050	71,587,909		358,695	12.5%	361,337	**0.0050**
General Service 50 to 4,999 kW	RTSR - Connection	kW	2.0847		593,383	1,237,020	43.2%	1,246,131	**2.1000**
Embedded Distributor	RTSR - Connection	kW	2.0847		13,717	28,596	1.0%	28,806	**2.1000**
Unmetered Scattered Load	RTSR - Connection	kWh	0.0051	1,542,043		7,881	0.3%	7,939	**0.0051**
Sentinel Lighting	RTSR - Connection	kW	1.7013		1,916	3,260	0.1%	3,284	**1.7138**
Street Lighting	RTSR - Connection	kW	1.5906		8,591	13,665	0.5%	13,766	**1.6024**

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RETAIL SERVICE CHARGES

Retail services refer to services provided by a distributor to retailers or customers related to the supply of competitive electricity as set out in the Retail Settlement Code. The current retail service rates and charges were established on a generic basis.

CNPI maintains the appropriate Retail Service Costs Variance Accounts to record the difference between charges rendered to customers and retailers, and the direct incremental costs for the provision of these services.

CNPI currently charges customers and retailers the generic Retail Service Charges approved by the Board. These Retail Service Charges are contained in CNPI's Tariff of Rates and Charges, effective January 1, 2016, and are provided in Exhibit 8 Tab 1 Schedule 9. CNPI is not proposing any changes to the existing Retail Service Charges.

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REGULATORY RATES

In the matter of EB-2015-0294, the Board established rates for the 2016 rate year for Wholesale Market Service, Rural and Remote Electricity Rate Protection, and the Ontario Electricity Support Program. As a result of the Board's decision in CNPI's 2015 IRM application (EB-2015-0058), these rates were implemented by CNPI with an effective date of January 1, 2016.

Description	Determinant	Rate
Wholesale Market Service Rate	$/kWh	0.0036
Rural or Remote Electricity Rate Protection Charge (RRRP)	$/kWh	0.0013
Ontario Electricity Support Program Charge (OESP)	$/kWh	0.0011

CNPI acknowledges that the Board may revise these rates for 2017, and proposes to incorporate any changes to these rates on its final Tariff of Rates and Charges following the Board's decision in this Application.

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SMART METERING CHARGE

On March 28, 2013, the OEB issued a Decision and Order (EB-2012-0100/EB-2012-0211) establishing a Smart Metering Entity charge of $0.79 per month for Residential and General Service < 50kW customers effective May 1, 2013.

CNPI recognizes that the smart metering charge is currently in effect until October 31, 2018, and has reflected the charge on its Tariff of Rates and Charges.

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SPECIFIC SERVICE CHARGES

CNPI is proposing to use only the prescribed Specific Service Charges. The Specific Service Charges currently charged by CNPI are contained in its Tariff of Rates and Charges, effective January 1, 2016, and are provided in Exhibit 8, Tab 1, Schedule 9. CNPI is not proposing any changes to the existing Specific Service Charges.

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LOW VOLTAGE CHARGES

Overview

The majority of CNPI's distribution system (all of its Fort Erie service territory and the vast majority of its Port Colborne service territory) is supplied from the IESO-controlled grid, and as such does not attract low voltage charges from Hydro One.

The portions of CNPI's distribution system that attract low voltage charges include CNPI's Eastern Ontario Power (EOP) service territory, which is fully embedded within Hydro One's distribution system through a single point of supply from Hydro One's 44 kV system as well as a very small section of CNPI's Port Colborne distribution system which is supplied from Hydro One's Crowland M13 feeder.

The Proposed Settlement Agreement approved by the Board in CNPI's most recent cost of service application (EB-2012-0112), provided for the harmonization of low voltage charges across all of CNPI's service territories.

An embedded distributor's forecast for low voltage costs is normally supported by forecast volumes and the host distributor's rates for low voltage service. However, given the unique characteristics of CNPI's two embedded supply points, the majority of CNPI's low voltage charges are a result of the timing of the output of third-party embedded generation facilities in relation to the timing of the peak load on these embedded supply point. This results in low voltage charges that are highly variable, and largely beyond CNPI's control.

The balance of this Schedule describes the unique operating characteristics associated with CNPI's embedded supply points, and proposes the use of the most recent annual actual low voltage charges (i.e. 2015 Actual) as the basis for the proposed 2017 Test Year low voltage charges. This approach is consistent with the approach presented and accepted in EB-2012-0112. CNPI submits that continuation of this approach is reasonable in light of the forecasting challenges presented below, the minimal rate impact associated with harmonized low voltage charges, and the fact that any differences will be recorded in a variance account.

Eastern Ontario Power

EOP's distribution system is connected to Hydro One's 44 kV distribution system at a single point of supply. However, embedded within EOP's distribution system are five merchant hydro generating stations with a combined name plate capacity of approximately 6 MW; EOP has an approximately 13 MW peak demand.

These embedded hydro electric generation stations are run-of-the-river style generators and are therefore not suited to any form of scheduled dispatch. In addition to water availability under the run-of-the-river operating regime, the stations are located on a navigable waterway; the Rideau Canal. This means that water control in the canal system rests with the National Parks Commission. The amount of generation at any particular time is entirely dependent upon water availability.

Port Colborne – Crowland TS

In Port Colborne the situation is somewhat similar to that of Eastern Ontario Power. A very small section of the Port Colborne distribution system is supplied from the end of Hydro One's Crowland M13 distribution feeder. The balance of the load in Port Colborne is supplied from the Port Colborne TS. Port Colborne has the capacity to supply all of its energy demand from the Port Colborne TS thus avoiding any low voltage charges. However, there is a General Service 50 to 4,999 kW customer with embedded generation that requires transfer trip technology to remain connected to the distribution system; this transfer trip capability is only available at the Crowland TS.

Under normal operating conditions, this customer will supply the majority and at times all of its energy requirements from its embedded generation facilities. However, during regular maintenance of the generators, the customer will require off peak energy from the distribution system and as a result, Port Colborne will incur low voltage costs from Hydro One. Should the customer experience a forced outage of its generating facilities, peak energy may be required and consequently the low voltage costs from Hydro One will be higher for that billing period.

Proposed Low Voltage Charges

Given this uncertainty related to the amount of energy supply from these embedded hydro electric generators, EOP is forecasting low voltage costs at the most recent recorded actual; the 2015 actual low voltage costs. In 2015, the actual low voltage cost from Hydro One was $141,832. CNPI is using this value as its bridge year and test year forecast.

Current low voltage rates in Gananoque are based on low voltage costs of $103,308 approved in EB-2012-0112; the 2013 actual costs were $100,140. CNPI's Low Voltage rates have not been changed during the IRM phase subsequent to CNPI's 2013 cost of service application.

CNPI has allocated the low voltage costs to the customer classes on the basis of the proportion of Retail Transmission Connection Rate revenues forecasted for the test year using the 2016 IRM approved rates and the forecasted volumes for the 2017 Test Year. Derivation of the proposed low voltage rates are shown in the table below.

Determination of Low Voltage Rates in CNPI

Low Voltage Revenue Requirement for 2017 $ 141,832

Customer Class	2016 RTSR Connection Rate	Test Year Billing Determinant Volume	Test Year Billing Determinant UOM	RTSR Connection Revenue	RTSR Revenue Distribution
Residential	0.0058	198,077,803	kWh	$ 1,148,851	41.4%
GS Less Than 50 kW	0.0050	67,907,332	kWh	$ 339,537	12.2%
GS 50 to 4,999 kW	2.0803	593,383	kW	$ 1,234,415	44.5%
Embedded Distributor	2.0803	13,717	kW	$ 28,535	1.0%
Unmetered Scattered Load	0.0051	1,462,761	kWh	$ 7,460	0.3%
Sentinel Lighting	1.6977	1,916	kW	$ 3,253	0.1%
Street Lighting	1.5873	8,591	kW	$ 13,636	0.5%

	Low Voltage Revenue Distribution	Test Year Billing Determinant Volume	Test Year Billing Determinant UOM	Proposed Low Voltage Distribution Rates Rate	Proposed Low Voltage Distribution Rates UOM
Residential	$ 58,704	198,077,803	kWh	0.0003	kWh
GS Less Than 50 kW	$ 17,350	67,907,332	kWh	0.0003	kWh
GS 50 to 4,999 kW	$ 63,076	593,383	kW	0.1063	kW
Embedded Distributor	$ 1,458	13,717	kW	0.1063	kW
Unmetered Scattered Load	$ 381	1,462,761	kWh	0.0003	kWh
Sentinel Lighting	$ 166	1,916	kW	0.0867	kW
Street Lighting	$ 697	8,591	kW	0.0811	kW

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LOSS ADJUSTMENT FACTORS

Electricity Supply

The majority of CNPI's distribution system (all of its Fort Erie service territory and the vast majority of its Port Colborne service territory) is supplied from the IESO-controlled grid. A very small portion of the Port Colborne service territory and the entire Eastern Ontario Power service territory are supplied from Hydro One's distribution systems. Further details on CNPI's embedded supply points are provided at Exhibit 8, Tab 1, Schedule 7 – Low Voltage Charges.

Supply Facilities Loss Factor

CNPI has determined the Supply Facilities Loss Factor from actual quantities recorded for each of its wholesale market delivery points. The calculated value has been consistent over the five year historical period, varying from a low of 1.0066 to a high of 1.0072. The five year average Supply Facilities Loss Factor is 1.0069 for all service territories on a combined basis. The details of this determination are provided in Appendix 2-R, Loss Factors.

Distribution Loss Factor

The Distribution Loss Factor for CNPI has been determined as prescribed in the Filing Requirements and the details are provided in Appendix 2-R, Loss Factors.

There is no wholesale energy delivered to CNPI that is for a Large Use Customer and no portion of the retail energy delivered by CNPI is for a Large Use Customer.

CNPI has determined its Distribution Loss Factor as the average of the previous five years' distribution loss factors and is calculated to be 1.0458. The details of this determination are provided in Appendix 2-R, Loss Factors.

Total Loss Factor

The Total Loss Factor for CNPI is 1.0530 and its derivation is detailed in the table below identified as Appendix 2-R, Loss Factors.

Appendix 2-R

Loss Factors

		Historical Years					5-Year Average
		2011	**2012**	**2013**	**2014**	**2015**	
	Losses Within Distributor's System						
A(1)	"Wholesale" kWh delivered to distributor (higher value)	570,956,950	563,961,180	533,940,710	536,706,901	499,722,580	541,057,664
A(2)	"Wholesale" kWh delivered to distributor (lower value)	567,150,686	559,993,930	530,349,462	533,188,097	496,129,658	537,362,367
B	Portion of "Wholesale" kWh delivered to distributor for its Large Use Customer(s)						-
C	Net "Wholesale" kWh delivered to distributor = **A(2) - B**	567,150,686	559,993,930	530,349,462	533,188,097	496,129,658	537,362,367
D	"Retail" kWh delivered by distributor	540,401,754	538,207,566	505,167,326	511,155,064	474,175,577	513,821,457
E	Portion of "Retail" kWh delivered by distributor to its Large Use Customer(s)						-
F	Net "Retail" kWh delivered by distributor = **D - E**	540,401,754	538,207,566	505,167,326	511,155,064	474,175,577	513,821,457
G	Loss Factor in Distributor's system = **C / F**	1.0495	1.0405	1.0498	1.0431	1.0463	1.0458
	Losses Upstream of Distributor's System						
H	Supply Facilities Loss Factor	1.0067	1.0071	1.0068	1.0066	1.0072	1.0069
	Total Losses						
I	Total Loss Factor = **G x H**	1.0565	1.0479	1.0570	1.0500	1.0539	1.0530

The following table compares the loss factors proposed in this Application to those approved in CNPI's 2013 cost of service application (EB-2012-0112).

Loss Factors	2013	2017
Supply Facility Loss Factor	1.0063	1.0069
Distribution Loss Factors		
Secondary Metered Customer < 5,000 kW	1.0476	1.0458
Primary Metered Customer < 5,000 kW	1.0371	1.0353
Total Loss Factors		
Secondary Metered Customer < 5,000 kW	1.0542	1.0530
Primary Metered Customer < 5,000 kW	1.0437	1.0425

MATERIALITY OF DISTRIBUTION LOSSES

CNPI's proposed distribution loss factor is 1.0458. Pursuant to the Board's Minimum Filing Requirements, the threshold for providing and explanation and mitigation plan with respect to distribution losses is 5%. In accordance with the Filing Requirements, CNPI – Fort Erie has not provided additional discussions of materiality.

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Appendix 2-R
Loss Factors

		Historical Years					5-Year Average
		2011	2012	2013	2014	2015	
	Losses Within Distributor's System						
A(1)	"Wholesale" kWh delivered to distributor (higher value)	570,956,950	563,961,180	533,940,710	536,706,901	499,722,580	541,057,664
A(2)	"Wholesale" kWh delivered to distributor (lower value)	567,150,686	559,993,930	530,349,462	533,188,097	496,129,658	537,362,367
B	Portion of "Wholesale" kWh delivered to distributor for its Large Use Customer(s)						-
C	Net "Wholesale" kWh delivered to distributor = **A(2) - B**	567,150,686	559,993,930	530,349,462	533,188,097	496,129,658	537,362,367
D	"Retail" kWh delivered by distributor	540,401,754	538,207,566	505,167,326	511,155,064	474,175,577	513,821,457
E	Portion of "Retail" kWh delivered by distributor to its Large Use Customer(s)						-
F	Net "Retail" kWh delivered by distributor = **D - E**	540,401,754	538,207,566	505,167,326	511,155,064	474,175,577	513,821,457
G	Loss Factor in Distributor's system = **C / F**	1.0495	1.0405	1.0498	1.0431	1.0463	1.0458
	Losses Upstream of Distributor's System						
H	Supply Facilities Loss Factor	1.0067	1.0071	1.0068	1.0066	1.0072	1.0069
	Total Losses						
I	Total Loss Factor = **G x H**	1.0565	1.0479	1.0570	1.0500	1.0539	1.0530

Notes:

A(1) If directly connected to the IESO-controlled grid, kWh pertains to the virtual meter on the primary or high voltage side of the transformer at the interface with the transmission grid. This corresponds to the "With Losses" kWh value provided by the IESO's MV-WEB. It is the <u>higher</u> of the two values provided by MV-WEB.

If fully embedded within a host distributor, kWh pertains to the virtual meter on the primary or high voltage side of the transformer, at the interface between the host distributor and the transmission grid. For example, if the host distributor is Hydro One Networks Inc., kWh from the Hydro One Networks' invoice corresponding to "Total kWh w Losses" should be reported. This corresponds to the <u>higher</u> of the two kWh values provided in Hydro One Networks' invoice.

If partially embedded, kWh pertains to the sum of the above.

A(2) If directly connected to the IESO-controlled grid, kWh pertains to a metering installation on the secondary or low voltage side of the transformer at the interface with the transmission grid. This corresponds to the "Without Losses" kWh value provided by the IESO's MV-WEB. It is the <u>lower</u> of the two kWh values provided by MV-WEB.

If fully embedded with the host distributor, kWh pertains to a metering installation on the secondary or low voltage side of the transformer at the interface between the embedded distributor and the host distributor. For example, if the host distributor is Hydro One Networks Inc., kWh from the Hydro One Networks' invoice corresponding to "Total kWh" should be reported. This corresponds to the <u>lower</u> of the two kWh values provided in Hydro One Networks' invoice.

If partially embedded, kWh pertains to the sum of the above.

Additionally, kWh pertaining to distributed generation directly connected to the distributor's own distribution network should be included in **A(2)**.

B	If a Large Use Customer is metered on the secondary or low voltage side of the transformer, the default loss is 1% (i.e., **B** = 1.01 X **E**).
D	kWh corresponding to D should equal metered or estimated kWh at the customer's delivery point.
G and **I**	These loss factors pertain to secondary-metered customers with demand less than 5,000 kW.
H	If directly connected to the IESO-controlled grid, SFLF = 1.0045.
	If fully embedded within a host distributor, SFLF = loss factor re losses in transformer at grid interface X loss factor re losses in host distributor's system. If the host distributor is Hydro One Networks Inc., SFLF = 1.0060 X 1.0278 = 1.0340. If partially embedded, SFLF should be calculated as the weighted average of above.
	Distributors that wish to propose a different SFLF should provide appropriate justification for any such proposal including supporting calculations and any other relevant material.

CURRENT AND PROPOSED TARIFF OF RATES AND CHARGES

The current and proposed tariff of rates and charges is attached.

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Current Tariff of Rates and Charges

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Canadian Niagara Power Inc.
TARIFF OF RATES AND CHARGES
Effective and Implementation Date January 1, 2016

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

EB-2015-0058

Fort Erie Service Area

RESIDENTIAL SERVICE CLASSIFICATION

The Residential Class (Regular) refers to a service taking electricity normally at 750 volts or less where the electricity is used for domestic and household purposes in a single family unit. A single family unit being a permanent structure located on a single parcel of land and approved by a civic authority as a dwelling and occupied for that purpose by a single customer. Residential rates are also applied to apartment buildings with 6 units or less that are bulk metered. Apartment buildings with more than 6 units that are bulk metered are deemed to be General Service. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable. In addition, the charges in the MONTHLY RATES AND CHARGES – Regulatory Component of this schedule do not apply to a customer that is an embedded wholesale market participant.

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Debt Retirement Charge, the Global Adjustment, and the HST.

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge	$	23.44
Rate Rider for Smart Meter Entity Charge - effective until October 31, 2018	$	0.79
Distribution Volumetric Rate	$/kWh	0.0152
Low Voltage Service Rate	$/kWh	0.0002
Rate Rider for Disposition of Deferral/Variance Accounts (2015) – effective until December 31, 2016	$/kWh	0.0008
Rate Rider for Disposition of Global Adjustment Account (2015) – effective until December 31, 2016 Applicable only for Non-RPP Customers	$/kWh	(0.0025)
Rate Rider for Disposition of Deferral/Variance Accounts (2016) – effective until December 31, 2017	$/kWh	(0.0004)
Rate Rider for Disposition of Global Adjustment Account (2016) – effective until December 31, 2017 Applicable only for Non-RPP Customers	$/kWh	0.0037
Retail Transmission Rate – Network Service Rate	$/kWh	0.0072
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	0.0058

MONTHLY RATES AND CHARGES - Regulatory Component

Wholesale Market Service Rate	$/kWh	0.0036
Rural or Remote Electricity Rate Protection Charge (RRRP)	$/kWh	0.0013
Ontario Electricity Support Program Charge (OESP)	$/kWh	0.0011
Standard Supply Service - Administrative Charge (if applicable)	$	0.25

Canadian Niagara Power Inc.
TARIFF OF RATES AND CHARGES
Effective and Implementation Date January 1, 2016

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

EB-2015-0058

Fort Erie Service Area

GENERAL SERVICE LESS THAN 50 kW SERVICE CLASSIFICATION

This classification refers to the supply of electrical energy to single commercial or industrial customer and whose average peak demand is (or is forecasted to be) less than 50 kW. Single commercial or industrial customers are interpreted as a structure or structures on a single parcel of land occupied by one customer. An apartment building with more than 6 units that is bulk metered and has an average peak demand less than 50 kW is deemed to be General Service less than 50 kW. The common area of a separately metered apartment building having a demand less than 50 kW is also deemed to be General Service less than 50 kW. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable. In addition, the charges in the MONTHLY RATES AND CHARGES – Regulatory Component of this schedule do not apply to a customer that is an embedded wholesale market participant.

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Debt Retirement Charge, the Global Adjustment, and the HST.

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge	$	28.26
Rate Rider for Smart Entity Charge - effective until October 31, 2018	$	0.79
Distribution Volumetric Rate	$/kWh	0.0230
Low Voltage Service Rate	$/kWh	0.0002
Rate Rider for Disposition of Deferral/Variance Accounts (2015) – effective until December 31, 2016	$/kWh	0.0008
Rate Rider for Disposition of Global Adjustment Account (2015) – effective until December 31, 2016 Applicable only for Non-RPP Customers	$/kWh	(0.0025)
Rate Rider for Disposition of Deferral/Variance Accounts (2016) – effective until December 31, 2017	$/kWh	(0.0006)
Rate Rider for Disposition of Global Adjustment Account (2016) – effective until December 31, 2017 Applicable only for Non-RPP Customers	$/kWh	0.0037
Retail Transmission Rate – Network Service Rate	$/kWh	0.0061
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	0.0050

MONTHLY RATES AND CHARGES - Regulatory Component

Wholesale Market Service Rate	$/kWh	0.0036
Rural or Remote Electricity Rate Protection Charge (RRRP)	$/kWh	0.0013
Ontario Electricity Support Program Charge (OESP)	$/kWh	0.0011
Standard Supply Service - Administrative Charge (if applicable)	$	0.25

Canadian Niagara Power Inc.

TARIFF OF RATES AND CHARGES

Effective and Implementation Date January 1, 2016

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EB-2015-0058

Fort Erie Service Area

GENERAL SERVICE 50 to 4,999 kW SERVICE CLASSIFICATION

This classification refers to the supply of electrical energy to single commercial or industrial customer and whose average peak demand is (or is forecasted to be) equal to or greater than 50 kW but less than 5000 kW. Single commercial or industrial customers are interpreted as a structure or structures on a single parcel of land occupied by one customer. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

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MONTHLY RATES AND CHARGES - Delivery Component

Service Charge	$	151.83
Distribution Volumetric Rate	$/kW	6.6887
Low Voltage Service Rate	$/kW	0.0735
Rate Rider for Disposition of Deferral/Variance Accounts (2015) – effective until December 31, 2016	$/kW	0.2602
Rate Rider for Disposition of Global Adjustment Account (2015) – effective until December 31, 2016 Applicable only for Non-RPP Customers	$/kW	(0.8619)
Rate Rider for Disposition of Deferral/Variance Accounts (2016) – effective until December 31, 2017	$/kW	(0.1678)
Rate Rider for Disposition of Global Adjustment Account (2016) – effective until December 31, 2017 Applicable only for Non-RPP Customers	$/kW	1.4104
Retail Transmission Rate – Network Service Rate	$/kW	2.5966
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	2.0803

MONTHLY RATES AND CHARGES - Regulatory Component

Wholesale Market Service Rate	$/kWh	0.0036
Rural or Remote Electricity Rate Protection Charge (RRRP)	$/kWh	0.0013
Ontario Electricity Support Program Charge (OESP)	$/kWh	0.0011
Standard Supply Service - Administrative Charge (if applicable)	$	0.25

Canadian Niagara Power Inc.

TARIFF OF RATES AND CHARGES

Effective and Implementation Date January 1, 2016

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Fort Erie Service Area

UNMETERED SCATTERED LOAD SERVICE CLASSIFICATION

This classification refers to the supply of electrical service to a customer that is deemed to have a constant load over a billing period, normally with minimum electrical consumption and the consumption is unmetered. Energy consumption is based on connected wattage and calculated hours of use. Examples of unmetered scattered load are cable television amplifiers, billOntario Energy Boards, area lighting. Further servicing details are available in the distributor's Conditions of

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

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It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Debt Retirement Charge, the Global Adjustment, and the HST.

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge (per customer)	$	32.96
Distribution Volumetric Rate	$/kWh	0.0179
Low Voltage Service Rate	$/kWh	0.0002
Rate Rider for Disposition of Deferral/Variance Accounts (2015) – effective until December 31, 2016	$/kWh	0.0008
Rate Rider for Disposition of Global Adjustment Account (2015) – effective until December 31, 2016 Applicable only for Non-RPP Customers	$/kWh	(0.0025)
Rate Rider for Disposition of Deferral/Variance Accounts (2016) – effective until December 31, 2017	$/kWh	(0.0005)
Rate Rider for Disposition of Global Adjustment Account (2016) – effective until December 31, 2017 Applicable only for Non-RPP Customers	$/kWh	0.0037
Retail Transmission Rate – Network Service Rate	$/kWh	0.0064
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	0.0051

MONTHLY RATES AND CHARGES - Regulatory Component

Wholesale Market Service Rate	$/kWh	0.0036
Rural or Remote Electricity Rate Protection Charge (RRRP)	$/kWh	0.0013
Ontario Electricity Support Program Charge (OESP)	$/kWh	0.0011
Standard Supply Service - Administrative Charge (if applicable)	$	0.25

Canadian Niagara Power Inc.

TARIFF OF RATES AND CHARGES

Effective and Implementation Date January 1, 2016

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EB-2015-0058

Fort Erie Service Area

SENTINEL LIGHTING SERVICE CLASSIFICATION

This classification refers to all services required to supply sentinel lighting equipment. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

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It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Debt Retirement Charge, the Global Adjustment, and the HST.

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge (per connection)	$	5.09
Distribution Volumetric Rate	$/kW	5.9010
Low Voltage Service Rate	$/kW	0.0542
Rate Rider for Disposition of Deferral/Variance Accounts (2015) – effective until December 31, 2016	$/kW	0.1459
Rate Rider for Disposition of Global Adjustment Account (2015) – effective until December 31, 2016 Applicable only for Non-RPP Customers	$/kW	(0.4758)
Rate Rider for Disposition of Deferral/Variance Accounts (2016) – effective until December 31, 2017	$/kW	(0.1318)
Retail Transmission Rate – Network Service Rate	$/kW	2.2129
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	1.6977

MONTHLY RATES AND CHARGES - Regulatory Component

Wholesale Market Service Rate	$/kWh	0.0036
Rural or Remote Electricity Rate Protection Charge (RRRP)	$/kWh	0.0013
Ontario Electricity Support Program Charge (OESP)	$/kWh	0.0011
Standard Supply Service - Administrative Charge (if applicable)	$	0.25

Canadian Niagara Power Inc.

TARIFF OF RATES AND CHARGES

Effective and Implementation Date January 1, 2016

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Fort Erie Service Area

STREET LIGHTING SERVICE CLASSIFICATION

This classification refers to the supply of electrical service for roadway lighting. Energy consumption is based on connected wattage and calculated hours of use. Customers are usually a Municipality, Region or the Ministry of Transportation. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

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MONTHLY RATES AND CHARGES - Delivery Component

Service Charge (per connection)	$	4.96
Distribution Volumetric Rate	$/kW	10.7965
Low Voltage Service Rate	$/kW	0.0507
Rate Rider for Disposition of Deferral/Variance Accounts (2015) – effective until December 31, 2016	$/kW	0.2456
Rate Rider for Disposition of Global Adjustment Account (2015) – effective until December 31, 2016 Applicable only for Non-RPP Customers	$/kW	(0.7670)
Rate Rider for Disposition of Deferral/Variance Accounts (2016) – effective until December 31, 2017	$/kW	(0.1521)
Rate Rider for Disposition of Global Adjustment Account (2016) – effective until December 31, 2017 Applicable only for Non-RPP Customers	$/kW	1.2279
Retail Transmission Rate – Network Service Rate	$/kW	1.9219
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	1.5873

MONTHLY RATES AND CHARGES - Regulatory Component

Wholesale Market Service Rate	$/kWh	0.0036
Rural or Remote Electricity Rate Protection Charge (RRRP)	$/kWh	0.0013
Ontario Electricity Support Program Charge (OESP)	$/kWh	0.0011
Standard Supply Service - Administrative Charge (if applicable)	$	0.25

Canadian Niagara Power Inc.
TARIFF OF RATES AND CHARGES
Effective and Implementation Date January 1, 2016

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Fort Erie Service Area

microFIT SERVICE CLASSIFICATION

This classification applies to an electricity generation facility contracted under the Independent Electricity System Operator's microFIT program and connected to the distributor's distribution system. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

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MONTHLY RATES AND CHARGES - Delivery Component

Service Charge	$	5.40

Canadian Niagara Power Inc.
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Effective and Implementation Date January 1, 2016

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Eastern Ontario Power Service Area
RESIDENTIAL SERVICE CLASSIFICATION

The Residential Class (Regular) refers to a service taking electricity normally at 750 volts or less where the electricity is used for domestic and household purposes in a single family unit. A single family unit being a permanent structure located on a single parcel of land and approved by a civic authority as a dwelling and occupied for that purpose by a single customer. Residential rates are also applied to apartment buildings with 6 units or less that are bulk metered. Apartment buildings with more than 6 units that are bulk metered are deemed to be General Service. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

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MONTHLY RATES AND CHARGES - Delivery Component

Service Charge	$	23.44
Rate Rider for Smart Meter Entity Charge - effective until October 31, 2018	$	0.79
Distribution Volumetric Rate	$/kWh	0.0152
Low Voltage Service Rate	$/kWh	0.0002
Rate Rider for Disposition of Deferral/Variance Accounts (2015) – effective until December 31, 2016	$/kWh	0.0003
Rate Rider for Disposition of Global Adjustment Account (2015) – effective until December 31, 2016 Applicable only for Non-RPP Customers	$/kWh	0.0075
Rate Rider for Disposition of Deferral/Variance Accounts (2016) – effective until December 31, 2017	$/kWh	(0.0027)
Rate Rider for Disposition of Global Adjustment Account (2016) – effective until December 31, 2017 Applicable only for Non-RPP Customers	$/kWh	0.0105
Retail Transmission Rate – Network Service Rate	$/kWh	0.0072
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	0.0058

MONTHLY RATES AND CHARGES - Regulatory Component

Wholesale Market Service Rate	$/kWh	0.0036
Rural or Remote Electricity Rate Protection Charge (RRRP)	$/kWh	0.0013
Ontario Electricity Support Program Charge (OESP)	$/kWh	0.0011
Standard Supply Service - Administrative Charge (if applicable)	$	0.25

Canadian Niagara Power Inc.
TARIFF OF RATES AND CHARGES
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Eastern Ontario Power Service Area
GENERAL SERVICE LESS THAN 50 kW SERVICE CLASSIFICATION

This classification refers to the supply of electrical energy to single commercial or industrial customer and whose average peak demand is (or is forecasted to be) less than 50 kW. Single commercial or industrial customers are interpreted as a structure or structures on a single parcel of land occupied by one customer. An apartment building with more than 6 units that is bulk metered and has an average peak demand less than 50 kW is deemed to be General Service less than 50 kW. The common area of a separately metered apartment building having a demand less than 50 kW is also deemed to be General Service less than 50 kW. Further servicing details are available in the distributor’s Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

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MONTHLY RATES AND CHARGES - Delivery Component

Service Charge	$	28.26
Rate Rider for Smart Meter Entity Charge - effective until October 31, 2018	$	0.79
Distribution Volumetric Rate	$/kWh	0.0230
Low Voltage Service Rate	$/kWh	0.0002
Rate Rider for Disposition of Deferral/Variance Accounts (2015) – effective until December 31, 2016	$/kWh	0.0003
Rate Rider for Disposition of Global Adjustment Account (2015) – effective until December 31, 2016 Applicable only for Non-RPP Customers	$/kWh	0.0075
Rate Rider for Disposition of Deferral/Variance Accounts (2016) – effective until December 31, 2017	$/kWh	(0.0027)
Rate Rider for Disposition of Global Adjustment Account (2016) – effective until December 31, 2017 Applicable only for Non-RPP Customers	$/kWh	0.0105
Retail Transmission Rate – Network Service Rate	$/kWh	0.0061
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	0.0050

MONTHLY RATES AND CHARGES - Regulatory Component

Wholesale Market Service Rate	$/kWh	0.0036
Rural or Remote Electricity Rate Protection Charge (RRRP)	$/kWh	0.0013
Ontario Electricity Support Program Charge (OESP)	$/kWh	0.0011
Standard Supply Service - Administrative Charge (if applicable)	$	0.25

Canadian Niagara Power Inc.
TARIFF OF RATES AND CHARGES
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Eastern Ontario Power Service Area

GENERAL SERVICE 50 to 4,999 kW SERVICE CLASSIFICATION

This classification refers to the supply of electrical energy to single commercial or industrial customer and whose average peak demand is (or is forecasted to be) equal to or greater than 50 kW but less than 5000 kW. Single commercial or industrial customers are interpreted as a structure or structures on a single parcel of land occupied by one customer. Further servicing details are available in the distributor's Conditions of Service.

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MONTHLY RATES AND CHARGES - Delivery Component

Service Charge	$	151.83
Distribution Volumetric Rate	$/kW	6.6887
Low Voltage Service Rate	$/kW	0.0735
Rate Rider for Disposition of Deferral/Variance Accounts (2015) – effective until December 31, 2016	$/kW	0.0758
Rate Rider for Disposition of Global Adjustment Account (2015) – effective until December 31, 2016 Applicable only for Non-RPP Customers	$/kW	2.6877
Rate Rider for Disposition of Deferral/Variance Accounts (2016) – effective until December 31, 2017	$/kW	(0.9950)
Rate Rider for Disposition of Global Adjustment Account (2016) – effective until December 31, 2017 Applicable only for Non-RPP Customers	$/kW	3.8538
Retail Transmission Rate – Network Service Rate	$/kW	2.5966
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	2.0803

MONTHLY RATES AND CHARGES - Regulatory Component

Wholesale Market Service Rate	$/kWh	0.0036
Rural or Remote Electricity Rate Protection Charge (RRRP)	$/kWh	0.0013
Ontario Electricity Support Program Charge (OESP)	$/kWh	0.0011
Standard Supply Service - Administrative Charge (if applicable)	$	0.25

Canadian Niagara Power Inc.
TARIFF OF RATES AND CHARGES
Effective and Implementation Date January 1, 2016

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EB-2015-0058

Eastern Ontario Power Service Area

UNMETERED SCATTERED LOAD SERVICE CLASSIFICATION

This classification refers to the supply of electrical service to a customer that is deemed to have a constant load over a billing period, normally with minimum electrical consumption and the consumption is unmetered. Energy consumption is based on connected wattage and calculated hours of use. Examples of unmetered scattered load are cable television amplifiers, billOntario Energy Boards, area lighting. Further servicing details are available in the distributor's Conditions of Service.

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MONTHLY RATES AND CHARGES - Delivery Component

Service Charge (per customer)	$	32.96
Distribution Volumetric Rate	$/kWh	0.0179
Low Voltage Service Rate	$/kWh	0.0002
Rate Rider for Disposition of Deferral/Variance Accounts (2015) – effective until December 31, 2016	$/kWh	0.0003
Rate Rider for Disposition of Deferral/Variance Accounts (2016) – effective until December 31, 2017	$/kWh	(0.0027)
Retail Transmission Rate – Network Service Rate	$/kWh	0.0064
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	0.0051

MONTHLY RATES AND CHARGES - Regulatory Component

Wholesale Market Service Rate	$/kWh	0.0036
Rural or Remote Electricity Rate Protection Charge (RRRP)	$/kWh	0.0013
Ontario Electricity Support Program Charge (OESP)	$/kWh	0.0011
Standard Supply Service - Administrative Charge (if applicable)	$	0.25

Canadian Niagara Power Inc.

TARIFF OF RATES AND CHARGES

Effective and Implementation Date January 1, 2016

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EB-2015-0058

Eastern Ontario Power Service Area

SENTINEL LIGHTING SERVICE CLASSIFICATION

This classification refers to all services required to supply sentinel lighting equipment. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

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It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Debt Retirement Charge, the Global Adjustment, and the HST.

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge (per connection)	$	5.09
Distribution Volumetric Rate	$/kW	5.9010
Low Voltage Service Rate	$/kW	0.0542
Rate Rider for Disposition of Deferral/Variance Accounts (2015) – effective until December 31, 2016	$/kW	0.2209
Rate Rider for Disposition of Deferral/Variance Accounts (2016) – effective until December 31, 2017	$/kW	(0.8848)
Retail Transmission Rate – Network Service Rate	$/kW	2.2129
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	1.6977

MONTHLY RATES AND CHARGES - Regulatory Component

Wholesale Market Service Rate	$/kWh	0.0036
Rural or Remote Electricity Rate Protection Charge (RRRP)	$/kWh	0.0013
Ontario Electricity Support Program Charge (OESP)	$/kWh	0.0011
Standard Supply Service - Administrative Charge (if applicable)	$	0.25

Canadian Niagara Power Inc.

TARIFF OF RATES AND CHARGES

Effective and Implementation Date January 1, 2016

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

EB-2015-0058

Eastern Ontario Power Service Area

STREET LIGHTING SERVICE CLASSIFICATION

This classification refers to the supply of electrical service for roadway lighting. Energy consumption is based on connected wattage and calculated hours of use. Customers are usually a Municipality, Region or the Ministry of Transportation. Further servicing details are available in the distributor’s Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor’s Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable. In addition, the charges in the MONTHLY RATES AND CHARGES – Regulatory Component of this schedule do not apply to a customer that is an embedded wholesale market participant.

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Debt Retirement Charge, the Global Adjustment, and the HST.

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge (per connection)	$	4.96
Distribution Volumetric Rate	$/kW	10.7965
Low Voltage Service Rate	$/kW	0.0507
Rate Rider for Disposition of Deferral/Variance Accounts (2015) – effective until December 31, 2016	$/kW	0.0756
Rate Rider for Disposition of Global Adjustment Account (2015) – effective until December 31, 2016 Applicable only for Non-RPP Customers	$/kW	2.4810
Rate Rider for Disposition of Deferral/Variance Accounts (2016) – effective until December 31, 2017	$/kW	(0.8905)
Rate Rider for Disposition of Global Adjustment Account (2016) – effective until December 31, 2017 Applicable only for Non-RPP Customers	$/kW	3.4611
Retail Transmission Rate – Network Service Rate	$/kW	1.9219
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	1.5873

MONTHLY RATES AND CHARGES - Regulatory Component

Wholesale Market Service Rate	$/kWh	0.0036
Rural or Remote Electricity Rate Protection Charge (RRRP)	$/kWh	0.0013
Ontario Electricity Support Program Charge (OESP)	$/kWh	0.0011
Standard Supply Service - Administrative Charge (if applicable)	$	0.25

Canadian Niagara Power Inc.

TARIFF OF RATES AND CHARGES

Effective and Implementation Date January 1, 2016

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EB-2015-0058

Eastern Ontario Power Service Area

microFIT SERVICE CLASSIFICATION

This classification applies to an electricity generation facility contracted under the Independent Electricity System Operator's microFIT program and connected to the distributor's distribution system. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable.

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Debt Retirement Charge, the Global Adjustment, and the HST.

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge	$	5.40

Canadian Niagara Power Inc.
TARIFF OF RATES AND CHARGES
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Port Colborne Service Area

RESIDENTIAL SERVICE CLASSIFICATION

The Residential Class (Regular) refers to a service taking electricity normally at 750 volts or less where the electricity is used for domestic and household purposes in a single family unit. A single family unit being a permanent structure located on a single parcel of land and approved by a civic authority as a dwelling and occupied for that purpose by a single customer. Residential rates are also applied to apartment buildings with 6 units or less that are bulk metered. Apartment buildings with more than 6 units that are bulk metered are deemed to be General Service. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable. In addition, the charges in the MONTHLY RATES AND CHARGES – Regulatory Component of this schedule do not apply to a customer that is an embedded wholesale market participant.

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Debt Retirement Charge, the Global Adjustment, and the HST.

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge	$	23.44
Rate Rider for Smart Meter Entity Charge - effective until October 31, 2018	$	0.79
Distribution Volumetric Rate	$/kWh	0.0152
Low Voltage Service Rate	$/kWh	0.0002
Rate Rider for Disposition of Deferral/Variance Accounts (2015) – effective until December 31, 2016	$/kWh	(0.0007)
Rate Rider for Disposition of Global Adjustment Account (2015) – effective until December 31, 2016 Applicable only for Non-RPP Customers	$/kWh	(0.0023)
Rate Rider for Disposition of Deferral/Variance Accounts (2016) – effective until December 31, 2017	$/kWh	(0.0013)
Rate Rider for Disposition of Global Adjustment Account (2016) – effective until December 31, 2017 Applicable only for Non-RPP Customers	$/kWh	0.0019
Rate Rider for Disposition of Deferred PIL's Variance Account 1562 – effective until December 31, 2016	$/kWh	0.0007
Retail Transmission Rate – Network Service Rate	$/kWh	0.0072
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	0.0058

MONTHLY RATES AND CHARGES - Regulatory Component

Wholesale Market Service Rate	$/kWh	0.0036
Rural or Remote Electricity Rate Protection Charge (RRRP)	$/kWh	0.0013
Ontario Electricity Support Program Charge (OESP)	$/kWh	0.0011
Standard Supply Service - Administrative Charge (if applicable)	$	0.25

Canadian Niagara Power Inc.

TARIFF OF RATES AND CHARGES

Effective and Implementation Date January 1, 2016

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Port Colborne Service Area

GENERAL SERVICE LESS THAN 50 kW SERVICE CLASSIFICATION

This classification refers to the supply of electrical energy to single commercial or industrial customer and whose average peak demand is (or is forecasted to be) less than 50 kW. Single commercial or industrial customers are interpreted as a structure or structures on a single parcel of land occupied by one customer. An apartment building with more than 6 units that is bulk metered and has an average peak demand less than 50 kW is deemed to be General Service less than 50 kW. The common area of a separately metered apartment building having a demand less than 50 kW is also deemed to be General Service less than 50 kW. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable. In addition, the charges in the MONTHLY RATES AND CHARGES – Regulatory Component of this schedule do not apply to a customer that is an embedded wholesale market participant.

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Debt Retirement Charge, the Global Adjustment, and the HST.

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge	$	28.26
Rate Rider for Smart Meter Entity Charge - effective until October 31, 2018	$	0.79
Distribution Volumetric Rate	$/kWh	0.0230
Low Voltage Service Rate	$/kWh	0.0002
Rate Rider for Disposition of Deferral/Variance Accounts (2015) – effective until December 31, 2016	$/kWh	(0.0006)
Rate Rider for Disposition of Global Adjustment Account (2015) – effective until December 31, 2016 Applicable only for Non-RPP Customers	$/kWh	(0.0023)
Rate Rider for Disposition of Deferral/Variance Accounts (2016) – effective until December 31, 2017	$/kWh	(0.0013)
Rate Rider for Disposition of Global Adjustment Account (2016) – effective until December 31, 2017 Applicable only for Non-RPP Customers	$/kWh	0.0019
Rate Rider for Disposition of Deferred PIL's Variance Account 1562 – effective until December 31, 2016	$/kWh	0.0005
Retail Transmission Rate – Network Service Rate	$/kWh	0.0061
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	0.0050

MONTHLY RATES AND CHARGES - Regulatory Component

Wholesale Market Service Rate	$/kWh	0.0036
Rural or Remote Electricity Rate Protection Charge (RRRP)	$/kWh	0.0013
Ontario Electricity Support Program Charge (OESP)	$/kWh	0.0011
Standard Supply Service - Administrative Charge (if applicable)	$	0.25

Canadian Niagara Power Inc.

TARIFF OF RATES AND CHARGES

Effective and Implementation Date January 1, 2016

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Port Colborne Service Area

GENERAL SERVICE 50 to 4,999 kW SERVICE CLASSIFICATION

This classification refers to the supply of electrical energy to single commercial or industrial customer and whose average peak demand is (or is forecasted to be) equal to or greater than 50 kW but less than 5000 kW. Single commercial or industrial customers are interpreted as a structure or structures on a single parcel of land occupied by one customer. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable. In addition, the charges in the MONTHLY RATES AND CHARGES – Regulatory Component of this schedule do not apply to a customer that is an embedded wholesale market participant.

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Debt Retirement Charge, the Global Adjustment, and the HST.

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge	$	151.83
Distribution Volumetric Rate	$/kW	6.6887
Low Voltage Service Rate	$/kW	0.0735
Rate Rider for Disposition of Deferral/Variance Accounts (2015) – effective until December 31, 2016	$/kW	(0.0384)
Rate Rider for Disposition of Global Adjustment Account (2015) – effective until December 31, 2016 Applicable only for Non-RPP Customers	$/kW	(0.6742)
Rate Rider for Disposition of Deferral/Variance Accounts (2016) – effective until December 31, 2017	$/kW	(0.4054)
Rate Rider for Disposition of Global Adjustment Account (2016) – effective until December 31, 2017 Applicable only for Non-RPP Customers	$/kW	0.6224
Rate Rider for Disposition of Deferred PIL's Variance Account 1562 – effective until December 31, 2016	$/kW	0.0811
Retail Transmission Rate – Network Service Rate	$/kW	2.5966
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	2.0803

MONTHLY RATES AND CHARGES - Regulatory Component

Wholesale Market Service Rate	$/kWh	0.0036
Rural or Remote Electricity Rate Protection Charge (RRRP)	$/kWh	0.0013
Ontario Electricity Support Program Charge (OESP)	$/kWh	0.0011
Standard Supply Service - Administrative Charge (if applicable)	$	0.25

Canadian Niagara Power Inc.
TARIFF OF RATES AND CHARGES
Effective and Implementation Date January 1, 2016

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Port Colborne Service Area

UNMETERED SCATTERED LOAD SERVICE CLASSIFICATION

This classification refers to the supply of electrical service to a customer that is deemed to have a constant load over a billing period, normally with minimum electrical consumption and the consumption is unmetered. Energy consumption is based on connected wattage and calculated hours of use. Examples of unmetered scattered load are cable television amplifiers, billOntario Energy Boards, area lighting. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable. In addition, the charges in the MONTHLY RATES AND CHARGES – Regulatory Component of this schedule do not apply to a customer that is an embedded wholesale market participant.

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Debt Retirement Charge, the Global Adjustment, and the HST.

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge (per customer)	$	32.96
Distribution Volumetric Rate	$/kWh	0.0179
Low Voltage Service Rate	$/kWh	0.0002
Rate Rider for Disposition of Deferral/Variance Accounts (2015) – effective until December 31, 2016	$/kWh	(0.0008)
Rate Rider for Disposition of Global Adjustment Account (2015) – effective until December 31, 2016 Applicable only for Non-RPP Customers	$/kWh	(0.0023)
Rate Rider for Disposition of Deferral/Variance Accounts (2016) – effective until December 31, 2017	$/kWh	(0.0013)
Rate Rider for Disposition of Global Adjustment Account (2016) – effective until December 31, 2017 Applicable only for Non-RPP Customers	$/kWh	0.0019
Rate Rider for Disposition of Deferred PIL's Variance Account 1562 – effective until December 31, 2016	$/kWh	0.0006
Retail Transmission Rate – Network Service Rate	$/kWh	0.0064
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	0.0051

MONTHLY RATES AND CHARGES - Regulatory Component

Wholesale Market Service Rate	$/kWh	0.0036
Rural or Remote Electricity Rate Protection Charge (RRRP)	$/kWh	0.0013
Ontario Electricity Support Program Charge (OESP)	$/kWh	0.0011
Standard Supply Service - Administrative Charge (if applicable)	$	0.25

Canadian Niagara Power Inc.
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Port Colborne Service Area

STANDBY POWER SERVICE CLASSIFICATION

The Standby subclass charge is applied to a customer with load displacement facilities behind its meter but is dependent on Canadian Niagara Power Inc. to supply a minimum amount of electricity in the event the customer's own facilities are out of service. The minimum amount of supply that Canadian Niagara Power Inc. must supply is a contracted amount agreed upon between the customer and Canadian Niagara Power Inc. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

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It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Debt Retirement Charge, the Global Adjustment, and the HST.

MONTHLY RATES AND CHARGES – APPROVED ON AN INTERIM BASIS

Standby Charge – for a month where standby power is not provided. The charge is applied to the contracted amount (e.g. nameplate rating of generation facility)	$/kW	1.1676

Canadian Niagara Power Inc.

TARIFF OF RATES AND CHARGES

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Port Colborne Service Area

SENTINEL LIGHTING SERVICE CLASSIFICATION

This classification refers to all services required to supply sentinel lighting equipment. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

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It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Debt Retirement Charge, the Global Adjustment, and the HST.

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge (per connection)	$	5.09
Distribution Volumetric Rate	$/kW	5.9010
Low Voltage Service Rate	$/kW	0.0542
Rate Rider for Disposition of Deferral/Variance Accounts (2015) – effective until December 31, 2016	$/kW	(0.2560)
Rate Rider for Disposition of Deferral/Variance Accounts (2016) – effective until December 31, 2017	$/kW	(0.3854)
Rate Rider for Disposition of Deferred PIL's Variance Account 1562 – effective until December 31, 2016	$/kW	0.9420
Retail Transmission Rate – Network Service Rate	$/kW	2.2129
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	1.6977

MONTHLY RATES AND CHARGES - Regulatory Component

Wholesale Market Service Rate	$/kWh	0.0036
Rural or Remote Electricity Rate Protection Charge (RRRP)	$/kWh	0.0013
Ontario Electricity Support Program Charge (OESP)	$/kWh	0.0011
Standard Supply Service - Administrative Charge (if applicable)	$	0.25

Canadian Niagara Power Inc.
TARIFF OF RATES AND CHARGES
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Port Colborne Service Area

STREET LIGHTING SERVICE CLASSIFICATION

This classification refers to the supply of electrical service for roadway lighting. Energy consumption is based on connected wattage and calculated hours of use. Customers are usually a Municipality, Region or the Ministry of Transportation. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable. In addition, the charges in the MONTHLY RATES AND CHARGES – Regulatory Component of this schedule do not apply to a customer that is an embedded wholesale market participant.

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Debt Retirement Charge, the Global Adjustment, and the HST.

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge (per connection)	$	4.96
Distribution Volumetric Rate	$/kW	10.7965
Low Voltage Service Rate	$/kW	0.0507
Rate Rider for Disposition of Deferral/Variance Accounts (2015) – effective until December 31, 2016	$/kW	(0.0490)
Rate Rider for Disposition of Global Adjustment Account (2015) – effective until December 31, 2016 Applicable only for Non-RPP Customers	$/kW	(0.7799)
Rate Rider for Disposition of Deferral/Variance Accounts (2016) – effective until December 31, 2017	$/kW	(0.4066)
Rate Rider for Disposition of Global Adjustment Account (2016) – effective until December 31, 2017 Applicable only for Non-RPP Customers	$/kW	0.6364
Rate Rider for Disposition of Deferred PIL's Variance Account 1562 – effective until December 31, 2016	$/kW	0.4369
Retail Transmission Rate – Network Service Rate	$/kW	1.9219
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	1.5873

MONTHLY RATES AND CHARGES - Regulatory Component

Wholesale Market Service Rate	$/kWh	0.0036
Rural or Remote Electricity Rate Protection Charge (RRRP)	$/kWh	0.0013
Ontario Electricity Support Program Charge (OESP)	$/kWh	0.0011
Standard Supply Service - Administrative Charge (if applicable)	$	0.25

Canadian Niagara Power Inc.
TARIFF OF RATES AND CHARGES
Effective and Implementation Date January 1, 2016

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Port Colborne Service Area

microFIT SERVICE CLASSIFICATION

This classification applies to an electricity generation facility contracted under the Independent Electricity System Operator's microFIT program and connected to the distributor's distribution system. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable.

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Debt Retirement Charge, the Global Adjustment, and the HST.

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge	$	5.40

Canadian Niagara Power Inc.
TARIFF OF RATES AND CHARGES
Effective and Implementation Date January 1, 2016

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All Service Areas
ONTARIO ELECTRICITY SUPPORT PROGRAM RECIPIENTS

In addition to the charges specified on Residential Classification pages of this tariff of rates and charges, the following credits are to be applied to eligible residential customers.

APPLICATION

The application of the charges are in accordance with the Distribution System Code (Section 9) and subsection 79.2(4) of the Ontario Energy Board Act, 1998.

The application of these charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

In this class:

"Aboriginal person" includes a person who is a First Nations person, a Métis person or an Inuit person;
"account-holder" means a consumer who has an account with a distributor that falls within a residential-rate classification as specified in a rate order made by the Ontario Energy Board under section 78 of the Act, and who lives at the service address to which the account relates for at least six months in a year;
"electricity-intensive medical device" means an oxygen concentrator, a mechanical ventilator, or such other device as may be specified by the Ontario Energy Board;
"household" means the account-holder and any other people living at the accountholder's service address for at least six months in a year, including people other than the account-holder's spouse, children or other relatives;
"household income" means the combined annual after-tax income of all members of a household aged 16 or over;

MONTHLY RATES AND CHARGES

Class A

(a) account-holders with a household income of $28,000 or less living in a household of one or two persons;
(b) account-holders with a household income of between $28,001 and $39,000 living in a household of three persons;
(c) account-holders with a household income of between $39,001 and $48,000 living in a household of five persons; and
(d) account-holders with a household income of between $48,001 and $52,000 living in a household of seven or more persons;
but does not include account-holders in Class E.

OESP Credit	$	(30.00)

Class B

(a) account-holders with a household income of $28,000 or less living in a household of three persons;
(b) account-holders with a household income of between $28,001 and $39,000 living in a household of four persons;
(c) account-holders with a household income of between $39,001 and $48,000 living in a household of six persons;
but does not include account-holders in Class F.

OESP Credit	$	(34.00)

Class C

(a) account-holders with a household income of $28,000 or less living in a household of four persons;
(b) account-holders with a household income of between $28,001 and $39,000 living in a household of five persons;
(c) account-holders with a household income of between $39,001 and $48,000 living in a household of seven or more persons;
but does not include account-holders in Class G.

OESP Credit	$	(38.00)

Class D

(a) account-holders with a household income of $28,000 or less living in a household of five persons; and
(b) account-holders with a household income of between $28,001 and $39,000 living in a household of six persons;
but does not include account-holders in Class H.

OESP Credit	$	(42.00)

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All Service Areas
ONTARIO ELECTRICITY SUPPORT PROGRAM RECIPIENTS

Class E

Class E comprises account-holders with a household income and household size described under Class A who also meet any of the following conditions:
(a) the dwelling to which the account relates is heated primarily by electricity;
(b) the account-holder or any member of the account-holder's household is an Aboriginal person; or
(c) the account-holder or any member of the account-holder's household regularly uses, for medical purposes, an electricity-intensive medical device at the dwelling to which the account relates.

OESP Credit	$	(45.00)

Class F

(a) account-holders with a household income of $28,000 or less living in a household of six or more persons;
(b) account-holders with a household income of between $28,001 and $39,000 living in a household of seven or more persons; or
(c) account-holders with a household income and household size described under Class B who also meet any of the following conditions:

i. the dwelling to which the account relates is heated primarily by electricity;
ii. the account-holder or any member of the account-holder's household is an Aboriginal person; or
iii. the account-holder or any member of the account-holder's household regularly uses, for medical purposes, an electricity-intensive medical device at the dwelling to which the account relates

OESP Credit	$	(50.00)

Class G

Class G comprises account-holders with a household income and household size described under Class C who also meet any of the following conditions:
(a) the dwelling to which the account relates is heated primarily by electricity;
(b) the account-holder or any member of the account-holder's household is an Aboriginal person; or
(c) the account-holder or any member of the account-holder's household regularly uses, for medical purposes, an electricity-intensive medical device at the dwelling to which the account relates.

OESP Credit	$	(55.00)

Class H

Class H comprises account-holders with a household income and household size described under Class D who also meet any of the following conditions:
(a) the dwelling to which the account relates is heated primarily by electricity;
(b) the account-holder or any member of the account-holder's household is an Aboriginal person ; or
(c) the account-holder or any member of the account-holder's household regularly uses, for medical purposes, an electricity-intensive medical device at the dwelling to which the account relates.

OESP Credit	$	(60.00)

Class I

Class I comprises account-holders with a household income and household size described under paragraphs (a) or (b) of Class F who also meet any of the following conditions:
(a) the dwelling to which the account relates is heated primarily by electricity;
(b) the account-holder or any member of the account-holder's household is an Aboriginal person; or
(c) the account-holder or any member of the account-holder's household regularly uses, for medical purposes, an electricity-intensive medical device at the dwelling to which the account relates.

OESP Credit	$	(75.00)

Canadian Niagara Power Inc.
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All Service Areas

ALLOWANCES

Transformer Allowance for Ownership - per kW of billing demand/month	$/kW	(0.60)
Primary Metering Allowance for transformer losses – applied to measured demand and energy	%	(1.00)

SPECIFIC SERVICE CHARGES

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Debt Retirement Charge, the Global Adjustment, and the HST.

Customer Administration

Arrears certificate (credit reference)	$	15.00
Statement of Account	$	15.00
Pulling Post Dated Cheques	$	15.00
Duplicate Invoices for previous billing	$	15.00
Request for other billing information	$	15.00
Easement Letter	$	15.00
Income Tax Letter	$	15.00
Notification charge	$	15.00
Account History	$	15.00
Credit Reference/credit check (plus credit agency costs)	$	15.00
Account set up charge/change of occupancy charge (plus credit agency costs if applicable)	$	30.00
Returned cheque charge (plus bank charges)	$	15.00
Charge to certify cheques	$	15.00
Legal letter charge	$	15.00
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 Charges - at meter - during regular hours	$	65.00
Disconnect/Reconnect Charges - at meter - after regular hours	$	185.00
Disconnect/Reconnect Charges at Pole - during regular hours	$	185.00
Disconnect/Reconnect at pole – after regular hours	$	415.00
Install/Remove load control device – during regular hours	$	65.00
Install/Remove load control device - after regular hours	$	185.00

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All Service Areas
SPECIFIC SERVICE CHARGES (continued)

Other

Special meter reads	$	30.00
Service Call - customer owned equipment	$	30.00
Service Call - after regular hours	$	165.00
Temporary service install & remove - overhead - no transformer	$	500.00
Temporary service install & remove - underground - no transformer	$	300.00
Temporary service install & remove - overhead - with transformer	$	1,000.00
Specific Charge for Access to the Power Poles – per pole/year	$	22.35

RETAIL SERVICE CHARGES (if applicable)

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

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Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable.

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Retail Service Charges refer to services provided by a distributor to retailers or customers related to the supply of competitive electricity.

One-time charge, per retailer, to establish the service agreement between the distributor and the retailer	$	100.00
Monthly Fixed Charge, per retailer	$	20.00
Monthly Variable Charge, per customer, per retailer	$/cust.	0.50
Distributor-consolidated billing monthly charge, per customer, per retailer	$/cust.	0.30
Retailer-consolidated billing monthly credit, per customer, per retailer	$/cust.	(0.30)
Service Transaction Requests (STR)		
Request fee, per request, applied to the requesting party	$	0.25
Processing fee, per request, applied to the requesting party	$	0.50
Request for customer information as outlined in Section 10.6.3 and Chapter 11 of the Retail Settlement Code directly to retailers and customers, if not delivered electronically through the Electronic Business Transaction (EBT) system, applied to the requesting party		
Up to twice a year	$	no charge
More than twice a year, per request (plus incremental delivery costs)	$	2.00

LOSS FACTORS

If the distributor is not capable of prorating changed loss factors jointly with distribution rates, the revised loss factors will be implemented upon the first subsequent billing for each billing cycle.

Total Loss Factor – Secondary Metered Customer <5,000kW	1.0542
Total Loss Factor – Primary Metered Customer <5,000kW	1.0437

Proposed Tariff of Rates and Charges

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Canadian Niagara Power Inc.
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RESIDENTIAL SERVICE CLASSIFICATION

The Residential Class (Regular) refers to a service taking electricity normally at 750 volts or less where the electricity is used for domestic and household purposes in a single family unit. A single family unit being a permanent structure located on a single parcel of land and approved by a civic authority as a dwelling and occupied for that purpose by a single customer. Residential rates are also applied to apartment buildings with 6 units or less that are bulk metered. Apartment buildings with more than 6 units that are bulk metered are deemed to be General Service. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable. In addition, the charges in the MONTHLY RATES AND CHARGES – Regulatory Component of this schedule do not apply to a customer that is an embedded wholesale market participant.

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Debt Retirement Charge, the Global Adjustment, and the HST.

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge	$	28.94
Rate Rider for Smart Meter Entity Charge - effective until October 31, 2018	$	0.79
Distribution Volumetric Rate	$/kWh	0.0140
Low Voltage Service Rate	$/kWh	0.0003
Rate Rider for Disposition of Deferral/Variance Accounts (2016) – effective until December 31, 2017	$/kWh	(0.0010)
Rate Rider for Disposition of Global Adjustment Account (2016) – effective until December 31, 2017 Applicable only for Non-RPP Customers	$/kWh	0.0041
Rate Rider for Disposition of Deferral/Variance Accounts (2017) – effective until December 31, 2017	$/kWh	(0.0034)
Rate Rider for Disposition of Global Adjustment Account (2017) – effective until December 31, 2017 Applicable only for Non-RPP Customers	$/kWh	0.0068
Rate Rider for the Recovery of Lost Revenue Adjustment (LRAM) – effective until December 31, 2017	$/kWh	0.0003
Rate Rider for Disposition of Group 2 Deferal/Variance Accounts (2017) – effective until December 31, 2017	$	(0.15)
Retail Transmission Rate – Network Service Rate	$/kWh	0.0069
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	0.0059

MONTHLY RATES AND CHARGES - Regulatory Component

Wholesale Market Service Rate	$/kWh	0.0036
Rural or Remote Electricity Rate Protection Charge (RRRP)	$/kWh	0.0013
Ontario Electricity Support Program Charge (OESP)	$/kWh	0.0011
Standard Supply Service - Administrative Charge (if applicable)	$	0.25

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GENERAL SERVICE LESS THAN 50 kW SERVICE CLASSIFICATION

This classification refers to the supply of electrical energy to single commercial or industrial customer and whose average peak demand is (or is forecasted to be) less than 50 kW. Single commercial or industrial customers are interpreted as a structure or structures on a single parcel of land occupied by one customer. An apartment building with more than 6 units that is bulk metered and has an average peak demand less than 50 kW is deemed to be General Service less than 50 kW. The common area of a separately metered apartment building having a demand less than 50 kW is also deemed to be General Service less than 50 kW. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable. In addition, the charges in the MONTHLY RATES AND CHARGES – Regulatory Component of this schedule do not apply to a customer that is an embedded wholesale market participant.

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Debt Retirement Charge, the Global Adjustment, and the HST.

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge	$	32.02
Rate Rider for Smart Entity Charge - effective until October 31, 2018	$	0.79
Distribution Volumetric Rate	$/kWh	0.0261
Low Voltage Service Rate	$/kWh	0.0003
Rate Rider for Disposition of Deferral/Variance Accounts (2016) – effective until December 31, 2017	$/kWh	(0.0012)
Rate Rider for Disposition of Global Adjustment Account (2016) – effective until December 31, 2017 Applicable only for Non-RPP Customers	$/kWh	0.0039
Rate Rider for Disposition of Deferral/Variance Accounts (2017) – effective until December 31, 2017	$/kWh	(0.0036)
Rate Rider for Disposition of Global Adjustment Account (2017) – effective until December 31, 2017 Applicable only for Non-RPP Customers	$/kWh	0.0068
Rate Rider for the Recovery of Lost Revenue Adjustment (LRAM) – effective until December 31, 2017	$/kWh	0.0019
Retail Transmission Rate – Network Service Rate	$/kWh	0.0058
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	0.0050

MONTHLY RATES AND CHARGES - Regulatory Component

Wholesale Market Service Rate	$/kWh	0.0036
Rural or Remote Electricity Rate Protection Charge (RRRP)	$/kWh	0.0013
Ontario Electricity Support Program Charge (OESP)	$/kWh	0.0011
Standard Supply Service - Administrative Charge (if applicable)	$	0.25

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GENERAL SERVICE 50 to 4,999 kW SERVICE CLASSIFICATION

This classification refers to the supply of electrical energy to single commercial or industrial customer and whose average peak demand is (or is forecasted to be) equal to or greater than 50 kW but less than 5000 kW. Single commercial or industrial customers are interpreted as a structure or structures on a single parcel of land occupied by one customer. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

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It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Debt Retirement Charge, the Global Adjustment, and the HST.

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge	$	172.04
Distribution Volumetric Rate	$/kW	7.5344
Low Voltage Service Rate	$/kW	0.1063
Rate Rider for Disposition of Deferral/Variance Accounts (2016) – effective until December 31, 2017	$/kW	(0.3866)
Rate Rider for Disposition of Global Adjustment Account (2016) – effective until December 31, 2017 Applicable only for Non-RPP Customers	$/kW	1.5024
Rate Rider for Disposition of Deferral/Variance Accounts (2017) – effective until December 31, 2017	$/kW	(1.1366)
Rate Rider for Disposition of Global Adjustment Account (2017) – effective until December 31, 2017 Applicable only for Non-RPP Customers	$/kW	1.9269
Rate Rider for the Recovery of Lost Revenue Adjustment (LRAM) – effective until December 31, 2017	$/kW	0.0957
Rate Rider for Disposition of MIST Meters (2017) – effective until December 31, 2021	$	7.05
Rate Rider for Disposition of Stranded Meters (2017) – effective until December 31, 2021	$	3.60
Rate Rider for Disposition of Global Adjustment Account (2017) - effective until December 31, 2017 Applicable only to Class A, Non-RPP customers who are not Wholesale Market Participants	$/kW	1.0638
Retail Transmission Rate – Network Service Rate	$/kW	2.4754
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	2.1000

MONTHLY RATES AND CHARGES - Regulatory Component

Wholesale Market Service Rate	$/kWh	0.0036
Rural or Remote Electricity Rate Protection Charge (RRRP)	$/kWh	0.0013
Ontario Electricity Support Program Charge (OESP)	$/kWh	0.0011
Standard Supply Service - Administrative Charge (if applicable)	$	0.25

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UNMETERED SCATTERED LOAD SERVICE CLASSIFICATION

This classification refers to the supply of electrical service to a customer that is deemed to have a constant load over a billing period, normally with minimum electrical consumption and the consumption is unmetered. Energy consumption is based on connected wattage and calculated hours of use. Examples of unmetered scattered load are cable television amplifiers, billOntario Energy Boards, area lighting. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

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It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Debt Retirement Charge, the Global Adjustment, and the HST.

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge (per customer)	$	50.53
Distribution Volumetric Rate	$/kWh	0.0274
Low Voltage Service Rate	$/kWh	0.0003
Rate Rider for Disposition of Deferral/Variance Accounts (2016) – effective until December 31, 2017	$/kWh	(0.0011)
Rate Rider for Disposition of Global Adjustment Account (2016) – effective until December 31, 2017 Applicable only for Non-RPP Customers	$/kWh	0.0026
Rate Rider for Disposition of Deferral/Variance Accounts (2017) – effective until December 31, 2017	$/kWh	(0.0037)
Rate Rider for Disposition of Global Adjustment Account (2017) – effective until December 31, 2017 Applicable only for Non-RPP Customers	$/kWh	0.0068
Retail Transmission Rate – Network Service Rate	$/kWh	0.0061
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	0.0051

MONTHLY RATES AND CHARGES - Regulatory Component

Wholesale Market Service Rate	$/kWh	0.0036
Rural or Remote Electricity Rate Protection Charge (RRRP)	$/kWh	0.0013
Ontario Electricity Support Program Charge (OESP)	$/kWh	0.0011
Standard Supply Service - Administrative Charge (if applicable)	$	0.25

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EMBEDDED DISTRIBUTOR

This classification applies to an electricity distributor licensed by the Board, that is provided electricity by means of this distributor's facilities. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

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No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

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It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Debt Retirement Charge, the Global Adjustment, and the HST.

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge	$	584.79
Distribution Volumetric Rate	$/kW	8.3087
Low Voltage Service Rate	$/kW	0.1063
Rate Rider for Disposition of Deferral/Variance Accounts (2016) – effective until December 31, 2017	$/kW	(0.3866)
Rate Rider for Disposition of Global Adjustment Account (2016) – effective until December 31, 2017 Applicable only for Non-RPP Customers	$/kW	1.5024
Rate Rider for Disposition of Deferral/Variance Accounts (2017) – effective until December 31, 2017	$/kW	(1.3685)
Rate Rider for Disposition of Global Adjustment Account (2017) – effective until December 31, 2017 Applicable only for Non-RPP Customers	$/kW	2.5499
Retail Transmission Rate – Network Service Rate	$/kW	2.4654
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	2.1000

MONTHLY RATES AND CHARGES - Regulatory Component

Wholesale Market Service Rate	$/kWh	0.0036
Rural or Remote Electricity Rate Protection Charge (RRRP)	$/kWh	0.0013
Ontario Electricity Support Program Charge (OESP)	$/kWh	0.0011
Standard Supply Service - Administrative Charge (if applicable)	$	0.25

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SENTINEL LIGHTING SERVICE CLASSIFICATION

This classification refers to all services required to supply sentinel lighting equipment. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

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It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Debt Retirement Charge, the Global Adjustment, and the HST.

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge (per connection)	$	5.77
Distribution Volumetric Rate	$/kW	6.6867
Low Voltage Service Rate	$/kW	0.0867
Rate Rider for Disposition of Deferral/Variance Accounts (2016) – effective until December 31, 2017	$/kW	(0.1918)
Rate Rider for Disposition of Deferral/Variance Accounts (2017) – effective until December 31, 2017	$/kW	(1.2014)
Retail Transmission Rate – Network Service Rate	$/kW	2.1097
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	1.7138

MONTHLY RATES AND CHARGES - Regulatory Component

Wholesale Market Service Rate	$/kWh	0.0036
Rural or Remote Electricity Rate Protection Charge (RRRP)	$/kWh	0.0013
Ontario Electricity Support Program Charge (OESP)	$/kWh	0.0011
Standard Supply Service - Administrative Charge (if applicable)	$	0.25

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STREET LIGHTING SERVICE CLASSIFICATION

This classification refers to the supply of electrical service for roadway lighting. Energy consumption is based on connected wattage and calculated hours of use. Customers are usually a Municipality, Region or the Ministry of Transportation. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

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It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Debt Retirement Charge, the Global Adjustment, and the HST.

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge (per connection)	$	4.06
Distribution Volumetric Rate	$/kW	8.8324
Low Voltage Service Rate	$/kW	0.0811
Rate Rider for Disposition of Deferral/Variance Accounts (2016) – effective until December 31, 2017	$/kW	(0.5255)
Rate Rider for Disposition of Global Adjustment Account (2016) – effective until December 31, 2017 Applicable only for Non-RPP Customers	$/kW	1.9654
Rate Rider for Disposition of Deferral/Variance Accounts (2017) – effective until December 31, 2017	$/kW	(1.1849)
Rate Rider for Disposition of Global Adjustment Account (2017 – effective until December 31, 2017 Applicable only for Non-RPP Customers	$/kW	2.2078
Retail Transmission Rate – Network Service Rate	$/kW	1.8322
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	1.6024

MONTHLY RATES AND CHARGES - Regulatory Component

Wholesale Market Service Rate	$/kWh	0.0036
Rural or Remote Electricity Rate Protection Charge (RRRP)	$/kWh	0.0013
Ontario Electricity Support Program Charge (OESP)	$/kWh	0.0011
Standard Supply Service - Administrative Charge (if applicable)	$	0.25

Canadian Niagara Power Inc.
TARIFF OF RATES AND CHARGES
Effective and Implementation Date January 1, 2017

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

EB-2016-0061

microFIT SERVICE CLASSIFICATION

This classification applies to an electricity generation facility contracted under the Independent Electricity System Operator's microFIT program and connected to the distributor's distribution system. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable.

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Debt Retirement Charge, the Global Adjustment, and the HST.

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge	$	5.40

Canadian Niagara Power Inc.
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STANDBY POWER SERVICE CLASSIFICATION

The Standby subclass charge is applied to a customer with load displacement facilities behind its meter but is dependent on Canadian Niagara Power Inc. to supply a minimum amount of electricity in the event the customer's own facilities are out of service. The minimum amount of supply that Canadian Niagara Power Inc. must supply is a contracted amount agreed upon between the customer and Canadian Niagara Power Inc. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable.

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Debt Retirement Charge, the Global Adjustment, and the HST.

MONTHLY RATES AND CHARGES – APPROVED ON AN INTERIM BASIS

Standby Charge – for a month where standby power is not provided. The charge is applied to the contracted amount (e.g. nameplate rating of generation facility)	$/kW	1.1676

Canadian Niagara Power Inc.

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ONTARIO ELECTRICITY SUPPORT PROGRAM RECIPIENTS

In addition to the charges specified on Residential Classification pages of this tariff of rates and charges, the following credits are to be applied to eligible residential customers.

APPLICATION

The application of the charges are in accordance with the Distribution System Code (Section 9) and subsection 79.2(4) of the Ontario Energy Board Act, 1998.

The application of these charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

In this class:

"Aboriginal person" includes a person who is a First Nations person, a Métis person or an Inuit person;
"account-holder" means a consumer who has an account with a distributor that falls within a residential-rate classification as specified in a rate order made by the Ontario Energy Board under section 78 of the Act, and who lives at the service address to which the account relates for at least six months in a year;
"electricity-intensive medical device" means an oxygen concentrator, a mechanical ventilator, or such other device as may be specified by the Ontario Energy Board;
"household" means the account-holder and any other people living at the accountholder's service address for at least six months in a year, including people other than the account-holder's spouse, children or other relatives;
"household income" means the combined annual after-tax income of all members of a household aged 16 or over;

MONTHLY RATES AND CHARGES

Class A

(a) account-holders with a household income of $28,000 or less living in a household of one or two persons;
(b) account-holders with a household income of between $28,001 and $39,000 living in a household of three persons;
(c) account-holders with a household income of between $39,001 and $48,000 living in a household of five persons; and
(d) account-holders with a household income of between $48,001 and $52,000 living in a household of seven or more persons;
but does not include account-holders in Class E.

OESP Credit	$	(30.00)

Class B

(a) account-holders with a household income of $28,000 or less living in a household of three persons;
(b) account-holders with a household income of between $28,001 and $39,000 living in a household of four persons;
(c) account-holders with a household income of between $39,001 and $48,000 living in a household of six persons;
but does not include account-holders in Class F.

OESP Credit	$	(34.00)

Class C

(a) account-holders with a household income of $28,000 or less living in a household of four persons;
(b) account-holders with a household income of between $28,001 and $39,000 living in a household of five persons;
(c) account-holders with a household income of between $39,001 and $48,000 living in a household of seven or more persons;
but does not include account-holders in Class G.

OESP Credit	$	(38.00)

Class D

(a) account-holders with a household income of $28,000 or less living in a household of five persons; and
(b) account-holders with a household income of between $28,001 and $39,000 living in a household of six persons;
but does not include account-holders in Class H.

OESP Credit	$	(42.00)

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ONTARIO ELECTRICITY SUPPORT PROGRAM RECIPIENTS

Class E

Class E comprises account-holders with a household income and household size described under Class A who also meet any of the following conditions:
(a) the dwelling to which the account relates is heated primarily by electricity;
(b) the account-holder or any member of the account-holder's household is an Aboriginal person; or
(c) the account-holder or any member of the account-holder's household regularly uses, for medical purposes, an electricity-intensive medical device at the dwelling to which the account relates.

OESP Credit	$	(45.00)

Class F

(a) account-holders with a household income of $28,000 or less living in a household of six or more persons;
(b) account-holders with a household income of between $28,001 and $39,000 living in a household of seven or more persons; or
(c) account-holders with a household income and household size described under Class B who also meet any of the following conditions:

i. the dwelling to which the account relates is heated primarily by electricity;
ii. the account-holder or any member of the account-holder's household is an Aboriginal person; or
iii. the account-holder or any member of the account-holder's household regularly uses, for medical purposes, an electricity-intensive medical device at the dwelling to which the account relates

OESP Credit	$	(50.00)

Class G

Class G comprises account-holders with a household income and household size described under Class C who also meet any of the following conditions:
(a) the dwelling to which the account relates is heated primarily by electricity;
(b) the account-holder or any member of the account-holder's household is an Aboriginal person; or
(c) the account-holder or any member of the account-holder's household regularly uses, for medical purposes, an electricity-intensive medical device at the dwelling to which the account relates.

OESP Credit	$	(55.00)

Class H

Class H comprises account-holders with a household income and household size described under Class D who also meet any of the following conditions:
(a) the dwelling to which the account relates is heated primarily by electricity;
(b) the account-holder or any member of the account-holder's household is an Aboriginal person ; or
(c) the account-holder or any member of the account-holder's household regularly uses, for medical purposes, an electricity-intensive medical device at the dwelling to which the account relates.

OESP Credit	$	(60.00)

Class I

Class I comprises account-holders with a household income and household size described under paragraphs (a) or (b) of Class F who also meet any of the following conditions:
(a) the dwelling to which the account relates is heated primarily by electricity;
(b) the account-holder or any member of the account-holder's household is an Aboriginal person; or
(c) the account-holder or any member of the account-holder's household regularly uses, for medical purposes, an electricity-intensive medical device at the dwelling to which the account relates.

OESP Credit	$	(75.00)

Canadian Niagara Power Inc.

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ALLOWANCES

Transformer Allowance for Ownership - per kW of billing demand/month	$/kW	(0.60)
Primary Metering Allowance for transformer losses – applied to measured demand and energy	%	(1.00)

SPECIFIC SERVICE CHARGES

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

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Customer Administration

Arrears certificate (credit reference)	$	15.00
Statement of Account	$	15.00
Pulling Post Dated Cheques	$	15.00
Duplicate Invoices for previous billing	$	15.00
Request for other billing information	$	15.00
Easement Letter	$	15.00
Income Tax Letter	$	15.00
Notification charge	$	15.00
Account History	$	15.00
Credit Reference/credit check (plus credit agency costs)	$	15.00
Account set up charge/change of occupancy charge (plus credit agency costs if applicable)	$	30.00
Returned cheque charge (plus bank charges)	$	15.00
Charge to certify cheques	$	15.00
Legal letter charge	$	15.00
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 Charges - at meter - during regular hours	$	65.00
Disconnect/Reconnect Charges - at meter - after regular hours	$	185.00
Disconnect/Reconnect Charges at Pole - during regular hours	$	185.00
Disconnect/Reconnect at pole – after regular hours	$	415.00
Install/Remove load control device – during regular hours	$	65.00
Install/Remove load control device - after regular hours	$	185.00

Canadian Niagara Power Inc.
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SPECIFIC SERVICE CHARGES (continued)

Other

Special meter reads	$	30.00
Service Call - customer owned equipment	$	30.00
Service Call - after regular hours	$	165.00
Temporary service install & remove - overhead - no transformer	$	500.00
Temporary service install & remove - underground - no transformer	$	300.00
Temporary service install & remove - overhead - with transformer	$	1,000.00
Specific Charge for Access to the Power Poles – per pole/year	$	22.35

RETAIL SERVICE CHARGES (if applicable)

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable.

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Retail Service Charges refer to services provided by a distributor to retailers or customers related to the supply of competitive electricity.

One-time charge, per retailer, to establish the service agreement between the distributor and the retailer	$	100.00
Monthly Fixed Charge, per retailer	$	20.00
Monthly Variable Charge, per customer, per retailer	$/cust.	0.50
Distributor-consolidated billing monthly charge, per customer, per retailer	$/cust.	0.30
Retailer-consolidated billing monthly credit, per customer, per retailer	$/cust.	(0.30)
Service Transaction Requests (STR)		
Request fee, per request, applied to the requesting party	$	0.25
Processing fee, per request, applied to the requesting party	$	0.50
Request for customer information as outlined in Section 10.6.3 and Chapter 11 of the Retail Settlement Code directly to retailers and customers, if not delivered electronically through the Electronic Business Transaction (EBT) system, applied to the requesting party		
Up to twice a year	$	no charge
More than twice a year, per request (plus incremental delivery costs)	$	2.00

LOSS FACTORS

If the distributor is not capable of prorating changed loss factors jointly with distribution rates, the revised loss factors will be implemented upon the first subsequent billing for each billing cycle.

Total Loss Factor – Secondary Metered Customer <5,000kW	1.0530
Total Loss Factor – Primary Metered Customer <5,000kW	1.0425

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TRACKED CHANGES COPY OF TARIFF OF RATES AND CHARGES

A copy of the tracked changes copy of the tariff of rates and charges is attached.

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Appendix A
Tracked Changes of Tariff Rates and Charges

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Canadian Niagara Power Inc.

TARIFF OF RATES AND CHARGES

Effective and Implementation Date January 1, 2017

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

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RESIDENTIAL SERVICE CLASSIFICATION

The Residential Class (Regular) refers to a service taking electricity normally at 750 volts or less where the electricity is used for domestic and household purposes in a single family unit. A single family unit being a permanent structure located on a single parcel of land and approved by a civic authority as a dwelling and occupied for that purpose by a single customer. Residential rates are also applied to apartment buildings with 6 units or less that are bulk metered. Apartment buildings with more than 6 units that are bulk metered are deemed to be General Service. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable. In addition, the charges in the MONTHLY RATES AND CHARGES – Regulatory Component of this schedule do not apply to a customer that is an embedded wholesale market participant.

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Debt Retirement Charge, the Global Adjustment, and the HST.

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge	$	28.94
Rate Rider for Smart Meter Entity Charge - effective until October 31, 2018	$	0.79
Distribution Volumetric Rate	$/kWh	0.0140
Low Voltage Service Rate	$/kWh	0.0003
Rate Rider for Disposition of Deferral/Variance Accounts (2016) – effective until December 31, 2017	$/kWh	(0.0010)
Rate Rider for Disposition of Global Adjustment Account (2016) – effective until December 31, 2017 Applicable only for Non-RPP Customers	$/kWh	0.0041
Rate Rider for Disposition of Deferral/Variance Accounts (2017) – effective until December 31, 2017	$/kWh	(0.0034)
Rate Rider for Disposition of Global Adjustment Account (2017) – effective until December 31, 2017 Applicable only for Non-RPP Customers	$/kWh	0.0068
Rate Rider for the Recovery of Lost Revenue Adjustment (LRAM) – effective until December 31, 2017	$/kWh	0.0003
Rate Rider for Disposition of Group 2 Deferal/Variance Accounts (2017) – effective until December 31, 2017	$	(0.15)
Retail Transmission Rate – Network Service Rate	$/kWh	0.0069
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	0.0059

MONTHLY RATES AND CHARGES - Regulatory Component

Wholesale Market Service Rate	$/kWh	0.0036
Rural or Remote Electricity Rate Protection Charge (RRRP)	$/kWh	0.0013
Ontario Electricity Support Program Charge (OESP)	$/kWh	0.0011
Standard Supply Service - Administrative Charge (if applicable)	$	0.25

Canadian Niagara Power Inc.

TARIFF OF RATES AND CHARGES

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GENERAL SERVICE LESS THAN 50 kW SERVICE CLASSIFICATION

This classification refers to the supply of electrical energy to single commercial or industrial customer and whose average peak demand is (or is forecasted to be) less than 50 kW. Single commercial or industrial customers are interpreted as a structure or structures on a single parcel of land occupied by one customer. An apartment building with more than 6 units that is bulk metered and has an average peak demand less than 50 kW is deemed to be General Service less than 50 kW. The common area of a separately metered apartment building having a demand less than 50 kW is also deemed to be General Service less than 50 kW. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable. In addition, the charges in the MONTHLY RATES AND CHARGES – Regulatory Component of this schedule do not apply to a customer that is an embedded wholesale market participant.

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Debt Retirement Charge, the Global Adjustment, and the HST.

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge	$	32.02
Rate Rider for Smart Entity Charge - effective until October 31, 2018	$	0.79
Distribution Volumetric Rate	$/kWh	0.0261
Low Voltage Service Rate	$/kWh	0.0003
Rate Rider for Disposition of Deferral/Variance Accounts (2016) – effective until December 31, 2017	$/kWh	(0.0012)
Rate Rider for Disposition of Global Adjustment Account (2016) – effective until December 31, 2017 Applicable only for Non-RPP Customers	$/kWh	0.0039
Rate Rider for Disposition of Deferral/Variance Accounts (2017) – effective until December 31, 2017	$/kWh	(0.0036)
Rate Rider for Disposition of Global Adjustment Account (2017) – effective until December 31, 2017 Applicable only for Non-RPP Customers	$/kWh	0.0068
Rate Rider for the Recovery of Lost Revenue Adjustment (LRAM) – effective until December 31, 2017	$/kWh	0.0019
Retail Transmission Rate – Network Service Rate	$/kWh	0.0058
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	0.0050

MONTHLY RATES AND CHARGES - Regulatory Component

Wholesale Market Service Rate	$/kWh	0.0036
Rural or Remote Electricity Rate Protection Charge (RRRP)	$/kWh	0.0013
Ontario Electricity Support Program Charge (OESP)	$/kWh	0.0011
Standard Supply Service - Administrative Charge (if applicable)	$	0.25

Canadian Niagara Power Inc.

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GENERAL SERVICE 50 to 4,999 kW SERVICE CLASSIFICATION

This classification refers to the supply of electrical energy to single commercial or industrial customer and whose average peak demand is (or is forecasted to be) equal to or greater than 50 kW but less than 5000 kW. Single commercial or industrial customers are interpreted as a structure or structures on a single parcel of land occupied by one customer. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable. In addition, the charges in the MONTHLY RATES AND CHARGES – Regulatory Component of this schedule do not apply to a customer that is an embedded wholesale market participant.

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Debt Retirement Charge, the Global Adjustment, and the HST.

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge	$	172.04
Distribution Volumetric Rate	$/kW	7.5344
Low Voltage Service Rate	$/kW	0.1063
Rate Rider for Disposition of Deferral/Variance Accounts (2016) – effective until December 31, 2017	$/kW	(0.3866)
Rate Rider for Disposition of Global Adjustment Account (2016) – effective until December 31, 2017 Applicable only for Non-RPP Customers	$/kW	1.5024
Rate Rider for Disposition of Deferral/Variance Accounts (2017) – effective until December 31, 2017	$/kW	(1.1366)
Rate Rider for Disposition of Global Adjustment Account (2017) – effective until December 31, 2017 Applicable only for Non-RPP Customers	$/kW	1.9269
Rate Rider for the Recovery of Lost Revenue Adjustment (LRAM) – effective until December 31, 2017	$/kW	0.0957
Rate Rider for Disposition of MIST Meters (2017) – effective until December 31, 2021	$	7.05
Rate Rider for Disposition of Stranded Meters (2017) – effective until December 31, 2021	$	3.60
Rate Rider for Disposition of Global Adjustment Account (2017) - effective until December 31, 2017 Applicable only to Class A, Non-RPP customers who are not Wholesale Market Participants	$/kW	1.0638
Retail Transmission Rate – Network Service Rate	$/kW	2.4754
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	2.1000

MONTHLY RATES AND CHARGES - Regulatory Component

Wholesale Market Service Rate	$/kWh	0.0036
Rural or Remote Electricity Rate Protection Charge (RRRP)	$/kWh	0.0013
Ontario Electricity Support Program Charge (OESP)	$/kWh	0.0011
Standard Supply Service - Administrative Charge (if applicable)	$	0.25

Canadian Niagara Power Inc.

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UNMETERED SCATTERED LOAD SERVICE CLASSIFICATION

This classification refers to the supply of electrical service to a customer that is deemed to have a constant load over a billing period, normally with minimum electrical consumption and the consumption is unmetered. Energy consumption is based on connected wattage and calculated hours of use. Examples of unmetered scattered load are cable television amplifiers, billOntario Energy Boards, area lighting. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

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It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Debt Retirement Charge, the Global Adjustment, and the HST.

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge (per customer)	$	50.53
Distribution Volumetric Rate	$/kWh	0.0274
Low Voltage Service Rate	$/kWh	0.0003
Rate Rider for Disposition of Deferral/Variance Accounts (2016) – effective until December 31, 2017	$/kWh	(0.0011)
Rate Rider for Disposition of Global Adjustment Account (2016) – effective until December 31, 2017 Applicable only for Non-RPP Customers	$/kWh	0.0026
Rate Rider for Disposition of Deferral/Variance Accounts (2017) – effective until December 31, 2017	$/kWh	(0.0037)
Rate Rider for Disposition of Global Adjustment Account (2017) – effective until December 31, 2017 Applicable only for Non-RPP Customers	$/kWh	0.0068
Retail Transmission Rate – Network Service Rate	$/kWh	0.0061
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	0.0051

MONTHLY RATES AND CHARGES - Regulatory Component

Wholesale Market Service Rate	$/kWh	0.0036
Rural or Remote Electricity Rate Protection Charge (RRRP)	$/kWh	0.0013

Canadian Niagara Power Inc.

TARIFF OF RATES AND CHARGES

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Ontario Electricity Support Program Charge (OESP)		$/kWh	0.0011
Standard Supply Service - Administrative Charge (if applicable)		$	0.25

Canadian Niagara Power Inc.
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EMBEDDED DISTRIBUTOR

This classification applies to an electricity distributor licensed by the Board, that is provided electricity by means of this distributor's facilities. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable. In addition, the charges in the MONTHLY RATES AND CHARGES – Regulatory Component of this schedule do not apply to a customer that is an embedded wholesale market participant.

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Debt Retirement Charge, the Global Adjustment, and the HST.

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge	$	584.79
Distribution Volumetric Rate	$/kW	8.3087
Low Voltage Service Rate	$/kW	0.1063
Rate Rider for Disposition of Deferral/Variance Accounts (2016) – effective until December 31, 2017	$/kW	(0.3866)
Rate Rider for Disposition of Global Adjustment Account (2016) – effective until December 31, 2017 Applicable only for Non-RPP Customers	$/kW	1.5024
Rate Rider for Disposition of Deferral/Variance Accounts (2017) – effective until December 31, 2017	$/kW	(1.3685)
Rate Rider for Disposition of Global Adjustment Account (2017) – effective until December 31, 2017 Applicable only for Non-RPP Customers	$/kW	2.5499
Retail Transmission Rate – Network Service Rate	$/kW	2.4654
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	2.1000
MONTHLY RATES AND CHARGES - Regulatory Component		
Wholesale Market Service Rate	$/kWh	0.0036
Rural or Remote Electricity Rate Protection Charge (RRRP)	$/kWh	0.0013
Ontario Electricity Support Program Charge (OESP)	$/kWh	0.0011
Standard Supply Service - Administrative Charge (if applicable)	$	0.25

SENTINEL LIGHTING SERVICE CLASSIFICATION

Canadian Niagara Power Inc.

TARIFF OF RATES AND CHARGES

Effective and Implementation Date January 1, 2017

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

EB-2016-0061

This classification refers to all services required to supply sentinel lighting equipment. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable. In addition, the charges in the MONTHLY RATES AND CHARGES – Regulatory Component of this schedule do not apply to a customer that is an embedded wholesale market participant.

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Debt Retirement Charge, the Global Adjustment, and the HST.

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge (per connection)	$	5.77
Distribution Volumetric Rate	$/kW	6.6867
Low Voltage Service Rate	$/kW	0.0867
Rate Rider for Disposition of Deferral/Variance Accounts (2016) – effective until December 31, 2017	$/kW	(0.1918)
Rate Rider for Disposition of Deferral/Variance Accounts (2017) – effective until December 31, 2017	$/kW	(1.2014)
Retail Transmission Rate – Network Service Rate	$/kW	2.1097
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	1.7138

MONTHLY RATES AND CHARGES - Regulatory Component

Wholesale Market Service Rate	$/kWh	0.0036
Rural or Remote Electricity Rate Protection Charge (RRRP)	$/kWh	0.0013
Ontario Electricity Support Program Charge (OESP)	$/kWh	0.0011
Standard Supply Service - Administrative Charge (if applicable)	$	0.25

STREET LIGHTING SERVICE CLASSIFICATION

Canadian Niagara Power Inc.

TARIFF OF RATES AND CHARGES

Effective and Implementation Date January 1, 2017

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

EB-2016-0061

This classification refers to the supply of electrical service for roadway lighting. Energy consumption is based on connected wattage and calculated hours of use. Customers are usually a Municipality, Region or the Ministry of Transportation. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable. In addition, the charges in the MONTHLY RATES AND CHARGES – Regulatory Component of this schedule do not apply to a customer that is an embedded wholesale market participant.

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Debt Retirement Charge, the Global Adjustment, and the HST.

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge (per connection)	$	4.06
Distribution Volumetric Rate	$/kW	8.8324
Low Voltage Service Rate	$/kW	0.0811
Rate Rider for Disposition of Deferral/Variance Accounts (2016) – effective until December 31, 2017	$/kW	(0.5255)
Rate Rider for Disposition of Global Adjustment Account (2016) – effective until December 31, 2017 Applicable only for Non-RPP Customers	$/kW	1.9654
Rate Rider for Disposition of Deferral/Variance Accounts (2017) – effective until December 31, 2017	$/kW	(1.1849)
Rate Rider for Disposition of Global Adjustment Account (2017 – effective until December 31, 2017 Applicable only for Non-RPP Customers	$/kW	2.2078
Retail Transmission Rate – Network Service Rate	$/kW	1.8322
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	1.6024

MONTHLY RATES AND CHARGES - Regulatory Component

Wholesale Market Service Rate	$/kWh	0.0036
Rural or Remote Electricity Rate Protection Charge (RRRP)	$/kWh	0.0013
Ontario Electricity Support Program Charge (OESP)	$/kWh	0.0011
Standard Supply Service - Administrative Charge (if applicable)	$	0.25

Canadian Niagara Power Inc.

TARIFF OF RATES AND CHARGES

Effective and Implementation Date January 1, 2017

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

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microFIT SERVICE CLASSIFICATION

This classification applies to an electricity generation facility contracted under the Independent Electricity System Operator's microFIT program and connected to the distributor's distribution system. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable.

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Debt Retirement Charge, the Global Adjustment, and the HST.

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge	$	5.40

STANDBY POWER SERVICE CLASSIFICATION

Canadian Niagara Power Inc.

TARIFF OF RATES AND CHARGES

Effective and Implementation Date January 1, 2017

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

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The Standby subclass charge is applied to a customer with load displacement facilities behind its meter but is dependent on Canadian Niagara Power Inc. to supply a minimum amount of electricity in the event the customer's own facilities are out of service. The minimum amount of supply that Canadian Niagara Power Inc. must supply is a contracted amount agreed upon between the customer and Canadian Niagara Power Inc. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable.

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Debt Retirement Charge, the Global Adjustment, and the HST.

MONTHLY RATES AND CHARGES – APPROVED ON AN INTERIM BASIS

Standby Charge – for a month where standby power is not provided. The charge is applied to the contracted amount (e.g. nameplate rating of generation facility)	$/kW	1.1676

ONTARIO ELECTRICITY SUPPORT PROGRAM RECIPIENTS

Canadian Niagara Power Inc.

TARIFF OF RATES AND CHARGES

Effective and Implementation Date January 1, 2017

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

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In addition to the charges specified on Residential Classification pages of this tariff of rates and charges, the following credits are to be applied to eligible residential customers.

APPLICATION

The application of the charges are in accordance with the Distribution System Code (Section 9) and subsection 79.2(4) of the Ontario Energy Board Act, 1998.

The application of these charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

In this class:

"Aboriginal person" includes a person who is a First Nations person, a Métis person or an Inuit person;
"account-holder" means a consumer who has an account with a distributor that falls within a residential-rate classification as specified in a rate order made by the Ontario Energy Board under section 78 of the Act, and who lives at the service address to which the account relates for at least six months in a year;
"electricity-intensive medical device" means an oxygen concentrator, a mechanical ventilator, or such other device as may be specified by the Ontario Energy Board;
"household" means the account-holder and any other people living at the accountholder's service address for at least six months in a year, including people other than the account-holder's spouse, children or other relatives;
"household income" means the combined annual after-tax income of all members of a household aged 16 or over;

MONTHLY RATES AND CHARGES

Class A

(a) account-holders with a household income of $28,000 or less living in a household of one or two persons;
(b) account-holders with a household income of between $28,001 and $39,000 living in a household of three persons;
(c) account-holders with a household income of between $39,001 and $48,000 living in a household of five persons; and
(d) account-holders with a household income of between $48,001 and $52,000 living in a household of seven or more persons;
but does not include account-holders in Class E.

OESP Credit	$	(30.00)

Class B

(a) account-holders with a household income of $28,000 or less living in a household of three persons;
(b) account-holders with a household income of between $28,001 and $39,000 living in a household of four persons;
(c) account-holders with a household income of between $39,001 and $48,000 living in a household of six persons;
but does not include account-holders in Class F.

OESP Credit	$	(34.00)

Class C

(a) account-holders with a household income of $28,000 or less living in a household of four persons;
(b) account-holders with a household income of between $28,001 and $39,000 living in a household of five persons;
(c) account-holders with a household income of between $39,001 and $48,000 living in a household of seven or more persons;
but does not include account-holders in Class G.

OESP Credit	$	(38.00)

Class D

(a) account-holders with a household income of $28,000 or less living in a household of five persons; and
(b) account-holders with a household income of between $28,001 and $39,000 living in a household of six persons;
but does not include account-holders in Class H.

OESP Credit	$	(42.00)

ONTARIO ELECTRICITY SUPPORT PROGRAM RECIPIENTS

Class E

Canadian Niagara Power Inc.

TARIFF OF RATES AND CHARGES

Effective and Implementation Date January 1, 2017

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

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Class E comprises account-holders with a household income and household size described under Class A who also meet any of the following conditions:
(a) the dwelling to which the account relates is heated primarily by electricity;
(b) the account-holder or any member of the account-holder's household is an Aboriginal person; or
(c) the account-holder or any member of the account-holder's household regularly uses, for medical purposes, an electricity-intensive medical device at the dwelling to which the account relates.

OESP Credit	$	(45.00)

Class F

(a) account-holders with a household income of $28,000 or less living in a household of six or more persons;
(b) account-holders with a household income of between $28,001 and $39,000 living in a household of seven or more persons; or
(c) account-holders with a household income and household size described under Class B who also meet any of the following conditions:

i. the dwelling to which the account relates is heated primarily by electricity;
ii. the account-holder or any member of the account-holder's household is an Aboriginal person; or
iii. the account-holder or any member of the account-holder's household regularly uses, for medical purposes, an electricity-intensive medical device at the dwelling to which the account relates

OESP Credit	$	(50.00)

Class G

Class G comprises account-holders with a household income and household size described under Class C who also meet any of the following conditions:
(a) the dwelling to which the account relates is heated primarily by electricity;
(b) the account-holder or any member of the account-holder's household is an Aboriginal person; or
(c) the account-holder or any member of the account-holder's household regularly uses, for medical purposes, an electricity-intensive medical device at the dwelling to which the account relates.

OESP Credit	$	(55.00)

Class H

Class H comprises account-holders with a household income and household size described under Class D who also meet any of the following conditions:
(a) the dwelling to which the account relates is heated primarily by electricity;
(b) the account-holder or any member of the account-holder's household is an Aboriginal person ; or
(c) the account-holder or any member of the account-holder's household regularly uses, for medical purposes, an electricity-intensive medical device at the dwelling to which the account relates.

OESP Credit	$	(60.00)

Class I

Class I comprises account-holders with a household income and household size described under paragraphs (a) or (b) of Class F who also meet any of the following conditions:
(a) the dwelling to which the account relates is heated primarily by electricity;
(b) the account-holder or any member of the account-holder's household is an Aboriginal person; or
(c) the account-holder or any member of the account-holder's household regularly uses, for medical purposes, an electricity-intensive medical device at the dwelling to which the account relates.

OESP Credit	$	(75.00)

ALLOWANCES

Canadian Niagara Power Inc.
TARIFF OF RATES AND CHARGES
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Transformer Allowance for Ownership - per kW of billing demand/month	$/kW	(0.60)
Primary Metering Allowance for transformer losses – applied to measured demand and energy	%	(1.00)

SPECIFIC SERVICE CHARGES

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Debt Retirement Charge, the Global Adjustment, and the HST.

Customer Administration

Arrears certificate (credit reference)	$	15.00
Statement of Account	$	15.00
Pulling Post Dated Cheques	$	15.00
Duplicate Invoices for previous billing	$	15.00
Request for other billing information	$	15.00
Easement Letter	$	15.00
Income Tax Letter	$	15.00
Notification charge	$	15.00
Account History	$	15.00
Credit Reference/credit check (plus credit agency costs)	$	15.00
Account set up charge/change of occupancy charge (plus credit agency costs if applicable)	$	30.00
Returned cheque charge (plus bank charges)	$	15.00
Charge to certify cheques	$	15.00
Legal letter charge	$	15.00
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 Charges - at meter - during regular hours	$	65.00
Disconnect/Reconnect Charges - at meter - after regular hours	$	185.00
Disconnect/Reconnect Charges at Pole - during regular hours	$	185.00
Disconnect/Reconnect at pole – after regular hours	$	415.00
Install/Remove load control device – during regular hours	$	65.00
Install/Remove load control device - after regular hours	$	185.00

SPECIFIC SERVICE CHARGES (continued)

Canadian Niagara Power Inc.
TARIFF OF RATES AND CHARGES
Effective and Implementation Date January 1, 2017

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

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Other

Special meter reads	$	30.00
Service Call - customer owned equipment	$	30.00
Service Call - after regular hours	$	165.00
Temporary service install & remove - overhead - no transformer	$	500.00
Temporary service install & remove - underground - no transformer	$	300.00
Temporary service install & remove - overhead - with transformer	$	1,000.00
Specific Charge for Access to the Power Poles – per pole/year	$	22.35

RETAIL SERVICE CHARGES (if applicable)

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor’s Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable.

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Debt Retirement Charge, the Global Adjustment, and the HST.

Retail Service Charges refer to services provided by a distributor to retailers or customers related to the supply of competitive electricity.

One-time charge, per retailer, to establish the service agreement between the distributor and the retailer	$	100.00
Monthly Fixed Charge, per retailer	$	20.00
Monthly Variable Charge, per customer, per retailer	$/cust.	0.50
Distributor-consolidated billing monthly charge, per customer, per retailer	$/cust.	0.30
Retailer-consolidated billing monthly credit, per customer, per retailer	$/cust.	(0.30)
Service Transaction Requests (STR)		
Request fee, per request, applied to the requesting party	$	0.25
Processing fee, per request, applied to the requesting party	$	0.50
Request for customer information as outlined in Section 10.6.3 and Chapter 11 of the Retail Settlement Code directly to retailers and customers, if not delivered electronically through the Electronic Business Transaction (EBT) system, applied to the requesting party		
Up to twice a year	$	no charge
More than twice a year, per request (plus incremental delivery costs)	$	2.00

LOSS FACTORS

If the distributor is not capable of prorating changed loss factors jointly with distribution rates, the revised loss factors will be implemented upon the first subsequent billing for each billing cycle.

Total Loss Factor – Secondary Metered Customer <5,000kW	1.0542
Total Loss Factor – Primary Metered Customer <5,000kW	1.0437

REVENUE RECONCILIATION

The following (consistent with Appendix 2-V) provides reconciliation between the revenue based on the 2017 Test Year proposed Distribution Rates and the total Base Revenue Requirement calculated in Exhibit 6 of this Application.

Appendix 2-V
Revenue Reconciliation

Rate Class	Customers/ Connections	Number of Customers/Connections			Test Year Consumption		Proposed Rates			Revenues at Proposed Rates	Class Specific Revenue Requirement	Transformer Allowance Credit	Total	Difference
		Start of Test Year	End of Test Year	Average	kWh	kW	Monthly Service Charge	Volumetric						
Residential	Customers			26,074.00	198,077,803		$ 30.47	$ 0.0116		$11,827,583.73	$11,827,584		$11,827,584	$ -
GS Less Than 50 kW	Customers			2,489.00	67,907,332		$ 32.02	$ 0.0261		$ 2,726,265.13	$ 2,726,265		$ 2,726,265	$ -
GS 50 to 4,999 kW	Customers			217.00	184,944,203	593,383	$ 172.04		$ 7.5344	$ 4,918,808.55	$ 4,719,136	$ 199,673	$ 4,918,809	$ -
Embedded Distributor	Customers			1.00	5,129,448	13,717	$ 584.79		$ 8.3087	$ 120,987.27	$ 120,987		$ 120,987	$ -
USL	Customers			35.00	1,462,761		$ 50.53	$ 0.0274		$ 61,365.20	$ 61,365		$ 61,365	$ -
Sentinel Lighting	Connections			695.00	629,014	1,916	$ 5.77		$ 6.6867	$ 60,914.12	$ 60,914		$ 60,914	$ -
Street Lighting	Connections			5,713.00	2,781,556	8,591	$ 4.06		$ 8.8324	$ 354,055.80	$ 354,056		$ 354,056	$ -
				-						$ -			$ -	$ -
				-						$ -			$ -	$ -
				-						$ -			$ -	$ -
				-						$ -			$ -	$ -
				-						$ -			$ -	$ -
				-						$ -			$ -	$ -
Total										$20,069,979.80	$19,870,307	$ 199,673	$20,069,980	$ -

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Appendix 2-V
Revenue Reconciliation

Rate Class	Customers/ Connections	Number of Customers/Connections			Test Year Consumption		Proposed Rates			Revenues at Proposed Rates	Class Specific Revenue Requirement	Transformer Allowance Credit	Total	Difference
		Start of Test Year	End of Test Year	Average	kWh	kW	Monthly Service Charge	Volumetric						
Residential	Customers			26,074.00	198,077,803		$ 30.47	$ 0.0116		$11,827,583.73	$11,827,584		$11,827,584	$ -
GS Less Than 50 kW	Customers			2,489.00	67,907,332		$ 32.02	$ 0.0261		$ 2,726,265.13	$ 2,726,265		$ 2,726,265	$ -
GS 50 to 4,999 kW	Customers			217.00	184,944,203	593,383	$ 172.04		$ 7.5344	$ 4,918,808.55	$ 4,719,136	$ 199,673	$ 4,918,809	$ -
Embedded Distributor	Customers			1.00	5,129,448	13,717	$ 584.79		$ 8.3087	$ 120,987.27	$ 120,987		$ 120,987	$ -
USL	Customers			35.00	1,462,761		$ 50.53	$ 0.0274		$ 61,365.20	$ 61,365		$ 61,365	$ -
Sentinel Lighting	Connections			695.00	629,014	1,916	$ 5.77		$ 6.6867	$ 60,914.12	$ 60,914		$ 60,914	$ -
Street Lighting	Connections			5,713.00	2,781,556	8,591	$ 4.06		$ 8.8324	$ 354,055.80	$ 354,056		$ 354,056	$ -
				-						$ -			$ -	$ -
				-						$ -			$ -	$ -
				-						$ -			$ -	$ -
				-						$ -			$ -	$ -
				-						$ -			$ -	$ -
				-						$ -			$ -	$ -
Total										$20,069,979.80	$19,870,307	$ 199,673	$20,069,980	$ -

Note

1 The class specific revenue requirements in column N must be the amounts used in the final rate design process. The total of column N should equate to the proposed base revenue requirement.

2 Rates should be entered with the number of decimal places that will show on the Tariff of Rates and Charges.

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BILL IMPACT INFORMATION

Introduction

This Application proposes harmonization of rate riders across CNPI's service territories. However, as a result of non-harmonized rate riders currently in place, a separate bill impact analysis must therefore be completed for each service territory.

CNPI has completed Appendix 2-W – Bill Impacts for representative ranges of end-users in each class. The as-filed Excel version of Appendix 2-W contains bill impact analysis for typical customers in the Residential and General Service classes for each of CNPI's service territories (Fort Erie, EOP, and Port Colborne).

CNPI has also included the detailed output of the Appendix 2-W analysis for representative samples of end-users across all rate classes and across all service territories. This detail is provide as Appendix A to this Schedule.

Summary of Bill Impact Results

The following tables provide a summary of the distribution and total bill impacts for all customer classes, for each service area. For Residential and General Service classes, the analysis includes the consumption and demand levels provided within the Appendix 2-W guidelines, as well as the 10th percentile level of 210 kWh per month for the Residential class.

For USL, Sentinel Lighting and Street Lighting classes, the analysis was performed at consumption and demand levels consistent with the average customer / connection in each class. Since CNPI serves only one customer in the proposed Embedded Distributor class, the analysis for this class was based on the average monthly forecasted demand and consumption for the 2017 Test Year.

Bill Impacts - Fort Erie Service Territory											
				Distribution Charges				Total Bill			
Class	kWh	kW	Energy Charge	2016 $	2017 $	Difference $	Difference %	2016 $	2017 $	Difference $	Difference %
Residential	100	-	RPP - TOU	$ 26.39	$ 32.46	$ 6.07	23.00%	$ 44.54	$ 51.37	$ 6.83	15.33%
Residential	210	-	RPP - TOU	$ 28.77	$ 33.95	$ 5.18	18.00%	$ 63.10	$ 68.89	$ 5.79	9.18%
Residential	250	-	RPP - TOU	$ 29.64	$ 34.49	$ 4.85	16.36%	$ 69.85	$ 75.26	$ 5.41	7.75%
Residential	500	-	RPP - TOU	$ 35.05	$ 37.86	$ 2.81	8.02%	$ 112.02	$ 115.08	$ 3.06	2.73%
Residential	750	-	RPP - TOU	$ 40.46	$ 41.24	$ 0.78	1.93%	$ 154.22	$ 154.90	$ 0.68	0.44%
Residential	1,000	-	RPP - TOU	$ 45.87	$ 44.62	-$ 1.25	-2.73%	$ 196.40	$ 194.72	-$ 1.68	-0.86%
Residential	1,500	-	RPP - TOU	$ 56.68	$ 51.37	-$ 5.31	-9.37%	$ 280.77	$ 274.37	-$ 6.40	-2.28%
Residential	2,000	-	RPP - TOU	$ 67.50	$ 58.12	-$ 9.38	-13.90%	$ 365.14	$ 354.01	-$ 11.13	-3.05%
Residential	100	-	Retailer	$ 26.83	$ 33.89	$ 7.06	26.31%	$ 51.53	$ 59.48	$ 7.95	15.43%
Residential	210	-	Retailer	$ 29.68	$ 36.88	$ 7.20	24.26%	$ 77.78	$ 85.85	$ 8.07	10.38%
Residential	250	-	Retailer	$ 30.72	$ 38.05	$ 7.33	23.86%	$ 87.32	$ 95.54	$ 8.22	9.41%
Residential	500	-	Retailer	$ 37.21	$ 44.84	$ 7.63	20.51%	$ 146.98	$ 155.47	$ 8.49	5.78%
Residential	750	-	Retailer	$ 43.70	$ 51.93	$ 8.23	18.83%	$ 206.64	$ 215.74	$ 9.10	4.40%
Residential	1,000	-	Retailer	$ 50.18	$ 58.57	$ 8.39	16.72%	$ 266.30	$ 275.51	$ 9.21	3.46%
Residential	1,500	-	Retailer	$ 63.16	$ 72.74	$ 9.58	15.17%	$ 385.62	$ 396.05	$ 10.43	2.70%
Residential	2,000	-	Retailer	$ 76.14	$ 86.02	$ 9.88	12.98%	$ 504.94	$ 515.58	$ 10.64	2.11%
GS Less Than 50 kW	1,000	-	RPP - TOU	$ 58.29	$ 62.02	$ 3.73	6.40%	$ 208.17	$ 212.01	$ 3.84	1.84%
GS Less Than 50 kW	2,000	-	RPP - TOU	$ 87.52	$ 91.22	$ 3.70	4.23%	$ 383.23	$ 386.66	$ 3.43	0.90%
GS Less Than 50 kW	5,000	-	RPP - TOU	$ 175.23	$ 178.84	$ 3.61	2.06%	$ 908.42	$ 910.60	$ 2.18	0.24%
GS Less Than 50 kW	10,000	-	RPP - TOU	$ 321.40	$ 324.87	$ 3.47	1.08%	$ 1,783.73	$ 1,783.84	$ 0.11	0.01%
GS Less Than 50 kW	15,000	-	RPP - TOU	$ 380.08	$ 385.31	$ 5.23	1.38%	$ 2,659.04	$ 2,657.09	-$ 1.95	-0.07%
GS Less Than 50 kW	1,000	-	Retailer	$ 62.60	$ 75.77	$ 13.17	21.04%	$ 278.07	$ 292.56	$ 14.49	5.21%
GS Less Than 50 kW	2,000	-	Retailer	$ 96.16	$ 118.72	$ 22.56	23.46%	$ 523.03	$ 547.77	$ 24.74	4.73%
GS Less Than 50 kW	5,000	-	Retailer	$ 196.82	$ 247.59	$ 50.77	25.80%	$ 1,257.92	$ 1,313.39	$ 55.47	4.41%
GS Less Than 50 kW	10,000	-	Retailer	$ 364.59	$ 462.37	$ 97.78	26.82%	$ 2,482.73	$ 2,589.42	$ 106.69	4.30%
GS Less Than 50 kW	15,000	-	Retailer	$ 398.05	$ 545.81	$ 147.76	37.12%	$ 3,707.54	$ 3,865.45	$ 157.91	4.26%
GS 50 to 4999 kW	20,000	60	Market	$ 596.02	$ 761.24	$ 165.22	27.72%	$ 3,582.55	$ 3,759.42	$ 176.87	4.94%
GS 50 to 4999 kW	40,000	100	Market	$ 892.14	$ 1,146.94	$ 254.80	28.56%	$ 6,720.24	$ 6,990.79	$ 270.55	4.03%
GS 50 to 4999 kW	200,000	500	Market	$ 3,853.38	$ 5,003.94	$ 1,150.56	29.86%	$ 32,913.80	$ 34,127.08	$ 1,213.28	3.69%
GS 50 to 4999 kW	400,000	1,000	Market	$ 7,554.93	$ 9,825.19	$ 2,270.26	30.05%	$ 65,655.75	$ 68,047.44	$ 2,391.69	3.64%
USL	3,500	-	RPP	$ 119.37	$ 152.20	$ 32.83	27.50%	$ 652.50	$ 688.27	$ 35.77	5.48%
Sentinel Lighting	75	0.25	RPP	$ 6.98	$ 7.51	$ 0.53	7.59%	$ 18.21	$ 18.77	$ 0.56	3.08%
Street Lighting	40	0.125	Market	$ 6.55	$ 5.18	-$ 1.37	-20.92%	$ 13.11	$ 11.55	-$ 1.56	-11.90%

Bill Impacts - Eastern Ontario Power Service Territory											
				Distribution Charges				Total Bill			
Class	kWh	kW	Energy Charge	2016 $	2017 $	Difference $	Difference %	2016 $	2017 $	Difference $	Difference %
Residential	100	-	RPP - TOU	$ 26.11	$ 32.46	$ 6.35	24.32%	$ 44.22	$ 51.37	$ 7.15	16.17%
Residential	210	-	RPP - TOU	$ 28.19	$ 33.95	$ 5.76	20.43%	$ 62.43	$ 68.89	$ 6.46	10.35%
Residential	250	-	RPP - TOU	$ 28.94	$ 34.49	$ 5.55	19.18%	$ 69.06	$ 75.26	$ 6.20	8.98%
Residential	500	-	RPP - TOU	$ 33.65	$ 37.86	$ 4.21	12.51%	$ 110.45	$ 115.08	$ 4.63	4.19%
Residential	750	-	RPP - TOU	$ 38.36	$ 41.24	$ 2.88	7.51%	$ 151.84	$ 154.90	$ 3.06	2.02%
Residential	1,000	-	RPP - TOU	$ 43.07	$ 44.62	$ 1.55	3.60%	$ 193.24	$ 194.72	$ 1.48	0.77%
Residential	1,500	-	RPP - TOU	$ 52.48	$ 51.37	-$ 1.11	-2.12%	$ 276.02	$ 274.37	-$ 1.65	-0.60%
Residential	2,000	-	RPP - TOU	$ 61.90	$ 58.12	-$ 3.78	-6.11%	$ 358.81	$ 354.01	-$ 4.80	-1.34%
Residential	100	-	Retailer	$ 28.23	$ 33.89	$ 5.66	20.05%	$ 53.11	$ 59.48	$ 6.37	11.99%
Residential	210	-	Retailer	$ 32.62	$ 36.88	$ 4.26	13.06%	$ 81.10	$ 85.85	$ 4.75	5.86%
Residential	250	-	Retailer	$ 34.22	$ 38.05	$ 3.83	11.19%	$ 91.28	$ 95.54	$ 4.26	4.67%
Residential	500	-	Retailer	$ 44.21	$ 44.84	$ 0.63	1.43%	$ 154.89	$ 155.47	$ 0.58	0.37%
Residential	750	-	Retailer	$ 54.20	$ 51.93	-$ 2.27	-4.19%	$ 218.51	$ 215.74	-$ 2.77	-1.27%
Residential	1,000	-	Retailer	$ 64.18	$ 58.57	-$ 5.61	-8.74%	$ 282.12	$ 275.51	-$ 6.61	-2.34%
Residential	1,500	-	Retailer	$ 84.16	$ 72.74	-$ 11.42	-13.57%	$ 409.35	$ 396.05	-$ 13.30	-3.25%
Residential	2,000	-	Retailer	$ 104.14	$ 86.02	-$ 18.12	-17.40%	$ 536.58	$ 515.58	-$ 21.00	-3.91%
GS Less Than 50 kW	1,000	-	RPP - TOU	$ 55.69	$ 62.02	$ 6.33	11.37%	$ 205.23	$ 212.01	$ 6.78	3.30%
GS Less Than 50 kW	2,000	-	RPP - TOU	$ 82.32	$ 91.22	$ 8.90	10.81%	$ 377.36	$ 386.66	$ 9.30	2.46%
GS Less Than 50 kW	5,000	-	RPP - TOU	$ 162.23	$ 178.84	$ 16.61	10.24%	$ 893.73	$ 910.60	$ 16.87	1.89%
GS Less Than 50 kW	10,000	-	RPP - TOU	$ 295.40	$ 324.87	$ 29.47	9.98%	$ 1,754.35	$ 1,783.84	$ 29.49	1.68%
GS Less Than 50 kW	15,000	-	RPP - TOU	$ 341.05	$ 385.31	$ 44.26	12.98%	$ 2,614.97	$ 2,657.09	$ 42.12	1.61%
GS Less Than 50 kW	1,000	-	Retailer	$ 76.80	$ 75.77	-$ 1.03	-1.34%	$ 294.12	$ 292.56	-$ 1.56	-0.53%
GS Less Than 50 kW	2,000	-	Retailer	$ 124.56	$ 118.72	-$ 5.84	-4.69%	$ 555.13	$ 547.77	-$ 7.36	-1.33%
GS Less Than 50 kW	5,000	-	Retailer	$ 267.82	$ 247.59	-$ 20.23	-7.55%	$ 1,338.15	$ 1,313.39	-$ 24.76	-1.85%
GS Less Than 50 kW	10,000	-	Retailer	$ 506.59	$ 462.37	-$ 44.22	-8.73%	$ 2,643.19	$ 2,589.42	-$ 53.77	-2.03%
GS Less Than 50 kW	15,000	-	Retailer	$ 611.05	$ 545.81	-$ 65.24	-10.68%	$ 3,948.23	$ 3,865.45	-$ 82.78	-2.10%
GS 50 to 4999 kW	20,000	60	Market	$ 894.90	$ 761.24	-$ 133.66	-14.94%	$ 3,920.29	$ 3,759.42	-$ 160.87	-4.10%
GS 50 to 4999 kW	40,000	100	Market	$ 1,390.28	$ 1,146.94	-$ 243.34	-17.50%	$ 7,283.14	$ 6,990.79	-$ 292.35	-4.01%
GS 50 to 4999 kW	200,000	500	Market	$ 6,344.08	$ 5,003.94	-$ 1,340.14	-21.12%	$ 35,728.29	$ 34,127.08	-$ 1,601.21	-4.48%
GS 50 to 4999 kW	400,000	1,000	Market	$ 12,536.33	$ 9,825.19	-$ 2,711.14	-21.63%	$ 71,284.73	$ 68,047.44	-$ 3,237.29	-4.54%
USL	3,500	-	RPP	$ 109.92	$ 152.20	$ 42.28	38.46%	$ 641.83	$ 688.27	$ 46.44	7.24%
Sentinel Lighting	75	0.25	RPP	$ 7.06	$ 7.51	$ 0.45	6.37%	$ 18.29	$ 18.77	$ 0.48	2.62%
Street Lighting	40	0.125	Market	$ 6.88	$ 5.18	-$ 1.70	-24.71%	$ 12.98	$ 11.55	-$ 1.43	-11.02%

Bill Impacts - Port Colborne Service Territory											
				Distribution Charges				Total Bill			
Class	kWh	kW	Energy Charge	2016 $	2017 $	Difference $	Difference %	2016 $	2017 $	Difference $	Difference %
Residential	100	-	RPP - TOU	$ 26.22	$ 32.46	$ 6.24	23.80%	$ 44.34	$ 51.37	$ 7.03	15.85%
Residential	210	-	RPP - TOU	$ 28.42	$ 33.95	$ 5.53	19.46%	$ 62.69	$ 68.89	$ 6.20	9.89%
Residential	250	-	RPP - TOU	$ 29.21	$ 34.49	$ 5.28	18.08%	$ 69.37	$ 75.26	$ 5.89	8.49%
Residential	500	-	RPP - TOU	$ 34.20	$ 37.86	$ 3.66	10.70%	$ 111.07	$ 115.08	$ 4.01	3.61%
Residential	750	-	RPP - TOU	$ 39.18	$ 41.24	$ 2.06	5.26%	$ 152.77	$ 154.90	$ 2.13	1.39%
Residential	1,000	-	RPP - TOU	$ 44.17	$ 44.62	$ 0.45	1.02%	$ 194.48	$ 194.72	$ 0.24	0.12%
Residential	1,500	-	RPP - TOU	$ 54.13	$ 51.37	-$ 2.76	-5.10%	$ 277.89	$ 274.37	-$ 3.52	-1.27%
Residential	2,000	-	RPP - TOU	$ 64.10	$ 58.12	-$ 5.98	-9.33%	$ 361.29	$ 354.01	-$ 7.28	-2.02%
Residential	100	-	Retailer	$ 26.50	$ 33.89	$ 7.39	27.89%	$ 51.15	$ 59.48	$ 8.33	16.29%
Residential	210	-	Retailer	$ 28.99	$ 36.88	$ 7.89	27.22%	$ 76.99	$ 85.85	$ 8.86	11.51%
Residential	250	-	Retailer	$ 29.89	$ 38.05	$ 8.16	27.30%	$ 86.39	$ 95.54	$ 9.15	10.59%
Residential	500	-	Retailer	$ 35.56	$ 44.84	$ 9.28	26.10%	$ 145.12	$ 155.47	$ 10.35	7.13%
Residential	750	-	Retailer	$ 41.22	$ 51.93	$ 10.71	25.98%	$ 203.84	$ 215.74	$ 11.90	5.84%
Residential	1,000	-	Retailer	$ 46.88	$ 58.57	$ 11.69	24.94%	$ 262.57	$ 275.51	$ 12.94	4.93%
Residential	1,500	-	Retailer	$ 58.21	$ 72.74	$ 14.53	24.96%	$ 380.03	$ 396.05	$ 16.02	4.22%
Residential	2,000	-	Retailer	$ 69.54	$ 86.02	$ 16.48	23.70%	$ 497.48	$ 515.58	$ 18.10	3.64%
GS Less Than 50 kW	1,000	-	RPP - TOU	$ 56.69	$ 62.02	$ 5.33	9.40%	$ 206.36	$ 212.01	$ 5.65	2.74%
GS Less Than 50 kW	2,000	-	RPP - TOU	$ 84.32	$ 91.22	$ 6.90	8.18%	$ 379.62	$ 386.66	$ 7.04	1.85%
GS Less Than 50 kW	5,000	-	RPP - TOU	$ 167.23	$ 178.84	$ 11.61	6.94%	$ 899.38	$ 910.60	$ 11.22	1.25%
GS Less Than 50 kW	10,000	-	RPP - TOU	$ 305.40	$ 324.87	$ 19.47	6.38%	$ 1,765.65	$ 1,783.84	$ 18.19	1.03%
GS Less Than 50 kW	15,000	-	RPP - TOU	$ 356.05	$ 385.31	$ 29.26	8.22%	$ 2,631.92	$ 2,657.09	$ 25.17	0.96%
GS Less Than 50 kW	1,000	-	Retailer	$ 59.40	$ 75.77	$ 16.37	27.56%	$ 274.46	$ 292.56	$ 18.10	6.59%
GS Less Than 50 kW	2,000	-	Retailer	$ 89.76	$ 118.72	$ 28.96	32.26%	$ 515.80	$ 547.77	$ 31.97	6.20%
GS Less Than 50 kW	5,000	-	Retailer	$ 180.82	$ 247.59	$ 66.77	36.93%	$ 1,239.84	$ 1,313.39	$ 73.55	5.93%
GS Less Than 50 kW	10,000	-	Retailer	$ 332.59	$ 462.37	$ 129.78	39.02%	$ 2,446.57	$ 2,589.42	$ 142.85	5.84%
GS Less Than 50 kW	15,000	-	Retailer	$ 350.05	$ 545.81	$ 195.76	55.92%	$ 3,653.30	$ 3,865.45	$ 212.15	5.81%
GS 50 to 4999 kW	20,000	60	Market	$ 532.69	$ 761.24	$ 228.55	42.90%	$ 3,510.99	$ 3,759.42	$ 248.43	7.08%
GS 50 to 4999 kW	40,000	100	Market	$ 786.60	$ 1,146.94	$ 360.34	45.81%	$ 6,600.98	$ 6,990.79	$ 389.81	5.91%
GS 50 to 4999 kW	200,000	500	Market	$ 3,325.68	$ 5,003.94	$ 1,678.26	50.46%	$ 32,317.50	$ 34,127.08	$ 1,809.58	5.60%
GS 50 to 4999 kW	400,000	1,000	Market	$ 6,499.53	$ 9,825.19	$ 3,325.66	51.17%	$ 64,463.14	$ 68,047.44	$ 3,584.30	5.56%
Embedded Distributor	427,454	1,143	Market	$ 7,407.25	$ 12,829.62	$ 5,422.37	73.20%	$ 69,802.20	$ 75,735.34	$ 5,933.14	8.50%
USL	3,500	-	RPP	$ 113.07	$ 152.20	$ 39.13	34.61%	$ 645.38	$ 688.27	$ 42.89	6.65%
Sentinel Lighting	75	0.25	RPP	$ 6.98	$ 7.51	$ 0.53	7.59%	$ 18.21	$ 18.77	$ 0.56	3.08%
Street Lighting	40	0.125	Market	$ 6.54	$ 5.18	-$ 1.36	-20.80%	$ 13.10	$ 11.55	-$ 1.55	-11.83%

The following table provides a summary of the range of impacts for each class, across all service territories, and all consumption and demand levels presented above. The Residential range is particularly sensitive to consumption levels with extremely low-volume users seeing the largest bill impacts. Variations in the General Service classes are more sensitive to the proposed harmonization of rate riders.

	Range of Bill Impact	
Class	**Low**	**High**
Residential	-3.91%	16.29%
GS Less Than 50 kW	-2.10%	6.59%
GS 50 to 4999 kW	-4.54%	7.08%
Embedded Distributor	8.50%	
USL	5.48%	7.24%
Sentinel Lighting	2.62%	3.08%
Street Lighting	-11.90%	-11.02%

Mitigation

CNPI has determined, based on 2015 data, that 10% of its residential customers consume 210 Kwh or less on a monthly basis. To determine this level of consumption at the tenth percentile, CNPI used a full data set of all customers with a complete twelve month billing cycle for the period of January 1 to December 31, 2015. This data set was exported from CNPI's billing system to Excel format and sorted on the basis of the total consumption for the year in descending order. Using Excel's percentile function, the twelve month consumption at the tenth percentile was 2529.96 Kwh per year or approximately 210 Kwh per month.

At this level of consumption, total bill impacts for the Residential class range from 5.86% to 11.51%, depending on the service territory and whether or not the customer has signed with a retailer. CNPI believes that the 210 kWh value for the 10th percentile is skewed lower by the presence of seasonal use dwellings in its service territory along the shores of Lake Erie and the St. Lawrence River. CNPI has nonetheless outlined a proposal for rate mitigation for its residential class in Exhibit 8, Tab 1, Schedule 12.

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Exhibit 8, Tab 1, Schedule 11, Appendix A – Contents

Appendix 2-W Summary Tables **4**

Appendix 2-W - As Filed
Appendix 2-W - Extra Run #1
Appendix 2-W - Extra Run #2
Appendix 2-W - Extra Run #3
Appendix 2-W - Extra Run #4
Appendix 2-W - Extra Run #5
Appendix 2-W - Extra Run #6
Appendix 2-W - Extra Run #7
Appendix 2-W - Extra Run #8
Appendix 2-W - Extra Run #9
Appendix 2-W - Extra Run #10
Appendix 2-W - Extra Run #11

Appendix 2-W Detailed Output **16**

Residential; 100 kWh; RPP - TOU; Fort Erie
Residential; 100 kWh; Retailer; Fort Erie
Residential; 100 kWh; RPP - TOU; Eastern Ontario Power
Residential; 100 kWh; Retailer; Eastern Ontario Power
Residential; 100 kWh; RPP - TOU; Port Colborne
Residential; 100 kWh; Retailer; Port Colborne
Residential; 210 kWh; RPP - TOU; Fort Erie
Residential; 210 kWh; Retailer; Fort Erie
Residential; 210 kWh; RPP - TOU; Eastern Ontario Power
Residential; 210 kWh; Retailer; Eastern Ontario Power
Residential; 210 kWh; RPP - TOU; Port Colborne
Residential; 210 kWh; Retailer; Port Colborne
Residential; 250 kWh; RPP - TOU; Fort Erie
Residential; 250 kWh; Retailer; Fort Erie
Residential; 250 kWh; RPP - TOU; Eastern Ontario Power
Residential; 250 kWh; Retailer; Eastern Ontario Power
Residential; 250 kWh; RPP - TOU; Port Colborne
Residential; 250 kWh; Retailer; Port Colborne
Residential; 500 kWh; RPP - TOU; Fort Erie
Residential; 500 kWh; Retailer; Fort Erie
Residential; 500 kWh; RPP - TOU; Eastern Ontario Power
Residential; 500 kWh; Retailer; Eastern Ontario Power
Residential; 500 kWh; RPP - TOU; Port Colborne

Residential; 500 kWh; Retailer; Port Colborne
Residential; 750 kWh; RPP - TOU; Fort Erie
Residential; 750 kWh; Retailer; Fort Erie
Residential; 750 kWh; RPP - TOU; Eastern Ontario Power
Residential; 750 kWh; Retailer; Eastern Ontario Power
Residential; 750 kWh; RPP - TOU; Port Colborne
Residential; 750 kWh; Retailer; Port Colborne
Residential; 1000 kWh; RPP - TOU; Fort Erie
Residential; 1000 kWh; Retailer; Fort Erie
Residential; 1000 kWh; RPP - TOU; Eastern Ontario Power
Residential; 1000 kWh; Retailer; Eastern Ontario Power
Residential; 1000 kWh; RPP - TOU; Port Colborne
Residential; 1000 kWh; Retailer; Port Colborne
Residential; 1500 kWh; RPP - TOU; Fort Erie
Residential; 1500 kWh; Retailer; Fort Erie
Residential; 1500 kWh; RPP - TOU; Eastern Ontario Power
Residential; 1500 kWh; Retailer; Eastern Ontario Power
Residential; 1500 kWh; RPP - TOU; Port Colborne
Residential; 1500 kWh; Retailer; Port Colborne
Residential; 2000 kWh; RPP - TOU; Fort Erie
Residential; 2000 kWh; Retailer; Fort Erie
Residential; 2000 kWh; RPP - TOU; Eastern Ontario Power
Residential; 2000 kWh; Retailer; Eastern Ontario Power
Residential; 2000 kWh; RPP - TOU; Port Colborne
Residential; 2000 kWh; Retailer; Port Colborne
GS Less Than 50 kW; 1000 kWh; RPP - TOU; Fort Erie
GS Less Than 50 kW; 1000 kWh; Retailer; Fort Erie
GS Less Than 50 kW; 1000 kWh; RPP - TOU; Eastern Ontario Power
GS Less Than 50 kW; 1000 kWh; Retailer; Eastern Ontario Power
GS Less Than 50 kW; 1000 kWh; RPP - TOU; Port Colborne
GS Less Than 50 kW; 1000 kWh; Retailer; Port Colborne
GS Less Than 50 kW; 2000 kWh; RPP - TOU; Fort Erie
GS Less Than 50 kW; 2000 kWh; Retailer; Fort Erie
GS Less Than 50 kW; 2000 kWh; RPP - TOU; Eastern Ontario Power
GS Less Than 50 kW; 2000 kWh; Retailer; Eastern Ontario Power
GS Less Than 50 kW; 2000 kWh; RPP - TOU; Port Colborne
GS Less Than 50 kW; 2000 kWh; Retailer; Port Colborne
GS Less Than 50 kW; 5000 kWh; RPP - TOU; Fort Erie
GS Less Than 50 kW; 5000 kWh; Retailer; Fort Erie
GS Less Than 50 kW; 5000 kWh; RPP - TOU; Eastern Ontario Power
GS Less Than 50 kW; 5000 kWh; Retailer; Eastern Ontario Power
GS Less Than 50 kW; 5000 kWh; RPP - TOU; Port Colborne
GS Less Than 50 kW; 5000 kWh; Retailer; Port Colborne

GS Less Than 50 kW; 10000 kWh; RPP - TOU; Fort Erie
GS Less Than 50 kW; 10000 kWh; Retailer; Fort Erie
GS Less Than 50 kW; 10000 kWh; RPP - TOU; Eastern Ontario Power
GS Less Than 50 kW; 10000 kWh; Retailer; Eastern Ontario Power
GS Less Than 50 kW; 10000 kWh; RPP - TOU; Port Colborne
GS Less Than 50 kW; 10000 kWh; Retailer; Port Colborne
GS Less Than 50 kW; 15000 kWh; RPP - TOU; Fort Erie
GS Less Than 50 kW; 15000 kWh; Retailer; Fort Erie
GS Less Than 50 kW; 15000 kWh; RPP - TOU; Eastern Ontario Power
GS Less Than 50 kW; 15000 kWh; Retailer; Eastern Ontario Power
GS Less Than 50 kW; 15000 kWh; RPP - TOU; Port Colborne
GS Less Than 50 kW; 15000 kWh; Retailer; Port Colborne
GS 50 to 4999 kW; 20000 kWh; 60 kW; Non-RPP; Fort Erie
GS 50 to 4999 kW; 20000 kWh; 60 kW; Non-RPP; Eastern Ontario Power
GS 50 to 4999 kW; 20000 kWh; 60 kW; Non-RPP; Port Colborne
GS 50 to 4999 kW; 40000 kWh; 100 kW; Non-RPP; Fort Erie
GS 50 to 4999 kW; 40000 kWh; 100 kW; Non-RPP; Eastern Ontario Power
GS 50 to 4999 kW; 40000 kWh; 100 kW; Non-RPP; Port Colborne
GS 50 to 4999 kW; 200000 kWh; 500 kW; Non-RPP; Fort Erie
GS 50 to 4999 kW; 200000 kWh; 500 kW; Non-RPP; Eastern Ontario Power
GS 50 to 4999 kW; 200000 kWh; 500 kW; Non-RPP; Port Colborne
GS 50 to 4999 kW; 400000 kWh; 1000 kW; Non-RPP; Fort Erie
GS 50 to 4999 kW; 400000 kWh; 1000 kW; Non-RPP; Eastern Ontario Power
GS 50 to 4999 kW; 400000 kWh; 1000 kW; Non-RPP; Port Colborne
Embedded Distributor; 427454 kWh; 1143 kW; Non-RPP; Port Colborne
Sentinel Lighting; 75 kWh; 0.25 kW; RPP; Fort Erie
Sentinel Lighting; 75 kWh; 0.25 kW; RPP; Eastern Ontario Power
Sentinel Lighting; 75 kWh; 0.25 kW; RPP; Port Colborne
Street Lighting; 40 kWh; 0.125 kW; Non-RPP; Fort Erie
Street Lighting; 40 kWh; 0.125 kW; Non-RPP; Eastern Ontario Power
Street Lighting; 40 kWh; 0.125 kW; Non-RPP; Port Colborne
Unmetered Scattered Load; 3500 kWh; RPP; Fort Erie
Unmetered Scattered Load; 3500 kWh; RPP; Eastern Ontario Power
Unmetered Scattered Load; 3500 kWh; RPP; Port Colborne

Appendix 2-W
Bill Impacts

The bill comparisons below must be provided for typical customers and consumption levels. Bill impacts must be provided for residential customers consuming 800 kWh per month and general service customers consuming 2,000 kWh per month and having a monthly demand of less than 50 kW. In addition, distributors must provide a range that is relevant to their service territory, class by class. A general guideline of consumption is provided below:

Residential (kWh) - 100, 250, 500, 800, 1000, 1500, 2000 (for customers on TOU and customers on retailer contracts)
GS<50kW (kWh) - 1000, 2000, 5000, 10000, 15000 (for customers on TOU and customers on retailer contracts)
GS>50kW (kW) - 60, 100, 500, 1000
Large User - range appropriate for utility
Lighting Classes and USL - 150 kWh and 1 kW, range appropriate for utility.

For certain classes where one or more customers have unique consumption and demand patterns and which may be significantly impacted by the proposed rate changes, the distributor must show a typical comparison, and provide an explanation.

Note: The Ontario Clean Energy Benefit is applicable to eligible customers only. Refer to the Ontario Clean Energy Benefit Act, 2010. Effective until December 31, 2015.

Note that cells with the highlighted color shown to the left indicate quantities that are loss adjusted.

Table 1

	RATE CLASSES / CATEGORIES (eg: Residential TOU, Residential Retailer)	Units	RPP? Non-RPP Retailer? Non-RPP Other?	OCEB Applicable?	Current Loss Factor (eg: 1.0351)	Proposed/ Approved Loss Factor (eg: 1.0351)	Consumption (kWh)	Demand kW (if applicable)
1	Residential TOU - Fort Erie	kWh	RPP	No	1.0542	1.053	750	
2	Residential TOU - EOP	kWh	RPP	No	1.0542	1.053	750	
3	Residential TOU - Port Colborne	kWh	RPP	No	1.0542	1.053	750	
4	GS < 50 kW TOU - Fort Erie	kWh	RPP	No	1.0542	1.053	2,000	
5	GS < 50 kW TOU - EOP	kWh	RPP	No	1.0542	1.053	2,000	
6	GS < 50 kW TOU - Port Colborne	kWh	RPP	No	1.0542	1.053	2,000	
7	GS > 50 kW Non-RPP - Fort Erie	kW	Non-RPP (Other)	No	1.0542	1.053	20,000	60
8	GS > 50 kW Non-RPP - EOP	kW	Non-RPP (Other)	No	1.0542	1.053	20,000	60
9	GS > 50 kW Non-RPP - Port Colborne	kW	Non-RPP (Other)	No	1.0542	1.053	20,000	60
10	Embedded Distributor	kW	Non-RPP (Other)	No	1.0542	1.053	427,454	1,143
11	Rate Class 11							
12	Rate Class 12							
13	Rate Class 13							
14	Rate Class 14							
15	Rate Class 15							
16	Rate Class 16							
17	Rate Class 17							
18	Rate Class 18							
19	Rate Class 19							
20	Rate Class 20							

Table 2

	RATE CLASSES / CATEGORIES (eg: Residential TOU, Residential Retailer)	Units	Sub-Total						Total	
			A		B		C		A + B + C	
			$	%	$	%	$	%	$	%
1	Residential TOU - Fort Erie	kWh	$ 4.56	13.1%	$ 0.78	1.9%	$ 0.61	1.2%	$ 0.69	0.4%
2	Residential TOU - EOP	kWh	$ 4.56	13.1%	$ 2.88	7.5%	$ 2.71	5.6%	$ 3.06	2.0%
3	Residential TOU - Port Colborne	kWh	$ 4.56	13.1%	$ 2.06	5.3%	$ 1.89	3.8%	$ 2.13	1.4%
4	GS < 50 kW TOU - Fort Erie	kWh	$ 13.76	18.5%	$ 3.70	4.2%	$ 3.04	2.7%	$ 3.42	0.9%
5	GS < 50 kW TOU - EOP	kWh	$ 13.76	18.5%	$ 8.90	10.8%	$ 8.24	7.8%	$ 9.30	2.5%
6	GS < 50 kW TOU - Port Colborne	kWh	$ 13.76	18.5%	$ 6.90	8.2%	$ 6.24	5.8%	$ 7.04	1.9%
7	GS > 50 kW Non-RPP - Fort Erie	kW	$ 87.34	15.8%	$ 165.22	27.7%	$ 159.13	18.2%	$ 176.87	4.9%
8	GS > 50 kW Non-RPP - EOP	kW	$ 87.34	15.8%	-$ 133.66	-14.9%	-$ 139.75	-11.9%	-$ 160.87	-4.1%
9	GS > 50 kW Non-RPP - Port Colborne	kW	$ 87.34	15.8%	$ 228.55	42.9%	$ 222.46	27.4%	$ 248.43	7.1%
10	Embedded Distributor	kW	$ 2,284.62	29.3%	$ 5,422.37	73.2%	$ 5,306.36	41.6%	$ 5,933.13	8.5%
11	Rate Class 11									
12	Rate Class 12									
13	Rate Class 13									
14	Rate Class 14									
15	Rate Class 15									
16	Rate Class 16									
17	Rate Class 17									
18	Rate Class 18									
19	Rate Class 19									
20	Rate Class 20									

Appendix 2-W
Bill Impacts

The bill comparisons below must be provided for typical customers and consumption levels. Bill impacts must be provided for residential customers consuming 800 kWh per month and general service customers consuming 2,000 kWh per month and having a monthly demand of less than 50 kW. In addition, distributors must provide a range that is relevant to their service territory, class by class. A general guideline of consumption is provided below:

Residential (kWh) - 100, 250, 500, 800, 1000, 1500, 2000 (for customers on TOU and customers on retailer contracts)
GS<50kW (kWh) - 1000, 2000, 5000, 10000, 15000 (for customers on TOU and customers on retailer contracts)
GS>50kW (kW) - 60, 100, 500, 1000
Large User - range appropriate for utility
Lighting Classes and USL - 150 kWh and 1 kW, range appropriate for utility.

For certain classes where one or more customers have unique consumption and demand patterns and which may be significantly impacted by the proposed rate changes, the distributor must show a typical comparison, and provide an explanation.

Note: The Ontario Clean Energy Benefit is applicable to eligible customers only. Refer to the Ontario Clean Energy Benefit Act, 2010. Effective until December 31, 2015.

Note that cells with the highlighted color shown to the left indicate quantities that are loss adjusted.

Table 1

	RATE CLASSES / CATEGORIES *(eg: Residential TOU, Residential Retailer)*	**Units**	**RPP? Non-RPP Retailer? Non-RPP Other?**	**OCEB Applicable?**	**Current Loss Factor** (eg: 1.0351)	**Proposed/ Approved Loss Factor** (eg: 1.0351)	**Consumption (kWh)**	**Demand kW (if applicable)**
1	Residential TOU - Fort Erie	**kWh**	RPP	No	1.0542	1.053	100	
2	Residential TOU - EOP	**kWh**	RPP	No	1.0542	1.053	100	
3	Residential TOU - Port Colborne	**kWh**	RPP	No	1.0542	1.053	100	
4	GS < 50 kW TOU - Fort Erie	**kWh**	RPP	No	1.0542	1.053	1,000	
5	GS < 50 kW TOU - EOP	**kWh**	RPP	No	1.0542	1.053	1,000	
6	GS < 50 kW TOU - Port Colborne	**kWh**	RPP	No	1.0542	1.053	1,000	
7	GS > 50 kW Non-RPP - Fort Erie	**kW**	Non-RPP (Other)	No	1.0542	1.053	40,000	100
8	GS > 50 kW Non-RPP - EOP	**kW**	Non-RPP (Other)	No	1.0542	1.053	40,000	100
9	GS > 50 kW Non-RPP - Port Colborne	**kW**	Non-RPP (Other)	No	1.0542	1.053	40,000	100
10	Rate Class 10							
11	Rate Class 11							
12	Rate Class 12							
13	Rate Class 13							
14	Rate Class 14							
15	Rate Class 15							
16	Rate Class 16							
17	Rate Class 17							
18	Rate Class 18							
19	Rate Class 19							
20	Rate Class 20							

Table 2

	RATE CLASSES / CATEGORIES *(eg: Residential TOU, Residential Retailer)*	**Units**	**Sub-Total**						**Total**	
			A		**B**		**C**		**A + B + C**	
			$	**%**	**$**	**%**	**$**	**%**	**$**	**%**
1	Residential TOU - Fort Erie	kWh	$ 6.70	26.8%	$ 6.07	23.0%	$ 6.04	21.8%	$ 6.83	15.3%
2	Residential TOU - EOP	kWh	$ 6.70	26.8%	$ 6.35	24.3%	$ 6.32	23.0%	$ 7.15	16.2%
3	Residential TOU - Port Colborne	kWh	$ 6.70	26.8%	$ 6.24	23.8%	$ 6.21	22.5%	$ 7.02	15.8%
4	GS < 50 kW TOU - Fort Erie	kWh	$ 8.76	17.1%	$ 3.73	6.4%	$ 3.40	4.9%	$ 3.84	1.8%
5	GS < 50 kW TOU - EOP	kWh	$ 8.76	17.1%	$ 6.33	11.4%	$ 6.00	8.9%	$ 6.77	3.3%
6	GS < 50 kW TOU - Port Colborne	kWh	$ 8.76	17.1%	$ 5.33	9.4%	$ 5.00	7.3%	$ 5.64	2.7%
7	GS > 50 kW Non-RPP - Fort Erie	kW	$ 125.00	15.2%	$ 254.80	28.6%	$ 244.65	18.0%	$ 270.55	4.0%
8	GS > 50 kW Non-RPP - EOP	kW	$ 125.00	15.2%	-$ 243.34	-17.5%	-$ 253.49	-13.6%	-$ 292.34	-4.0%
9	GS > 50 kW Non-RPP - Port Colborne	kW	$ 125.00	15.2%	$ 360.34	45.8%	$ 350.19	27.9%	$ 389.81	5.9%
10	Rate Class 10									
11	Rate Class 11									
12	Rate Class 12									
13	Rate Class 13									
14	Rate Class 14									
15	Rate Class 15									
16	Rate Class 16									
17	Rate Class 17									
18	Rate Class 18									
19	Rate Class 19									
20	Rate Class 20									

Appendix 2-W
Bill Impacts

The bill comparisons below must be provided for typical customers and consumption levels. Bill impacts must be provided for residential customers consuming 800 kWh per month and general service customers consuming 2,000 kWh per month and having a monthly demand of less than 50 kW. In addition, distributors must provide a range that is relevant to their service territory, class by class. A general guideline of consumption is provided below:

Residential (kWh) - 100, 250, 500, 800, 1000, 1500, 2000 (for customers on TOU and customers on retailer contracts)
GS<50kW (kWh) - 1000, 2000, 5000, 10000, 15000 (for customers on TOU and customers on retailer contracts)
GS>50kW (kW) - 60, 100, 500, 1000
Large User - range appropriate for utility
Lighting Classes and USL - 150 kWh and 1 kW, range appropriate for utility.

For certain classes where one or more customers have unique consumption and demand patterns and which may be significantly impacted by the proposed rate changes, the distributor must show a typical comparison, and provide an explanation.

Note: The Ontario Clean Energy Benefit is applicable to eligible customers only. Refer to the Ontario Clean Energy Benefit Act, 2010. Effective until December 31, 2015.

Note that cells with the highlighted color shown to the left indicate quantities that are loss adjusted.

Table 1

	RATE CLASSES / CATEGORIES *(eg: Residential TOU, Residential Retailer)*	Units	RPP? Non-RPP Retailer? Non-RPP Other?	OCEB Applicable?	Current Loss Factor (eg: 1.0351)	Proposed/ Approved Loss Factor (eg: 1.0351)	Consumption (kWh)	Demand kW (if applicable)
1	Residential TOU - Fort Erie	**kWh**	RPP	No	1.0542	1.053	210	
2	Residential TOU - EOP	**kWh**	RPP	No	1.0542	1.053	210	
3	Residential TOU - Port Colborne	**kWh**	RPP	No	1.0542	1.053	210	
4	GS < 50 kW TOU - Fort Erie	**kWh**	RPP	No	1.0542	1.053	5,000	
5	GS < 50 kW TOU - EOP	**kWh**	RPP	No	1.0542	1.053	5,000	
6	GS < 50 kW TOU - Port Colborne	**kWh**	RPP	No	1.0542	1.053	5,000	
7	GS > 50 kW Non-RPP - Fort Erie	**kW**	Non-RPP (Other)	No	1.0542	1.053	200,000	500
8	GS > 50 kW Non-RPP - EOP	**kW**	Non-RPP (Other)	No	1.0542	1.053	200,000	500
9	GS > 50 kW Non-RPP - Port Colborne	**kW**	Non-RPP (Other)	No	1.0542	1.053	200,000	500
10	Rate Class 10							
11	Rate Class 11							
12	Rate Class 12							
13	Rate Class 13							
14	Rate Class 14							
15	Rate Class 15							
16	Rate Class 16							
17	Rate Class 17							
18	Rate Class 18							
19	Rate Class 19							
20	Rate Class 20							

Table 2

	RATE CLASSES / CATEGORIES *(eg: Residential TOU, Residential Retailer)*	Units	Sub-Total						Total	
			A		B		C		A + B + C	
			$	%	$	%	$	%	$	%
1	Residential TOU - Fort Erie	kWh	$ 6.34	23.8%	$ 5.17	18.0%	$ 5.13	16.2%	$ 5.79	9.2%
2	Residential TOU - EOP	kWh	$ 6.34	23.8%	$ 5.76	20.4%	$ 5.71	18.4%	$ 6.45	10.3%
3	Residential TOU - Port Colborne	kWh	$ 6.34	23.8%	$ 5.53	19.5%	$ 5.48	17.5%	$ 6.19	9.9%
4	GS < 50 kW TOU - Fort Erie	kWh	$ 28.76	20.1%	$ 3.61	2.1%	$ 1.97	0.8%	$ 2.18	0.2%
5	GS < 50 kW TOU - EOP	kWh	$ 28.76	20.1%	$ 16.61	10.2%	$ 14.97	6.8%	$ 16.87	1.9%
6	GS < 50 kW TOU - Port Colborne	kWh	$ 28.76	20.1%	$ 11.61	6.9%	$ 9.97	4.4%	$ 11.22	1.2%
7	GS > 50 kW Non-RPP - Fort Erie	kW	$ 501.56	14.3%	$ 1,150.56	29.9%	$ 1,099.81	17.8%	$ 1,213.28	3.7%
8	GS > 50 kW Non-RPP - EOP	kW	$ 501.56	14.3%	-$ 1,340.14	-21.1%	-$ 1,390.89	-16.0%	-$ 1,601.21	-4.5%
9	GS > 50 kW Non-RPP - Port Colborne	kW	$ 501.56	14.3%	$ 1,678.26	50.5%	$ 1,627.51	28.7%	$ 1,809.59	5.6%
10	Rate Class 10									
11	Rate Class 11									
12	Rate Class 12									
13	Rate Class 13									
14	Rate Class 14									
15	Rate Class 15									
16	Rate Class 16									
17	Rate Class 17									
18	Rate Class 18									
19	Rate Class 19									
20	Rate Class 20									

Appendix 2-W
Bill Impacts

The bill comparisons below must be provided for typical customers and consumption levels. Bill impacts must be provided for residential customers consuming 800 kWh per month and general service customers consuming 2,000 kWh per month and having a monthly demand of less than 50 kW. In addition, distributors must provide a range that is relevant to their service territory, class by class. A general guideline of consumption is provided below:

Residential (kWh) - 100, 250, 500, 800, 1000, 1500, 2000 (for customers on TOU and customers on retailer contracts)
GS<50kW (kWh) - 1000, 2000, 5000, 10000, 15000 (for customers on TOU and customers on retailer contracts)
GS>50kW (kW) - 60, 100, 500, 1000
Large User - range appropriate for utility
Lighting Classes and USL - 150 kWh and 1 kW, range appropriate for utility.

For certain classes where one or more customers have unique consumption and demand patterns and which may be significantly impacted by the proposed rate changes, the distributor must show a typical comparison, and provide an explanation.

Note: The Ontario Clean Energy Benefit is applicable to eligible customers only. Refer to the Ontario Clean Energy Benefit Act, 2010. Effective until December 31, 2015.

Note that cells with the highlighted color shown to the left indicate quantities that are loss adjusted.

Table 1

	RATE CLASSES / CATEGORIES (eg: Residential TOU, Residential Retailer)	Units	RPP? Non-RPP Retailer? Non-RPP Other?	OCEB Applicable?	Current Loss Factor (eg: 1.0351)	Proposed/ Approved Loss Factor (eg: 1.0351)	Consumption (kWh)	Demand kW (if applicable)
1	Residential TOU - Fort Erie	kWh	RPP	No	1.0542	1.053	250	
2	Residential TOU - EOP	kWh	RPP	No	1.0542	1.053	250	
3	Residential TOU - Port Colborne	kWh	RPP	No	1.0542	1.053	250	
4	GS < 50 kW TOU - Fort Erie	kWh	RPP	No	1.0542	1.053	10,000	
5	GS < 50 kW TOU - EOP	kWh	RPP	No	1.0542	1.053	10,000	
6	GS < 50 kW TOU - Port Colborne	kWh	RPP	No	1.0542	1.053	10,000	
7	GS > 50 kW Non-RPP - Fort Erie	kW	Non-RPP (Other)	No	1.0542	1.053	400,000	1,000
8	GS > 50 kW Non-RPP - EOP	kW	Non-RPP (Other)	No	1.0542	1.053	400,000	1,000
9	GS > 50 kW Non-RPP - Port Colborne	kW	Non-RPP (Other)	No	1.0542	1.053	400,000	1,000
10	Rate Class 10							
11	Rate Class 11							
12	Rate Class 12							
13	Rate Class 13							
14	Rate Class 14							
15	Rate Class 15							
16	Rate Class 16							
17	Rate Class 17							
18	Rate Class 18							
19	Rate Class 19							
20	Rate Class 20							

Table 2

	RATE CLASSES / CATEGORIES (eg: Residential TOU, Residential Retailer)	Units	Sub-Total						Total	
			A		B		C		A + B + C	
			$	%	$	%	$	%	$	%
1	Residential TOU - Fort Erie	kWh	$ 6.21	22.8%	$ 4.85	16.4%	$ 4.79	14.5%	$ 5.41	7.7%
2	Residential TOU - EOP	kWh	$ 6.21	22.8%	$ 5.55	19.2%	$ 5.49	17.0%	$ 6.20	9.0%
3	Residential TOU - Port Colborne	kWh	$ 6.21	22.8%	$ 5.27	18.0%	$ 5.22	16.0%	$ 5.89	8.5%
4	GS < 50 kW TOU - Fort Erie	kWh	$ 53.76	20.8%	$ 3.47	1.1%	$ 0.18	0.0%	$ 0.12	0.0%
5	GS < 50 kW TOU - EOP	kWh	$ 53.76	20.8%	$ 29.47	10.0%	$ 26.18	6.3%	$ 29.50	1.7%
6	GS < 50 kW TOU - Port Colborne	kWh	$ 53.76	20.8%	$ 19.47	6.4%	$ 16.18	3.8%	$ 18.20	1.0%
7	GS > 50 kW Non-RPP - Fort Erie	kW	$ 972.26	14.2%	$ 2,270.26	30.1%	$ 2,168.76	17.7%	$ 2,391.70	3.6%
8	GS > 50 kW Non-RPP - EOP	kW	$ 972.26	14.2%	-$ 2,711.14	-21.6%	-$ 2,812.64	-16.3%	-$ 3,237.29	-4.5%
9	GS > 50 kW Non-RPP - Port Colborne	kW	$ 972.26	14.2%	$ 3,325.66	51.2%	$ 3,224.16	28.8%	$ 3,584.30	5.6%
10	Rate Class 10									
11	Rate Class 11									
12	Rate Class 12									
13	Rate Class 13									
14	Rate Class 14									
15	Rate Class 15									
16	Rate Class 16									
17	Rate Class 17									
18	Rate Class 18									
19	Rate Class 19									
20	Rate Class 20									

Appendix 2-W
Bill Impacts

The bill comparisons below must be provided for typical customers and consumption levels. Bill impacts must be provided for residential customers consuming 800 kWh per month and general service customers consuming 2,000 kWh per month and having a monthly demand of less than 50 kW. In addition, distributors must provide a range that is relevant to their service territory, class by class. A general guideline of consumption is provided below:

Residential (kWh) - 100, 250, 500, 800, 1000, 1500, 2000 (for customers on TOU and customers on retailer contracts)
GS<50kW (kWh) - 1000, 2000, 5000, 10000, 15000 (for customers on TOU and customers on retailer contracts)
GS>50kW (kW) - 60, 100, 500, 1000
Large User - range appropriate for utility
Lighting Classes and USL - 150 kWh and 1 kW, range appropriate for utility.

For certain classes where one or more customers have unique consumption and demand patterns and which may be significantly impacted by the proposed rate changes, the distributor must show a typical comparison, and provide an explanation.

Note: The Ontario Clean Energy Benefit is applicable to eligible customers only. Refer to the Ontario Clean Energy Benefit Act, 2010. Effective until December 31, 2015.

Note that cells with the highlighted color shown to the left indicate quantities that are loss adjusted.

Table 1

	RATE CLASSES / CATEGORIES *(eg: Residential TOU, Residential Retailer)*	Units	RPP? Non-RPP Retailer? Non-RPP Other?	OCEB Applicable?	Current Loss Factor (eg: 1.0351)	Proposed/ Approved Loss Factor (eg: 1.0351)	Consumption (kWh)	Demand kW (if applicable)
1	Residential TOU - Fort Erie	kWh	RPP	No	1.0542	1.053	500	
2	Residential TOU - EOP	kWh	RPP	No	1.0542	1.053	500	
3	Residential TOU - Port Colborne	kWh	RPP	No	1.0542	1.053	500	
4	GS < 50 kW TOU - Fort Erie	kWh	RPP	No	1.0542	1.053	15,000	
5	GS < 50 kW TOU - EOP	kWh	RPP	No	1.0542	1.053	15,000	
6	GS < 50 kW TOU - Port Colborne	kWh	RPP	No	1.0542	1.053	15,000	
7	Street Lighting - Fort Erie	kW	Non-RPP (Other)	No	1.0542	1.053	40	0.125
8	Street Lighting - EOP	kW	Non-RPP (Other)	No	1.0542	1.053	40	0.125
9	Street Lighting - Port Colborne	kW	Non-RPP (Other)	No	1.0542	1.053	40	0.125
10	Rate Class 10							
11	Rate Class 11							
12	Rate Class 12							
13	Rate Class 13							
14	Rate Class 14							
15	Rate Class 15							
16	Rate Class 16							
17	Rate Class 17							
18	Rate Class 18							
19	Rate Class 19							
20	Rate Class 20							

Table 2

	RATE CLASSES / CATEGORIES *(eg: Residential TOU, Residential Retailer)*	Units	Sub-Total						Total	
			A		B		C		A + B + C	
			$	%	$	%	$	%	$	%
1	Residential TOU - Fort Erie	kWh	$ 5.38	17.3%	$ 2.82	8.0%	$ 2.70	6.4%	$ 3.05	2.7%
2	Residential TOU - EOP	kWh	$ 5.38	17.3%	$ 4.22	12.5%	$ 4.10	10.1%	$ 4.63	4.2%
3	Residential TOU - Port Colborne	kWh	$ 5.38	17.3%	$ 3.67	10.7%	$ 3.55	8.7%	$ 4.01	3.6%
4	GS < 50 kW TOU - Fort Erie	kWh	$ 78.76	21.1%	$ 5.26	1.4%	$ 0.32	0.1%	-$ 1.95	-0.1%
5	GS < 50 kW TOU - EOP	kWh	$ 78.76	21.1%	$ 44.26	13.0%	$ 39.32	7.6%	$ 42.12	1.6%
6	GS < 50 kW TOU - Port Colborne	kWh	$ 78.76	21.1%	$ 29.26	8.2%	$ 24.32	4.6%	$ 25.17	1.0%
7	Street Lighting - Fort Erie	kW	-$ 1.15	-18.2%	-$ 1.37	-20.9%	-$ 1.38	-19.8%	-$ 1.56	-11.9%
8	Street Lighting - EOP	kW	-$ 1.15	-18.2%	-$ 1.26	-19.6%	-$ 1.27	-18.4%	-$ 1.43	-11.0%
9	Street Lighting - Port Colborne	kW	-$ 1.15	-18.2%	-$ 1.36	-20.8%	-$ 1.37	-19.6%	-$ 1.55	-11.8%
10	Rate Class 10									
11	Rate Class 11									
12	Rate Class 12									
13	Rate Class 13									
14	Rate Class 14									
15	Rate Class 15									
16	Rate Class 16									
17	Rate Class 17									
18	Rate Class 18									
19	Rate Class 19									
20	Rate Class 20			9						

Appendix 2-W
Bill Impacts

The bill comparisons below must be provided for typical customers and consumption levels. Bill impacts must be provided for residential customers consuming 800 kWh per month and general service customers consuming 2,000 kWh per month and having a monthly demand of less than 50 kW. In addition, distributors must provide a range that is relevant to their service territory, class by class. A general guideline of consumption is provided below:

Residential (kWh) - 100, 250, 500, 800, 1000, 1500, 2000 (for customers on TOU and customers on retailer contracts)
GS<50kW (kWh) - 1000, 2000, 5000, 10000, 15000 (for customers on TOU and customers on retailer contracts)
GS>50kW (kW) - 60, 100, 500, 1000
Large User - range appropriate for utility
Lighting Classes and USL - 150 kWh and 1 kW, range appropriate for utility.

For certain classes where one or more customers have unique consumption and demand patterns and which may be significantly impacted by the proposed rate changes, the distributor must show a typical comparison, and provide an explanation.

Note: The Ontario Clean Energy Benefit is applicable to eligible customers only. Refer to the Ontario Clean Energy Benefit Act, 2010. Effective until December 31, 2015.

Note that cells with the highlighted color shown to the left indicate quantities that are loss adjusted.

Table 1

	RATE CLASSES / CATEGORIES *(eg: Residential TOU, Residential Retailer)*	Units	RPP? Non-RPP Retailer? Non-RPP Other?	OCEB Applicable?	Current Loss Factor (eg: 1.0351)	Proposed/ Approved Loss Factor (eg: 1.0351)	Consumption (kWh)	Demand kW (if applicable)
1	Residential TOU - Fort Erie	kWh	RPP	No	1.0542	1.053	1,000	
2	Residential TOU - EOP	kWh	RPP	No	1.0542	1.053	1,000	
3	Residential TOU - Port Colborne	kWh	RPP	No	1.0542	1.053	1,000	
4	Residential TOU - Fort Erie	kWh	RPP	No	1.0542	1.053	1,500	
5	Residential TOU - EOP	kWh	RPP	No	1.0542	1.053	1,500	
6	Residential TOU - Port Colborne	kWh	RPP	No	1.0542	1.053	1,500	
7	Sentinel - Fort Erie	kW	Non-RPP (Other)	No	1.0542	1.053	75	0.25
8	Sentinel - EOP	kW	Non-RPP (Other)	No	1.0542	1.053	75	0.25
9	Sentinel - Port Colborne	kW	Non-RPP (Other)	No	1.0542	1.053	75	0.25
10	Rate Class 10							
11	Rate Class 11							
12	Rate Class 12							
13	Rate Class 13							
14	Rate Class 14							
15	Rate Class 15							
16	Rate Class 16							
17	Rate Class 17							
18	Rate Class 18							
19	Rate Class 19							
20	Rate Class 20							

Table 2

	RATE CLASSES / CATEGORIES *(eg: Residential TOU, Residential Retailer)*	Units	Sub-Total						Total	
			A		B		C		A + B + C	
			$	%	$	%	$	%	$	%
1	Residential TOU - Fort Erie	kWh	$ 3.73	9.7%	-$ 1.25	-2.7%	-$ 1.48	-2.5%	-$ 1.68	-0.9%
2	Residential TOU - EOP	kWh	$ 3.73	9.7%	$ 1.55	3.6%	$ 1.32	2.3%	$ 1.49	0.8%
3	Residential TOU - Port Colborne	kWh	$ 3.73	9.7%	$ 0.45	1.0%	$ 0.22	0.4%	$ 0.25	0.1%
4	Residential TOU - Fort Erie	kWh	$ 2.08	4.5%	-$ 5.31	-9.4%	-$ 5.65	-7.3%	-$ 6.40	-2.3%
5	Residential TOU - EOP	kWh	$ 2.08	4.5%	-$ 1.11	-2.1%	-$ 1.45	-2.0%	-$ 1.65	-0.6%
6	Residential TOU - Port Colborne	kWh	$ 2.08	4.5%	-$ 2.76	-5.1%	-$ 3.10	-4.2%	-$ 3.52	-1.3%
7	Sentinel - Fort Erie	kW	$ 0.88	13.3%	$ 0.52	7.5%	$ 0.50	6.3%	$ 0.57	3.1%
8	Sentinel - EOP	kW	$ 0.88	13.3%	$ 0.45	6.4%	$ 0.43	5.4%	$ 0.49	2.7%
9	Sentinel - Port Colborne	kW	$ 0.88	13.3%	$ 0.52	7.5%	$ 0.50	6.3%	$ 0.57	3.1%
10	Rate Class 10									
11	Rate Class 11									
12	Rate Class 12									
13	Rate Class 13									
14	Rate Class 14									
15	Rate Class 15									
16	Rate Class 16									
17	Rate Class 17									
18	Rate Class 18									
19	Rate Class 19									
20	Rate Class 20									

Appendix 2-W
Bill Impacts

The bill comparisons below must be provided for typical customers and consumption levels. Bill impacts must be provided for residential customers consuming 800 kWh per month and general service customers consuming 2,000 kWh per month and having a monthly demand of less than 50 kW. In addition, distributors must provide a range that is relevant to their service territory, class by class. A general guideline of consumption is provided below:

Residential (kWh) - 100, 250, 500, 800, 1000, 1500, 2000 (for customers on TOU and customers on retailer contracts)
GS<50kW (kWh) - 1000, 2000, 5000, 10000, 15000 (for customers on TOU and customers on retailer contracts)
GS>50kW (kW) - 60, 100, 500, 1000
Large User - range appropriate for utility
Lighting Classes and USL - 150 kWh and 1 kW, range appropriate for utility.

For certain classes where one or more customers have unique consumption and demand patterns and which may be significantly impacted by the proposed rate changes, the distributor must show a typical comparison, and provide an explanation.

Note: The Ontario Clean Energy Benefit is applicable to eligible customers only. Refer to the Ontario Clean Energy Benefit Act, 2010. Effective until December 31, 2015.

Note that cells with the highlighted color shown to the left indicate quantities that are loss adjusted.

Table 1

	RATE CLASSES / CATEGORIES *(eg: Residential TOU, Residential Retailer)*	Units	RPP? Non-RPP Retailer? Non-RPP Other?	OCEB Applicable?	Current Loss Factor (eg: 1.0351)	Proposed/ Approved Loss Factor (eg: 1.0351)	Consumption (kWh)	Demand kW (if applicable)
1	Residential TOU - Fort Erie	kWh	RPP	No	1.0542	1.053	2,000	
2	Residential TOU - EOP	kWh	RPP	No	1.0542	1.053	2,000	
3	Residential TOU - Port Colborne	kWh	RPP	No	1.0542	1.053	2,000	
4	USL - Fort Erie	kWh	RPP	No	1.0542	1.053	3,500	
5	USL - EOP	kWh	RPP	No	1.0542	1.053	3,500	
6	USL - Port Colborne	kWh	RPP	No	1.0542	1.053	3,500	
7	Rate Class 7							
8	Rate Class 8							
9	Rate Class 9							
10	Rate Class 10							
11	Rate Class 11							
12	Rate Class 12							
13	Rate Class 13							
14	Rate Class 14							
15	Rate Class 15							
16	Rate Class 16							
17	Rate Class 17							
18	Rate Class 18							
19	Rate Class 19							
20	Rate Class 20							

Table 2

	RATE CLASSES / CATEGORIES *(eg: Residential TOU, Residential Retailer)*	Units	Sub-Total						Total	
			A		B		C		A + B + C	
			$	%	$	%	$	%	$	%
1	Residential TOU - Fort Erie	kWh	$ 0.43	0.8%	-$ 9.38	-13.9%	-$ 9.83	-10.4%	-$ 11.13	-3.0%
2	Residential TOU - EOP	kWh	$ 0.43	0.8%	-$ 3.78	-6.1%	-$ 4.23	-4.7%	-$ 4.80	-1.3%
3	Residential TOU - Port Colborne	kWh	$ 0.43	0.8%	-$ 5.98	-9.3%	-$ 6.43	-7.0%	-$ 7.28	-2.0%
4	USL - Fort Erie	kWh	$ 50.82	53.2%	$ 32.83	27.5%	$ 31.68	19.6%	$ 35.77	5.5%
5	USL - EOP	kWh	$ 50.82	53.2%	$ 42.28	38.5%	$ 41.13	27.0%	$ 46.45	7.2%
6	USL - Port Colborne	kWh	$ 50.82	53.2%	$ 39.13	34.6%	$ 37.98	24.4%	$ 42.89	6.6%
7	Rate Class 7									
8	Rate Class 8									
9	Rate Class 9									
10	Rate Class 10									
11	Rate Class 11									
12	Rate Class 12									
13	Rate Class 13									
14	Rate Class 14									
15	Rate Class 15									
16	Rate Class 16									
17	Rate Class 17									
18	Rate Class 18									
19	Rate Class 19									
20	Rate Class 20									

Appendix 2-W
Bill Impacts

The bill comparisons below must be provided for typical customers and consumption levels. Bill impacts must be provided for residential customers consuming 800 kWh per month and general service customers consuming 2,000 kWh per month and having a monthly demand of less than 50 kW. In addition, distributors must provide a range that is relevant to their service territory, class by class. A general guideline of consumption is provided below:

Residential (kWh) - 100, 250, 500, 800, 1000, 1500, 2000 (for customers on TOU and customers on retailer contracts)
GS<50kW (kWh) - 1000, 2000, 5000, 10000, 15000 (for customers on TOU and customers on retailer contracts)
GS>50kW (kW) - 60, 100, 500, 1000
Large User - range appropriate for utility
Lighting Classes and USL - 150 kWh and 1 kW, range appropriate for utility.

For certain classes where one or more customers have unique consumption and demand patterns and which may be significantly impacted by the proposed rate changes, the distributor must show a typical comparison, and provide an explanation.

Note: The Ontario Clean Energy Benefit is applicable to eligible customers only. Refer to the Ontario Clean Energy Benefit Act, 2010. Effective until December 31, 2015.

Note that cells with the highlighted color shown to the left indicate quantities that are loss adjusted.

Table 1

	RATE CLASSES / CATEGORIES *(eg: Residential TOU, Residential Retailer)*	Units	RPP? Non-RPP Retailer? Non-RPP Other?	OCEB Applicable?	Current Loss Factor (eg: 1.0351)	Proposed/ Approved Loss Factor (eg: 1.0351)	Consumption (kWh)	Demand kW (if applicable)
1	Residential Retailer - Fort Erie	kWh	Non-RPP (Retailer)	No	1.0542	1.053	100	
2	Residential Retailer - EOP	kWh	Non-RPP (Retailer)	No	1.0542	1.053	100	
3	Residential Retailer - Port Colborne	kWh	Non-RPP (Retailer)	No	1.0542	1.053	100	
4	Residential Retailer - Fort Erie	kWh	Non-RPP (Retailer)	No	1.0542	1.053	210	
5	Residential Retailer - EOP	kWh	Non-RPP (Retailer)	No	1.0542	1.053	210	
6	Residential Retailer - Port Colborne	kWh	Non-RPP (Retailer)	No	1.0542	1.053	210	
7	GS<50 kW Retailer - Fort Erie	kWh	Non-RPP (Retailer)	No	1.0542	1.053	1,000	
8	GS<50 kW Retailer - EOP	kWh	Non-RPP (Retailer)	No	1.0542	1.053	1,000	
9	GS<50 kW Retailer - Port Colborne	kWh	Non-RPP (Retailer)	No	1.0542	1.053	1,000	
10	Rate Class 10							
11	Rate Class 11							
12	Rate Class 12							
13	Rate Class 13							
14	Rate Class 14							
15	Rate Class 15							
16	Rate Class 16							
17	Rate Class 17							
18	Rate Class 18							
19	Rate Class 19							
20	Rate Class 20							

Table 2

	RATE CLASSES / CATEGORIES *(eg: Residential TOU, Residential Retailer)*	Units	Sub-Total						Total	
			A		B		C		A + B + C	
			$	%	$	%	$	%	$	%
1	Residential Retailer - Fort Erie	kWh	$ 6.70	26.8%	$ 7.06	26.3%	$ 7.04	25.0%	$ 7.95	15.4%
2	Residential Retailer - EOP	kWh	$ 6.70	26.8%	$ 5.66	20.1%	$ 5.64	19.0%	$ 6.37	12.0%
3	Residential Retailer - Port Colborne	kWh	$ 6.70	26.8%	$ 7.39	27.9%	$ 7.37	26.4%	$ 8.32	16.3%
4	Residential Retailer - Fort Erie	kWh	$ 6.34	23.8%	$ 7.20	24.2%	$ 7.15	22.0%	$ 8.08	10.4%
5	Residential Retailer - EOP	kWh	$ 6.34	23.8%	$ 4.26	13.0%	$ 4.21	11.9%	$ 4.75	5.9%
6	Residential Retailer - Port Colborne	kWh	$ 6.34	23.8%	$ 7.89	27.2%	$ 7.84	24.6%	$ 8.86	11.5%
7	GS<50 kW Retailer - Fort Erie	kWh	$ 8.76	17.1%	$ 13.16	21.0%	$ 12.83	17.3%	$ 14.49	5.2%
8	GS<50 kW Retailer - EOP	kWh	$ 8.76	17.1%	-$ 1.04	-1.4%	-$ 1.37	-1.5%	-$ 1.55	-0.5%
9	GS<50 kW Retailer - Port Colborne	kWh	$ 8.76	17.1%	$ 16.36	27.5%	$ 16.03	22.5%	$ 18.11	6.6%
10	Rate Class 10									
11	Rate Class 11									
12	Rate Class 12									
13	Rate Class 13									
14	Rate Class 14									
15	Rate Class 15									
16	Rate Class 16									
17	Rate Class 17									
18	Rate Class 18									
19	Rate Class 19									
20	Rate Class 20									

Appendix 2-W
Bill Impacts

The bill comparisons below must be provided for typical customers and consumption levels. Bill impacts must be provided for residential customers consuming 800 kWh per month and general service customers consuming 2,000 kWh per month and having a monthly demand of less than 50 kW. In addition, distributors must provide a range that is relevant to their service territory, class by class. A general guideline of consumption is provided below:

Residential (kWh) - 100, 250, 500, 800, 1000, 1500, 2000 (for customers on TOU and customers on retailer contracts)
GS<50kW (kWh) - 1000, 2000, 5000, 10000, 15000 (for customers on TOU and customers on retailer contracts)
GS>50kW (kW) - 60, 100, 500, 1000
Large User - range appropriate for utility
Lighting Classes and USL - 150 kWh and 1 kW, range appropriate for utility.

For certain classes where one or more customers have unique consumption and demand patterns and which may be significantly impacted by the proposed rate changes, the distributor must show a typical comparison, and provide an explanation.

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Note that cells with the highlighted color shown to the left indicate quantities that are loss adjusted.

Table 1

	RATE CLASSES / CATEGORIES *(eg: Residential TOU, Residential Retailer)*	Units	RPP? Non-RPP Retailer? Non-RPP Other?	OCEB Applicable?	Current Loss Factor (eg: 1.0351)	Proposed/ Approved Loss Factor (eg: 1.0351)	Consumption (kWh)	Demand kW (if applicable)
1	Residential Retailer - Fort Erie	kWh	Non-RPP (Retailer)	No	1.0542	1.053	250	
2	Residential Retailer - EOP	kWh	Non-RPP (Retailer)	No	1.0542	1.053	250	
3	Residential Retailer - Port Colborne	kWh	Non-RPP (Retailer)	No	1.0542	1.053	250	
4	Residential Retailer - Fort Erie	kWh	Non-RPP (Retailer)	No	1.0542	1.053	500	
5	Residential Retailer - EOP	kWh	Non-RPP (Retailer)	No	1.0542	1.053	500	
6	Residential Retailer - Port Colborne	kWh	Non-RPP (Retailer)	No	1.0542	1.053	500	
7	GS<50 kW Retailer - Fort Erie	kWh	Non-RPP (Retailer)	No	1.0542	1.053	2,000	
8	GS<50 kW Retailer - EOP	kWh	Non-RPP (Retailer)	No	1.0542	1.053	2,000	
9	GS<50 kW Retailer - Port Colborne	kWh	Non-RPP (Retailer)	No	1.0542	1.053	2,000	
10	Rate Class 10							
11	Rate Class 11							
12	Rate Class 12							
13	Rate Class 13							
14	Rate Class 14							
15	Rate Class 15							
16	Rate Class 16							
17	Rate Class 17							
18	Rate Class 18							
19	Rate Class 19							
20	Rate Class 20							

Table 2

	RATE CLASSES / CATEGORIES *(eg: Residential TOU, Residential Retailer)*	Units	Sub-Total						Total	
			A		B		C		A + B + C	
			$	%	$	%	$	%	$	%
1	Residential Retailer - Fort Erie	kWh	$ 6.21	22.8%	$ 7.33	23.9%	$ 7.27	21.3%	$ 8.22	9.4%
2	Residential Retailer - EOP	kWh	$ 6.21	22.8%	$ 3.83	11.2%	$ 3.77	10.0%	$ 4.26	4.7%
3	Residential Retailer - Port Colborne	kWh	$ 6.21	22.8%	$ 8.16	27.3%	$ 8.10	24.3%	$ 9.15	10.6%
4	Residential Retailer - Fort Erie	kWh	$ 5.38	17.3%	$ 7.63	20.5%	$ 7.52	17.1%	$ 8.49	5.8%
5	Residential Retailer - EOP	kWh	$ 5.38	17.3%	$ 0.63	1.4%	$ 0.52	1.0%	$ 0.58	0.4%
6	Residential Retailer - Port Colborne	kWh	$ 5.38	17.3%	$ 9.28	26.1%	$ 9.17	21.6%	$ 10.36	7.1%
7	GS<50 kW Retailer - Fort Erie	kWh	$ 13.76	18.5%	$ 22.56	23.5%	$ 21.91	18.3%	$ 24.74	4.7%
8	GS<50 kW Retailer - EOP	kWh	$ 13.76	18.5%	-$ 5.84	-4.7%	-$ 6.49	-4.4%	-$ 7.36	-1.3%
9	GS<50 kW Retailer - Port Colborne	kWh	$ 13.76	18.5%	$ 28.96	32.3%	$ 28.31	25.0%	$ 31.97	6.2%
10	Rate Class 10									
11	Rate Class 11									
12	Rate Class 12									
13	Rate Class 13									
14	Rate Class 14									
15	Rate Class 15									
16	Rate Class 16									
17	Rate Class 17									
18	Rate Class 18									
19	Rate Class 19									
20	Rate Class 20									

Appendix 2-W
Bill Impacts

The bill comparisons below must be provided for typical customers and consumption levels. Bill impacts must be provided for residential customers consuming 800 kWh per month and general service customers consuming 2,000 kWh per month and having a monthly demand of less than 50 kW. In addition, distributors must provide a range that is relevant to their service territory, class by class. A general guideline of consumption is provided below:

Residential (kWh) - 100, 250, 500, 800, 1000, 1500, 2000 (for customers on TOU and customers on retailer contracts)
GS<50kW (kWh) - 1000, 2000, 5000, 10000, 15000 (for customers on TOU and customers on retailer contracts)
GS>50kW (kW) - 60, 100, 500, 1000
Large User - range appropriate for utility
Lighting Classes and USL - 150 kWh and 1 kW, range appropriate for utility.

For certain classes where one or more customers have unique consumption and demand patterns and which may be significantly impacted by the proposed rate changes, the distributor must show a typical comparison, and provide an explanation.

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Note that cells with the highlighted color shown to the left indicate quantities that are loss adjusted.

Table 1

	RATE CLASSES / CATEGORIES *(eg: Residential TOU, Residential Retailer)*	**Units**	**RPP? Non-RPP Retailer? Non-RPP Other?**	**OCEB Applicable?**	**Current Loss Factor** (eg: 1.0351)	**Proposed/ Approved Loss Factor** (eg: 1.0351)	**Consumption (kWh)**	**Demand kW (if applicable)**
1	Residential Retailer - Fort Erie	**kWh**	Non-RPP (Retailer)	No	1.0542	1.053	750	
2	Residential Retailer - EOP	**kWh**	Non-RPP (Retailer)	No	1.0542	1.053	750	
3	Residential Retailer - Port Colborne	**kWh**	Non-RPP (Retailer)	No	1.0542	1.053	750	
4	Residential Retailer - Fort Erie	**kWh**	Non-RPP (Retailer)	No	1.0542	1.053	1,000	
5	Residential Retailer - EOP	**kWh**	Non-RPP (Retailer)	No	1.0542	1.053	1,000	
6	Residential Retailer - Port Colborne	**kWh**	Non-RPP (Retailer)	No	1.0542	1.053	1,000	
7	GS<50 kW Retailer - Fort Erie	**kWh**	Non-RPP (Retailer)	No	1.0542	1.053	5,000	
8	GS<50 kW Retailer - EOP	**kWh**	Non-RPP (Retailer)	No	1.0542	1.053	5,000	
9	GS<50 kW Retailer - Port Colborne	**kWh**	Non-RPP (Retailer)	No	1.0542	1.053	5,000	
10	Rate Class 10							
11	Rate Class 11							
12	Rate Class 12							
13	Rate Class 13							
14	Rate Class 14							
15	Rate Class 15							
16	Rate Class 16							
17	Rate Class 17							
18	Rate Class 18							
19	Rate Class 19							
20	Rate Class 20							

Table 2

	RATE CLASSES / CATEGORIES *(eg: Residential TOU, Residential Retailer)*	**Units**	**Sub-Total**						**Total**	
			A		**B**		**C**		**A + B + C**	
			$	**%**	**$**	**%**	**$**	**%**	**$**	**%**
1	Residential Retailer - Fort Erie	kWh	$ 4.56	13.1%	$ 8.23	18.8%	$ 8.06	14.9%	$ 9.10	4.4%
2	Residential Retailer - EOP	kWh	$ 4.56	13.1%	-$ 2.27	-4.2%	-$ 2.44	-3.8%	-$ 2.76	-1.3%
3	Residential Retailer - Port Colborne	kWh	$ 4.56	13.1%	$ 10.71	26.0%	$ 10.54	20.5%	$ 11.90	5.8%
4	Residential Retailer - Fort Erie	kWh	$ 3.73	9.7%	$ 8.38	16.7%	$ 8.16	12.8%	$ 9.21	3.5%
5	Residential Retailer - EOP	kWh	$ 3.73	9.7%	-$ 5.62	-8.8%	-$ 5.84	-7.5%	-$ 6.61	-2.3%
6	Residential Retailer - Port Colborne	kWh	$ 3.73	9.7%	$ 11.68	24.9%	$ 11.46	18.9%	$ 12.94	4.9%
7	GS<50 kW Retailer - Fort Erie	kWh	$ 28.76	20.1%	$ 50.77	25.8%	$ 49.12	19.2%	$ 55.47	4.4%
8	GS<50 kW Retailer - EOP	kWh	$ 28.76	20.1%	-$ 20.23	-7.6%	-$ 21.88	-6.7%	-$ 24.76	-1.9%
9	GS<50 kW Retailer - Port Colborne	kWh	$ 28.76	20.1%	$ 66.77	36.9%	$ 65.12	27.2%	$ 73.55	5.9%
10	Rate Class 10									
11	Rate Class 11									
12	Rate Class 12									
13	Rate Class 13									
14	Rate Class 14									
15	Rate Class 15									
16	Rate Class 16									
17	Rate Class 17									
18	Rate Class 18									
19	Rate Class 19									
20	Rate Class 20									

Appendix 2-W
Bill Impacts

The bill comparisons below must be provided for typical customers and consumption levels. Bill impacts must be provided for residential customers consuming 800 kWh per month and general service customers consuming 2,000 kWh per month and having a monthly demand of less than 50 kW. In addition, distributors must provide a range that is relevant to their service territory, class by class. A general guideline of consumption is provided below:

Residential (kWh) - 100, 250, 500, 800, 1000, 1500, 2000 (for customers on TOU and customers on retailer contracts)
GS<50kW (kWh) - 1000, 2000, 5000, 10000, 15000 (for customers on TOU and customers on retailer contracts)
GS>50kW (kW) - 60, 100, 500, 1000
Large User - range appropriate for utility
Lighting Classes and USL - 150 kWh and 1 kW, range appropriate for utility.

For certain classes where one or more customers have unique consumption and demand patterns and which may be significantly impacted by the proposed rate changes, the distributor must show a typical comparison, and provide an explanation.

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Note that cells with the highlighted color shown to the left indicate quantities that are loss adjusted.

Table 1

	RATE CLASSES / CATEGORIES *(eg: Residential TOU, Residential Retailer)*	Units	RPP? Non-RPP Retailer? Non-RPP Other?	OCEB Applicable?	Current Loss Factor (eg: 1.0351)	Proposed/ Approved Loss Factor (eg: 1.0351)	Consumption (kWh)	Demand kW (if applicable)
1	Residential Retailer - Fort Erie	kWh	Non-RPP (Retailer)	No	1.0542	1.053	1,500	
2	Residential Retailer - EOP	kWh	Non-RPP (Retailer)	No	1.0542	1.053	1,500	
3	Residential Retailer - Port Colborne	kWh	Non-RPP (Retailer)	No	1.0542	1.053	1,500	
4	Residential Retailer - Fort Erie	kWh	Non-RPP (Retailer)	No	1.0542	1.053	2,000	
5	Residential Retailer - EOP	kWh	Non-RPP (Retailer)	No	1.0542	1.053	2,000	
6	Residential Retailer - Port Colborne	kWh	Non-RPP (Retailer)	No	1.0542	1.053	2,000	
7	GS<50 kW Retailer - Fort Erie	kWh	Non-RPP (Retailer)	No	1.0542	1.053	10,000	
8	GS<50 kW Retailer - EOP	kWh	Non-RPP (Retailer)	No	1.0542	1.053	10,000	
9	GS<50 kW Retailer - Port Colborne	kWh	Non-RPP (Retailer)	No	1.0542	1.053	10,000	
10	Rate Class 10							
11	Rate Class 11							
12	Rate Class 12							
13	Rate Class 13							
14	Rate Class 14							
15	Rate Class 15							
16	Rate Class 16							
17	Rate Class 17							
18	Rate Class 18							
19	Rate Class 19							
20	Rate Class 20							

Table 2

	RATE CLASSES / CATEGORIES *(eg: Residential TOU, Residential Retailer)*	Units	Sub-Total						Total	
			A		B		C		A + B + C	
			$	%	$	%	$	%	$	%
1	Residential Retailer - Fort Erie	kWh	$ 2.08	4.5%	$ 9.58	15.2%	$ 9.24	11.0%	$ 10.43	2.7%
2	Residential Retailer - EOP	kWh	$ 2.08	4.5%	-$ 11.42	-13.6%	-$ 11.76	-11.2%	-$ 13.30	-3.2%
3	Residential Retailer - Port Colborne	kWh	$ 2.08	4.5%	$ 14.53	25.0%	$ 14.19	18.0%	$ 16.03	4.2%
4	Residential Retailer - Fort Erie	kWh	$ 0.43	0.8%	$ 9.88	13.0%	$ 9.43	9.1%	$ 10.64	2.1%
5	Residential Retailer - EOP	kWh	$ 0.43	0.8%	-$ 18.12	-17.4%	-$ 18.57	-14.1%	-$ 21.00	-3.9%
6	Residential Retailer - Port Colborne	kWh	$ 0.43	0.8%	$ 16.48	23.7%	$ 16.03	16.5%	$ 18.10	3.6%
7	GS<50 kW Retailer - Fort Erie	kWh	$ 53.76	20.8%	$ 97.78	26.8%	$ 94.49	19.6%	$ 106.69	4.3%
8	GS<50 kW Retailer - EOP	kWh	$ 53.76	20.8%	-$ 44.22	-8.7%	-$ 47.51	-7.6%	-$ 53.77	-2.0%
9	GS<50 kW Retailer - Port Colborne	kWh	$ 53.76	20.8%	$ 129.78	39.0%	$ 126.49	28.1%	$ 142.85	5.8%
10	Rate Class 10									
11	Rate Class 11									
12	Rate Class 12									
13	Rate Class 13									
14	Rate Class 14									
15	Rate Class 15									
16	Rate Class 16									
17	Rate Class 17									
18	Rate Class 18									
19	Rate Class 19									
20	Rate Class 20									

Appendix 2-W
Bill Impacts

The bill comparisons below must be provided for typical customers and consumption levels. Bill impacts must be provided for residential customers consuming 800 kWh per month and general service customers consuming 2,000 kWh per month and having a monthly demand of less than 50 kW. In addition, distributors must provide a range that is relevant to their service territory, class by class. A general guideline of consumption is provided below:

Residential (kWh) - 100, 250, 500, 800, 1000, 1500, 2000 (for customers on TOU and customers on retailer contracts)
GS<50kW (kWh) - 1000, 2000, 5000, 10000, 15000 (for customers on TOU and customers on retailer contracts)
GS>50kW (kW) - 60, 100, 500, 1000
Large User - range appropriate for utility
Lighting Classes and USL - 150 kWh and 1 kW, range appropriate for utility.

For certain classes where one or more customers have unique consumption and demand patterns and which may be significantly impacted by the proposed rate changes, the distributor must show a typical comparison, and provide an explanation.

Note: The Ontario Clean Energy Benefit is applicable to eligible customers only. Refer to the Ontario Clean Energy Benefit Act, 2010. Effective until December 31, 2015.

Note that cells with the highlighted color shown to the left indicate quantities that are loss adjusted.

Table 1

	RATE CLASSES / CATEGORIES *(eg: Residential TOU, Residential Retailer)*	Units	RPP? Non-RPP Retailer? Non-RPP Other?	OCEB Applicable?	Current Loss Factor (eg: 1.0351)	Proposed/ Approved Loss Factor (eg: 1.0351)	Consumption (kWh)	Demand kW (if applicable)
1	GS<50 kW Retailer - Fort Erie	**kWh**	Non-RPP (Retailer)	No	1.0542	1.053	15,000	
2	GS<50 kW Retailer - EOP	**kWh**	Non-RPP (Retailer)	No	1.0542	1.053	15,000	
3	GS<50 kW Retailer - Port Colborne	**kWh**	Non-RPP (Retailer)	No	1.0542	1.053	15,000	
4								
5								
6								
7								
8								
9								
10								
11								
12								
13								
14								
15								
16								
17								
18								
19								
20								

Table 2

	RATE CLASSES / CATEGORIES *(eg: Residential TOU, Residential Retailer)*	Units	Sub-Total						Total	
			A		B		C		A + B + C	
			$	%	$	%	$	%	$	%
1	GS<50 kW Retailer - Fort Erie	kWh	$ 78.76	21.1%	$ 147.76	37.1%	$ 142.82	24.9%	$ 157.91	4.3%
2	GS<50 kW Retailer - EOP	kWh	$ 78.76	21.1%	-$ 65.24	-10.7%	-$ 70.18	-8.9%	-$ 82.78	-2.1%
3	GS<50 kW Retailer - Port Colborne	kWh	$ 78.76	21.1%	$ 195.76	55.9%	$ 190.82	36.3%	$ 212.15	5.8%
4										
5										
6										
7										
8										
9										
10										
11										
12										
13										
14										
15										
16										
17										
18										
19										
20										

Customer Class:	Residential TOU - Fort Erie	
RPP / Non-RPP:	RPP	
Consumption	100	kWh
Demand	-	kW
Current Loss Factor	1.0542	
Proposed/Approved Loss Factor	1.0530	
Ontario Clean Energy Benefit Applied?	No	

		Current Board-Approved			Proposed			Impact	
	Charge Unit	**Rate ($)**	**Volume**	**Charge ($)**	**Rate ($)**	**Volume**	**Charge ($)**	**$ Change**	**% Change**
Monthly Service Charge	Monthly	$ 23.4400	1	$ 23.44	$ 30.4700	1	$ 30.47	$ 7.03	29.99%
Smart Meter Rate Adder			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
Distribution Volumetric Rate	per kWh	$ 0.0152	100	$ 1.52	$ 0.0116	100	$ 1.16	-$ 0.36	-23.68%
Smart Meter Disposition Rider			100	$ -		100	$ -	$ -	
LRAM & SSM Rate Rider	per kWh		100	$ -	$ 0.0003	100	$ 0.03	$ 0.03	
			100	$ -		100	$ -	$ -	
			100	$ -		100	$ -	$ -	
			100	$ -		100	$ -	$ -	
			100	$ -		100	$ -	$ -	
			100	$ -		100	$ -	$ -	
			100	$ -		100	$ -	$ -	
			100	$ -		100	$ -	$ -	
Sub-Total A (excluding pass through)				$ 24.96			$ 31.66	**$ 6.70**	**26.84%**
DVA - Total in Effect 2016	per kWh	$ 0.0004	100	$ 0.04		100	$ -	-$ 0.04	-100.00%
DVA - Total in Effect 2017 (Var)	per kWh		100	$ -	-$ 0.0044	100	-$ 0.44	-$ 0.44	
DVA - Total in Effect 2017 (Fixed)	Monthly		1	$ -	-$ 0.1500	1	-$ 0.15	-$ 0.15	
			100	$ -		100	$ -	$ -	
Low Voltage Service Charge	per kWh	$ 0.0002	100	$ 0.02	$ 0.0003	100	$ 0.03	$ 0.01	50.00%
Line Losses on Cost of Power	per kWh	$ 0.1077	5	$ 0.58	$ 0.1077	5	$ 0.57	-$ 0.01	-2.21%
Smart Meter Entity Charge	Monthly	$ 0.7900	1	$ 0.79	$ 0.7900	1	$ 0.79	$ -	0.00%
Sub-Total B - Distribution (includes Sub-Total A)				**$ 26.39**			**$ 32.46**	**$ 6.07**	**22.99%**
RTSR - Network	per kWh	$ 0.0072	105	$ 0.76	$ 0.0069	105	$ 0.73	-$ 0.03	-4.28%
RTSR - Line and Transformation Connection	per kWh	$ 0.0058	105	$ 0.61	$ 0.0059	105	$ 0.62	$ 0.01	1.61%
Sub-Total C - Delivery (including Sub-Total B)				**$ 27.76**			**$ 33.81**	**$ 6.04**	**21.77%**
Wholesale Market Service Charge (WMSC)	per kWh	$ 0.0036	105	$ 0.38	$ 0.0036	105	$ 0.38	-$ 0.00	-0.11%
Rural and Remote Rate Protection (RRRP)	per kWh	$ 0.0013	105	$ 0.14	$ 0.0013	105	$ 0.14	-$ 0.00	-0.11%
Standard Supply Service Charge	Monthly	$ 0.2500	1	$ 0.25	$ 0.2500	1	$ 0.25	$ -	0.00%
Debt Retirement Charge (DRC)			100	$ -					
Ontario Electricity Support Program (OESP)	per kWh	$ 0.0011	105	$ 0.12	$ 0.0011	105	$ 0.12	-$ 0.00	-0.11%
TOU - Off Peak	per kWh	$ 0.0830	64	$ 5.31	$ 0.0830	64	$ 5.31	$ -	0.00%
TOU - Mid Peak	per kWh	$ 0.1280	18	$ 2.30	$ 0.1280	18	$ 2.30	$ -	0.00%
TOU - On Peak	per kWh	$ 0.1750	18	$ 3.15	$ 0.1750	18	$ 3.15	$ -	0.00%
Total Bill on TOU (before Taxes)				**$ 39.41**			**$ 45.46**	**$ 6.04**	**15.33%**
HST		13%		$ 5.12	13%		$ 5.91	$ 0.79	15.33%
Total Bill (including HST)				$ 44.54			$ 51.37	$ 6.83	15.33%
Ontario Clean Energy Benefit [1]									
Total Bill on TOU				**$ 44.54**			**$ 51.37**	**$ 6.83**	**15.33%**

Customer Class:	Residential Retailer - Fort Erie
RPP / Non-RPP:	Non-RPP (Retailer)
Consumption	100 kWh
Demand	- kW
Current Loss Factor	1.0542
Proposed/Approved Loss Factor	1.0530
Ontario Clean Energy Benefit Applied?	No

		Current Board-Approved			Proposed			Impact	
	Charge Unit	**Rate ($)**	**Volume**	**Charge ($)**	**Rate ($)**	**Volume**	**Charge ($)**	**$ Change**	**% Change**
Monthly Service Charge	Monthly	$ 23.4400	1	$ 23.44	$ 30.4700	1	$ 30.47	$ 7.03	29.99%
Smart Meter Rate Adder			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
Distribution Volumetric Rate	per kWh	$ 0.0152	100	$ 1.52	$ 0.0116	100	$ 1.16	-$ 0.36	-23.68%
Smart Meter Disposition Rider			100	$ -		100	$ -	$ -	
LRAM & SSM Rate Rider	per kWh		100	$ -	$ 0.0003	100	$ 0.03	$ 0.03	
			100	$ -		100	$ -	$ -	
			100	$ -		100	$ -	$ -	
			100	$ -		100	$ -	$ -	
			100	$ -		100	$ -	$ -	
			100	$ -		100	$ -	$ -	
			100	$ -		100	$ -	$ -	
			100	$ -		100	$ -	$ -	
Sub-Total A (excluding pass through)				$ 24.96			$ 31.66	**$ 6.70**	**26.84%**
DVA - Total in Effect 2016	per kWh	$ 0.0016	100	$ 0.16		100	$ -	-$ 0.16	-100.00%
DVA - Total in Effect 2017 (Var)	per kWh		100	$ -	$ 0.0068	100	$ 0.68	$ 0.68	
DVA - Total in Effect 2017 (Fixed)	Monthly		1	$ -	-$ 0.1500	1	-$ 0.15	-$ 0.15	
			100	$ -		100	$ -	$ -	
Low Voltage Service Charge	per kWh	$ 0.0002	100	$ 0.02	$ 0.0003	100	$ 0.03	$ 0.01	50.00%
Line Losses on Cost of Power	per kWh	$ 0.1652	5	$ 0.90	$ 0.1652	5	$ 0.88	-$ 0.02	-2.21%
Smart Meter Entity Charge	Monthly	$ 0.7900	1	$ 0.79	$ 0.7900	1	$ 0.79	$ -	0.00%
Sub-Total B - Distribution (includes Sub-Total A)				**$ 26.83**			**$ 33.89**	**$ 7.06**	**26.32%**
RTSR - Network	per kWh	$ 0.0072	105	$ 0.76	$ 0.0069	105	$ 0.73	-$ 0.03	-4.28%
RTSR - Line and Transformation Connection	per kWh	$ 0.0058	105	$ 0.61	$ 0.0059	105	$ 0.62	$ 0.01	1.61%
Sub-Total C - Delivery (including Sub-Total B)				**$ 28.20**			**$ 35.23**	**$ 7.04**	**24.96%**
Wholesale Market Service Charge (WMSC)	per kWh	$ 0.0036	105	$ 0.38	$ 0.0036	105	$ 0.38	-$ 0.00	-0.11%
Rural and Remote Rate Protection (RRRP)	per kWh	$ 0.0013	105	$ 0.14	$ 0.0013	105	$ 0.14	-$ 0.00	-0.11%
Standard Supply Service Charge	Monthly	$ 0.2500	1	$ 0.25	$ 0.2500	1	$ 0.25	$ -	0.00%
Debt Retirement Charge (DRC)			100	$ -					
Ontario Electricity Support Program (OESP)	per kWh	$ 0.0011	105	$ 0.12	$ 0.0011	105	$ 0.12	-$ 0.00	-0.11%
Non-RPP Retailer Avg. Price + GA	per kWh	$ 0.1652	100	$ 16.52	$ 0.1652	100	$ 16.52	$ -	0.00%
Total Bill on Non-RPP Avg. Price				**$ 45.60**			**$ 52.64**	**$ 7.04**	**15.43%**
HST		13%		$ 5.93	13%		$ 6.84	$ 0.91	15.43%
Total Bill (including HST)				$ 51.53			$ 59.48	$ 7.95	15.43%
Ontario Clean Energy Benefit [1]									
Total Bill on Non-RPP Avg. Price				**$ 51.53**			**$ 59.48**	**$ 7.95**	**15.43%**

Customer Class:	Residential TOU - EOP	
RPP / Non-RPP:	RPP	
Consumption	100	kWh
Demand	-	kW
Current Loss Factor	1.0542	
Proposed/Approved Loss Factor	1.0530	
Ontario Clean Energy Benefit Applied?	No	

		Current Board-Approved			Proposed			Impact	
	Charge Unit	**Rate ($)**	**Volume**	**Charge ($)**	**Rate ($)**	**Volume**	**Charge ($)**	**$ Change**	**% Change**
Monthly Service Charge	Monthly	$ 23.4400	1	$ 23.44	$ 30.4700	1	$ 30.47	$ 7.03	29.99%
Smart Meter Rate Adder			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
Distribution Volumetric Rate	per kWh	$ 0.0152	100	$ 1.52	$ 0.0116	100	$ 1.16	-$ 0.36	-23.68%
Smart Meter Disposition Rider			100	$ -		100	$ -	$ -	
LRAM & SSM Rate Rider	per kWh		100	$ -	$ 0.0003	100	$ 0.03	$ 0.03	
			100	$ -		100	$ -	$ -	
			100	$ -		100	$ -	$ -	
			100	$ -		100	$ -	$ -	
			100	$ -		100	$ -	$ -	
			100	$ -		100	$ -	$ -	
			100	$ -		100	$ -	$ -	
			100	$ -		100	$ -	$ -	
Sub-Total A (excluding pass through)				$ 24.96			$ 31.66	**$ 6.70**	**26.84%**
DVA - Total in Effect 2016	per kWh	-$ 0.0024	100	-$ 0.24		100	$ -	$ 0.24	-100.00%
DVA - Total in Effect 2017 (Var)	per kWh		100	$ -	-$ 0.0044	100	-$ 0.44	-$ 0.44	
DVA - Total in Effect 2017 (Fixed)	Monthly		1	$ -	-$ 0.1500	1	-$ 0.15	-$ 0.15	
			100	$ -		100	$ -	$ -	
Low Voltage Service Charge	per kWh	$ 0.0002	100	$ 0.02	$ 0.0003	100	$ 0.03	$ 0.01	50.00%
Line Losses on Cost of Power	per kWh	$ 0.1077	5	$ 0.58	$ 0.1077	5	$ 0.57	-$ 0.01	-2.21%
Smart Meter Entity Charge	Monthly	$ 0.7900	1	$ 0.79	$ 0.7900	1	$ 0.79	$ -	0.00%
Sub-Total B - Distribution (includes Sub-Total A)				**$ 26.11**			**$ 32.46**	**$ 6.35**	**24.31%**
RTSR - Network	per kWh	$ 0.0072	105	$ 0.76	$ 0.0069	105	$ 0.73	-$ 0.03	-4.28%
RTSR - Line and Transformation Connection	per kWh	$ 0.0058	105	$ 0.61	$ 0.0059	105	$ 0.62	$ 0.01	1.61%
Sub-Total C - Delivery (including Sub-Total B)				**$ 27.48**			**$ 33.81**	**$ 6.32**	**23.01%**
Wholesale Market Service Charge (WMSC)	per kWh	$ 0.0036	105	$ 0.38	$ 0.0036	105	$ 0.38	-$ 0.00	-0.11%
Rural and Remote Rate Protection (RRRP)	per kWh	$ 0.0013	105	$ 0.14	$ 0.0013	105	$ 0.14	-$ 0.00	-0.11%
Standard Supply Service Charge	Monthly	$ 0.2500	1	$ 0.25	$ 0.2500	1	$ 0.25	$ -	0.00%
Debt Retirement Charge (DRC)			100	$ -					
Ontario Electricity Support Program (OESP)	per kWh	$ 0.0011	105	$ 0.12	$ 0.0011	105	$ 0.12	-$ 0.00	-0.11%
TOU - Off Peak	per kWh	$ 0.0830	64	$ 5.31	$ 0.0830	64	$ 5.31	$ -	0.00%
TOU - Mid Peak	per kWh	$ 0.1280	18	$ 2.30	$ 0.1280	18	$ 2.30	$ -	0.00%
TOU - On Peak	per kWh	$ 0.1750	18	$ 3.15	$ 0.1750	18	$ 3.15	$ -	0.00%
Total Bill on TOU (before Taxes)				**$ 39.13**			**$ 45.46**	**$ 6.32**	**16.16%**
HST		13%		$ 5.09	13%		$ 5.91	$ 0.82	16.16%
Total Bill (including HST)				$ 44.22			$ 51.37	$ 7.15	16.16%
Ontario Clean Energy Benefit [1]									
Total Bill on TOU				**$ 44.22**			**$ 51.37**	**$ 7.15**	**16.16%**

Customer Class:	**Residential Retailer - EOP**	
RPP / Non-RPP:	**Non-RPP (Retailer)**	
Consumption	**100**	**kWh**
Demand	**-**	**kW**
Current Loss Factor	**1.0542**	
Proposed/Approved Loss Factor	**1.0530**	
Ontario Clean Energy Benefit Applied?	**No**	

		Current Board-Approved			**Proposed**			**Impact**	
	Charge Unit	**Rate ($)**	**Volume**	**Charge ($)**	**Rate ($)**	**Volume**	**Charge ($)**	**$ Change**	**% Change**
Monthly Service Charge	Monthly	$ 23.4400	1	$ 23.44	$ 30.4700	1	$ 30.47	$ 7.03	29.99%
Smart Meter Rate Adder			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
Distribution Volumetric Rate	per kWh	$ 0.0152	100	$ 1.52	$ 0.0116	100	$ 1.16	-$ 0.36	-23.68%
Smart Meter Disposition Rider			100	$ -		100	$ -	$ -	
LRAM & SSM Rate Rider	per kWh		100	$ -	$ 0.0003	100	$ 0.03	$ 0.03	
			100	$ -		100	$ -	$ -	
			100	$ -		100	$ -	$ -	
			100	$ -		100	$ -	$ -	
			100	$ -		100	$ -	$ -	
			100	$ -		100	$ -	$ -	
			100	$ -		100	$ -	$ -	
			100	$ -		100	$ -	$ -	
Sub-Total A (excluding pass through)				$ 24.96			$ 31.66	**$ 6.70**	**26.84%**
DVA - Total in Effect 2016	per kWh	$ 0.0156	100	$ 1.56		100	$ -	-$ 1.56	-100.00%
DVA - Total in Effect 2017 (Var)	per kWh		100	$ -	$ 0.0068	100	$ 0.68	$ 0.68	
DVA - Total in Effect 2017 (Fixed)	Monthly		1	$ -	-$ 0.1500	1	-$ 0.15	-$ 0.15	
			100	$ -		100	$ -	$ -	
Low Voltage Service Charge	per kWh	$ 0.0002	100	$ 0.02	$ 0.0003	100	$ 0.03	$ 0.01	50.00%
Line Losses on Cost of Power	per kWh	$ 0.1652	5	$ 0.90	$ 0.1652	5	$ 0.88	-$ 0.02	-2.21%
Smart Meter Entity Charge	Monthly	$ 0.7900	1	$ 0.79	$ 0.7900	1	$ 0.79	$ -	0.00%
Sub-Total B - Distribution (includes Sub-Total A)				**$ 28.23**			**$ 33.89**	**$ 5.66**	**20.05%**
RTSR - Network	per kWh	$ 0.0072	105	$ 0.76	$ 0.0069	105	$ 0.73	-$ 0.03	-4.28%
RTSR - Line and Transformation Connection	per kWh	$ 0.0058	105	$ 0.61	$ 0.0059	105	$ 0.62	$ 0.01	1.61%
Sub-Total C - Delivery (including Sub-Total B)				**$ 29.60**			**$ 35.23**	**$ 5.64**	**19.05%**
Wholesale Market Service Charge (WMSC)	per kWh	$ 0.0036	105	$ 0.38	$ 0.0036	105	$ 0.38	-$ 0.00	-0.11%
Rural and Remote Rate Protection (RRRP)	per kWh	$ 0.0013	105	$ 0.14	$ 0.0013	105	$ 0.14	-$ 0.00	-0.11%
Standard Supply Service Charge	Monthly	$ 0.2500	1	$ 0.25	$ 0.2500	1	$ 0.25	$ -	0.00%
Debt Retirement Charge (DRC)			100	$ -					
Ontario Electricity Support Program (OESP)	per kWh	$ 0.0011	105	$ 0.12	$ 0.0011	105	$ 0.12	-$ 0.00	-0.11%
Non-RPP Retailer Avg. Price + GA	per kWh	$ 0.1652	100	$ 16.52	$ 0.1652	100	$ 16.52	$ -	0.00%
Total Bill on Non-RPP Avg. Price				**$ 47.00**			**$ 52.64**	**$ 5.64**	**11.99%**
HST		13%		$ 6.11	13%		$ 6.84	$ 0.73	11.99%
Total Bill (including HST)				$ 53.11			$ 59.48	$ 6.37	11.99%
Ontario Clean Energy Benefit [1]									
Total Bill on Non-RPP Avg. Price				**$ 53.11**			**$ 59.48**	**$ 6.37**	**11.99%**

Customer Class:	Residential TOU - Port Colborne	
RPP / Non-RPP:	RPP	
Consumption	100	kWh
Demand	-	kW
Current Loss Factor	1.0542	
Proposed/Approved Loss Factor	1.0530	
Ontario Clean Energy Benefit Applied?	No	

		Current Board-Approved			Proposed			Impact	
	Charge Unit	Rate ($)	Volume	Charge ($)	Rate ($)	Volume	Charge ($)	$ Change	% Change
Monthly Service Charge	Monthly	$ 23.4400	1	$ 23.44	$ 30.4700	1	$ 30.47	$ 7.03	29.99%
Smart Meter Rate Adder			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
Distribution Volumetric Rate	per kWh	$ 0.0152	100	$ 1.52	$ 0.0116	100	$ 1.16	-$ 0.36	-23.68%
Smart Meter Disposition Rider			100	$ -		100	$ -	$ -	
LRAM & SSM Rate Rider	per kWh		100	$ -	$ 0.0003	100	$ 0.03	$ 0.03	
			100	$ -		100	$ -	$ -	
			100	$ -		100	$ -	$ -	
			100	$ -		100	$ -	$ -	
			100	$ -		100	$ -	$ -	
			100	$ -		100	$ -	$ -	
			100	$ -		100	$ -	$ -	
			100	$ -		100	$ -	$ -	
Sub-Total A (excluding pass through)				$ 24.96			$ 31.66	**$ 6.70**	**26.84%**
DVA - Total in Effect 2016	per kWh	-$ 0.0013	100	-$ 0.13		100	$ -	$ 0.13	-100.00%
DVA - Total in Effect 2017 (Var)	per kWh		100	$ -	-$ 0.0044	100	-$ 0.44	-$ 0.44	
DVA - Total in Effect 2017 (Fixed)	Monthly		1	$ -	-$ 0.1500	1	-$ 0.15	-$ 0.15	
			100	$ -		100	$ -	$ -	
Low Voltage Service Charge	per kWh	$ 0.0002	100	$ 0.02	$ 0.0003	100	$ 0.03	$ 0.01	50.00%
Line Losses on Cost of Power	per kWh	$ 0.1077	5	$ 0.58	$ 0.1077	5	$ 0.57	-$ 0.01	-2.21%
Smart Meter Entity Charge	Monthly	$ 0.7900	1	$ 0.79	$ 0.7900	1	$ 0.79	$ -	0.00%
Sub-Total B - Distribution (includes Sub-Total A)				**$ 26.22**			**$ 32.46**	**$ 6.24**	**23.78%**
RTSR - Network	per kWh	$ 0.0072	105	$ 0.76	$ 0.0069	105	$ 0.73	-$ 0.03	-4.28%
RTSR - Line and Transformation Connection	per kWh	$ 0.0058	105	$ 0.61	$ 0.0059	105	$ 0.62	$ 0.01	1.61%
Sub-Total C - Delivery (including Sub-Total B)				**$ 27.59**			**$ 33.81**	**$ 6.21**	**22.52%**
Wholesale Market Service Charge (WMSC)	per kWh	$ 0.0036	105	$ 0.38	$ 0.0036	105	$ 0.38	-$ 0.00	-0.11%
Rural and Remote Rate Protection (RRRP)	per kWh	$ 0.0013	105	$ 0.14	$ 0.0013	105	$ 0.14	-$ 0.00	-0.11%
Standard Supply Service Charge	Monthly	$ 0.2500	1	$ 0.25	$ 0.2500	1	$ 0.25	$ -	0.00%
Debt Retirement Charge (DRC)			100	$ -					
Ontario Electricity Support Program (OESP)	per kWh	$ 0.0011	105	$ 0.12	$ 0.0011	105	$ 0.12	-$ 0.00	-0.11%
TOU - Off Peak	per kWh	$ 0.0830	64	$ 5.31	$ 0.0830	64	$ 5.31	$ -	0.00%
TOU - Mid Peak	per kWh	$ 0.1280	18	$ 2.30	$ 0.1280	18	$ 2.30	$ -	0.00%
TOU - On Peak	per kWh	$ 0.1750	18	$ 3.15	$ 0.1750	18	$ 3.15	$ -	0.00%
Total Bill on TOU (before Taxes)				**$ 39.24**			**$ 45.46**	**$ 6.21**	**15.83%**
HST		13%		$ 5.10	13%		$ 5.91	$ 0.81	15.83%
Total Bill (including HST)				$ 44.34			$ 51.37	$ 7.02	15.83%
Ontario Clean Energy Benefit [1]									
Total Bill on TOU				**$ 44.34**			**$ 51.37**	**$ 7.02**	**15.83%**

Customer Class:	Residential Retailer - Port Colborne	
RPP / Non-RPP:	Non-RPP (Retailer)	
Consumption	100	kWh
Demand	-	kW
Current Loss Factor	1.0542	
Proposed/Approved Loss Factor	1.0530	
Ontario Clean Energy Benefit Applied?	No	

		Current Board-Approved			Proposed			Impact	
	Charge Unit	**Rate ($)**	**Volume**	**Charge ($)**	**Rate ($)**	**Volume**	**Charge ($)**	**$ Change**	**% Change**
Monthly Service Charge	Monthly	$ 23.4400	1	$ 23.44	$ 30.4700	1	$ 30.47	$ 7.03	29.99%
Smart Meter Rate Adder			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
Distribution Volumetric Rate	per kWh	$ 0.0152	100	$ 1.52	$ 0.0116	100	$ 1.16	-$ 0.36	-23.68%
Smart Meter Disposition Rider			100	$ -		100	$ -	$ -	
LRAM & SSM Rate Rider	per kWh		100	$ -	$ 0.0003	100	$ 0.03	$ 0.03	
			100	$ -		100	$ -	$ -	
			100	$ -		100	$ -	$ -	
			100	$ -		100	$ -	$ -	
			100	$ -		100	$ -	$ -	
			100	$ -		100	$ -	$ -	
			100	$ -		100	$ -	$ -	
			100	$ -		100	$ -	$ -	
Sub-Total A (excluding pass through)				$ 24.96			$ 31.66	**$ 6.70**	**26.84%**
DVA - Total in Effect 2016	per kWh	-$ 0.0017	100	-$ 0.17		100	$ -	$ 0.17	-100.00%
DVA - Total in Effect 2017 (Var)	per kWh		100	$ -	$ 0.0068	100	$ 0.68	$ 0.68	
DVA - Total in Effect 2017 (Fixed)	Monthly		1	$ -	-$ 0.1500	1	-$ 0.15	-$ 0.15	
			100	$ -		100	$ -	$ -	
Low Voltage Service Charge	per kWh	$ 0.0002	100	$ 0.02	$ 0.0003	100	$ 0.03	$ 0.01	50.00%
Line Losses on Cost of Power	per kWh	$ 0.1652	5	$ 0.90	$ 0.1652	5	$ 0.88	-$ 0.02	-2.21%
Smart Meter Entity Charge	Monthly	$ 0.7900	1	$ 0.79	$ 0.7900	1	$ 0.79	$ -	0.00%
Sub-Total B - Distribution (includes Sub-Total A)				**$ 26.50**			**$ 33.89**	**$ 7.39**	**27.89%**
RTSR - Network	per kWh	$ 0.0072	105	$ 0.76	$ 0.0069	105	$ 0.73	-$ 0.03	-4.28%
RTSR - Line and Transformation Connection	per kWh	$ 0.0058	105	$ 0.61	$ 0.0059	105	$ 0.62	$ 0.01	1.61%
Sub-Total C - Delivery (including Sub-Total B)				**$ 27.87**			**$ 35.23**	**$ 7.37**	**26.44%**
Wholesale Market Service Charge (WMSC)	per kWh	$ 0.0036	105	$ 0.38	$ 0.0036	105	$ 0.38	-$ 0.00	-0.11%
Rural and Remote Rate Protection (RRRP)	per kWh	$ 0.0013	105	$ 0.14	$ 0.0013	105	$ 0.14	-$ 0.00	-0.11%
Standard Supply Service Charge	Monthly	$ 0.2500	1	$ 0.25	$ 0.2500	1	$ 0.25	$ -	0.00%
Debt Retirement Charge (DRC)			100	$ -					
Ontario Electricity Support Program (OESP)	per kWh	$ 0.0011	105	$ 0.12	$ 0.0011	105	$ 0.12	-$ 0.00	-0.11%
Non-RPP Retailer Avg. Price + GA	per kWh	$ 0.1652	100	$ 16.52	$ 0.1652	100	$ 16.52	$ -	0.00%
Total Bill on Non-RPP Avg. Price				**$ 45.27**			**$ 52.64**	**$ 7.37**	**16.27%**
HST		13%		$ 5.88	13%		$ 6.84	$ 0.96	16.27%
Total Bill (including HST)				$ 51.15			$ 59.48	$ 8.32	16.27%
Ontario Clean Energy Benefit [1]									
Total Bill on Non-RPP Avg. Price				**$ 51.15**			**$ 59.48**	**$ 8.32**	**16.27%**

Customer Class:	Residential TOU - Fort Erie	
RPP / Non-RPP:	RPP	
Consumption	210	kWh
Demand	-	kW
Current Loss Factor	1.0542	
Proposed/Approved Loss Factor	1.0530	
Ontario Clean Energy Benefit Applied?	No	

		Current Board-Approved			Proposed			Impact	
	Charge Unit	**Rate ($)**	**Volume**	**Charge ($)**	**Rate ($)**	**Volume**	**Charge ($)**	**$ Change**	**% Change**
Monthly Service Charge	Monthly	$ 23.4400	1	$ 23.44	$ 30.4700	1	$ 30.47	$ 7.03	29.99%
Smart Meter Rate Adder			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
Distribution Volumetric Rate	per kWh	$ 0.0152	210	$ 3.19	$ 0.0116	210	$ 2.44	-$ 0.76	-23.68%
Smart Meter Disposition Rider			210	$ -		210	$ -	$ -	
LRAM & SSM Rate Rider	per kWh		210	$ -	$ 0.0003	210	$ 0.06	$ 0.06	
			210	$ -		210	$ -	$ -	
			210	$ -		210	$ -	$ -	
			210	$ -		210	$ -	$ -	
			210	$ -		210	$ -	$ -	
			210	$ -		210	$ -	$ -	
			210	$ -		210	$ -	$ -	
			210	$ -		210	$ -	$ -	
Sub-Total A (excluding pass through)				$ 26.63			$ 32.97	**$ 6.34**	**23.79%**
DVA - Total in Effect 2016	per kWh	$ 0.0004	210	$ 0.08		210	$ -	-$ 0.08	-100.00%
DVA - Total in Effect 2017 (Var)	per kWh		210	$ -	-$ 0.0044	210	-$ 0.92	-$ 0.92	
DVA - Total in Effect 2017 (Fixed)	Monthly		1	$ -	-$ 0.1500	1	-$ 0.15	-$ 0.15	
			210	$ -		210	$ -	$ -	
Low Voltage Service Charge	per kWh	$ 0.0002	210	$ 0.04	$ 0.0003	210	$ 0.06	$ 0.02	50.00%
Line Losses on Cost of Power	per kWh	$ 0.1077	11	$ 1.23	$ 0.1077	11	$ 1.20	-$ 0.03	-2.21%
Smart Meter Entity Charge	Monthly	$ 0.7900	1	$ 0.79	$ 0.7900	1	$ 0.79	$ -	0.00%
Sub-Total B - Distribution (includes Sub-Total A)				**$ 28.77**			**$ 33.95**	**$ 5.17**	**17.98%**
RTSR - Network	per kWh	$ 0.0072	221	$ 1.59	$ 0.0069	221	$ 1.53	-$ 0.07	-4.28%
RTSR - Line and Transformation Connection	per kWh	$ 0.0058	221	$ 1.28	$ 0.0059	221	$ 1.30	$ 0.02	1.61%
Sub-Total C - Delivery (including Sub-Total B)				**$ 31.65**			**$ 36.78**	**$ 5.13**	**16.19%**
Wholesale Market Service Charge (WMSC)	per kWh	$ 0.0036	221	$ 0.80	$ 0.0036	221	$ 0.80	-$ 0.00	-0.11%
Rural and Remote Rate Protection (RRRP)	per kWh	$ 0.0013	221	$ 0.29	$ 0.0013	221	$ 0.29	-$ 0.00	-0.11%
Standard Supply Service Charge	Monthly	$ 0.2500	1	$ 0.25	$ 0.2500	1	$ 0.25	$ -	0.00%
Debt Retirement Charge (DRC)			210	$ -					
Ontario Electricity Support Program (OESP)	per kWh	$ 0.0011	221	$ 0.24	$ 0.0011	221	$ 0.24	-$ 0.00	-0.11%
TOU - Off Peak	per kWh	$ 0.0830	134	$ 11.16	$ 0.0830	134	$ 11.16	$ -	0.00%
TOU - Mid Peak	per kWh	$ 0.1280	38	$ 4.84	$ 0.1280	38	$ 4.84	$ -	0.00%
TOU - On Peak	per kWh	$ 0.1750	38	$ 6.62	$ 0.1750	38	$ 6.62	$ -	0.00%
Total Bill on TOU (before Taxes)				**$ 55.84**			**$ 60.96**	**$ 5.12**	**9.18%**
HST		13%		$ 7.26	13%		$ 7.93	$ 0.67	9.18%
Total Bill (including HST)				$ 63.10			$ 68.89	$ 5.79	9.18%
Ontario Clean Energy Benefit [1]									
Total Bill on TOU				**$ 63.10**			**$ 68.89**	**$ 5.79**	**9.18%**

Customer Class:	**Residential Retailer - Fort Erie**	
RPP / Non-RPP:	**Non-RPP (Retailer)**	
Consumption	**210**	**kWh**
Demand	**-**	**kW**
Current Loss Factor	**1.0542**	
Proposed/Approved Loss Factor	**1.0530**	
Ontario Clean Energy Benefit Applied?	**No**	

		Current Board-Approved			**Proposed**			**Impact**	
	Charge Unit	**Rate ($)**	**Volume**	**Charge ($)**	**Rate ($)**	**Volume**	**Charge ($)**	**$ Change**	**% Change**
Monthly Service Charge	Monthly	$ 23.4400	1	$ 23.44	$ 30.4700	1	$ 30.47	$ 7.03	29.99%
Smart Meter Rate Adder			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
Distribution Volumetric Rate	per kWh	$ 0.0152	210	$ 3.19	$ 0.0116	210	$ 2.44	-$ 0.76	-23.68%
Smart Meter Disposition Rider			210	$ -		210	$ -	$ -	
LRAM & SSM Rate Rider	per kWh		210	$ -	$ 0.0003	210	$ 0.06	$ 0.06	
			210	$ -		210	$ -	$ -	
			210	$ -		210	$ -	$ -	
			210	$ -		210	$ -	$ -	
			210	$ -		210	$ -	$ -	
			210	$ -		210	$ -	$ -	
			210	$ -		210	$ -	$ -	
			210	$ -		210	$ -	$ -	
Sub-Total A (excluding pass through)				$ 26.63			$ 32.97	**$ 6.34**	**23.79%**
DVA - Total in Effect 2016	per kWh	$ 0.0016	210	$ 0.34		210	$ -	-$ 0.34	-100.00%
DVA - Total in Effect 2017 (Var)	per kWh		210	$ -	$ 0.0065	210	$ 1.37	$ 1.37	
DVA - Total in Effect 2017 (Fixed)	Monthly		1	$ -	-$ 0.1500	1	-$ 0.15	-$ 0.15	
			210	$ -		210	$ -	$ -	
Low Voltage Service Charge	per kWh	$ 0.0002	210	$ 0.04	$ 0.0003	210	$ 0.06	$ 0.02	50.00%
Line Losses on Cost of Power	per kWh	$ 0.1652	11	$ 1.88	$ 0.1652	11	$ 1.84	-$ 0.04	-2.21%
Smart Meter Entity Charge	Monthly	$ 0.7900	1	$ 0.79	$ 0.7900	1	$ 0.79	$ -	0.00%
Sub-Total B - Distribution (includes Sub-Total A)				**$ 29.68**			**$ 36.88**	**$ 7.20**	**24.24%**
RTSR - Network	per kWh	$ 0.0072	221	$ 1.59	$ 0.0069	221	$ 1.53	-$ 0.07	-4.28%
RTSR - Line and Transformation Connection	per kWh	$ 0.0058	221	$ 1.28	$ 0.0059	221	$ 1.30	$ 0.02	1.61%
Sub-Total C - Delivery (including Sub-Total B)				**$ 32.56**			**$ 39.71**	**$ 7.15**	**21.95%**
Wholesale Market Service Charge (WMSC)	per kWh	$ 0.0036	221	$ 0.80	$ 0.0036	221	$ 0.80	-$ 0.00	-0.11%
Rural and Remote Rate Protection (RRRP)	per kWh	$ 0.0013	221	$ 0.29	$ 0.0013	221	$ 0.29	-$ 0.00	-0.11%
Standard Supply Service Charge	Monthly	$ 0.2500	1	$ 0.25	$ 0.2500	1	$ 0.25	$ -	0.00%
Debt Retirement Charge (DRC)			210	$ -					
Ontario Electricity Support Program (OESP)	per kWh	$ 0.0011	221	$ 0.24	$ 0.0011	221	$ 0.24	-$ 0.00	-0.11%
Non-RPP Retailer Avg. Price + GA	per kWh	$ 0.1652	210	$ 34.69	$ 0.1652	210	$ 34.69	$ -	0.00%
Total Bill on Non-RPP Avg. Price				**$ 68.83**			**$ 75.97**	**$ 7.15**	**10.38%**
HST		13%		$ 8.95	13%		$ 9.88	$ 0.93	10.38%
Total Bill (including HST)				$ 77.78			$ 85.85	$ 8.08	10.38%
Ontario Clean Energy Benefit [1]									
Total Bill on Non-RPP Avg. Price				**$ 77.78**			**$ 85.85**	**$ 8.08**	**10.38%**

Customer Class:	Residential TOU - EOP
RPP / Non-RPP:	RPP
Consumption	210 kWh
Demand	- kW
Current Loss Factor	1.0542
Proposed/Approved Loss Factor	1.0530
Ontario Clean Energy Benefit Applied?	No

		Current Board-Approved			Proposed			Impact	
	Charge Unit	**Rate ($)**	**Volume**	**Charge ($)**	**Rate ($)**	**Volume**	**Charge ($)**	**$ Change**	**% Change**
Monthly Service Charge	Monthly	$ 23.4400	1	$ 23.44	$ 30.4700	1	$ 30.47	$ 7.03	29.99%
Smart Meter Rate Adder			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
Distribution Volumetric Rate	per kWh	$ 0.0152	210	$ 3.19	$ 0.0116	210	$ 2.44	-$ 0.76	-23.68%
Smart Meter Disposition Rider			210	$ -		210	$ -	$ -	
LRAM & SSM Rate Rider	per kWh		210	$ -	$ 0.0003	210	$ 0.06	$ 0.06	
			210	$ -		210	$ -	$ -	
			210	$ -		210	$ -	$ -	
			210	$ -		210	$ -	$ -	
			210	$ -		210	$ -	$ -	
			210	$ -		210	$ -	$ -	
			210	$ -		210	$ -	$ -	
			210	$ -		210	$ -	$ -	
Sub-Total A (excluding pass through)				$ 26.63			$ 32.97	**$ 6.34**	**23.79%**
DVA - Total in Effect 2016	per kWh	-$ 0.0024	210	-$ 0.50		210	$ -	$ 0.50	-100.00%
DVA - Total in Effect 2017 (Var)	per kWh		210	$ -	-$ 0.0044	210	-$ 0.92	-$ 0.92	
DVA - Total in Effect 2017 (Fixed)	Monthly		1	$ -	-$ 0.1500	1	-$ 0.15	-$ 0.15	
			210	$ -		210	$ -	$ -	
Low Voltage Service Charge	per kWh	$ 0.0002	210	$ 0.04	$ 0.0003	210	$ 0.06	$ 0.02	50.00%
Line Losses on Cost of Power	per kWh	$ 0.1077	11	$ 1.23	$ 0.1077	11	$ 1.20	-$ 0.03	-2.21%
Smart Meter Entity Charge	Monthly	$ 0.7900	1	$ 0.79	$ 0.7900	1	$ 0.79	$ -	0.00%
Sub-Total B - Distribution (includes Sub-Total A)				**$ 28.19**			**$ 33.95**	**$ 5.76**	**20.44%**
RTSR - Network	per kWh	$ 0.0072	221	$ 1.59	$ 0.0069	221	$ 1.53	-$ 0.07	-4.28%
RTSR - Line and Transformation Connection	per kWh	$ 0.0058	221	$ 1.28	$ 0.0059	221	$ 1.30	$ 0.02	1.61%
Sub-Total C - Delivery (including Sub-Total B)				**$ 31.06**			**$ 36.78**	**$ 5.71**	**18.39%**
Wholesale Market Service Charge (WMSC)	per kWh	$ 0.0036	221	$ 0.80	$ 0.0036	221	$ 0.80	-$ 0.00	-0.11%
Rural and Remote Rate Protection (RRRP)	per kWh	$ 0.0013	221	$ 0.29	$ 0.0013	221	$ 0.29	-$ 0.00	-0.11%
Standard Supply Service Charge	Monthly	$ 0.2500	1	$ 0.25	$ 0.2500	1	$ 0.25	$ -	0.00%
Debt Retirement Charge (DRC)			210	$ -					
Ontario Electricity Support Program (OESP)	per kWh	$ 0.0011	221	$ 0.24	$ 0.0011	221	$ 0.24	-$ 0.00	-0.11%
TOU - Off Peak	per kWh	$ 0.0830	134	$ 11.16	$ 0.0830	134	$ 11.16	$ -	0.00%
TOU - Mid Peak	per kWh	$ 0.1280	38	$ 4.84	$ 0.1280	38	$ 4.84	$ -	0.00%
TOU - On Peak	per kWh	$ 0.1750	38	$ 6.62	$ 0.1750	38	$ 6.62	$ -	0.00%
Total Bill on TOU (before Taxes)				**$ 55.25**			**$ 60.96**	**$ 5.71**	**10.34%**
HST		13%		$ 7.18	13%		$ 7.93	$ 0.74	10.34%
Total Bill (including HST)				$ 62.43			$ 68.89	$ 6.45	10.34%
Ontario Clean Energy Benefit [1]									
Total Bill on TOU				**$ 62.43**			**$ 68.89**	**$ 6.45**	**10.34%**

Customer Class:	Residential Retailer - EOP
RPP / Non-RPP:	Non-RPP (Retailer)
Consumption	210 kWh
Demand	- kW
Current Loss Factor	1.0542
Proposed/Approved Loss Factor	1.0530
Ontario Clean Energy Benefit Applied?	No

		Current Board-Approved			**Proposed**			**Impact**	
	Charge Unit	**Rate ($)**	**Volume**	**Charge ($)**	**Rate ($)**	**Volume**	**Charge ($)**	**$ Change**	**% Change**
Monthly Service Charge	Monthly	$ 23.4400	1	$ 23.44	$ 30.4700	1	$ 30.47	$ 7.03	29.99%
Smart Meter Rate Adder			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
Distribution Volumetric Rate	per kWh	$ 0.0152	210	$ 3.19	$ 0.0116	210	$ 2.44	-$ 0.76	-23.68%
Smart Meter Disposition Rider			210	$ -		210	$ -	$ -	
LRAM & SSM Rate Rider	per kWh		210	$ -	$ 0.0003	210	$ 0.06	$ 0.06	
			210	$ -		210	$ -	$ -	
			210	$ -		210	$ -	$ -	
			210	$ -		210	$ -	$ -	
			210	$ -		210	$ -	$ -	
			210	$ -		210	$ -	$ -	
			210	$ -		210	$ -	$ -	
			210	$ -		210	$ -	$ -	
Sub-Total A (excluding pass through)				$ 26.63			$ 32.97	**$ 6.34**	**23.79%**
DVA - Total in Effect 2016	per kWh	$ 0.0156	210	$ 3.28		210	$ -	-$ 3.28	-100.00%
DVA - Total in Effect 2017 (Var)	per kWh		210	$ -	$ 0.0065	210	$ 1.37	$ 1.37	
DVA - Total in Effect 2017 (Fixed)	Monthly		1	$ -	-$ 0.1500	1	-$ 0.15	-$ 0.15	
			210	$ -		210	$ -	$ -	
Low Voltage Service Charge	per kWh	$ 0.0002	210	$ 0.04	$ 0.0003	210	$ 0.06	$ 0.02	50.00%
Line Losses on Cost of Power	per kWh	$ 0.1652	11	$ 1.88	$ 0.1652	11	$ 1.84	-$ 0.04	-2.21%
Smart Meter Entity Charge	Monthly	$ 0.7900	1	$ 0.79	$ 0.7900	1	$ 0.79	$ -	0.00%
Sub-Total B - Distribution (includes Sub-Total A)				**$ 32.62**			**$ 36.88**	**$ 4.26**	**13.05%**
RTSR - Network	per kWh	$ 0.0072	221	$ 1.59	$ 0.0069	221	$ 1.53	-$ 0.07	-4.28%
RTSR - Line and Transformation Connection	per kWh	$ 0.0058	221	$ 1.28	$ 0.0059	221	$ 1.30	$ 0.02	1.61%
Sub-Total C - Delivery (including Sub-Total B)				**$ 35.50**			**$ 39.71**	**$ 4.21**	**11.85%**
Wholesale Market Service Charge (WMSC)	per kWh	$ 0.0036	221	$ 0.80	$ 0.0036	221	$ 0.80	-$ 0.00	-0.11%
Rural and Remote Rate Protection (RRRP)	per kWh	$ 0.0013	221	$ 0.29	$ 0.0013	221	$ 0.29	-$ 0.00	-0.11%
Standard Supply Service Charge	Monthly	$ 0.2500	1	$ 0.25	$ 0.2500	1	$ 0.25	$ -	0.00%
Debt Retirement Charge (DRC)			210	$ -					
Ontario Electricity Support Program (OESP)	per kWh	$ 0.0011	221	$ 0.24	$ 0.0011	221	$ 0.24	-$ 0.00	-0.11%
Non-RPP Retailer Avg. Price + GA	per kWh	$ 0.1652	210	$ 34.69	$ 0.1652	210	$ 34.69	$ -	0.00%
Total Bill on Non-RPP Avg. Price				**$ 71.77**			**$ 75.97**	**$ 4.21**	**5.86%**
HST		13%		$ 9.33	13%		$ 9.88	$ 0.55	5.86%
Total Bill (including HST)				$ 81.10			$ 85.85	$ 4.75	5.86%
Ontario Clean Energy Benefit [1]									
Total Bill on Non-RPP Avg. Price				**$ 81.10**			**$ 85.85**	**$ 4.75**	**5.86%**

Customer Class:	Residential TOU - Port Colborne	
RPP / Non-RPP:	RPP	
Consumption	210	kWh
Demand	-	kW
Current Loss Factor	1.0542	
Proposed/Approved Loss Factor	1.0530	
Ontario Clean Energy Benefit Applied?	No	

		Current Board-Approved			**Proposed**			**Impact**	
	Charge Unit	**Rate ($)**	**Volume**	**Charge ($)**	**Rate ($)**	**Volume**	**Charge ($)**	**$ Change**	**% Change**
Monthly Service Charge	Monthly	$ 23.4400	1	$ 23.44	$ 30.4700	1	$ 30.47	$ 7.03	29.99%
Smart Meter Rate Adder			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
Distribution Volumetric Rate	per kWh	$ 0.0152	210	$ 3.19	$ 0.0116	210	$ 2.44	-$ 0.76	-23.68%
Smart Meter Disposition Rider			210	$ -		210	$ -	$ -	
LRAM & SSM Rate Rider	per kWh		210	$ -	$ 0.0003	210	$ 0.06	$ 0.06	
			210	$ -		210	$ -	$ -	
			210	$ -		210	$ -	$ -	
			210	$ -		210	$ -	$ -	
			210	$ -		210	$ -	$ -	
			210	$ -		210	$ -	$ -	
			210	$ -		210	$ -	$ -	
			210	$ -		210	$ -	$ -	
Sub-Total A (excluding pass through)				$ 26.63			$ 32.97	**$ 6.34**	**23.79%**
DVA - Total in Effect 2016	per kWh	-$ 0.0013	210	-$ 0.27		210	$ -	$ 0.27	-100.00%
DVA - Total in Effect 2017 (Var)	per kWh		210	$ -	-$ 0.0044	210	-$ 0.92	-$ 0.92	
DVA - Total in Effect 2017 (Fixed)	Monthly		1	$ -	-$ 0.1500	1	-$ 0.15	-$ 0.15	
			210	$ -		210	$ -	$ -	
Low Voltage Service Charge	per kWh	$ 0.0002	210	$ 0.04	$ 0.0003	210	$ 0.06	$ 0.02	50.00%
Line Losses on Cost of Power	per kWh	$ 0.1077	11	$ 1.23	$ 0.1077	11	$ 1.20	-$ 0.03	-2.21%
Smart Meter Entity Charge	Monthly	$ 0.7900	1	$ 0.79	$ 0.7900	1	$ 0.79	$ -	0.00%
Sub-Total B - Distribution (includes Sub-Total A)				**$ 28.42**			**$ 33.95**	**$ 5.53**	**19.46%**
RTSR - Network	per kWh	$ 0.0072	221	$ 1.59	$ 0.0069	221	$ 1.53	-$ 0.07	-4.28%
RTSR - Line and Transformation Connection	per kWh	$ 0.0058	221	$ 1.28	$ 0.0059	221	$ 1.30	$ 0.02	1.61%
Sub-Total C - Delivery (including Sub-Total B)				**$ 31.29**			**$ 36.78**	**$ 5.48**	**17.52%**
Wholesale Market Service Charge (WMSC)	per kWh	$ 0.0036	221	$ 0.80	$ 0.0036	221	$ 0.80	-$ 0.00	-0.11%
Rural and Remote Rate Protection (RRRP)	per kWh	$ 0.0013	221	$ 0.29	$ 0.0013	221	$ 0.29	-$ 0.00	-0.11%
Standard Supply Service Charge	Monthly	$ 0.2500	1	$ 0.25	$ 0.2500	1	$ 0.25	$ -	0.00%
Debt Retirement Charge (DRC)			210	$ -					
Ontario Electricity Support Program (OESP)	per kWh	$ 0.0011	221	$ 0.24	$ 0.0011	221	$ 0.24	-$ 0.00	-0.11%
TOU - Off Peak	per kWh	$ 0.0830	134	$ 11.16	$ 0.0830	134	$ 11.16	$ -	0.00%
TOU - Mid Peak	per kWh	$ 0.1280	38	$ 4.84	$ 0.1280	38	$ 4.84	$ -	0.00%
TOU - On Peak	per kWh	$ 0.1750	38	$ 6.62	$ 0.1750	38	$ 6.62	$ -	0.00%
Total Bill on TOU (before Taxes)				**$ 55.48**			**$ 60.96**	**$ 5.48**	**9.88%**
HST		13%		$ 7.21	13%		$ 7.93	$ 0.71	9.88%
Total Bill (including HST)				$ 62.69			$ 68.89	$ 6.19	9.88%
Ontario Clean Energy Benefit [1]									
Total Bill on TOU				**$ 62.69**			**$ 68.89**	**$ 6.19**	**9.88%**

Customer Class:	**Residential Retailer - Port Colborne**	
RPP / Non-RPP:	**Non-RPP (Retailer)**	
Consumption	**210**	**kWh**
Demand	**-**	**kW**
Current Loss Factor	**1.0542**	
Proposed/Approved Loss Factor	**1.0530**	
Ontario Clean Energy Benefit Applied?	**No**	

		Current Board-Approved			**Proposed**			**Impact**	
	Charge Unit	**Rate ($)**	**Volume**	**Charge ($)**	**Rate ($)**	**Volume**	**Charge ($)**	**$ Change**	**% Change**
Monthly Service Charge	Monthly	$ 23.4400	1	$ 23.44	$ 30.4700	1	$ 30.47	$ 7.03	29.99%
Smart Meter Rate Adder			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
Distribution Volumetric Rate	per kWh	$ 0.0152	210	$ 3.19	$ 0.0116	210	$ 2.44	-$ 0.76	-23.68%
Smart Meter Disposition Rider			210	$ -		210	$ -	$ -	
LRAM & SSM Rate Rider	per kWh		210	$ -	$ 0.0003	210	$ 0.06	$ 0.06	
			210	$ -		210	$ -	$ -	
			210	$ -		210	$ -	$ -	
			210	$ -		210	$ -	$ -	
			210	$ -		210	$ -	$ -	
			210	$ -		210	$ -	$ -	
			210	$ -		210	$ -	$ -	
			210	$ -		210	$ -	$ -	
Sub-Total A (excluding pass through)				$ 26.63			$ 32.97	**$ 6.34**	**23.79%**
DVA - Total in Effect 2016	per kWh	-$ 0.0017	210	-$ 0.36		210	$ -	$ 0.36	-100.00%
DVA - Total in Effect 2017 (Var)	per kWh		210	$ -	$ 0.0065	210	$ 1.37	$ 1.37	
DVA - Total in Effect 2017 (Fixed)	Monthly		1	$ -	-$ 0.1500	1	-$ 0.15	-$ 0.15	
			210	$ -		210	$ -	$ -	
Low Voltage Service Charge	per kWh	$ 0.0002	210	$ 0.04	$ 0.0003	210	$ 0.06	$ 0.02	50.00%
Line Losses on Cost of Power	per kWh	$ 0.1652	11	$ 1.88	$ 0.1652	11	$ 1.84	-$ 0.04	-2.21%
Smart Meter Entity Charge	Monthly	$ 0.7900	1	$ 0.79	$ 0.7900	1	$ 0.79	$ -	0.00%
Sub-Total B - Distribution (includes Sub-Total A)				**$ 28.99**			**$ 36.88**	**$ 7.89**	**27.21%**
RTSR - Network	per kWh	$ 0.0072	221	$ 1.59	$ 0.0069	221	$ 1.53	-$ 0.07	-4.28%
RTSR - Line and Transformation Connection	per kWh	$ 0.0058	221	$ 1.28	$ 0.0059	221	$ 1.30	$ 0.02	1.61%
Sub-Total C - Delivery (including Sub-Total B)				**$ 31.87**			**$ 39.71**	**$ 7.84**	**24.61%**
Wholesale Market Service Charge (WMSC)	per kWh	$ 0.0036	221	$ 0.80	$ 0.0036	221	$ 0.80	-$ 0.00	-0.11%
Rural and Remote Rate Protection (RRRP)	per kWh	$ 0.0013	221	$ 0.29	$ 0.0013	221	$ 0.29	-$ 0.00	-0.11%
Standard Supply Service Charge	Monthly	$ 0.2500	1	$ 0.25	$ 0.2500	1	$ 0.25	$ -	0.00%
Debt Retirement Charge (DRC)			210	$ -					
Ontario Electricity Support Program (OESP)	per kWh	$ 0.0011	221	$ 0.24	$ 0.0011	221	$ 0.24	-$ 0.00	-0.11%
Non-RPP Retailer Avg. Price + GA	per kWh	$ 0.1652	210	$ 34.69	$ 0.1652	210	$ 34.69	$ -	0.00%
Total Bill on Non-RPP Avg. Price				**$ 68.14**			**$ 75.97**	**$ 7.84**	**11.51%**
HST		13%		$ 8.86	13%		$ 9.88	$ 1.02	11.51%
Total Bill (including HST)				$ 76.99			$ 85.85	$ 8.86	11.51%
Ontario Clean Energy Benefit [1]									
Total Bill on Non-RPP Avg. Price				**$ 76.99**			**$ 85.85**	**$ 8.86**	**11.51%**

Customer Class:	Residential TOU - Fort Erie	
RPP / Non-RPP:	RPP	
Consumption	250	kWh
Demand	-	kW
Current Loss Factor	1.0542	
Proposed/Approved Loss Factor	1.0530	
Ontario Clean Energy Benefit Applied?	No	

		Current Board-Approved			Proposed			Impact	
	Charge Unit	**Rate ($)**	**Volume**	**Charge ($)**	**Rate ($)**	**Volume**	**Charge ($)**	**$ Change**	**% Change**
Monthly Service Charge	Monthly	$ 23.4400	1	$ 23.44	$ 30.4700	1	$ 30.47	$ 7.03	29.99%
Smart Meter Rate Adder			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
Distribution Volumetric Rate	per kWh	$ 0.0152	250	$ 3.80	$ 0.0116	250	$ 2.90	-$ 0.90	-23.68%
Smart Meter Disposition Rider			250	$ -		250	$ -	$ -	
LRAM & SSM Rate Rider	per kWh		250	$ -	$ 0.0003	250	$ 0.08	$ 0.08	
			250	$ -		250	$ -	$ -	
			250	$ -		250	$ -	$ -	
			250	$ -		250	$ -	$ -	
			250	$ -		250	$ -	$ -	
			250	$ -		250	$ -	$ -	
			250	$ -		250	$ -	$ -	
			250	$ -		250	$ -	$ -	
Sub-Total A (excluding pass through)				$ 27.24			$ 33.45	**$ 6.21**	**22.78%**
DVA - Total in Effect 2016	per kWh	$ 0.0004	250	$ 0.10		250	$ -	-$ 0.10	-100.00%
DVA - Total in Effect 2017 (Var)	per kWh		250	$ -	-$ 0.0044	250	-$ 1.10	-$ 1.10	
DVA - Total in Effect 2017 (Fixed)	Monthly		1	$ -	-$ 0.1500	1	-$ 0.15	-$ 0.15	
			250	$ -		250	$ -	$ -	
Low Voltage Service Charge	per kWh	$ 0.0002	250	$ 0.05	$ 0.0003	250	$ 0.08	$ 0.03	50.00%
Line Losses on Cost of Power	per kWh	$ 0.1077	14	$ 1.46	$ 0.1077	13	$ 1.43	-$ 0.03	-2.21%
Smart Meter Entity Charge	Monthly	$ 0.7900	1	$ 0.79	$ 0.7900	1	$ 0.79	$ -	0.00%
Sub-Total B - Distribution (includes Sub-Total A)				**$ 29.64**			**$ 34.49**	**$ 4.85**	**16.36%**
RTSR - Network	per kWh	$ 0.0072	264	$ 1.90	$ 0.0069	263	$ 1.82	-$ 0.08	-4.28%
RTSR - Line and Transformation Connection	per kWh	$ 0.0058	264	$ 1.53	$ 0.0059	263	$ 1.55	$ 0.02	1.61%
Sub-Total C - Delivery (including Sub-Total B)				**$ 33.06**			**$ 37.86**	**$ 4.79**	**14.49%**
Wholesale Market Service Charge (WMSC)	per kWh	$ 0.0036	264	$ 0.95	$ 0.0036	263	$ 0.95	-$ 0.00	-0.11%
Rural and Remote Rate Protection (RRRP)	per kWh	$ 0.0013	264	$ 0.34	$ 0.0013	263	$ 0.34	-$ 0.00	-0.11%
Standard Supply Service Charge	Monthly	$ 0.2500	1	$ 0.25	$ 0.2500	1	$ 0.25	$ -	0.00%
Debt Retirement Charge (DRC)			250	$ -					
Ontario Electricity Support Program (OESP)	per kWh	$ 0.0011	264	$ 0.29	$ 0.0011	263	$ 0.29	-$ 0.00	-0.11%
TOU - Off Peak	per kWh	$ 0.0830	160	$ 13.28	$ 0.0830	160	$ 13.28	$ -	0.00%
TOU - Mid Peak	per kWh	$ 0.1280	45	$ 5.76	$ 0.1280	45	$ 5.76	$ -	0.00%
TOU - On Peak	per kWh	$ 0.1750	45	$ 7.88	$ 0.1750	45	$ 7.88	$ -	0.00%
Total Bill on TOU (before Taxes)				**$ 61.81**			**$ 66.60**	**$ 4.79**	**7.75%**
HST		13%		$ 8.04	13%		$ 8.66	$ 0.62	7.75%
Total Bill (including HST)				$ 69.85			$ 75.26	$ 5.41	7.75%
Ontario Clean Energy Benefit [1]									
Total Bill on TOU				**$ 69.85**			**$ 75.26**	**$ 5.41**	**7.75%**

Customer Class:	Residential Retailer - Fort Erie
RPP / Non-RPP:	Non-RPP (Retailer)
Consumption	250 kWh
Demand	- kW
Current Loss Factor	1.0542
Proposed/Approved Loss Factor	1.0530
Ontario Clean Energy Benefit Applied?	No

		Current Board-Approved			Proposed			Impact	
	Charge Unit	Rate ($)	Volume	Charge ($)	Rate ($)	Volume	Charge ($)	$ Change	% Change
Monthly Service Charge	Monthly	$ 23.4400	1	$ 23.44	$ 30.4700	1	$ 30.47	$ 7.03	29.99%
Smart Meter Rate Adder			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
Distribution Volumetric Rate	per kWh	$ 0.0152	250	$ 3.80	$ 0.0116	250	$ 2.90	-$ 0.90	-23.68%
Smart Meter Disposition Rider			250	$ -		250	$ -	$ -	
LRAM & SSM Rate Rider	per kWh		250	$ -	$ 0.0003	250	$ 0.08	$ 0.08	
			250	$ -		250	$ -	$ -	
			250	$ -		250	$ -	$ -	
			250	$ -		250	$ -	$ -	
			250	$ -		250	$ -	$ -	
			250	$ -		250	$ -	$ -	
			250	$ -		250	$ -	$ -	
			250	$ -		250	$ -	$ -	
Sub-Total A (excluding pass through)				$ 27.24			$ 33.45	**$ 6.21**	**22.78%**
DVA - Total in Effect 2016	per kWh	$ 0.0016	250	$ 0.40		250	$ -	-$ 0.40	-100.00%
DVA - Total in Effect 2017 (Var)	per kWh		250	$ -	$ 0.0068	250	$ 1.70	$ 1.70	
DVA - Total in Effect 2017 (Fixed)	Monthly		1	$ -	-$ 0.1500	1	-$ 0.15	-$ 0.15	
			250	$ -		250	$ -	$ -	
Low Voltage Service Charge	per kWh	$ 0.0002	250	$ 0.05	$ 0.0003	250	$ 0.08	$ 0.03	50.00%
Line Losses on Cost of Power	per kWh	$ 0.1652	14	$ 2.24	$ 0.1652	13	$ 2.19	-$ 0.05	-2.21%
Smart Meter Entity Charge	Monthly	$ 0.7900	1	$ 0.79	$ 0.7900	1	$ 0.79	$ -	0.00%
Sub-Total B - Distribution (includes Sub-Total A)				**$ 30.72**			**$ 38.05**	**$ 7.33**	**23.86%**
RTSR - Network	per kWh	$ 0.0072	264	$ 1.90	$ 0.0069	263	$ 1.82	-$ 0.08	-4.28%
RTSR - Line and Transformation Connection	per kWh	$ 0.0058	264	$ 1.53	$ 0.0059	263	$ 1.55	$ 0.02	1.61%
Sub-Total C - Delivery (including Sub-Total B)				**$ 34.14**			**$ 41.42**	**$ 7.27**	**21.30%**
Wholesale Market Service Charge (WMSC)	per kWh	$ 0.0036	264	$ 0.95	$ 0.0036	263	$ 0.95	-$ 0.00	-0.11%
Rural and Remote Rate Protection (RRRP)	per kWh	$ 0.0013	264	$ 0.34	$ 0.0013	263	$ 0.34	-$ 0.00	-0.11%
Standard Supply Service Charge	Monthly	$ 0.2500	1	$ 0.25	$ 0.2500	1	$ 0.25	$ -	0.00%
Debt Retirement Charge (DRC)			250	$ -					
Ontario Electricity Support Program (OESP)	per kWh	$ 0.0011	264	$ 0.29	$ 0.0011	263	$ 0.29	-$ 0.00	-0.11%
Non-RPP Retailer Avg. Price + GA	per kWh	$ 0.1652	250	$ 41.30	$ 0.1652	250	$ 41.30	$ -	0.00%
Total Bill on Non-RPP Avg. Price				**$ 77.28**			**$ 84.55**	**$ 7.27**	**9.41%**
HST		13%		$ 10.05	13%		$ 10.99	$ 0.95	9.41%
Total Bill (including HST)				$ 87.32			$ 95.54	$ 8.22	9.41%
Ontario Clean Energy Benefit [1]									
Total Bill on Non-RPP Avg. Price				**$ 87.32**			**$ 95.54**	**$ 8.22**	**9.41%**

Customer Class:	**Residential TOU - EOP**	
RPP / Non-RPP:	**RPP**	
Consumption	**250**	**kWh**
Demand	**-**	**kW**
Current Loss Factor	**1.0542**	
Proposed/Approved Loss Factor	**1.0530**	
Ontario Clean Energy Benefit Applied?	**No**	

		Current Board-Approved			**Proposed**			**Impact**	
	Charge Unit	**Rate ($)**	**Volume**	**Charge ($)**	**Rate ($)**	**Volume**	**Charge ($)**	**$ Change**	**% Change**
Monthly Service Charge	Monthly	$ 23.4400	1	$ 23.44	$ 30.4700	1	$ 30.47	$ 7.03	29.99%
Smart Meter Rate Adder			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
Distribution Volumetric Rate	per kWh	$ 0.0152	250	$ 3.80	$ 0.0116	250	$ 2.90	-$ 0.90	-23.68%
Smart Meter Disposition Rider			250	$ -		250	$ -	$ -	
LRAM & SSM Rate Rider	per kWh		250	$ -	$ 0.0003	250	$ 0.08	$ 0.08	
			250	$ -		250	$ -	$ -	
			250	$ -		250	$ -	$ -	
			250	$ -		250	$ -	$ -	
			250	$ -		250	$ -	$ -	
			250	$ -		250	$ -	$ -	
			250	$ -		250	$ -	$ -	
			250	$ -		250	$ -	$ -	
Sub-Total A (excluding pass through)				$ 27.24			$ 33.45	**$ 6.21**	**22.78%**
DVA - Total in Effect 2016	per kWh	-$ 0.0024	250	-$ 0.60		250	$ -	$ 0.60	-100.00%
DVA - Total in Effect 2017 (Var)	per kWh		250	$ -	-$ 0.0044	250	-$ 1.10	-$ 1.10	
DVA - Total in Effect 2017 (Fixed)	Monthly		1	$ -	-$ 0.1500	1	-$ 0.15	-$ 0.15	
			250	$ -		250	$ -	$ -	
Low Voltage Service Charge	per kWh	$ 0.0002	250	$ 0.05	$ 0.0003	250	$ 0.08	$ 0.03	50.00%
Line Losses on Cost of Power	per kWh	$ 0.1077	14	$ 1.46	$ 0.1077	13	$ 1.43	-$ 0.03	-2.21%
Smart Meter Entity Charge	Monthly	$ 0.7900	1	$ 0.79	$ 0.7900	1	$ 0.79	$ -	0.00%
Sub-Total B - Distribution (includes Sub-Total A)				**$ 28.94**			**$ 34.49**	**$ 5.55**	**19.17%**
RTSR - Network	per kWh	$ 0.0072	264	$ 1.90	$ 0.0069	263	$ 1.82	-$ 0.08	-4.28%
RTSR - Line and Transformation Connection	per kWh	$ 0.0058	264	$ 1.53	$ 0.0059	263	$ 1.55	$ 0.02	1.61%
Sub-Total C - Delivery (including Sub-Total B)				**$ 32.36**			**$ 37.86**	**$ 5.49**	**16.97%**
Wholesale Market Service Charge (WMSC)	per kWh	$ 0.0036	264	$ 0.95	$ 0.0036	263	$ 0.95	-$ 0.00	-0.11%
Rural and Remote Rate Protection (RRRP)	per kWh	$ 0.0013	264	$ 0.34	$ 0.0013	263	$ 0.34	-$ 0.00	-0.11%
Standard Supply Service Charge	Monthly	$ 0.2500	1	$ 0.25	$ 0.2500	1	$ 0.25	$ -	0.00%
Debt Retirement Charge (DRC)			250	$ -					
Ontario Electricity Support Program (OESP)	per kWh	$ 0.0011	264	$ 0.29	$ 0.0011	263	$ 0.29	-$ 0.00	-0.11%
TOU - Off Peak	per kWh	$ 0.0830	160	$ 13.28	$ 0.0830	160	$ 13.28	$ -	0.00%
TOU - Mid Peak	per kWh	$ 0.1280	45	$ 5.76	$ 0.1280	45	$ 5.76	$ -	0.00%
TOU - On Peak	per kWh	$ 0.1750	45	$ 7.88	$ 0.1750	45	$ 7.88	$ -	0.00%
Total Bill on TOU (before Taxes)				**$ 61.11**			**$ 66.60**	**$ 5.49**	**8.98%**
HST		13%		$ 7.94	13%		$ 8.66	$ 0.71	8.98%
Total Bill (including HST)				$ 69.06			$ 75.26	$ 6.20	8.98%
Ontario Clean Energy Benefit [1]									
Total Bill on TOU				**$ 69.06**			**$ 75.26**	**$ 6.20**	**8.98%**

Customer Class:	Residential Retailer - EOP	
RPP / Non-RPP:	Non-RPP (Retailer)	
Consumption	250	kWh
Demand	-	kW
Current Loss Factor	1.0542	
Proposed/Approved Loss Factor	1.0530	
Ontario Clean Energy Benefit Applied?	No	

		Current Board-Approved			Proposed			Impact	
	Charge Unit	**Rate ($)**	**Volume**	**Charge ($)**	**Rate ($)**	**Volume**	**Charge ($)**	**$ Change**	**% Change**
Monthly Service Charge	Monthly	$ 23.4400	1	$ 23.44	$ 30.4700	1	$ 30.47	$ 7.03	29.99%
Smart Meter Rate Adder			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
Distribution Volumetric Rate	per kWh	$ 0.0152	250	$ 3.80	$ 0.0116	250	$ 2.90	-$ 0.90	-23.68%
Smart Meter Disposition Rider			250	$ -		250	$ -	$ -	
LRAM & SSM Rate Rider	per kWh		250	$ -	$ 0.0003	250	$ 0.08	$ 0.08	
			250	$ -		250	$ -	$ -	
			250	$ -		250	$ -	$ -	
			250	$ -		250	$ -	$ -	
			250	$ -		250	$ -	$ -	
			250	$ -		250	$ -	$ -	
			250	$ -		250	$ -	$ -	
			250	$ -		250	$ -	$ -	
Sub-Total A (excluding pass through)				$ 27.24			$ 33.45	**$ 6.21**	**22.78%**
DVA - Total in Effect 2016	per kWh	$ 0.0156	250	$ 3.90		250	$ -	-$ 3.90	-100.00%
DVA - Total in Effect 2017 (Var)	per kWh		250	$ -	$ 0.0068	250	$ 1.70	$ 1.70	
DVA - Total in Effect 2017 (Fixed)	Monthly		1	$ -	-$ 0.1500	1	-$ 0.15	-$ 0.15	
			250	$ -		250	$ -	$ -	
Low Voltage Service Charge	per kWh	$ 0.0002	250	$ 0.05	$ 0.0003	250	$ 0.08	$ 0.03	50.00%
Line Losses on Cost of Power	per kWh	$ 0.1652	14	$ 2.24	$ 0.1652	13	$ 2.19	-$ 0.05	-2.21%
Smart Meter Entity Charge	Monthly	$ 0.7900	1	$ 0.79	$ 0.7900	1	$ 0.79	$ -	0.00%
Sub-Total B - Distribution (includes Sub-Total A)				**$ 34.22**			**$ 38.05**	**$ 3.83**	**11.19%**
RTSR - Network	per kWh	$ 0.0072	264	$ 1.90	$ 0.0069	263	$ 1.82	-$ 0.08	-4.28%
RTSR - Line and Transformation Connection	per kWh	$ 0.0058	264	$ 1.53	$ 0.0059	263	$ 1.55	$ 0.02	1.61%
Sub-Total C - Delivery (including Sub-Total B)				**$ 37.64**			**$ 41.42**	**$ 3.77**	**10.03%**
Wholesale Market Service Charge (WMSC)	per kWh	$ 0.0036	264	$ 0.95	$ 0.0036	263	$ 0.95	-$ 0.00	-0.11%
Rural and Remote Rate Protection (RRRP)	per kWh	$ 0.0013	264	$ 0.34	$ 0.0013	263	$ 0.34	-$ 0.00	-0.11%
Standard Supply Service Charge	Monthly	$ 0.2500	1	$ 0.25	$ 0.2500	1	$ 0.25	$ -	0.00%
Debt Retirement Charge (DRC)			250	$ -					
Ontario Electricity Support Program (OESP)	per kWh	$ 0.0011	264	$ 0.29	$ 0.0011	263	$ 0.29	-$ 0.00	-0.11%
Non-RPP Retailer Avg. Price + GA	per kWh	$ 0.1652	250	$ 41.30	$ 0.1652	250	$ 41.30	$ -	0.00%
Total Bill on Non-RPP Avg. Price				**$ 80.78**			**$ 84.55**	**$ 3.77**	**4.67%**
HST		13%		$ 10.50	13%		$ 10.99	$ 0.49	4.67%
Total Bill (including HST)				$ 91.28			$ 95.54	$ 4.26	4.67%
Ontario Clean Energy Benefit [1]									
Total Bill on Non-RPP Avg. Price				**$ 91.28**			**$ 95.54**	**$ 4.26**	**4.67%**

Customer Class:	Residential TOU - Port Colborne	
RPP / Non-RPP:	RPP	
Consumption	250	kWh
Demand	-	kW
Current Loss Factor	1.0542	
Proposed/Approved Loss Factor	1.0530	
Ontario Clean Energy Benefit Applied?	No	

		Current Board-Approved			Proposed			Impact	
	Charge Unit	**Rate ($)**	**Volume**	**Charge ($)**	**Rate ($)**	**Volume**	**Charge ($)**	**$ Change**	**% Change**
Monthly Service Charge	Monthly	$ 23.4400	1	$ 23.44	$ 30.4700	1	$ 30.47	$ 7.03	29.99%
Smart Meter Rate Adder			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
Distribution Volumetric Rate	per kWh	$ 0.0152	250	$ 3.80	$ 0.0116	250	$ 2.90	-$ 0.90	-23.68%
Smart Meter Disposition Rider			250	$ -		250	$ -	$ -	
LRAM & SSM Rate Rider	per kWh		250	$ -	$ 0.0003	250	$ 0.08	$ 0.08	
			250	$ -		250	$ -	$ -	
			250	$ -		250	$ -	$ -	
			250	$ -		250	$ -	$ -	
			250	$ -		250	$ -	$ -	
			250	$ -		250	$ -	$ -	
			250	$ -		250	$ -	$ -	
			250	$ -		250	$ -	$ -	
Sub-Total A (excluding pass through)				$ 27.24			$ 33.45	**$ 6.21**	**22.78%**
DVA - Total in Effect 2016	per kWh	-$ 0.0013	250	-$ 0.33		250	$ -	$ 0.33	-100.00%
DVA - Total in Effect 2017 (Var)	per kWh		250	$ -	-$ 0.0044	250	-$ 1.10	-$ 1.10	
DVA - Total in Effect 2017 (Fixed)	Monthly		1	$ -	-$ 0.1500	1	-$ 0.15	-$ 0.15	
			250	$ -		250	$ -	$ -	
Low Voltage Service Charge	per kWh	$ 0.0002	250	$ 0.05	$ 0.0003	250	$ 0.08	$ 0.03	50.00%
Line Losses on Cost of Power	per kWh	$ 0.1077	14	$ 1.46	$ 0.1077	13	$ 1.43	-$ 0.03	-2.21%
Smart Meter Entity Charge	Monthly	$ 0.7900	1	$ 0.79	$ 0.7900	1	$ 0.79	$ -	0.00%
Sub-Total B - Distribution (includes Sub-Total A)				**$ 29.21**			**$ 34.49**	**$ 5.27**	**18.05%**
RTSR - Network	per kWh	$ 0.0072	264	$ 1.90	$ 0.0069	263	$ 1.82	-$ 0.08	-4.28%
RTSR - Line and Transformation Connection	per kWh	$ 0.0058	264	$ 1.53	$ 0.0059	263	$ 1.55	$ 0.02	1.61%
Sub-Total C - Delivery (including Sub-Total B)				**$ 32.64**			**$ 37.86**	**$ 5.22**	**15.98%**
Wholesale Market Service Charge (WMSC)	per kWh	$ 0.0036	264	$ 0.95	$ 0.0036	263	$ 0.95	-$ 0.00	-0.11%
Rural and Remote Rate Protection (RRRP)	per kWh	$ 0.0013	264	$ 0.34	$ 0.0013	263	$ 0.34	-$ 0.00	-0.11%
Standard Supply Service Charge	Monthly	$ 0.2500	1	$ 0.25	$ 0.2500	1	$ 0.25	$ -	0.00%
Debt Retirement Charge (DRC)			250	$ -					
Ontario Electricity Support Program (OESP)	per kWh	$ 0.0011	264	$ 0.29	$ 0.0011	263	$ 0.29	-$ 0.00	-0.11%
TOU - Off Peak	per kWh	$ 0.0830	160	$ 13.28	$ 0.0830	160	$ 13.28	$ -	0.00%
TOU - Mid Peak	per kWh	$ 0.1280	45	$ 5.76	$ 0.1280	45	$ 5.76	$ -	0.00%
TOU - On Peak	per kWh	$ 0.1750	45	$ 7.88	$ 0.1750	45	$ 7.88	$ -	0.00%
Total Bill on TOU (before Taxes)				**$ 61.39**			**$ 66.60**	**$ 5.21**	**8.49%**
HST		13%		$ 7.98	13%		$ 8.66	$ 0.68	8.49%
Total Bill (including HST)				$ 69.37			$ 75.26	$ 5.89	8.49%
Ontario Clean Energy Benefit [1]									
Total Bill on TOU				**$ 69.37**			**$ 75.26**	**$ 5.89**	**8.49%**

Customer Class:	**Residential Retailer - Port Colborne**	
RPP / Non-RPP:	**Non-RPP (Retailer)**	
Consumption	**250**	**kWh**
Demand	**-**	**kW**
Current Loss Factor	**1.0542**	
Proposed/Approved Loss Factor	**1.0530**	
Ontario Clean Energy Benefit Applied?	**No**	

		Current Board-Approved			**Proposed**			**Impact**	
	Charge Unit	**Rate ($)**	**Volume**	**Charge ($)**	**Rate ($)**	**Volume**	**Charge ($)**	**$ Change**	**% Change**
Monthly Service Charge	Monthly	$ 23.4400	1	$ 23.44	$ 30.4700	1	$ 30.47	$ 7.03	29.99%
Smart Meter Rate Adder			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
Distribution Volumetric Rate	per kWh	$ 0.0152	250	$ 3.80	$ 0.0116	250	$ 2.90	-$ 0.90	-23.68%
Smart Meter Disposition Rider			250	$ -		250	$ -	$ -	
LRAM & SSM Rate Rider	per kWh		250	$ -	$ 0.0003	250	$ 0.08	$ 0.08	
			250	$ -		250	$ -	$ -	
			250	$ -		250	$ -	$ -	
			250	$ -		250	$ -	$ -	
			250	$ -		250	$ -	$ -	
			250	$ -		250	$ -	$ -	
			250	$ -		250	$ -	$ -	
			250	$ -		250	$ -	$ -	
Sub-Total A (excluding pass through)				$ 27.24			$ 33.45	**$ 6.21**	**22.78%**
DVA - Total in Effect 2016	per kWh	-$ 0.0017	250	-$ 0.43		250	$ -	$ 0.43	-100.00%
DVA - Total in Effect 2017 (Var)	per kWh		250	$ -	$ 0.0068	250	$ 1.70	$ 1.70	
DVA - Total in Effect 2017 (Fixed)	Monthly		1	$ -	-$ 0.1500	1	-$ 0.15	-$ 0.15	
			250	$ -		250	$ -	$ -	
Low Voltage Service Charge	per kWh	$ 0.0002	250	$ 0.05	$ 0.0003	250	$ 0.08	$ 0.03	50.00%
Line Losses on Cost of Power	per kWh	$ 0.1652	14	$ 2.24	$ 0.1652	13	$ 2.19	-$ 0.05	-2.21%
Smart Meter Entity Charge	Monthly	$ 0.7900	1	$ 0.79	$ 0.7900	1	$ 0.79	$ -	0.00%
Sub-Total B - Distribution (includes Sub-Total A)				**$ 29.89**			**$ 38.05**	**$ 8.16**	**27.28%**
RTSR - Network	per kWh	$ 0.0072	264	$ 1.90	$ 0.0069	263	$ 1.82	-$ 0.08	-4.28%
RTSR - Line and Transformation Connection	per kWh	$ 0.0058	264	$ 1.53	$ 0.0059	263	$ 1.55	$ 0.02	1.61%
Sub-Total C - Delivery (including Sub-Total B)				**$ 33.32**			**$ 41.42**	**$ 8.10**	**24.31%**
Wholesale Market Service Charge (WMSC)	per kWh	$ 0.0036	264	$ 0.95	$ 0.0036	263	$ 0.95	-$ 0.00	-0.11%
Rural and Remote Rate Protection (RRRP)	per kWh	$ 0.0013	264	$ 0.34	$ 0.0013	263	$ 0.34	-$ 0.00	-0.11%
Standard Supply Service Charge	Monthly	$ 0.2500	1	$ 0.25	$ 0.2500	1	$ 0.25	$ -	0.00%
Debt Retirement Charge (DRC)			250	$ -					
Ontario Electricity Support Program (OESP)	per kWh	$ 0.0011	264	$ 0.29	$ 0.0011	263	$ 0.29	-$ 0.00	-0.11%
Non-RPP Retailer Avg. Price + GA	per kWh	$ 0.1652	250	$ 41.30	$ 0.1652	250	$ 41.30	$ -	0.00%
Total Bill on Non-RPP Avg. Price				**$ 76.45**			**$ 84.55**	**$ 8.10**	**10.59%**
HST		13%		$ 9.94	13%		$ 10.99	$ 1.05	10.59%
Total Bill (including HST)				$ 86.39			$ 95.54	$ 9.15	10.59%
Ontario Clean Energy Benefit [1]									
Total Bill on Non-RPP Avg. Price				**$ 86.39**			**$ 95.54**	**$ 9.15**	**10.59%**

Customer Class:	**Residential TOU - Fort Erie**	
RPP / Non-RPP:	**RPP**	
Consumption	**500**	**kWh**
Demand	**-**	**kW**
Current Loss Factor	**1.0542**	
Proposed/Approved Loss Factor	**1.0530**	
Ontario Clean Energy Benefit Applied?	**No**	

		Current Board-Approved			**Proposed**			**Impact**	
	Charge Unit	**Rate ($)**	**Volume**	**Charge ($)**	**Rate ($)**	**Volume**	**Charge ($)**	**$ Change**	**% Change**
Monthly Service Charge	Monthly	$ 23.4400	1	$ 23.44	$ 30.4700	1	$ 30.47	$ 7.03	29.99%
Smart Meter Rate Adder			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
Distribution Volumetric Rate	per kWh	$ 0.0152	500	$ 7.60	$ 0.0116	500	$ 5.80	-$ 1.80	-23.68%
Smart Meter Disposition Rider			500	$ -		500	$ -	$ -	
LRAM & SSM Rate Rider	per kWh		500	$ -	$ 0.0003	500	$ 0.15	$ 0.15	
			500	$ -		500	$ -	$ -	
			500	$ -		500	$ -	$ -	
			500	$ -		500	$ -	$ -	
			500	$ -		500	$ -	$ -	
			500	$ -		500	$ -	$ -	
			500	$ -		500	$ -	$ -	
			500	$ -		500	$ -	$ -	
Sub-Total A (excluding pass through)				$ 31.04			$ 36.42	**$ 5.38**	**17.33%**
DVA - Total in Effect 2016	per kWh	$ 0.0004	500	$ 0.20		500	$ -	-$ 0.20	-100.00%
DVA - Total in Effect 2017 (Var)	per kWh		500	$ -	-$ 0.0044	500	-$ 2.20	-$ 2.20	
DVA - Total in Effect 2017 (Fixed)	Monthly		1	$ -	-$ 0.1500	1	-$ 0.15	-$ 0.15	
			500	$ -		500	$ -	$ -	
Low Voltage Service Charge	per kWh	$ 0.0002	500	$ 0.10	$ 0.0003	500	$ 0.15	$ 0.05	50.00%
Line Losses on Cost of Power	per kWh	$ 0.1077	27	$ 2.92	$ 0.1077	27	$ 2.85	-$ 0.06	-2.21%
Smart Meter Entity Charge	Monthly	$ 0.7900	1	$ 0.79	$ 0.7900	1	$ 0.79	$ -	0.00%
Sub-Total B - Distribution (includes Sub-Total A)				**$ 35.05**			**$ 37.86**	**$ 2.82**	**8.03%**
RTSR - Network	per kWh	$ 0.0072	527	$ 3.80	$ 0.0069	527	$ 3.63	-$ 0.16	-4.28%
RTSR - Line and Transformation Connection	per kWh	$ 0.0058	527	$ 3.06	$ 0.0059	527	$ 3.11	$ 0.05	1.61%
Sub-Total C - Delivery (including Sub-Total B)				**$ 41.90**			**$ 44.60**	**$ 2.70**	**6.45%**
Wholesale Market Service Charge (WMSC)	per kWh	$ 0.0036	527	$ 1.90	$ 0.0036	527	$ 1.90	-$ 0.00	-0.11%
Rural and Remote Rate Protection (RRRP)	per kWh	$ 0.0013	527	$ 0.69	$ 0.0013	527	$ 0.68	-$ 0.00	-0.11%
Standard Supply Service Charge	Monthly	$ 0.2500	1	$ 0.25	$ 0.2500	1	$ 0.25	$ -	0.00%
Debt Retirement Charge (DRC)			500	$ -					
Ontario Electricity Support Program (OESP)	per kWh	$ 0.0011	527	$ 0.58	$ 0.0011	527	$ 0.58	-$ 0.00	-0.11%
TOU - Off Peak	per kWh	$ 0.0830	320	$ 26.56	$ 0.0830	320	$ 26.56	$ -	0.00%
TOU - Mid Peak	per kWh	$ 0.1280	90	$ 11.52	$ 0.1280	90	$ 11.52	$ -	0.00%
TOU - On Peak	per kWh	$ 0.1750	90	$ 15.75	$ 0.1750	90	$ 15.75	$ -	0.00%
Total Bill on TOU (before Taxes)				**$ 99.14**			**$ 101.84**	**$ 2.70**	**2.72%**
HST		13%		$ 12.89	13%		$ 13.24	$ 0.35	2.72%
Total Bill (including HST)				$ 112.03			$ 115.08	$ 3.05	2.72%
Ontario Clean Energy Benefit [1]									
Total Bill on TOU				**$ 112.03**			**$ 115.08**	**$ 3.05**	**2.72%**

Customer Class:	**Residential Retailer - Fort Erie**
RPP / Non-RPP:	**Non-RPP (Retailer)**
Consumption	**500** kWh
Demand	**-** kW
Current Loss Factor	**1.0542**
Proposed/Approved Loss Factor	**1.0530**
Ontario Clean Energy Benefit Applied?	**No**

		Current Board-Approved			Proposed			Impact	
	Charge Unit	**Rate ($)**	**Volume**	**Charge ($)**	**Rate ($)**	**Volume**	**Charge ($)**	**$ Change**	**% Change**
Monthly Service Charge	Monthly	$ 23.4400	1	$ 23.44	$ 30.4700	1	$ 30.47	$ 7.03	29.99%
Smart Meter Rate Adder			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
Distribution Volumetric Rate	per kWh	$ 0.0152	500	$ 7.60	$ 0.0116	500	$ 5.80	-$ 1.80	-23.68%
Smart Meter Disposition Rider			500	$ -		500	$ -	$ -	
LRAM & SSM Rate Rider	per kWh		500	$ -	$ 0.0003	500	$ 0.15	$ 0.15	
			500	$ -		500	$ -	$ -	
			500	$ -		500	$ -	$ -	
			500	$ -		500	$ -	$ -	
			500	$ -		500	$ -	$ -	
			500	$ -		500	$ -	$ -	
			500	$ -		500	$ -	$ -	
			500	$ -		500	$ -	$ -	
Sub-Total A (excluding pass through)				$ 31.04			$ 36.42	**$ 5.38**	**17.33%**
DVA - Total in Effect 2016	per kWh	$ 0.0016	500	$ 0.80		500	$ -	-$ 0.80	-100.00%
DVA - Total in Effect 2017 (Var)	per kWh		500	$ -	$ 0.0065	500	$ 3.25	$ 3.25	
DVA - Total in Effect 2017 (Fixed)	Monthly		1	$ -	-$ 0.1500	1	-$ 0.15	-$ 0.15	
			500	$ -		500	$ -	$ -	
Low Voltage Service Charge	per kWh	$ 0.0002	500	$ 0.10	$ 0.0003	500	$ 0.15	$ 0.05	50.00%
Line Losses on Cost of Power	per kWh	$ 0.1652	27	$ 4.48	$ 0.1652	27	$ 4.38	-$ 0.10	-2.21%
Smart Meter Entity Charge	Monthly	$ 0.7900	1	$ 0.79	$ 0.7900	1	$ 0.79	$ -	0.00%
Sub-Total B - Distribution (includes Sub-Total A)				**$ 37.21**			**$ 44.84**	**$ 7.63**	**20.51%**
RTSR - Network	per kWh	$ 0.0072	527	$ 3.80	$ 0.0069	527	$ 3.63	-$ 0.16	-4.28%
RTSR - Line and Transformation Connection	per kWh	$ 0.0058	527	$ 3.06	$ 0.0059	527	$ 3.11	$ 0.05	1.61%
Sub-Total C - Delivery (including Sub-Total B)				**$ 44.06**			**$ 51.58**	**$ 7.52**	**17.06%**
Wholesale Market Service Charge (WMSC)	per kWh	$ 0.0036	527	$ 1.90	$ 0.0036	527	$ 1.90	-$ 0.00	-0.11%
Rural and Remote Rate Protection (RRRP)	per kWh	$ 0.0013	527	$ 0.69	$ 0.0013	527	$ 0.68	-$ 0.00	-0.11%
Standard Supply Service Charge	Monthly	$ 0.2500	1	$ 0.25	$ 0.2500	1	$ 0.25	$ -	0.00%
Debt Retirement Charge (DRC)			500	$ -					
Ontario Electricity Support Program (OESP)	per kWh	$ 0.0011	527	$ 0.58	$ 0.0011	527	$ 0.58	-$ 0.00	-0.11%
Non-RPP Retailer Avg. Price + GA	per kWh	$ 0.1652	500	$ 82.60	$ 0.1652	500	$ 82.60	$ -	0.00%
Total Bill on Non-RPP Avg. Price				**$ 130.07**			**$ 137.59**	**$ 7.51**	**5.78%**
HST		13%		$ 16.91	13%		$ 17.89	$ 0.98	5.78%
Total Bill (including HST)				$ 146.98			$ 155.47	$ 8.49	5.78%
Ontario Clean Energy Benefit [1]									
Total Bill on Non-RPP Avg. Price				**$ 146.98**			**$ 155.47**	**$ 8.49**	**5.78%**

Customer Class:	Residential TOU - EOP	
RPP / Non-RPP:	RPP	
Consumption	500	kWh
Demand	-	kW
Current Loss Factor	1.0542	
Proposed/Approved Loss Factor	1.0530	
Ontario Clean Energy Benefit Applied?	No	

		Current Board-Approved			Proposed			Impact	
	Charge Unit	**Rate ($)**	**Volume**	**Charge ($)**	**Rate ($)**	**Volume**	**Charge ($)**	**$ Change**	**% Change**
Monthly Service Charge	Monthly	$ 23.4400	1	$ 23.44	$ 30.4700	1	$ 30.47	$ 7.03	29.99%
Smart Meter Rate Adder			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
Distribution Volumetric Rate	per kWh	$ 0.0152	500	$ 7.60	$ 0.0116	500	$ 5.80	-$ 1.80	-23.68%
Smart Meter Disposition Rider			500	$ -		500	$ -	$ -	
LRAM & SSM Rate Rider	per kWh		500	$ -	$ 0.0003	500	$ 0.15	$ 0.15	
			500	$ -		500	$ -	$ -	
			500	$ -		500	$ -	$ -	
			500	$ -		500	$ -	$ -	
			500	$ -		500	$ -	$ -	
			500	$ -		500	$ -	$ -	
			500	$ -		500	$ -	$ -	
			500	$ -		500	$ -	$ -	
Sub-Total A (excluding pass through)				$ 31.04			$ 36.42	**$ 5.38**	**17.33%**
DVA - Total in Effect 2016	per kWh	-$ 0.0024	500	-$ 1.20		500	$ -	$ 1.20	-100.00%
DVA - Total in Effect 2017 (Var)	per kWh		500	$ -	-$ 0.0044	500	-$ 2.20	-$ 2.20	
DVA - Total in Effect 2017 (Fixed)	Monthly		1	$ -	-$ 0.1500	1	-$ 0.15	-$ 0.15	
			500	$ -		500	$ -	$ -	
Low Voltage Service Charge	per kWh	$ 0.0002	500	$ 0.10	$ 0.0003	500	$ 0.15	$ 0.05	50.00%
Line Losses on Cost of Power	per kWh	$ 0.1077	27	$ 2.92	$ 0.1077	27	$ 2.85	-$ 0.06	-2.21%
Smart Meter Entity Charge	Monthly	$ 0.7900	1	$ 0.79	$ 0.7900	1	$ 0.79	$ -	0.00%
Sub-Total B - Distribution (includes Sub-Total A)				**$ 33.65**			**$ 37.86**	**$ 4.22**	**12.53%**
RTSR - Network	per kWh	$ 0.0072	527	$ 3.80	$ 0.0069	527	$ 3.63	-$ 0.16	-4.28%
RTSR - Line and Transformation Connection	per kWh	$ 0.0058	527	$ 3.06	$ 0.0059	527	$ 3.11	$ 0.05	1.61%
Sub-Total C - Delivery (including Sub-Total B)				**$ 40.50**			**$ 44.60**	**$ 4.10**	**10.13%**
Wholesale Market Service Charge (WMSC)	per kWh	$ 0.0036	527	$ 1.90	$ 0.0036	527	$ 1.90	-$ 0.00	-0.11%
Rural and Remote Rate Protection (RRRP)	per kWh	$ 0.0013	527	$ 0.69	$ 0.0013	527	$ 0.68	-$ 0.00	-0.11%
Standard Supply Service Charge	Monthly	$ 0.2500	1	$ 0.25	$ 0.2500	1	$ 0.25	$ -	0.00%
Debt Retirement Charge (DRC)			500	$ -					
Ontario Electricity Support Program (OESP)	per kWh	$ 0.0011	527	$ 0.58	$ 0.0011	527	$ 0.58	-$ 0.00	-0.11%
TOU - Off Peak	per kWh	$ 0.0830	320	$ 26.56	$ 0.0830	320	$ 26.56	$ -	0.00%
TOU - Mid Peak	per kWh	$ 0.1280	90	$ 11.52	$ 0.1280	90	$ 11.52	$ -	0.00%
TOU - On Peak	per kWh	$ 0.1750	90	$ 15.75	$ 0.1750	90	$ 15.75	$ -	0.00%
Total Bill on TOU (before Taxes)				**$ 97.74**			**$ 101.84**	**$ 4.10**	**4.19%**
HST		13%		$ 12.71	13%		$ 13.24	$ 0.53	4.19%
Total Bill (including HST)				$ 110.45			$ 115.08	$ 4.63	4.19%
Ontario Clean Energy Benefit [1]									
Total Bill on TOU				**$ 110.45**			**$ 115.08**	**$ 4.63**	**4.19%**

Customer Class:	Residential Retailer - EOP
RPP / Non-RPP:	Non-RPP (Retailer)
Consumption	500 kWh
Demand	- kW
Current Loss Factor	1.0542
Proposed/Approved Loss Factor	1.0530
Ontario Clean Energy Benefit Applied?	No

		Current Board-Approved			Proposed			Impact	
	Charge Unit	**Rate ($)**	**Volume**	**Charge ($)**	**Rate ($)**	**Volume**	**Charge ($)**	**$ Change**	**% Change**
Monthly Service Charge	Monthly	$ 23.4400	1	$ 23.44	$ 30.4700	1	$ 30.47	$ 7.03	29.99%
Smart Meter Rate Adder			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
Distribution Volumetric Rate	per kWh	$ 0.0152	500	$ 7.60	$ 0.0116	500	$ 5.80	-$ 1.80	-23.68%
Smart Meter Disposition Rider			500	$ -		500	$ -	$ -	
LRAM & SSM Rate Rider	per kWh		500	$ -	$ 0.0003	500	$ 0.15	$ 0.15	
			500	$ -		500	$ -	$ -	
			500	$ -		500	$ -	$ -	
			500	$ -		500	$ -	$ -	
			500	$ -		500	$ -	$ -	
			500	$ -		500	$ -	$ -	
			500	$ -		500	$ -	$ -	
			500	$ -		500	$ -	$ -	
Sub-Total A (excluding pass through)				$ 31.04			$ 36.42	**$ 5.38**	**17.33%**
DVA - Total in Effect 2016	per kWh	$ 0.0156	500	$ 7.80		500	$ -	-$ 7.80	-100.00%
DVA - Total in Effect 2017 (Var)	per kWh		500	$ -	$ 0.0065	500	$ 3.25	$ 3.25	
DVA - Total in Effect 2017 (Fixed)	Monthly		1	$ -	-$ 0.1500	1	-$ 0.15	-$ 0.15	
			500	$ -		500	$ -	$ -	
Low Voltage Service Charge	per kWh	$ 0.0002	500	$ 0.10	$ 0.0003	500	$ 0.15	$ 0.05	50.00%
Line Losses on Cost of Power	per kWh	$ 0.1652	27	$ 4.48	$ 0.1652	27	$ 4.38	-$ 0.10	-2.21%
Smart Meter Entity Charge	Monthly	$ 0.7900	1	$ 0.79	$ 0.7900	1	$ 0.79	$ -	0.00%
Sub-Total B - Distribution (includes Sub-Total A)				**$ 44.21**			**$ 44.84**	**$ 0.63**	**1.43%**
RTSR - Network	per kWh	$ 0.0072	527	$ 3.80	$ 0.0069	527	$ 3.63	-$ 0.16	-4.28%
RTSR - Line and Transformation Connection	per kWh	$ 0.0058	527	$ 3.06	$ 0.0059	527	$ 3.11	$ 0.05	1.61%
Sub-Total C - Delivery (including Sub-Total B)				**$ 51.06**			**$ 51.58**	**$ 0.52**	**1.01%**
Wholesale Market Service Charge (WMSC)	per kWh	$ 0.0036	527	$ 1.90	$ 0.0036	527	$ 1.90	-$ 0.00	-0.11%
Rural and Remote Rate Protection (RRRP)	per kWh	$ 0.0013	527	$ 0.69	$ 0.0013	527	$ 0.68	-$ 0.00	-0.11%
Standard Supply Service Charge	Monthly	$ 0.2500	1	$ 0.25	$ 0.2500	1	$ 0.25	$ -	0.00%
Debt Retirement Charge (DRC)			500	$ -					
Ontario Electricity Support Program (OESP)	per kWh	$ 0.0011	527	$ 0.58	$ 0.0011	527	$ 0.58	-$ 0.00	-0.11%
Non-RPP Retailer Avg. Price + GA	per kWh	$ 0.1652	500	$ 82.60	$ 0.1652	500	$ 82.60	$ -	0.00%
Total Bill on Non-RPP Avg. Price				**$ 137.07**			**$ 137.59**	**$ 0.51**	**0.38%**
HST		13%		$ 17.82	13%		$ 17.89	$ 0.07	0.38%
Total Bill (including HST)				$ 154.89			$ 155.47	$ 0.58	0.38%
Ontario Clean Energy Benefit [1]									
Total Bill on Non-RPP Avg. Price				**$ 154.89**			**$ 155.47**	**$ 0.58**	**0.38%**

Customer Class:	**Residential TOU - Port Colborne**
RPP / Non-RPP:	**RPP**
Consumption	**500** kWh
Demand	**-** kW
Current Loss Factor	**1.0542**
Proposed/Approved Loss Factor	**1.0530**
Ontario Clean Energy Benefit Applied?	**No**

		Current Board-Approved			**Proposed**			**Impact**	
	Charge Unit	**Rate ($)**	**Volume**	**Charge ($)**	**Rate ($)**	**Volume**	**Charge ($)**	**$ Change**	**% Change**
Monthly Service Charge	Monthly	$ 23.4400	1	$ 23.44	$ 30.4700	1	$ 30.47	$ 7.03	29.99%
Smart Meter Rate Adder			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
Distribution Volumetric Rate	per kWh	$ 0.0152	500	$ 7.60	$ 0.0116	500	$ 5.80	-$ 1.80	-23.68%
Smart Meter Disposition Rider			500	$ -		500	$ -	$ -	
LRAM & SSM Rate Rider	per kWh		500	$ -	$ 0.0003	500	$ 0.15	$ 0.15	
			500	$ -		500	$ -	$ -	
			500	$ -		500	$ -	$ -	
			500	$ -		500	$ -	$ -	
			500	$ -		500	$ -	$ -	
			500	$ -		500	$ -	$ -	
			500	$ -		500	$ -	$ -	
			500	$ -		500	$ -	$ -	
Sub-Total A (excluding pass through)				$ 31.04			$ 36.42	**$ 5.38**	**17.33%**
DVA - Total in Effect 2016	per kWh	-$ 0.0013	500	-$ 0.65		500	$ -	$ 0.65	-100.00%
DVA - Total in Effect 2017 (Var)	per kWh		500	$ -	-$ 0.0044	500	-$ 2.20	-$ 2.20	
DVA - Total in Effect 2017 (Fixed)	Monthly		1	$ -	-$ 0.1500	1	-$ 0.15	-$ 0.15	
			500	$ -		500	$ -	$ -	
Low Voltage Service Charge	per kWh	$ 0.0002	500	$ 0.10	$ 0.0003	500	$ 0.15	$ 0.05	50.00%
Line Losses on Cost of Power	per kWh	$ 0.1077	27	$ 2.92	$ 0.1077	27	$ 2.85	-$ 0.06	-2.21%
Smart Meter Entity Charge	Monthly	$ 0.7900	1	$ 0.79	$ 0.7900	1	$ 0.79	$ -	0.00%
Sub-Total B - Distribution (includes Sub-Total A)				**$ 34.20**			**$ 37.86**	**$ 3.67**	**10.72%**
RTSR - Network	per kWh	$ 0.0072	527	$ 3.80	$ 0.0069	527	$ 3.63	-$ 0.16	-4.28%
RTSR - Line and Transformation Connection	per kWh	$ 0.0058	527	$ 3.06	$ 0.0059	527	$ 3.11	$ 0.05	1.61%
Sub-Total C - Delivery (including Sub-Total B)				**$ 41.05**			**$ 44.60**	**$ 3.55**	**8.65%**
Wholesale Market Service Charge (WMSC)	per kWh	$ 0.0036	527	$ 1.90	$ 0.0036	527	$ 1.90	-$ 0.00	-0.11%
Rural and Remote Rate Protection (RRRP)	per kWh	$ 0.0013	527	$ 0.69	$ 0.0013	527	$ 0.68	-$ 0.00	-0.11%
Standard Supply Service Charge	Monthly	$ 0.2500	1	$ 0.25	$ 0.2500	1	$ 0.25	$ -	0.00%
Debt Retirement Charge (DRC)			500	$ -					
Ontario Electricity Support Program (OESP)	per kWh	$ 0.0011	527	$ 0.58	$ 0.0011	527	$ 0.58	-$ 0.00	-0.11%
TOU - Off Peak	per kWh	$ 0.0830	320	$ 26.56	$ 0.0830	320	$ 26.56	$ -	0.00%
TOU - Mid Peak	per kWh	$ 0.1280	90	$ 11.52	$ 0.1280	90	$ 11.52	$ -	0.00%
TOU - On Peak	per kWh	$ 0.1750	90	$ 15.75	$ 0.1750	90	$ 15.75	$ -	0.00%
Total Bill on TOU (before Taxes)				**$ 98.29**			**$ 101.84**	**$ 3.55**	**3.61%**
HST		13%		$ 12.78	13%		$ 13.24	$ 0.46	3.61%
Total Bill (including HST)				$ 111.07			$ 115.08	$ 4.01	3.61%
Ontario Clean Energy Benefit [1]									
Total Bill on TOU				**$ 111.07**			**$ 115.08**	**$ 4.01**	**3.61%**

Customer Class:	**Residential Retailer - Port Colborne**	
RPP / Non-RPP:	**Non-RPP (Retailer)**	
Consumption	**500**	**kWh**
Demand	**-**	**kW**
Current Loss Factor	**1.0542**	
Proposed/Approved Loss Factor	**1.0530**	
Ontario Clean Energy Benefit Applied?	**No**	

		Current Board-Approved			**Proposed**			**Impact**	
	Charge Unit	**Rate ($)**	**Volume**	**Charge ($)**	**Rate ($)**	**Volume**	**Charge ($)**	**$ Change**	**% Change**
Monthly Service Charge	Monthly	$ 23.4400	1	$ 23.44	$ 30.4700	1	$ 30.47	$ 7.03	29.99%
Smart Meter Rate Adder			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
Distribution Volumetric Rate	per kWh	$ 0.0152	500	$ 7.60	$ 0.0116	500	$ 5.80	-$ 1.80	-23.68%
Smart Meter Disposition Rider			500	$ -		500	$ -	$ -	
LRAM & SSM Rate Rider	per kWh		500	$ -	$ 0.0003	500	$ 0.15	$ 0.15	
			500	$ -		500	$ -	$ -	
			500	$ -		500	$ -	$ -	
			500	$ -		500	$ -	$ -	
			500	$ -		500	$ -	$ -	
			500	$ -		500	$ -	$ -	
			500	$ -		500	$ -	$ -	
			500	$ -		500	$ -	$ -	
Sub-Total A (excluding pass through)				$ 31.04			$ 36.42	**$ 5.38**	**17.33%**
DVA - Total in Effect 2016	per kWh	-$ 0.0017	500	-$ 0.85		500	$ -	$ 0.85	-100.00%
DVA - Total in Effect 2017 (Var)	per kWh		500	$ -	$ 0.0065	500	$ 3.25	$ 3.25	
DVA - Total in Effect 2017 (Fixed)	Monthly		1	$ -	-$ 0.1500	1	-$ 0.15	-$ 0.15	
			500	$ -		500	$ -	$ -	
Low Voltage Service Charge	per kWh	$ 0.0002	500	$ 0.10	$ 0.0003	500	$ 0.15	$ 0.05	50.00%
Line Losses on Cost of Power	per kWh	$ 0.1652	27	$ 4.48	$ 0.1652	27	$ 4.38	-$ 0.10	-2.21%
Smart Meter Entity Charge	Monthly	$ 0.7900	1	$ 0.79	$ 0.7900	1	$ 0.79	$ -	0.00%
Sub-Total B - Distribution (includes Sub-Total A)				**$ 35.56**			**$ 44.84**	**$ 9.28**	**26.10%**
RTSR - Network	per kWh	$ 0.0072	527	$ 3.80	$ 0.0069	527	$ 3.63	-$ 0.16	-4.28%
RTSR - Line and Transformation Connection	per kWh	$ 0.0058	527	$ 3.06	$ 0.0059	527	$ 3.11	$ 0.05	1.61%
Sub-Total C - Delivery (including Sub-Total B)				**$ 42.41**			**$ 51.58**	**$ 9.17**	**21.62%**
Wholesale Market Service Charge (WMSC)	per kWh	$ 0.0036	527	$ 1.90	$ 0.0036	527	$ 1.90	-$ 0.00	-0.11%
Rural and Remote Rate Protection (RRRP)	per kWh	$ 0.0013	527	$ 0.69	$ 0.0013	527	$ 0.68	-$ 0.00	-0.11%
Standard Supply Service Charge	Monthly	$ 0.2500	1	$ 0.25	$ 0.2500	1	$ 0.25	$ -	0.00%
Debt Retirement Charge (DRC)			500	$ -					
Ontario Electricity Support Program (OESP)	per kWh	$ 0.0011	527	$ 0.58	$ 0.0011	527	$ 0.58	-$ 0.00	-0.11%
Non-RPP Retailer Avg. Price + GA	per kWh	$ 0.1652	500	$ 82.60	$ 0.1652	500	$ 82.60	$ -	0.00%
Total Bill on Non-RPP Avg. Price				**$ 128.42**			**$ 137.59**	**$ 9.16**	**7.14%**
HST		13%		$ 16.69	13%		$ 17.89	$ 1.19	7.14%
Total Bill (including HST)				$ 145.12			$ 155.47	$ 10.36	7.14%
Ontario Clean Energy Benefit [1]									
Total Bill on Non-RPP Avg. Price				**$ 145.12**			**$ 155.47**	**$ 10.36**	**7.14%**

Customer Class:	**Residential TOU - Fort Erie**	
RPP / Non-RPP:	**RPP**	
Consumption	**750**	**kWh**
Demand	**-**	**kW**
Current Loss Factor	**1.0542**	
Proposed/Approved Loss Factor	**1.0530**	
Ontario Clean Energy Benefit Applied?	**No**	

		Current Board-Approved			**Proposed**			**Impact**	
	Charge Unit	**Rate ($)**	**Volume**	**Charge ($)**	**Rate ($)**	**Volume**	**Charge ($)**	**$ Change**	**% Change**
Monthly Service Charge	Monthly	$ 23.4400	1	$ 23.44	$ 30.4700	1	$ 30.47	$ 7.03	29.99%
Smart Meter Rate Adder			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
Distribution Volumetric Rate	per kWh	$ 0.0152	750	$ 11.40	$ 0.0116	750	$ 8.70	-$ 2.70	-23.68%
Smart Meter Disposition Rider			750	$ -		750	$ -	$ -	
LRAM & SSM Rate Rider	per kWh		750	$ -	$ 0.0003	750	$ 0.23	$ 0.23	
			750	$ -		750	$ -	$ -	
			750	$ -		750	$ -	$ -	
			750	$ -		750	$ -	$ -	
			750	$ -		750	$ -	$ -	
			750	$ -		750	$ -	$ -	
			750	$ -		750	$ -	$ -	
			750	$ -		750	$ -	$ -	
Sub-Total A (excluding pass through)				$ 34.84			$ 39.40	**$ 4.56**	**13.07%**
DVA - Total in Effect 2016	per kWh	$ 0.0004	750	$ 0.30		750	$ -	-$ 0.30	-100.00%
DVA - Total in Effect 2017 (Var)	per kWh		750	$ -	-$ 0.0044	750	-$ 3.30	-$ 3.30	
DVA - Total in Effect 2017 (Fixed)	Monthly		1	$ -	-$ 0.1500	1	-$ 0.15	-$ 0.15	
			750	$ -		750	$ -	$ -	
Low Voltage Service Charge	per kWh	$ 0.0002	750	$ 0.15	$ 0.0003	750	$ 0.23	$ 0.08	50.00%
Line Losses on Cost of Power	per kWh	$ 0.1077	41	$ 4.38	$ 0.1077	40	$ 4.28	-$ 0.10	-2.21%
Smart Meter Entity Charge	Monthly	$ 0.7900	1	$ 0.79	$ 0.7900	1	$ 0.79	$ -	0.00%
Sub-Total B - Distribution (includes Sub-Total A)				**$ 40.46**			**$ 41.24**	**$ 0.78**	**1.94%**
RTSR - Network	per kWh	$ 0.0072	791	$ 5.69	$ 0.0069	790	$ 5.45	-$ 0.24	-4.28%
RTSR - Line and Transformation Connection	per kWh	$ 0.0058	791	$ 4.59	$ 0.0059	790	$ 4.66	$ 0.07	1.61%
Sub-Total C - Delivery (including Sub-Total B)				**$ 50.73**			**$ 51.35**	**$ 0.61**	**1.21%**
Wholesale Market Service Charge (WMSC)	per kWh	$ 0.0036	791	$ 2.85	$ 0.0036	790	$ 2.84	-$ 0.00	-0.11%
Rural and Remote Rate Protection (RRRP)	per kWh	$ 0.0013	791	$ 1.03	$ 0.0013	790	$ 1.03	-$ 0.00	-0.11%
Standard Supply Service Charge	Monthly	$ 0.2500	1	$ 0.25	$ 0.2500	1	$ 0.25	$ -	0.00%
Debt Retirement Charge (DRC)			750	$ -					
Ontario Electricity Support Program (OESP)	per kWh	$ 0.0011	791	$ 0.87	$ 0.0011	790	$ 0.87	-$ 0.00	-0.11%
TOU - Off Peak	per kWh	$ 0.0830	480	$ 39.84	$ 0.0830	480	$ 39.84	$ -	0.00%
TOU - Mid Peak	per kWh	$ 0.1280	135	$ 17.28	$ 0.1280	135	$ 17.28	$ -	0.00%
TOU - On Peak	per kWh	$ 0.1750	135	$ 23.63	$ 0.1750	135	$ 23.63	$ -	0.00%
Total Bill on TOU (before Taxes)				**$ 136.47**			**$ 137.08**	**$ 0.61**	**0.45%**
HST		13%		$ 17.74	13%		$ 17.82	$ 0.08	0.45%
Total Bill (including HST)				$ 154.22			$ 154.90	$ 0.69	0.45%
Ontario Clean Energy Benefit [1]									
Total Bill on TOU				**$ 154.22**			**$ 154.90**	**$ 0.69**	**0.45%**

Customer Class:	**Residential Retailer - Fort Erie**
RPP / Non-RPP:	**Non-RPP (Retailer)**
Consumption	**750** kWh
Demand	**-** kW
Current Loss Factor	**1.0542**
Proposed/Approved Loss Factor	**1.0530**
Ontario Clean Energy Benefit Applied?	**No**

		Current Board-Approved			Proposed			Impact	
	Charge Unit	**Rate ($)**	**Volume**	**Charge ($)**	**Rate ($)**	**Volume**	**Charge ($)**	**$ Change**	**% Change**
Monthly Service Charge	Monthly	$ 23.4400	1	$ 23.44	$ 30.4700	1	$ 30.47	$ 7.03	29.99%
Smart Meter Rate Adder			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
Distribution Volumetric Rate	per kWh	$ 0.0152	750	$ 11.40	$ 0.0116	750	$ 8.70	-$ 2.70	-23.68%
Smart Meter Disposition Rider			750	$ -		750	$ -	$ -	
LRAM & SSM Rate Rider	per kWh		750	$ -	$ 0.0003	750	$ 0.23	$ 0.23	
			750	$ -		750	$ -	$ -	
			750	$ -		750	$ -	$ -	
			750	$ -		750	$ -	$ -	
			750	$ -		750	$ -	$ -	
			750	$ -		750	$ -	$ -	
			750	$ -		750	$ -	$ -	
			750	$ -		750	$ -	$ -	
Sub-Total A (excluding pass through)				$ 34.84			$ 39.40	**$ 4.56**	**13.07%**
DVA - Total in Effect 2016	per kWh	$ 0.0016	750	$ 1.20		750	$ -	-$ 1.20	-100.00%
DVA - Total in Effect 2017 (Var)	per kWh		750	$ -	$ 0.0068	750	$ 5.10	$ 5.10	
DVA - Total in Effect 2017 (Fixed)	Monthly		1	$ -	-$ 0.1500	1	-$ 0.15	-$ 0.15	
			750	$ -		750	$ -	$ -	
Low Voltage Service Charge	per kWh	$ 0.0002	750	$ 0.15	$ 0.0003	750	$ 0.23	$ 0.08	50.00%
Line Losses on Cost of Power	per kWh	$ 0.1652	41	$ 6.72	$ 0.1652	40	$ 6.57	-$ 0.15	-2.21%
Smart Meter Entity Charge	Monthly	$ 0.7900	1	$ 0.79	$ 0.7900	1	$ 0.79	$ -	0.00%
Sub-Total B - Distribution (includes Sub-Total A)				**$ 43.70**			**$ 51.93**	**$ 8.23**	**18.84%**
RTSR - Network	per kWh	$ 0.0072	791	$ 5.69	$ 0.0069	790	$ 5.45	-$ 0.24	-4.28%
RTSR - Line and Transformation Connection	per kWh	$ 0.0058	791	$ 4.59	$ 0.0059	790	$ 4.66	$ 0.07	1.61%
Sub-Total C - Delivery (including Sub-Total B)				**$ 53.97**			**$ 62.04**	**$ 8.06**	**14.94%**
Wholesale Market Service Charge (WMSC)	per kWh	$ 0.0036	791	$ 2.85	$ 0.0036	790	$ 2.84	-$ 0.00	-0.11%
Rural and Remote Rate Protection (RRRP)	per kWh	$ 0.0013	791	$ 1.03	$ 0.0013	790	$ 1.03	-$ 0.00	-0.11%
Standard Supply Service Charge	Monthly	$ 0.2500	1	$ 0.25	$ 0.2500	1	$ 0.25	$ -	0.00%
Debt Retirement Charge (DRC)			750	$ -					
Ontario Electricity Support Program (OESP)	per kWh	$ 0.0011	791	$ 0.87	$ 0.0011	790	$ 0.87	-$ 0.00	-0.11%
Non-RPP Retailer Avg. Price + GA	per kWh	$ 0.1652	750	$ 123.90	$ 0.1652	750	$ 123.90	$ -	0.00%
Total Bill on Non-RPP Avg. Price				**$ 182.87**			**$ 190.92**	**$ 8.06**	**4.41%**
HST		13%		$ 23.77	13%		$ 24.82	$ 1.05	4.41%
Total Bill (including HST)				$ 206.64			$ 215.74	$ 9.10	4.41%
Ontario Clean Energy Benefit [1]									
Total Bill on Non-RPP Avg. Price				**$ 206.64**			**$ 215.74**	**$ 9.10**	**4.41%**

Customer Class:	**Residential TOU - EOP**	
RPP / Non-RPP:	**RPP**	
Consumption	**750**	**kWh**
Demand	**-**	**kW**
Current Loss Factor	**1.0542**	
Proposed/Approved Loss Factor	**1.0530**	
Ontario Clean Energy Benefit Applied?	**No**	

		Current Board-Approved			**Proposed**			**Impact**	
	Charge Unit	**Rate ($)**	**Volume**	**Charge ($)**	**Rate ($)**	**Volume**	**Charge ($)**	**$ Change**	**% Change**
Monthly Service Charge	Monthly	$ 23.4400	1	$ 23.44	$ 30.4700	1	$ 30.47	$ 7.03	29.99%
Smart Meter Rate Adder			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
Distribution Volumetric Rate	per kWh	$ 0.0152	750	$ 11.40	$ 0.0116	750	$ 8.70	-$ 2.70	-23.68%
Smart Meter Disposition Rider			750	$ -		750	$ -	$ -	
LRAM & SSM Rate Rider	per kWh		750	$ -	$ 0.0003	750	$ 0.23	$ 0.23	
			750	$ -		750	$ -	$ -	
			750	$ -		750	$ -	$ -	
			750	$ -		750	$ -	$ -	
			750	$ -		750	$ -	$ -	
			750	$ -		750	$ -	$ -	
			750	$ -		750	$ -	$ -	
			750	$ -		750	$ -	$ -	
Sub-Total A (excluding pass through)				$ 34.84			$ 39.40	**$ 4.56**	**13.07%**
DVA - Total in Effect 2016	per kWh	-$ 0.0024	750	-$ 1.80		750	$ -	$ 1.80	-100.00%
DVA - Total in Effect 2017 (Var)	per kWh		750	$ -	-$ 0.0044	750	-$ 3.30	-$ 3.30	
DVA - Total in Effect 2017 (Fixed)	Monthly		1	$ -	-$ 0.1500	1	-$ 0.15	-$ 0.15	
			750	$ -		750	$ -	$ -	
Low Voltage Service Charge	per kWh	$ 0.0002	750	$ 0.15	$ 0.0003	750	$ 0.23	$ 0.08	50.00%
Line Losses on Cost of Power	per kWh	$ 0.1077	41	$ 4.38	$ 0.1077	40	$ 4.28	-$ 0.10	-2.21%
Smart Meter Entity Charge		$ 0.7900	1	$ 0.79	$ 0.7900	1	$ 0.79	$ -	0.00%
Sub-Total B - Distribution (includes Sub-Total A)				**$ 38.36**			**$ 41.24**	**$ 2.88**	**7.52%**
RTSR - Network	per kWh	$ 0.0072	791	$ 5.69	$ 0.0069	790	$ 5.45	-$ 0.24	-4.28%
RTSR - Line and Transformation Connection	per kWh	$ 0.0058	791	$ 4.59	$ 0.0059	790	$ 4.66	$ 0.07	1.61%
Sub-Total C - Delivery (including Sub-Total B)				**$ 48.63**			**$ 51.35**	**$ 2.71**	**5.58%**
Wholesale Market Service Charge (WMSC)	per kWh	$ 0.0036	791	$ 2.85	$ 0.0036	790	$ 2.84	-$ 0.00	-0.11%
Rural and Remote Rate Protection (RRRP)	per kWh	$ 0.0013	791	$ 1.03	$ 0.0013	790	$ 1.03	-$ 0.00	-0.11%
Standard Supply Service Charge	Monthly	$ 0.2500	1	$ 0.25	$ 0.2500	1	$ 0.25	$ -	0.00%
Debt Retirement Charge (DRC)			750	$ -					
Ontario Electricity Support Program (OESP)	per kWh	$ 0.0011	791	$ 0.87	$ 0.0011	790	$ 0.87	-$ 0.00	-0.11%
TOU - Off Peak	per kWh	$ 0.0830	480	$ 39.84	$ 0.0830	480	$ 39.84	$ -	0.00%
TOU - Mid Peak	per kWh	$ 0.1280	135	$ 17.28	$ 0.1280	135	$ 17.28	$ -	0.00%
TOU - On Peak	per kWh	$ 0.1750	135	$ 23.63	$ 0.1750	135	$ 23.63	$ -	0.00%
Total Bill on TOU (before Taxes)				**$ 134.37**			**$ 137.08**	**$ 2.71**	**2.02%**
HST		13%		$ 17.47	13%		$ 17.82	$ 0.35	2.02%
Total Bill (including HST)				$ 151.84			$ 154.90	$ 3.06	2.02%
***Ontario Clean Energy Benefit* [1]**									
Total Bill on TOU				**$ 151.84**			**$ 154.90**	**$ 3.06**	**2.02%**

Customer Class:	**Residential Retailer - EOP**	
RPP / Non-RPP:	**Non-RPP (Retailer)**	
Consumption	**750**	**kWh**
Demand	**-**	**kW**
Current Loss Factor	**1.0542**	
Proposed/Approved Loss Factor	**1.0530**	
Ontario Clean Energy Benefit Applied?	**No**	

		Current Board-Approved			**Proposed**			**Impact**	
	Charge Unit	**Rate ($)**	**Volume**	**Charge ($)**	**Rate ($)**	**Volume**	**Charge ($)**	**$ Change**	**% Change**
Monthly Service Charge	Monthly	$ 23.4400	1	$ 23.44	$ 30.4700	1	$ 30.47	$ 7.03	29.99%
Smart Meter Rate Adder			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
Distribution Volumetric Rate	per kWh	$ 0.0152	750	$ 11.40	$ 0.0116	750	$ 8.70	-$ 2.70	-23.68%
Smart Meter Disposition Rider			750	$ -		750	$ -	$ -	
LRAM & SSM Rate Rider	per kWh		750	$ -	$ 0.0003	750	$ 0.23	$ 0.23	
			750	$ -		750	$ -	$ -	
			750	$ -		750	$ -	$ -	
			750	$ -		750	$ -	$ -	
			750	$ -		750	$ -	$ -	
			750	$ -		750	$ -	$ -	
			750	$ -		750	$ -	$ -	
			750	$ -		750	$ -	$ -	
Sub-Total A (excluding pass through)				$ 34.84			$ 39.40	**$ 4.56**	**13.07%**
DVA - Total in Effect 2016	per kWh	$ 0.0156	750	$ 11.70		750	$ -	-$ 11.70	-100.00%
DVA - Total in Effect 2017 (Var)	per kWh		750	$ -	$ 0.0068	750	$ 5.10	$ 5.10	
DVA - Total in Effect 2017 (Fixed)	Monthly		1	$ -	-$ 0.1500	1	-$ 0.15	-$ 0.15	
			750	$ -		750	$ -	$ -	
Low Voltage Service Charge	per kWh	$ 0.0002	750	$ 0.15	$ 0.0003	750	$ 0.23	$ 0.08	50.00%
Line Losses on Cost of Power	per kWh	$ 0.1652	41	$ 6.72	$ 0.1652	40	$ 6.57	-$ 0.15	-2.21%
Smart Meter Entity Charge	Monthly	$ 0.7900	1	$ 0.79	$ 0.7900	1	$ 0.79	$ -	0.00%
Sub-Total B - Distribution (includes Sub-Total A)				**$ 54.20**			**$ 51.93**	**-$ 2.27**	**-4.19%**
RTSR - Network	per kWh	$ 0.0072	791	$ 5.69	$ 0.0069	790	$ 5.45	-$ 0.24	-4.28%
RTSR - Line and Transformation Connection	per kWh	$ 0.0058	791	$ 4.59	$ 0.0059	790	$ 4.66	$ 0.07	1.61%
Sub-Total C - Delivery (including Sub-Total B)				**$ 64.47**			**$ 62.04**	**-$ 2.44**	**-3.78%**
Wholesale Market Service Charge (WMSC)	per kWh	$ 0.0036	791	$ 2.85	$ 0.0036	790	$ 2.84	-$ 0.00	-0.11%
Rural and Remote Rate Protection (RRRP)	per kWh	$ 0.0013	791	$ 1.03	$ 0.0013	790	$ 1.03	-$ 0.00	-0.11%
Standard Supply Service Charge	Monthly	$ 0.2500	1	$ 0.25	$ 0.2500	1	$ 0.25	$ -	0.00%
Debt Retirement Charge (DRC)			750	$ -					
Ontario Electricity Support Program (OESP)	per kWh	$ 0.0011	791	$ 0.87	$ 0.0011	790	$ 0.87	-$ 0.00	-0.11%
Non-RPP Retailer Avg. Price + GA	per kWh	$ 0.1652	750	$ 123.90	$ 0.1652	750	$ 123.90	$ -	0.00%
Total Bill on Non-RPP Avg. Price				**$ 193.37**			**$ 190.92**	**-$ 2.44**	**-1.26%**
HST		13%		$ 25.14	13%		$ 24.82	-$ 0.32	-1.26%
Total Bill (including HST)				$ 218.51			$ 215.74	-$ 2.76	-1.26%
Ontario Clean Energy Benefit [1]									
Total Bill on Non-RPP Avg. Price				**$ 218.51**			**$ 215.74**	**-$ 2.76**	**-1.26%**

Customer Class:	**Residential TOU - Port Colborne**	
RPP / Non-RPP:	**RPP**	
Consumption	**750**	**kWh**
Demand	**-**	**kW**
Current Loss Factor	**1.0542**	
Proposed/Approved Loss Factor	**1.0530**	
Ontario Clean Energy Benefit Applied?	**No**	

		Current Board-Approved			**Proposed**			**Impact**	
	Charge Unit	**Rate ($)**	**Volume**	**Charge ($)**	**Rate ($)**	**Volume**	**Charge ($)**	**$ Change**	**% Change**
Monthly Service Charge	Monthly	$ 23.4400	1	$ 23.44	$ 30.4700	1	$ 30.47	$ 7.03	29.99%
Smart Meter Rate Adder			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
Distribution Volumetric Rate	per kWh	$ 0.0152	750	$ 11.40	$ 0.0116	750	$ 8.70	-$ 2.70	-23.68%
Smart Meter Disposition Rider			750	$ -		750	$ -	$ -	
LRAM & SSM Rate Rider	per kWh		750	$ -	$ 0.0003	750	$ 0.23	$ 0.23	
			750	$ -		750	$ -	$ -	
			750	$ -		750	$ -	$ -	
			750	$ -		750	$ -	$ -	
			750	$ -		750	$ -	$ -	
			750	$ -		750	$ -	$ -	
			750	$ -		750	$ -	$ -	
			750	$ -		750	$ -	$ -	
Sub-Total A (excluding pass through)				$ 34.84			$ 39.40	**$ 4.56**	**13.07%**
DVA - Total in Effect 2016	per kWh	-$ 0.0013	750	-$ 0.98		750	$ -	$ 0.98	-100.00%
DVA - Total in Effect 2017 (Var)	per kWh		750	$ -	-$ 0.0044	750	-$ 3.30	-$ 3.30	
DVA - Total in Effect 2017 (Fixed)	Monthly		1	$ -	-$ 0.1500	1	-$ 0.15	-$ 0.15	
			750	$ -		750	$ -	$ -	
Low Voltage Service Charge	per kWh	$ 0.0002	750	$ 0.15	$ 0.0003	750	$ 0.23	$ 0.08	50.00%
Line Losses on Cost of Power	per kWh	$ 0.1077	41	$ 4.38	$ 0.1077	40	$ 4.28	-$ 0.10	-2.21%
Smart Meter Entity Charge	Monthly	$ 0.7900	1	$ 0.79	$ 0.7900	1	$ 0.79	$ -	0.00%
Sub-Total B - Distribution (includes Sub-Total A)				**$ 39.18**			**$ 41.24**	**$ 2.06**	**5.25%**
RTSR - Network	per kWh	$ 0.0072	791	$ 5.69	$ 0.0069	790	$ 5.45	-$ 0.24	-4.28%
RTSR - Line and Transformation Connection	per kWh	$ 0.0058	791	$ 4.59	$ 0.0059	790	$ 4.66	$ 0.07	1.61%
Sub-Total C - Delivery (including Sub-Total B)				**$ 49.46**			**$ 51.35**	**$ 1.89**	**3.82%**
Wholesale Market Service Charge (WMSC)	per kWh	$ 0.0036	791	$ 2.85	$ 0.0036	790	$ 2.84	-$ 0.00	-0.11%
Rural and Remote Rate Protection (RRRP)	per kWh	$ 0.0013	791	$ 1.03	$ 0.0013	790	$ 1.03	-$ 0.00	-0.11%
Standard Supply Service Charge	Monthly	$ 0.2500	1	$ 0.25	$ 0.2500	1	$ 0.25	$ -	0.00%
Debt Retirement Charge (DRC)			750	$ -					
Ontario Electricity Support Program (OESP)	per kWh	$ 0.0011	791	$ 0.87	$ 0.0011	790	$ 0.87	-$ 0.00	-0.11%
TOU - Off Peak	per kWh	$ 0.0830	480	$ 39.84	$ 0.0830	480	$ 39.84	$ -	0.00%
TOU - Mid Peak	per kWh	$ 0.1280	135	$ 17.28	$ 0.1280	135	$ 17.28	$ -	0.00%
TOU - On Peak	per kWh	$ 0.1750	135	$ 23.63	$ 0.1750	135	$ 23.63	$ -	0.00%
Total Bill on TOU (before Taxes)				**$ 135.20**			**$ 137.08**	**$ 1.88**	**1.39%**
HST		13%		$ 17.58	13%		$ 17.82	$ 0.24	1.39%
Total Bill (including HST)				$ 152.77			$ 154.90	$ 2.13	1.39%
Ontario Clean Energy Benefit [1]									
Total Bill on TOU				**$ 152.77**			**$ 154.90**	**$ 2.13**	**1.39%**

Customer Class:	Residential Retailer - Port Colborne
RPP / Non-RPP:	Non-RPP (Retailer)
Consumption	750 kWh
Demand	- kW
Current Loss Factor	1.0542
Proposed/Approved Loss Factor	1.0530
Ontario Clean Energy Benefit Applied?	No

		Current Board-Approved			Proposed			Impact	
	Charge Unit	**Rate ($)**	**Volume**	**Charge ($)**	**Rate ($)**	**Volume**	**Charge ($)**	**$ Change**	**% Change**
Monthly Service Charge	Monthly	$ 23.4400	1	$ 23.44	$ 30.4700	1	$ 30.47	$ 7.03	29.99%
Smart Meter Rate Adder			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
Distribution Volumetric Rate	per kWh	$ 0.0152	750	$ 11.40	$ 0.0116	750	$ 8.70	-$ 2.70	-23.68%
Smart Meter Disposition Rider			750	$ -		750	$ -	$ -	
LRAM & SSM Rate Rider	per kWh		750	$ -	$ 0.0003	750	$ 0.23	$ 0.23	
			750	$ -		750	$ -	$ -	
			750	$ -		750	$ -	$ -	
			750	$ -		750	$ -	$ -	
			750	$ -		750	$ -	$ -	
			750	$ -		750	$ -	$ -	
			750	$ -		750	$ -	$ -	
			750	$ -		750	$ -	$ -	
Sub-Total A (excluding pass through)				$ 34.84			$ 39.40	**$ 4.56**	**13.07%**
DVA - Total in Effect 2016	per kWh	-$ 0.0017	750	-$ 1.28		750	$ -	$ 1.28	-100.00%
DVA - Total in Effect 2017 (Var)	per kWh		750	$ -	$ 0.0068	750	$ 5.10	$ 5.10	
DVA - Total in Effect 2017 (Fixed)	Monthly		1	$ -	-$ 0.1500	1	-$ 0.15	-$ 0.15	
			750	$ -		750	$ -	$ -	
Low Voltage Service Charge	per kWh	$ 0.0002	750	$ 0.15	$ 0.0003	750	$ 0.23	$ 0.08	50.00%
Line Losses on Cost of Power	per kWh	$ 0.1652	41	$ 6.72	$ 0.1652	40	$ 6.57	-$ 0.15	-2.21%
Smart Meter Entity Charge	Monthly	$ 0.7900	1	$ 0.79	$ 0.7900	1	$ 0.79	$ -	0.00%
Sub-Total B - Distribution (includes Sub-Total A)				**$ 41.22**			**$ 51.93**	**$ 10.71**	**25.97%**
RTSR - Network	per kWh	$ 0.0072	791	$ 5.69	$ 0.0069	790	$ 5.45	-$ 0.24	-4.28%
RTSR - Line and Transformation Connection	per kWh	$ 0.0058	791	$ 4.59	$ 0.0059	790	$ 4.66	$ 0.07	1.61%
Sub-Total C - Delivery (including Sub-Total B)				**$ 51.50**			**$ 62.04**	**$ 10.54**	**20.46%**
Wholesale Market Service Charge (WMSC)	per kWh	$ 0.0036	791	$ 2.85	$ 0.0036	790	$ 2.84	-$ 0.00	-0.11%
Rural and Remote Rate Protection (RRRP)	per kWh	$ 0.0013	791	$ 1.03	$ 0.0013	790	$ 1.03	-$ 0.00	-0.11%
Standard Supply Service Charge	Monthly	$ 0.2500	1	$ 0.25	$ 0.2500	1	$ 0.25	$ -	0.00%
Debt Retirement Charge (DRC)			750	$ -					
Ontario Electricity Support Program (OESP)	per kWh	$ 0.0011	791	$ 0.87	$ 0.0011	790	$ 0.87	-$ 0.00	-0.11%
Non-RPP Retailer Avg. Price + GA	per kWh	$ 0.1652	750	$ 123.90	$ 0.1652	750	$ 123.90	$ -	0.00%
Total Bill on Non-RPP Avg. Price				**$ 180.39**			**$ 190.92**	**$ 10.53**	**5.84%**
HST		13%		$ 23.45	13%		$ 24.82	$ 1.37	5.84%
Total Bill (including HST)				$ 203.84			$ 215.74	$ 11.90	5.84%
Ontario Clean Energy Benefit [1]									
Total Bill on Non-RPP Avg. Price				**$ 203.84**			**$ 215.74**	**$ 11.90**	**5.84%**

Customer Class:	Residential TOU - Fort Erie
RPP / Non-RPP:	RPP
Consumption	1,000 kWh
Demand	- kW
Current Loss Factor	1.0542
Proposed/Approved Loss Factor	1.0530
Ontario Clean Energy Benefit Applied?	No

		Current Board-Approved			Proposed			Impact	
	Charge Unit	**Rate ($)**	**Volume**	**Charge ($)**	**Rate ($)**	**Volume**	**Charge ($)**	**$ Change**	**% Change**
Monthly Service Charge	Monthly	$ 23.4400	1	$ 23.44	$ 30.4700	1	$ 30.47	$ 7.03	29.99%
Smart Meter Rate Adder			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
Distribution Volumetric Rate	per kWh	$ 0.0152	1,000	$ 15.20	$ 0.0116	1,000	$ 11.60	-$ 3.60	-23.68%
Smart Meter Disposition Rider			1,000	$ -		1,000	$ -	$ -	
LRAM & SSM Rate Rider	per kWh		1,000	$ -	$ 0.0003	1,000	$ 0.30	$ 0.30	
			1,000	$ -		1,000	$ -	$ -	
			1,000	$ -		1,000	$ -	$ -	
			1,000	$ -		1,000	$ -	$ -	
			1,000	$ -		1,000	$ -	$ -	
			1,000	$ -		1,000	$ -	$ -	
			1,000	$ -		1,000	$ -	$ -	
			1,000	$ -		1,000	$ -	$ -	
Sub-Total A (excluding pass through)				$ 38.64			$ 42.37	**$ 3.73**	**9.65%**
DVA - Total in Effect 2016	per kWh	$ 0.0004	1,000	$ 0.40		1,000	$ -	-$ 0.40	-100.00%
DVA - Total in Effect 2017 (Var)	per kWh		1,000	$ -	-$ 0.0044	1,000	-$ 4.40	-$ 4.40	
DVA - Total in Effect 2017 (Fixed)	Monthly		1	$ -	-$ 0.1500	1	-$ 0.15	-$ 0.15	
			1,000	$ -		1,000	$ -	$ -	
Low Voltage Service Charge	per kWh	$ 0.0002	1,000	$ 0.20	$ 0.0003	1,000	$ 0.30	$ 0.10	50.00%
Line Losses on Cost of Power	per kWh	$ 0.1077	54	$ 5.84	$ 0.1077	53	$ 5.71	-$ 0.13	-2.21%
Smart Meter Entity Charge	Monthly	$ 0.7900	1	$ 0.79	$ 0.7900	1	$ 0.79	$ -	0.00%
Sub-Total B - Distribution (includes Sub-Total A)				**$ 45.87**			**$ 44.62**	**-$ 1.25**	**-2.72%**
RTSR - Network	per kWh	$ 0.0072	1,054	$ 7.59	$ 0.0069	1,053	$ 7.27	-$ 0.32	-4.28%
RTSR - Line and Transformation Connection	per kWh	$ 0.0058	1,054	$ 6.11	$ 0.0059	1,053	$ 6.21	$ 0.10	1.61%
Sub-Total C - Delivery (including Sub-Total B)				**$ 59.57**			**$ 58.09**	**-$ 1.48**	**-2.48%**
Wholesale Market Service Charge (WMSC)	per kWh	$ 0.0036	1,054	$ 3.80	$ 0.0036	1,053	$ 3.79	-$ 0.00	-0.11%
Rural and Remote Rate Protection (RRRP)	per kWh	$ 0.0013	1,054	$ 1.37	$ 0.0013	1,053	$ 1.37	-$ 0.00	-0.11%
Standard Supply Service Charge	Monthly	$ 0.2500	1	$ 0.25	$ 0.2500	1	$ 0.25	$ -	0.00%
Debt Retirement Charge (DRC)			1,000	$ -					
Ontario Electricity Support Program (OESP)	per kWh	$ 0.0011	1,054	$ 1.16	$ 0.0011	1,053	$ 1.16	-$ 0.00	-0.11%
TOU - Off Peak	per kWh	$ 0.0830	640	$ 53.12	$ 0.0830	640	$ 53.12	$ -	0.00%
TOU - Mid Peak	per kWh	$ 0.1280	180	$ 23.04	$ 0.1280	180	$ 23.04	$ -	0.00%
TOU - On Peak	per kWh	$ 0.1750	180	$ 31.50	$ 0.1750	180	$ 31.50	$ -	0.00%
Total Bill on TOU (before Taxes)				**$ 173.80**			**$ 172.32**	**-$ 1.48**	**-0.85%**
HST		13%		$ 22.59	13%		$ 22.40	-$ 0.19	-0.85%
Total Bill (including HST)				$ 196.40			$ 194.72	-$ 1.68	-0.85%
Ontario Clean Energy Benefit [1]									
Total Bill on TOU				**$ 196.40**			**$ 194.72**	**-$ 1.68**	**-0.85%**

Customer Class:	Residential Retailer - Fort Erie	
RPP / Non-RPP:	Non-RPP (Retailer)	
Consumption	1,000	kWh
Demand	-	kW
Current Loss Factor	1.0542	
Proposed/Approved Loss Factor	1.0530	
Ontario Clean Energy Benefit Applied?	No	

		Current Board-Approved			**Proposed**			**Impact**	
	Charge Unit	**Rate ($)**	**Volume**	**Charge ($)**	**Rate ($)**	**Volume**	**Charge ($)**	**$ Change**	**% Change**
Monthly Service Charge	Monthly	$ 23.4400	1	$ 23.44	$ 30.4700	1	$ 30.47	$ 7.03	29.99%
Smart Meter Rate Adder			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
Distribution Volumetric Rate	per kWh	$ 0.0152	1,000	$ 15.20	$ 0.0116	1,000	$ 11.60	-$ 3.60	-23.68%
Smart Meter Disposition Rider			1,000	$ -		1,000	$ -	$ -	
LRAM & SSM Rate Rider	per kWh		1,000	$ -	$ 0.0003	1,000	$ 0.30	$ 0.30	
			1,000	$ -		1,000	$ -	$ -	
			1,000	$ -		1,000	$ -	$ -	
			1,000	$ -		1,000	$ -	$ -	
			1,000	$ -		1,000	$ -	$ -	
			1,000	$ -		1,000	$ -	$ -	
			1,000	$ -		1,000	$ -	$ -	
			1,000	$ -		1,000	$ -	$ -	
Sub-Total A (excluding pass through)				$ 38.64			$ 42.37	**$ 3.73**	**9.65%**
DVA - Total in Effect 2016	per kWh	$ 0.0016	1,000	$ 1.60		1,000	$ -	-$ 1.60	-100.00%
DVA - Total in Effect 2017 (Var)	per kWh		1,000	$ -	$ 0.0065	1,000	$ 6.50	$ 6.50	
DVA - Total in Effect 2017 (Fixed)	Monthly		1	$ -	-$ 0.1500	1	-$ 0.15	-$ 0.15	
			1,000	$ -		1,000	$ -	$ -	
Low Voltage Service Charge	per kWh	$ 0.0002	1,000	$ 0.20	$ 0.0003	1,000	$ 0.30	$ 0.10	50.00%
Line Losses on Cost of Power	per kWh	$ 0.1652	54	$ 8.95	$ 0.1652	53	$ 8.76	-$ 0.20	-2.21%
Smart Meter Entity Charge	Monthly	$ 0.7900	1	$ 0.79	$ 0.7900	1	$ 0.79	$ -	0.00%
Sub-Total B - Distribution (includes Sub-Total A)				**$ 50.18**			**$ 58.57**	**$ 8.38**	**16.70%**
RTSR - Network	per kWh	$ 0.0072	1,054	$ 7.59	$ 0.0069	1,053	$ 7.27	-$ 0.32	-4.28%
RTSR - Line and Transformation Connection	per kWh	$ 0.0058	1,054	$ 6.11	$ 0.0059	1,053	$ 6.21	$ 0.10	1.61%
Sub-Total C - Delivery (including Sub-Total B)				**$ 63.89**			**$ 72.04**	**$ 8.16**	**12.77%**
Wholesale Market Service Charge (WMSC)	per kWh	$ 0.0036	1,054	$ 3.80	$ 0.0036	1,053	$ 3.79	-$ 0.00	-0.11%
Rural and Remote Rate Protection (RRRP)	per kWh	$ 0.0013	1,054	$ 1.37	$ 0.0013	1,053	$ 1.37	-$ 0.00	-0.11%
Standard Supply Service Charge	Monthly	$ 0.2500	1	$ 0.25	$ 0.2500	1	$ 0.25	$ -	0.00%
Debt Retirement Charge (DRC)			1,000	$ -					
Ontario Electricity Support Program (OESP)	per kWh	$ 0.0011	1,054	$ 1.16	$ 0.0011	1,053	$ 1.16	-$ 0.00	-0.11%
Non-RPP Retailer Avg. Price + GA	per kWh	$ 0.1652	1,000	$ 165.20	$ 0.1652	1,000	$ 165.20	$ -	0.00%
Total Bill on Non-RPP Avg. Price				**$ 235.66**			**$ 243.81**	**$ 8.15**	**3.46%**
HST		13%		$ 30.64	13%		$ 31.70	$ 1.06	3.46%
Total Bill (including HST)				$ 266.30			$ 275.51	$ 9.21	3.46%
Ontario Clean Energy Benefit [1]									
Total Bill on Non-RPP Avg. Price				**$ 266.30**			**$ 275.51**	**$ 9.21**	**3.46%**

Customer Class:	Residential TOU - EOP	
RPP / Non-RPP:	RPP	
Consumption	1,000	kWh
Demand	-	kW
Current Loss Factor	1.0542	
Proposed/Approved Loss Factor	1.0530	
Ontario Clean Energy Benefit Applied?	No	

		Current Board-Approved			Proposed			Impact	
	Charge Unit	**Rate ($)**	**Volume**	**Charge ($)**	**Rate ($)**	**Volume**	**Charge ($)**	**$ Change**	**% Change**
Monthly Service Charge	Monthly	$ 23.4400	1	$ 23.44	$ 30.4700	1	$ 30.47	$ 7.03	29.99%
Smart Meter Rate Adder			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
Distribution Volumetric Rate	per kWh	$ 0.0152	1,000	$ 15.20	$ 0.0116	1,000	$ 11.60	-$ 3.60	-23.68%
Smart Meter Disposition Rider			1,000	$ -		1,000	$ -	$ -	
LRAM & SSM Rate Rider	per kWh		1,000	$ -	$ 0.0003	1,000	$ 0.30	$ 0.30	
			1,000	$ -		1,000	$ -	$ -	
			1,000	$ -		1,000	$ -	$ -	
			1,000	$ -		1,000	$ -	$ -	
			1,000	$ -		1,000	$ -	$ -	
			1,000	$ -		1,000	$ -	$ -	
			1,000	$ -		1,000	$ -	$ -	
			1,000	$ -		1,000	$ -	$ -	
Sub-Total A (excluding pass through)				$ 38.64			$ 42.37	**$ 3.73**	**9.65%**
DVA - Total in Effect 2016	per kWh	-$ 0.0024	1,000	-$ 2.40		1,000	$ -	$ 2.40	-100.00%
DVA - Total in Effect 2017 (Var)	per kWh		1,000	$ -	-$ 0.0044	1,000	-$ 4.40	-$ 4.40	
DVA - Total in Effect 2017 (Fixed)	Monthly		1	$ -	-$ 0.1500	1	-$ 0.15	-$ 0.15	
			1,000	$ -		1,000	$ -	$ -	
Low Voltage Service Charge	per kWh	$ 0.0002	1,000	$ 0.20	$ 0.0003	1,000	$ 0.30	$ 0.10	50.00%
Line Losses on Cost of Power	per kWh	$ 0.1077	54	$ 5.84	$ 0.1077	53	$ 5.71	-$ 0.13	-2.21%
Smart Meter Entity Charge	Monthly	$ 0.7900	1	$ 0.79	$ 0.7900	1	$ 0.79	$ -	0.00%
Sub-Total B - Distribution (includes Sub-Total A)				**$ 43.07**			**$ 44.62**	**$ 1.55**	**3.60%**
RTSR - Network	per kWh	$ 0.0072	1,054	$ 7.59	$ 0.0069	1,053	$ 7.27	-$ 0.32	-4.28%
RTSR - Line and Transformation Connection	per kWh	$ 0.0058	1,054	$ 6.11	$ 0.0059	1,053	$ 6.21	$ 0.10	1.61%
Sub-Total C - Delivery (including Sub-Total B)				**$ 56.77**			**$ 58.09**	**$ 1.32**	**2.33%**
Wholesale Market Service Charge (WMSC)	per kWh	$ 0.0036	1,054	$ 3.80	$ 0.0036	1,053	$ 3.79	-$ 0.00	-0.11%
Rural and Remote Rate Protection (RRRP)	per kWh	$ 0.0013	1,054	$ 1.37	$ 0.0013	1,053	$ 1.37	-$ 0.00	-0.11%
Standard Supply Service Charge	Monthly	$ 0.2500	1	$ 0.25	$ 0.2500	1	$ 0.25	$ -	0.00%
Debt Retirement Charge (DRC)			1,000	$ -					
Ontario Electricity Support Program (OESP)	per kWh	$ 0.0011	1,054	$ 1.16	$ 0.0011	1,053	$ 1.16	-$ 0.00	-0.11%
TOU - Off Peak	per kWh	$ 0.0830	640	$ 53.12	$ 0.0830	640	$ 53.12	$ -	0.00%
TOU - Mid Peak	per kWh	$ 0.1280	180	$ 23.04	$ 0.1280	180	$ 23.04	$ -	0.00%
TOU - On Peak	per kWh	$ 0.1750	180	$ 31.50	$ 0.1750	180	$ 31.50	$ -	0.00%
Total Bill on TOU (before Taxes)				**$ 171.00**			**$ 172.32**	**$ 1.32**	**0.77%**
HST		13%		$ 22.23	13%		$ 22.40	$ 0.17	0.77%
Total Bill (including HST)				$ 193.24			$ 194.72	$ 1.49	0.77%
Ontario Clean Energy Benefit [1]									
Total Bill on TOU				**$ 193.24**			**$ 194.72**	**$ 1.49**	**0.77%**

Customer Class:	**Residential Retailer - EOP**
RPP / Non-RPP:	**Non-RPP (Retailer)**
Consumption	**1,000** kWh
Demand	**-** kW
Current Loss Factor	**1.0542**
Proposed/Approved Loss Factor	**1.0530**
Ontario Clean Energy Benefit Applied?	**No**

		Current Board-Approved			Proposed			Impact	
	Charge Unit	**Rate ($)**	**Volume**	**Charge ($)**	**Rate ($)**	**Volume**	**Charge ($)**	**$ Change**	**% Change**
Monthly Service Charge	Monthly	$ 23.4400	1	$ 23.44	$ 30.4700	1	$ 30.47	$ 7.03	29.99%
Smart Meter Rate Adder			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
Distribution Volumetric Rate	per kWh	$ 0.0152	1,000	$ 15.20	$ 0.0116	1,000	$ 11.60	-$ 3.60	-23.68%
Smart Meter Disposition Rider			1,000	$ -		1,000	$ -	$ -	
LRAM & SSM Rate Rider			1,000	$ -	$ 0.0003	1,000	$ 0.30	$ 0.30	
			1,000	$ -		1,000	$ -	$ -	
			1,000	$ -		1,000	$ -	$ -	
			1,000	$ -		1,000	$ -	$ -	
			1,000	$ -		1,000	$ -	$ -	
			1,000	$ -		1,000	$ -	$ -	
			1,000	$ -		1,000	$ -	$ -	
			1,000	$ -		1,000	$ -	$ -	
Sub-Total A (excluding pass through)				$ 38.64			$ 42.37	**$ 3.73**	**9.65%**
DVA - Total in Effect 2016	per kWh	$ 0.0156	1,000	$ 15.60		1,000	$ -	-$ 15.60	-100.00%
DVA - Total in Effect 2017 (Var)	per kWh		1,000	$ -	$ 0.0065	1,000	$ 6.50	$ 6.50	
DVA - Total in Effect 2017 (Fixed)	Monthly		1	$ -	-$ 0.1500	1	-$ 0.15	-$ 0.15	
			1,000	$ -		1,000	$ -	$ -	
Low Voltage Service Charge	per kWh	$ 0.0002	1,000	$ 0.20	$ 0.0003	1,000	$ 0.30	$ 0.10	50.00%
Line Losses on Cost of Power	per kWh	$ 0.1652	54	$ 8.95	$ 0.1652	53	$ 8.76	-$ 0.20	-2.21%
Smart Meter Entity Charge	Monthly	$ 0.7900	1	$ 0.79	$ 0.7900	1	$ 0.79	$ -	0.00%
Sub-Total B - Distribution (includes Sub-Total A)				**$ 64.18**			**$ 58.57**	**-$ 5.62**	**-8.75%**
RTSR - Network	per kWh	$ 0.0072	1,054	$ 7.59	$ 0.0069	1,053	$ 7.27	-$ 0.32	-4.28%
RTSR - Line and Transformation Connection	per kWh	$ 0.0058	1,054	$ 6.11	$ 0.0059	1,053	$ 6.21	$ 0.10	1.61%
Sub-Total C - Delivery (including Sub-Total B)				**$ 77.89**			**$ 72.04**	**-$ 5.84**	**-7.50%**
Wholesale Market Service Charge (WMSC)	per kWh	$ 0.0036	1,054	$ 3.80	$ 0.0036	1,053	$ 3.79	-$ 0.00	-0.11%
Rural and Remote Rate Protection (RRRP)	per kWh	$ 0.0013	1,054	$ 1.37	$ 0.0013	1,053	$ 1.37	-$ 0.00	-0.11%
Standard Supply Service Charge	Monthly	$ 0.2500	1	$ 0.25	$ 0.2500	1	$ 0.25	$ -	0.00%
Debt Retirement Charge (DRC)			1,000	$ -					
Ontario Electricity Support Program (OESP)	per kWh	$ 0.0011	1,054	$ 1.16	$ 0.0011	1,053	$ 1.16	-$ 0.00	-0.11%
Non-RPP Retailer Avg. Price + GA	per kWh	$ 0.1652	1,000	$ 165.20	$ 0.1652	1,000	$ 165.20	$ -	0.00%
Total Bill on Non-RPP Avg. Price				**$ 249.66**			**$ 243.81**	**-$ 5.85**	**-2.34%**
HST		13%		$ 32.46	13%		$ 31.70	-$ 0.76	-2.34%
Total Bill (including HST)				$ 282.12			$ 275.51	-$ 6.61	-2.34%
Ontario Clean Energy Benefit [1]									
Total Bill on Non-RPP Avg. Price				**$ 282.12**			**$ 275.51**	**-$ 6.61**	**-2.34%**

Customer Class:	**Residential TOU - Port Colborne**	
RPP / Non-RPP:	**RPP**	
Consumption	**1,000**	**kWh**
Demand	**-**	**kW**
Current Loss Factor	**1.0542**	
Proposed/Approved Loss Factor	**1.0530**	
Ontario Clean Energy Benefit Applied?	**No**	

		Current Board-Approved			**Proposed**			**Impact**	
	Charge Unit	**Rate ($)**	**Volume**	**Charge ($)**	**Rate ($)**	**Volume**	**Charge ($)**	**$ Change**	**% Change**
Monthly Service Charge	Monthly	$ 23.4400	1	$ 23.44	$ 30.4700	1	$ 30.47	$ 7.03	29.99%
Smart Meter Rate Adder			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
Distribution Volumetric Rate	per kWh	$ 0.0152	1,000	$ 15.20	$ 0.0116	1,000	$ 11.60	-$ 3.60	-23.68%
Smart Meter Disposition Rider			1,000	$ -		1,000	$ -	$ -	
LRAM & SSM Rate Rider	per kWh		1,000	$ -	$ 0.0003	1,000	$ 0.30	$ 0.30	
			1,000	$ -		1,000	$ -	$ -	
			1,000	$ -		1,000	$ -	$ -	
			1,000	$ -		1,000	$ -	$ -	
			1,000	$ -		1,000	$ -	$ -	
			1,000	$ -		1,000	$ -	$ -	
			1,000	$ -		1,000	$ -	$ -	
			1,000	$ -		1,000	$ -	$ -	
Sub-Total A (excluding pass through)				$ 38.64			$ 42.37	**$ 3.73**	**9.65%**
DVA - Total in Effect 2016	per kWh	-$ 0.0013	1,000	-$ 1.30		1,000	$ -	$ 1.30	-100.00%
DVA - Total in Effect 2017 (Var)	per kWh		1,000	$ -	-$ 0.0044	1,000	-$ 4.40	-$ 4.40	
DVA - Total in Effect 2017 (Fixed)	Monthly		1	$ -	-$ 0.1500	1	-$ 0.15	-$ 0.15	
			1,000	$ -		1,000	$ -	$ -	
Low Voltage Service Charge	per kWh	$ 0.0002	1,000	$ 0.20	$ 0.0003	1,000	$ 0.30	$ 0.10	50.00%
Line Losses on Cost of Power	per kWh	$ 0.1077	54	$ 5.84	$ 0.1077	53	$ 5.71	-$ 0.13	-2.21%
Smart Meter Entity Charge	Monthly	$ 0.7900	1	$ 0.79	$ 0.7900	1	$ 0.79	$ -	0.00%
Sub-Total B - Distribution (includes Sub-Total A)				**$ 44.17**			**$ 44.62**	**$ 0.45**	**1.02%**
RTSR - Network	per kWh	$ 0.0072	1,054	$ 7.59	$ 0.0069	1,053	$ 7.27	-$ 0.32	-4.28%
RTSR - Line and Transformation Connection	per kWh	$ 0.0058	1,054	$ 6.11	$ 0.0059	1,053	$ 6.21	$ 0.10	1.61%
Sub-Total C - Delivery (including Sub-Total B)				**$ 57.87**			**$ 58.09**	**$ 0.22**	**0.39%**
Wholesale Market Service Charge (WMSC)	per kWh	$ 0.0036	1,054	$ 3.80	$ 0.0036	1,053	$ 3.79	-$ 0.00	-0.11%
Rural and Remote Rate Protection (RRRP)	per kWh	$ 0.0013	1,054	$ 1.37	$ 0.0013	1,053	$ 1.37	-$ 0.00	-0.11%
Standard Supply Service Charge	Monthly	$ 0.2500	1	$ 0.25	$ 0.2500	1	$ 0.25	$ -	0.00%
Debt Retirement Charge (DRC)			1,000	$ -					
Ontario Electricity Support Program (OESP)	per kWh	$ 0.0011	1,054	$ 1.16	$ 0.0011	1,053	$ 1.16	-$ 0.00	-0.11%
TOU - Off Peak	per kWh	$ 0.0830	640	$ 53.12	$ 0.0830	640	$ 53.12	$ -	0.00%
TOU - Mid Peak	per kWh	$ 0.1280	180	$ 23.04	$ 0.1280	180	$ 23.04	$ -	0.00%
TOU - On Peak	per kWh	$ 0.1750	180	$ 31.50	$ 0.1750	180	$ 31.50	$ -	0.00%
Total Bill on TOU (before Taxes)				**$ 172.10**			**$ 172.32**	**$ 0.22**	**0.13%**
HST		13%		$ 22.37	13%		$ 22.40	$ 0.03	0.13%
Total Bill (including HST)				$ 194.48			$ 194.72	$ 0.25	0.13%
Ontario Clean Energy Benefit [1]									
Total Bill on TOU				**$ 194.48**			**$ 194.72**	**$ 0.25**	**0.13%**

Customer Class:	**Residential Retailer - Port Colborne**
RPP / Non-RPP:	**Non-RPP (Retailer)**
Consumption	**1,000** kWh
Demand	**-** kW
Current Loss Factor	**1.0542**
Proposed/Approved Loss Factor	**1.0530**
Ontario Clean Energy Benefit Applied?	**No**

		Current Board-Approved			Proposed			Impact	
	Charge Unit	**Rate ($)**	**Volume**	**Charge ($)**	**Rate ($)**	**Volume**	**Charge ($)**	**$ Change**	**% Change**
Monthly Service Charge	Monthly	$ 23.4400	1	$ 23.44	$ 30.4700	1	$ 30.47	$ 7.03	29.99%
Smart Meter Rate Adder			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
Distribution Volumetric Rate	per kWh	$ 0.0152	1,000	$ 15.20	$ 0.0116	1,000	$ 11.60	-$ 3.60	-23.68%
Smart Meter Disposition Rider			1,000	$ -		1,000	$ -	$ -	
LRAM & SSM Rate Rider	per kWh		1,000	$ -	$ 0.0003	1,000	$ 0.30	$ 0.30	
			1,000	$ -		1,000	$ -	$ -	
			1,000	$ -		1,000	$ -	$ -	
			1,000	$ -		1,000	$ -	$ -	
			1,000	$ -		1,000	$ -	$ -	
			1,000	$ -		1,000	$ -	$ -	
			1,000	$ -		1,000	$ -	$ -	
			1,000	$ -		1,000	$ -	$ -	
Sub-Total A (excluding pass through)				$ 38.64			$ 42.37	**$ 3.73**	**9.65%**
DVA - Total in Effect 2016	per kWh	-$ 0.0017	1,000	-$ 1.70		1,000	$ -	$ 1.70	-100.00%
DVA - Total in Effect 2017 (Var)	per kWh		1,000	$ -	$ 0.0065	1,000	$ 6.50	$ 6.50	
DVA - Total in Effect 2017 (Fixed)	Monthly		1	$ -	-$ 0.1500	1	-$ 0.15	-$ 0.15	
			1,000	$ -		1,000	$ -	$ -	
Low Voltage Service Charge	per kWh	$ 0.0002	1,000	$ 0.20	$ 0.0003	1,000	$ 0.30	$ 0.10	50.00%
Line Losses on Cost of Power	per kWh	$ 0.1652	54	$ 8.95	$ 0.1652	53	$ 8.76	-$ 0.20	-2.21%
Smart Meter Entity Charge	Monthly	$ 0.7900	1	$ 0.79	$ 0.7900	1	$ 0.79	$ -	0.00%
Sub-Total B - Distribution (includes Sub-Total A)				**$ 46.88**			**$ 58.57**	**$ 11.68**	**24.92%**
RTSR - Network	per kWh	$ 0.0072	1,054	$ 7.59	$ 0.0069	1,053	$ 7.27	-$ 0.32	-4.28%
RTSR - Line and Transformation Connection	per kWh	$ 0.0058	1,054	$ 6.11	$ 0.0059	1,053	$ 6.21	$ 0.10	1.61%
Sub-Total C - Delivery (including Sub-Total B)				**$ 60.59**			**$ 72.04**	**$ 11.46**	**18.91%**
Wholesale Market Service Charge (WMSC)	per kWh	$ 0.0036	1,054	$ 3.80	$ 0.0036	1,053	$ 3.79	-$ 0.00	-0.11%
Rural and Remote Rate Protection (RRRP)	per kWh	$ 0.0013	1,054	$ 1.37	$ 0.0013	1,053	$ 1.37	-$ 0.00	-0.11%
Standard Supply Service Charge	Monthly	$ 0.2500	1	$ 0.25	$ 0.2500	1	$ 0.25	$ -	0.00%
Debt Retirement Charge (DRC)			1,000	$ -					
Ontario Electricity Support Program (OESP)	per kWh	$ 0.0011	1,054	$ 1.16	$ 0.0011	1,053	$ 1.16	-$ 0.00	-0.11%
Non-RPP Retailer Avg. Price + GA	per kWh	$ 0.1652	1,000	$ 165.20	$ 0.1652	1,000	$ 165.20	$ -	0.00%
Total Bill on Non-RPP Avg. Price				**$ 232.36**			**$ 243.81**	**$ 11.45**	**4.93%**
HST		13%		$ 30.21	13%		$ 31.70	$ 1.49	4.93%
Total Bill (including HST)				$ 262.57			$ 275.51	$ 12.94	4.93%
Ontario Clean Energy Benefit [1]									
Total Bill on Non-RPP Avg. Price				**$ 262.57**			**$ 275.51**	**$ 12.94**	**4.93%**

Customer Class:	**Residential TOU - Fort Erie**	
RPP / Non-RPP:	**RPP**	
Consumption	**1,500**	**kWh**
Demand	**-**	**kW**
Current Loss Factor	**1.0542**	
Proposed/Approved Loss Factor	**1.0530**	
Ontario Clean Energy Benefit Applied?	**No**	

		Current Board-Approved			Proposed			Impact	
	Charge Unit	**Rate ($)**	**Volume**	**Charge ($)**	**Rate ($)**	**Volume**	**Charge ($)**	**$ Change**	**% Change**
Monthly Service Charge	Monthly	$ 23.4400	1	$ 23.44	$ 30.4700	1	$ 30.47	$ 7.03	29.99%
Smart Meter Rate Adder			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
Distribution Volumetric Rate	per kWh	$ 0.0152	1,500	$ 22.80	$ 0.0116	1,500	$ 17.40	-$ 5.40	-23.68%
Smart Meter Disposition Rider			1,500	$ -		1,500	$ -	$ -	
LRAM & SSM Rate Rider	per kWh		1,500	$ -	$ 0.0003	1,500	$ 0.45	$ 0.45	
			1,500	$ -		1,500	$ -	$ -	
			1,500	$ -		1,500	$ -	$ -	
			1,500	$ -		1,500	$ -	$ -	
			1,500	$ -		1,500	$ -	$ -	
			1,500	$ -		1,500	$ -	$ -	
			1,500	$ -		1,500	$ -	$ -	
			1,500	$ -		1,500	$ -	$ -	
Sub-Total A (excluding pass through)				$ 46.24			$ 48.32	**$ 2.08**	**4.50%**
DVA - Total in Effect 2016	per kWh	$ 0.0004	1,500	$ 0.60		1,500	$ -	-$ 0.60	-100.00%
DVA - Total in Effect 2017 (Var)	per kWh		1,500	$ -	-$ 0.0044	1,500	-$ 6.60	-$ 6.60	
DVA - Total in Effect 2017 (Fixed)	Monthly		1	$ -	-$ 0.1500	1	-$ 0.15	-$ 0.15	
			1,500	$ -		1,500	$ -	$ -	
Low Voltage Service Charge	per kWh	$ 0.0002	1,500	$ 0.30	$ 0.0003	1,500	$ 0.45	$ 0.15	50.00%
Line Losses on Cost of Power	per kWh	$ 0.1077	81	$ 8.75	$ 0.1077	80	$ 8.56	-$ 0.19	-2.21%
Smart Meter Entity Charge	Monthly	$ 0.7900	1	$ 0.79	$ 0.7900	1	$ 0.79	$ -	0.00%
Sub-Total B - Distribution (includes Sub-Total A)				**$ 56.68**			**$ 51.37**	**-$ 5.31**	**-9.37%**
RTSR - Network	per kWh	$ 0.0072	1,581	$ 11.39	$ 0.0069	1,580	$ 10.90	-$ 0.49	-4.28%
RTSR - Line and Transformation Connection	per kWh	$ 0.0058	1,581	$ 9.17	$ 0.0059	1,580	$ 9.32	$ 0.15	1.61%
Sub-Total C - Delivery (including Sub-Total B)				**$ 77.24**			**$ 71.59**	**-$ 5.65**	**-7.32%**
Wholesale Market Service Charge (WMSC)	per kWh	$ 0.0036	1,581	$ 5.69	$ 0.0036	1,580	$ 5.69	-$ 0.01	-0.11%
Rural and Remote Rate Protection (RRRP)	per kWh	$ 0.0013	1,581	$ 2.06	$ 0.0013	1,580	$ 2.05	-$ 0.00	-0.11%
Standard Supply Service Charge	Monthly	$ 0.2500	1	$ 0.25	$ 0.2500	1	$ 0.25	$ -	0.00%
Debt Retirement Charge (DRC)			1,500	$ -					
Ontario Electricity Support Program (OESP)	per kWh	$ 0.0011	1,581	$ 1.74	$ 0.0011	1,580	$ 1.74	-$ 0.00	-0.11%
TOU - Off Peak	per kWh	$ 0.0830	960	$ 79.68	$ 0.0830	960	$ 79.68	$ -	0.00%
TOU - Mid Peak	per kWh	$ 0.1280	270	$ 34.56	$ 0.1280	270	$ 34.56	$ -	0.00%
TOU - On Peak	per kWh	$ 0.1750	270	$ 47.25	$ 0.1750	270	$ 47.25	$ -	0.00%
Total Bill on TOU (before Taxes)				**$ 248.47**			**$ 242.80**	**-$ 5.66**	**-2.28%**
HST		13%		$ 32.30	13%		$ 31.56	-$ 0.74	-2.28%
Total Bill (including HST)				$ 280.77			$ 274.37	-$ 6.40	-2.28%
***Ontario Clean Energy Benefit* [1]**									
Total Bill on TOU				**$ 280.77**			**$ 274.37**	**-$ 6.40**	**-2.28%**

Customer Class:	Residential Retailer - Fort Erie
RPP / Non-RPP:	Non-RPP (Retailer)
Consumption	1,500 kWh
Demand	- kW
Current Loss Factor	1.0542
Proposed/Approved Loss Factor	1.0530
Ontario Clean Energy Benefit Applied?	No

		Current Board-Approved			Proposed			Impact	
	Charge Unit	**Rate ($)**	**Volume**	**Charge ($)**	**Rate ($)**	**Volume**	**Charge ($)**	**$ Change**	**% Change**
Monthly Service Charge	Monthly	$ 23.4400	1	$ 23.44	$ 30.4700	1	$ 30.47	$ 7.03	29.99%
Smart Meter Rate Adder			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
Distribution Volumetric Rate	per kWh	$ 0.0152	1,500	$ 22.80	$ 0.0116	1,500	$ 17.40	-$ 5.40	-23.68%
Smart Meter Disposition Rider			1,500	$ -		1,500	$ -	$ -	
LRAM & SSM Rate Rider	per kWh		1,500	$ -	$ 0.0003	1,500	$ 0.45	$ 0.45	
			1,500	$ -		1,500	$ -	$ -	
			1,500	$ -		1,500	$ -	$ -	
			1,500	$ -		1,500	$ -	$ -	
			1,500	$ -		1,500	$ -	$ -	
			1,500	$ -		1,500	$ -	$ -	
			1,500	$ -		1,500	$ -	$ -	
			1,500	$ -		1,500	$ -	$ -	
Sub-Total A (excluding pass through)				$ 46.24			$ 48.32	**$ 2.08**	**4.50%**
DVA - Total in Effect 2016	per kWh	$ 0.0016	1,500	$ 2.40		1,500	$ -	-$ 2.40	-100.00%
DVA - Total in Effect 2017 (Var)	per kWh		1,500	$ -	$ 0.0068	1,500	$ 10.20	$ 10.20	
DVA - Total in Effect 2017 (Fixed)	Monthly		1	$ -	-$ 0.1500	1	-$ 0.15	-$ 0.15	
			1,500	$ -		1,500	$ -	$ -	
Low Voltage Service Charge	per kWh	$ 0.0002	1,500	$ 0.30	$ 0.0003	1,500	$ 0.45	$ 0.15	50.00%
Line Losses on Cost of Power	per kWh	$ 0.1652	81	$ 13.43	$ 0.1652	80	$ 13.13	-$ 0.30	-2.21%
Smart Meter Entity Charge	Monthly	$ 0.7900	1	$ 0.79	$ 0.7900	1	$ 0.79	$ -	0.00%
Sub-Total B - Distribution (includes Sub-Total A)				**$ 63.16**			**$ 72.74**	**$ 9.58**	**15.17%**
RTSR - Network	per kWh	$ 0.0072	1,581	$ 11.39	$ 0.0069	1,580	$ 10.90	-$ 0.49	-4.28%
RTSR - Line and Transformation Connection	per kWh	$ 0.0058	1,581	$ 9.17	$ 0.0059	1,580	$ 9.32	$ 0.15	1.61%
Sub-Total C - Delivery (including Sub-Total B)				**$ 83.72**			**$ 92.96**	**$ 9.24**	**11.04%**
Wholesale Market Service Charge (WMSC)	per kWh	$ 0.0036	1,581	$ 5.69	$ 0.0036	1,580	$ 5.69	-$ 0.01	-0.11%
Rural and Remote Rate Protection (RRRP)	per kWh	$ 0.0013	1,581	$ 2.06	$ 0.0013	1,580	$ 2.05	-$ 0.00	-0.11%
Standard Supply Service Charge	Monthly	$ 0.2500	1	$ 0.25	$ 0.2500	1	$ 0.25	$ -	0.00%
Debt Retirement Charge (DRC)			1,500	$ -					
Ontario Electricity Support Program (OESP)	per kWh	$ 0.0011	1,581	$ 1.74	$ 0.0011	1,580	$ 1.74	-$ 0.00	-0.11%
Non-RPP Retailer Avg. Price + GA	per kWh	$ 0.1652	1,500	$ 247.80	$ 0.1652	1,500	$ 247.80	$ -	0.00%
Total Bill on Non-RPP Avg. Price				**$ 341.26**			**$ 350.49**	**$ 9.23**	**2.71%**
HST		13%		$ 44.36	13%		$ 45.56	$ 1.20	2.71%
Total Bill (including HST)				$ 385.62			$ 396.05	$ 10.43	2.71%
Ontario Clean Energy Benefit [1]									
Total Bill on Non-RPP Avg. Price				**$ 385.62**			**$ 396.05**	**$ 10.43**	**2.71%**

Customer Class:	Residential TOU - EOP	
RPP / Non-RPP:	RPP	
Consumption	1,500	kWh
Demand	-	kW
Current Loss Factor	1.0542	
Proposed/Approved Loss Factor	1.0530	
Ontario Clean Energy Benefit Applied?	No	

		Current Board-Approved			Proposed			Impact	
	Charge Unit	**Rate ($)**	**Volume**	**Charge ($)**	**Rate ($)**	**Volume**	**Charge ($)**	**$ Change**	**% Change**
Monthly Service Charge	Monthly	$ 23.4400	1	$ 23.44	$ 30.4700	1	$ 30.47	$ 7.03	29.99%
Smart Meter Rate Adder			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
Distribution Volumetric Rate	per kWh	$ 0.0152	1,500	$ 22.80	$ 0.0116	1,500	$ 17.40	-$ 5.40	-23.68%
Smart Meter Disposition Rider			1,500	$ -		1,500	$ -	$ -	
LRAM & SSM Rate Rider	per kWh		1,500	$ -	$ 0.0003	1,500	$ 0.45	$ 0.45	
			1,500	$ -		1,500	$ -	$ -	
			1,500	$ -		1,500	$ -	$ -	
			1,500	$ -		1,500	$ -	$ -	
			1,500	$ -		1,500	$ -	$ -	
			1,500	$ -		1,500	$ -	$ -	
			1,500	$ -		1,500	$ -	$ -	
			1,500	$ -		1,500	$ -	$ -	
Sub-Total A (excluding pass through)				$ 46.24			$ 48.32	**$ 2.08**	**4.50%**
DVA - Total in Effect 2016	per kWh	-$ 0.0024	1,500	-$ 3.60		1,500	$ -	$ 3.60	-100.00%
DVA - Total in Effect 2017 (Var)	per kWh		1,500	$ -	-$ 0.0044	1,500	-$ 6.60	-$ 6.60	
DVA - Total in Effect 2017 (Fixed)	Monthly		1	$ -	-$ 0.1500	1	-$ 0.15	-$ 0.15	
			1,500	$ -		1,500	$ -	$ -	
Low Voltage Service Charge	per kWh	$ 0.0002	1,500	$ 0.30	$ 0.0003	1,500	$ 0.45	$ 0.15	50.00%
Line Losses on Cost of Power	per kWh	$ 0.1077	81	$ 8.75	$ 0.1077	80	$ 8.56	-$ 0.19	-2.21%
Smart Meter Entity Charge	Monthly	$ 0.7900	1	$ 0.79	$ 0.7900	1	$ 0.79	$ -	0.00%
Sub-Total B - Distribution (includes Sub-Total A)				**$ 52.48**			**$ 51.37**	**-$ 1.11**	**-2.12%**
RTSR - Network	per kWh	$ 0.0072	1,581	$ 11.39	$ 0.0069	1,580	$ 10.90	-$ 0.49	-4.28%
RTSR - Line and Transformation Connection	per kWh	$ 0.0058	1,581	$ 9.17	$ 0.0059	1,580	$ 9.32	$ 0.15	1.61%
Sub-Total C - Delivery (including Sub-Total B)				**$ 73.04**			**$ 71.59**	**-$ 1.45**	**-1.99%**
Wholesale Market Service Charge (WMSC)	per kWh	$ 0.0036	1,581	$ 5.69	$ 0.0036	1,580	$ 5.69	-$ 0.01	-0.11%
Rural and Remote Rate Protection (RRRP)	per kWh	$ 0.0013	1,581	$ 2.06	$ 0.0013	1,580	$ 2.05	-$ 0.00	-0.11%
Standard Supply Service Charge	Monthly	$ 0.2500	1	$ 0.25	$ 0.2500	1	$ 0.25	$ -	0.00%
Debt Retirement Charge (DRC)			1,500	$ -					
Ontario Electricity Support Program (OESP)	per kWh	$ 0.0011	1,581	$ 1.74	$ 0.0011	1,580	$ 1.74	-$ 0.00	-0.11%
TOU - Off Peak	per kWh	$ 0.0830	960	$ 79.68	$ 0.0830	960	$ 79.68	$ -	0.00%
TOU - Mid Peak	per kWh	$ 0.1280	270	$ 34.56	$ 0.1280	270	$ 34.56	$ -	0.00%
TOU - On Peak	per kWh	$ 0.1750	270	$ 47.25	$ 0.1750	270	$ 47.25	$ -	0.00%
Total Bill on TOU (before Taxes)				**$ 244.27**			**$ 242.80**	**-$ 1.46**	**-0.60%**
HST		13%		$ 31.75	13%		$ 31.56	-$ 0.19	-0.60%
Total Bill (including HST)				$ 276.02			$ 274.37	-$ 1.65	-0.60%
Ontario Clean Energy Benefit [1]									
Total Bill on TOU				**$ 276.02**			**$ 274.37**	**-$ 1.65**	**-0.60%**

Customer Class:	**Residential Retailer - EOP**	
RPP / Non-RPP:	**Non-RPP (Retailer)**	
Consumption	**1,500**	**kWh**
Demand	**-**	**kW**
Current Loss Factor	**1.0542**	
Proposed/Approved Loss Factor	**1.0530**	
Ontario Clean Energy Benefit Applied?	**No**	

		Current Board-Approved			**Proposed**			**Impact**	
	Charge Unit	**Rate ($)**	**Volume**	**Charge ($)**	**Rate ($)**	**Volume**	**Charge ($)**	**$ Change**	**% Change**
Monthly Service Charge	Monthly	$ 23.4400	1	$ 23.44	$ 30.4700	1	$ 30.47	$ 7.03	29.99%
Smart Meter Rate Adder			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
Distribution Volumetric Rate	per kWh	$ 0.0152	1,500	$ 22.80	$ 0.0116	1,500	$ 17.40	-$ 5.40	-23.68%
Smart Meter Disposition Rider			1,500	$ -		1,500	$ -	$ -	
LRAM & SSM Rate Rider	per kWh		1,500	$ -	$ 0.0003	1,500	$ 0.45	$ 0.45	
			1,500	$ -		1,500	$ -	$ -	
			1,500	$ -		1,500	$ -	$ -	
			1,500	$ -		1,500	$ -	$ -	
			1,500	$ -		1,500	$ -	$ -	
			1,500	$ -		1,500	$ -	$ -	
			1,500	$ -		1,500	$ -	$ -	
			1,500	$ -		1,500	$ -	$ -	
Sub-Total A (excluding pass through)				$ 46.24			$ 48.32	**$ 2.08**	**4.50%**
DVA - Total in Effect 2016	per kWh	$ 0.0156	1,500	$ 23.40		1,500	$ -	-$ 23.40	-100.00%
DVA - Total in Effect 2017 (Var)	per kWh		1,500	$ -	$ 0.0068	1,500	$ 10.20	$ 10.20	
DVA - Total in Effect 2017 (Fixed)	Monthly		1	$ -	-$ 0.1500	1	-$ 0.15	-$ 0.15	
			1,500	$ -		1,500	$ -	$ -	
Low Voltage Service Charge	per kWh	$ 0.0002	1,500	$ 0.30	$ 0.0003	1,500	$ 0.45	$ 0.15	50.00%
Line Losses on Cost of Power	per kWh	$ 0.1652	81	$ 13.43	$ 0.1652	80	$ 13.13	-$ 0.30	-2.21%
Smart Meter Entity Charge	Monthly	$ 0.7900	1	$ 0.79	$ 0.7900	1	$ 0.79	$ -	0.00%
Sub-Total B - Distribution (includes Sub-Total A)				**$ 84.16**			**$ 72.74**	**-$ 11.42**	**-13.57%**
RTSR - Network	per kWh	$ 0.0072	1,581	$ 11.39	$ 0.0069	1,580	$ 10.90	-$ 0.49	-4.28%
RTSR - Line and Transformation Connection	per kWh	$ 0.0058	1,581	$ 9.17	$ 0.0059	1,580	$ 9.32	$ 0.15	1.61%
Sub-Total C - Delivery (including Sub-Total B)				**$ 104.72**			**$ 92.96**	**-$ 11.76**	**-11.23%**
Wholesale Market Service Charge (WMSC)	per kWh	$ 0.0036	1,581	$ 5.69	$ 0.0036	1,580	$ 5.69	-$ 0.01	-0.11%
Rural and Remote Rate Protection (RRRP)	per kWh	$ 0.0013	1,581	$ 2.06	$ 0.0013	1,580	$ 2.05	-$ 0.00	-0.11%
Standard Supply Service Charge	Monthly	$ 0.2500	1	$ 0.25	$ 0.2500	1	$ 0.25	$ -	0.00%
Debt Retirement Charge (DRC)			1,500	$ -					
Ontario Electricity Support Program (OESP)	per kWh	$ 0.0011	1,581	$ 1.74	$ 0.0011	1,580	$ 1.74	-$ 0.00	-0.11%
Non-RPP Retailer Avg. Price + GA	per kWh	$ 0.1652	1,500	$ 247.80	$ 0.1652	1,500	$ 247.80	$ -	0.00%
Total Bill on Non-RPP Avg. Price				**$ 362.26**			**$ 350.49**	**-$ 11.77**	**-3.25%**
HST		13%		$ 47.09	13%		$ 45.56	-$ 1.53	-3.25%
Total Bill (including HST)				$ 409.35			$ 396.05	-$ 13.30	-3.25%
Ontario Clean Energy Benefit [1]									
Total Bill on Non-RPP Avg. Price				**$ 409.35**			**$ 396.05**	**-$ 13.30**	**-3.25%**

Customer Class:	**Residential TOU - Port Colborne**
RPP / Non-RPP:	**RPP**
Consumption	**1,500** kWh
Demand	**-** kW
Current Loss Factor	**1.0542**
Proposed/Approved Loss Factor	**1.0530**
Ontario Clean Energy Benefit Applied?	**No**

		Current Board-Approved			Proposed			Impact	
	Charge Unit	**Rate ($)**	**Volume**	**Charge ($)**	**Rate ($)**	**Volume**	**Charge ($)**	**$ Change**	**% Change**
Monthly Service Charge	Monthly	$ 23.4400	1	$ 23.44	$ 30.4700	1	$ 30.47	$ 7.03	29.99%
Smart Meter Rate Adder			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
Distribution Volumetric Rate	per kWh	$ 0.0152	1,500	$ 22.80	$ 0.0116	1,500	$ 17.40	-$ 5.40	-23.68%
Smart Meter Disposition Rider			1,500	$ -		1,500	$ -	$ -	
LRAM & SSM Rate Rider	per kWh		1,500	$ -	$ 0.0003	1,500	$ 0.45	$ 0.45	
			1,500	$ -		1,500	$ -	$ -	
			1,500	$ -		1,500	$ -	$ -	
			1,500	$ -		1,500	$ -	$ -	
			1,500	$ -		1,500	$ -	$ -	
			1,500	$ -		1,500	$ -	$ -	
			1,500	$ -		1,500	$ -	$ -	
			1,500	$ -		1,500	$ -	$ -	
Sub-Total A (excluding pass through)				$ 46.24			$ 48.32	**$ 2.08**	**4.50%**
DVA - Total in Effect 2016	per kWh	-$ 0.0013	1,500	-$ 1.95		1,500	$ -	$ 1.95	-100.00%
DVA - Total in Effect 2017 (Var)	per kWh		1,500	$ -	-$ 0.0044	1,500	-$ 6.60	-$ 6.60	
DVA - Total in Effect 2017 (Fixed)	Monthly		1	$ -	-$ 0.1500	1	-$ 0.15	-$ 0.15	
			1,500	$ -		1,500	$ -	$ -	
Low Voltage Service Charge	per kWh	$ 0.0002	1,500	$ 0.30	$ 0.0003	1,500	$ 0.45	$ 0.15	50.00%
Line Losses on Cost of Power	per kWh	$ 0.1077	81	$ 8.75	$ 0.1077	80	$ 8.56	-$ 0.19	-2.21%
Smart Meter Entity Charge	Monthly	$ 0.7900	1	$ 0.79	$ 0.7900	1	$ 0.79	$ -	0.00%
Sub-Total B - Distribution (includes Sub-Total A)				**$ 54.13**			**$ 51.37**	**-$ 2.76**	**-5.11%**
RTSR - Network	per kWh	$ 0.0072	1,581	$ 11.39	$ 0.0069	1,580	$ 10.90	-$ 0.49	-4.28%
RTSR - Line and Transformation Connection	per kWh	$ 0.0058	1,581	$ 9.17	$ 0.0059	1,580	$ 9.32	$ 0.15	1.61%
Sub-Total C - Delivery (including Sub-Total B)				**$ 74.69**			**$ 71.59**	**-$ 3.10**	**-4.15%**
Wholesale Market Service Charge (WMSC)	per kWh	$ 0.0036	1,581	$ 5.69	$ 0.0036	1,580	$ 5.69	-$ 0.01	-0.11%
Rural and Remote Rate Protection (RRRP)	per kWh	$ 0.0013	1,581	$ 2.06	$ 0.0013	1,580	$ 2.05	-$ 0.00	-0.11%
Standard Supply Service Charge	Monthly	$ 0.2500	1	$ 0.25	$ 0.2500	1	$ 0.25	$ -	0.00%
Debt Retirement Charge (DRC)			1,500	$ -					
Ontario Electricity Support Program (OESP)	per kWh	$ 0.0011	1,581	$ 1.74	$ 0.0011	1,580	$ 1.74	-$ 0.00	-0.11%
TOU - Off Peak	per kWh	$ 0.0830	960	$ 79.68	$ 0.0830	960	$ 79.68	$ -	0.00%
TOU - Mid Peak	per kWh	$ 0.1280	270	$ 34.56	$ 0.1280	270	$ 34.56	$ -	0.00%
TOU - On Peak	per kWh	$ 0.1750	270	$ 47.25	$ 0.1750	270	$ 47.25	$ -	0.00%
Total Bill on TOU (before Taxes)				**$ 245.92**			**$ 242.80**	**-$ 3.11**	**-1.27%**
HST		13%		$ 31.97	13%		$ 31.56	-$ 0.40	-1.27%
Total Bill (including HST)				$ 277.89			$ 274.37	-$ 3.52	-1.27%
Ontario Clean Energy Benefit [1]									
Total Bill on TOU				**$ 277.89**			**$ 274.37**	**-$ 3.52**	**-1.27%**

Customer Class:	**Residential Retailer - Port Colborne**
RPP / Non-RPP:	**Non-RPP (Retailer)**
Consumption	**1,500** kWh
Demand	**-** kW
Current Loss Factor	**1.0542**
Proposed/Approved Loss Factor	**1.0530**
Ontario Clean Energy Benefit Applied?	**No**

		Current Board-Approved			**Proposed**			**Impact**	
	Charge Unit	**Rate ($)**	**Volume**	**Charge ($)**	**Rate ($)**	**Volume**	**Charge ($)**	**$ Change**	**% Change**
Monthly Service Charge	Monthly	$ 23.4400	1	$ 23.44	$ 30.4700	1	$ 30.47	$ 7.03	29.99%
Smart Meter Rate Adder			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
Distribution Volumetric Rate	per kWh	$ 0.0152	1,500	$ 22.80	$ 0.0116	1,500	$ 17.40	-$ 5.40	-23.68%
Smart Meter Disposition Rider			1,500	$ -		1,500	$ -	$ -	
LRAM & SSM Rate Rider	per kWh		1,500	$ -	$ 0.0003	1,500	$ 0.45	$ 0.45	
			1,500	$ -		1,500	$ -	$ -	
			1,500	$ -		1,500	$ -	$ -	
			1,500	$ -		1,500	$ -	$ -	
			1,500	$ -		1,500	$ -	$ -	
			1,500	$ -		1,500	$ -	$ -	
			1,500	$ -		1,500	$ -	$ -	
			1,500	$ -		1,500	$ -	$ -	
Sub-Total A (excluding pass through)				$ 46.24			$ 48.32	**$ 2.08**	**4.50%**
DVA - Total in Effect 2016	per kWh	-$ 0.0017	1,500	-$ 2.55		1,500	$ -	$ 2.55	-100.00%
DVA - Total in Effect 2017 (Var)	per kWh		1,500	$ -	$ 0.0068	1,500	$ 10.20	$ 10.20	
DVA - Total in Effect 2017 (Fixed)	Monthly		1	$ -	-$ 0.1500	1	-$ 0.15	-$ 0.15	
			1,500	$ -		1,500	$ -	$ -	
Low Voltage Service Charge	per kWh	$ 0.0002	1,500	$ 0.30	$ 0.0003	1,500	$ 0.45	$ 0.15	50.00%
Line Losses on Cost of Power	per kWh	$ 0.1652	81	$ 13.43	$ 0.1652	80	$ 13.13	-$ 0.30	-2.21%
Smart Meter Entity Charge	Monthly	$ 0.7900	1	$ 0.79	$ 0.7900	1	$ 0.79	$ -	0.00%
Sub-Total B - Distribution (includes Sub-Total A)				**$ 58.21**			**$ 72.74**	**$ 14.53**	**24.97%**
RTSR - Network	per kWh	$ 0.0072	1,581	$ 11.39	$ 0.0069	1,580	$ 10.90	-$ 0.49	-4.28%
RTSR - Line and Transformation Connection	per kWh	$ 0.0058	1,581	$ 9.17	$ 0.0059	1,580	$ 9.32	$ 0.15	1.61%
Sub-Total C - Delivery (including Sub-Total B)				**$ 78.77**			**$ 92.96**	**$ 14.19**	**18.02%**
Wholesale Market Service Charge (WMSC)	per kWh	$ 0.0036	1,581	$ 5.69	$ 0.0036	1,580	$ 5.69	-$ 0.01	-0.11%
Rural and Remote Rate Protection (RRRP)	per kWh	$ 0.0013	1,581	$ 2.06	$ 0.0013	1,580	$ 2.05	-$ 0.00	-0.11%
Standard Supply Service Charge	Monthly	$ 0.2500	1	$ 0.25	$ 0.2500	1	$ 0.25	$ -	0.00%
Debt Retirement Charge (DRC)			1,500	$ -					
Ontario Electricity Support Program (OESP)	per kWh	$ 0.0011	1,581	$ 1.74	$ 0.0011	1,580	$ 1.74	-$ 0.00	-0.11%
Non-RPP Retailer Avg. Price + GA	per kWh	$ 0.1652	1,500	$ 247.80	$ 0.1652	1,500	$ 247.80	$ -	0.00%
Total Bill on Non-RPP Avg. Price				**$ 336.31**			**$ 350.49**	**$ 14.18**	**4.22%**
HST		13%		$ 43.72	13%		$ 45.56	$ 1.84	4.22%
Total Bill (including HST)				$ 380.03			$ 396.05	$ 16.03	4.22%
Ontario Clean Energy Benefit [1]									
Total Bill on Non-RPP Avg. Price				**$ 380.03**			**$ 396.05**	**$ 16.03**	**4.22%**

Customer Class:	Residential TOU - Fort Erie	
RPP / Non-RPP:	RPP	
Consumption	2,000	kWh
Demand	-	kW
Current Loss Factor	1.0542	
Proposed/Approved Loss Factor	1.0530	
Ontario Clean Energy Benefit Applied?	No	

		Current Board-Approved			Proposed			Impact	
	Charge Unit	**Rate ($)**	**Volume**	**Charge ($)**	**Rate ($)**	**Volume**	**Charge ($)**	**$ Change**	**% Change**
Monthly Service Charge	Monthly	$ 23.4400	1	$ 23.44	$ 30.4700	1	$ 30.47	$ 7.03	29.99%
Smart Meter Rate Adder			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
Distribution Volumetric Rate	per kWh	$ 0.0152	2,000	$ 30.40	$ 0.0116	2,000	$ 23.20	-$ 7.20	-23.68%
Smart Meter Disposition Rider			2,000	$ -		2,000	$ -	$ -	
LRAM & SSM Rate Rider	per kWh		2,000	$ -	$ 0.0003	2,000	$ 0.60	$ 0.60	
			2,000	$ -		2,000	$ -	$ -	
			2,000	$ -		2,000	$ -	$ -	
			2,000	$ -		2,000	$ -	$ -	
			2,000	$ -		2,000	$ -	$ -	
			2,000	$ -		2,000	$ -	$ -	
			2,000	$ -		2,000	$ -	$ -	
			2,000	$ -		2,000	$ -	$ -	
Sub-Total A (excluding pass through)				$ 53.84			$ 54.27	**$ 0.43**	**0.80%**
DVA - Total in Effect 2016	per kWh	$ 0.0004	2,000	$ 0.80		2,000	$ -	-$ 0.80	-100.00%
DVA - Total in Effect 2017 (Var)	per kWh		2,000	$ -	-$ 0.0044	2,000	-$ 8.80	-$ 8.80	
DVA - Total in Effect 2017 (Fixed)	Monthly		1	$ -	-$ 0.1500	1	-$ 0.15	-$ 0.15	
			2,000	$ -		2,000	$ -	$ -	
Low Voltage Service Charge	per kWh	$ 0.0002	2,000	$ 0.40	$ 0.0003	2,000	$ 0.60	$ 0.20	50.00%
Line Losses on Cost of Power	per kWh	$ 0.1077	108	$ 11.67	$ 0.1077	106	$ 11.41	-$ 0.26	-2.21%
Smart Meter Entity Charge	Monthly	$ 0.7900	1	$ 0.79	$ 0.7900	1	$ 0.79	$ -	0.00%
Sub-Total B - Distribution (includes Sub-Total A)				**$ 67.50**			**$ 58.12**	**-$ 9.38**	**-13.89%**
RTSR - Network	per kWh	$ 0.0072	2,108	$ 15.18	$ 0.0069	2,106	$ 14.53	-$ 0.65	-4.28%
RTSR - Line and Transformation Connection	per kWh	$ 0.0058	2,108	$ 12.23	$ 0.0059	2,106	$ 12.43	$ 0.20	1.61%
Sub-Total C - Delivery (including Sub-Total B)				**$ 94.91**			**$ 85.08**	**-$ 9.83**	**-10.36%**
Wholesale Market Service Charge (WMSC)	per kWh	$ 0.0036	2,108	$ 7.59	$ 0.0036	2,106	$ 7.58	-$ 0.01	-0.11%
Rural and Remote Rate Protection (RRRP)	per kWh	$ 0.0013	2,108	$ 2.74	$ 0.0013	2,106	$ 2.74	-$ 0.00	-0.11%
Standard Supply Service Charge	Monthly	$ 0.2500	1	$ 0.25	$ 0.2500	1	$ 0.25	$ -	0.00%
Debt Retirement Charge (DRC)			2,000	$ -					
Ontario Electricity Support Program (OESP)	per kWh	$ 0.0011	2,108	$ 2.32	$ 0.0011	2,106	$ 2.32	-$ 0.00	-0.11%
TOU - Off Peak	per kWh	$ 0.0830	1,280	$ 106.24	$ 0.0830	1,280	$ 106.24	$ -	0.00%
TOU - Mid Peak	per kWh	$ 0.1280	360	$ 46.08	$ 0.1280	360	$ 46.08	$ -	0.00%
TOU - On Peak	per kWh	$ 0.1750	360	$ 63.00	$ 0.1750	360	$ 63.00	$ -	0.00%
Total Bill on TOU (before Taxes)				**$ 323.13**			**$ 313.28**	**-$ 9.85**	**-3.05%**
HST		13%		$ 42.01	13%		$ 40.73	-$ 1.28	-3.05%
Total Bill (including HST)				$ 365.14			$ 354.01	-$ 11.13	-3.05%
Ontario Clean Energy Benefit [1]									
Total Bill on TOU				**$ 365.14**			**$ 354.01**	**-$ 11.13**	**-3.05%**

Customer Class:	Residential Retailer - Fort Erie	
RPP / Non-RPP:	Non-RPP (Retailer)	
Consumption	2,000	kWh
Demand	-	kW
Current Loss Factor	1.0542	
Proposed/Approved Loss Factor	1.0530	
Ontario Clean Energy Benefit Applied?	No	

		Current Board-Approved			Proposed			Impact	
	Charge Unit	Rate ($)	Volume	Charge ($)	Rate ($)	Volume	Charge ($)	$ Change	% Change
Monthly Service Charge	Monthly	$ 23.4400	1	$ 23.44	$ 30.4700	1	$ 30.47	$ 7.03	29.99%
Smart Meter Rate Adder			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
Distribution Volumetric Rate	per kWh	$ 0.0152	2,000	$ 30.40	$ 0.0116	2,000	$ 23.20	-$ 7.20	-23.68%
Smart Meter Disposition Rider			2,000	$ -		2,000	$ -	$ -	
LRAM & SSM Rate Rider	per kWh		2,000	$ -	$ 0.0003	2,000	$ 0.60	$ 0.60	
			2,000	$ -		2,000	$ -	$ -	
			2,000	$ -		2,000	$ -	$ -	
			2,000	$ -		2,000	$ -	$ -	
			2,000	$ -		2,000	$ -	$ -	
			2,000	$ -		2,000	$ -	$ -	
			2,000	$ -		2,000	$ -	$ -	
			2,000	$ -		2,000	$ -	$ -	
Sub-Total A (excluding pass through)				$ 53.84			$ 54.27	**$ 0.43**	**0.80%**
DVA - Total in Effect 2016	per kWh	$ 0.0016	2,000	$ 3.20		2,000	$ -	-$ 3.20	-100.00%
DVA - Total in Effect 2017 (Var)	per kWh		2,000	$ -	$ 0.0065	2,000	$ 13.00	$ 13.00	
DVA - Total in Effect 2017 (Fixed)	Monthly		1	$ -	-$ 0.1500	1	-$ 0.15	-$ 0.15	
			2,000	$ -		2,000	$ -	$ -	
Low Voltage Service Charge	per kWh	$ 0.0002	2,000	$ 0.40	$ 0.0003	2,000	$ 0.60	$ 0.20	50.00%
Line Losses on Cost of Power	per kWh	$ 0.1652	108	$ 17.91	$ 0.1652	106	$ 17.51	-$ 0.40	-2.21%
Smart Meter Entity Charge	Monthly	$ 0.7900	1	$ 0.79	$ 0.7900	1	$ 0.79	$ -	0.00%
Sub-Total B - Distribution (includes Sub-Total A)				**$ 76.14**			**$ 86.02**	**$ 9.88**	**12.98%**
RTSR - Network	per kWh	$ 0.0072	2,108	$ 15.18	$ 0.0069	2,106	$ 14.53	-$ 0.65	-4.28%
RTSR - Line and Transformation Connection	per kWh	$ 0.0058	2,108	$ 12.23	$ 0.0059	2,106	$ 12.43	$ 0.20	1.61%
Sub-Total C - Delivery (including Sub-Total B)				**$ 103.55**			**$ 112.98**	**$ 9.43**	**9.11%**
Wholesale Market Service Charge (WMSC)	per kWh	$ 0.0036	2,108	$ 7.59	$ 0.0036	2,106	$ 7.58	-$ 0.01	-0.11%
Rural and Remote Rate Protection (RRRP)	per kWh	$ 0.0013	2,108	$ 2.74	$ 0.0013	2,106	$ 2.74	-$ 0.00	-0.11%
Standard Supply Service Charge	Monthly	$ 0.2500	1	$ 0.25	$ 0.2500	1	$ 0.25	$ -	0.00%
Debt Retirement Charge (DRC)			2,000	$ -					
Ontario Electricity Support Program (OESP)	per kWh	$ 0.0011	2,108	$ 2.32	$ 0.0011	2,106	$ 2.32	-$ 0.00	-0.11%
Non-RPP Retailer Avg. Price + GA	per kWh	$ 0.1652	2,000	$ 330.40	$ 0.1652	2,000	$ 330.40	$ -	0.00%
Total Bill on Non-RPP Avg. Price				**$ 446.85**			**$ 456.26**	**$ 9.42**	**2.11%**
HST		13%		$ 58.09	13%		$ 59.31	$ 1.22	2.11%
Total Bill (including HST)				$ 504.94			$ 515.58	$ 10.64	2.11%
Ontario Clean Energy Benefit [1]									
Total Bill on Non-RPP Avg. Price				**$ 504.94**			**$ 515.58**	**$ 10.64**	**2.11%**

Customer Class:	Residential TOU - EOP	
RPP / Non-RPP:	RPP	
Consumption	2,000	kWh
Demand	-	kW
Current Loss Factor	1.0542	
Proposed/Approved Loss Factor	1.0530	
Ontario Clean Energy Benefit Applied?	No	

		Current Board-Approved			**Proposed**			**Impact**	
	Charge Unit	**Rate ($)**	**Volume**	**Charge ($)**	**Rate ($)**	**Volume**	**Charge ($)**	**$ Change**	**% Change**
Monthly Service Charge	Monthly	$ 23.4400	1	$ 23.44	$ 30.4700	1	$ 30.47	$ 7.03	29.99%
Smart Meter Rate Adder			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
Distribution Volumetric Rate	per kWh	$ 0.0152	2,000	$ 30.40	$ 0.0116	2,000	$ 23.20	-$ 7.20	-23.68%
Smart Meter Disposition Rider			2,000	$ -		2,000	$ -	$ -	
LRAM & SSM Rate Rider	per kWh		2,000	$ -	$ 0.0003	2,000	$ 0.60	$ 0.60	
			2,000	$ -		2,000	$ -	$ -	
			2,000	$ -		2,000	$ -	$ -	
			2,000	$ -		2,000	$ -	$ -	
			2,000	$ -		2,000	$ -	$ -	
			2,000	$ -		2,000	$ -	$ -	
			2,000	$ -		2,000	$ -	$ -	
			2,000	$ -		2,000	$ -	$ -	
Sub-Total A (excluding pass through)				$ 53.84			$ 54.27	**$ 0.43**	**0.80%**
DVA - Total in Effect 2016	per kWh	-$ 0.0024	2,000	-$ 4.80		2,000	$ -	$ 4.80	-100.00%
DVA - Total in Effect 2017 (Var)	per kWh		2,000	$ -	-$ 0.0044	2,000	-$ 8.80	-$ 8.80	
DVA - Total in Effect 2017 (Fixed)	Monthly		1	$ -	-$ 0.1500	1	-$ 0.15	-$ 0.15	
			2,000	$ -		2,000	$ -	$ -	
Low Voltage Service Charge	per kWh	$ 0.0002	2,000	$ 0.40	$ 0.0003	2,000	$ 0.60	$ 0.20	50.00%
Line Losses on Cost of Power	per kWh	$ 0.1077	108	$ 11.67	$ 0.1077	106	$ 11.41	-$ 0.26	-2.21%
Smart Meter Entity Charge	Monthly	$ 0.7900	1	$ 0.79	$ 0.7900	1	$ 0.79	$ -	0.00%
Sub-Total B - Distribution (includes Sub-Total A)				**$ 61.90**			**$ 58.12**	**-$ 3.78**	**-6.10%**
RTSR - Network	per kWh	$ 0.0072	2,108	$ 15.18	$ 0.0069	2,106	$ 14.53	-$ 0.65	-4.28%
RTSR - Line and Transformation Connection	per kWh	$ 0.0058	2,108	$ 12.23	$ 0.0059	2,106	$ 12.43	$ 0.20	1.61%
Sub-Total C - Delivery (including Sub-Total B)				**$ 89.31**			**$ 85.08**	**-$ 4.23**	**-4.74%**
Wholesale Market Service Charge (WMSC)	per kWh	$ 0.0036	2,108	$ 7.59	$ 0.0036	2,106	$ 7.58	-$ 0.01	-0.11%
Rural and Remote Rate Protection (RRRP)	per kWh	$ 0.0013	2,108	$ 2.74	$ 0.0013	2,106	$ 2.74	-$ 0.00	-0.11%
Standard Supply Service Charge	Monthly	$ 0.2500	1	$ 0.25	$ 0.2500	1	$ 0.25	$ -	0.00%
Debt Retirement Charge (DRC)			2,000	$ -					
Ontario Electricity Support Program (OESP)	per kWh	$ 0.0011	2,108	$ 2.32	$ 0.0011	2,106	$ 2.32	-$ 0.00	-0.11%
TOU - Off Peak	per kWh	$ 0.0830	1,280	$ 106.24	$ 0.0830	1,280	$ 106.24	$ -	0.00%
TOU - Mid Peak	per kWh	$ 0.1280	360	$ 46.08	$ 0.1280	360	$ 46.08	$ -	0.00%
TOU - On Peak	per kWh	$ 0.1750	360	$ 63.00	$ 0.1750	360	$ 63.00	$ -	0.00%
Total Bill on TOU (before Taxes)				**$ 317.53**			**$ 313.28**	**-$ 4.25**	**-1.34%**
HST		13%		$ 41.28	13%		$ 40.73	-$ 0.55	-1.34%
Total Bill (including HST)				$ 358.81			$ 354.01	-$ 4.80	-1.34%
Ontario Clean Energy Benefit [1]									
Total Bill on TOU				**$ 358.81**			**$ 354.01**	**-$ 4.80**	**-1.34%**

Customer Class:	Residential Retailer - EOP	
RPP / Non-RPP:	Non-RPP (Retailer)	
Consumption	2,000	kWh
Demand	-	kW
Current Loss Factor	1.0542	
Proposed/Approved Loss Factor	1.0530	
Ontario Clean Energy Benefit Applied?	No	

		Current Board-Approved			Proposed			Impact	
	Charge Unit	Rate ($)	Volume	Charge ($)	Rate ($)	Volume	Charge ($)	$ Change	% Change
Monthly Service Charge	Monthly	$ 23.4400	1	$ 23.44	$ 30.4700	1	$ 30.47	$ 7.03	29.99%
Smart Meter Rate Adder			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
Distribution Volumetric Rate	per kWh	$ 0.0152	2,000	$ 30.40	$ 0.0116	2,000	$ 23.20	-$ 7.20	-23.68%
Smart Meter Disposition Rider			2,000	$ -		2,000	$ -	$ -	
LRAM & SSM Rate Rider	per kWh		2,000	$ -	$ 0.0003	2,000	$ 0.60	$ 0.60	
			2,000	$ -		2,000	$ -	$ -	
			2,000	$ -		2,000	$ -	$ -	
			2,000	$ -		2,000	$ -	$ -	
			2,000	$ -		2,000	$ -	$ -	
			2,000	$ -		2,000	$ -	$ -	
			2,000	$ -		2,000	$ -	$ -	
			2,000	$ -		2,000	$ -	$ -	
Sub-Total A (excluding pass through)				$ 53.84			$ 54.27	**$ 0.43**	**0.80%**
DVA - Total in Effect 2016	per kWh	$ 0.0156	2,000	$ 31.20		2,000	$ -	-$ 31.20	-100.00%
DVA - Total in Effect 2017 (Var)	per kWh		2,000	$ -	$ 0.0065	2,000	$ 13.00	$ 13.00	
DVA - Total in Effect 2017 (Fixed)	Monthly		1	$ -	-$ 0.1500	1	-$ 0.15	-$ 0.15	
			2,000	$ -		2,000	$ -	$ -	
Low Voltage Service Charge	per kWh	$ 0.0002	2,000	$ 0.40	$ 0.0003	2,000	$ 0.60	$ 0.20	50.00%
Line Losses on Cost of Power	per kWh	$ 0.1652	108	$ 17.91	$ 0.1652	106	$ 17.51	-$ 0.40	-2.21%
Smart Meter Entity Charge	Monthly	$ 0.7900	1	$ 0.79	$ 0.7900	1	$ 0.79	$ -	0.00%
Sub-Total B - Distribution (includes Sub-Total A)				**$ 104.14**			**$ 86.02**	**-$ 18.12**	**-17.40%**
RTSR - Network	per kWh	$ 0.0072	2,108	$ 15.18	$ 0.0069	2,106	$ 14.53	-$ 0.65	-4.28%
RTSR - Line and Transformation Connection	per kWh	$ 0.0058	2,108	$ 12.23	$ 0.0059	2,106	$ 12.43	$ 0.20	1.61%
Sub-Total C - Delivery (including Sub-Total B)				**$ 131.55**			**$ 112.98**	**-$ 18.57**	**-14.12%**
Wholesale Market Service Charge (WMSC)	per kWh	$ 0.0036	2,108	$ 7.59	$ 0.0036	2,106	$ 7.58	-$ 0.01	-0.11%
Rural and Remote Rate Protection (RRRP)	per kWh	$ 0.0013	2,108	$ 2.74	$ 0.0013	2,106	$ 2.74	-$ 0.00	-0.11%
Standard Supply Service Charge	Monthly	$ 0.2500	1	$ 0.25	$ 0.2500	1	$ 0.25	$ -	0.00%
Debt Retirement Charge (DRC)			2,000	$ -					
Ontario Electricity Support Program (OESP)	per kWh	$ 0.0011	2,108	$ 2.32	$ 0.0011	2,106	$ 2.32	-$ 0.00	-0.11%
Non-RPP Retailer Avg. Price + GA	per kWh	$ 0.1652	2,000	$ 330.40	$ 0.1652	2,000	$ 330.40	$ -	0.00%
Total Bill on Non-RPP Avg. Price				**$ 474.85**			**$ 456.26**	**-$ 18.58**	**-3.91%**
HST		13%		$ 61.73	13%		$ 59.31	-$ 2.42	-3.91%
Total Bill (including HST)				$ 536.58			$ 515.58	-$ 21.00	-3.91%
Ontario Clean Energy Benefit [1]									
Total Bill on Non-RPP Avg. Price				**$ 536.58**			**$ 515.58**	**-$ 21.00**	**-3.91%**

Customer Class:	Residential TOU - Port Colborne	
RPP / Non-RPP:	RPP	
Consumption	2,000	kWh
Demand	-	kW
Current Loss Factor	1.0542	
Proposed/Approved Loss Factor	1.0530	
Ontario Clean Energy Benefit Applied?	No	

		Current Board-Approved			Proposed			Impact	
	Charge Unit	**Rate ($)**	**Volume**	**Charge ($)**	**Rate ($)**	**Volume**	**Charge ($)**	**$ Change**	**% Change**
Monthly Service Charge	Monthly	$ 23.4400	1	$ 23.44	$ 30.4700	1	$ 30.47	$ 7.03	29.99%
Smart Meter Rate Adder			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
Distribution Volumetric Rate	per kWh	$ 0.0152	2,000	$ 30.40	$ 0.0116	2,000	$ 23.20	-$ 7.20	-23.68%
Smart Meter Disposition Rider			2,000	$ -		2,000	$ -	$ -	
LRAM & SSM Rate Rider	per kWh		2,000	$ -	$ 0.0003	2,000	$ 0.60	$ 0.60	
			2,000	$ -		2,000	$ -	$ -	
			2,000	$ -		2,000	$ -	$ -	
			2,000	$ -		2,000	$ -	$ -	
			2,000	$ -		2,000	$ -	$ -	
			2,000	$ -		2,000	$ -	$ -	
			2,000	$ -		2,000	$ -	$ -	
			2,000	$ -		2,000	$ -	$ -	
Sub-Total A (excluding pass through)				$ 53.84			$ 54.27	**$ 0.43**	**0.80%**
DVA - Total in Effect 2016	per kWh	-$ 0.0013	2,000	-$ 2.60		2,000	$ -	$ 2.60	-100.00%
DVA - Total in Effect 2017 (Var)	per kWh		2,000	$ -	-$ 0.0044	2,000	-$ 8.80	-$ 8.80	
DVA - Total in Effect 2017 (Fixed)	Monthly		1	$ -	-$ 0.1500	1	-$ 0.15	-$ 0.15	
			2,000	$ -		2,000	$ -	$ -	
Low Voltage Service Charge	per kWh	$ 0.0002	2,000	$ 0.40	$ 0.0003	2,000	$ 0.60	$ 0.20	50.00%
Line Losses on Cost of Power	per kWh	$ 0.1077	108	$ 11.67	$ 0.1077	106	$ 11.41	-$ 0.26	-2.21%
Smart Meter Entity Charge	Monthly	$ 0.7900	1	$ 0.79	$ 0.7900	1	$ 0.79	$ -	0.00%
Sub-Total B - Distribution (includes Sub-Total A)				**$ 64.10**			**$ 58.12**	**-$ 5.98**	**-9.33%**
RTSR - Network	per kWh	$ 0.0072	2,108	$ 15.18	$ 0.0069	2,106	$ 14.53	-$ 0.65	-4.28%
RTSR - Line and Transformation Connection	per kWh	$ 0.0058	2,108	$ 12.23	$ 0.0059	2,106	$ 12.43	$ 0.20	1.61%
Sub-Total C - Delivery (including Sub-Total B)				**$ 91.51**			**$ 85.08**	**-$ 6.43**	**-7.03%**
Wholesale Market Service Charge (WMSC)	per kWh	$ 0.0036	2,108	$ 7.59	$ 0.0036	2,106	$ 7.58	-$ 0.01	-0.11%
Rural and Remote Rate Protection (RRRP)	per kWh	$ 0.0013	2,108	$ 2.74	$ 0.0013	2,106	$ 2.74	-$ 0.00	-0.11%
Standard Supply Service Charge	Monthly	$ 0.2500	1	$ 0.25	$ 0.2500	1	$ 0.25	$ -	0.00%
Debt Retirement Charge (DRC)			2,000	$ -					
Ontario Electricity Support Program (OESP)	per kWh	$ 0.0011	2,108	$ 2.32	$ 0.0011	2,106	$ 2.32	-$ 0.00	-0.11%
TOU - Off Peak	per kWh	$ 0.0830	1,280	$ 106.24	$ 0.0830	1,280	$ 106.24	$ -	0.00%
TOU - Mid Peak	per kWh	$ 0.1280	360	$ 46.08	$ 0.1280	360	$ 46.08	$ -	0.00%
TOU - On Peak	per kWh	$ 0.1750	360	$ 63.00	$ 0.1750	360	$ 63.00	$ -	0.00%
Total Bill on TOU (before Taxes)				**$ 319.73**			**$ 313.28**	**-$ 6.45**	**-2.02%**
HST		13%		$ 41.56	13%		$ 40.73	-$ 0.84	-2.02%
Total Bill (including HST)				$ 361.29			$ 354.01	-$ 7.28	-2.02%
Ontario Clean Energy Benefit [1]									
Total Bill on TOU				**$ 361.29**			**$ 354.01**	**-$ 7.28**	**-2.02%**

Customer Class:	Residential Retailer - Port Colborne	
RPP / Non-RPP:	Non-RPP (Retailer)	
Consumption	2,000	kWh
Demand	-	kW
Current Loss Factor	1.0542	
Proposed/Approved Loss Factor	1.0530	
Ontario Clean Energy Benefit Applied?	No	

		Current Board-Approved			Proposed			Impact	
	Charge Unit	**Rate ($)**	**Volume**	**Charge ($)**	**Rate ($)**	**Volume**	**Charge ($)**	**$ Change**	**% Change**
Monthly Service Charge	Monthly	$ 23.4400	1	$ 23.44	$ 30.4700	1	$ 30.47	$ 7.03	29.99%
Smart Meter Rate Adder			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
Distribution Volumetric Rate	per kWh	$ 0.0152	2,000	$ 30.40	$ 0.0116	2,000	$ 23.20	-$ 7.20	-23.68%
Smart Meter Disposition Rider			2,000	$ -		2,000	$ -	$ -	
LRAM & SSM Rate Rider	per kWh		2,000	$ -	$ 0.0003	2,000	$ 0.60	$ 0.60	
			2,000	$ -		2,000	$ -	$ -	
			2,000	$ -		2,000	$ -	$ -	
			2,000	$ -		2,000	$ -	$ -	
			2,000	$ -		2,000	$ -	$ -	
			2,000	$ -		2,000	$ -	$ -	
			2,000	$ -		2,000	$ -	$ -	
			2,000	$ -		2,000	$ -	$ -	
Sub-Total A (excluding pass through)				$ 53.84			$ 54.27	**$ 0.43**	**0.80%**
DVA - Total in Effect 2016	per kWh	-$ 0.0017	2,000	-$ 3.40		2,000	$ -	$ 3.40	-100.00%
DVA - Total in Effect 2017 (Var)	per kWh		2,000	$ -	$ 0.0065	2,000	$ 13.00	$ 13.00	
DVA - Total in Effect 2017 (Fixed)	Monthly		1	$ -	-$ 0.1500	1	-$ 0.15	-$ 0.15	
			2,000	$ -		2,000	$ -	$ -	
Low Voltage Service Charge	per kWh	$ 0.0002	2,000	$ 0.40	$ 0.0003	2,000	$ 0.60	$ 0.20	50.00%
Line Losses on Cost of Power	per kWh	$ 0.1652	108	$ 17.91	$ 0.1652	106	$ 17.51	-$ 0.40	-2.21%
Smart Meter Entity Charge	Monthly	$ 0.7900	1	$ 0.79	$ 0.7900	1	$ 0.79	$ -	0.00%
Sub-Total B - Distribution (includes Sub-Total A)				**$ 69.54**			**$ 86.02**	**$ 16.48**	**23.70%**
RTSR - Network	per kWh	$ 0.0072	2,108	$ 15.18	$ 0.0069	2,106	$ 14.53	-$ 0.65	-4.28%
RTSR - Line and Transformation Connection	per kWh	$ 0.0058	2,108	$ 12.23	$ 0.0059	2,106	$ 12.43	$ 0.20	1.61%
Sub-Total C - Delivery (including Sub-Total B)				**$ 96.95**			**$ 112.98**	**$ 16.03**	**16.54%**
Wholesale Market Service Charge (WMSC)	per kWh	$ 0.0036	2,108	$ 7.59	$ 0.0036	2,106	$ 7.58	-$ 0.01	-0.11%
Rural and Remote Rate Protection (RRRP)	per kWh	$ 0.0013	2,108	$ 2.74	$ 0.0013	2,106	$ 2.74	-$ 0.00	-0.11%
Standard Supply Service Charge	Monthly	$ 0.2500	1	$ 0.25	$ 0.2500	1	$ 0.25	$ -	0.00%
Debt Retirement Charge (DRC)			2,000	$ -					
Ontario Electricity Support Program (OESP)	per kWh	$ 0.0011	2,108	$ 2.32	$ 0.0011	2,106	$ 2.32	-$ 0.00	-0.11%
Non-RPP Retailer Avg. Price + GA	per kWh	$ 0.1652	2,000	$ 330.40	$ 0.1652	2,000	$ 330.40	$ -	0.00%
Total Bill on Non-RPP Avg. Price				**$ 440.25**			**$ 456.26**	**$ 16.02**	**3.64%**
HST		13%		$ 57.23	13%		$ 59.31	$ 2.08	3.64%
Total Bill (including HST)				$ 497.48			$ 515.58	$ 18.10	3.64%
***Ontario Clean Energy Benefit* [1]**									
Total Bill on Non-RPP Avg. Price				**$ 497.48**			**$ 515.58**	**$ 18.10**	**3.64%**

Customer Class:	**GS < 50 kW TOU - Fort Erie**	
RPP / Non-RPP:	**RPP**	
Consumption	**1,000**	**kWh**
Demand	**-**	**kW**
Current Loss Factor	**1.0542**	
Proposed/Approved Loss Factor	**1.0530**	
Ontario Clean Energy Benefit Applied?	**No**	

		Current Board-Approved			**Proposed**			**Impact**	
	Charge Unit	**Rate ($)**	**Volume**	**Charge ($)**	**Rate ($)**	**Volume**	**Charge ($)**	**$ Change**	**% Change**
Monthly Service Charge	Monthly	$ 28.2600	1	$ 28.26	$ 32.0200	1	$ 32.02	$ 3.76	13.31%
Smart Meter Rate Adder			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
Distribution Volumetric Rate	per kWh	$ 0.0230	1,000	$ 23.00	$ 0.0261	1,000	$ 26.10	$ 3.10	13.48%
Smart Meter Disposition Rider			1,000	$ -		1,000	$ -	$ -	
LRAM & SSM Rate Rider	per kWh		1,000	$ -	$ 0.0019	1,000	$ 1.90	$ 1.90	
			1,000	$ -		1,000	$ -	$ -	
			1,000	$ -		1,000	$ -	$ -	
			1,000	$ -		1,000	$ -	$ -	
			1,000	$ -		1,000	$ -	$ -	
			1,000	$ -		1,000	$ -	$ -	
			1,000	$ -		1,000	$ -	$ -	
			1,000	$ -		1,000	$ -	$ -	
Sub-Total A (excluding pass through)				$ 51.26			$ 60.02	**$ 8.76**	**17.09%**
DVA - Total in Effect 2016	per kWh	$ 0.0002	1,000	$ 0.20		1,000	$ -	-$ 0.20	-100.00%
DVA - Total in Effect 2017	per kWh		1,000	$ -	-$ 0.0048	1,000	-$ 4.80	-$ 4.80	
			1,000	$ -		1,000	$ -	$ -	
			1,000	$ -		1,000	$ -	$ -	
Low Voltage Service Charge	per kWh	$ 0.0002	1,000	$ 0.20	$ 0.0003	1,000	$ 0.30	$ 0.10	50.00%
Line Losses on Cost of Power	per kWh	$ 0.1077	54	$ 5.84	$ 0.1077	53	$ 5.71	-$ 0.13	-2.21%
Smart Meter Entity Charge	Monthly	$ 0.7900	1	$ 0.79	$ 0.7900	1	$ 0.79	$ -	0.00%
Sub-Total B - Distribution (includes Sub-Total A)				**$ 58.29**			**$ 62.02**	**$ 3.73**	**6.40%**
RTSR - Network	per kWh	$ 0.0061	1,054	$ 6.43	$ 0.0058	1,053	$ 6.11	-$ 0.32	-5.03%
RTSR - Line and Transformation Connection	per kWh	$ 0.0050	1,054	$ 5.27	$ 0.0050	1,053	$ 5.27	-$ 0.01	-0.11%
Sub-Total C - Delivery (including Sub-Total B)				**$ 69.99**			**$ 73.39**	**$ 3.40**	**4.86%**
Wholesale Market Service Charge (WMSC)	per kWh	$ 0.0036	1,054	$ 3.80	$ 0.0036	1,053	$ 3.79	-$ 0.00	-0.11%
Rural and Remote Rate Protection (RRRP)	per kWh	$ 0.0013	1,054	$ 1.37	$ 0.0013	1,053	$ 1.37	-$ 0.00	-0.11%
Standard Supply Service Charge	Monthly	$ 0.2500	1	$ 0.25	$ 0.2500	1	$ 0.25	$ -	0.00%
Debt Retirement Charge (DRC)			1,000	$ -		1,000	$ -	$ -	
Ontario Electricity Support Program (OESP)	per kWh	$ 0.0011	1,054	$ 1.16	$ 0.0011	1,053	$ 1.16	-$ 0.00	-0.11%
TOU - Off Peak	per kWh	$ 0.0830	640	$ 53.12	$ 0.0830	640	$ 53.12	$ -	0.00%
TOU - Mid Peak	per kWh	$ 0.1280	180	$ 23.04	$ 0.1280	180	$ 23.04	$ -	0.00%
TOU - On Peak	per kWh	$ 0.1750	180	$ 31.50	$ 0.1750	180	$ 31.50	$ -	0.00%
Total Bill on TOU (before Taxes)				**$ 184.22**			**$ 187.62**	**$ 3.39**	**1.84%**
HST		13%		$ 23.95	13%		$ 24.39	$ 0.44	1.84%
Total Bill (including HST)				$ 208.17			$ 212.01	$ 3.84	1.84%
Ontario Clean Energy Benefit [1]									
Total Bill on TOU				**$ 208.17**			**$ 212.01**	**$ 3.84**	**1.84%**

Customer Class:	**GS<50 kW Retailer - Fort Erie**
RPP / Non-RPP:	**Non-RPP (Retailer)**
Consumption	**1,000** kWh
Demand	**0** kW
Current Loss Factor	**1.0542**
Proposed/Approved Loss Factor	**1.0530**
Ontario Clean Energy Benefit Applied?	**No**

		Current Board-Approved			Proposed			Impact	
	Charge Unit	**Rate ($)**	**Volume**	**Charge ($)**	**Rate ($)**	**Volume**	**Charge ($)**	**$ Change**	**% Change**
Monthly Service Charge	Monthly	$ 28.2600	1	$ 28.26	$ 32.0200	1	$ 32.02	$ 3.76	13.31%
Smart Meter Rate Adder			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
Distribution Volumetric Rate	per kWh	$ 0.0230	1,000	$ 23.00	$ 0.0261	1,000	$ 26.10	$ 3.10	13.48%
Smart Meter Disposition Rider			1,000	$ -		1,000	$ -	$ -	
LRAM & SSM Rate Rider	per kWh		1,000	$ -	$ 0.0019	1,000	$ 1.90	$ 1.90	
			1,000	$ -		1,000	$ -	$ -	
			1,000	$ -		1,000	$ -	$ -	
			1,000	$ -		1,000	$ -	$ -	
			1,000	$ -		1,000	$ -	$ -	
			1,000	$ -		1,000	$ -	$ -	
			1,000	$ -		1,000	$ -	$ -	
			1,000	$ -		1,000	$ -	$ -	
Sub-Total A (excluding pass through)				$ 51.26			$ 60.02	**$ 8.76**	**17.09%**
DVA - Total in Effect 2016	per kWh	$ 0.0014	1,000	$ 1.40		1,000	$ -	-$ 1.40	-100.00%
DVA - Total in Effect 2017	per kWh		1,000	$ -	$ 0.0059	1,000	$ 5.90	$ 5.90	
			1,000	$ -		1,000	$ -	$ -	
			1,000	$ -		1,000	$ -	$ -	
Low Voltage Service Charge	per kWh	$ 0.0002	1,000	$ 0.20	$ 0.0003	1,000	$ 0.30	$ 0.10	50.00%
Line Losses on Cost of Power	per kWh	$ 0.1652	54	$ 8.95	$ 0.1652	53	$ 8.76	-$ 0.20	-2.21%
Smart Meter Entity Charge	Monthly	$ 0.7900	1	$ 0.79	$ 0.7900	1	$ 0.79	$ -	0.00%
Sub-Total B - Distribution (includes Sub-Total A)				**$ 62.60**			**$ 75.77**	**$ 13.16**	**21.02%**
RTSR - Network	per kWh	$ 0.0061	1,054	$ 6.43	$ 0.0058	1,053	$ 6.11	-$ 0.32	-5.03%
RTSR - Line and Transformation Connection	per kWh	$ 0.0050	1,054	$ 5.27	$ 0.0050	1,053	$ 5.27	-$ 0.01	-0.11%
Sub-Total C - Delivery (including Sub-Total B)				**$ 74.31**			**$ 87.14**	**$ 12.83**	**17.27%**
Wholesale Market Service Charge (WMSC)	per kWh	$ 0.0036	1,054	$ 3.80	$ 0.0036	1,053	$ 3.79	-$ 0.00	-0.11%
Rural and Remote Rate Protection (RRRP)	per kWh	$ 0.0013	1,054	$ 1.37	$ 0.0013	1,053	$ 1.37	-$ 0.00	-0.11%
Standard Supply Service Charge	Monthly	$ 0.2500	1	$ 0.25	$ 0.2500	1	$ 0.25	$ -	0.00%
Debt Retirement Charge (DRC)			1,000	$ -		1,000	$ -	$ -	
Ontario Electricity Support Program (OESP)	per kWh	$ 0.0011	1,054	$ 1.16	$ 0.0011	1,053	$ 1.16	-$ 0.00	-0.11%
Non-RPP Retailer Avg. Price + GA	per kWh	$ 0.1652	1,000	$ 165.20	$ 0.1652	1,000	$ 165.20	$ -	0.00%
Total Bill on Non-RPP Avg. Price				**$ 246.08**			**$ 258.91**	**$ 12.83**	**5.21%**
HST		13%		$ 31.99	13%		$ 33.66	$ 1.67	5.21%
Total Bill (including HST)				$ 278.07			$ 292.56	$ 14.49	5.21%
Ontario Clean Energy Benefit [1]									
Total Bill on Non-RPP Avg. Price				**$ 278.07**			**$ 292.56**	**$ 14.49**	**5.21%**

Customer Class:	**GS < 50 kW TOU - EOP**	
RPP / Non-RPP:	**RPP**	
Consumption	**1,000**	**kWh**
Demand	**-**	**kW**
Current Loss Factor	**1.0542**	
Proposed/Approved Loss Factor	**1.0530**	
Ontario Clean Energy Benefit Applied?	**No**	

		Current Board-Approved			**Proposed**			**Impact**	
	Charge Unit	**Rate ($)**	**Volume**	**Charge ($)**	**Rate ($)**	**Volume**	**Charge ($)**	**$ Change**	**% Change**
Monthly Service Charge	Monthly	$ 28.2600	1	$ 28.26	$ 32.0200	1	$ 32.02	$ 3.76	13.31%
Smart Meter Rate Adder			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
Distribution Volumetric Rate	per kWh	$ 0.0230	1,000	$ 23.00	$ 0.0261	1,000	$ 26.10	$ 3.10	13.48%
Smart Meter Disposition Rider			1,000	$ -		1,000	$ -	$ -	
LRAM & SSM Rate Rider	per kWh		1,000	$ -	$ 0.0019	1,000	$ 1.90	$ 1.90	
			1,000	$ -		1,000	$ -	$ -	
			1,000	$ -		1,000	$ -	$ -	
			1,000	$ -		1,000	$ -	$ -	
			1,000	$ -		1,000	$ -	$ -	
			1,000	$ -		1,000	$ -	$ -	
			1,000	$ -		1,000	$ -	$ -	
			1,000	$ -		1,000	$ -	$ -	
Sub-Total A (excluding pass through)				$ 51.26			$ 60.02	**$ 8.76**	**17.09%**
DVA - Total in Effect 2016	per kWh	-$ 0.0024	1,000	-$ 2.40	-$ 0.0048	1,000	-$ 4.80	-$ 2.40	100.00%
DVA - Total in Effect 2017	per kWh		1,000	$ -		1,000	$ -	$ -	
			1,000	$ -		1,000	$ -	$ -	
			1,000	$ -		1,000	$ -	$ -	
Low Voltage Service Charge	per kWh	$ 0.0002	1,000	$ 0.20	$ 0.0003	1,000	$ 0.30	$ 0.10	50.00%
Line Losses on Cost of Power	per kWh	$ 0.1077	54	$ 5.84	$ 0.1077	53	$ 5.71	-$ 0.13	-2.21%
Smart Meter Entity Charge	Monthly	$ 0.7900	1	$ 0.79	$ 0.7900	1	$ 0.79	$ -	0.00%
Sub-Total B - Distribution (includes Sub-Total A)				**$ 55.69**			**$ 62.02**	**$ 6.33**	**11.37%**
RTSR - Network	per kWh	$ 0.0061	1,054	$ 6.43	$ 0.0058	1,053	$ 6.11	-$ 0.32	-5.03%
RTSR - Line and Transformation Connection	per kWh	$ 0.0050	1,054	$ 5.27	$ 0.0050	1,053	$ 5.27	-$ 0.01	-0.11%
Sub-Total C - Delivery (including Sub-Total B)				**$ 67.39**			**$ 73.39**	**$ 6.00**	**8.91%**
Wholesale Market Service Charge (WMSC)	per kWh	$ 0.0036	1,054	$ 3.80	$ 0.0036	1,053	$ 3.79	-$ 0.00	-0.11%
Rural and Remote Rate Protection (RRRP)	per kWh	$ 0.0013	1,054	$ 1.37	$ 0.0013	1,053	$ 1.37	-$ 0.00	-0.11%
Standard Supply Service Charge	Monthly	$ 0.2500	1	$ 0.25	$ 0.2500	1	$ 0.25	$ -	0.00%
Debt Retirement Charge (DRC)			1,000	$ -		1,000	$ -	$ -	
Ontario Electricity Support Program (OESP)	per kWh	$ 0.0011	1,054	$ 1.16	$ 0.0011	1,053	$ 1.16	-$ 0.00	-0.11%
TOU - Off Peak	per kWh	$ 0.0830	640	$ 53.12	$ 0.0830	640	$ 53.12	$ -	0.00%
TOU - Mid Peak	per kWh	$ 0.1280	180	$ 23.04	$ 0.1280	180	$ 23.04	$ -	0.00%
TOU - On Peak	per kWh	$ 0.1750	180	$ 31.50	$ 0.1750	180	$ 31.50	$ -	0.00%
Total Bill on TOU (before Taxes)				**$ 181.62**			**$ 187.62**	**$ 5.99**	**3.30%**
HST		13%		$ 23.61	13%		$ 24.39	$ 0.78	3.30%
Total Bill (including HST)				$ 205.23			$ 212.01	$ 6.77	3.30%
Ontario Clean Energy Benefit [1]									
Total Bill on TOU				**$ 205.23**			**$ 212.01**	**$ 6.77**	**3.30%**

Customer Class:	**GS<50 kW Retailer - EOP**	
RPP / Non-RPP:	**Non-RPP (Retailer)**	
Consumption	**1,000**	**kWh**
Demand	**0**	**kW**
Current Loss Factor	**1.0542**	
Proposed/Approved Loss Factor	**1.0530**	
Ontario Clean Energy Benefit Applied?	**No**	

		Current Board-Approved			**Proposed**			**Impact**	
	Charge Unit	**Rate ($)**	**Volume**	**Charge ($)**	**Rate ($)**	**Volume**	**Charge ($)**	**$ Change**	**% Change**
Monthly Service Charge	Monthly	$ 28.2600	1	$ 28.26	$ 32.0200	1	$ 32.02	$ 3.76	13.31%
Smart Meter Rate Adder			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
Distribution Volumetric Rate	per kWh	$ 0.0230	1,000	$ 23.00	$ 0.0261	1,000	$ 26.10	$ 3.10	13.48%
Smart Meter Disposition Rider			1,000	$ -		1,000	$ -	$ -	
LRAM & SSM Rate Rider	per kWh		1,000	$ -	$ 0.0019	1,000	$ 1.90	$ 1.90	
			1,000	$ -		1,000	$ -	$ -	
			1,000	$ -		1,000	$ -	$ -	
			1,000	$ -		1,000	$ -	$ -	
			1,000	$ -		1,000	$ -	$ -	
			1,000	$ -		1,000	$ -	$ -	
			1,000	$ -		1,000	$ -	$ -	
			1,000	$ -		1,000	$ -	$ -	
Sub-Total A (excluding pass through)				$ 51.26			$ 60.02	**$ 8.76**	**17.09%**
DVA - Total in Effect 2016	per kWh	$ 0.0156	1,000	$ 15.60		1,000	$ -	-$ 15.60	-100.00%
DVA - Total in Effect 2017	per kWh		1,000	$ -	$ 0.0059	1,000	$ 5.90	$ 5.90	
			1,000	$ -		1,000	$ -	$ -	
			1,000	$ -		1,000	$ -	$ -	
Low Voltage Service Charge	per kWh	$ 0.0002	1,000	$ 0.20	$ 0.0003	1,000	$ 0.30	$ 0.10	50.00%
Line Losses on Cost of Power	per kWh	$ 0.1652	54	$ 8.95	$ 0.1652	53	$ 8.76	-$ 0.20	-2.21%
Smart Meter Entity Charge	Monthly	$ 0.7900	1	$ 0.79	$ 0.7900	1	$ 0.79	$ -	0.00%
Sub-Total B - Distribution (includes Sub-Total A)				**$ 76.80**			**$ 75.77**	**-$ 1.04**	**-1.35%**
RTSR - Network	per kWh	$ 0.0061	1,054	$ 6.43	$ 0.0058	1,053	$ 6.11	-$ 0.32	-5.03%
RTSR - Line and Transformation Connection	per kWh	$ 0.0050	1,054	$ 5.27	$ 0.0050	1,053	$ 5.27	-$ 0.01	-0.11%
Sub-Total C - Delivery (including Sub-Total B)				**$ 88.51**			**$ 87.14**	**-$ 1.37**	**-1.55%**
Wholesale Market Service Charge (WMSC)	per kWh	$ 0.0036	1,054	$ 3.80	$ 0.0036	1,053	$ 3.79	-$ 0.00	-0.11%
Rural and Remote Rate Protection (RRRP)	per kWh	$ 0.0013	1,054	$ 1.37	$ 0.0013	1,053	$ 1.37	-$ 0.00	-0.11%
Standard Supply Service Charge	Monthly	$ 0.2500	1	$ 0.25	$ 0.2500	1	$ 0.25	$ -	0.00%
Debt Retirement Charge (DRC)			1,000	$ -		1,000	$ -	$ -	
Ontario Electricity Support Program (OESP)	per kWh	$ 0.0011	1,054	$ 1.16	$ 0.0011	1,053	$ 1.16	-$ 0.00	-0.11%
Non-RPP Retailer Avg. Price + GA	per kWh	$ 0.1652	1,000	$ 165.20	$ 0.1652	1,000	$ 165.20	$ -	0.00%
Total Bill on Non-RPP Avg. Price				**$ 260.28**			**$ 258.91**	**-$ 1.37**	**-0.53%**
HST		13%		$ 33.84	13%		$ 33.66	-$ 0.18	-0.53%
Total Bill (including HST)				$ 294.12			$ 292.56	-$ 1.55	-0.53%
Ontario Clean Energy Benefit [1]									
Total Bill on Non-RPP Avg. Price				**$ 294.12**			**$ 292.56**	**-$ 1.55**	**-0.53%**

Customer Class:	**GS < 50 kW TOU - Port Colborne**	
RPP / Non-RPP:	**RPP**	
Consumption	**1,000**	**kWh**
Demand	**-**	**kW**
Current Loss Factor	**1.0542**	
Proposed/Approved Loss Factor	**1.0530**	
Ontario Clean Energy Benefit Applied?	**No**	

		Current Board-Approved			**Proposed**			**Impact**	
	Charge Unit	**Rate ($)**	**Volume**	**Charge ($)**	**Rate ($)**	**Volume**	**Charge ($)**	**$ Change**	**% Change**
Monthly Service Charge	Monthly	$ 28.2600	1	$ 28.26	$ 32.0200	1	$ 32.02	$ 3.76	13.31%
Smart Meter Rate Adder			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
Distribution Volumetric Rate	per kWh	$ 0.0230	1,000	$ 23.00	$ 0.0261	1,000	$ 26.10	$ 3.10	13.48%
Smart Meter Disposition Rider			1,000	$ -		1,000	$ -	$ -	
LRAM & SSM Rate Rider	per kWh		1,000	$ -	$ 0.0019	1,000	$ 1.90	$ 1.90	
			1,000	$ -		1,000	$ -	$ -	
			1,000	$ -		1,000	$ -	$ -	
			1,000	$ -		1,000	$ -	$ -	
			1,000	$ -		1,000	$ -	$ -	
			1,000	$ -		1,000	$ -	$ -	
			1,000	$ -		1,000	$ -	$ -	
			1,000	$ -		1,000	$ -	$ -	
Sub-Total A (excluding pass through)				$ 51.26			$ 60.02	**$ 8.76**	**17.09%**
DVA - Total in Effect 2016	per kWh	-$ 0.0014	1,000	-$ 1.40	-$ 0.0048	1,000	-$ 4.80	-$ 3.40	242.86%
DVA - Total in Effect 2017	per kWh		1,000	$ -		1,000	$ -	$ -	
			1,000	$ -		1,000	$ -	$ -	
			1,000	$ -		1,000	$ -	$ -	
Low Voltage Service Charge	per kWh	$ 0.0002	1,000	$ 0.20	$ 0.0003	1,000	$ 0.30	$ 0.10	50.00%
Line Losses on Cost of Power	per kWh	$ 0.1077	54	$ 5.84	$ 0.1077	53	$ 5.71	-$ 0.13	-2.21%
Smart Meter Entity Charge	Monthly	$ 0.7900	1	$ 0.79	$ 0.7900	1	$ 0.79	$ -	0.00%
Sub-Total B - Distribution (includes Sub-Total A)				**$ 56.69**			**$ 62.02**	**$ 5.33**	**9.40%**
RTSR - Network	per kWh	$ 0.0061	1,054	$ 6.43	$ 0.0058	1,053	$ 6.11	-$ 0.32	-5.03%
RTSR - Line and Transformation Connection	per kWh	$ 0.0050	1,054	$ 5.27	$ 0.0050	1,053	$ 5.27	-$ 0.01	-0.11%
Sub-Total C - Delivery (including Sub-Total B)				**$ 68.39**			**$ 73.39**	**$ 5.00**	**7.31%**
Wholesale Market Service Charge (WMSC)	per kWh	$ 0.0036	1,054	$ 3.80	$ 0.0036	1,053	$ 3.79	-$ 0.00	-0.11%
Rural and Remote Rate Protection (RRRP)	per kWh	$ 0.0013	1,054	$ 1.37	$ 0.0013	1,053	$ 1.37	-$ 0.00	-0.11%
Standard Supply Service Charge	Monthly	$ 0.2500	1	$ 0.25	$ 0.2500	1	$ 0.25	$ -	0.00%
Debt Retirement Charge (DRC)			1,000	$ -		1,000	$ -	$ -	
Ontario Electricity Support Program (OESP)	per kWh	$ 0.0011	1,054	$ 1.16	$ 0.0011	1,053	$ 1.16	-$ 0.00	-0.11%
TOU - Off Peak	per kWh	$ 0.0830	640	$ 53.12	$ 0.0830	640	$ 53.12	$ -	0.00%
TOU - Mid Peak	per kWh	$ 0.1280	180	$ 23.04	$ 0.1280	180	$ 23.04	$ -	0.00%
TOU - On Peak	per kWh	$ 0.1750	180	$ 31.50	$ 0.1750	180	$ 31.50	$ -	0.00%
Total Bill on TOU (before Taxes)				**$ 182.62**			**$ 187.62**	**$ 4.99**	**2.73%**
HST		13%		$ 23.74	13%		$ 24.39	$ 0.65	2.73%
Total Bill (including HST)				$ 206.36			$ 212.01	$ 5.64	2.73%
Ontario Clean Energy Benefit [1]									
Total Bill on TOU				**$ 206.36**			**$ 212.01**	**$ 5.64**	**2.73%**

Customer Class:	**GS<50 kW Retailer - Port Colborne**	
RPP / Non-RPP:	**Non-RPP (Retailer)**	
Consumption	**1,000**	**kWh**
Demand	**0**	**kW**
Current Loss Factor	**1.0542**	
Proposed/Approved Loss Factor	**1.0530**	
Ontario Clean Energy Benefit Applied?	**No**	

		Current Board-Approved			**Proposed**			**Impact**	
	Charge Unit	**Rate ($)**	**Volume**	**Charge ($)**	**Rate ($)**	**Volume**	**Charge ($)**	**$ Change**	**% Change**
Monthly Service Charge	Monthly	$ 28.2600	1	$ 28.26	$ 32.0200	1	$ 32.02	$ 3.76	13.31%
Smart Meter Rate Adder			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
Distribution Volumetric Rate	per kWh	$ 0.0230	1,000	$ 23.00	$ 0.0261	1,000	$ 26.10	$ 3.10	13.48%
Smart Meter Disposition Rider			1,000	$ -		1,000	$ -	$ -	
LRAM & SSM Rate Rider	per kWh		1,000	$ -	$ 0.0019	1,000	$ 1.90	$ 1.90	
			1,000	$ -		1,000	$ -	$ -	
			1,000	$ -		1,000	$ -	$ -	
			1,000	$ -		1,000	$ -	$ -	
			1,000	$ -		1,000	$ -	$ -	
			1,000	$ -		1,000	$ -	$ -	
			1,000	$ -		1,000	$ -	$ -	
			1,000	$ -		1,000	$ -	$ -	
Sub-Total A (excluding pass through)				$ 51.26			$ 60.02	**$ 8.76**	**17.09%**
DVA - Total in Effect 2016	per kWh	-$ 0.0018	1,000	-$ 1.80		1,000	$ -	$ 1.80	-100.00%
DVA - Total in Effect 2017	per kWh		1,000	$ -	$ 0.0059	1,000	$ 5.90	$ 5.90	
			1,000	$ -		1,000	$ -	$ -	
			1,000	$ -		1,000	$ -	$ -	
Low Voltage Service Charge	per kWh	$ 0.0002	1,000	$ 0.20	$ 0.0003	1,000	$ 0.30	$ 0.10	50.00%
Line Losses on Cost of Power	per kWh	$ 0.1652	54	$ 8.95	$ 0.1652	53	$ 8.76	-$ 0.20	-2.21%
Smart Meter Entity Charge	Monthly	$ 0.7900	1	$ 0.79	$ 0.7900	1	$ 0.79	$ -	0.00%
Sub-Total B - Distribution (includes Sub-Total A)				**$ 59.40**			**$ 75.77**	**$ 16.36**	**27.54%**
RTSR - Network	per kWh	$ 0.0061	1,054	$ 6.43	$ 0.0058	1,053	$ 6.11	-$ 0.32	-5.03%
RTSR - Line and Transformation Connection	per kWh	$ 0.0050	1,054	$ 5.27	$ 0.0050	1,053	$ 5.27	-$ 0.01	-0.11%
Sub-Total C - Delivery (including Sub-Total B)				**$ 71.11**			**$ 87.14**	**$ 16.03**	**22.55%**
Wholesale Market Service Charge (WMSC)	per kWh	$ 0.0036	1,054	$ 3.80	$ 0.0036	1,053	$ 3.79	-$ 0.00	-0.11%
Rural and Remote Rate Protection (RRRP)	per kWh	$ 0.0013	1,054	$ 1.37	$ 0.0013	1,053	$ 1.37	-$ 0.00	-0.11%
Standard Supply Service Charge	Monthly	$ 0.2500	1	$ 0.25	$ 0.2500	1	$ 0.25	$ -	0.00%
Debt Retirement Charge (DRC)			1,000	$ -		1,000	$ -	$ -	
Ontario Electricity Support Program (OESP)	per kWh	$ 0.0011	1,054	$ 1.16	$ 0.0011	1,053	$ 1.16	-$ 0.00	-0.11%
Non-RPP Retailer Avg. Price + GA	per kWh	$ 0.1652	1,000	$ 165.20	$ 0.1652	1,000	$ 165.20	$ -	0.00%
Total Bill on Non-RPP Avg. Price				**$ 242.88**			**$ 258.91**	**$ 16.03**	**6.60%**
HST		13%		$ 31.57	13%		$ 33.66	$ 2.08	6.60%
Total Bill (including HST)				$ 274.46			$ 292.56	$ 18.11	6.60%
Ontario Clean Energy Benefit [1]									
Total Bill on Non-RPP Avg. Price				**$ 274.46**			**$ 292.56**	**$ 18.11**	**6.60%**

Customer Class:	**GS < 50 kW TOU - Fort Erie**	
RPP / Non-RPP:	**RPP**	
Consumption	**2,000**	**kWh**
Demand	**-**	**kW**
Current Loss Factor	**1.0542**	
Proposed/Approved Loss Factor	**1.0530**	
Ontario Clean Energy Benefit Applied?	**No**	

		Current Board-Approved			**Proposed**			**Impact**	
	Charge Unit	**Rate ($)**	**Volume**	**Charge ($)**	**Rate ($)**	**Volume**	**Charge ($)**	**$ Change**	**% Change**
Monthly Service Charge	Monthly	$ 28.2600	1	$ 28.26	$ 32.0200	1	$ 32.02	$ 3.76	13.31%
Smart Meter Rate Adder			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
Distribution Volumetric Rate	per kWh	$ 0.0230	2,000	$ 46.00	$ 0.0261	2,000	$ 52.20	$ 6.20	13.48%
Smart Meter Disposition Rider			2,000	$ -		2,000	$ -	$ -	
LRAM & SSM Rate Rider	per kWh		2,000	$ -	$ 0.0019	2,000	$ 3.80	$ 3.80	
			2,000	$ -		2,000	$ -	$ -	
			2,000	$ -		2,000	$ -	$ -	
			2,000	$ -		2,000	$ -	$ -	
			2,000	$ -		2,000	$ -	$ -	
			2,000	$ -		2,000	$ -	$ -	
			2,000	$ -		2,000	$ -	$ -	
			2,000	$ -		2,000	$ -	$ -	
Sub-Total A (excluding pass through)				$ 74.26			$ 88.02	**$ 13.76**	**18.53%**
DVA - Total in Effect 2016	per kWh	$ 0.0002	2,000	$ 0.40		2,000	$ -	-$ 0.40	-100.00%
DVA - Total in Effect 2017	per kWh		2,000	$ -	-$ 0.0048	2,000	-$ 9.60	-$ 9.60	
			2,000	$ -		2,000	$ -	$ -	
			2,000	$ -		2,000	$ -	$ -	
Low Voltage Service Charge	per kWh	$ 0.0002	2,000	$ 0.40	$ 0.0003	2,000	$ 0.60	$ 0.20	50.00%
Line Losses on Cost of Power	per kWh	$ 0.1077	108	$ 11.67	$ 0.1077	106	$ 11.41	-$ 0.26	-2.21%
Smart Meter Entity Charge	Monthly	$ 0.7900	1	$ 0.79	$ 0.7900	1	$ 0.79	$ -	0.00%
Sub-Total B - Distribution (includes Sub-Total A)				**$ 87.52**			**$ 91.22**	**$ 3.70**	**4.23%**
RTSR - Network	per kWh	$ 0.0061	2,108	$ 12.86	$ 0.0058	2,106	$ 12.21	-$ 0.65	-5.03%
RTSR - Line and Transformation Connection	per kWh	$ 0.0050	2,108	$ 10.54	$ 0.0050	2,106	$ 10.53	-$ 0.01	-0.11%
Sub-Total C - Delivery (including Sub-Total B)				**$ 110.92**			**$ 113.97**	**$ 3.04**	**2.74%**
Wholesale Market Service Charge (WMSC)	per kWh	$ 0.0036	2,108	$ 7.59	$ 0.0036	2,106	$ 7.58	-$ 0.01	-0.11%
Rural and Remote Rate Protection (RRRP)	per kWh	$ 0.0013	2,108	$ 2.74	$ 0.0013	2,106	$ 2.74	-$ 0.00	-0.11%
Standard Supply Service Charge	Monthly	$ 0.2500	1	$ 0.25	$ 0.2500	1	$ 0.25	$ -	0.00%
Debt Retirement Charge (DRC)			2,000	$ -		2,000	$ -	$ -	
Ontario Electricity Support Program (OESP)	per kWh	$ 0.0011	2,108	$ 2.32	$ 0.0011	2,106	$ 2.32	-$ 0.00	-0.11%
TOU - Off Peak	per kWh	$ 0.0830	1,280	$ 106.24	$ 0.0830	1,280	$ 106.24	$ -	0.00%
TOU - Mid Peak	per kWh	$ 0.1280	360	$ 46.08	$ 0.1280	360	$ 46.08	$ -	0.00%
TOU - On Peak	per kWh	$ 0.1750	360	$ 63.00	$ 0.1750	360	$ 63.00	$ -	0.00%
Total Bill on TOU (before Taxes)				**$ 339.14**			**$ 342.17**	**$ 3.03**	**0.89%**
HST		13%		$ 44.09	13%		$ 44.48	$ 0.39	0.89%
Total Bill (including HST)				$ 383.23			$ 386.66	$ 3.42	0.89%
Ontario Clean Energy Benefit [1]									
Total Bill on TOU				**$ 383.23**			**$ 386.66**	**$ 3.42**	**0.89%**

Customer Class:	**GS<50 kW Retailer - Fort Erie**	
RPP / Non-RPP:	**Non-RPP (Retailer)**	
Consumption	**2,000**	**kWh**
Demand	**0**	**kW**
Current Loss Factor	**1.0542**	
Proposed/Approved Loss Factor	**1.0530**	
Ontario Clean Energy Benefit Applied?	**No**	

		Current Board-Approved			Proposed			Impact	
	Charge Unit	**Rate ($)**	**Volume**	**Charge ($)**	**Rate ($)**	**Volume**	**Charge ($)**	**$ Change**	**% Change**
Monthly Service Charge	Monthly	$ 28.2600	1	$ 28.26	$ 32.0200	1	$ 32.02	$ 3.76	13.31%
Smart Meter Rate Adder			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
Distribution Volumetric Rate	per kWh	$ 0.0230	2,000	$ 46.00	$ 0.0261	2,000	$ 52.20	$ 6.20	13.48%
Smart Meter Disposition Rider			2,000	$ -		2,000	$ -	$ -	
LRAM & SSM Rate Rider	per kWh		2,000	$ -	$ 0.0019	2,000	$ 3.80	$ 3.80	
			2,000	$ -		2,000	$ -	$ -	
			2,000	$ -		2,000	$ -	$ -	
			2,000	$ -		2,000	$ -	$ -	
			2,000	$ -		2,000	$ -	$ -	
			2,000	$ -		2,000	$ -	$ -	
			2,000	$ -		2,000	$ -	$ -	
			2,000	$ -		2,000	$ -	$ -	
Sub-Total A (excluding pass through)				$ 74.26			$ 88.02	**$ 13.76**	**18.53%**
DVA - Total in Effect 2016	per kWh	$ 0.0014	2,000	$ 2.80		2,000	$ -	-$ 2.80	-100.00%
DVA - Total in Effect 2017	per kWh		2,000	$ -	$ 0.0059	2,000	$ 11.80	$ 11.80	
			2,000	$ -		2,000	$ -	$ -	
			2,000	$ -		2,000	$ -	$ -	
Low Voltage Service Charge	per kWh	$ 0.0002	2,000	$ 0.40	$ 0.0003	2,000	$ 0.60	$ 0.20	50.00%
Line Losses on Cost of Power	per kWh	$ 0.1652	108	$ 17.91	$ 0.1652	106	$ 17.51	-$ 0.40	-2.21%
Smart Meter Entity Charge	Monthly	$ 0.7900	1	$ 0.79	$ 0.7900	1	$ 0.79	$ -	0.00%
Sub-Total B - Distribution (includes Sub-Total A)				**$ 96.16**			**$ 118.72**	**$ 22.56**	**23.47%**
RTSR - Network	per kWh	$ 0.0061	2,108	$ 12.86	$ 0.0058	2,106	$ 12.21	-$ 0.65	-5.03%
RTSR - Line and Transformation Connection	per kWh	$ 0.0050	2,108	$ 10.54	$ 0.0050	2,106	$ 10.53	-$ 0.01	-0.11%
Sub-Total C - Delivery (including Sub-Total B)				**$ 119.56**			**$ 141.47**	**$ 21.91**	**18.32%**
Wholesale Market Service Charge (WMSC)	per kWh	$ 0.0036	2,108	$ 7.59	$ 0.0036	2,106	$ 7.58	-$ 0.01	-0.11%
Rural and Remote Rate Protection (RRRP)	per kWh	$ 0.0013	2,108	$ 2.74	$ 0.0013	2,106	$ 2.74	-$ 0.00	-0.11%
Standard Supply Service Charge	Monthly	$ 0.2500	1	$ 0.25	$ 0.2500	1	$ 0.25	$ -	0.00%
Debt Retirement Charge (DRC)			2,000	$ -		2,000	$ -	$ -	
Ontario Electricity Support Program (OESP)	per kWh	$ 0.0011	2,108	$ 2.32	$ 0.0011	2,106	$ 2.32	-$ 0.00	-0.11%
Non-RPP Retailer Avg. Price + GA	per kWh	$ 0.1652	2,000	$ 330.40	$ 0.1652	2,000	$ 330.40	$ -	0.00%
Total Bill on Non-RPP Avg. Price				**$ 462.86**			**$ 484.75**	**$ 21.89**	**4.73%**
HST		13%		$ 60.17	13%		$ 63.02	$ 2.85	4.73%
Total Bill (including HST)				$ 523.03			$ 547.77	$ 24.74	4.73%
Ontario Clean Energy Benefit [1]									
Total Bill on Non-RPP Avg. Price				**$ 523.03**			**$ 547.77**	**$ 24.74**	**4.73%**

Customer Class:	**GS < 50 kW TOU - EOP**	
RPP / Non-RPP:	**RPP**	
Consumption	**2,000**	**kWh**
Demand	**-**	**kW**
Current Loss Factor	**1.0542**	
Proposed/Approved Loss Factor	**1.0530**	
Ontario Clean Energy Benefit Applied?	**No**	

		Current Board-Approved			**Proposed**			**Impact**	
	Charge Unit	**Rate ($)**	**Volume**	**Charge ($)**	**Rate ($)**	**Volume**	**Charge ($)**	**$ Change**	**% Change**
Monthly Service Charge	Monthly	$ 28.2600	1	$ 28.26	$ 32.0200	1	$ 32.02	$ 3.76	13.31%
Smart Meter Rate Adder			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
Distribution Volumetric Rate	per kWh	$ 0.0230	2,000	$ 46.00	$ 0.0261	2,000	$ 52.20	$ 6.20	13.48%
Smart Meter Disposition Rider			2,000	$ -		2,000	$ -	$ -	
LRAM & SSM Rate Rider	per kWh		2,000	$ -	$ 0.0019	2,000	$ 3.80	$ 3.80	
			2,000	$ -		2,000	$ -	$ -	
			2,000	$ -		2,000	$ -	$ -	
			2,000	$ -		2,000	$ -	$ -	
			2,000	$ -		2,000	$ -	$ -	
			2,000	$ -		2,000	$ -	$ -	
			2,000	$ -		2,000	$ -	$ -	
			2,000	$ -		2,000	$ -	$ -	
Sub-Total A (excluding pass through)				$ 74.26			$ 88.02	**$ 13.76**	**18.53%**
DVA - Total in Effect 2016	per kWh	-$ 0.0024	2,000	-$ 4.80	-$ 0.0048	2,000	-$ 9.60	-$ 4.80	100.00%
DVA - Total in Effect 2017	per kWh		2,000	$ -		2,000	$ -	$ -	
			2,000	$ -		2,000	$ -	$ -	
			2,000	$ -		2,000	$ -	$ -	
Low Voltage Service Charge	per kWh	$ 0.0002	2,000	$ 0.40	$ 0.0003	2,000	$ 0.60	$ 0.20	50.00%
Line Losses on Cost of Power	per kWh	$ 0.1077	108	$ 11.67	$ 0.1077	106	$ 11.41	-$ 0.26	-2.21%
Smart Meter Entity Charge	Monthly	$ 0.7900	1	$ 0.79	$ 0.7900	1	$ 0.79	$ -	0.00%
Sub-Total B - Distribution (includes Sub-Total A)				**$ 82.32**			**$ 91.22**	**$ 8.90**	**10.81%**
RTSR - Network	per kWh	$ 0.0061	2,108	$ 12.86	$ 0.0058	2,106	$ 12.21	-$ 0.65	-5.03%
RTSR - Line and Transformation Connection	per kWh	$ 0.0050	2,108	$ 10.54	$ 0.0050	2,106	$ 10.53	-$ 0.01	-0.11%
Sub-Total C - Delivery (including Sub-Total B)				**$ 105.72**			**$ 113.97**	**$ 8.24**	**7.80%**
Wholesale Market Service Charge (WMSC)	per kWh	$ 0.0036	2,108	$ 7.59	$ 0.0036	2,106	$ 7.58	-$ 0.01	-0.11%
Rural and Remote Rate Protection (RRRP)	per kWh	$ 0.0013	2,108	$ 2.74	$ 0.0013	2,106	$ 2.74	-$ 0.00	-0.11%
Standard Supply Service Charge	Monthly	$ 0.2500	1	$ 0.25	$ 0.2500	1	$ 0.25	$ -	0.00%
Debt Retirement Charge (DRC)			2,000	$ -		2,000	$ -	$ -	
Ontario Electricity Support Program (OESP)	per kWh	$ 0.0011	2,108	$ 2.32	$ 0.0011	2,106	$ 2.32	-$ 0.00	-0.11%
TOU - Off Peak	per kWh	$ 0.0830	1,280	$ 106.24	$ 0.0830	1,280	$ 106.24	$ -	0.00%
TOU - Mid Peak	per kWh	$ 0.1280	360	$ 46.08	$ 0.1280	360	$ 46.08	$ -	0.00%
TOU - On Peak	per kWh	$ 0.1750	360	$ 63.00	$ 0.1750	360	$ 63.00	$ -	0.00%
Total Bill on TOU (before Taxes)				**$ 333.94**			**$ 342.17**	**$ 8.23**	**2.46%**
HST		13%		$ 43.41	13%		$ 44.48	$ 1.07	2.46%
Total Bill (including HST)				$ 377.36			$ 386.66	$ 9.30	2.46%
Ontario Clean Energy Benefit [1]									
Total Bill on TOU				**$ 377.36**			**$ 386.66**	**$ 9.30**	**2.46%**

Customer Class:	**GS<50 kW Retailer - EOP**
RPP / Non-RPP:	**Non-RPP (Retailer)**
Consumption	**2,000** kWh
Demand	**0** kW
Current Loss Factor	**1.0542**
Proposed/Approved Loss Factor	**1.0530**
Ontario Clean Energy Benefit Applied?	**No**

		Current Board-Approved			Proposed			Impact	
	Charge Unit	**Rate ($)**	**Volume**	**Charge ($)**	**Rate ($)**	**Volume**	**Charge ($)**	**$ Change**	**% Change**
Monthly Service Charge	Monthly	$ 28.2600	1	$ 28.26	$ 32.0200	1	$ 32.02	$ 3.76	13.31%
Smart Meter Rate Adder			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
Distribution Volumetric Rate	per kWh	$ 0.0230	2,000	$ 46.00	$ 0.0261	2,000	$ 52.20	$ 6.20	13.48%
Smart Meter Disposition Rider			2,000	$ -		2,000	$ -	$ -	
LRAM & SSM Rate Rider	per kWh		2,000	$ -	$ 0.0019	2,000	$ 3.80	$ 3.80	
			2,000	$ -		2,000	$ -	$ -	
			2,000	$ -		2,000	$ -	$ -	
			2,000	$ -		2,000	$ -	$ -	
			2,000	$ -		2,000	$ -	$ -	
			2,000	$ -		2,000	$ -	$ -	
			2,000	$ -		2,000	$ -	$ -	
			2,000	$ -		2,000	$ -	$ -	
Sub-Total A (excluding pass through)				$ 74.26			$ 88.02	**$ 13.76**	**18.53%**
DVA - Total in Effect 2016	per kWh	$ 0.0156	2,000	$ 31.20		2,000	$ -	-$ 31.20	-100.00%
DVA - Total in Effect 2017	per kWh		2,000	$ -	$ 0.0059	2,000	$ 11.80	$ 11.80	
			2,000	$ -		2,000	$ -	$ -	
			2,000	$ -		2,000	$ -	$ -	
Low Voltage Service Charge	per kWh	$ 0.0002	2,000	$ 0.40	$ 0.0003	2,000	$ 0.60	$ 0.20	50.00%
Line Losses on Cost of Power	per kWh	$ 0.1652	108	$ 17.91	$ 0.1652	106	$ 17.51	-$ 0.40	-2.21%
Smart Meter Entity Charge	Monthly	$ 0.7900	1	$ 0.79	$ 0.7900	1	$ 0.79	$ -	0.00%
Sub-Total B - Distribution (includes Sub-Total A)				**$ 124.56**			**$ 118.72**	**-$ 5.84**	**-4.69%**
RTSR - Network	per kWh	$ 0.0061	2,108	$ 12.86	$ 0.0058	2,106	$ 12.21	-$ 0.65	-5.03%
RTSR - Line and Transformation Connection	per kWh	$ 0.0050	2,108	$ 10.54	$ 0.0050	2,106	$ 10.53	-$ 0.01	-0.11%
Sub-Total C - Delivery (including Sub-Total B)				**$ 147.96**			**$ 141.47**	**-$ 6.49**	**-4.39%**
Wholesale Market Service Charge (WMSC)	per kWh	$ 0.0036	2,108	$ 7.59	$ 0.0036	2,106	$ 7.58	-$ 0.01	-0.11%
Rural and Remote Rate Protection (RRRP)	per kWh	$ 0.0013	2,108	$ 2.74	$ 0.0013	2,106	$ 2.74	-$ 0.00	-0.11%
Standard Supply Service Charge	Monthly	$ 0.2500	1	$ 0.25	$ 0.2500	1	$ 0.25	$ -	0.00%
Debt Retirement Charge (DRC)			2,000	$ -		2,000	$ -	$ -	
Ontario Electricity Support Program (OESP)	per kWh	$ 0.0011	2,108	$ 2.32	$ 0.0011	2,106	$ 2.32	-$ 0.00	-0.11%
Non-RPP Retailer Avg. Price + GA	per kWh	$ 0.1652	2,000	$ 330.40	$ 0.1652	2,000	$ 330.40	$ -	0.00%
Total Bill on Non-RPP Avg. Price				**$ 491.26**			**$ 484.75**	**-$ 6.51**	**-1.33%**
HST		13%		$ 63.86	13%		$ 63.02	-$ 0.85	-1.33%
Total Bill (including HST)				$ 555.13			$ 547.77	-$ 7.36	-1.33%
Ontario Clean Energy Benefit [1]									
Total Bill on Non-RPP Avg. Price				**$ 555.13**			**$ 547.77**	**-$ 7.36**	**-1.33%**

Customer Class:	**GS < 50 kW TOU - Port Colborne**	
RPP / Non-RPP:	**RPP**	
Consumption	**2,000**	**kWh**
Demand	**-**	**kW**
Current Loss Factor	**1.0542**	
Proposed/Approved Loss Factor	**1.0530**	
Ontario Clean Energy Benefit Applied?	**No**	

		Current Board-Approved			**Proposed**			**Impact**	
	Charge Unit	**Rate ($)**	**Volume**	**Charge ($)**	**Rate ($)**	**Volume**	**Charge ($)**	**$ Change**	**% Change**
Monthly Service Charge	Monthly	$ 28.2600	1	$ 28.26	$ 32.0200	1	$ 32.02	$ 3.76	13.31%
Smart Meter Rate Adder			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
Distribution Volumetric Rate	per kWh	$ 0.0230	2,000	$ 46.00	$ 0.0261	2,000	$ 52.20	$ 6.20	13.48%
Smart Meter Disposition Rider			2,000	$ -		2,000	$ -	$ -	
LRAM & SSM Rate Rider	per kWh		2,000	$ -	$ 0.0019	2,000	$ 3.80	$ 3.80	
			2,000	$ -		2,000	$ -	$ -	
			2,000	$ -		2,000	$ -	$ -	
			2,000	$ -		2,000	$ -	$ -	
			2,000	$ -		2,000	$ -	$ -	
			2,000	$ -		2,000	$ -	$ -	
			2,000	$ -		2,000	$ -	$ -	
			2,000	$ -		2,000	$ -	$ -	
Sub-Total A (excluding pass through)				$ 74.26			$ 88.02	**$ 13.76**	**18.53%**
DVA - Total in Effect 2016	per kWh	-$ 0.0014	2,000	-$ 2.80	-$ 0.0048	2,000	-$ 9.60	-$ 6.80	242.86%
DVA - Total in Effect 2017	per kWh		2,000	$ -		2,000	$ -	$ -	
			2,000	$ -		2,000	$ -	$ -	
			2,000	$ -		2,000	$ -	$ -	
Low Voltage Service Charge	per kWh	$ 0.0002	2,000	$ 0.40	$ 0.0003	2,000	$ 0.60	$ 0.20	50.00%
Line Losses on Cost of Power	per kWh	$ 0.1077	108	$ 11.67	$ 0.1077	106	$ 11.41	-$ 0.26	-2.21%
Smart Meter Entity Charge	Monthly	$ 0.7900	1	$ 0.79	$ 0.7900	1	$ 0.79	$ -	0.00%
Sub-Total B - Distribution (includes Sub-Total A)				**$ 84.32**			**$ 91.22**	**$ 6.90**	**8.18%**
RTSR - Network	per kWh	$ 0.0061	2,108	$ 12.86	$ 0.0058	2,106	$ 12.21	-$ 0.65	-5.03%
RTSR - Line and Transformation Connection	per kWh	$ 0.0050	2,108	$ 10.54	$ 0.0050	2,106	$ 10.53	-$ 0.01	-0.11%
Sub-Total C - Delivery (including Sub-Total B)				**$ 107.72**			**$ 113.97**	**$ 6.24**	**5.80%**
Wholesale Market Service Charge (WMSC)	per kWh	$ 0.0036	2,108	$ 7.59	$ 0.0036	2,106	$ 7.58	-$ 0.01	-0.11%
Rural and Remote Rate Protection (RRRP)	per kWh	$ 0.0013	2,108	$ 2.74	$ 0.0013	2,106	$ 2.74	-$ 0.00	-0.11%
Standard Supply Service Charge	Monthly	$ 0.2500	1	$ 0.25	$ 0.2500	1	$ 0.25	$ -	0.00%
Debt Retirement Charge (DRC)			2,000	$ -		2,000	$ -	$ -	
Ontario Electricity Support Program (OESP)	per kWh	$ 0.0011	2,108	$ 2.32	$ 0.0011	2,106	$ 2.32	-$ 0.00	-0.11%
TOU - Off Peak	per kWh	$ 0.0830	1,280	$ 106.24	$ 0.0830	1,280	$ 106.24	$ -	0.00%
TOU - Mid Peak	per kWh	$ 0.1280	360	$ 46.08	$ 0.1280	360	$ 46.08	$ -	0.00%
TOU - On Peak	per kWh	$ 0.1750	360	$ 63.00	$ 0.1750	360	$ 63.00	$ -	0.00%
Total Bill on TOU (before Taxes)				**$ 335.94**			**$ 342.17**	**$ 6.23**	**1.85%**
HST		13%		$ 43.67	13%		$ 44.48	$ 0.81	1.85%
Total Bill (including HST)				$ 379.62			$ 386.66	$ 7.04	1.85%
***Ontario Clean Energy Benefit* [1]**									
Total Bill on TOU				**$ 379.62**			**$ 386.66**	**$ 7.04**	**1.85%**

Customer Class:	**GS<50 kW Retailer - Port Colborne**	
RPP / Non-RPP:	**Non-RPP (Retailer)**	
Consumption	**2,000**	**kWh**
Demand	**0**	**kW**
Current Loss Factor	**1.0542**	
Proposed/Approved Loss Factor	**1.0530**	
Ontario Clean Energy Benefit Applied?	**No**	

		Current Board-Approved			**Proposed**			**Impact**	
	Charge Unit	**Rate ($)**	**Volume**	**Charge ($)**	**Rate ($)**	**Volume**	**Charge ($)**	**$ Change**	**% Change**
Monthly Service Charge	Monthly	$ 28.2600	1	$ 28.26	$ 32.0200	1	$ 32.02	$ 3.76	13.31%
Smart Meter Rate Adder			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
Distribution Volumetric Rate	per kWh	$ 0.0230	2,000	$ 46.00	$ 0.0261	2,000	$ 52.20	$ 6.20	13.48%
Smart Meter Disposition Rider			2,000	$ -		2,000	$ -	$ -	
LRAM & SSM Rate Rider	per kWh		2,000	$ -	$ 0.0019	2,000	$ 3.80	$ 3.80	
			2,000	$ -		2,000	$ -	$ -	
			2,000	$ -		2,000	$ -	$ -	
			2,000	$ -		2,000	$ -	$ -	
			2,000	$ -		2,000	$ -	$ -	
			2,000	$ -		2,000	$ -	$ -	
			2,000	$ -		2,000	$ -	$ -	
			2,000	$ -		2,000	$ -	$ -	
Sub-Total A (excluding pass through)				$ 74.26			$ 88.02	**$ 13.76**	**18.53%**
DVA - Total in Effect 2016	per kWh	-$ 0.0018	2,000	-$ 3.60		2,000	$ -	$ 3.60	-100.00%
DVA - Total in Effect 2017	per kWh		2,000	$ -	$ 0.0059	2,000	$ 11.80	$ 11.80	
			2,000	$ -		2,000	$ -	$ -	
			2,000	$ -		2,000	$ -	$ -	
Low Voltage Service Charge	per kWh	$ 0.0002	2,000	$ 0.40	$ 0.0003	2,000	$ 0.60	$ 0.20	50.00%
Line Losses on Cost of Power	per kWh	$ 0.1652	108	$ 17.91	$ 0.1652	106	$ 17.51	-$ 0.40	-2.21%
Smart Meter Entity Charge	Monthly	$ 0.7900	1	$ 0.79	$ 0.7900	1	$ 0.79	$ -	0.00%
Sub-Total B - Distribution (includes Sub-Total A)				**$ 89.76**			**$ 118.72**	**$ 28.96**	**32.27%**
RTSR - Network	per kWh	$ 0.0061	2,108	$ 12.86	$ 0.0058	2,106	$ 12.21	-$ 0.65	-5.03%
RTSR - Line and Transformation Connection	per kWh	$ 0.0050	2,108	$ 10.54	$ 0.0050	2,106	$ 10.53	-$ 0.01	-0.11%
Sub-Total C - Delivery (including Sub-Total B)				**$ 113.16**			**$ 141.47**	**$ 28.31**	**25.01%**
Wholesale Market Service Charge (WMSC)	per kWh	$ 0.0036	2,108	$ 7.59	$ 0.0036	2,106	$ 7.58	-$ 0.01	-0.11%
Rural and Remote Rate Protection (RRRP)	per kWh	$ 0.0013	2,108	$ 2.74	$ 0.0013	2,106	$ 2.74	-$ 0.00	-0.11%
Standard Supply Service Charge	Monthly	$ 0.2500	1	$ 0.25	$ 0.2500	1	$ 0.25	$ -	0.00%
Debt Retirement Charge (DRC)			2,000	$ -		2,000	$ -	$ -	
Ontario Electricity Support Program (OESP)	per kWh	$ 0.0011	2,108	$ 2.32	$ 0.0011	2,106	$ 2.32	-$ 0.00	-0.11%
Non-RPP Retailer Avg. Price + GA	per kWh	$ 0.1652	2,000	$ 330.40	$ 0.1652	2,000	$ 330.40	$ -	0.00%
Total Bill on Non-RPP Avg. Price				**$ 456.46**			**$ 484.75**	**$ 28.29**	**6.20%**
HST		13%		$ 59.34	13%		$ 63.02	$ 3.68	6.20%
Total Bill (including HST)				$ 515.80			$ 547.77	$ 31.97	6.20%
***Ontario Clean Energy Benefit* [1]**									
Total Bill on Non-RPP Avg. Price				**$ 515.80**			**$ 547.77**	**$ 31.97**	**6.20%**

Customer Class:	**GS < 50 kW TOU - Fort Erie**
RPP / Non-RPP:	**RPP**
Consumption	**5,000** kWh
Demand	**-** kW
Current Loss Factor	**1.0542**
Proposed/Approved Loss Factor	**1.0530**
Ontario Clean Energy Benefit Applied?	**No**

		Current Board-Approved			Proposed			Impact	
	Charge Unit	**Rate ($)**	**Volume**	**Charge ($)**	**Rate ($)**	**Volume**	**Charge ($)**	**$ Change**	**% Change**
Monthly Service Charge	Monthly	$ 28.2600	1	$ 28.26	$ 32.0200	1	$ 32.02	$ 3.76	13.31%
Smart Meter Rate Adder			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
Distribution Volumetric Rate	per kWh	$ 0.0230	5,000	$ 115.00	$ 0.0261	5,000	$ 130.50	$ 15.50	13.48%
Smart Meter Disposition Rider			5,000	$ -		5,000	$ -	$ -	
LRAM & SSM Rate Rider	per kWh		5,000	$ -	$ 0.0019	5,000	$ 9.50	$ 9.50	
			5,000	$ -		5,000	$ -	$ -	
			5,000	$ -		5,000	$ -	$ -	
			5,000	$ -		5,000	$ -	$ -	
			5,000	$ -		5,000	$ -	$ -	
			5,000	$ -		5,000	$ -	$ -	
			5,000	$ -		5,000	$ -	$ -	
			5,000	$ -		5,000	$ -	$ -	
Sub-Total A (excluding pass through)				$ 143.26			$ 172.02	**$ 28.76**	**20.08%**
DVA - Total in Effect 2016	per kWh	$ 0.0002	5,000	$ 1.00		5,000	$ -	-$ 1.00	-100.00%
DVA - Total in Effect 2017	per kWh		5,000	$ -	-$ 0.0048	5,000	-$ 24.00	-$ 24.00	
			5,000	$ -		5,000	$ -	$ -	
			5,000	$ -		5,000	$ -	$ -	
Low Voltage Service Charge	per kWh	$ 0.0002	5,000	$ 1.00	$ 0.0003	5,000	$ 1.50	$ 0.50	50.00%
Line Losses on Cost of Power	per kWh	$ 0.1077	271	$ 29.18	$ 0.1077	265	$ 28.53	-$ 0.65	-2.21%
Smart Meter Entity Charge	Monthly	$ 0.7900	1	$ 0.79	$ 0.7900	1	$ 0.79	$ -	0.00%
Sub-Total B - Distribution (includes Sub-Total A)				**$ 175.23**			**$ 178.84**	**$ 3.61**	**2.06%**
RTSR - Network	per kWh	$ 0.0061	5,271	$ 32.15	$ 0.0058	5,265	$ 30.54	-$ 1.62	-5.03%
RTSR - Line and Transformation Connection	per kWh	$ 0.0050	5,271	$ 26.36	$ 0.0050	5,265	$ 26.33	-$ 0.03	-0.11%
Sub-Total C - Delivery (including Sub-Total B)				**$ 233.73**			**$ 235.70**	**$ 1.97**	**0.84%**
Wholesale Market Service Charge (WMSC)	per kWh	$ 0.0036	5,271	$ 18.98	$ 0.0036	5,265	$ 18.95	-$ 0.02	-0.11%
Rural and Remote Rate Protection (RRRP)	per kWh	$ 0.0013	5,271	$ 6.85	$ 0.0013	5,265	$ 6.84	-$ 0.01	-0.11%
Standard Supply Service Charge	Monthly	$ 0.2500	1	$ 0.25	$ 0.2500	1	$ 0.25	$ -	0.00%
Debt Retirement Charge (DRC)			5,000	$ -		5,000	$ -	$ -	
Ontario Electricity Support Program (OESP)	per kWh	$ 0.0011	5,271	$ 5.80	$ 0.0011	5,265	$ 5.79	-$ 0.01	-0.11%
TOU - Off Peak	per kWh	$ 0.0830	3,200	$ 265.60	$ 0.0830	3,200	$ 265.60	$ -	0.00%
TOU - Mid Peak	per kWh	$ 0.1280	900	$ 115.20	$ 0.1280	900	$ 115.20	$ -	0.00%
TOU - On Peak	per kWh	$ 0.1750	900	$ 157.50	$ 0.1750	900	$ 157.50	$ -	0.00%
Total Bill on TOU (before Taxes)				**$ 803.91**			**$ 805.84**	**$ 1.93**	**0.24%**
HST		13%		$ 104.51	13%		$ 104.76	$ 0.25	0.24%
Total Bill (including HST)				$ 908.42			$ 910.60	$ 2.18	0.24%
Ontario Clean Energy Benefit [1]									
Total Bill on TOU				**$ 908.42**			**$ 910.60**	**$ 2.18**	**0.24%**

Customer Class:	**GS<50 kW Retailer - Fort Erie**
RPP / Non-RPP:	**Non-RPP (Retailer)**
Consumption	**5,000** kWh
Demand	**0** kW
Current Loss Factor	**1.0542**
Proposed/Approved Loss Factor	**1.0530**
Ontario Clean Energy Benefit Applied?	**No**

		Current Board-Approved			**Proposed**			**Impact**	
	Charge Unit	**Rate ($)**	**Volume**	**Charge ($)**	**Rate ($)**	**Volume**	**Charge ($)**	**$ Change**	**% Change**
Monthly Service Charge	Monthly	$ 28.2600	1	$ 28.26	$ 32.0200	1	$ 32.02	$ 3.76	13.31%
Smart Meter Rate Adder			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
Distribution Volumetric Rate	per kWh	$ 0.0230	5,000	$ 115.00	$ 0.0261	5,000	$ 130.50	$ 15.50	13.48%
Smart Meter Disposition Rider			5,000	$ -		5,000	$ -	$ -	
LRAM & SSM Rate Rider	per kWh		5,000	$ -	$ 0.0019	5,000	$ 9.50	$ 9.50	
			5,000	$ -		5,000	$ -	$ -	
			5,000	$ -		5,000	$ -	$ -	
			5,000	$ -		5,000	$ -	$ -	
			5,000	$ -		5,000	$ -	$ -	
			5,000	$ -		5,000	$ -	$ -	
			5,000	$ -		5,000	$ -	$ -	
			5,000	$ -		5,000	$ -	$ -	
Sub-Total A (excluding pass through)				$ 143.26			$ 172.02	**$ 28.76**	**20.08%**
DVA - Total in Effect 2016	per kWh	$ 0.0014	5,000	$ 7.00		5,000	$ -	-$ 7.00	-100.00%
DVA - Total in Effect 2017	per kWh		5,000	$ -	$ 0.0059	5,000	$ 29.50	$ 29.50	
			5,000	$ -		5,000	$ -	$ -	
			5,000	$ -		5,000	$ -	$ -	
Low Voltage Service Charge	per kWh	$ 0.0002	5,000	$ 1.00	$ 0.0003	5,000	$ 1.50	$ 0.50	50.00%
Line Losses on Cost of Power	per kWh	$ 0.1652	271	$ 44.77	$ 0.1652	265	$ 43.78	-$ 0.99	-2.21%
Smart Meter Entity Charge	Monthly	$ 0.7900	1	$ 0.79	$ 0.7900	1	$ 0.79	$ -	0.00%
Sub-Total B - Distribution (includes Sub-Total A)				**$ 196.82**			**$ 247.59**	**$ 50.77**	**25.79%**
RTSR - Network	per kWh	$ 0.0061	5,271	$ 32.15	$ 0.0058	5,265	$ 30.54	-$ 1.62	-5.03%
RTSR - Line and Transformation Connection	per kWh	$ 0.0050	5,271	$ 26.36	$ 0.0050	5,265	$ 26.33	-$ 0.03	-0.11%
Sub-Total C - Delivery (including Sub-Total B)				**$ 255.33**			**$ 304.45**	**$ 49.12**	**19.24%**
Wholesale Market Service Charge (WMSC)	per kWh	$ 0.0036	5,271	$ 18.98	$ 0.0036	5,265	$ 18.95	-$ 0.02	-0.11%
Rural and Remote Rate Protection (RRRP)	per kWh	$ 0.0013	5,271	$ 6.85	$ 0.0013	5,265	$ 6.84	-$ 0.01	-0.11%
Standard Supply Service Charge	Monthly	$ 0.2500	1	$ 0.25	$ 0.2500	1	$ 0.25	$ -	0.00%
Debt Retirement Charge (DRC)			5,000	$ -		5,000	$ -	$ -	
Ontario Electricity Support Program (OESP)	per kWh	$ 0.0011	5,271	$ 5.80	$ 0.0011	5,265	$ 5.79	-$ 0.01	-0.11%
Non-RPP Retailer Avg. Price + GA	per kWh	$ 0.1652	5,000	$ 826.00	$ 0.1652	5,000	$ 826.00	$ -	0.00%
Total Bill on Non-RPP Avg. Price				**$ 1,113.20**			**$ 1,162.29**	**$ 49.09**	**4.41%**
HST		13%		$ 144.72	13%		$ 151.10	$ 6.38	4.41%
Total Bill (including HST)				$ 1,257.92			$ 1,313.39	$ 55.47	4.41%
Ontario Clean Energy Benefit [1]									
Total Bill on Non-RPP Avg. Price				**$ 1,257.92**			**$ 1,313.39**	**$ 55.47**	**4.41%**

Customer Class:	**GS < 50 kW TOU - EOP**	
RPP / Non-RPP:	**RPP**	
Consumption	**5,000**	**kWh**
Demand	**-**	**kW**
Current Loss Factor	**1.0542**	
Proposed/Approved Loss Factor	**1.0530**	
Ontario Clean Energy Benefit Applied?	**No**	

		Current Board-Approved			**Proposed**			**Impact**	
	Charge Unit	**Rate ($)**	**Volume**	**Charge ($)**	**Rate ($)**	**Volume**	**Charge ($)**	**$ Change**	**% Change**
Monthly Service Charge	Monthly	$ 28.2600	1	$ 28.26	$ 32.0200	1	$ 32.02	$ 3.76	13.31%
Smart Meter Rate Adder			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
Distribution Volumetric Rate	per kWh	$ 0.0230	5,000	$ 115.00	$ 0.0261	5,000	$ 130.50	$ 15.50	13.48%
Smart Meter Disposition Rider			5,000	$ -		5,000	$ -	$ -	
LRAM & SSM Rate Rider	per kWh		5,000	$ -	$ 0.0019	5,000	$ 9.50	$ 9.50	
			5,000	$ -		5,000	$ -	$ -	
			5,000	$ -		5,000	$ -	$ -	
			5,000	$ -		5,000	$ -	$ -	
			5,000	$ -		5,000	$ -	$ -	
			5,000	$ -		5,000	$ -	$ -	
			5,000	$ -		5,000	$ -	$ -	
			5,000	$ -		5,000	$ -	$ -	
Sub-Total A (excluding pass through)				$ 143.26			$ 172.02	**$ 28.76**	**20.08%**
DVA - Total in Effect 2016	per kWh	-$ 0.0024	5,000	-$ 12.00	-$ 0.0048	5,000	-$ 24.00	-$ 12.00	100.00%
DVA - Total in Effect 2017	per kWh		5,000	$ -		5,000	$ -	$ -	
			5,000	$ -		5,000	$ -	$ -	
			5,000	$ -		5,000	$ -	$ -	
Low Voltage Service Charge	per kWh	$ 0.0002	5,000	$ 1.00	$ 0.0003	5,000	$ 1.50	$ 0.50	50.00%
Line Losses on Cost of Power	per kWh	$ 0.1077	271	$ 29.18	$ 0.1077	265	$ 28.53	-$ 0.65	-2.21%
Smart Meter Entity Charge	Monthly	$ 0.7900	1	$ 0.79	$ 0.7900	1	$ 0.79	$ -	0.00%
Sub-Total B - Distribution (includes Sub-Total A)				**$ 162.23**			**$ 178.84**	**$ 16.61**	**10.24%**
RTSR - Network	per kWh	$ 0.0061	5,271	$ 32.15	$ 0.0058	5,265	$ 30.54	-$ 1.62	-5.03%
RTSR - Line and Transformation Connection	per kWh	$ 0.0050	5,271	$ 26.36	$ 0.0050	5,265	$ 26.33	-$ 0.03	-0.11%
Sub-Total C - Delivery (including Sub-Total B)				**$ 220.73**			**$ 235.70**	**$ 14.97**	**6.78%**
Wholesale Market Service Charge (WMSC)	per kWh	$ 0.0036	5,271	$ 18.98	$ 0.0036	5,265	$ 18.95	-$ 0.02	-0.11%
Rural and Remote Rate Protection (RRRP)	per kWh	$ 0.0013	5,271	$ 6.85	$ 0.0013	5,265	$ 6.84	-$ 0.01	-0.11%
Standard Supply Service Charge	Monthly	$ 0.2500	1	$ 0.25	$ 0.2500	1	$ 0.25	$ -	0.00%
Debt Retirement Charge (DRC)			5,000	$ -		5,000	$ -	$ -	
Ontario Electricity Support Program (OESP)	per kWh	$ 0.0011	5,271	$ 5.80	$ 0.0011	5,265	$ 5.79	-$ 0.01	-0.11%
TOU - Off Peak	per kWh	$ 0.0830	3,200	$ 265.60	$ 0.0830	3,200	$ 265.60	$ -	0.00%
TOU - Mid Peak	per kWh	$ 0.1280	900	$ 115.20	$ 0.1280	900	$ 115.20	$ -	0.00%
TOU - On Peak	per kWh	$ 0.1750	900	$ 157.50	$ 0.1750	900	$ 157.50	$ -	0.00%
Total Bill on TOU (before Taxes)				**$ 790.91**			**$ 805.84**	**$ 14.93**	**1.89%**
HST		13%		$ 102.82	13%		$ 104.76	$ 1.94	1.89%
Total Bill (including HST)				$ 893.73			$ 910.60	$ 16.87	1.89%
Ontario Clean Energy Benefit [1]									
Total Bill on TOU				**$ 893.73**			**$ 910.60**	**$ 16.87**	**1.89%**

Customer Class:	**GS<50 kW Retailer - EOP**
RPP / Non-RPP:	**Non-RPP (Retailer)**
Consumption	**5,000** kWh
Demand	**0** kW
Current Loss Factor	**1.0542**
Proposed/Approved Loss Factor	**1.0530**
Ontario Clean Energy Benefit Applied?	**No**

		Current Board-Approved			Proposed			Impact	
	Charge Unit	**Rate ($)**	**Volume**	**Charge ($)**	**Rate ($)**	**Volume**	**Charge ($)**	**$ Change**	**% Change**
Monthly Service Charge	Monthly	$ 28.2600	1	$ 28.26	$ 32.0200	1	$ 32.02	$ 3.76	13.31%
Smart Meter Rate Adder			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
Distribution Volumetric Rate	per kWh	$ 0.0230	5,000	$ 115.00	$ 0.0261	5,000	$ 130.50	$ 15.50	13.48%
Smart Meter Disposition Rider			5,000	$ -		5,000	$ -	$ -	
LRAM & SSM Rate Rider	per kWh		5,000	$ -	$ 0.0019	5,000	$ 9.50	$ 9.50	
			5,000	$ -		5,000	$ -	$ -	
			5,000	$ -		5,000	$ -	$ -	
			5,000	$ -		5,000	$ -	$ -	
			5,000	$ -		5,000	$ -	$ -	
			5,000	$ -		5,000	$ -	$ -	
			5,000	$ -		5,000	$ -	$ -	
			5,000	$ -		5,000	$ -	$ -	
Sub-Total A (excluding pass through)				$ 143.26			$ 172.02	**$ 28.76**	**20.08%**
DVA - Total in Effect 2016	per kWh	$ 0.0156	5,000	$ 78.00		5,000	$ -	-$ 78.00	-100.00%
DVA - Total in Effect 2017	per kWh		5,000	$ -	$ 0.0059	5,000	$ 29.50	$ 29.50	
			5,000	$ -		5,000	$ -	$ -	
			5,000	$ -		5,000	$ -	$ -	
Low Voltage Service Charge	per kWh	$ 0.0002	5,000	$ 1.00	$ 0.0003	5,000	$ 1.50	$ 0.50	50.00%
Line Losses on Cost of Power	per kWh	$ 0.1652	271	$ 44.77	$ 0.1652	265	$ 43.78	-$ 0.99	-2.21%
Smart Meter Entity Charge	Monthly	$ 0.7900	1	$ 0.79	$ 0.7900	1	$ 0.79	$ -	0.00%
Sub-Total B - Distribution (includes Sub-Total A)				**$ 267.82**			**$ 247.59**	**-$ 20.23**	**-7.55%**
RTSR - Network	per kWh	$ 0.0061	5,271	$ 32.15	$ 0.0058	5,265	$ 30.54	-$ 1.62	-5.03%
RTSR - Line and Transformation Connection	per kWh	$ 0.0050	5,271	$ 26.36	$ 0.0050	5,265	$ 26.33	-$ 0.03	-0.11%
Sub-Total C - Delivery (including Sub-Total B)				**$ 326.33**			**$ 304.45**	**-$ 21.88**	**-6.70%**
Wholesale Market Service Charge (WMSC)	per kWh	$ 0.0036	5,271	$ 18.98	$ 0.0036	5,265	$ 18.95	-$ 0.02	-0.11%
Rural and Remote Rate Protection (RRRP)	per kWh	$ 0.0013	5,271	$ 6.85	$ 0.0013	5,265	$ 6.84	-$ 0.01	-0.11%
Standard Supply Service Charge	Monthly	$ 0.2500	1	$ 0.25	$ 0.2500	1	$ 0.25	$ -	0.00%
Debt Retirement Charge (DRC)			5,000	$ -		5,000	$ -	$ -	
Ontario Electricity Support Program (OESP)	per kWh	$ 0.0011	5,271	$ 5.80	$ 0.0011	5,265	$ 5.79	-$ 0.01	-0.11%
Non-RPP Retailer Avg. Price + GA	per kWh	$ 0.1652	5,000	$ 826.00	$ 0.1652	5,000	$ 826.00	$ -	0.00%
Total Bill on Non-RPP Avg. Price				**$ 1,184.20**			**$ 1,162.29**	**-$ 21.91**	**-1.85%**
HST		13%		$ 153.95	13%		$ 151.10	-$ 2.85	-1.85%
Total Bill (including HST)				$ 1,338.15			$ 1,313.39	-$ 24.76	-1.85%
Ontario Clean Energy Benefit [1]									
Total Bill on Non-RPP Avg. Price				**$ 1,338.15**			**$ 1,313.39**	**-$ 24.76**	**-1.85%**

Customer Class:	**GS < 50 kW TOU - Port Colborne**	
RPP / Non-RPP:	**RPP**	
Consumption	**5,000**	**kWh**
Demand	**-**	**kW**
Current Loss Factor	**1.0542**	
Proposed/Approved Loss Factor	**1.0530**	
Ontario Clean Energy Benefit Applied?	**No**	

		Current Board-Approved			Proposed			Impact	
	Charge Unit	**Rate ($)**	**Volume**	**Charge ($)**	**Rate ($)**	**Volume**	**Charge ($)**	**$ Change**	**% Change**
Monthly Service Charge	Monthly	$ 28.2600	1	$ 28.26	$ 32.0200	1	$ 32.02	$ 3.76	13.31%
Smart Meter Rate Adder			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
Distribution Volumetric Rate	per kWh	$ 0.0230	5,000	$ 115.00	$ 0.0261	5,000	$ 130.50	$ 15.50	13.48%
Smart Meter Disposition Rider			5,000	$ -		5,000	$ -	$ -	
LRAM & SSM Rate Rider	per kWh		5,000	$ -	$ 0.0019	5,000	$ 9.50	$ 9.50	
			5,000	$ -		5,000	$ -	$ -	
			5,000	$ -		5,000	$ -	$ -	
			5,000	$ -		5,000	$ -	$ -	
			5,000	$ -		5,000	$ -	$ -	
			5,000	$ -		5,000	$ -	$ -	
			5,000	$ -		5,000	$ -	$ -	
			5,000	$ -		5,000	$ -	$ -	
Sub-Total A (excluding pass through)				$ 143.26			$ 172.02	**$ 28.76**	**20.08%**
DVA - Total in Effect 2016	per kWh	-$ 0.0014	5,000	-$ 7.00	-$ 0.0048	5,000	-$ 24.00	-$ 17.00	242.86%
DVA - Total in Effect 2017	per kWh		5,000	$ -		5,000	$ -	$ -	
			5,000	$ -		5,000	$ -	$ -	
			5,000	$ -		5,000	$ -	$ -	
Low Voltage Service Charge	per kWh	$ 0.0002	5,000	$ 1.00	$ 0.0003	5,000	$ 1.50	$ 0.50	50.00%
Line Losses on Cost of Power	per kWh	$ 0.1077	271	$ 29.18	$ 0.1077	265	$ 28.53	-$ 0.65	-2.21%
Smart Meter Entity Charge	Monthly	$ 0.7900	1	$ 0.79	$ 0.7900	1	$ 0.79	$ -	0.00%
Sub-Total B - Distribution (includes Sub-Total A)				**$ 167.23**			**$ 178.84**	**$ 11.61**	**6.95%**
RTSR - Network	per kWh	$ 0.0061	5,271	$ 32.15	$ 0.0058	5,265	$ 30.54	-$ 1.62	-5.03%
RTSR - Line and Transformation Connection	per kWh	$ 0.0050	5,271	$ 26.36	$ 0.0050	5,265	$ 26.33	-$ 0.03	-0.11%
Sub-Total C - Delivery (including Sub-Total B)				**$ 225.73**			**$ 235.70**	**$ 9.97**	**4.42%**
Wholesale Market Service Charge (WMSC)	per kWh	$ 0.0036	5,271	$ 18.98	$ 0.0036	5,265	$ 18.95	-$ 0.02	-0.11%
Rural and Remote Rate Protection (RRRP)	per kWh	$ 0.0013	5,271	$ 6.85	$ 0.0013	5,265	$ 6.84	-$ 0.01	-0.11%
Standard Supply Service Charge	Monthly	$ 0.2500	1	$ 0.25	$ 0.2500	1	$ 0.25	$ -	0.00%
Debt Retirement Charge (DRC)			5,000	$ -		5,000	$ -	$ -	
Ontario Electricity Support Program (OESP)	per kWh	$ 0.0011	5,271	$ 5.80	$ 0.0011	5,265	$ 5.79	-$ 0.01	-0.11%
TOU - Off Peak	per kWh	$ 0.0830	3,200	$ 265.60	$ 0.0830	3,200	$ 265.60	$ -	0.00%
TOU - Mid Peak	per kWh	$ 0.1280	900	$ 115.20	$ 0.1280	900	$ 115.20	$ -	0.00%
TOU - On Peak	per kWh	$ 0.1750	900	$ 157.50	$ 0.1750	900	$ 157.50	$ -	0.00%
Total Bill on TOU (before Taxes)				**$ 795.91**			**$ 805.84**	**$ 9.93**	**1.25%**
HST		13%		$ 103.47	13%		$ 104.76	$ 1.29	1.25%
Total Bill (including HST)				$ 899.38			$ 910.60	$ 11.22	1.25%
Ontario Clean Energy Benefit [1]									
Total Bill on TOU				**$ 899.38**			**$ 910.60**	**$ 11.22**	**1.25%**

Customer Class:	**GS<50 kW Retailer - Port Colborne**	
RPP / Non-RPP:	**Non-RPP (Retailer)**	
Consumption	**5,000**	**kWh**
Demand	**0**	**kW**
Current Loss Factor	**1.0542**	
Proposed/Approved Loss Factor	**1.0530**	
Ontario Clean Energy Benefit Applied?	**No**	

		Current Board-Approved			**Proposed**			**Impact**	
	Charge Unit	**Rate ($)**	**Volume**	**Charge ($)**	**Rate ($)**	**Volume**	**Charge ($)**	**$ Change**	**% Change**
Monthly Service Charge	Monthly	$ 28.2600	1	$ 28.26	$ 32.0200	1	$ 32.02	$ 3.76	13.31%
Smart Meter Rate Adder			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
Distribution Volumetric Rate	per kWh	$ 0.0230	5,000	$ 115.00	$ 0.0261	5,000	$ 130.50	$ 15.50	13.48%
Smart Meter Disposition Rider			5,000	$ -		5,000	$ -	$ -	
LRAM & SSM Rate Rider	per kWh		5,000	$ -	$ 0.0019	5,000	$ 9.50	$ 9.50	
			5,000	$ -		5,000	$ -	$ -	
			5,000	$ -		5,000	$ -	$ -	
			5,000	$ -		5,000	$ -	$ -	
			5,000	$ -		5,000	$ -	$ -	
			5,000	$ -		5,000	$ -	$ -	
			5,000	$ -		5,000	$ -	$ -	
			5,000	$ -		5,000	$ -	$ -	
Sub-Total A (excluding pass through)				$ 143.26			$ 172.02	**$ 28.76**	**20.08%**
DVA - Total in Effect 2016	per kWh	-$ 0.0018	5,000	-$ 9.00		5,000	$ -	$ 9.00	-100.00%
DVA - Total in Effect 2017	per kWh		5,000	$ -	$ 0.0059	5,000	$ 29.50	$ 29.50	
			5,000	$ -		5,000	$ -	$ -	
			5,000	$ -		5,000	$ -	$ -	
Low Voltage Service Charge	per kWh	$ 0.0002	5,000	$ 1.00	$ 0.0003	5,000	$ 1.50	$ 0.50	50.00%
Line Losses on Cost of Power	per kWh	$ 0.1652	271	$ 44.77	$ 0.1652	265	$ 43.78	-$ 0.99	-2.21%
Smart Meter Entity Charge	Monthly	$ 0.7900	1	$ 0.79	$ 0.7900	1	$ 0.79	$ -	0.00%
Sub-Total B - Distribution (includes Sub-Total A)				**$ 180.82**			**$ 247.59**	**$ 66.77**	**36.93%**
RTSR - Network	per kWh	$ 0.0061	5,271	$ 32.15	$ 0.0058	5,265	$ 30.54	-$ 1.62	-5.03%
RTSR - Line and Transformation Connection	per kWh	$ 0.0050	5,271	$ 26.36	$ 0.0050	5,265	$ 26.33	-$ 0.03	-0.11%
Sub-Total C - Delivery (including Sub-Total B)				**$ 239.33**			**$ 304.45**	**$ 65.12**	**27.21%**
Wholesale Market Service Charge (WMSC)	per kWh	$ 0.0036	5,271	$ 18.98	$ 0.0036	5,265	$ 18.95	-$ 0.02	-0.11%
Rural and Remote Rate Protection (RRRP)	per kWh	$ 0.0013	5,271	$ 6.85	$ 0.0013	5,265	$ 6.84	-$ 0.01	-0.11%
Standard Supply Service Charge	Monthly	$ 0.2500	1	$ 0.25	$ 0.2500	1	$ 0.25	$ -	0.00%
Debt Retirement Charge (DRC)			5,000	$ -		5,000	$ -	$ -	
Ontario Electricity Support Program (OESP)	per kWh	$ 0.0011	5,271	$ 5.80	$ 0.0011	5,265	$ 5.79	-$ 0.01	-0.11%
Non-RPP Retailer Avg. Price + GA	per kWh	$ 0.1652	5,000	$ 826.00	$ 0.1652	5,000	$ 826.00	$ -	0.00%
Total Bill on Non-RPP Avg. Price				**$ 1,097.20**			**$ 1,162.29**	**$ 65.09**	**5.93%**
HST		13%		$ 142.64	13%		$ 151.10	$ 8.46	5.93%
Total Bill (including HST)				$ 1,239.84			$ 1,313.39	$ 73.55	5.93%
Ontario Clean Energy Benefit [1]									
Total Bill on Non-RPP Avg. Price				**$ 1,239.84**			**$ 1,313.39**	**$ 73.55**	**5.93%**

Customer Class:	**GS < 50 kW TOU - Fort Erie**	
RPP / Non-RPP:	**RPP**	
Consumption	**10,000**	**kWh**
Demand	**-**	**kW**
Current Loss Factor	**1.0542**	
Proposed/Approved Loss Factor	**1.0530**	
Ontario Clean Energy Benefit Applied?	**No**	

		Current Board-Approved			**Proposed**			**Impact**	
	Charge Unit	**Rate ($)**	**Volume**	**Charge ($)**	**Rate ($)**	**Volume**	**Charge ($)**	**$ Change**	**% Change**
Monthly Service Charge	Monthly	$ 28.2600	1	$ 28.26	$ 32.0200	1	$ 32.02	$ 3.76	13.31%
Smart Meter Rate Adder			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
Distribution Volumetric Rate	per kWh	$ 0.0230	10,000	$ 230.00	$ 0.0261	10,000	$ 261.00	$ 31.00	13.48%
Smart Meter Disposition Rider			10,000	$ -		10,000	$ -	$ -	
LRAM & SSM Rate Rider	per kWh		10,000	$ -	$ 0.0019	10,000	$ 19.00	$ 19.00	
			10,000	$ -		10,000	$ -	$ -	
			10,000	$ -		10,000	$ -	$ -	
			10,000	$ -		10,000	$ -	$ -	
			10,000	$ -		10,000	$ -	$ -	
			10,000	$ -		10,000	$ -	$ -	
			10,000	$ -		10,000	$ -	$ -	
			10,000	$ -		10,000	$ -	$ -	
Sub-Total A (excluding pass through)				$ 258.26			$ 312.02	**$ 53.76**	**20.82%**
DVA - Total in Effect 2016	per kWh	$ 0.0002	10,000	$ 2.00		10,000	$ -	-$ 2.00	-100.00%
DVA - Total in Effect 2017	per kWh		10,000	$ -	-$ 0.0048	10,000	-$ 48.00	-$ 48.00	
			10,000	$ -		10,000	$ -	$ -	
			10,000	$ -		10,000	$ -	$ -	
Low Voltage Service Charge	per kWh	$ 0.0002	10,000	$ 2.00	$ 0.0003	10,000	$ 3.00	$ 1.00	50.00%
Line Losses on Cost of Power	per kWh	$ 0.1077	542	$ 58.35	$ 0.1077	530	$ 57.06	-$ 1.29	-2.21%
Smart Meter Entity Charge	Monthly	$ 0.7900	1	$ 0.79	$ 0.7900	1	$ 0.79	$ -	0.00%
Sub-Total B - Distribution (includes Sub-Total A)				**$ 321.40**			**$ 324.87**	**$ 3.47**	**1.08%**
RTSR - Network	per kWh	$ 0.0061	10,542	$ 64.31	$ 0.0058	10,530	$ 61.07	-$ 3.23	-5.03%
RTSR - Line and Transformation Connection	per kWh	$ 0.0050	10,542	$ 52.71	$ 0.0050	10,530	$ 52.65	-$ 0.06	-0.11%
Sub-Total C - Delivery (including Sub-Total B)				**$ 438.42**			**$ 438.59**	**$ 0.18**	**0.04%**
Wholesale Market Service Charge (WMSC)	per kWh	$ 0.0036	10,542	$ 37.95	$ 0.0036	10,530	$ 37.91	-$ 0.04	-0.11%
Rural and Remote Rate Protection (RRRP)	per kWh	$ 0.0013	10,542	$ 13.70	$ 0.0013	10,530	$ 13.69	-$ 0.02	-0.11%
Standard Supply Service Charge	Monthly	$ 0.2500	1	$ 0.25	$ 0.2500	1	$ 0.25	$ -	0.00%
Debt Retirement Charge (DRC)			10,000	$ -		10,000	$ -	$ -	
Ontario Electricity Support Program (OESP)	per kWh	$ 0.0011	10,542	$ 11.60	$ 0.0011	10,530	$ 11.58	-$ 0.01	-0.11%
TOU - Off Peak	per kWh	$ 0.0830	6,400	$ 531.20	$ 0.0830	6,400	$ 531.20	$ -	0.00%
TOU - Mid Peak	per kWh	$ 0.1280	1,800	$ 230.40	$ 0.1280	1,800	$ 230.40	$ -	0.00%
TOU - On Peak	per kWh	$ 0.1750	1,800	$ 315.00	$ 0.1750	1,800	$ 315.00	$ -	0.00%
Total Bill on TOU (before Taxes)				**$ 1,578.52**			**$ 1,578.62**	**$ 0.10**	**0.01%**
HST		13%		$ 205.21	13%		$ 205.22	$ 0.01	0.01%
Total Bill (including HST)				$ 1,783.73			$ 1,783.84	$ 0.12	0.01%
Ontario Clean Energy Benefit [1]									
Total Bill on TOU				**$ 1,783.73**			**$ 1,783.84**	**$ 0.12**	**0.01%**

Customer Class:	**GS<50 kW Retailer - Fort Erie**	
RPP / Non-RPP:	**Non-RPP (Retailer)**	
Consumption	**10,000**	**kWh**
Demand	**0**	**kW**
Current Loss Factor	**1.0542**	
Proposed/Approved Loss Factor	**1.0530**	
Ontario Clean Energy Benefit Applied?	**No**	

		Current Board-Approved			**Proposed**			**Impact**	
	Charge Unit	**Rate ($)**	**Volume**	**Charge ($)**	**Rate ($)**	**Volume**	**Charge ($)**	**$ Change**	**% Change**
Monthly Service Charge	Monthly	$ 28.2600	1	$ 28.26	$ 32.0200	1	$ 32.02	$ 3.76	13.31%
Smart Meter Rate Adder			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
Distribution Volumetric Rate	per kWh	$ 0.0230	10,000	$ 230.00	$ 0.0261	10,000	$ 261.00	$ 31.00	13.48%
Smart Meter Disposition Rider			10,000	$ -		10,000	$ -	$ -	
LRAM & SSM Rate Rider	per kWh		10,000	$ -	$ 0.0019	10,000	$ 19.00	$ 19.00	
			10,000	$ -		10,000	$ -	$ -	
			10,000	$ -		10,000	$ -	$ -	
			10,000	$ -		10,000	$ -	$ -	
			10,000	$ -		10,000	$ -	$ -	
			10,000	$ -		10,000	$ -	$ -	
			10,000	$ -		10,000	$ -	$ -	
			10,000	$ -		10,000	$ -	$ -	
Sub-Total A (excluding pass through)				$ 258.26			$ 312.02	**$ 53.76**	**20.82%**
DVA - Total in Effect 2016	per kWh	$ 0.0014	10,000	$ 14.00		10,000	$ -	-$ 14.00	-100.00%
DVA - Total in Effect 2017	per kWh		10,000	$ -	$ 0.0059	10,000	$ 59.00	$ 59.00	
			10,000	$ -		10,000	$ -	$ -	
			10,000	$ -		10,000	$ -	$ -	
Low Voltage Service Charge	per kWh	$ 0.0002	10,000	$ 2.00	$ 0.0003	10,000	$ 3.00	$ 1.00	50.00%
Line Losses on Cost of Power	per kWh	$ 0.1652	542	$ 89.54	$ 0.1652	530	$ 87.56	-$ 1.98	-2.21%
Smart Meter Entity Charge	Monthly	$ 0.7900	1	$ 0.79	$ 0.7900	1	$ 0.79	$ -	0.00%
Sub-Total B - Distribution (includes Sub-Total A)				**$ 364.59**			**$ 462.37**	**$ 97.78**	**26.82%**
RTSR - Network	per kWh	$ 0.0061	10,542	$ 64.31	$ 0.0058	10,530	$ 61.07	-$ 3.23	-5.03%
RTSR - Line and Transformation Connection	per kWh	$ 0.0050	10,542	$ 52.71	$ 0.0050	10,530	$ 52.65	-$ 0.06	-0.11%
Sub-Total C - Delivery (including Sub-Total B)				**$ 481.60**			**$ 576.09**	**$ 94.49**	**19.62%**
Wholesale Market Service Charge (WMSC)	per kWh	$ 0.0036	10,542	$ 37.95	$ 0.0036	10,530	$ 37.91	-$ 0.04	-0.11%
Rural and Remote Rate Protection (RRRP)	per kWh	$ 0.0013	10,542	$ 13.70	$ 0.0013	10,530	$ 13.69	-$ 0.02	-0.11%
Standard Supply Service Charge	Monthly	$ 0.2500	1	$ 0.25	$ 0.2500	1	$ 0.25	$ -	0.00%
Debt Retirement Charge (DRC)			10,000	$ -		10,000	$ -	$ -	
Ontario Electricity Support Program (OESP)	per kWh	$ 0.0011	10,542	$ 11.60	$ 0.0011	10,530	$ 11.58	-$ 0.01	-0.11%
Non-RPP Retailer Avg. Price + GA	per kWh	$ 0.1652	10,000	$ 1,652.00	$ 0.1652	10,000	$ 1,652.00	$ -	0.00%
Total Bill on Non-RPP Avg. Price				**$ 2,197.11**			**$ 2,291.52**	**$ 94.41**	**4.30%**
HST		13%		$ 285.62	13%		$ 297.90	$ 12.27	4.30%
Total Bill (including HST)				$ 2,482.73			$ 2,589.42	$ 106.69	4.30%
***Ontario Clean Energy Benefit* [1]**									
Total Bill on Non-RPP Avg. Price				**$ 2,482.73**			**$ 2,589.42**	**$ 106.69**	**4.30%**

Customer Class:	**GS < 50 kW TOU - EOP**	
RPP / Non-RPP:	**RPP**	
Consumption	**10,000**	**kWh**
Demand	**-**	**kW**
Current Loss Factor	**1.0542**	
Proposed/Approved Loss Factor	**1.0530**	
Ontario Clean Energy Benefit Applied?	**No**	

		Current Board-Approved			Proposed			Impact	
	Charge Unit	**Rate ($)**	**Volume**	**Charge ($)**	**Rate ($)**	**Volume**	**Charge ($)**	**$ Change**	**% Change**
Monthly Service Charge	Monthly	$ 28.2600	1	$ 28.26	$ 32.0200	1	$ 32.02	$ 3.76	13.31%
Smart Meter Rate Adder			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
Distribution Volumetric Rate	per kWh	$ 0.0230	10,000	$ 230.00	$ 0.0261	10,000	$ 261.00	$ 31.00	13.48%
Smart Meter Disposition Rider			10,000	$ -		10,000	$ -	$ -	
LRAM & SSM Rate Rider	per kWh		10,000	$ -	$ 0.0019	10,000	$ 19.00	$ 19.00	
			10,000	$ -		10,000	$ -	$ -	
			10,000	$ -		10,000	$ -	$ -	
			10,000	$ -		10,000	$ -	$ -	
			10,000	$ -		10,000	$ -	$ -	
			10,000	$ -		10,000	$ -	$ -	
			10,000	$ -		10,000	$ -	$ -	
			10,000	$ -		10,000	$ -	$ -	
Sub-Total A (excluding pass through)				$ 258.26			$ 312.02	**$ 53.76**	**20.82%**
DVA - Total in Effect 2016	per kWh	-$ 0.0024	10,000	-$ 24.00	-$ 0.0048	10,000	-$ 48.00	-$ 24.00	100.00%
DVA - Total in Effect 2017	per kWh		10,000	$ -		10,000	$ -	$ -	
			10,000	$ -		10,000	$ -	$ -	
			10,000	$ -		10,000	$ -	$ -	
Low Voltage Service Charge	per kWh	$ 0.0002	10,000	$ 2.00	$ 0.0003	10,000	$ 3.00	$ 1.00	50.00%
Line Losses on Cost of Power	per kWh	$ 0.1077	542	$ 58.35	$ 0.1077	530	$ 57.06	-$ 1.29	-2.21%
Smart Meter Entity Charge	Monthly	$ 0.7900	1	$ 0.79	$ 0.7900	1	$ 0.79	$ -	0.00%
Sub-Total B - Distribution (includes Sub-Total A)				**$ 295.40**			**$ 324.87**	**$ 29.47**	**9.98%**
RTSR - Network	per kWh	$ 0.0061	10,542	$ 64.31	$ 0.0058	10,530	$ 61.07	-$ 3.23	-5.03%
RTSR - Line and Transformation Connection	per kWh	$ 0.0050	10,542	$ 52.71	$ 0.0050	10,530	$ 52.65	-$ 0.06	-0.11%
Sub-Total C - Delivery (including Sub-Total B)				**$ 412.42**			**$ 438.59**	**$ 26.18**	**6.35%**
Wholesale Market Service Charge (WMSC)	per kWh	$ 0.0036	10,542	$ 37.95	$ 0.0036	10,530	$ 37.91	-$ 0.04	-0.11%
Rural and Remote Rate Protection (RRRP)	per kWh	$ 0.0013	10,542	$ 13.70	$ 0.0013	10,530	$ 13.69	-$ 0.02	-0.11%
Standard Supply Service Charge	Monthly	$ 0.2500	1	$ 0.25	$ 0.2500	1	$ 0.25	$ -	0.00%
Debt Retirement Charge (DRC)			10,000	$ -		10,000	$ -	$ -	
Ontario Electricity Support Program (OESP)	per kWh	$ 0.0011	10,542	$ 11.60	$ 0.0011	10,530	$ 11.58	-$ 0.01	-0.11%
TOU - Off Peak	per kWh	$ 0.0830	6,400	$ 531.20	$ 0.0830	6,400	$ 531.20	$ -	0.00%
TOU - Mid Peak	per kWh	$ 0.1280	1,800	$ 230.40	$ 0.1280	1,800	$ 230.40	$ -	0.00%
TOU - On Peak	per kWh	$ 0.1750	1,800	$ 315.00	$ 0.1750	1,800	$ 315.00	$ -	0.00%
Total Bill on TOU (before Taxes)				**$ 1,552.52**			**$ 1,578.62**	**$ 26.10**	**1.68%**
HST		13%		$ 201.83	13%		$ 205.22	$ 3.39	1.68%
Total Bill (including HST)				$ 1,754.35			$ 1,783.84	$ 29.50	1.68%
Ontario Clean Energy Benefit [1]									
Total Bill on TOU				**$ 1,754.35**			**$ 1,783.84**	**$ 29.50**	**1.68%**

Customer Class:	**GS<50 kW Retailer - EOP**
RPP / Non-RPP:	**Non-RPP (Retailer)**
Consumption	**10,000** kWh
Demand	**0** kW
Current Loss Factor	**1.0542**
Proposed/Approved Loss Factor	**1.0530**
Ontario Clean Energy Benefit Applied?	**No**

		Current Board-Approved			**Proposed**			**Impact**	
	Charge Unit	**Rate ($)**	**Volume**	**Charge ($)**	**Rate ($)**	**Volume**	**Charge ($)**	**$ Change**	**% Change**
Monthly Service Charge	Monthly	$ 28.2600	1	$ 28.26	$ 32.0200	1	$ 32.02	$ 3.76	13.31%
Smart Meter Rate Adder			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
Distribution Volumetric Rate	per kWh	$ 0.0230	10,000	$ 230.00	$ 0.0261	10,000	$ 261.00	$ 31.00	13.48%
Smart Meter Disposition Rider			10,000	$ -		10,000	$ -	$ -	
LRAM & SSM Rate Rider	per kWh		10,000	$ -	$ 0.0019	10,000	$ 19.00	$ 19.00	
			10,000	$ -		10,000	$ -	$ -	
			10,000	$ -		10,000	$ -	$ -	
			10,000	$ -		10,000	$ -	$ -	
			10,000	$ -		10,000	$ -	$ -	
			10,000	$ -		10,000	$ -	$ -	
			10,000	$ -		10,000	$ -	$ -	
			10,000	$ -		10,000	$ -	$ -	
Sub-Total A (excluding pass through)				$ 258.26			$ 312.02	**$ 53.76**	**20.82%**
DVA - Total in Effect 2016	per kWh	$ 0.0156	10,000	$ 156.00		10,000	$ -	-$ 156.00	-100.00%
DVA - Total in Effect 2017	per kWh		10,000	$ -	$ 0.0059	10,000	$ 59.00	$ 59.00	
			10,000	$ -		10,000	$ -	$ -	
			10,000	$ -		10,000	$ -	$ -	
Low Voltage Service Charge	per kWh	$ 0.0002	10,000	$ 2.00	$ 0.0003	10,000	$ 3.00	$ 1.00	50.00%
Line Losses on Cost of Power	per kWh	$ 0.1652	542	$ 89.54	$ 0.1652	530	$ 87.56	-$ 1.98	-2.21%
Smart Meter Entity Charge	Monthly	$ 0.7900	1	$ 0.79	$ 0.7900	1	$ 0.79	$ -	0.00%
Sub-Total B - Distribution (includes Sub-Total A)				**$ 506.59**			**$ 462.37**	**-$ 44.22**	**-8.73%**
RTSR - Network	per kWh	$ 0.0061	10,542	$ 64.31	$ 0.0058	10,530	$ 61.07	-$ 3.23	-5.03%
RTSR - Line and Transformation Connection	per kWh	$ 0.0050	10,542	$ 52.71	$ 0.0050	10,530	$ 52.65	-$ 0.06	-0.11%
Sub-Total C - Delivery (including Sub-Total B)				**$ 623.60**			**$ 576.09**	**-$ 47.51**	**-7.62%**
Wholesale Market Service Charge (WMSC)	per kWh	$ 0.0036	10,542	$ 37.95	$ 0.0036	10,530	$ 37.91	-$ 0.04	-0.11%
Rural and Remote Rate Protection (RRRP)	per kWh	$ 0.0013	10,542	$ 13.70	$ 0.0013	10,530	$ 13.69	-$ 0.02	-0.11%
Standard Supply Service Charge	Monthly	$ 0.2500	1	$ 0.25	$ 0.2500	1	$ 0.25	$ -	0.00%
Debt Retirement Charge (DRC)			10,000	$ -		10,000	$ -	$ -	
Ontario Electricity Support Program (OESP)	per kWh	$ 0.0011	10,542	$ 11.60	$ 0.0011	10,530	$ 11.58	-$ 0.01	-0.11%
Non-RPP Retailer Avg. Price + GA	per kWh	$ 0.1652	10,000	$ 1,652.00	$ 0.1652	10,000	$ 1,652.00	$ -	0.00%
Total Bill on Non-RPP Avg. Price				**$ 2,339.11**			**$ 2,291.52**	**-$ 47.59**	**-2.03%**
HST		13%		$ 304.08	13%		$ 297.90	-$ 6.19	-2.03%
Total Bill (including HST)				$ 2,643.19			$ 2,589.42	-$ 53.77	-2.03%
Ontario Clean Energy Benefit [1]									
Total Bill on Non-RPP Avg. Price				**$ 2,643.19**			**$ 2,589.42**	**-$ 53.77**	**-2.03%**

Customer Class:	**GS < 50 kW TOU - Port Colborne**	
RPP / Non-RPP:	**RPP**	
Consumption	**10,000**	**kWh**
Demand	**-**	**kW**
Current Loss Factor	**1.0542**	
Proposed/Approved Loss Factor	**1.0530**	
Ontario Clean Energy Benefit Applied?	**No**	

		Current Board-Approved			Proposed			Impact	
	Charge Unit	**Rate ($)**	**Volume**	**Charge ($)**	**Rate ($)**	**Volume**	**Charge ($)**	**$ Change**	**% Change**
Monthly Service Charge	Monthly	$ 28.2600	1	$ 28.26	$ 32.0200	1	$ 32.02	$ 3.76	13.31%
Smart Meter Rate Adder			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
Distribution Volumetric Rate	per kWh	$ 0.0230	10,000	$ 230.00	$ 0.0261	10,000	$ 261.00	$ 31.00	13.48%
Smart Meter Disposition Rider			10,000	$ -		10,000	$ -	$ -	
LRAM & SSM Rate Rider	per kWh		10,000	$ -	$ 0.0019	10,000	$ 19.00	$ 19.00	
			10,000	$ -		10,000	$ -	$ -	
			10,000	$ -		10,000	$ -	$ -	
			10,000	$ -		10,000	$ -	$ -	
			10,000	$ -		10,000	$ -	$ -	
			10,000	$ -		10,000	$ -	$ -	
			10,000	$ -		10,000	$ -	$ -	
			10,000	$ -		10,000	$ -	$ -	
Sub-Total A (excluding pass through)				$ 258.26			$ 312.02	**$ 53.76**	**20.82%**
DVA - Total in Effect 2016	per kWh	-$ 0.0014	10,000	-$ 14.00	-$ 0.0048	10,000	-$ 48.00	-$ 34.00	242.86%
DVA - Total in Effect 2017	per kWh		10,000	$ -		10,000	$ -	$ -	
			10,000	$ -		10,000	$ -	$ -	
			10,000	$ -		10,000	$ -	$ -	
Low Voltage Service Charge	per kWh	$ 0.0002	10,000	$ 2.00	$ 0.0003	10,000	$ 3.00	$ 1.00	50.00%
Line Losses on Cost of Power	per kWh	$ 0.1077	542	$ 58.35	$ 0.1077	530	$ 57.06	-$ 1.29	-2.21%
Smart Meter Entity Charge	Monthly	$ 0.7900	1	$ 0.79	$ 0.7900	1	$ 0.79	$ -	0.00%
Sub-Total B - Distribution (includes Sub-Total A)				**$ 305.40**			**$ 324.87**	**$ 19.47**	**6.37%**
RTSR - Network	per kWh	$ 0.0061	10,542	$ 64.31	$ 0.0058	10,530	$ 61.07	-$ 3.23	-5.03%
RTSR - Line and Transformation Connection	per kWh	$ 0.0050	10,542	$ 52.71	$ 0.0050	10,530	$ 52.65	-$ 0.06	-0.11%
Sub-Total C - Delivery (including Sub-Total B)				**$ 422.42**			**$ 438.59**	**$ 16.18**	**3.83%**
Wholesale Market Service Charge (WMSC)	per kWh	$ 0.0036	10,542	$ 37.95	$ 0.0036	10,530	$ 37.91	-$ 0.04	-0.11%
Rural and Remote Rate Protection (RRRP)	per kWh	$ 0.0013	10,542	$ 13.70	$ 0.0013	10,530	$ 13.69	-$ 0.02	-0.11%
Standard Supply Service Charge	Monthly	$ 0.2500	1	$ 0.25	$ 0.2500	1	$ 0.25	$ -	0.00%
Debt Retirement Charge (DRC)			10,000	$ -		10,000	$ -	$ -	
Ontario Electricity Support Program (OESP)	per kWh	$ 0.0011	10,542	$ 11.60	$ 0.0011	10,530	$ 11.58	-$ 0.01	-0.11%
TOU - Off Peak	per kWh	$ 0.0830	6,400	$ 531.20	$ 0.0830	6,400	$ 531.20	$ -	0.00%
TOU - Mid Peak	per kWh	$ 0.1280	1,800	$ 230.40	$ 0.1280	1,800	$ 230.40	$ -	0.00%
TOU - On Peak	per kWh	$ 0.1750	1,800	$ 315.00	$ 0.1750	1,800	$ 315.00	$ -	0.00%
Total Bill on TOU (before Taxes)				**$ 1,562.52**			**$ 1,578.62**	**$ 16.10**	**1.03%**
HST		13%		$ 203.13	13%		$ 205.22	$ 2.09	1.03%
Total Bill (including HST)				$ 1,765.65			$ 1,783.84	$ 18.20	1.03%
***Ontario Clean Energy Benefit* [1]**									
Total Bill on TOU				**$ 1,765.65**			**$ 1,783.84**	**$ 18.20**	**1.03%**

Customer Class:	**GS<50 kW Retailer - Port Colborne**
RPP / Non-RPP:	**Non-RPP (Retailer)**
Consumption	**10,000** kWh
Demand	**0** kW
Current Loss Factor	**1.0542**
Proposed/Approved Loss Factor	**1.0530**
Ontario Clean Energy Benefit Applied?	**No**

		Current Board-Approved			Proposed			Impact	
	Charge Unit	**Rate ($)**	**Volume**	**Charge ($)**	**Rate ($)**	**Volume**	**Charge ($)**	**$ Change**	**% Change**
Monthly Service Charge	Monthly	$ 28.2600	1	$ 28.26	$ 32.0200	1	$ 32.02	$ 3.76	13.31%
Smart Meter Rate Adder			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
Distribution Volumetric Rate	per kWh	$ 0.0230	10,000	$ 230.00	$ 0.0261	10,000	$ 261.00	$ 31.00	13.48%
Smart Meter Disposition Rider			10,000	$ -		10,000	$ -	$ -	
LRAM & SSM Rate Rider	per kWh		10,000	$ -	$ 0.0019	10,000	$ 19.00	$ 19.00	
			10,000	$ -		10,000	$ -	$ -	
			10,000	$ -		10,000	$ -	$ -	
			10,000	$ -		10,000	$ -	$ -	
			10,000	$ -		10,000	$ -	$ -	
			10,000	$ -		10,000	$ -	$ -	
			10,000	$ -		10,000	$ -	$ -	
			10,000	$ -		10,000	$ -	$ -	
Sub-Total A (excluding pass through)				$ 258.26			$ 312.02	**$ 53.76**	**20.82%**
DVA - Total in Effect 2016	per kWh	-$ 0.0018	10,000	-$ 18.00		10,000	$ -	$ 18.00	-100.00%
DVA - Total in Effect 2017	per kWh		10,000	$ -	$ 0.0059	10,000	$ 59.00	$ 59.00	
			10,000	$ -		10,000	$ -	$ -	
			10,000	$ -		10,000	$ -	$ -	
Low Voltage Service Charge	per kWh	$ 0.0002	10,000	$ 2.00	$ 0.0003	10,000	$ 3.00	$ 1.00	50.00%
Line Losses on Cost of Power	per kWh	$ 0.1652	542	$ 89.54	$ 0.1652	530	$ 87.56	-$ 1.98	-2.21%
Smart Meter Entity Charge	Monthly	$ 0.7900	1	$ 0.79	$ 0.7900	1	$ 0.79	$ -	0.00%
Sub-Total B - Distribution (includes Sub-Total A)				**$ 332.59**			**$ 462.37**	**$ 129.78**	**39.02%**
RTSR - Network	per kWh	$ 0.0061	10,542	$ 64.31	$ 0.0058	10,530	$ 61.07	-$ 3.23	-5.03%
RTSR - Line and Transformation Connection	per kWh	$ 0.0050	10,542	$ 52.71	$ 0.0050	10,530	$ 52.65	-$ 0.06	-0.11%
Sub-Total C - Delivery (including Sub-Total B)				**$ 449.60**			**$ 576.09**	**$ 126.49**	**28.13%**
Wholesale Market Service Charge (WMSC)	per kWh	$ 0.0036	10,542	$ 37.95	$ 0.0036	10,530	$ 37.91	-$ 0.04	-0.11%
Rural and Remote Rate Protection (RRRP)	per kWh	$ 0.0013	10,542	$ 13.70	$ 0.0013	10,530	$ 13.69	-$ 0.02	-0.11%
Standard Supply Service Charge	Monthly	$ 0.2500	1	$ 0.25	$ 0.2500	1	$ 0.25	$ -	0.00%
Debt Retirement Charge (DRC)			10,000	$ -		10,000	$ -	$ -	
Ontario Electricity Support Program (OESP)	per kWh	$ 0.0011	10,542	$ 11.60	$ 0.0011	10,530	$ 11.58	-$ 0.01	-0.11%
Non-RPP Retailer Avg. Price + GA	per kWh	$ 0.1652	10,000	$ 1,652.00	$ 0.1652	10,000	$ 1,652.00	$ -	0.00%
Total Bill on Non-RPP Avg. Price				**$ 2,165.11**			**$ 2,291.52**	**$ 126.41**	**5.84%**
HST		13%		$ 281.46	13%		$ 297.90	$ 16.43	5.84%
Total Bill (including HST)				$ 2,446.57			$ 2,589.42	$ 142.85	5.84%
***Ontario Clean Energy Benefit* [1]**									
Total Bill on Non-RPP Avg. Price				**$ 2,446.57**			**$ 2,589.42**	**$ 142.85**	**5.84%**

Customer Class:	**GS < 50 kW TOU - Fort Erie**	
RPP / Non-RPP:	**RPP**	
Consumption	**15,000**	**kWh**
Demand	**-**	**kW**
Current Loss Factor	**1.0542**	
Proposed/Approved Loss Factor	**1.0530**	
Ontario Clean Energy Benefit Applied?	**No**	

		Current Board-Approved			Proposed			Impact	
	Charge Unit	**Rate ($)**	**Volume**	**Charge ($)**	**Rate ($)**	**Volume**	**Charge ($)**	**$ Change**	**% Change**
Monthly Service Charge	Monthly	$ 28.2600	1	$ 28.26	$ 32.0200	1	$ 32.02	$ 3.76	13.31%
Smart Meter Rate Adder			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
Distribution Volumetric Rate	per kWh	$ 0.0230	15,000	$ 345.00	$ 0.0261	15,000	$ 391.50	$ 46.50	13.48%
Smart Meter Disposition Rider			15,000	$ -		15,000	$ -	$ -	
LRAM & SSM Rate Rider	per kWh		15,000	$ -	$ 0.0019	15,000	$ 28.50	$ 28.50	
			15,000	$ -		15,000	$ -	$ -	
			15,000	$ -		15,000	$ -	$ -	
			15,000	$ -		15,000	$ -	$ -	
			15,000	$ -		15,000	$ -	$ -	
			15,000	$ -		15,000	$ -	$ -	
			15,000	$ -		15,000	$ -	$ -	
			15,000	$ -		15,000	$ -	$ -	
Sub-Total A (excluding pass through)				$ 373.26			$ 452.02	**$ 78.76**	**21.10%**
DVA - Total in Effect 2016	per kWh	$ 0.0002	15,000	$ 3.00		15,000	$ -	-$ 3.00	-100.00%
DVA - Total in Effect 2017	per kWh		15,000	$ -	-$ 0.0048	15,000	-$ 72.00	-$ 72.00	
			15,000	$ -		15,000	$ -	$ -	
			15,000	$ -		15,000	$ -	$ -	
Low Voltage Service Charge	per kWh	$ 0.0002	15,000	$ 3.00	$ 0.0003	15,000	$ 4.50	$ 1.50	50.00%
Line Losses on Cost of Power	per kWh	$ -	-	$ -	$ -	-	$ -	$ -	
Smart Meter Entity Charge	Monthly	$ 0.7900	1	$ 0.79	$ 0.7900	1	$ 0.79	$ -	0.00%
Sub-Total B - Distribution (includes Sub-Total A)				**$ 380.05**			**$ 385.31**	**$ 5.26**	**1.38%**
RTSR - Network	per kWh	$ 0.0061	15,813	$ 96.46	$ 0.0058	15,795	$ 91.61	-$ 4.85	-5.03%
RTSR - Line and Transformation Connection	per kWh	$ 0.0050	15,813	$ 79.07	$ 0.0050	15,795	$ 78.98	-$ 0.09	-0.11%
Sub-Total C - Delivery (including Sub-Total B)				**$ 555.57**			**$ 555.90**	**$ 0.32**	**0.06%**
Wholesale Market Service Charge (WMSC)	per kWh	$ 0.0036	15,813	$ 56.93	$ 0.0036	15,795	$ 56.86	-$ 0.06	-0.11%
Rural and Remote Rate Protection (RRRP)	per kWh	$ 0.0013	15,813	$ 20.56	$ 0.0013	15,795	$ 20.53	-$ 0.02	-0.11%
Standard Supply Service Charge	Monthly	$ 0.2500	1	$ 0.25	$ 0.2500	1	$ 0.25	$ -	0.00%
Debt Retirement Charge (DRC)			15,000	$ -		15,000	$ -	$ -	
Ontario Electricity Support Program (OESP)	per kWh	$ 0.0011	15,813	$ 17.39	$ 0.0011	15,795	$ 17.37	-$ 0.02	-0.11%
TOU - Off Peak	per kWh	$ 0.0830	10,120	$ 839.99	$ 0.0830	10,109	$ 839.03	-$ 0.96	-0.11%
TOU - Mid Peak	per kWh	$ 0.1280	2,846	$ 364.33	$ 0.1280	2,843	$ 363.92	-$ 0.41	-0.11%
TOU - On Peak	per kWh	$ 0.1750	2,846	$ 498.11	$ 0.1750	2,843	$ 497.54	-$ 0.57	-0.11%
Total Bill on TOU (before Taxes)				**$ 2,353.13**			**$ 2,351.41**	**-$ 1.72**	**-0.07%**
HST		13%		$ 305.91	13%		$ 305.68	-$ 0.22	-0.07%
Total Bill (including HST)				$ 2,659.04			$ 2,657.09	-$ 1.95	-0.07%
***Ontario Clean Energy Benefit* [1]**									
Total Bill on TOU				**$ 2,659.04**			**$ 2,657.09**	**-$ 1.95**	**-0.07%**

Customer Class:	**GS<50 kW Retailer - Fort Erie**
RPP / Non-RPP:	**Non-RPP (Retailer)**
Consumption	**15,000** kWh
Demand	**-** kW
Current Loss Factor	**1.0542**
Proposed/Approved Loss Factor	**1.0530**
Ontario Clean Energy Benefit Applied?	**No**

		Current Board-Approved			**Proposed**			**Impact**	
	Charge Unit	**Rate ($)**	**Volume**	**Charge ($)**	**Rate ($)**	**Volume**	**Charge ($)**	**$ Change**	**% Change**
Monthly Service Charge	Monthly	$ 28.2600	1	$ 28.26	$ 32.0200	1	$ 32.02	$ 3.76	13.31%
Smart Meter Rate Adder			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
Distribution Volumetric Rate	per kWh	$ 0.0230	15,000	$ 345.00	$ 0.0261	15,000	$ 391.50	$ 46.50	13.48%
Smart Meter Disposition Rider			15,000	$ -		15,000	$ -	$ -	
LRAM & SSM Rate Rider	per kWh		15,000	$ -	$ 0.0019	15,000	$ 28.50	$ 28.50	
			15,000	$ -		15,000	$ -	$ -	
			15,000	$ -		15,000	$ -	$ -	
			15,000	$ -		15,000	$ -	$ -	
			15,000	$ -		15,000	$ -	$ -	
			15,000	$ -		15,000	$ -	$ -	
			15,000	$ -		15,000	$ -	$ -	
			15,000	$ -		15,000	$ -	$ -	
Sub-Total A (excluding pass through)				$ 373.26			$ 452.02	**$ 78.76**	**21.10%**
DVA - Total in Effect 2016	per kWh	$ 0.0014	15,000	$ 21.00		15,000	$ -	-$ 21.00	-100.00%
DVA - Total in Effect 2017	per kWh		15,000	$ -	$ 0.0059	15,000	$ 88.50	$ 88.50	
			15,000	$ -		1	$ -	$ -	
			15,000	$ -		15,000	$ -	$ -	
Low Voltage Service Charge	per kWh	$ 0.0002	15,000	$ 3.00	$ 0.0003	15,000	$ 4.50	$ 1.50	50.00%
Line Losses on Cost of Power	per kWh	$ -	-	$ -	$ -	-	$ -	$ -	
Smart Meter Entity Charge	Monthly	$ 0.7900	1	$ 0.79	$ 0.7900	1	$ 0.79	$ -	0.00%
Sub-Total B - Distribution (includes Sub-Total A)				**$ 398.05**			**$ 545.81**	**$ 147.76**	**37.12%**
RTSR - Network	per kWh	$ 0.0061	15,813	$ 96.46	$ 0.0058	15,795	$ 91.61	-$ 4.85	-5.03%
RTSR - Line and Transformation Connection	per kWh	$ 0.0050	15,813	$ 79.07	$ 0.0050	15,795	$ 78.98	-$ 0.09	-0.11%
Sub-Total C - Delivery (including Sub-Total B)				**$ 573.57**			**$ 716.40**	**$ 142.82**	**24.90%**
Wholesale Market Service Charge (WMSC)	per kWh	$ 0.0036	15,813	$ 56.93	$ 0.0036	15,795	$ 56.86	-$ 0.06	-0.11%
Rural and Remote Rate Protection (RRRP)	per kWh	$ 0.0013	15,813	$ 20.56	$ 0.0013	15,795	$ 20.53	-$ 0.02	-0.11%
Standard Supply Service Charge	Monthly	$ 0.2500	1	$ 0.25	$ 0.2500	1	$ 0.25	$ -	0.00%
Debt Retirement Charge (DRC)			15,000	$ -		15,000	$ -	$ -	
Ontario Electricity Support Program (OESP)	per kWh	$ 0.0011	15,813	$ 17.39	$ 0.0011	15,795	$ 17.37	-$ 0.02	-0.11%
Non-RPP Retailer Avg. Price + GA	per kWh	$ 0.1652	15,813	$ 2,612.31	$ 0.1652	15,795	$ 2,609.33	-$ 2.97	-0.11%
Total Bill on Non-RPP Avg. Price				**$ 3,281.01**			**$ 3,420.75**	**$ 139.74**	**4.26%**
HST		13%		$ 426.53	13%		$ 444.70	$ 18.17	4.26%
Total Bill (including HST)				$ 3,707.54			$ 3,865.45	$ 157.91	4.26%
Ontario Clean Energy Benefit [1]									
Total Bill on Non-RPP Avg. Price				**$ 3,707.54**			**$ 3,865.45**	**$ 157.91**	**4.26%**

Customer Class:	**GS < 50 kW TOU - EOP**
RPP / Non-RPP:	**RPP**
Consumption	**15,000** kWh
Demand	**-** kW
Current Loss Factor	**1.0542**
Proposed/Approved Loss Factor	**1.0530**
Ontario Clean Energy Benefit Applied?	**No**

		Current Board-Approved			Proposed			Impact	
	Charge Unit	**Rate ($)**	**Volume**	**Charge ($)**	**Rate ($)**	**Volume**	**Charge ($)**	**$ Change**	**% Change**
Monthly Service Charge	Monthly	$ 28.2600	1	$ 28.26	$ 32.0200	1	$ 32.02	$ 3.76	13.31%
Smart Meter Rate Adder			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
Distribution Volumetric Rate	per kWh	$ 0.0230	15,000	$ 345.00	$ 0.0261	15,000	$ 391.50	$ 46.50	13.48%
Smart Meter Disposition Rider			15,000	$ -		15,000	$ -	$ -	
LRAM & SSM Rate Rider	per kWh		15,000	$ -	$ 0.0019	15,000	$ 28.50	$ 28.50	
			15,000	$ -		15,000	$ -	$ -	
			15,000	$ -		15,000	$ -	$ -	
			15,000	$ -		15,000	$ -	$ -	
			15,000	$ -		15,000	$ -	$ -	
			15,000	$ -		15,000	$ -	$ -	
			15,000	$ -		15,000	$ -	$ -	
			15,000	$ -		15,000	$ -	$ -	
Sub-Total A (excluding pass through)				$ 373.26			$ 452.02	**$ 78.76**	**21.10%**
DVA - Total in Effect 2016	per kWh	-$ 0.0024	15,000	-$ 36.00	-$ 0.0048	15,000	-$ 72.00	-$ 36.00	100.00%
DVA - Total in Effect 2017	per kWh		15,000	$ -		15,000	$ -	$ -	
			15,000	$ -		15,000	$ -	$ -	
			15,000	$ -		15,000	$ -	$ -	
Low Voltage Service Charge	per kWh	$ 0.0002	15,000	$ 3.00	$ 0.0003	15,000	$ 4.50	$ 1.50	50.00%
Line Losses on Cost of Power	per kWh	$ -	-	$ -	$ -	-	$ -	$ -	
Smart Meter Entity Charge	Monthly	$ 0.7900	1	$ 0.79	$ 0.7900	1	$ 0.79	$ -	0.00%
Sub-Total B - Distribution (includes Sub-Total A)				**$ 341.05**			**$ 385.31**	**$ 44.26**	**12.98%**
RTSR - Network	per kWh	$ 0.0061	15,813	$ 96.46	$ 0.0058	15,795	$ 91.61	-$ 4.85	-5.03%
RTSR - Line and Transformation Connection	per kWh	$ 0.0050	15,813	$ 79.07	$ 0.0050	15,795	$ 78.98	-$ 0.09	-0.11%
Sub-Total C - Delivery (including Sub-Total B)				**$ 516.57**			**$ 555.90**	**$ 39.32**	**7.61%**
Wholesale Market Service Charge (WMSC)	per kWh	$ 0.0036	15,813	$ 56.93	$ 0.0036	15,795	$ 56.86	-$ 0.06	-0.11%
Rural and Remote Rate Protection (RRRP)	per kWh	$ 0.0013	15,813	$ 20.56	$ 0.0013	15,795	$ 20.53	-$ 0.02	-0.11%
Standard Supply Service Charge	Monthly	$ 0.2500	1	$ 0.25	$ 0.2500	1	$ 0.25	$ -	0.00%
Debt Retirement Charge (DRC)			15,000	$ -		15,000	$ -	$ -	
Ontario Electricity Support Program (OESP)	per kWh	$ 0.0011	15,813	$ 17.39	$ 0.0011	15,795	$ 17.37	-$ 0.02	-0.11%
TOU - Off Peak	per kWh	$ 0.0830	10,120	$ 839.99	$ 0.0830	10,109	$ 839.03	-$ 0.96	-0.11%
TOU - Mid Peak	per kWh	$ 0.1280	2,846	$ 364.33	$ 0.1280	2,843	$ 363.92	-$ 0.41	-0.11%
TOU - On Peak	per kWh	$ 0.1750	2,846	$ 498.11	$ 0.1750	2,843	$ 497.54	-$ 0.57	-0.11%
Total Bill on TOU (before Taxes)				**$ 2,314.13**			**$ 2,351.41**	**$ 37.28**	**1.61%**
HST		13%		$ 300.84	13%		$ 305.68	$ 4.85	1.61%
Total Bill (including HST)				$ 2,614.97			$ 2,657.09	$ 42.12	1.61%
Ontario Clean Energy Benefit [1]									
Total Bill on TOU				**$ 2,614.97**			**$ 2,657.09**	**$ 42.12**	**1.61%**

Customer Class:	**GS<50 kW Retailer - EOP**	
RPP / Non-RPP:	**Non-RPP (Retailer)**	
Consumption	**15,000**	**kWh**
Demand	**-**	**kW**
Current Loss Factor	**1.0542**	
Proposed/Approved Loss Factor	**1.0530**	
Ontario Clean Energy Benefit Applied?	**No**	

		Current Board-Approved			Proposed			Impact	
	Charge Unit	**Rate ($)**	**Volume**	**Charge ($)**	**Rate ($)**	**Volume**	**Charge ($)**	**$ Change**	**% Change**
Monthly Service Charge	Monthly	$ 28.2600	1	$ 28.26	$ 32.0200	1	$ 32.02	$ 3.76	13.31%
Smart Meter Rate Adder			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
Distribution Volumetric Rate	per kWh	$ 0.0230	15,000	$ 345.00	$ 0.0261	15,000	$ 391.50	$ 46.50	13.48%
Smart Meter Disposition Rider			15,000	$ -		15,000	$ -	$ -	
LRAM & SSM Rate Rider	per kWh		15,000	$ -	$ 0.0019	15,000	$ 28.50	$ 28.50	
			15,000	$ -		15,000	$ -	$ -	
			15,000	$ -		15,000	$ -	$ -	
			15,000	$ -		15,000	$ -	$ -	
			15,000	$ -		15,000	$ -	$ -	
			15,000	$ -		15,000	$ -	$ -	
			15,000	$ -		15,000	$ -	$ -	
			15,000	$ -		15,000	$ -	$ -	
Sub-Total A (excluding pass through)				$ 373.26			$ 452.02	**$ 78.76**	**21.10%**
DVA - Total in Effect 2016	per kWh	$ 0.0156	15,000	$ 234.00		15,000	$ -	-$ 234.00	-100.00%
DVA - Total in Effect 2017	per kWh		15,000	$ -	$ 0.0059	15,000	$ 88.50	$ 88.50	
			15,000	$ -		1	$ -	$ -	
			15,000	$ -		15,000	$ -	$ -	
Low Voltage Service Charge	per kWh	$ 0.0002	15,000	$ 3.00	$ 0.0003	15,000	$ 4.50	$ 1.50	50.00%
Line Losses on Cost of Power	per kWh	$ -	-	$ -	$ -	-	$ -	$ -	
Smart Meter Entity Charge	Monthly	$ 0.7900	1	$ 0.79	$ 0.7900	1	$ 0.79	$ -	0.00%
Sub-Total B - Distribution (includes Sub-Total A)				**$ 611.05**			**$ 545.81**	**-$ 65.24**	**-10.68%**
RTSR - Network	per kWh	$ 0.0061	15,813	$ 96.46	$ 0.0058	15,795	$ 91.61	-$ 4.85	-5.03%
RTSR - Line and Transformation Connection	per kWh	$ 0.0050	15,813	$ 79.07	$ 0.0050	15,795	$ 78.98	-$ 0.09	-0.11%
Sub-Total C - Delivery (including Sub-Total B)				**$ 786.57**			**$ 716.40**	**-$ 70.18**	**-8.92%**
Wholesale Market Service Charge (WMSC)	per kWh	$ 0.0036	15,813	$ 56.93	$ 0.0036	15,795	$ 56.86	-$ 0.06	-0.11%
Rural and Remote Rate Protection (RRRP)	per kWh	$ 0.0013	15,813	$ 20.56	$ 0.0013	15,795	$ 20.53	-$ 0.02	-0.11%
Standard Supply Service Charge	Monthly	$ 0.2500	1	$ 0.25	$ 0.2500	1	$ 0.25	$ -	0.00%
Debt Retirement Charge (DRC)			15,000	$ -		15,000	$ -	$ -	
Ontario Electricity Support Program (OESP)	per kWh	$ 0.0011	15,813	$ 17.39	$ 0.0011	15,795	$ 17.37	-$ 0.02	-0.11%
Non-RPP Retailer Avg. Price + GA	per kWh	$ 0.1652	15,813	$ 2,612.31	$ 0.1652	15,795	$ 2,609.33	-$ 2.97	-0.11%
Total Bill on Non-RPP Avg. Price				**$ 3,494.01**			**$ 3,420.75**	**-$ 73.26**	**-2.10%**
HST		13%		$ 454.22	13%		$ 444.70	-$ 9.52	-2.10%
Total Bill (including HST)				$ 3,948.23			$ 3,865.45	-$ 82.78	-2.10%
Ontario Clean Energy Benefit [1]									
Total Bill on Non-RPP Avg. Price				**$ 3,948.23**			**$ 3,865.45**	**-$ 82.78**	**-2.10%**

Customer Class:	**GS < 50 kW TOU - Port Colborne**	
RPP / Non-RPP:	**RPP**	
Consumption	**15,000**	**kWh**
Demand	**-**	**kW**
Current Loss Factor	**1.0542**	
Proposed/Approved Loss Factor	**1.0530**	
Ontario Clean Energy Benefit Applied?	**No**	

		Current Board-Approved			**Proposed**			**Impact**	
	Charge Unit	**Rate ($)**	**Volume**	**Charge ($)**	**Rate ($)**	**Volume**	**Charge ($)**	**$ Change**	**% Change**
Monthly Service Charge	Monthly	$ 28.2600	1	$ 28.26	$ 32.0200	1	$ 32.02	$ 3.76	13.31%
Smart Meter Rate Adder			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
Distribution Volumetric Rate	per kWh	$ 0.0230	15,000	$ 345.00	$ 0.0261	15,000	$ 391.50	$ 46.50	13.48%
Smart Meter Disposition Rider			15,000	$ -		15,000	$ -	$ -	
LRAM & SSM Rate Rider	per kWh		15,000	$ -	$ 0.0019	15,000	$ 28.50	$ 28.50	
			15,000	$ -		15,000	$ -	$ -	
			15,000	$ -		15,000	$ -	$ -	
			15,000	$ -		15,000	$ -	$ -	
			15,000	$ -		15,000	$ -	$ -	
			15,000	$ -		15,000	$ -	$ -	
			15,000	$ -		15,000	$ -	$ -	
			15,000	$ -		15,000	$ -	$ -	
Sub-Total A (excluding pass through)				$ 373.26			$ 452.02	**$ 78.76**	**21.10%**
DVA - Total in Effect 2016	per kWh	-$ 0.0014	15,000	-$ 21.00	-$ 0.0048	15,000	-$ 72.00	-$ 51.00	242.86%
DVA - Total in Effect 2017	per kWh		15,000	$ -		15,000	$ -	$ -	
			15,000	$ -		15,000	$ -	$ -	
			15,000	$ -		15,000	$ -	$ -	
Low Voltage Service Charge	per kWh	$ 0.0002	15,000	$ 3.00	$ 0.0003	15,000	$ 4.50	$ 1.50	50.00%
Line Losses on Cost of Power	per kWh	$ -	-	$ -	$ -	-	$ -	$ -	
Smart Meter Entity Charge	Monthly	$ 0.7900	1	$ 0.79	$ 0.7900	1	$ 0.79	$ -	0.00%
Sub-Total B - Distribution (includes Sub-Total A)				**$ 356.05**			**$ 385.31**	**$ 29.26**	**8.22%**
RTSR - Network	per kWh	$ 0.0061	15,813	$ 96.46	$ 0.0058	15,795	$ 91.61	-$ 4.85	-5.03%
RTSR - Line and Transformation Connection	per kWh	$ 0.0050	15,813	$ 79.07	$ 0.0050	15,795	$ 78.98	-$ 0.09	-0.11%
Sub-Total C - Delivery (including Sub-Total B)				**$ 531.57**			**$ 555.90**	**$ 24.32**	**4.58%**
Wholesale Market Service Charge (WMSC)	per kWh	$ 0.0036	15,813	$ 56.93	$ 0.0036	15,795	$ 56.86	-$ 0.06	-0.11%
Rural and Remote Rate Protection (RRRP)	per kWh	$ 0.0013	15,813	$ 20.56	$ 0.0013	15,795	$ 20.53	-$ 0.02	-0.11%
Standard Supply Service Charge	Monthly	$ 0.2500	1	$ 0.25	$ 0.2500	1	$ 0.25	$ -	0.00%
Debt Retirement Charge (DRC)			15,000	$ -		15,000	$ -	$ -	
Ontario Electricity Support Program (OESP)	per kWh	$ 0.0011	15,813	$ 17.39	$ 0.0011	15,795	$ 17.37	-$ 0.02	-0.11%
TOU - Off Peak	per kWh	$ 0.0830	10,120	$ 839.99	$ 0.0830	10,109	$ 839.03	-$ 0.96	-0.11%
TOU - Mid Peak	per kWh	$ 0.1280	2,846	$ 364.33	$ 0.1280	2,843	$ 363.92	-$ 0.41	-0.11%
TOU - On Peak	per kWh	$ 0.1750	2,846	$ 498.11	$ 0.1750	2,843	$ 497.54	-$ 0.57	-0.11%
Total Bill on TOU (before Taxes)				**$ 2,329.13**			**$ 2,351.41**	**$ 22.28**	**0.96%**
HST		13%		$ 302.79	13%		$ 305.68	$ 2.90	0.96%
Total Bill (including HST)				$ 2,631.92			$ 2,657.09	$ 25.17	0.96%
Ontario Clean Energy Benefit [1]									
Total Bill on TOU				**$ 2,631.92**			**$ 2,657.09**	**$ 25.17**	**0.96%**

Customer Class:	**GS<50 kW Retailer - Port Colborne**
RPP / Non-RPP:	**Non-RPP (Retailer)**
Consumption	**15,000** kWh
Demand	**-** kW
Current Loss Factor	**1.0542**
Proposed/Approved Loss Factor	**1.0530**
Ontario Clean Energy Benefit Applied?	**No**

	Charge Unit	Current Board-Approved Rate ($)	Current Volume	Current Charge ($)	Proposed Rate ($)	Proposed Volume	Proposed Charge ($)	Impact $ Change	Impact % Change
Monthly Service Charge	Monthly	$ 28.2600	1	$ 28.26	$ 32.0200	1	$ 32.02	$ 3.76	13.31%
Smart Meter Rate Adder			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
Distribution Volumetric Rate	per kWh	$ 0.0230	15,000	$ 345.00	$ 0.0261	15,000	$ 391.50	$ 46.50	13.48%
Smart Meter Disposition Rider			15,000	$ -		15,000	$ -	$ -	
LRAM & SSM Rate Rider	per kWh		15,000	$ -	$ 0.0019	15,000	$ 28.50	$ 28.50	
			15,000	$ -		15,000	$ -	$ -	
			15,000	$ -		15,000	$ -	$ -	
			15,000	$ -		15,000	$ -	$ -	
			15,000	$ -		15,000	$ -	$ -	
			15,000	$ -		15,000	$ -	$ -	
			15,000	$ -		15,000	$ -	$ -	
			15,000	$ -		15,000	$ -	$ -	
Sub-Total A (excluding pass through)				$ 373.26			$ 452.02	**$ 78.76**	**21.10%**
DVA - Total in Effect 2016	per kWh	-$ 0.0018	15,000	-$ 27.00		15,000	$ -	$ 27.00	-100.00%
DVA - Total in Effect 2017	per kWh		15,000	$ -	$ 0.0059	15,000	$ 88.50	$ 88.50	
			15,000	$ -		1	$ -	$ -	
			15,000	$ -		15,000	$ -	$ -	
Low Voltage Service Charge	per kWh	$ 0.0002	15,000	$ 3.00	$ 0.0003	15,000	$ 4.50	$ 1.50	50.00%
Line Losses on Cost of Power	per kWh	$ -	-	$ -	$ -	-	$ -	$ -	
Smart Meter Entity Charge	Monthly	$ 0.7900	1	$ 0.79	$ 0.7900	1	$ 0.79	$ -	0.00%
Sub-Total B - Distribution (includes Sub-Total A)				**$ 350.05**			**$ 545.81**	**$ 195.76**	**55.92%**
RTSR - Network	per kWh	$ 0.0061	15,813	$ 96.46	$ 0.0058	15,795	$ 91.61	-$ 4.85	-5.03%
RTSR - Line and Transformation Connection	per kWh	$ 0.0050	15,813	$ 79.07	$ 0.0050	15,795	$ 78.98	-$ 0.09	-0.11%
Sub-Total C - Delivery (including Sub-Total B)				**$ 525.57**			**$ 716.40**	**$ 190.82**	**36.31%**
Wholesale Market Service Charge (WMSC)	per kWh	$ 0.0036	15,813	$ 56.93	$ 0.0036	15,795	$ 56.86	-$ 0.06	-0.11%
Rural and Remote Rate Protection (RRRP)	per kWh	$ 0.0013	15,813	$ 20.56	$ 0.0013	15,795	$ 20.53	-$ 0.02	-0.11%
Standard Supply Service Charge	Monthly	$ 0.2500	1	$ 0.25	$ 0.2500	1	$ 0.25	$ -	0.00%
Debt Retirement Charge (DRC)			15,000	$ -		15,000	$ -	$ -	
Ontario Electricity Support Program (OESP)	per kWh	$ 0.0011	15,813	$ 17.39	$ 0.0011	15,795	$ 17.37	-$ 0.02	-0.11%
Non-RPP Retailer Avg. Price + GA	per kWh	$ 0.1652	15,813	$ 2,612.31	$ 0.1652	15,795	$ 2,609.33	-$ 2.97	-0.11%
Total Bill on Non-RPP Avg. Price				**$ 3,233.01**			**$ 3,420.75**	**$ 187.74**	**5.81%**
HST		13%		$ 420.29	13%		$ 444.70	$ 24.41	5.81%
Total Bill (including HST)				$ 3,653.30			$ 3,865.45	$ 212.15	5.81%
Ontario Clean Energy Benefit [1]									
Total Bill on Non-RPP Avg. Price				**$ 3,653.30**			**$ 3,865.45**	**$ 212.15**	**5.81%**

Customer Class:	**GS > 50 kW Non-RPP - Fort Erie**
RPP / Non-RPP:	**Non-RPP (Other)**
Consumption	**20,000** kWh
Demand	**60** kW
Current Loss Factor	**1.0542**
Proposed/Approved Loss Factor	**1.0530**
Ontario Clean Energy Benefit Applied?	**No**

		Current Board-Approved			**Proposed**			**Impact**	
	Charge Unit	**Rate ($)**	**Volume**	**Charge ($)**	**Rate ($)**	**Volume**	**Charge ($)**	**$ Change**	**% Change**
Monthly Service Charge	Monthly	$ 151.8300	1	$ 151.83	$ 172.0400	1	$ 172.04	$ 20.21	13.31%
Smart Meter Rate Adder			1	$ -		1	$ -	$ -	
MIST Disposition Rate Rider	Monthly		1	$ -	$ 7.0500	1	$ 7.05	$ 7.05	
Stranded Meter Disposition Rate Rider	Monthly		1	$ -	$ 3.6000	1	$ 3.60	$ 3.60	
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
Distribution Volumetric Rate	per kW	$ 6.6887	60	$ 401.32	$ 7.5344	60	$ 452.06	$ 50.74	12.64%
Smart Meter Disposition Rider			60	$ -		60	$ -	$ -	
LRAM & SSM Rate Rider	per kW		60	$ -	$ 0.0957	60	$ 5.74	$ 5.74	
			60	$ -		60	$ -	$ -	
			60	$ -		60	$ -	$ -	
			60	$ -		60	$ -	$ -	
			60	$ -		60	$ -	$ -	
			60	$ -		60	$ -	$ -	
			60	$ -		60	$ -	$ -	
			60	$ -		60	$ -	$ -	
Sub-Total A (excluding pass through)				$ 553.15			$ 640.50	**$ 87.34**	**15.79%**
DVA - Total in Effect 2016	per kW	$ 0.6409	60	$ 38.45		60	$ -	-$ 38.45	-100.00%
DVA - Total in Effect 2017	per kW		60	$ -	$ 1.9061	60	$ 114.37	$ 114.37	
			60	$ -		60	$ -	$ -	
			60	$ -		60	$ -	$ -	
Low Voltage Service Charge	per kW	$ 0.0735	60	$ 4.41	$ 0.1063	60	$ 6.38	$ 1.97	44.63%
Line Losses on Cost of Power		$ -	-	$ -	$ -	-	$ -	$ -	
Smart Meter Entity Charge		$ -	1	$ -	$ -	1	$ -	$ -	
Sub-Total B - Distribution (includes Sub-Total A)				**$ 596.02**			**$ 761.24**	**$ 165.22**	**27.72%**
RTSR - Network	per kW	$ 2.5966	60	$ 155.80	$ 2.4754	60	$ 148.52	-$ 7.27	-4.67%
RTSR - Line and Transformation Connection	per kW	$ 2.0803	60	$ 124.82	$ 2.1000	60	$ 126.00	$ 1.18	0.95%
Sub-Total C - Delivery (including Sub-Total B)				**$ 876.63**			**$ 1,035.76**	**$ 159.13**	**18.15%**
Wholesale Market Service Charge (WMSC)	per kWh	$ 0.0036	21,084	$ 75.90	$ 0.0036	21,060	$ 75.82	-$ 0.09	-0.11%
Rural and Remote Rate Protection (RRRP)	per kWh	$ 0.0013	21,084	$ 27.41	$ 0.0013	21,060	$ 27.38	-$ 0.03	-0.11%
Standard Supply Service Charge	Monthly	$ 0.2500	1	$ 0.25	$ 0.2500	1	$ 0.25	$ -	0.00%
Debt Retirement Charge (DRC)			20,000	$ -		20,000	$ -	$ -	
Ontario Electricity Support Program (OESP)	per kWh	$ 0.0011	21,084	$ 23.19	$ 0.0011	21,060	$ 23.17		0.00%
Average IESO Wholesale Market Price	per kWh	$ 0.1028	21,084	$ 2,167.01	$ 0.1028	21,060	$ 2,164.55	-$ 2.47	-0.11%
Total Bill on Average IESO Wholesale Market Price				**$ 3,170.40**			**$ 3,326.92**	**$ 156.52**	**4.94%**
HST		13%		$ 412.15	13%		$ 432.50	$ 20.35	4.94%
Total Bill (including HST)				$ 3,582.55			$ 3,759.42	$ 176.87	4.94%
Ontario Clean Energy Benefit [1]									
Total Bill on Average IESO Wholesale Market Price				**$ 3,582.55**			**$ 3,759.42**	**$ 176.87**	**4.94%**

Customer Class:	**GS > 50 kW Non-RPP - EOP**
RPP / Non-RPP:	**Non-RPP (Other)**
Consumption	**20,000 kWh**
Demand	**60 kW**
Current Loss Factor	**1.0542**
Proposed/Approved Loss Factor	**1.0530**
Ontario Clean Energy Benefit Applied?	**No**

		Current Board-Approved			Proposed			Impact	
	Charge Unit	**Rate ($)**	**Volume**	**Charge ($)**	**Rate ($)**	**Volume**	**Charge ($)**	**$ Change**	**% Change**
Monthly Service Charge	Monthly	$ 151.8300	1	$ 151.83	$ 172.0400	1	$ 172.04	$ 20.21	13.31%
Smart Meter Rate Adder			1	$ -		1	$ -	$ -	
MIST Disposition Rate Rider	Monthly		1	$ -	$ 7.0500	1	$ 7.05	$ 7.05	
Stranded Meter Disposition Rate Rider	Monthly		1	$ -	$ 3.6000	1	$ 3.60	$ 3.60	
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
Distribution Volumetric Rate	per kW	$ 6.6887	60	$ 401.32	$ 7.5344	60	$ 452.06	$ 50.74	12.64%
Smart Meter Disposition Rider			60	$ -		60	$ -	$ -	
LRAM & SSM Rate Rider	per kW		60	$ -	$ 0.0957	60	$ 5.74	$ 5.74	
			60	$ -		60	$ -	$ -	
			60	$ -		60	$ -	$ -	
			60	$ -		60	$ -	$ -	
			60	$ -		60	$ -	$ -	
			60	$ -		60	$ -	$ -	
			60	$ -		60	$ -	$ -	
			60	$ -		60	$ -	$ -	
Sub-Total A (excluding pass through)				$ 553.15			$ 640.50	**$ 87.34**	**15.79%**
DVA - Total in Effect 2016	per kW	$ 5.6223	60	$ 337.34		60	$ -	-$ 337.34	-100.00%
DVA - Total in Effect 2017	per kW		60	$ -	$ 1.9061	60	$ 114.37	$ 114.37	
			60	$ -		60	$ -	$ -	
			60	$ -		60	$ -	$ -	
Low Voltage Service Charge	per kW	$ 0.0735	60	$ 4.41	$ 0.1063	60	$ 6.38	$ 1.97	44.63%
Line Losses on Cost of Power		$ -	-	$ -	$ -	-	$ -	$ -	
Smart Meter Entity Charge			1	$ -		1	$ -	$ -	
Sub-Total B - Distribution (includes Sub-Total A)				**$ 894.90**			**$ 761.24**	**-$ 133.66**	**-14.94%**
RTSR - Network	per kW	$ 2.5966	60	$ 155.80	$ 2.4754	60	$ 148.52	-$ 7.27	-4.67%
RTSR - Line and Transformation Connection	per kW	$ 2.0803	60	$ 124.82	$ 2.1000	60	$ 126.00	$ 1.18	0.95%
Sub-Total C - Delivery (including Sub-Total B)				**$ 1,175.51**			**$ 1,035.76**	**-$ 139.75**	**-11.89%**
Wholesale Market Service Charge (WMSC)	per kWh	$ 0.0036	21,084	$ 75.90	$ 0.0036	21,060	$ 75.82	-$ 0.09	-0.11%
Rural and Remote Rate Protection (RRRP)	per kWh	$ 0.0013	21,084	$ 27.41	$ 0.0013	21,060	$ 27.38	-$ 0.03	-0.11%
Standard Supply Service Charge	Monthly	$ 0.2500	1	$ 0.25	$ 0.2500	1	$ 0.25	$ -	0.00%
Debt Retirement Charge (DRC)			20,000	$ -		20,000	$ -	$ -	
Ontario Electricity Support Program (OESP)	per kWh	$ 0.0011	21,084	$ 23.19	$ 0.0011	21,060	$ 23.17		0.00%
Average IESO Wholesale Market Price	per kWh	$ 0.1028	21,084	$ 2,167.01	$ 0.1028	21,060	$ 2,164.55	-$ 2.47	-0.11%
Total Bill on Average IESO Wholesale Market Price				**$ 3,469.28**			**$ 3,326.92**	**-$ 142.36**	**-4.10%**
HST		13%		$ 451.01	13%		$ 432.50	-$ 18.51	-4.10%
Total Bill (including HST)				$ 3,920.29			$ 3,759.42	-$ 160.87	-4.10%
Ontario Clean Energy Benefit [1]									
Total Bill on Average IESO Wholesale Market Price				**$ 3,920.29**			**$ 3,759.42**	**-$ 160.87**	**-4.10%**

Customer Class:	GS > 50 kW Non-RPP - Port Colborne	
RPP / Non-RPP:	Non-RPP (Other)	
Consumption	20,000	kWh
Demand	60	kW
Current Loss Factor	1.0542	
Proposed/Approved Loss Factor	1.0530	
Ontario Clean Energy Benefit Applied?	No	

		Current Board-Approved			Proposed			Impact	
	Charge Unit	**Rate ($)**	**Volume**	**Charge ($)**	**Rate ($)**	**Volume**	**Charge ($)**	**$ Change**	**% Change**
Monthly Service Charge	Monthly	$ 151.8300	1	$ 151.83	$ 172.0400	1	$ 172.04	$ 20.21	13.31%
Smart Meter Rate Adder			1	$ -		1	$ -	$ -	
MIST Disposition Rate Rider	Monthly		1	$ -	$ 7.0500	1	$ 7.05	$ 7.05	
Stranded Meter Disposition Rate Rider	Monthly		1	$ -	$ 3.6000	1	$ 3.60	$ 3.60	
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
Distribution Volumetric Rate	per kW	$ 6.6887	60	$ 401.32	$ 7.5344	60	$ 452.06	$ 50.74	12.64%
Smart Meter Disposition Rider			60	$ -		60	$ -	$ -	
LRAM & SSM Rate Rider	per kW		60	$ -	$ 0.0957	60	$ 5.74	$ 5.74	
			60	$ -		60	$ -	$ -	
			60	$ -		60	$ -	$ -	
			60	$ -		60	$ -	$ -	
			60	$ -		60	$ -	$ -	
			60	$ -		60	$ -	$ -	
			60	$ -		60	$ -	$ -	
			60	$ -		60	$ -	$ -	
Sub-Total A (excluding pass through)				$ 553.15			$ 640.50	**$ 87.34**	**15.79%**
DVA - Total in Effect 2016	per kW	-$ 0.4145	60	-$ 24.87		60	$ -	$ 24.87	-100.00%
DVA - Total in Effect 2017	per kW		60	$ -	$ 1.9061	60	$ 114.37	$ 114.37	
			60	$ -		60	$ -	$ -	
			60	$ -		60	$ -	$ -	
Low Voltage Service Charge	per kW	$ 0.0735	60	$ 4.41	$ 0.1063	60	$ 6.38	$ 1.97	44.63%
Line Losses on Cost of Power		$ -	-	$ -	$ -	-	$ -	$ -	
Smart Meter Entity Charge			1	$ -		1	$ -	$ -	
Sub-Total B - Distribution (includes Sub-Total A)				**$ 532.69**			**$ 761.24**	**$ 228.55**	**42.90%**
RTSR - Network	per kW	$ 2.5966	60	$ 155.80	$ 2.4754	60	$ 148.52	-$ 7.27	-4.67%
RTSR - Line and Transformation Connection	per kW	$ 2.0803	60	$ 124.82	$ 2.1000	60	$ 126.00	$ 1.18	0.95%
Sub-Total C - Delivery (including Sub-Total B)				**$ 813.31**			**$ 1,035.76**	**$ 222.46**	**27.35%**
Wholesale Market Service Charge (WMSC)	per kWh	$ 0.0036	21,084	$ 75.90	$ 0.0036	21,060	$ 75.82	-$ 0.09	-0.11%
Rural and Remote Rate Protection (RRRP)	per kWh	$ 0.0013	21,084	$ 27.41	$ 0.0013	21,060	$ 27.38	-$ 0.03	-0.11%
Standard Supply Service Charge	Monthly	$ 0.2500	1	$ 0.25	$ 0.2500	1	$ 0.25	$ -	0.00%
Debt Retirement Charge (DRC)			20,000	$ -		20,000	$ -	$ -	
Ontario Electricity Support Program (OESP)	per kWh	$ 0.0011	21,084	$ 23.19	$ 0.0011	21,060	$ 23.17		0.00%
Average IESO Wholesale Market Price	per kWh	$ 0.1028	21,084	$ 2,167.01	$ 0.1028	21,060	$ 2,164.55	-$ 2.47	-0.11%
Total Bill on Average IESO Wholesale Market Price				**$ 3,107.07**			**$ 3,326.92**	**$ 219.85**	**7.08%**
HST		13%		$ 403.92	13%		$ 432.50	$ 28.58	7.08%
Total Bill (including HST)				$ 3,510.99			$ 3,759.42	$ 248.43	7.08%
Ontario Clean Energy Benefit [1]									
Total Bill on Average IESO Wholesale Market Price				**$ 3,510.99**			**$ 3,759.42**	**$ 248.43**	**7.08%**

Customer Class:	**GS > 50 kW Non-RPP - Fort Erie**	
RPP / Non-RPP:	**Non-RPP (Other)**	
Consumption	**40,000**	**kWh**
Demand	**100**	**kW**
Current Loss Factor	**1.0542**	
Proposed/Approved Loss Factor	**1.0530**	
Ontario Clean Energy Benefit Applied?	**No**	

		Current Board-Approved			**Proposed**			**Impact**	
	Charge Unit	**Rate ($)**	**Volume**	**Charge ($)**	**Rate ($)**	**Volume**	**Charge ($)**	**$ Change**	**% Change**
Monthly Service Charge	Monthly	$ 151.8300	1	$ 151.83	$ 172.0400	1	$ 172.04	$ 20.21	13.31%
Smart Meter Rate Adder			1	$ -		1	$ -	$ -	
MIST Disposition Rate Rider	Monthly		1	$ -	$ 7.0500	1	$ 7.05	$ 7.05	
Stranded Meter Disposition Rate Rider	Monthly		1	$ -	$ 3.6000	1	$ 3.60	$ 3.60	
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
Distribution Volumetric Rate	per kW	$ 6.6887	100	$ 668.87	$ 7.5344	100	$ 753.44	$ 84.57	12.64%
Smart Meter Disposition Rider			100	$ -		100	$ -	$ -	
LRAM & SSM Rate Rider	per kW		100	$ -	$ 0.0957	100	$ 9.57	$ 9.57	
			100	$ -		100	$ -	$ -	
			100	$ -		100	$ -	$ -	
			100	$ -		100	$ -	$ -	
			100	$ -		100	$ -	$ -	
			100	$ -		100	$ -	$ -	
			100	$ -		100	$ -	$ -	
			100	$ -		100	$ -	$ -	
Sub-Total A (excluding pass through)				$ 820.70			$ 945.70	**$ 125.00**	**15.23%**
DVA - Total in Effect 2016	per kW	$ 0.6409	100	$ 64.09		100	$ -	-$ 64.09	-100.00%
DVA - Total in Effect 2017	per kW		100	$ -	$ 1.9061	100	$ 190.61	$ 190.61	
			100	$ -		100	$ -	$ -	
			100	$ -		100	$ -	$ -	
Low Voltage Service Charge	per kW	$ 0.0735	100	$ 7.35	$ 0.1063	100	$ 10.63	$ 3.28	44.63%
Line Losses on Cost of Power		$ -	-	$ -	$ -	-	$ -	$ -	
Smart Meter Entity Charge		$ -	1	$ -	$ -	1	$ -	$ -	
Sub-Total B - Distribution (includes Sub-Total A)				**$ 892.14**			**$ 1,146.94**	**$ 254.80**	**28.56%**
RTSR - Network	per kW	$ 2.5966	100	$ 259.66	$ 2.4754	100	$ 247.54	-$ 12.12	-4.67%
RTSR - Line and Transformation Connection	per kW	$ 2.0803	100	$ 208.03	$ 2.1000	100	$ 210.00	$ 1.97	0.95%
Sub-Total C - Delivery (including Sub-Total B)				**$ 1,359.83**			**$ 1,604.48**	**$ 244.65**	**17.99%**
Wholesale Market Service Charge (WMSC)	per kWh	$ 0.0036	42,168	$ 151.80	$ 0.0036	42,120	$ 151.63	-$ 0.17	-0.11%
Rural and Remote Rate Protection (RRRP)	per kWh	$ 0.0013	42,168	$ 54.82	$ 0.0013	42,120	$ 54.76	-$ 0.06	-0.11%
Standard Supply Service Charge	Monthly	$ 0.2500	1	$ 0.25	$ 0.2500	1	$ 0.25	$ -	0.00%
Debt Retirement Charge (DRC)			40,000	$ -		40,000	$ -	$ -	
Ontario Electricity Support Program (OESP)	per kWh	$ 0.0011	42,168	$ 46.38	$ 0.0011	42,120	$ 46.33		0.00%
Average IESO Wholesale Market Price	per kWh	$ 0.1028	42,168	$ 4,334.03	$ 0.1028	42,120	$ 4,329.09	-$ 4.93	-0.11%
Total Bill on Average IESO Wholesale Market Price				**$ 5,947.12**			**$ 6,186.54**	**$ 239.43**	**4.03%**
HST		13%		$ 773.12	13%		$ 804.25	$ 31.13	4.03%
Total Bill (including HST)				$ 6,720.24			$ 6,990.79	$ 270.55	4.03%
Ontario Clean Energy Benefit [1]									
Total Bill on Average IESO Wholesale Market Price				**$ 6,720.24**			**$ 6,990.79**	**$ 270.55**	**4.03%**

Customer Class:	GS > 50 kW Non-RPP - EOP
RPP / Non-RPP:	Non-RPP (Other)
Consumption	40,000 kWh
Demand	100 kW
Current Loss Factor	1.0542
Proposed/Approved Loss Factor	1.0530
Ontario Clean Energy Benefit Applied?	No

		Current Board-Approved			Proposed			Impact	
	Charge Unit	**Rate ($)**	**Volume**	**Charge ($)**	**Rate ($)**	**Volume**	**Charge ($)**	**$ Change**	**% Change**
Monthly Service Charge	Monthly	$ 151.8300	1	$ 151.83	$ 172.0400	1	$ 172.04	$ 20.21	13.31%
Smart Meter Rate Adder			1	$ -		1	$ -	$ -	
MIST Disposition Rate Rider	Monthly		1	$ -	$ 7.0500	1	$ 7.05	$ 7.05	
Stranded Meter Disposition Rate Rider	Monthly		1	$ -	$ 3.6000	1	$ 3.60	$ 3.60	
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
Distribution Volumetric Rate	per kW	$ 6.6887	100	$ 668.87	$ 7.5344	100	$ 753.44	$ 84.57	12.64%
Smart Meter Disposition Rider			100	$ -		100	$ -	$ -	
LRAM & SSM Rate Rider	per kW		100	$ -	$ 0.0957	100	$ 9.57	$ 9.57	
			100	$ -		100	$ -	$ -	
			100	$ -		100	$ -	$ -	
			100	$ -		100	$ -	$ -	
			100	$ -		100	$ -	$ -	
			100	$ -		100	$ -	$ -	
			100	$ -		100	$ -	$ -	
			100	$ -		100	$ -	$ -	
Sub-Total A (excluding pass through)				$ 820.70			$ 945.70	**$ 125.00**	**15.23%**
DVA - Total in Effect 2016	per kW	$ 5.6223	100	$ 562.23		100	$ -	-$ 562.23	-100.00%
DVA - Total in Effect 2017	per kW		100	$ -	$ 1.9061	100	$ 190.61	$ 190.61	
			100	$ -		100	$ -	$ -	
			100	$ -		100	$ -	$ -	
Low Voltage Service Charge	per kW	$ 0.0735	100	$ 7.35	$ 0.1063	100	$ 10.63	$ 3.28	44.63%
Line Losses on Cost of Power		$ -	-	$ -	$ -	-	$ -	$ -	
Smart Meter Entity Charge			1	$ -		1	$ -	$ -	
Sub-Total B - Distribution (includes Sub-Total A)				**$ 1,390.28**			**$ 1,146.94**	**-$ 243.34**	**-17.50%**
RTSR - Network	per kW	$ 2.5966	100	$ 259.66	$ 2.4754	100	$ 247.54	-$ 12.12	-4.67%
RTSR - Line and Transformation Connection	per kW	$ 2.0803	100	$ 208.03	$ 2.1000	100	$ 210.00	$ 1.97	0.95%
Sub-Total C - Delivery (including Sub-Total B)				**$ 1,857.97**			**$ 1,604.48**	**-$ 253.49**	**-13.64%**
Wholesale Market Service Charge (WMSC)	per kWh	$ 0.0036	42,168	$ 151.80	$ 0.0036	42,120	$ 151.63	-$ 0.17	-0.11%
Rural and Remote Rate Protection (RRRP)	per kWh	$ 0.0013	42,168	$ 54.82	$ 0.0013	42,120	$ 54.76	-$ 0.06	-0.11%
Standard Supply Service Charge	Monthly	$ 0.2500	1	$ 0.25	$ 0.2500	1	$ 0.25	$ -	0.00%
Debt Retirement Charge (DRC)			40,000	$ -		40,000	$ -	$ -	
Ontario Electricity Support Program (OESP)	per kWh	$ 0.0011	42,168	$ 46.38	$ 0.0011	42,120	$ 46.33		0.00%
Average IESO Wholesale Market Price	per kWh	$ 0.1028	42,168	$ 4,334.03	$ 0.1028	42,120	$ 4,329.09	-$ 4.93	-0.11%
Total Bill on Average IESO Wholesale Market Price				**$ 6,445.26**			**$ 6,186.54**	**-$ 258.71**	**-4.01%**
HST		13%		$ 837.88	13%		$ 804.25	-$ 33.63	-4.01%
Total Bill (including HST)				$ 7,283.14			$ 6,990.79	-$ 292.34	-4.01%
Ontario Clean Energy Benefit [1]									
Total Bill on Average IESO Wholesale Market Price				**$ 7,283.14**			**$ 6,990.79**	**-$ 292.34**	**-4.01%**

Customer Class:	**GS > 50 kW Non-RPP - Port Colborne**
RPP / Non-RPP:	**Non-RPP (Other)**
Consumption	**40,000** kWh
Demand	**100** kW
Current Loss Factor	**1.0542**
Proposed/Approved Loss Factor	**1.0530**
Ontario Clean Energy Benefit Applied?	**No**

		Current Board-Approved			Proposed			Impact	
	Charge Unit	**Rate ($)**	**Volume**	**Charge ($)**	**Rate ($)**	**Volume**	**Charge ($)**	**$ Change**	**% Change**
Monthly Service Charge	Monthly	$ 151.8300	1	$ 151.83	$ 172.0400	1	$ 172.04	$ 20.21	13.31%
Smart Meter Rate Adder			1	$ -		1	$ -	$ -	
MIST Disposition Rate Rider	Monthly		1	$ -	$ 7.0500	1	$ 7.05	$ 7.05	
Stranded Meter Disposition Rate Rider	Monthly		1	$ -	$ 3.6000	1	$ 3.60	$ 3.60	
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
Distribution Volumetric Rate	per kW	$ 6.6887	100	$ 668.87	$ 7.5344	100	$ 753.44	$ 84.57	12.64%
Smart Meter Disposition Rider			100	$ -		100	$ -	$ -	
LRAM & SSM Rate Rider	per kW		100	$ -	$ 0.0957	100	$ 9.57	$ 9.57	
			100	$ -		100	$ -	$ -	
			100	$ -		100	$ -	$ -	
			100	$ -		100	$ -	$ -	
			100	$ -		100	$ -	$ -	
			100	$ -		100	$ -	$ -	
			100	$ -		100	$ -	$ -	
			100	$ -		100	$ -	$ -	
Sub-Total A (excluding pass through)				$ 820.70			$ 945.70	**$ 125.00**	**15.23%**
DVA - Total in Effect 2016	per kW	-$ 0.4145	100	-$ 41.45		100	$ -	$ 41.45	-100.00%
DVA - Total in Effect 2017	per kW		100	$ -	$ 1.9061	100	$ 190.61	$ 190.61	
			100	$ -		100	$ -	$ -	
			100	$ -		100	$ -	$ -	
Low Voltage Service Charge	per kW	$ 0.0735	100	$ 7.35	$ 0.1063	100	$ 10.63	$ 3.28	44.63%
Line Losses on Cost of Power		$ -	-	$ -	$ -	-	$ -	$ -	
Smart Meter Entity Charge			1	$ -		1	$ -	$ -	
Sub-Total B - Distribution (includes Sub-Total A)				**$ 786.60**			**$ 1,146.94**	**$ 360.34**	**45.81%**
RTSR - Network	per kW	$ 2.5966	100	$ 259.66	$ 2.4754	100	$ 247.54	-$ 12.12	-4.67%
RTSR - Line and Transformation Connection	per kW	$ 2.0803	100	$ 208.03	$ 2.1000	100	$ 210.00	$ 1.97	0.95%
Sub-Total C - Delivery (including Sub-Total B)				**$ 1,254.29**			**$ 1,604.48**	**$ 350.19**	**27.92%**
Wholesale Market Service Charge (WMSC)	per kWh	$ 0.0036	42,168	$ 151.80	$ 0.0036	42,120	$ 151.63	-$ 0.17	-0.11%
Rural and Remote Rate Protection (RRRP)	per kWh	$ 0.0013	42,168	$ 54.82	$ 0.0013	42,120	$ 54.76	-$ 0.06	-0.11%
Standard Supply Service Charge	Monthly	$ 0.2500	1	$ 0.25	$ 0.2500	1	$ 0.25	$ -	0.00%
Debt Retirement Charge (DRC)			40,000	$ -		40,000	$ -	$ -	
Ontario Electricity Support Program (OESP)	per kWh	$ 0.0011	42,168	$ 46.38	$ 0.0011	42,120	$ 46.33		0.00%
Average IESO Wholesale Market Price	per kWh	$ 0.1028	42,168	$ 4,334.03	$ 0.1028	42,120	$ 4,329.09	-$ 4.93	-0.11%
Total Bill on Average IESO Wholesale Market Price				**$ 5,841.58**			**$ 6,186.54**	**$ 344.97**	**5.91%**
HST		13%		$ 759.40	13%		$ 804.25	$ 44.85	5.91%
Total Bill (including HST)				$ 6,600.98			$ 6,990.79	$ 389.81	5.91%
Ontario Clean Energy Benefit [1]									
Total Bill on Average IESO Wholesale Market Price				**$ 6,600.98**			**$ 6,990.79**	**$ 389.81**	**5.91%**

Customer Class:	**GS > 50 kW Non-RPP - Fort Erie**
RPP / Non-RPP:	**Non-RPP (Other)**
Consumption	**200,000** kWh
Demand	**500** kW
Current Loss Factor	**1.0542**
Proposed/Approved Loss Factor	**1.0530**
Ontario Clean Energy Benefit Applied?	**No**

		Current Board-Approved			**Proposed**			**Impact**	
	Charge Unit	**Rate ($)**	**Volume**	**Charge ($)**	**Rate ($)**	**Volume**	**Charge ($)**	**$ Change**	**% Change**
Monthly Service Charge	Monthly	$ 151.8300	1	$ 151.83	$ 172.0400	1	$ 172.04	$ 20.21	13.31%
Smart Meter Rate Adder			1	$ -		1	$ -	$ -	
MIST Disposition Rate Rider	Monthly		1	$ -	$ 7.0500	1	$ 7.05	$ 7.05	
Stranded Meter Disposition Rate Rider	Monthly		1	$ -	$ 3.6000	1	$ 3.60	$ 3.60	
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
Distribution Volumetric Rate	per kW	$ 6.6887	500	$ 3,344.35	$ 7.5344	500	$ 3,767.20	$ 422.85	12.64%
Smart Meter Disposition Rider			500	$ -		500	$ -	$ -	
LRAM & SSM Rate Rider	per kW		500	$ -	$ 0.0957	500	$ 47.85	$ 47.85	
			500	$ -		500	$ -	$ -	
			500	$ -		500	$ -	$ -	
			500	$ -		500	$ -	$ -	
			500	$ -		500	$ -	$ -	
			500	$ -		500	$ -	$ -	
			500	$ -		500	$ -	$ -	
			500	$ -		500	$ -	$ -	
Sub-Total A (excluding pass through)				$ 3,496.18			$ 3,997.74	**$ 501.56**	**14.35%**
DVA - Total in Effect 2016	per kW	$ 0.6409	500	$ 320.45		500	$ -	-$ 320.45	-100.00%
DVA - Total in Effect 2017	per kW		500	$ -	$ 1.9061	500	$ 953.05	$ 953.05	
			500	$ -		500	$ -	$ -	
			500	$ -		500	$ -	$ -	
Low Voltage Service Charge	per kW	$ 0.0735	500	$ 36.75	$ 0.1063	500	$ 53.15	$ 16.40	44.63%
Line Losses on Cost of Power		$ -	-	$ -	$ -	-	$ -	$ -	
Smart Meter Entity Charge		$ -	1	$ -	$ -	1	$ -	$ -	
Sub-Total B - Distribution (includes Sub-Total A)				**$ 3,853.38**			**$ 5,003.94**	**$ 1,150.56**	**29.86%**
RTSR - Network	per kW	$ 2.5966	500	$ 1,298.30	$ 2.4754	500	$ 1,237.70	-$ 60.60	-4.67%
RTSR - Line and Transformation Connection	per kW	$ 2.0803	500	$ 1,040.15	$ 2.1000	500	$ 1,050.00	$ 9.85	0.95%
Sub-Total C - Delivery (including Sub-Total B)				**$ 6,191.83**			**$ 7,291.64**	**$ 1,099.81**	**17.76%**
Wholesale Market Service Charge (WMSC)	per kWh	$ 0.0036	210,840	$ 759.02	$ 0.0036	210,600	$ 758.16	-$ 0.86	-0.11%
Rural and Remote Rate Protection (RRRP)	per kWh	$ 0.0013	210,840	$ 274.09	$ 0.0013	210,600	$ 273.78	-$ 0.31	-0.11%
Standard Supply Service Charge	Monthly	$ 0.2500	1	$ 0.25	$ 0.2500	1	$ 0.25	$ -	0.00%
Debt Retirement Charge (DRC)			200,000	$ -		200,000	$ -	$ -	
Ontario Electricity Support Program (OESP)	per kWh	$ 0.0011	210,840	$ 231.92	$ 0.0011	210,600	$ 231.66		0.00%
Average IESO Wholesale Market Price	per kWh	$ 0.1028	210,840	$ 21,670.14	$ 0.1028	210,600	$ 21,645.47	-$ 24.67	-0.11%
Total Bill on Average IESO Wholesale Market Price				**$ 29,127.26**			**$ 30,200.96**	**$ 1,073.70**	**3.69%**
HST		13%		$ 3,786.54	13%		$ 3,926.12	$ 139.58	3.69%
Total Bill (including HST)				$ 32,913.80			$ 34,127.08	$ 1,213.28	3.69%
Ontario Clean Energy Benefit [1]									
Total Bill on Average IESO Wholesale Market Price				**$ 32,913.80**			**$ 34,127.08**	**$ 1,213.28**	**3.69%**

Customer Class:	**GS > 50 kW Non-RPP - EOP**
RPP / Non-RPP:	**Non-RPP (Other)**
Consumption	**200,000** kWh
Demand	**500** kW
Current Loss Factor	**1.0542**
Proposed/Approved Loss Factor	**1.0530**
Ontario Clean Energy Benefit Applied?	**No**

		Current Board-Approved			**Proposed**			**Impact**	
	Charge Unit	**Rate ($)**	**Volume**	**Charge ($)**	**Rate ($)**	**Volume**	**Charge ($)**	**$ Change**	**% Change**
Monthly Service Charge	Monthly	$ 151.8300	1	$ 151.83	$ 172.0400	1	$ 172.04	$ 20.21	13.31%
Smart Meter Rate Adder			1	$ -		1	$ -	$ -	
MIST Disposition Rate Rider	Monthly		1	$ -	$ 7.0500	1	$ 7.05	$ 7.05	
Stranded Meter Disposition Rate Rider	Monthly		1	$ -	$ 3.6000	1	$ 3.60	$ 3.60	
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
Distribution Volumetric Rate	per kW	$ 6.6887	500	$ 3,344.35	$ 7.5344	500	$ 3,767.20	$ 422.85	12.64%
Smart Meter Disposition Rider			500	$ -		500	$ -	$ -	
LRAM & SSM Rate Rider	per kW		500	$ -	$ 0.0957	500	$ 47.85	$ 47.85	
			500	$ -		500	$ -	$ -	
			500	$ -		500	$ -	$ -	
			500	$ -		500	$ -	$ -	
			500	$ -		500	$ -	$ -	
			500	$ -		500	$ -	$ -	
			500	$ -		500	$ -	$ -	
			500	$ -		500	$ -	$ -	
Sub-Total A (excluding pass through)				$ 3,496.18			$ 3,997.74	**$ 501.56**	**14.35%**
DVA - Total in Effect 2016	per kW	$ 5.6223	500	$ 2,811.15		500	$ -	-$ 2,811.15	-100.00%
DVA - Total in Effect 2017	per kW		500	$ -	$ 1.9061	500	$ 953.05	$ 953.05	
			500	$ -		500	$ -	$ -	
			500	$ -		500	$ -	$ -	
Low Voltage Service Charge	per kW	$ 0.0735	500	$ 36.75	$ 0.1063	500	$ 53.15	$ 16.40	44.63%
Line Losses on Cost of Power		$ -	-	$ -	$ -	-	$ -	$ -	
Smart Meter Entity Charge			1	$ -		1	$ -	$ -	
Sub-Total B - Distribution (includes Sub-Total A)				**$ 6,344.08**			**$ 5,003.94**	**-$ 1,340.14**	**-21.12%**
RTSR - Network	per kW	$ 2.5966	500	$ 1,298.30	$ 2.4754	500	$ 1,237.70	-$ 60.60	-4.67%
RTSR - Line and Transformation Connection	per kW	$ 2.0803	500	$ 1,040.15	$ 2.1000	500	$ 1,050.00	$ 9.85	0.95%
Sub-Total C - Delivery (including Sub-Total B)				**$ 8,682.53**			**$ 7,291.64**	**-$ 1,390.89**	**-16.02%**
Wholesale Market Service Charge (WMSC)	per kWh	$ 0.0036	210,840	$ 759.02	$ 0.0036	210,600	$ 758.16	-$ 0.86	-0.11%
Rural and Remote Rate Protection (RRRP)	per kWh	$ 0.0013	210,840	$ 274.09	$ 0.0013	210,600	$ 273.78	-$ 0.31	-0.11%
Standard Supply Service Charge	Monthly	$ 0.2500	1	$ 0.25	$ 0.2500	1	$ 0.25	$ -	0.00%
Debt Retirement Charge (DRC)			200,000	$ -		200,000	$ -	$ -	
Ontario Electricity Support Program (OESP)	per kWh	$ 0.0011	210,840	$ 231.92	$ 0.0011	210,600	$ 231.66		0.00%
Average IESO Wholesale Market Price	per kWh	$ 0.1028	210,840	$ 21,670.14	$ 0.1028	210,600	$ 21,645.47	-$ 24.67	-0.11%
Total Bill on Average IESO Wholesale Market Price				**$ 31,617.96**			**$ 30,200.96**	**-$ 1,417.00**	**-4.48%**
HST		13%		$ 4,110.33	13%		$ 3,926.12	-$ 184.21	-4.48%
Total Bill (including HST)				$ 35,728.29			$ 34,127.08	-$ 1,601.21	-4.48%
Ontario Clean Energy Benefit [1]									
Total Bill on Average IESO Wholesale Market Price				**$ 35,728.29**			**$ 34,127.08**	**-$ 1,601.21**	**-4.48%**

Customer Class:	**GS > 50 kW Non-RPP - Port Colborne**	
RPP / Non-RPP:	**Non-RPP (Other)**	
Consumption	**200,000**	**kWh**
Demand	**500**	**kW**
Current Loss Factor	**1.0542**	
Proposed/Approved Loss Factor	**1.0530**	
Ontario Clean Energy Benefit Applied?	**No**	

		Current Board-Approved			**Proposed**			**Impact**	
	Charge Unit	**Rate ($)**	**Volume**	**Charge ($)**	**Rate ($)**	**Volume**	**Charge ($)**	**$ Change**	**% Change**
Monthly Service Charge	Monthly	$ 151.8300	1	$ 151.83	$ 172.0400	1	$ 172.04	$ 20.21	13.31%
Smart Meter Rate Adder			1	$ -		1	$ -	$ -	
MIST Disposition Rate Rider	Monthly		1	$ -	$ 7.0500	1	$ 7.05	$ 7.05	
Stranded Meter Disposition Rate Rider	Monthly		1	$ -	$ 3.6000	1	$ 3.60	$ 3.60	
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
Distribution Volumetric Rate	per kW	$ 6.6887	500	$ 3,344.35	$ 7.5344	500	$ 3,767.20	$ 422.85	12.64%
Smart Meter Disposition Rider			500	$ -		500	$ -	$ -	
LRAM & SSM Rate Rider	per kW		500	$ -	$ 0.0957	500	$ 47.85	$ 47.85	
			500	$ -		500	$ -	$ -	
			500	$ -		500	$ -	$ -	
			500	$ -		500	$ -	$ -	
			500	$ -		500	$ -	$ -	
			500	$ -		500	$ -	$ -	
			500	$ -		500	$ -	$ -	
			500	$ -		500	$ -	$ -	
Sub-Total A (excluding pass through)				$ 3,496.18			$ 3,997.74	**$ 501.56**	**14.35%**
DVA - Total in Effect 2016	per kW	-$ 0.4145	500	-$ 207.25		500	$ -	$ 207.25	-100.00%
DVA - Total in Effect 2017	per kW		500	$ -	$ 1.9061	500	$ 953.05	$ 953.05	
			500	$ -		500	$ -	$ -	
			500	$ -		500	$ -	$ -	
Low Voltage Service Charge	per kW	$ 0.0735	500	$ 36.75	$ 0.1063	500	$ 53.15	$ 16.40	44.63%
Line Losses on Cost of Power		$ -	-	$ -	$ -	-	$ -	$ -	
Smart Meter Entity Charge			1	$ -		1	$ -	$ -	
Sub-Total B - Distribution (includes Sub-Total A)				**$ 3,325.68**			**$ 5,003.94**	**$ 1,678.26**	**50.46%**
RTSR - Network	per kW	$ 2.5966	500	$ 1,298.30	$ 2.4754	500	$ 1,237.70	-$ 60.60	-4.67%
RTSR - Line and Transformation Connection	per kW	$ 2.0803	500	$ 1,040.15	$ 2.1000	500	$ 1,050.00	$ 9.85	0.95%
Sub-Total C - Delivery (including Sub-Total B)				**$ 5,664.13**			**$ 7,291.64**	**$ 1,627.51**	**28.73%**
Wholesale Market Service Charge (WMSC)	per kWh	$ 0.0036	210,840	$ 759.02	$ 0.0036	210,600	$ 758.16	-$ 0.86	-0.11%
Rural and Remote Rate Protection (RRRP)	per kWh	$ 0.0013	210,840	$ 274.09	$ 0.0013	210,600	$ 273.78	-$ 0.31	-0.11%
Standard Supply Service Charge	Monthly	$ 0.2500	1	$ 0.25	$ 0.2500	1	$ 0.25	$ -	0.00%
Debt Retirement Charge (DRC)			200,000	$ -		200,000	$ -	$ -	
Ontario Electricity Support Program (OESP)	per kWh	$ 0.0011	210,840	$ 231.92	$ 0.0011	210,600	$ 231.66		0.00%
Average IESO Wholesale Market Price	per kWh	$ 0.1028	210,840	$ 21,670.14	$ 0.1028	210,600	$ 21,645.47	-$ 24.67	-0.11%
Total Bill on Average IESO Wholesale Market Price				**$ 28,599.56**			**$ 30,200.96**	**$ 1,601.40**	**5.60%**
HST		13%		$ 3,717.94	13%		$ 3,926.12	$ 208.18	5.60%
Total Bill (including HST)				$ 32,317.50			$ 34,127.08	$ 1,809.59	5.60%
***Ontario Clean Energy Benefit* [1]**									
Total Bill on Average IESO Wholesale Market Price				**$ 32,317.50**			**$ 34,127.08**	**$ 1,809.59**	**5.60%**

Customer Class:	**GS > 50 kW Non-RPP - Fort Erie**	
RPP / Non-RPP:	**Non-RPP (Other)**	
Consumption	**400,000**	**kWh**
Demand	**1,000**	**kW**
Current Loss Factor	**1.0542**	
Proposed/Approved Loss Factor	**1.0530**	
Ontario Clean Energy Benefit Applied?	**No**	

		Current Board-Approved			**Proposed**			**Impact**	
	Charge Unit	**Rate ($)**	**Volume**	**Charge ($)**	**Rate ($)**	**Volume**	**Charge ($)**	**$ Change**	**% Change**
Monthly Service Charge	Monthly	$ 151.8300	1	$ 151.83	$ 172.0400	1	$ 172.04	$ 20.21	13.31%
Smart Meter Rate Adder			1	$ -		1	$ -	$ -	
MIST Disposition Rate Rider	Monthly		1	$ -	$ 7.0500	1	$ 7.05	$ 7.05	
Stranded Meter Disposition Rate Rider	Monthly		1	$ -	$ 3.6000	1	$ 3.60	$ 3.60	
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
Distribution Volumetric Rate	per kW	$ 6.6887	1,000	$ 6,688.70	$ 7.5344	1,000	$ 7,534.40	$ 845.70	12.64%
Smart Meter Disposition Rider			1,000	$ -		1,000	$ -	$ -	
LRAM & SSM Rate Rider	per kW		1,000	$ -	$ 0.0957	1,000	$ 95.70	$ 95.70	
			1,000	$ -		1,000	$ -	$ -	
			1,000	$ -		1,000	$ -	$ -	
			1,000	$ -		1,000	$ -	$ -	
			1,000	$ -		1,000	$ -	$ -	
			1,000	$ -		1,000	$ -	$ -	
			1,000	$ -		1,000	$ -	$ -	
			1,000	$ -		1,000	$ -	$ -	
Sub-Total A (excluding pass through)				$ 6,840.53			$ 7,812.79	**$ 972.26**	**14.21%**
DVA - Total in Effect 2016	per kW	$ 0.6409	1,000	$ 640.90		1,000	$ -	-$ 640.90	-100.00%
DVA - Total in Effect 2017	per kW		1,000	$ -	$ 1.9061	1,000	$ 1,906.10	$ 1,906.10	
			1,000	$ -		1,000	$ -	$ -	
			1,000	$ -		1,000	$ -	$ -	
Low Voltage Service Charge	per kW	$ 0.0735	1,000	$ 73.50	$ 0.1063	1,000	$ 106.30	$ 32.80	44.63%
Line Losses on Cost of Power		$ -	-	$ -	$ -	-	$ -	$ -	
Smart Meter Entity Charge		$ -	1	$ -	$ -	1	$ -	$ -	
Sub-Total B - Distribution (includes Sub-Total A)				**$ 7,554.93**			**$ 9,825.19**	**$ 2,270.26**	**30.05%**
RTSR - Network	per kW	$ 2.5966	1,000	$ 2,596.60	$ 2.4754	1,000	$ 2,475.40	-$ 121.20	-4.67%
RTSR - Line and Transformation Connection	per kW	$ 2.0803	1,000	$ 2,080.30	$ 2.1000	1,000	$ 2,100.00	$ 19.70	0.95%
Sub-Total C - Delivery (including Sub-Total B)				**$ 12,231.83**			**$ 14,400.59**	**$ 2,168.76**	**17.73%**
Wholesale Market Service Charge (WMSC)	per kWh	$ 0.0036	421,680	$ 1,518.05	$ 0.0036	421,200	$ 1,516.32	-$ 1.73	-0.11%
Rural and Remote Rate Protection (RRRP)	per kWh	$ 0.0013	421,680	$ 548.18	$ 0.0013	421,200	$ 547.56	-$ 0.62	-0.11%
Standard Supply Service Charge	Monthly	$ 0.2500	1	$ 0.25	$ 0.2500	1	$ 0.25	$ -	0.00%
Debt Retirement Charge (DRC)			400,000	$ -		400,000	$ -	$ -	
Ontario Electricity Support Program (OESP)	per kWh	$ 0.0011	421,680	$ 463.85	$ 0.0011	421,200	$ 463.32		0.00%
Average IESO Wholesale Market Price	per kWh	$ 0.1028	421,680	$ 43,340.27	$ 0.1028	421,200	$ 43,290.94	-$ 49.33	-0.11%
Total Bill on Average IESO Wholesale Market Price				**$ 58,102.43**			**$ 60,218.98**	**$ 2,116.55**	**3.64%**
HST		13%		$ 7,553.32	13%		$ 7,828.47	$ 275.15	3.64%
Total Bill (including HST)				$ 65,655.75			$ 68,047.44	$ 2,391.70	3.64%
Ontario Clean Energy Benefit [1]									
Total Bill on Average IESO Wholesale Market Price				**$ 65,655.75**			**$ 68,047.44**	**$ 2,391.70**	**3.64%**

Customer Class:	**GS > 50 kW Non-RPP - EOP**	
RPP / Non-RPP:	**Non-RPP (Other)**	
Consumption	**400,000**	**kWh**
Demand	**1,000**	**kW**
Current Loss Factor	**1.0542**	
Proposed/Approved Loss Factor	**1.0530**	
Ontario Clean Energy Benefit Applied?	**No**	

		Current Board-Approved			**Proposed**			**Impact**	
	Charge Unit	**Rate ($)**	**Volume**	**Charge ($)**	**Rate ($)**	**Volume**	**Charge ($)**	**$ Change**	**% Change**
Monthly Service Charge	Monthly	$ 151.8300	1	$ 151.83	$ 172.0400	1	$ 172.04	$ 20.21	13.31%
Smart Meter Rate Adder			1	$ -		1	$ -	$ -	
MIST Disposition Rate Rider	Monthly		1	$ -	$ 7.0500	1	$ 7.05	$ 7.05	
Stranded Meter Disposition Rate Rider	Monthly		1	$ -	$ 3.6000	1	$ 3.60	$ 3.60	
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
Distribution Volumetric Rate	per kW	$ 6.6887	1,000	$ 6,688.70	$ 7.5344	1,000	$ 7,534.40	$ 845.70	12.64%
Smart Meter Disposition Rider			1,000	$ -		1,000	$ -	$ -	
LRAM & SSM Rate Rider	per kW		1,000	$ -	$ 0.0957	1,000	$ 95.70	$ 95.70	
			1,000	$ -		1,000	$ -	$ -	
			1,000	$ -		1,000	$ -	$ -	
			1,000	$ -		1,000	$ -	$ -	
			1,000	$ -		1,000	$ -	$ -	
			1,000	$ -		1,000	$ -	$ -	
			1,000	$ -		1,000	$ -	$ -	
			1,000	$ -		1,000	$ -	$ -	
Sub-Total A (excluding pass through)				$ 6,840.53			$ 7,812.79	**$ 972.26**	**14.21%**
DVA - Total in Effect 2016	per kW	$ 5.6223	1,000	$ 5,622.30		1,000	$ -	-$ 5,622.30	-100.00%
DVA - Total in Effect 2017	per kW		1,000	$ -	$ 1.9061	1,000	$ 1,906.10	$ 1,906.10	
			1,000	$ -		1,000	$ -	$ -	
			1,000	$ -		1,000	$ -	$ -	
Low Voltage Service Charge	per kW	$ 0.0735	1,000	$ 73.50	$ 0.1063	1,000	$ 106.30	$ 32.80	44.63%
Line Losses on Cost of Power		$ -	-	$ -	$ -	-	$ -	$ -	
Smart Meter Entity Charge			1	$ -		1	$ -	$ -	
Sub-Total B - Distribution (includes Sub-Total A)				**$ 12,536.33**			**$ 9,825.19**	**-$ 2,711.14**	**-21.63%**
RTSR - Network	per kW	$ 2.5966	1,000	$ 2,596.60	$ 2.4754	1,000	$ 2,475.40	-$ 121.20	-4.67%
RTSR - Line and Transformation Connection	per kW	$ 2.0803	1,000	$ 2,080.30	$ 2.1000	1,000	$ 2,100.00	$ 19.70	0.95%
Sub-Total C - Delivery (including Sub-Total B)				**$ 17,213.23**			**$ 14,400.59**	**-$ 2,812.64**	**-16.34%**
Wholesale Market Service Charge (WMSC)	per kWh	$ 0.0036	421,680	$ 1,518.05	$ 0.0036	421,200	$ 1,516.32	-$ 1.73	-0.11%
Rural and Remote Rate Protection (RRRP)	per kWh	$ 0.0013	421,680	$ 548.18	$ 0.0013	421,200	$ 547.56	-$ 0.62	-0.11%
Standard Supply Service Charge	Monthly	$ 0.2500	1	$ 0.25	$ 0.2500	1	$ 0.25	$ -	0.00%
Debt Retirement Charge (DRC)			400,000	$ -		400,000	$ -	$ -	
Ontario Electricity Support Program (OESP)	per kWh	$ 0.0011	421,680	$ 463.85	$ 0.0011	421,200	$ 463.32		0.00%
Average IESO Wholesale Market Price	per kWh	$ 0.1028	421,680	$ 43,340.27	$ 0.1028	421,200	$ 43,290.94	-$ 49.33	-0.11%
Total Bill on Average IESO Wholesale Market Price				**$ 63,083.83**			**$ 60,218.98**	**-$ 2,864.85**	**-4.54%**
HST		13%		$ 8,200.90	13%		$ 7,828.47	-$ 372.43	-4.54%
Total Bill (including HST)				$ 71,284.73			$ 68,047.44	-$ 3,237.29	-4.54%
Ontario Clean Energy Benefit [1]									
Total Bill on Average IESO Wholesale Market Price				**$ 71,284.73**			**$ 68,047.44**	**-$ 3,237.29**	**-4.54%**

Customer Class:	**GS > 50 kW Non-RPP - Port Colborne**
RPP / Non-RPP:	**Non-RPP (Other)**
Consumption	**400,000** kWh
Demand	**1,000** kW
Current Loss Factor	**1.0542**
Proposed/Approved Loss Factor	**1.0530**
Ontario Clean Energy Benefit Applied?	**No**

		Current Board-Approved			Proposed			Impact	
	Charge Unit	**Rate ($)**	**Volume**	**Charge ($)**	**Rate ($)**	**Volume**	**Charge ($)**	**$ Change**	**% Change**
Monthly Service Charge	Monthly	$ 151.8300	1	$ 151.83	$ 172.0400	1	$ 172.04	$ 20.21	13.31%
Smart Meter Rate Adder			1	$ -		1	$ -	$ -	
MIST Disposition Rate Rider	Monthly		1	$ -	$ 7.0500	1	$ 7.05	$ 7.05	
Stranded Meter Disposition Rate Rider	Monthly		1	$ -	$ 3.6000	1	$ 3.60	$ 3.60	
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
Distribution Volumetric Rate	per kW	$ 6.6887	1,000	$ 6,688.70	$ 7.5344	1,000	$ 7,534.40	$ 845.70	12.64%
Smart Meter Disposition Rider			1,000	$ -		1,000	$ -	$ -	
LRAM & SSM Rate Rider	per kW		1,000	$ -	$ 0.0957	1,000	$ 95.70	$ 95.70	
			1,000	$ -		1,000	$ -	$ -	
			1,000	$ -		1,000	$ -	$ -	
			1,000	$ -		1,000	$ -	$ -	
			1,000	$ -		1,000	$ -	$ -	
			1,000	$ -		1,000	$ -	$ -	
			1,000	$ -		1,000	$ -	$ -	
			1,000	$ -		1,000	$ -	$ -	
Sub-Total A (excluding pass through)				$ 6,840.53			$ 7,812.79	**$ 972.26**	**14.21%**
DVA - Total in Effect 2016	per kW	-$ 0.4145	1,000	-$ 414.50		1,000	$ -	$ 414.50	-100.00%
DVA - Total in Effect 2017	per kW		1,000	$ -	$ 1.9061	1,000	$ 1,906.10	$ 1,906.10	
			1,000	$ -		1,000	$ -	$ -	
			1,000	$ -		1,000	$ -	$ -	
Low Voltage Service Charge	per kW	$ 0.0735	1,000	$ 73.50	$ 0.1063	1,000	$ 106.30	$ 32.80	44.63%
Line Losses on Cost of Power		$ -	-	$ -	$ -	-	$ -	$ -	
Smart Meter Entity Charge			1	$ -		1	$ -	$ -	
Sub-Total B - Distribution (includes Sub-Total A)				**$ 6,499.53**			**$ 9,825.19**	**$ 3,325.66**	**51.17%**
RTSR - Network	per kW	$ 2.5966	1,000	$ 2,596.60	$ 2.4754	1,000	$ 2,475.40	-$ 121.20	-4.67%
RTSR - Line and Transformation Connection	per kW	$ 2.0803	1,000	$ 2,080.30	$ 2.1000	1,000	$ 2,100.00	$ 19.70	0.95%
Sub-Total C - Delivery (including Sub-Total B)				**$ 11,176.43**			**$ 14,400.59**	**$ 3,224.16**	**28.85%**
Wholesale Market Service Charge (WMSC)	per kWh	$ 0.0036	421,680	$ 1,518.05	$ 0.0036	421,200	$ 1,516.32	-$ 1.73	-0.11%
Rural and Remote Rate Protection (RRRP)	per kWh	$ 0.0013	421,680	$ 548.18	$ 0.0013	421,200	$ 547.56	-$ 0.62	-0.11%
Standard Supply Service Charge	Monthly	$ 0.2500	1	$ 0.25	$ 0.2500	1	$ 0.25	$ -	0.00%
Debt Retirement Charge (DRC)			400,000	$ -		400,000	$ -	$ -	
Ontario Electricity Support Program (OESP)	per kWh	$ 0.0011	421,680	$ 463.85	$ 0.0011	421,200	$ 463.32		0.00%
Average IESO Wholesale Market Price	per kWh	$ 0.1028	421,680	$ 43,340.27	$ 0.1028	421,200	$ 43,290.94	-$ 49.33	-0.11%
Total Bill on Average IESO Wholesale Market Price				**$ 57,047.03**			**$ 60,218.98**	**$ 3,171.95**	**5.56%**
HST		13%		$ 7,416.11	13%		$ 7,828.47	$ 412.35	5.56%
Total Bill (including HST)				$ 64,463.14			$ 68,047.44	$ 3,584.30	5.56%
Ontario Clean Energy Benefit [1]									
Total Bill on Average IESO Wholesale Market Price				**$ 64,463.14**			**$ 68,047.44**	**$ 3,584.30**	**5.56%**

Customer Class:	**Embedded Distributor**	
RPP / Non-RPP:	**Non-RPP (Other)**	
Consumption	**427,454**	**kWh**
Demand	**1,143**	**kW**
Current Loss Factor	**1.0542**	
Proposed/Approved Loss Factor	**1.0530**	
Ontario Clean Energy Benefit Applied?	**No**	

		Current Board-Approved			**Proposed**			**Impact**	
	Charge Unit	**Rate ($)**	**Volume**	**Charge ($)**	**Rate ($)**	**Volume**	**Charge ($)**	**$ Change**	**% Change**
Monthly Service Charge	Monthly	$ 151.8300	1	$ 151.83	$ 584.7900	1	$ 584.79	$ 432.96	285.16%
Smart Meter Rate Adder			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
Distribution Volumetric Rate	per kW	$ 6.6887	1,143	$ 7,645.18	$ 8.3087	1,143	$ 9,496.84	$ 1,851.66	24.22%
Smart Meter Disposition Rider			1,143	$ -		1,143	$ -	$ -	
LRAM & SSM Rate Rider			1,143	$ -		1,143	$ -	$ -	
			1,143	$ -		1,143	$ -	$ -	
			1,143	$ -		1,143	$ -	$ -	
			1,143	$ -		1,143	$ -	$ -	
			1,143	$ -		1,143	$ -	$ -	
			1,143	$ -		1,143	$ -	$ -	
			1,143	$ -		1,143	$ -	$ -	
			1,143	$ -		1,143	$ -	$ -	
Sub-Total A (excluding pass through)				$ 7,797.01			$ 10,081.63	**$ 2,284.62**	**29.30%**
DVA - Total in Effect 2016	per kW	-$ 0.4145	1,143	-$ 473.77		1,143	$ -	$ 473.77	-100.00%
DVA - Total in Effect 2017	per kW		1,143	$ -	$ 2.2972	1,143	$ 2,625.70	$ 2,625.70	
			1,143	$ -		1,143	$ -	$ -	
			1,143	$ -		1,143	$ -	$ -	
Low Voltage Service Charge	per kW	$ 0.0735	1,143	$ 84.01	$ 0.1063	1,143	$ 121.50	$ 37.49	44.63%
Line Losses on Cost of Power		$ -	-	$ -	$ -	-	$ -	$ -	
Smart Meter Entity Charge			1	$ -	$ 0.7900	1	$ 0.79	$ 0.79	
Sub-Total B - Distribution (includes Sub-Total A)				**$ 7,407.25**			**$ 12,829.62**	**$ 5,422.37**	**73.20%**
RTSR - Network	per kW	$ 2.5966	1,143	$ 2,967.91	$ 2.4754	1,143	$ 2,829.38	-$ 138.53	-4.67%
RTSR - Line and Transformation Connection	per kW	$ 2.0803	1,143	$ 2,377.78	$ 2.1000	1,143	$ 2,400.30	$ 22.52	0.95%
Sub-Total C - Delivery (including Sub-Total B)				**$ 12,752.95**			**$ 18,059.31**	**$ 5,306.36**	**41.61%**
Wholesale Market Service Charge (WMSC)	per kWh	$ 0.0036	450,622	$ 1,622.24	$ 0.0036	450,109	$ 1,620.39	-$ 1.85	-0.11%
Rural and Remote Rate Protection (RRRP)	per kWh	$ 0.0013	450,622	$ 585.81	$ 0.0013	450,109	$ 585.14	-$ 0.67	-0.11%
Standard Supply Service Charge	Monthly	$ 0.2500	1	$ 0.25	$ 0.2500	1	$ 0.25	$ -	0.00%
Debt Retirement Charge (DRC)			427,454	$ -		427,454	$ -	$ -	
Ontario Electricity Support Program (OESP)	per kWh	$ 0.0011	450,622	$ 495.68	$ 0.0011	450,109	$ 495.12		0.00%
Average IESO Wholesale Market Price	per kWh	$ 0.1028	450,622	$ 46,314.93	$ 0.1028	450,109	$ 46,262.21	-$ 52.72	-0.11%
Total Bill on Average IESO Wholesale Market Price				**$ 61,771.86**			**$ 67,022.42**	**$ 5,250.56**	**8.50%**
HST		13%		$ 8,030.34	13%		$ 8,712.91	$ 682.57	8.50%
Total Bill (including HST)				$ 69,802.20			$ 75,735.34	$ 5,933.13	8.50%
Ontario Clean Energy Benefit [1]									
Total Bill on Average IESO Wholesale Market Price				**$ 69,802.20**			**$ 75,735.34**	**$ 5,933.13**	**8.50%**

Customer Class:	**Street Lighting - Fort Erie**	
RPP / Non-RPP:	**Non-RPP (Other)**	
Consumption	**40**	**kWh**
Demand	**0**	**kW**
Current Loss Factor	**1.0542**	
Proposed/Approved Loss Factor	**1.0530**	
Ontario Clean Energy Benefit Applied?	**No**	

		Current Board-Approved			**Proposed**			**Impact**	
	Charge Unit	**Rate ($)**	**Volume**	**Charge ($)**	**Rate ($)**	**Volume**	**Charge ($)**	**$ Change**	**% Change**
Monthly Service Charge	Monthly	$ 4.9600	1	$ 4.96	$ 4.0600	1	$ 4.06	-$ 0.90	-18.15%
Smart Meter Rate Adder			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
Distribution Volumetric Rate	per kW	$ 10.7965	0	$ 1.35	$ 8.8324	0	$ 1.10	-$ 0.25	-18.19%
Smart Meter Disposition Rider			0	$ -		0	$ -	$ -	
LRAM & SSM Rate Rider	per kW		0	$ -		0	$ -	$ -	
			0	$ -		0	$ -	$ -	
			0	$ -		0	$ -	$ -	
			0	$ -		0	$ -	$ -	
			0	$ -		0	$ -	$ -	
			0	$ -		0	$ -	$ -	
			0	$ -		0	$ -	$ -	
			0	$ -		0	$ -	$ -	
Sub-Total A (excluding pass through)				$ 6.31			$ 5.16	**-$ 1.15**	**-18.16%**
DVA - Total in Effect 2016	per kW	$ 0.0935	0	$ 0.01		0	$ -	-$ 0.01	-100.00%
DVA - Total in Effect 2017	per kW		0	$ -	-$ 1.7104	0	-$ 0.21	-$ 0.21	
			0	$ -		0	$ -	$ -	
			0	$ -		0	$ -	$ -	
Low Voltage Service Charge	per kW	$ 0.0507	0	$ 0.01	$ 0.0811	0	$ 0.01	$ 0.00	59.96%
Line Losses on Cost of Power	per kW	$ 0.1028	2	$ 0.22	$ 0.1028	2	$ 0.22	-$ 0.00	-2.21%
Smart Meter Entity Charge		$ -	1	$ -	$ -	1	$ -	$ -	
Sub-Total B - Distribution (includes Sub-Total A)				**$ 6.55**			**$ 5.18**	**-$ 1.37**	**-20.95%**
RTSR - Network	per kW	$ 1.9219	0	$ 0.24	$ 1.8322	0	$ 0.23	-$ 0.01	-4.67%
RTSR - Line and Transformation Connection	per kW	$ 1.5873	0	$ 0.20	$ 1.6024	0	$ 0.20	$ 0.00	0.95%
Sub-Total C - Delivery (including Sub-Total B)				**$ 6.99**			**$ 5.61**	**-$ 1.38**	**-19.77%**
Wholesale Market Service Charge (WMSC)	per kWh	$ 0.0036	42	$ 0.15	$ 0.0036	42	$ 0.15	-$ 0.00	-0.11%
Rural and Remote Rate Protection (RRRP)	per kWh	$ 0.0013	42	$ 0.05	$ 0.0013	42	$ 0.05	-$ 0.00	-0.11%
Standard Supply Service Charge	Monthly	$ 0.2500	1	$ 0.25	$ 0.2500	1	$ 0.25	$ -	0.00%
Debt Retirement Charge (DRC)			40	$ -		40	$ -	$ -	
Ontario Electricity Support Program (OESP)	per kWh	$ 0.0011	42	$ 0.05	$ 0.0011	42	$ 0.05		0.00%
Average IESO Wholesale Market Price	per kWh	$ 0.1028	40	$ 4.11	$ 0.1028	40	$ 4.11	$ -	0.00%
Total Bill on Average IESO Wholesale Market Price				**$ 11.60**			**$ 10.22**	**-$ 1.38**	**-11.91%**
HST		13%		$ 1.51	13%		$ 1.33	-$ 0.18	-11.91%
Total Bill (including HST)				$ 13.11			$ 11.55	-$ 1.56	-11.91%
Ontario Clean Energy Benefit [1]									
Total Bill on Average IESO Wholesale Market Price				**$ 13.11**			**$ 11.55**	**-$ 1.56**	**-11.91%**

Customer Class:	**Street Lighting - EOP**	
RPP / Non-RPP:	**Non-RPP (Other)**	
Consumption	**40**	**kWh**
Demand	**0**	**kW**
Current Loss Factor	**1.0542**	
Proposed/Approved Loss Factor	**1.0530**	
Ontario Clean Energy Benefit Applied?	**No**	

		Current Board-Approved			Proposed			Impact	
	Charge Unit	**Rate ($)**	**Volume**	**Charge ($)**	**Rate ($)**	**Volume**	**Charge ($)**	**$ Change**	**% Change**
Monthly Service Charge	Monthly	$ 4.9600	1	$ 4.96	$ 4.0600	1	$ 4.06	-$ 0.90	-18.15%
Smart Meter Rate Adder			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
Distribution Volumetric Rate	per kW	$ 10.7965	0	$ 1.35	$ 8.8324	0	$ 1.10	-$ 0.25	-18.19%
Smart Meter Disposition Rider			0	$ -		0	$ -	$ -	
LRAM & SSM Rate Rider	per kW		0	$ -		0	$ -	$ -	
			0	$ -		0	$ -	$ -	
			0	$ -		0	$ -	$ -	
			0	$ -		0	$ -	$ -	
			0	$ -		0	$ -	$ -	
			0	$ -		0	$ -	$ -	
			0	$ -		0	$ -	$ -	
			0	$ -		0	$ -	$ -	
Sub-Total A (excluding pass through)				$ 6.31			$ 5.16	**-$ 1.15**	**-18.16%**
DVA - Total in Effect 2016	per kW	-$ 0.8149	0	-$ 0.10		0	$ -	$ 0.10	-100.00%
DVA - Total in Effect 2017	per kW		0	$ -	-$ 1.7104	0	-$ 0.21	-$ 0.21	
			0	$ -		0	$ -	$ -	
			0	$ -		0	$ -	$ -	
Low Voltage Service Charge	per kW	$ 0.0507	0	$ 0.01	$ 0.0811	0	$ 0.01	$ 0.00	59.96%
Line Losses on Cost of Power	per kW	$ 0.1028	2	$ 0.22	$ 0.1028	2	$ 0.22	-$ 0.00	-2.21%
Smart Meter Entity Charge		$ -	1	$ -	$ -	1	$ -	$ -	
Sub-Total B - Distribution (includes Sub-Total A)				**$ 6.44**			**$ 5.18**	**-$ 1.26**	**-19.55%**
RTSR - Network	per kW	$ 1.9219	0	$ 0.24	$ 1.8322	0	$ 0.23	-$ 0.01	-4.67%
RTSR - Line and Transformation Connection	per kW	$ 1.5873	0	$ 0.20	$ 1.6024	0	$ 0.20	$ 0.00	0.95%
Sub-Total C - Delivery (including Sub-Total B)				**$ 6.88**			**$ 5.61**	**-$ 1.27**	**-18.44%**
Wholesale Market Service Charge (WMSC)	per kWh	$ 0.0036	42	$ 0.15	$ 0.0036	42	$ 0.15	-$ 0.00	-0.11%
Rural and Remote Rate Protection (RRRP)	per kWh	$ 0.0013	42	$ 0.05	$ 0.0013	42	$ 0.05	-$ 0.00	-0.11%
Standard Supply Service Charge	Monthly	$ 0.2500	1	$ 0.25	$ 0.2500	1	$ 0.25	$ -	0.00%
Debt Retirement Charge (DRC)			40	$ -		40	$ -	$ -	
Ontario Electricity Support Program (OESP)	per kWh	$ 0.0011	42	$ 0.05	$ 0.0011	42	$ 0.05		0.00%
Average IESO Wholesale Market Price	per kWh	$ 0.1028	40	$ 4.11	$ 0.1028	40	$ 4.11	$ -	0.00%
Total Bill on Average IESO Wholesale Market Price				**$ 11.49**			**$ 10.22**	**-$ 1.27**	**-11.04%**
HST		13%		$ 1.49	13%		$ 1.33	-$ 0.16	-11.04%
Total Bill (including HST)				$ 12.98			$ 11.55	-$ 1.43	-11.04%
Ontario Clean Energy Benefit [1]									
Total Bill on Average IESO Wholesale Market Price				**$ 12.98**			**$ 11.55**	**-$ 1.43**	**-11.04%**

Customer Class:	**Street Lighting - Port Colborne**
RPP / Non-RPP:	**Non-RPP (Other)**
Consumption	**40** kWh
Demand	**0** kW
Current Loss Factor	**1.0542**
Proposed/Approved Loss Factor	**1.0530**
Ontario Clean Energy Benefit Applied?	**No**

		Current Board-Approved			**Proposed**			**Impact**	
	Charge Unit	**Rate ($)**	**Volume**	**Charge ($)**	**Rate ($)**	**Volume**	**Charge ($)**	**$ Change**	**% Change**
Monthly Service Charge	Monthly	$ 4.9600	1	$ 4.96	$ 4.0600	1	$ 4.06	-$ 0.90	-18.15%
Smart Meter Rate Adder			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
Distribution Volumetric Rate	per kW	$ 10.7965	0	$ 1.35	$ 8.8324	0	$ 1.10	-$ 0.25	-18.19%
Smart Meter Disposition Rider			0	$ -		0	$ -	$ -	
LRAM & SSM Rate Rider	per kW		0	$ -		0	$ -	$ -	
			0	$ -		0	$ -	$ -	
			0	$ -		0	$ -	$ -	
			0	$ -		0	$ -	$ -	
			0	$ -		0	$ -	$ -	
			0	$ -		0	$ -	$ -	
			0	$ -		0	$ -	$ -	
			0	$ -		0	$ -	$ -	
Sub-Total A (excluding pass through)				$ 6.31			$ 5.16	**-$ 1.15**	**-18.16%**
DVA - Total in Effect 2016	per kW	-$ 0.0187	0	-$ 0.00		0	$ -	$ 0.00	-100.00%
DVA - Total in Effect 2017	per kW		0	$ -	-$ 1.7104	0	-$ 0.21	-$ 0.21	
			0	$ -		0	$ -	$ -	
			0	$ -		0	$ -	$ -	
Low Voltage Service Charge	per kW	$ 0.0507	0	$ 0.01	$ 0.0811	0	$ 0.01	$ 0.00	59.96%
Line Losses on Cost of Power	per kW	$ 0.1028	2	$ 0.22	$ 0.1028	2	$ 0.22	-$ 0.00	-2.21%
Smart Meter Entity Charge		$ -	1	$ -	$ -	1	$ -	$ -	
Sub-Total B - Distribution (includes Sub-Total A)				**$ 6.54**			**$ 5.18**	**-$ 1.36**	**-20.78%**
RTSR - Network	per kW	$ 1.9219	0	$ 0.24	$ 1.8322	0	$ 0.23	-$ 0.01	-4.67%
RTSR - Line and Transformation Connection	per kW	$ 1.5873	0	$ 0.20	$ 1.6024	0	$ 0.20	$ 0.00	0.95%
Sub-Total C - Delivery (including Sub-Total B)				**$ 6.98**			**$ 5.61**	**-$ 1.37**	**-19.60%**
Wholesale Market Service Charge (WMSC)	per kWh	$ 0.0036	42	$ 0.15	$ 0.0036	42	$ 0.15	-$ 0.00	-0.11%
Rural and Remote Rate Protection (RRRP)	per kWh	$ 0.0013	42	$ 0.05	$ 0.0013	42	$ 0.05	-$ 0.00	-0.11%
Standard Supply Service Charge	Monthly	$ 0.2500	1	$ 0.25	$ 0.2500	1	$ 0.25	$ -	0.00%
Debt Retirement Charge (DRC)			40	$ -		40	$ -	$ -	
Ontario Electricity Support Program (OESP)	per kWh	$ 0.0011	42	$ 0.05	$ 0.0011	42	$ 0.05		0.00%
Average IESO Wholesale Market Price	per kWh	$ 0.1028	40	$ 4.11	$ 0.1028	40	$ 4.11	$ -	0.00%
Total Bill on Average IESO Wholesale Market Price				**$ 11.59**			**$ 10.22**	**-$ 1.37**	**-11.80%**
HST		13%		$ 1.51	13%		$ 1.33	-$ 0.18	-11.80%
Total Bill (including HST)				$ 13.10			$ 11.55	-$ 1.55	-11.80%
Ontario Clean Energy Benefit [1]									
Total Bill on Average IESO Wholesale Market Price				**$ 13.10**			**$ 11.55**	**-$ 1.55**	**-11.80%**

Customer Class:	**Sentinel - Fort Erie**	
RPP / Non-RPP:	**Non-RPP (Other)**	
Consumption	**75**	**kWh**
Demand	**0**	**kW**
Current Loss Factor	**1.0542**	
Proposed/Approved Loss Factor	**1.0530**	
Ontario Clean Energy Benefit Applied?	**No**	

		Current Board-Approved			**Proposed**			**Impact**	
	Charge Unit	**Rate ($)**	**Volume**	**Charge ($)**	**Rate ($)**	**Volume**	**Charge ($)**	**$ Change**	**% Change**
Monthly Service Charge	Monthly	$ 5.0900	1	$ 5.09	$ 5.7700	1	$ 5.77	$ 0.68	13.36%
Smart Meter Rate Adder			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
Distribution Volumetric Rate	per kW	$ 5.9010	0	$ 1.48	$ 6.6867	0	$ 1.67	$ 0.20	13.31%
Smart Meter Disposition Rider			0	$ -		0	$ -	$ -	
LRAM & SSM Rate Rider			0	$ -		0	$ -	$ -	
			0	$ -		0	$ -	$ -	
			0	$ -		0	$ -	$ -	
			0	$ -		0	$ -	$ -	
			0	$ -		0	$ -	$ -	
			0	$ -		0	$ -	$ -	
			0	$ -		0	$ -	$ -	
			0	$ -		0	$ -	$ -	
Sub-Total A (excluding pass through)				$ 6.57			$ 7.44	**$ 0.88**	**13.35%**
DVA - Total in Effect 2016	per kW	$ 0.0141	0	$ 0.00		0	$ -	-$ 0.00	-100.00%
DVA - Total in Effect 2017	per kW		0	$ -	-$ 1.3932	0	-$ 0.35	-$ 0.35	
			0	$ -		0	$ -	$ -	
			0	$ -		0	$ -	$ -	
Low Voltage Service Charge	per kW	$ 0.0542	0	$ 0.01	$ 0.0867	0	$ 0.02	$ 0.01	59.96%
Line Losses on Cost of Power	per kW	$ 0.0990	4	$ 0.40	$ 0.0990	4	$ 0.39	-$ 0.01	-2.21%
Smart Meter Entity Charge		$ -	1	$ -	$ -	1	$ -	$ -	
Sub-Total B - Distribution (includes Sub-Total A)				**$ 6.98**			**$ 7.51**	**$ 0.52**	**7.50%**
RTSR - Network	per kW	$ 2.2129	0	$ 0.55	$ 2.1097	0	$ 0.53	-$ 0.03	-4.66%
RTSR - Line and Transformation Connection	per kW	$ 1.6977	0	$ 0.42	$ 1.7138	0	$ 0.43	$ 0.00	0.95%
Sub-Total C - Delivery (including Sub-Total B)				**$ 7.96**			**$ 8.46**	**$ 0.50**	**6.31%**
Wholesale Market Service Charge (WMSC)	per kWh	$ 0.0036	79	$ 0.28	$ 0.0036	79	$ 0.28	-$ 0.00	-0.11%
Rural and Remote Rate Protection (RRRP)	per kWh	$ 0.0013	79	$ 0.10	$ 0.0013	79	$ 0.10	-$ 0.00	-0.11%
Standard Supply Service Charge	Monthly	$ 0.2500	1	$ 0.25	$ 0.2500	1	$ 0.25	$ -	0.00%
Debt Retirement Charge (DRC)			75	$ -		75	$ -	$ -	
Ontario Electricity Support Program (OESP)	per kWh	$ 0.0011	79	$ 0.09	$ 0.0011	79	$ 0.09		0.00%
RPP First Tier	per kWh	$ 0.0990	75	$ 7.43	$ 0.0990	75	$ 7.43	$ -	0.00%
Total Bill on Average IESO Wholesale Market Price				**$ 16.11**			**$ 16.61**	**$ 0.50**	**3.11%**
HST		13%		$ 2.09	13%		$ 2.16	$ 0.07	3.11%
Total Bill (including HST)				$ 18.21			$ 18.77	$ 0.57	3.11%
Ontario Clean Energy Benefit [1]									
Total Bill on Average IESO Wholesale Market Price				**$ 18.21**			**$ 18.77**	**$ 0.57**	**3.11%**

Customer Class:	**Sentinel - EOP**	
RPP / Non-RPP:	**Non-RPP (Other)**	
Consumption	**75**	**kWh**
Demand	**0**	**kW**
Current Loss Factor	**1.0542**	
Proposed/Approved Loss Factor	**1.0530**	
Ontario Clean Energy Benefit Applied?	**No**	

		Current Board-Approved			Proposed			Impact	
	Charge Unit	**Rate ($)**	**Volume**	**Charge ($)**	**Rate ($)**	**Volume**	**Charge ($)**	**$ Change**	**% Change**
Monthly Service Charge	Monthly	$ 5.0900	1	$ 5.09	$ 5.7700	1	$ 5.77	$ 0.68	13.36%
Smart Meter Rate Adder			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
Distribution Volumetric Rate	per kW	$ 5.9010	0	$ 1.48	$ 6.6867	0	$ 1.67	$ 0.20	13.31%
Smart Meter Disposition Rider			0	$ -		0	$ -	$ -	
LRAM & SSM Rate Rider			0	$ -		0	$ -	$ -	
			0	$ -		0	$ -	$ -	
			0	$ -		0	$ -	$ -	
			0	$ -		0	$ -	$ -	
			0	$ -		0	$ -	$ -	
			0	$ -		0	$ -	$ -	
			0	$ -		0	$ -	$ -	
			0	$ -		0	$ -	$ -	
Sub-Total A (excluding pass through)				$ 6.57			$ 7.44	**$ 0.88**	**13.35%**
DVA - Total in Effect 2016	per kW	$ 0.3006	0	$ 0.08		0	$ -	-$ 0.08	-100.00%
DVA - Total in Effect 2017	per kW		0	$ -	-$ 1.3932	0	-$ 0.35	-$ 0.35	
			0	$ -		0	$ -	$ -	
			0	$ -		0	$ -	$ -	
Low Voltage Service Charge	per kW	$ 0.0542	0	$ 0.01	$ 0.0867	0	$ 0.02	$ 0.01	59.96%
Line Losses on Cost of Power	per kW	$ 0.0990	4	$ 0.40	$ 0.0990	4	$ 0.39	-$ 0.01	-2.21%
Smart Meter Entity Charge		$ -	1	$ -	$ -	1	$ -	$ -	
Sub-Total B - Distribution (includes Sub-Total A)				**$ 7.06**			**$ 7.51**	**$ 0.45**	**6.41%**
RTSR - Network	per kW	$ 2.2129	0	$ 0.55	$ 2.1097	0	$ 0.53	-$ 0.03	-4.66%
RTSR - Line and Transformation Connection	per kW	$ 1.6977	0	$ 0.42	$ 1.7138	0	$ 0.43	$ 0.00	0.95%
Sub-Total C - Delivery (including Sub-Total B)				**$ 8.03**			**$ 8.46**	**$ 0.43**	**5.36%**
Wholesale Market Service Charge (WMSC)	per kWh	$ 0.0036	79	$ 0.28	$ 0.0036	79	$ 0.28	-$ 0.00	-0.11%
Rural and Remote Rate Protection (RRRP)	per kWh	$ 0.0013	79	$ 0.10	$ 0.0013	79	$ 0.10	-$ 0.00	-0.11%
Standard Supply Service Charge	Monthly	$ 0.2500	1	$ 0.25	$ 0.2500	1	$ 0.25	$ -	0.00%
Debt Retirement Charge (DRC)			75	$ -		75	$ -	$ -	
Ontario Electricity Support Program (OESP)	per kWh	$ 0.0011	79	$ 0.09	$ 0.0011	79	$ 0.09		0.00%
RPP First Tier	per kWh	$ 0.0990	75	$ 7.43	$ 0.0990	75	$ 7.43	$ -	0.00%
Total Bill on Average IESO Wholesale Market Price				**$ 16.18**			**$ 16.61**	**$ 0.43**	**2.66%**
HST		13%		$ 2.10	13%		$ 2.16	$ 0.06	2.66%
Total Bill (including HST)				$ 18.29			$ 18.77	$ 0.49	2.66%
Ontario Clean Energy Benefit [1]									
Total Bill on Average IESO Wholesale Market Price				**$ 18.29**			**$ 18.77**	**$ 0.49**	**2.66%**

Customer Class:	**Sentinel - Port Colborne**	
RPP / Non-RPP:	**Non-RPP (Other)**	
Consumption	**75**	**kWh**
Demand	**0**	**kW**
Current Loss Factor	**1.0542**	
Proposed/Approved Loss Factor	**1.0530**	
Ontario Clean Energy Benefit Applied?	**No**	

		Current Board-Approved			**Proposed**			**Impact**	
	Charge Unit	**Rate ($)**	**Volume**	**Charge ($)**	**Rate ($)**	**Volume**	**Charge ($)**	**$ Change**	**% Change**
Monthly Service Charge	Monthly	$ 5.0900	1	$ 5.09	$ 5.7700	1	$ 5.77	$ 0.68	13.36%
Smart Meter Rate Adder			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
Distribution Volumetric Rate	per kW	$ 5.9010	0	$ 1.48	$ 6.6867	0	$ 1.67	$ 0.20	13.31%
Smart Meter Disposition Rider			0	$ -		0	$ -	$ -	
LRAM & SSM Rate Rider			0	$ -		0	$ -	$ -	
			0	$ -		0	$ -	$ -	
			0	$ -		0	$ -	$ -	
			0	$ -		0	$ -	$ -	
			0	$ -		0	$ -	$ -	
			0	$ -		0	$ -	$ -	
			0	$ -		0	$ -	$ -	
			0	$ -		0	$ -	$ -	
Sub-Total A (excluding pass through)				$ 6.57			$ 7.44	**$ 0.88**	**13.35%**
DVA - Total in Effect 2016	per kW	$ 0.0141	0	$ 0.00		0	$ -	-$ 0.00	-100.00%
DVA - Total in Effect 2017	per kW		0	$ -	-$ 1.3932	0	-$ 0.35	-$ 0.35	
			0	$ -		0	$ -	$ -	
			0	$ -		0	$ -	$ -	
Low Voltage Service Charge	per kW	$ 0.0542	0	$ 0.01	$ 0.0867	0	$ 0.02	$ 0.01	59.96%
Line Losses on Cost of Power	per kW	$ 0.0990	4	$ 0.40	$ 0.0990	4	$ 0.39	-$ 0.01	-2.21%
Smart Meter Entity Charge		$ -	1	$ -	$ -	1	$ -	$ -	
Sub-Total B - Distribution (includes Sub-Total A)				**$ 6.98**			**$ 7.51**	**$ 0.52**	**7.50%**
RTSR - Network	per kW	$ 2.2129	0	$ 0.55	$ 2.1097	0	$ 0.53	-$ 0.03	-4.66%
RTSR - Line and Transformation Connection	per kW	$ 1.6977	0	$ 0.42	$ 1.7138	0	$ 0.43	$ 0.00	0.95%
Sub-Total C - Delivery (including Sub-Total B)				**$ 7.96**			**$ 8.46**	**$ 0.50**	**6.31%**
Wholesale Market Service Charge (WMSC)	per kWh	$ 0.0036	79	$ 0.28	$ 0.0036	79	$ 0.28	-$ 0.00	-0.11%
Rural and Remote Rate Protection (RRRP)	per kWh	$ 0.0013	79	$ 0.10	$ 0.0013	79	$ 0.10	-$ 0.00	-0.11%
Standard Supply Service Charge	Monthly	$ 0.2500	1	$ 0.25	$ 0.2500	1	$ 0.25	$ -	0.00%
Debt Retirement Charge (DRC)			75	$ -		75	$ -	$ -	
Ontario Electricity Support Program (OESP)	per kWh	$ 0.0011	79	$ 0.09	$ 0.0011	79	$ 0.09		0.00%
RPP First Tier	per kWh	$ 0.0990	75	$ 7.43	$ 0.0990	75	$ 7.43	$ -	0.00%
Total Bill on Average IESO Wholesale Market Price				**$ 16.11**			**$ 16.61**	**$ 0.50**	**3.11%**
HST		13%		$ 2.09	13%		$ 2.16	$ 0.07	3.11%
Total Bill (including HST)				$ 18.21			$ 18.77	$ 0.57	3.11%
Ontario Clean Energy Benefit [1]									
Total Bill on Average IESO Wholesale Market Price				**$ 18.21**			**$ 18.77**	**$ 0.57**	**3.11%**

Customer Class:	**USL - Fort Erie**	
RPP / Non-RPP:	**RPP**	
Consumption	**3,500**	**kWh**
Demand	**-**	**kW**
Current Loss Factor	**1.0542**	
Proposed/Approved Loss Factor	**1.0530**	
Ontario Clean Energy Benefit Applied?	**No**	

		Current Board-Approved			Proposed			Impact	
	Charge Unit	**Rate ($)**	**Volume**	**Charge ($)**	**Rate ($)**	**Volume**	**Charge ($)**	**$ Change**	**% Change**
Monthly Service Charge	Monthly	$ 32.9600	1	$ 32.96	$ 50.5300	1	$ 50.53	$ 17.57	53.31%
Smart Meter Rate Adder			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
Distribution Volumetric Rate	per kWh	$ 0.0179	3,500	$ 62.65	$ 0.0274	3,500	$ 95.90	$ 33.25	53.07%
Smart Meter Disposition Rider			3,500	$ -		3,500	$ -	$ -	
LRAM & SSM Rate Rider			3,500	$ -		3,500	$ -	$ -	
			3,500	$ -		3,500	$ -	$ -	
			3,500	$ -		3,500	$ -	$ -	
			3,500	$ -		3,500	$ -	$ -	
			3,500	$ -		3,500	$ -	$ -	
			3,500	$ -		3,500	$ -	$ -	
			3,500	$ -		3,500	$ -	$ -	
			3,500	$ -		3,500	$ -	$ -	
Sub-Total A (excluding pass through)				$ 95.61			$ 146.43	**$ 50.82**	**53.15%**
DVA - Total in Effect 2016	per kWh	$ 0.0003	3,500	$ 1.05		3,500	$ -	-$ 1.05	-100.00%
DVA - Total in Effect 2017 (Var)	per kWh		3,500	$ -	-$ 0.0048	3,500	-$ 16.80	-$ 16.80	
	Monthly		1	$ -		1	$ -	$ -	
			3,500	$ -		3,500	$ -	$ -	
Low Voltage Service Charge	per kWh	$ 0.0002	3,500	$ 0.70	$ 0.0003	3,500	$ 1.05	$ 0.35	50.00%
Line Losses on Cost of Power	per kWh	$ 0.1160	190	$ 22.01	$ 0.1160	186	$ 21.52	-$ 0.49	-2.21%
Smart Meter Entity Charge			1	$ -		1	$ -	$ -	
Sub-Total B - Distribution (includes Sub-Total A)				**$ 119.37**			**$ 152.20**	**$ 32.83**	**27.51%**
RTSR - Network	per kWh	$ 0.0064	3,690	$ 23.61	$ 0.0061	3,686	$ 22.48	-$ 1.13	-4.80%
RTSR - Line and Transformation Connection	per kWh	$ 0.0051	3,690	$ 18.82	$ 0.0051	3,686	$ 18.80	-$ 0.02	-0.11%
Sub-Total C - Delivery (including Sub-Total B)				**$ 161.80**			**$ 193.48**	**$ 31.68**	**19.58%**
Wholesale Market Service Charge (WMSC)	per kWh	$ 0.0036	3,690	$ 13.28	$ 0.0036	3,686	$ 13.27	-$ 0.02	-0.11%
Rural and Remote Rate Protection (RRRP)	per kWh	$ 0.0013	3,690	$ 4.80	$ 0.0013	3,686	$ 4.79	-$ 0.01	-0.11%
Standard Supply Service Charge	Monthly	$ 0.2500	1	$ 0.25	$ 0.2500	1	$ 0.25	$ -	0.00%
Debt Retirement Charge (DRC)			3,500	$ -		3,500	$ -	$ -	
Ontario Electricity Support Program (OESP)	per kWh	$ 0.0011	3,690	$ 4.06	$ 0.0011	3,686	$ 4.05	-$ 0.00	-0.11%
RPP - Tier 1	per kWh	$ 0.0990	750	$ 74.25	$ 0.0990	750	$ 74.25	$ -	0.00%
RPP - Tier 2	per kWh	$ 0.1160	2,750	$ 319.00	$ 0.1160	2,750	$ 319.00	$ -	0.00%
				$ -			$ -	$ -	
Total Bill on TOU (before Taxes)				**$ 577.43**			**$ 609.09**	**$ 31.65**	**5.48%**
HST		13%		$ 75.07	13%		$ 79.18	$ 4.11	5.48%
Total Bill (including HST)				$ 652.50			$ 688.27	$ 35.77	5.48%
Ontario Clean Energy Benefit [1]									
Total Bill on TOU				**$ 652.50**			**$ 688.27**	**$ 35.77**	**5.48%**

Customer Class:	USL - EOP	
RPP / Non-RPP:	RPP	
Consumption	3,500	kWh
Demand	-	kW
Current Loss Factor	1.0542	
Proposed/Approved Loss Factor	1.0530	
Ontario Clean Energy Benefit Applied?	No	

		Current Board-Approved			**Proposed**			**Impact**	
	Charge Unit	**Rate ($)**	**Volume**	**Charge ($)**	**Rate ($)**	**Volume**	**Charge ($)**	**$ Change**	**% Change**
Monthly Service Charge	Monthly	$ 32.9600	1	$ 32.96	$ 50.5300	1	$ 50.53	$ 17.57	53.31%
Smart Meter Rate Adder			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
Distribution Volumetric Rate	per kWh	$ 0.0179	3,500	$ 62.65	$ 0.0274	3,500	$ 95.90	$ 33.25	53.07%
Smart Meter Disposition Rider			3,500	$ -		3,500	$ -	$ -	
LRAM & SSM Rate Rider			3,500	$ -		3,500	$ -	$ -	
			3,500	$ -		3,500	$ -	$ -	
			3,500	$ -		3,500	$ -	$ -	
			3,500	$ -		3,500	$ -	$ -	
			3,500	$ -		3,500	$ -	$ -	
			3,500	$ -		3,500	$ -	$ -	
			3,500	$ -		3,500	$ -	$ -	
			3,500	$ -		3,500	$ -	$ -	
Sub-Total A (excluding pass through)				$ 95.61			$ 146.43	**$ 50.82**	**53.15%**
DVA - Total in Effect 2016	per kWh	-$ 0.0024	3,500	-$ 8.40		3,500	$ -	$ 8.40	-100.00%
DVA - Total in Effect 2017 (Var)	per kWh		3,500	$ -	-$ 0.0048	3,500	-$ 16.80	-$ 16.80	
	Monthly		1	$ -		1	$ -	$ -	
			3,500	$ -		3,500	$ -	$ -	
Low Voltage Service Charge	per kWh	$ 0.0002	3,500	$ 0.70	$ 0.0003	3,500	$ 1.05	$ 0.35	50.00%
Line Losses on Cost of Power	per kWh	$ 0.1160	190	$ 22.01	$ 0.1160	186	$ 21.52	-$ 0.49	-2.21%
Smart Meter Entity Charge			1	$ -		1	$ -	$ -	
Sub-Total B - Distribution (includes Sub-Total A)				**$ 109.92**			**$ 152.20**	**$ 42.28**	**38.47%**
RTSR - Network	per kWh	$ 0.0064	3,690	$ 23.61	$ 0.0061	3,686	$ 22.48	-$ 1.13	-4.80%
RTSR - Line and Transformation Connection	per kWh	$ 0.0051	3,690	$ 18.82	$ 0.0051	3,686	$ 18.80	-$ 0.02	-0.11%
Sub-Total C - Delivery (including Sub-Total B)				**$ 152.35**			**$ 193.48**	**$ 41.13**	**27.00%**
Wholesale Market Service Charge (WMSC)	per kWh	$ 0.0036	3,690	$ 13.28	$ 0.0036	3,686	$ 13.27	-$ 0.02	-0.11%
Rural and Remote Rate Protection (RRRP)	per kWh	$ 0.0013	3,690	$ 4.80	$ 0.0013	3,686	$ 4.79	-$ 0.01	-0.11%
Standard Supply Service Charge	Monthly	$ 0.2500	1	$ 0.25	$ 0.2500	1	$ 0.25	$ -	0.00%
Debt Retirement Charge (DRC)			3,500	$ -		3,500	$ -	$ -	
Ontario Electricity Support Program (OESP)	per kWh	$ 0.0011	3,690	$ 4.06	$ 0.0011	3,686	$ 4.05	-$ 0.00	-0.11%
RPP - Tier 1	per kWh	$ 0.0990	750	$ 74.25	$ 0.0990	750	$ 74.25	$ -	0.00%
RPP - Tier 2	per kWh	$ 0.1160	2,750	$ 319.00	$ 0.1160	2,750	$ 319.00	$ -	0.00%
				$ -			$ -	$ -	
Total Bill on TOU (before Taxes)				**$ 567.98**			**$ 609.09**	**$ 41.10**	**7.24%**
HST		13%		$ 73.84	13%		$ 79.18	$ 5.34	7.24%
Total Bill (including HST)				$ 641.82			$ 688.27	$ 46.45	7.24%
Ontario Clean Energy Benefit [1]									
Total Bill on TOU				**$ 641.82**			**$ 688.27**	**$ 46.45**	**7.24%**

Customer Class:	**USL - Port Colborne**	
RPP / Non-RPP:	**RPP**	
Consumption	**3,500**	**kWh**
Demand	**-**	**kW**
Current Loss Factor	**1.0542**	
Proposed/Approved Loss Factor	**1.0530**	
Ontario Clean Energy Benefit Applied?	**No**	

		Current Board-Approved			**Proposed**			**Impact**	
	Charge Unit	**Rate ($)**	**Volume**	**Charge ($)**	**Rate ($)**	**Volume**	**Charge ($)**	**$ Change**	**% Change**
Monthly Service Charge	Monthly	$ 32.9600	1	$ 32.96	$ 50.5300	1	$ 50.53	$ 17.57	53.31%
Smart Meter Rate Adder			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
Distribution Volumetric Rate	per kWh	$ 0.0179	3,500	$ 62.65	$ 0.0274	3,500	$ 95.90	$ 33.25	53.07%
Smart Meter Disposition Rider			3,500	$ -		3,500	$ -	$ -	
LRAM & SSM Rate Rider			3,500	$ -		3,500	$ -	$ -	
			3,500	$ -		3,500	$ -	$ -	
			3,500	$ -		3,500	$ -	$ -	
			3,500	$ -		3,500	$ -	$ -	
			3,500	$ -		3,500	$ -	$ -	
			3,500	$ -		3,500	$ -	$ -	
			3,500	$ -		3,500	$ -	$ -	
			3,500	$ -		3,500	$ -	$ -	
Sub-Total A (excluding pass through)				$ 95.61			$ 146.43	**$ 50.82**	**53.15%**
DVA - Total in Effect 2016	per kWh	-$ 0.0015	3,500	-$ 5.25		3,500	$ -	$ 5.25	-100.00%
DVA - Total in Effect 2017 (Var)	per kWh		3,500	$ -	-$ 0.0048	3,500	-$ 16.80	-$ 16.80	
	Monthly		1	$ -		1	$ -	$ -	
			3,500	$ -		3,500	$ -	$ -	
Low Voltage Service Charge	per kWh	$ 0.0002	3,500	$ 0.70	$ 0.0003	3,500	$ 1.05	$ 0.35	50.00%
Line Losses on Cost of Power	per kWh	$ 0.1160	190	$ 22.01	$ 0.1160	186	$ 21.52	-$ 0.49	-2.21%
Smart Meter Entity Charge			1	$ -		1	$ -	$ -	
Sub-Total B - Distribution (includes Sub-Total A)				**$ 113.07**			**$ 152.20**	**$ 39.13**	**34.61%**
RTSR - Network	per kWh	$ 0.0064	3,690	$ 23.61	$ 0.0061	3,686	$ 22.48	-$ 1.13	-4.80%
RTSR - Line and Transformation Connection	per kWh	$ 0.0051	3,690	$ 18.82	$ 0.0051	3,686	$ 18.80	-$ 0.02	-0.11%
Sub-Total C - Delivery (including Sub-Total B)				**$ 155.50**			**$ 193.48**	**$ 37.98**	**24.42%**
Wholesale Market Service Charge (WMSC)	per kWh	$ 0.0036	3,690	$ 13.28	$ 0.0036	3,686	$ 13.27	-$ 0.02	-0.11%
Rural and Remote Rate Protection (RRRP)	per kWh	$ 0.0013	3,690	$ 4.80	$ 0.0013	3,686	$ 4.79	-$ 0.01	-0.11%
Standard Supply Service Charge	Monthly	$ 0.2500	1	$ 0.25	$ 0.2500	1	$ 0.25	$ -	0.00%
Debt Retirement Charge (DRC)			3,500	$ -		3,500	$ -	$ -	
Ontario Electricity Support Program (OESP)	per kWh	$ 0.0011	3,690	$ 4.06	$ 0.0011	3,686	$ 4.05	-$ 0.00	-0.11%
RPP - Tier 1	per kWh	$ 0.0990	750	$ 74.25	$ 0.0990	750	$ 74.25	$ -	0.00%
RPP - Tier 2	per kWh	$ 0.1160	2,750	$ 319.00	$ 0.1160	2,750	$ 319.00	$ -	0.00%
				$ -			$ -	$ -	
Total Bill on TOU (before Taxes)				**$ 571.13**			**$ 609.09**	**$ 37.95**	**6.65%**
HST		13%		$ 74.25	13%		$ 79.18	$ 4.93	6.65%
Total Bill (including HST)				$ 645.38			$ 688.27	$ 42.89	6.65%
Ontario Clean Energy Benefit [1]									
Total Bill on TOU				**$ 645.38**			**$ 688.27**	**$ 42.89**	**6.65%**

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RATE MITIGATION

CNPI has analyzed the total bill impact for typical end users across all rate classes in Exhibit 8, Tab 1, Schedule 11. The following table summarizes the range of impacts for all rate classes, across all service territories, and at a wide range of consumption and demand levels. As outlined throughout Exhibits 7 and 8, adjustments to cost allocation, harmonization of rate riders, and the decoupling adjustments to Residential rates have resulted in a large range of bill impacts for certain classes.

	Range of Bill Impact	
Class	**Low**	**High**
Residential	-3.91%	16.29%
GS Less Than 50 kW	-2.10%	6.59%
GS 50 to 4999 kW	-4.56%	6.73%
Embedded Distributor	8.50%	
USL	5.48%	7.24%
Sentinel Lighting	2.62%	3.08%
Street Lighting	-11.90%	-11.02%

On average, a Residential customer on RPP-TOU rates, using 750 kWh per month will see a total bill increase of 1.28%. The average General Service less than 50 kW customer on TOU-RPP rates using 2000 kWh per month will see a total bill increase of 1.74%.

Impacts to the Embedded Distributor, USL and Street Lighting classes are largely a result of the establishment of a separate Embedded Distributor class and refinements to the Cost Allocation process outlined in Exhibit 7. Total bill impacts for Residential customers using greater than 500 kWh per month, as well as all General Service and Sentinel Lighting customers are generally in the range of -4% to 7%.

Residential customers with very low consumption (i.e. at or near the 10^{th} percentile of 210 kWh per month), may experience bill impacts exceeding 10%. As a result, CNPI has presented a possible rate mitigation scenario for the entire Residential class as outlined below.

Residential Rate Mitigation

CNPI has determined, based on 2015 data, that 10% of its residential customers consume 210 Kwh or less on a monthly basis. To determine this level of consumption at the tenth percentile, CNPI used a full data set of all customers with a complete twelve month billing cycle for the period of January 1 to December 31, 2015. This data set was exported from CNPI's billing system to Excel format and sorted on the basis of the total consumption for the year in descending order. Using Excel's percentile function, the twelve month consumption at the tenth percentile was 2529.96 Kwh per year or approximately 210 Kwh per month.

At this level of consumption, total bill impacts for the Residential class range from 5.86% to 11.51%, depending on the service territory and whether or not the customer has signed with a retailer.

Analysis of Bill Impact

The largest bill impact for a Residential customer at the 10th percentile is for a customer located in the Port Colborne service area, consuming 210 kWh per month, and purchasing energy through a retailer contract. The detailed Appendix 2-W bill impact analysis for this customer is reproduced on the following page. The total bill increase of 11.51% equates to $8.86, or $1.16 above the 10% threshold of $7.70.

Appendix 2-W Output

Residential, Retailer Supply, 210 kWh/month, Port Colborne

		Current Board-Approved			Proposed			Impact	
	Charge Unit	Rate ($)	Volume	Charge ($)	Rate ($)	Volume	Charge ($)	$ Change	% Change
Monthly Service Charge	Monthly	$ 23.4400	1	$ 23.44	$ 30.4700	1	$ 30.47	$ 7.03	29.99%
Smart Meter Rate Adder			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
Distribution Volumetric Rate	per kWh	$ 0.0152	210	$ 3.19	$ 0.0116	210	$ 2.44	-$ 0.76	-23.68%
Smart Meter Disposition Rider			210	$ -		210	$ -	$ -	
LRAM & SSM Rate Rider			210	$ -	$ 0.0003	210	$ 0.06	$ 0.06	
			210	$ -		210	$ -	$ -	
			210	$ -		210	$ -	$ -	
			210	$ -		210	$ -	$ -	
			210	$ -		210	$ -	$ -	
			210	$ -		210	$ -	$ -	
			210	$ -		210	$ -	$ -	
			210	$ -		210	$ -	$ -	
Sub-Total A (excluding pass through)				$ 26.63			$ 32.97	**$ 6.34**	**23.79%**
DVA - Total in Effect 2016	per kWh	-$ 0.0017	210	-$ 0.36		210	$ -	$ 0.36	-100.00%
DVA - Total in Effect 2017 (Var)	per kWh		210	$ -	$ 0.0065	210	$ 1.37	$ 1.37	
DVA - Total in Effect 2017 (Fixed)	Monthly		1	$ -	-$ 0.1500	1	-$ 0.15	-$ 0.15	
			210	$ -		210	$ -	$ -	
Low Voltage Service Charge	per kWh	$ 0.0002	210	$ 0.04	$ 0.0003	210	$ 0.06	$ 0.02	50.00%
Line Losses on Cost of Power		$ 0.1652	11	$ 1.88	$ 0.1652	11	$ 1.84	-$ 0.04	-2.21%
Smart Meter Entity Charge		$ 0.7900	1	$ 0.79	$ 0.7900	1	$ 0.79	$ -	0.00%
Sub-Total B - Distribution (includes Sub-Total A)				**$ 28.99**			**$ 36.88**	**$ 7.89**	**27.21%**
RTSR - Network	per kWh	$ 0.0072	221	$ 1.59	$ 0.0069	221	$ 1.53	-$ 0.07	-4.28%
RTSR - Line and Transformation Connection	per kWh	$ 0.0058	221	$ 1.28	$ 0.0059	221	$ 1.30	$ 0.02	1.61%
Sub-Total C - Delivery (including Sub-Total B)				**$ 31.87**			**$ 39.71**	**$ 7.84**	**24.61%**
Wholesale Market Service Charge (WMSC)	per kWh	$ 0.0036	221	$ 0.80	$ 0.0036	221	$ 0.80	-$ 0.00	-0.11%
Rural and Remote Rate Protection (RRRP)	per kWh	$ 0.0013	221	$ 0.29	$ 0.0013	221	$ 0.29	-$ 0.00	-0.11%
Standard Supply Service Charge	Monthly	$ 0.2500	1	$ 0.25	$ 0.2500	1	$ 0.25	$ -	0.00%
Debt Retirement Charge (DRC)			210	$ -					
Ontario Electricity Support Program (OESP)	per kWh	$ 0.0011	221	$ 0.24	$ 0.0011	221	$ 0.24	-$ 0.00	-0.11%
Non-RPP Retailer Avg. Price + GA		$ 0.1652	210	$ 34.69	$ 0.1652	210	$ 34.69	$ -	0.00%
Total Bill on Non-RPP Avg. Price				**$ 68.14**			**$ 75.97**	**$ 7.84**	**11.51%**
HST		13%		$ 8.86	13%		$ 9.88	$ 1.02	11.51%
Total Bill (including HST)				$ 76.99			$ 85.85	$ 8.86	11.51%
Ontario Clean Energy Benefit [1]									
Total Bill on Non-RPP Avg. Price				**$ 76.99**			**$ 85.85**	**$ 8.86**	**11.51%**

<u>Proposed Approach to Residential Mitigation</u>

Assuming the Board determines that mitigation is necessary, CNPI proposes to provide mitigation by modifying the decoupling related adjustments it makes to the fixed and volumetric rates for residential customers in the remaining years of the transition to fully fixed rates, including the addition of a 5th transitional year. CNPI has filed a second version of its rate design model in live Excel format that includes an adjustment to the Residential decoupling mechanism that limits the overall total bill impact to 10%. The effect of this adjustment is to reduce the amount of the Monthly Service Charge increase from $3.67 to

$2.14. The modified decoupling adjustment, which would extend the decoupling adjustment period from four years to five, is illustrated below.

Revenue Decoupling for the Residential Rate Class - 2nd Increment
EB-2016-0061

Rate Class	Customers/ Connections		Test Year Consumption		Proposed Rates			Proposed Revenues			Proposed Split	
		Average for 2017	kWh	kW	Monthly Service Charge	Volumetric		Fixed	Variable	Total	Fixed	Variable
						kWh	kW	$	$	$		
Residential	Customers	26,074	198,077,803		$ 26.80	$ 0.0174		8,385,273	3,442,311	11,827,584	70.9%	29.1%
GS Less Than 50 kW	Customers	2,489	67,907,332		$ 32.02	$ 0.0261		956,449	1,769,816	2,726,265	35.1%	64.9%
GS 50 to 4,999 kW	Customers	217	184,944,203	593,383	$ 172.04		$ 7.5344	448,004	4,470,804	4,918,809	9.1%	90.9%
Embedded Distributor	Customers	1	5,129,448	13,717	$ 584.79		$ 8.3087	7,017	113,970	120,987	5.8%	94.2%
USL	Customers	35	1,462,761		$ 50.53	$ 0.0274		21,223	40,142	61,365	34.6%	65.4%
Sentinel Lighting	Connections	695	629,014	1,916	$ 5.77		$ 6.6867	48,102	12,812	60,914	79.0%	21.0%
Street Lighting	Connections	5,713	2,781,556	8,591	$ 4.06		$ 8.8324	278,177	75,879	354,056	78.6%	21.4%
Total		35,224	460,932,117	617,607				10,144,246	9,925,733	20,069,980	50.5%	49.5%

Residential Decoupling

Current Monthly Service Charge (post 2017 COS adjustment)	$ 26.80	Monthly Service Charge to Achieve 100% Recovery	$ 37.80
Max Increment to Limit 10th Percentile to 10% Total Bill Increase	$ 2.14	Remaining Total Adjustment to Achieve 100% Recovery	$ 8.86
Proposed Residential Monthly Service Charge (2nd increment)	$ 28.94	Approximate Adjustment over 2 remaining years	$ 4.43
Difference in Adjustment With Mitigation	-$ 1.52	Approximate Adjustment over 3 years (Proposed Mitigation)	**$ 2.95**

Decoupled Residential Rates

Rate Class	Customers/ Connections		Test Year Consumption		Proposed Rates			Proposed Revenues			Existing Split	
		Average for 2017	kWh	kW	Monthly Service Charge	Volumetric		Fixed	Variable	Total	Fixed	Variable
						kWh	kW	$	$	$		
Residential	Customers	26,074	198,077,803		**$ 28.94**	**$ 0.0140**		9,054,979	2,772,605	11,827,584	76.6%	23.4%

Balance Check -

CNPI has acknowledged throughout this application that certain items impacting rates (e.g. RTSR's, Cost of Capital parameters, and certain regulatory rates) will be subject to adjustment based on information that becomes available during the course of the proceeding. CNPI proposes to run its rate design model with all changes made throughout the course of this proceeding and re-check whether the Residential 10th percentile total bill impacts remain above 10%. Should any total bill impacts remain above this threshold, CNPI proposes that the mitigation approach methodology as illustrated above should be adjusted to account for any changes to pre-mitigation rates, and final Residential rates will be proposed so as to limit the total bill impact to 10%.

The proposed Tariff of Rates and Charges filed at Exhibit 8, Tab 1, Schedule 9 reflect the above adjustments for Residential rate mitigation.

DEFERRAL AND VARIANCE ACCOUNT OVERVIEW

Overview

Canadian Niagara Power Inc. ("CNPI") is applying for the recovery of its Group 1 regulatory deferral and variance account ("DVA") balances as at December 31, 2015 with projected interest to December 31, 2016. The net total of Group 1 accounts being requested for disposition is a credit of $383,648. CNPI is also seeking recovery of selected Group 2 and other DVA accounts including: a credit of $38,857 for OEB 1508 Sub-account Financial Assistance Payment and Recovery Variance – Ontario Clean Energy Benefit Act (interest only); a credit of $71,997 for OEB 1592 PILs and Tax Variance for 2006 and Subsequent Years (see Tab 2 of this Exhibit), and a debit of $255,421 for OEB 1568 LRAM (see Tab 6 of this Exhibit).

CNPI is also requesting the disposition of the OEB 1557 MIST Cost Deferral Account within Tab 3 of this Exhibit along with the recovery of stranded meter costs relating to MIST implementation within Exhibit 2, Tab 1, Schedule 8. CNPI is requesting that a new sub account of OEB 1557 be created to track the stranded costs and recovery requested within this Application.

CNPI is not requesting disposition of balances relating to OEB 1508 Sub-account Financial Assistance Payment and Recovery Variance – Ontario Clean Energy Benefit Act (principal only), OEB 1508 Sub-account Pension Deferral, OEB 1508 Sub-account Pension Expense Variance, OEB 1508 Sub-account Other Post Employment Benefits, and OEB 1508 Sub-account OPEB Expense Variance. The principal portion of OEB 1508 Sub-account Financial Assistance Payment and Recovery Variance has not been requested for disposition as it will be settled with the Independent Electricity System Operator ("IESO"). Per EB-2013-0368/EB-2013-0369, the 1508 Sub-accounts relating to Pension and OPEB expenses have been used to record the difference between reporting under Section 3461 and Section 3462, starting January 1, 2013. These have not been requested for disposition within this Application as the balances will be reviewed in a future proceeding.

Harmonization of Rates

In CNPI's last Cost of Service Application (EB-2012-0112), a plan was proposed that would harmonize rates in its three service territories (Fort Erie, Port Colborne and Gananoque) by 2016; the plan was subsequently accepted by the Board and has been implemented by CNPI. Within this Application, CNPI is proposing the harmonization of its DVA balances and rate rider calculations for the three service territories effective January 1, 2017. CNPI has prepared one set of schedules within this Exhibit that calculate one set of rate riders to be effective January 1, 2017. CNPI has also proposed a harmonized rate rider calculation for an existing rate rider with an expiry date of December 31, 2017 that was approved as part of CNPI's 2016 IRM (EB-2015-0058) in Tab 5 of this Exhibit.

Continuity Schedules

CNPI has completed an unlocked version of the EDDVAR continuity schedule released for 2016 Cost of Service ("COS") proceedings. Some revisions were made to the unlocked version to account for the fact that this schedule was prepared for CNPI's 2017 COS Application. For example, references to 2014 have been changed to 2015. Additionally, adjustments have been made to the Q4 2015 columns for the purposes of rate rider calculations, but these amounts will not be reported in either the 2015 RRR filings nor have they been reported in the 2015 audited financial statements. Refer to Tables 9.1.1.1 and 9.1.1.2 below for additional detail. The completed continuity schedule can be found in Schedule 2 of this Tab. A summary of outstanding balances as at December 31, 2015 (adjusted for Board approved dispositions in 2016), plus 2016 projected interest can be found in Table 9.1.1.1 below:

Table 9.1.1.1: Summary of Outstanding Deferral and Variance Account Balances

Account Descriptions	Account Number	Requested for Disposition (Y/N)	31-Dec-15 Principal Balance (A)	31-Dec-15 Interest Balance (B)	31-Dec-15 Total C = A + B	2016 Projected Interest (D)	Total Claim E = C + D
Group 1							
LV Variance Account	1550	Yes	41,015	122	41,136	451	41,587
Smart Metering Entity Charge Variance Account	1551	Yes	(13,285)	16,329	3,044	(146)	2,898
RSVA - Wholesale Market Service Charge	1580	Yes	(861,506)	(4,717)	(866,222)	(9,477)	(875,699)
RSVA - Retail Transmission Network Charge	1584	Yes	(161,591)	(135)	(161,727)	(1,778)	(163,504)
RSVA - Retail Transmission Connection Charge	1586	Yes	(9,153)	10	(9,143)	(101)	(9,244)
RSVA - Power (excluding Global Adjustment)	1588	Yes	(557,829)	(5,112)	(562,941)	(6,136)	(569,077)
RSVA - Global Adjustment	1589	Yes	1,161,026	9,254	1,170,280	12,771	1,183,052
Disposition and Recovery/Refund of Regulatory Balances (2015)	1595	Yes	5,711	565	6,276	63	6,339
					-		-
Group 1 Total			**(395,612)**	**16,316**	**(379,296)**	**(4,352)**	**(383,648)**
Group 2							
Other Regulatory Assets - Sub-Account - Financial Assistance Payment and Recovery Variance - Ontario Clean Energy Benefit Act	1508	Yes	-	(38,857)	(38,857)	-	(38,857)
					-		-
Group 2 Total			**-**	**(38,857)**	**(38,857)**	**-**	**(38,857)**
PILs and Tax Variance for 2006 and Subsequent Years (excludes sub-account and contra account below)	1592	Yes	(61,710)	(9,609)	(71,319)	(679)	(71,997)
PILs and Tax Variance for 2006 and Subsequent Years - Sub-Account HST/OVAT Input Tax Credits (ITCs)	1592	Yes	(2,910)	2,910	0	-	0
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Stranded Meter Costs5	1555	Yes	0	-	0	-	0
LRAM Variance Account	1568	Yes	252,642	-	252,642	2,779	255,421
Total of Group 1, Group 2, and above			**(207,591)**	**(29,239)**	**(236,830)**	**(2,251)**	**(239,081)**

The continuity schedule provided in Schedule 2 of this Tab shows a tie-out with the 2.1.7 annual RRR filing and any differences are explained in Appendix A of the continuity schedule. Table 9.1.1.2 below shows a tie-out of the continuity schedule as at December 31, 2015 to the audited financial statements, with explanations of the differences in Note A of the table.

Table 9.1.1.2 Tie out of DVA Continuity Schedule to Audited Financial Statements (in '000's)

	31-Dec-15	
Per Continuity Schedule		
Group 1 Total Including 1589	***11***	
Group 2 Total	***(39)***	
Other Accounts		
PILS and Tax Variances for 2006 and Subsequent (1592)	(71)	
	(71)	
Total Deferral and Variance per Continuity Schedule	***(99)***	A
Per Audited Financial Statements		
Current Regulatory Assets	***-***	
Long-term Regulatory Assets	***12,043***	
Current Regulatory Liabilities	***(738)***	
Long-term Regulatory Liabilities	***(3,095)***	
Total Deferral and Variance	***8,210***	B
Difference	***(8,309)***	A - B

Notes:

A

(6,731)	Account balances grouped as regulatory in audited financial statements, but reported elsewhere on the 2.1.7 RRR filing. Balance includes CNPI Transmission regulatory balances and deferred tax balances.
547	OCEB adjustment in continuity schedule to clear outstanding principal balances. Adjustment recorded in financial statements and RRR filings in 2016.
(234)	MIST meter balance not reported in continuity schedule but requested for disposition within this Exhibit of this Application.
(1,806)	Group 1 and Group 2 balances not requested for disposition within this Application. Balance includes Pension and OPEB balances reported in OEB 1508. Balance also includes account balances where active rate riders still exist at the end of 2015, including balances in OEB 1595 and OEB 1562.
12	Fixed priced, MicroFIT, and FIT adjustment true-up was performed in 2016 for the 2015 year and recorded in the continuity schedule as a Principal Adjustment during 2015 in OEB 1588, but not recorded in financial statements and the RRR filings until 2016.
(97)	Global adjustment true-up was performed in 2016 for the 2015 year and recorded in the continuity schedule as a Principal Adjustment during 2015 in OEB 1589, but not recorded in the financial statements and RRR filings until 2016.
(8,309)	

Description of Group 1, Group 2, and Other DVA Accounts

Group 1 Accounts

CNPI's Group 1 DVAs currently used are described below. All accounts are used in accordance with the Accounting Procedures Handbook:

- **1550 – Low Voltage Variance Account**
  Low Voltage account is used to record the difference between the amount of low voltage charges paid to the IESO or host distributor and the amounts billed to customers for low voltage charges. These amounts are calculated on an accrual basis, as are the carrying charges, which are assessed on the monthly opening principal balance of this account. CNPI is requesting disposition of the balance of the Low Voltage Variance account as at December 31, 2015, plus forecasted interest to December 31, 2016, within this Exhibit.

- **1551 – Smart Metering Entity Charge Variance Account ("SME")**
  SME is used monthly to record the variances arising from the Smart Metering Entity charges paid to the IESO and the amounts billed to Residential Service and General Service <50kW customers. These amounts are calculated on an accrual basis, as are the carrying charges, which are assessed on the monthly opening principal balance of this account. CNPI is requesting disposition of the balance of this account as at December 31, 2015, plus forecasted interest to December 31, 2016, within this Exhibit.

- **1580 – Retail Settlement Variance Account – Wholesale Market Service Charges ("RSVA$_{WMS}$")**
  RSVA$_{WMS}$ is used to record the difference between the amount of wholesale market service charges paid to the IESO or host distributor and the amounts billed to customers. These amounts are calculated on an accrual basis, as are the carrying charges, which are assessed on the monthly opening principal balance of this RSVA account. CNPI is requesting disposition of the balance of

the $RSVA_{WMS}$ account as at December 31, 2015, plus forecasted interest to December 31, 2016, within this Exhibit.

- **1584 – Retail Settlement Variance Account – Retail Transmission Network Charges (“$RSVA_{NW}$”)**

  $RSVA_{NW}$ is used to record the difference between the amount of retail transmission network charges paid to the IESO or host distributor and the amounts billed to customers. These amounts are calculated on an accrual basis, as are the carrying charges, which are assessed on the monthly opening principal balance of this RSVA account. CNPI is requesting disposition of the balance of the $RSVA_{NW}$ account as at December 31, 2015, plus forecasted interest to December 31, 2016, within this Exhibit.

- **1586 – Retail Settlement Variance Account – Retail Transmission Connection Charges (“$RSVA_{CN}$”)**

  $RSVA_{CN}$ is used to record the difference between the amount of retail transmission connection costs paid to the IESO or host distributor and the amounts billed to customers. These amounts are calculated on an accrual basis, as are the carrying charges, which are assessed on the monthly opening principal balance of this RSVA account. CNPI is requesting disposition of the balance of the $RSVA_{CN}$ account as at December 31, 2015, plus forecasted interest to December 31, 2016, within this Exhibit.

- **1588 – Retail Settlement Variance Account– Power (“$RSVA_{POWER}$”)**

  The $RSVA_{POWER}$ account is used to record the net differences in energy costs using the settlement invoice received from the IESO, host distributor or embedded generator and the amounts billed to customers for energy. These amounts are calculated on an accrual basis, as are the carrying charges, which are assessed on the monthly opening principal balance of this RSVA account. CNPI is requesting disposition of the balance of the $RSVA_{POWER}$ account as at

December 31, 2015, plus forecasted interest to December 31, 2016, within this Exhibit.

- **1589 – Retail Settlement Variance Account – Global Adjustment (“RSVA$_{GA}$”)**
  The RSVA$_{GA}$ account is used to record the net differences between the Global Adjustment amount billed, to non-RPP consumers and the Global Adjustment charge to a distributor for non-RPP consumers, using the settlement invoice received from the IESO or host distributor. These amounts are calculated on an accrual basis, as are the carrying charges, which are assessed on the monthly opening principal balance of this RSVA account. CNPI is requesting disposition of the balance of the RSVA$_{GA}$ account as at December 31, 2015, plus forecasted interest to December 31, 2016, within this Exhibit.

- **1595 – Recovery/Disposition of Regulatory Asset Balances (Recovery or Refund Period completed)**
  This OEB account includes the regulatory asset or liability balances approved for disposition by the OEB in previous applications, offset by the recoveries from DVA rate riders assessed on customer bills. The rate rider amounts are calculated on an accrual basis, as are the carrying charges, which are assessed on the monthly opening principal balance of this recovery account. Separate Sub-Accounts have been created to appropriately track each Board approved recovery.
  Sub-Accounts (2015) for EB-2014-0061 – The recovery period for disposition of the Lost Revenue Adjustment Mechanism Variance Account (“LRAMVA”) ended December 31, 2015. The recovery period for disposition of Deferral/Variance Accounts (2015) and the Global Adjustment Account (2015) ends December 31, 2016. Therefore, CNPI is only requesting disposition of the LRAMVA Sub-Account within this Exhibit.
  Sub-Accounts (2016) for EB-2015-0058 – CNPI is not requesting recovery of the residual balances in these Sub-Accounts as the recovery period is effective

until December 31, 2017. CNPI is proposing a new harmonized rate rider for the 2017 year and this is discussed further in Tab 5 of this Exhibit.

Group 2 Accounts

CNPI's Group 2 DVAs currently used are described below. All accounts are used in accordance with the Accounting Procedures Handbook:

- **1508 – Other Regulatory Assets – Ontario Clean Energy Benefit Sub-Account ("OCEB")**

  This Sub-Account is used to record the difference between the amounts of reimbursement claimed from the IESO and the financial assistance credited to eligible accounts. The carrying charges are assessed on an accrual basis on the monthly opening principal balance of this regulatory account. CNPI is requesting disposition of the interest balance of this Sub-Account as at December 31, 2015 because the OCEB initiative had a sunset date of December 31, 2015. The principal balance has not been requested for disposition as it will be settled with the IESO.

- **1508 – Other Regulatory Assets – Ontario Electricity Support Program ("OESP")**

  This Sub-Account is used to record the difference between the amounts of reimbursement claimed from the IESO and the financial assistance credited to eligible accounts. Carrying charges are not assessed on this regulatory account. CNPI has a $Nil balance in this account as at December 31, 2015 as the program does not commence until January 1, 2016.

- **1508 – Other Regulatory Assets – Pension Deferral Sub-Account**

  Per EB-2013-0368/EB-2013-0369, this Sub-Account is used to record the initial recognition of "unrecognized losses," "unrecognized past service cost," and "unrecognized transition obligations" for CNPI's transition to section 3462, Employee Future Benefits, in Part II of the CPA Canada Handbook, effective

January 1, 2013. No carrying charges apply to this account. CNPI is not requesting disposition of the balance of this Sub-Account.

- **1508 – Other Regulatory Assets – Pension Expense Variance Sub-Account**
  Per EB-2013-0368/EB-2013-0369, this Sub-Account is used to record the difference between pension expense under Section 3461 and Section 3462, starting January 1, 2013. No carrying charges apply to this account. CNPI is not requesting disposition of the balance of this Sub-Account.

- **1508 – Other Regulatory Assets – Other Post Employment Benefits ("OPEB") Deferral Sub-Account**
  Per EB-2013-0368/EB-2013-0369, this Sub-Account is used to record the initial recognition of "unrecognized losses," "unrecognized past service cost," and "unrecognized transition obligations" for CNPI's transition to section 3462, Employee Future Benefits, in Part II of the CPA Canada Handbook, effective January 1, 2013. No carrying charges apply to this account. CNPI is not requesting disposition of the balance of this Sub-Account.

- **1508 – Other Regulatory Assets – OPEB Expense Variance Sub-Account**
  Per EB-2013-0368/EB-2013-0369, this Sub-Account is used to record the difference between OPEB expense under Section 3461 and Section 3462, starting January 1, 2013. No carrying charges apply to this account. CNPI is not requesting disposition of the balance of this Sub-Account.

- **1572 – Extraordinary Event Losses**
  This account is used to record extraordinary event losses that meet qualifying criteria as established by the OEB. The carrying charges are assessed on an accrual basis on the monthly opening principal balance of this regulatory account. As of December 31, 2015, CNPI has a $Nil balance in this account but CNPI is requesting to keep the account open for use in the event that extraordinary event losses are incurred in the future.

- **1582 – Retail Settlement Variance Account – One-time Wholesale Market Service (“RSVA$_{\text{One-Time}}$”)**

  RSVA$_{\text{One-Time}}$ is used to record the difference between the non-recurring wholesale market services charges paid to the IESO and the amounts billed to customers. These amounts are calculated on an accrual basis, as are the carrying charges, which are assessed on the monthly opening principal balance of this RSVA account. As of December 31, 2015, CNPI has a $Nil balance in this account. CNPI is requesting to keep the account open for use in the event that One-Time Wholesale Market Service costs are incurred in the future.

Other DVA Accounts

CNPI’s Other DVAs currently used are described below. All accounts are used in accordance with the Accounting Procedures Handbook:

- **1555 – Smart Meter Capital and Recovery Offset Variance Account – Stranded Meter Costs Sub-Account**

  This account is used to record the stranded costs associated with conventional or accumulation meters removed at the time of installation of smart meters. Costs to be accumulated in this account include the net book value cost of removed meters less any net sale proceeds when received. Carrying charges are not authorized for this Sub-Account. CNPI is requesting disposition of the residual balance of this account within this Exhibit.

- **1557 – Metering Inside the Settlement Timeframe (“MIST”) Cost Deferral Account**

  This account is used to record incremental costs associated with implementing the amendments made to the Distribution System code dated May 21, 2014. CNPI is requesting disposition of the balance of this account in Tab 3 of this Exhibit.

- **1562 – Deferred Payments in Lieu of Taxes**

  This account is used to record the amount resulting from the Board approved PILS methodology. The carrying charges are assessed on an accrual basis on the monthly opening principal balance of this account. CNPI requested disposition of this account in its previous Cost of Service proceeding (EB-2012-0112). As of December 31, 2015, CNPI had a $Nil balance in this account. CNPI is requesting that this account be closed as of December 31, 2015.

- **1563 – Contra Account Deferred Payments in Lieu of Taxes**

  Amounts recorded in this account in are accordance with the Board's accounting instructions for PILS as set out in the April 2003 Board issued Frequently Asked Questions on the APH. The carrying charges are assessed on an accrual basis on the monthly opening principal balance of this account. CNPI is not requesting disposition of the balance of this account as the recovery period for disposition of this account ends December 31, 2016.

- **1568 – LRAM Variance Account**

  This account is used to record the lost revenue adjustment mechanism ("LRAM") variances in relation to the conservation and demand management ("CDM") programs or activities undertaken by a distributor in accordance with Board-prescribed requirements (e.g. license, codes and guidelines). The carrying charges are assessed on an accrual basis on the monthly opening principal balance of this account. CNPI is requesting disposition of the balance of this account as at December 31, 2015, plus forecasted interest to December 31, 2016, within Tab 6 of this Exhibit.

- **1592 – PILs and Tax Variance for 2006 and Subsequent Years (“$\text{PILS}_{\text{Post 2006}}$”)**

  $\text{PILS}_{\text{Post 2006}}$ is used to record the tax impact of differences that result from legislative or regulatory changes to the tax rates or rules as compared to models previously submitted in COS or IRM proceedings. These amounts are calculated on an accrual basis, as are the carrying charges, which are assessed on the monthly opening principal balance of this account. CNPI is requesting disposition of the balance of this account as at December 31, 2015, plus forecasted interest to December 31, 2016, within Tab 2 of this Exhibit.

- **1592 – PILs and Tax Variance for 2006 and Subsequent Years – HST/OVAT Input Tax Credits (ITCs)**

  Effective July 1, 2010, this account is used to record the incremental ITC CNPI received on distribution revenue requirement items that were previously subject to PST and became subject to HST. Tracking of these amounts continued until the effective date of CNPI’s Cost of Service Application EB-2012-0112 (i.e. January 1, 2013), after which the ITC was reflected in rate base and revenue requirement calculations going forward. The carrying charges are assessed on an accrual basis on the monthly opening principal balance of this account. Fifty percent of the confirmed balance shall be returnable to the ratepayers. CNPI requested disposition of this account in its previous Cost of Service proceeding (EB-2012-0112). As of December 31, 2015 CNPI had a $Nil balance in this account. CNPI is requesting that this account be closed as of December 31, 2015.

Carrying Charges

In accordance with the APH, CNPI calculates simple interest on monthly opening principal balances of the aforementioned OEB accounts (accounts in which interest is deemed acceptable only) using the OEB prescribed interest rates. See Table 9.1.1.3 below for quarterly Board approved interest rates used for the simple interest calculations since its last Cost of Service proceeding. CNPI follows the accrual approach for record keeping and financial reporting, and follows the same approach when calculating carrying charges.

Table 9.1.1.3 Board Approved Interest Rates

Quarter	Board Approved Interest Rates
2015 Q1	1.47%
2015 Q2	1.10%
2015 Q3	1.10%
2015 Q4	1.10%

Quarter	Board Approved Interest Rates
2014 Q1	1.47%
2014 Q2	1.47%
2014 Q3	1.47%
2014 Q4	1.47%

Quarter	Board Approved Interest Rates
2013 Q1	1.47%
2013 Q2	1.47%
2013 Q3	1.47%
2013 Q4	1.47%

Quarter	Board Approved Interest Rates
2012 Q1	1.47%
2012 Q2	1.47%
2012 Q3	1.47%
2012 Q4	1.47%

New Accounts Requested

CNPI is requesting the following new deferral or variance accounts:

- **OEB 1557 Sub-Account (MIST$_{\text{STRANDED}}$) for EB-2016-0061** – CNPI is requesting to create this Sub-Account upon approval within this Application, of the disposition of the meters stranded as a result of the implementation of MIST.
- **OEB 1595 Sub-Account (2017$_{\text{POWER}}$) for EB-2016-0061** – CNPI is requesting to create this Sub-Account upon approval within this Application, of the disposition of DVA balances as at December 31, 2015.
- **OEB 1595 Sub-Account (2017$_{\text{GA}}$) for EB-2016-0061** – CNPI is requesting to create this Sub-Account upon approval within this Application, of the disposition of DVA balances as at December 31, 2015.
- **OEB 1595 Sub-Account (2017$_{\text{LRAM}}$) for EB-2016-0061** – CNPI is requesting to create this Sub-Account upon approval within this Application, of the disposition of LRAM balances as at December 31, 2015.

Adjustments to DVAs

CNPI has not made any material adjustments to DVA balances that were previously approved by the Board on a final basis in both COS and IRM proceedings (i.e. balances that were adjusted subsequent to the balance sheet date that were cleared in the most recent rates proceeding). Occasionally, immaterial adjustments to a previously approved 1595 recovery account may be made in the event that there is a billing correction posted subsequent to the request for disposition. That adjustment is then moved to another 1595 recovery account and is requested for disposition in a subsequent proceeding. CNPI is not aware of any adjustments that have been made to previously approved 1595 recovery accounts, in DVA balances sought for disposition within this proceeding.

Reconciliation - Energy Sales and Cost of Power Mapped to USoA Account

A breakdown of energy sales and cost of power expense balances, as reported in the Audited Financial Statements, and mapped to USoA account numbers can be found in Table 9.1.1.4 below.

Table 9.1.1.4 Reconciliation of Energy Sales and Cost of Power (in '000's)

	2015	
Per 2.1.7 filing		
Energy Sales		
4006 Residential Energy Sales	19,699	
4010 Commercial Energy Sales	6,248	
4015 Industrial Energy Sales	19,414	
4025 Street Lighting Energy Sales	355	
4030 Sentinel Lighting Energy	65	
4035 General Energy Sales	161	
4050 Revenue Adjustment	(574)	
4055 Energy Sales For Retailers/Others	3,879	
4060 Interdepartmental Energy Sales	166	
4062 Billed - WMS	1,989	
4066 Billed - NW	3,398	
4068 Billed - CN	2,743	
4075 Billed - LV	49	
4076 Billed - SME	268	
	57,861	
Other Power Supply Expenses		
4705 Power Purchased	32,995	
4707 Charges - Global Adjustment	16,419	
4708 Charges - WMS	1,989	
4714 Charges - NW	3,398	
4716 Charges - CN	2,743	
4750 Charge - LV	49	
4751 Charges - SME	268	
	57,861	
Profit (Loss)	***-***	***s/b 0***
Per Audited Financial Statements		
Sale of Energy	***57,861***	
Cost of Power Purchased	***57,861***	
Profit (Loss)	***-***	***s/b 0***
Difference		
Energy Sales	***-***	***s/b 0***
Other Power Supply Expenses	***-***	***s/b 0***
Profit (Loss)	***-***	***s/b 0***

Pro-ration of IESO Global Adjustment Charge into RPP and non-RPP Portions

CNPI confirms that it has a process in place to ensure that non-RPP Global Adjustment values are recorded in the correct Income Statement accounts and DVAs.

Description of Settlement Process with the IESO (or Host Distributor for Gananoque region)

<u>Billing of Class A and B Customers</u>

Customers (both Class A and B) are billed on a one month billing lag (i.e. January consumption would be billed to customers in February). Class B non-RPP customers were billed using the 1st estimate for Global Adjustment, as published by the IESO, prior to 2016; starting January 2016 Class B non-RPP customers are being billed using the 2nd GA estimate. Class A customers are billed using their peak demand factor (PDF) multiplied by the actual total monthly Global Adjustment published by the IESO. Since the IESO bills based on the same methodology, the amount billed to Class A customers is equal to the amount charged by the IESO for Class A Global Adjustment (charge type 147). A monthly check is completed to ensure that the amount billed to Class A customers equals the amount billed by the IESO for Class A Global Adjustment. Since this is the case, there will be no variance created for Global Adjustment for Class A customers within OEB account 1589.

CNPI served one Class A customer in 2014 in the Port Colborne service territory. As of July 1, 2015, Canadian Niagara Power is serving two Class A customers (one in each of Fort Erie and Port Colborne service territories) with a combined peak demand factor of 0.00029577. Given that these two Class A customers were only part of Class A during a portion of 2015, a portion of the residual OEB account 1589 balance being requested for disposition within this Application is being allocated to these Class A customers. See continuity schedule in Schedule 2 of this Tab of this Application as well as Tab 5 for rate rider calculations.

<u>RPP Tiered & TOU Customers and the IESO Settlement Process (Hydro One as Host Distributor for the Eastern Ontario Power Service Territory)</u>

Given the one month billing lag discussed above, consumption data and IESO settlements submitted to the IESO (or host distributor) are also filed with a one month lag. For example, the February IESO settlement submission (due by the fourth business day in March) would be based on January consumption values and inputs. Consumption values for RPP tiered and TOU customers are obtained from the accounting system by running detailed reports that pull relevant information from actual customer billings during the period. Specific consumption value dates are entered before the report is run to ensure the appropriate consumption values are included in the output of the report. The consumption values are inputted into an excel spreadsheet for use in the settlements computation (see below). In addition, inputs for the weighted average energy price (obtained from an independent 3rd party database and includes embedded generation prices), the final Global Adjustment rate (published by OEB), RPP tiered electricity prices and TOU electricity prices (published by the OEB) are also entered into the aforementioned spreadsheet. All of these inputs are also based on a one month lag so that consumption values are consistent with all inputs.

Using these inputs and consumption values for RPP and TOU customers, the following two sets of computations are completed:

1. The difference between the weighted average energy price and the RPP tiered and TOU pricing is multiplied by the applicable RPP and TOU consumption values (referred to as the Fixed Price Adjustment variance). This variance is treated as a payable back to the IESO and is recorded in OEB account 1588. The accounting entry consists of a debit to OEB account 1588 and a credit payable to the IESO.
2. The final Global Adjustment rate is multiplied by the RPP and TOU consumption values to determine the amount receivable from the IESO (referred to as the Global Adjustment variance). This credit is recorded in OEB account 1589. The accounting entry consists of a debit receivable from the IESO and a credit to OEB account 1589.

The net of the above two calculations, along with the consumption values and number of customers is reported in the applicable tiers/buckets on the Former 1598 IESO settlements submission form. Submissions are done on a monthly basis.

True-ups are completed on an annual basis in conjunction with the preparation of IRM and/or CoS proceedings. All consumption values are re-run out of the accounting system and all inputs are re-entered to ensure no typographical errors were made or to account for any changes in externally provided inputs (weighted average energy price, final Global Adjustment rate). Any differences that arise as a result of the true-ups are typically due to billing corrections (i.e. consumption value changes) that have occurred after the original IESO settlement submissions were submitted. The true-up amounts are reported as Other Adjustments on the DVA continuity schedules for IRM and/or CoS proceedings in the year in which it relates to.

Based on the above process in place, any residual balance that remains in OEB account 1589 at the end of the reporting period, would not be attributed to RPP (tiered and TOU) customers; rather, the residual balances should be allocated to non-RPP Class B customers.

<u>Final Variance Settlement Amount</u>

In addition to the Fixed Price Adjustment and the Global Adjustment variances, the final RPP variance settlement amount is also filed on the Former 1598 IESO settlements form submission. Detailed reports are run out of the accounting system that compile final customer billings in which final RPP variance settlement amounts have been assessed for those RPP customers that have left / opted out of RPP pricing.

DEFERRAL AND VARIANCE ACCOUNT WORKFORM

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Ontario Energy Board

2016 Deferral/Variance Account Workform

Version 2.6 unlock

Utility Name	Canadian Niagara Power Inc.
Service Territory	CNPI Consol
Assigned EB Number	EB-2016-0061
Name of Contact and Title	Brian Vander Vloet, Manager of Regulatory Accoun
Phone Number	905-871-0330
Email Address	brian.vandervloet@cnpower.com

General Notes

Notes

Pale green cells represent input cells.

Pale blue cells represent drop-down lists. The applicant should select the appropriate item from the drop-down list.

White cells contain fixed values, automatically generated values or formulae.

Ontario Energy Board

2016 Deferral/Variance Account Workform

	Account Descriptions	Account Number
	Group 1 Accounts	
1	LV Variance Account	1550
2	Smart Metering Entity Charge Variance Account	1551
3	RSVA - Wholesale Market Service Charge	1580
4	RSVA - Retail Transmission Network Charge	1584
5	RSVA - Retail Transmission Connection Charge	1586
6	RSVA - Power (excluding Global Adjustment)	1588
7	RSVA - Global Adjustment	1589
8	Disposition and Recovery/Refund of Regulatory Balances (2009)	1595
9	Disposition and Recovery/Refund of Regulatory Balances (2010)	1595
10	Disposition and Recovery/Refund of Regulatory Balances (2011)	1595
11	Disposition and Recovery/Refund of Regulatory Balances (2012)	1595
12	Disposition and Recovery/Refund of Regulatory Balances (2013)	1595
13	Disposition and Recovery/Refund of Regulatory Balances (2014)	1595
14	Disposition and Recovery/Refund of Regulatory Balances (2015)	1595
	Group 1 Sub-Total (including Account 1589 - Global Adjustment)	
	Group 1 Sub-Total (excluding Account 1589 - Global Adjustment)	
	RSVA - Global Adjustment	**1589**
	Group 2 Accounts	
15	Other Regulatory Assets - Sub-Account - Deferred IFRS Transition Costs	1508
16	Other Regulatory Assets - Sub-Account - Incremental Capital Charges	1508
17	Other Regulatory Assets - Sub-Account - Financial Assistance Payment and Recovery Variance - Ontario Clean Energy Benefit Act[8]	1508
18	Other Regulatory Assets - Sub-Account - Financial Assistance Payment and Recovery Carrying Charges	1508
19	Other Regulatory Assets - Sub-Account - Other [4] **- OEB Cost Assessments + Other**	1508
20	Retail Cost Variance Account - Retail	1518
21	Misc. Deferred Debits	1525
22	Board-Approved CDM Variance Account	1567
23	Extra-Ordinary Event Costs	1572
24	Deferred Rate Impact Amounts	1574
25	RSVA - One-time	1582
26	Other Deferred Credits	2425
	Group 2 Sub-Total	
27	PILs and Tax Variance for 2006 and Subsequent Years (excludes sub-account and contra account below)	1592
28	PILs and Tax Variance for 2006 and Subsequent Years - Sub-Account HST/OVAT Input Tax Credits (ITCs)	1592
	Total of Group 1 and Group 2 Accounts (including 1562 and 1592)	

	Account Descriptions	Account Number
29	**LRAM Variance Account**	**1568**
	Total including Account 1568	
30	Renewable Generation Connection Capital Deferral Account	1531
31	Renewable Generation Connection OM&A Deferral Account	1532
32	Renewable Generation Connection Funding Adder Deferral Account	1533
33	Smart Grid Capital Deferral Account	1534
34	Smart Grid OM&A Deferral Account	1535
35	Smart Grid Funding Adder Deferral Account	1536
36	Retail Cost Variance Account - STR	1548
37	Smart Meter Capital and Recovery Offset Variance - Sub-Account - Capital[5]	1555
38	Smart Meter Capital and Recovery Offset Variance - Sub-Account - Recoveries[5]	1555
39	Smart Meter Capital and Recovery Offset Variance - Sub-Account - Stranded Meter Costs[5]	1555
40	Smart Meter OM&A Variance[5]	1556
41	IFRS-CGAAP Transition PP&E Amounts Balance + Return Component[6]	1575
42	Accounting Changes Under CGAAP Balance + Return Component[6]	1576

For all Board-Approved dispositions, please ensure that the disposition amount has the same sign (e.g: debit balances are to have a positive figure and credit balance are to have a negative

1 Do not include interest, adjustments, or OEB approved dispositions in this column

2 Please provide explanations for the nature of the adjustments. If the adjustment relates to previously OEB Approved disp

As per the January 6, 2011 Letter from the Board, regarding the implementation of the Ontario Clean Energy Benefit:

3 "By way of exception... The Board does acticipate that licensed distributors that cannot adapt their invoices as of January

balances in "Sub account Financial Assistance Payment and Recovery Variance - Ontario Clean Energy Benefit Act" will

4 Please describe "other" components of 1508 and add more component lines if necessary.

5 Deferral accounts related to Smart Meter deployment are not to be recovered/refunded through the Deferral and Variance

Guideline: Smart Meter Disposition and Cost Recovery (G-2011-0001)

6 The Board requires that disposition of Account 1575 and Account 1576 shall require the use of separate rate riders. In the "Adjustments during 2015" column of the continuity schedule, please enter the amounts to be included in the Account 1575 and 1576 rate rider calculation from the applicable Chapter 2 appendices. For Account 1575, please

ntario Energy Board

2016 Deferral/Variance Account Workform

Account Descriptions	Account Number
Group 1 Accounts	
LV Variance Account	1550
Smart Metering Entity Charge Variance Account	1551
RSVA - Wholesale Market Service Charge	1580
RSVA - Retail Transmission Network Charge	1584
RSVA - Retail Transmission Connection Charge	1586
RSVA - Power (excluding Global Adjustment)	1588
RSVA - Global Adjustment	1589
Disposition and Recovery/Refund of Regulatory Balances (2009)	1595
Disposition and Recovery/Refund of Regulatory Balances (2010)	1595
Disposition and Recovery/Refund of Regulatory Balances (2011)	1595
Disposition and Recovery/Refund of Regulatory Balances (2012)	1595
Disposition and Recovery/Refund of Regulatory Balances (2013)	1595
Disposition and Recovery/Refund of Regulatory Balances (2014)	1595
Disposition and Recovery/Refund of Regulatory Balances (2015)	1595
Group 1 Sub-Total (including Account 1589 - Global Adjustment)	
Group 1 Sub-Total (excluding Account 1589 - Global Adjustment)	
RSVA - Global Adjustment	**1589**
Group 2 Accounts	
Other Regulatory Assets - Sub-Account - Deferred IFRS Transition Costs	1508
Other Regulatory Assets - Sub-Account - Incremental Capital Charges	1508
Other Regulatory Assets - Sub-Account - Financial Assistance Payment and Recovery Variance - Ontario Clean Energy Benefit Act[8]	1508
Other Regulatory Assets - Sub-Account - Financial Assistance Payment and Recovery Carrying Charges	1508
Other Regulatory Assets - Sub-Account - Other [4] **- OEB Cost Assessments + Other**	1508
Retail Cost Variance Account - Retail	1518
Misc. Deferred Debits	1525
Board-Approved CDM Variance Account	1567
Extra-Ordinary Event Costs	1572
Deferred Rate Impact Amounts	1574
RSVA - One-time	1582
Other Deferred Credits	2425
Group 2 Sub-Total	
PILs and Tax Variance for 2006 and Subsequent Years (excludes sub-account and contra account below)	1592
PILs and Tax Variance for 2006 and Subsequent Years - Sub-Account HST/OVAT Input Tax Credits (ITCs)	1592
Total of Group 1 and Group 2 Accounts (including 1562 and 1592)	

Account Descriptions	Account Number
LRAM Variance Account	**1568**
Total including Account 1568	
Renewable Generation Connection Capital Deferral Account	1531
Renewable Generation Connection OM&A Deferral Account	1532
Renewable Generation Connection Funding Adder Deferral Account	1533
Smart Grid Capital Deferral Account	1534
Smart Grid OM&A Deferral Account	1535
Smart Grid Funding Adder Deferral Account	1536
Retail Cost Variance Account - STR	1548
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Capital[5]	1555
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Recoveries[5]	1555
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Stranded Meter Costs[5]	1555
Smart Meter OM&A Variance[5]	1556
IFRS-CGAAP Transition PP&E Amounts Balance + Return Component[6]	1575
Accounting Changes Under CGAAP Balance + Return Component[6]	1576

For all Board-Approved dispositions, please ensure that the disposition amount has the same sign (e.g: debit balances are to have a positive figure and credit balance are to have a negative

Do not include interest, adjustments, or OEB approved dispositions in this column

Please provide explanations for the nature of the adjustments. If the adjustment relates to previously OEB Approved disp

As per the January 6, 2011 Letter from the Board, regarding the implementation of the Ontario Clean Energy Benefit:

"By way of exception... The Board does acticipate that licensed distributors that cannot adapt their invoices as of January

balances in "Sub account Financial Assistance Payment and Recovery Variance - Ontario Clean Energy Benefit Act" will

Please describe "other" components of 1508 and add more component lines if necessary.

Deferral accounts related to Smart Meter deployment are not to be recovered/refunded through the Deferral and Variance

Guideline: Smart Meter Disposition and Cost Recovery (G-2011-0001)

The Board requires that disposition of Account 1575 and Account 1576 shall require the use of separate rate riders. In the "Adjustments during 2015" column of the continuity schedule, please enter the amounts to be included in the Account 1575 and 1576 rate rider calculation from the applicable Chapter 2 appendices. For Account 1575, please

ntario Energy Board

2016 Deferral/Variance Account Workform

2011

Account Descriptions	Account Number	Opening Principal Amounts as of Jan-1-11	Transactions[2] Debit / (Credit) during 2011	Board-Approved Disposition during 2011	Principal Adjustments[2] during 2011	Closing Principal Balance as of Dec-31-11	Opening Interest Amounts as of Jan-1-11	Interest Jan-1 to Dec-31-11	Board-Approved Disposition during 2011	Interest Adjustments[1] during 2011	Closing Interest Amounts as of Dec-31-11
Group 1 Accounts											
LV Variance Account	1550	$0				$0	$0				$0
Smart Metering Entity Charge Variance Account	1551	$0				$0	$0				$0
RSVA - Wholesale Market Service Charge	1580	$0				$0	$0				$0
RSVA - Retail Transmission Network Charge	1584	$0				$0	$0				$0
RSVA - Retail Transmission Connection Charge	1586	$0				$0	$0				$0
RSVA - Power (excluding Global Adjustment)	1588	$0				$0	$0				$0
RSVA - Global Adjustment	1589	$0				$0	$0				$0
Disposition and Recovery/Refund of Regulatory Balances (2009)	1595	$0				$0	$0				$0
Disposition and Recovery/Refund of Regulatory Balances (2010)	1595	$0				$0	$0				$0
Disposition and Recovery/Refund of Regulatory Balances (2011)	1595	$0				$0	$0				$0
Disposition and Recovery/Refund of Regulatory Balances (2012)	1595	$0				$0	$0				$0
Disposition and Recovery/Refund of Regulatory Balances (2013)	1595	$0				$0	$0				$0
Disposition and Recovery/Refund of Regulatory Balances (2014)	1595	$0				$0	$0				$0
Disposition and Recovery/Refund of Regulatory Balances (2015)	1595	$0				$0	$0				$0
Group 1 Sub-Total (including Account 1589 - Global Adjustment)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Group 1 Sub-Total (excluding Account 1589 - Global Adjustment)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
RSVA - Global Adjustment	**1589**	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Group 2 Accounts											
Other Regulatory Assets - Sub-Account - Deferred IFRS Transition Costs	1508	$0			$85,421	$85,421	$0			$1,839	$1,839
Other Regulatory Assets - Sub-Account - Incremental Capital Charges	1508	$0				$0	$0				$0
Other Regulatory Assets - Sub-Account - Financial Assistance Payment and Recovery Variance - Ontario Clean Energy Benefit Act[8]	1508		-$518,401			-$518,401	$0	-$7,076			-$7,076
Other Regulatory Assets - Sub-Account - Financial Assistance Payment and Recovery Carrying Charges	1508										
Other Regulatory Assets - Sub-Account - Other [4] **- OEB Cost Assessments + Other**	1508	$0	$134		$22,449	$22,583	$0			$15,366	$15,366
Retail Cost Variance Account - Retail	1518	$0				$0	$0				$0
Misc. Deferred Debits	1525	$0				$0	$0				$0
Board-Approved CDM Variance Account	1567					$0	$0				$0
Extra-Ordinary Event Costs	1572	$0				$0	$0				$0
Deferred Rate Impact Amounts	1574	$0				$0	$0				$0
RSVA - One-time	1582	$0				$0	$0				$0
Other Deferred Credits	2425	$0				$0	$0				$0
Group 2 Sub-Total		$0	-$518,267	$0	$107,870	-$410,397	$0	-$7,076	$0	$17,205	$10,129
PILs and Tax Variance for 2006 and Subsequent Years (excludes sub-account and contra account below)	1592	$0				$0	$0				$0
PILs and Tax Variance for 2006 and Subsequent Years - Sub-Account HST/OVAT Input Tax Credits (ITCs)	1592	$0			$0	$0	$0			$0	$0
Total of Group 1 and Group 2 Accounts (including 1562 and 1592)		$0	-$518,267	$0	$107,870	-$410,397	$0	-$7,076	$0	$17,205	$10,129

Account Descriptions	Account Number	2011 Opening Principal Amounts as of Jan-1-11	Transactions[2] Debit / (Credit) during 2011	Board-Approved Disposition during 2011	Principal Adjustments[2] during 2011	Closing Principal Balance as of Dec-31-11	Opening Interest Amounts as of Jan-1-11	Interest Jan-1 to Dec-31-11	Board-Approved Disposition during 2011	Interest Adjustments[1] during 2011	Closing Interest Amounts as of Dec-31-11
LRAM Variance Account	**1568**					$0					$0
Total including Account 1568		$0	-$518,267	$0	$107,870	-$410,397	$0	-$7,076	$0	$17,205	$10,129
Renewable Generation Connection Capital Deferral Account	1531	$0				$0	$0				$0
Renewable Generation Connection OM&A Deferral Account	1532	$0				$0	$0				$0
Renewable Generation Connection Funding Adder Deferral Account	1533	$0				$0	$0				$0
Smart Grid Capital Deferral Account	1534	$0				$0	$0				$0
Smart Grid OM&A Deferral Account	1535	$0				$0	$0				$0
Smart Grid Funding Adder Deferral Account	1536	$0				$0	$0				$0
Retail Cost Variance Account - STR	1548	$0				$0	$0				$0
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Capital[5]	1555	$0				$0	$0				$0
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Recoveries[5]	1555	$0				$0	$0				$0
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Stranded Meter Costs[5]	1555	$0				$0	$0				$0
Smart Meter OM&A Variance[5]	1556	$0				$0	$0				$0
IFRS-CGAAP Transition PP&E Amounts Balance + Return Component[6]	1575										
Accounting Changes Under CGAAP Balance + Return Component[6]	1576										

For all Board-Approved dispositions, please ensure that the disposition amount has the same sign (e.g: debit balances are to have a positive figure and credit balance are to have a negative

Do not include interest, adjustments, or OEB approved dispositions in this column

Please provide explanations for the nature of the adjustments. If the adjustment relates to previously OEB Approved disposed balances, please provide amounts for adjustments and include supporting documentations.

As per the January 6, 2011 Letter from the Board, regarding the implementation of the Ontario Clean Energy Benefit:

"By way of exception... The Board does acticipate that licensed distributors that cannot adapt their invoices as of January 1, 2011 will require a variance account for OCEB purposes... The Board expects that any principal balances in "Sub account Financial Assistance Payment and Recovery Variance - Ontario Clean Energy Benefit Act" will be addressed through the monthly settlement process with the IESO or the host distributor, as applicable.

Please describe "other" components of 1508 and add more component lines if necessary.

Deferral accounts related to Smart Meter deployment are not to be recovered/refunded through the Deferral and Variance Account rate rider. For details on how to dispose of balances in Smart Meter accounts see the Board's Guideline: Smart Meter Disposition and Cost Recovery (G-2011-0001)

The Board requires that disposition of Account 1575 and Account 1576 shall require the use of separate rate riders. In the "Adjustments during 2015" column of the continuity schedule, please enter the amounts to be included in the Account 1575 and 1576 rate rider calculation from the applicable Chapter 2 appendices. For Account 1575, please

Ontario Energy Board

2016 Deferral/Variance Account Workform

Account Descriptions	Account Number	2012: Opening Principal Amounts as of Jan-1-12	Transactions[2] Debit / (Credit) during 2012	Board-Approved Disposition during 2012	Principal Adjustments[2] during 2012	Closing Principal Balance as of Dec-31-12	Opening Interest Amounts as of Jan-1-12	Interest Jan-1 to Dec-31-12	Board-Approved Disposition during 2012	Interest Adjustments[1] during 2012	Closing Interest Amounts as of Dec-31-12	Opening Principal Amounts as of Jan-1-13	Transactions[2] Debit / (Credit) during 2013	Board-Approved Disposition during 2013
Group 1 Accounts														
LV Variance Account	1550	$0				$0	$0				$0	$0		
Smart Metering Entity Charge Variance Account	1551	$0				$0	$0				$0	$0		
RSVA - Wholesale Market Service Charge	1580	$0				$0	$0				$0	$0		
RSVA - Retail Transmission Network Charge	1584	$0				$0	$0				$0	$0		
RSVA - Retail Transmission Connection Charge	1586	$0				$0	$0				$0	$0		
RSVA - Power (excluding Global Adjustment)	1588	$0				$0	$0				$0	$0		
RSVA - Global Adjustment	1589	$0				$0	$0				$0	$0		
Disposition and Recovery/Refund of Regulatory Balances (2009)	1595	$0				$0	$0				$0	$0		
Disposition and Recovery/Refund of Regulatory Balances (2010)	1595	$0				$0	$0				$0	$0		
Disposition and Recovery/Refund of Regulatory Balances (2011)	1595	$0				$0	$0				$0	$0		
Disposition and Recovery/Refund of Regulatory Balances (2012)	1595	$0				$0	$0				$0	$0		
Disposition and Recovery/Refund of Regulatory Balances (2013)	1595	$0				$0	$0				$0	$0		
Disposition and Recovery/Refund of Regulatory Balances (2014)	1595	$0				$0	$0				$0	$0		
Disposition and Recovery/Refund of Regulatory Balances (2015)	1595	$0				$0	$0				$0	$0		
Group 1 Sub-Total (including Account 1589 - Global Adjustment)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Group 1 Sub-Total (excluding Account 1589 - Global Adjustment)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
RSVA - Global Adjustment	**1589**	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Group 2 Accounts														
Other Regulatory Assets - Sub-Account - Deferred IFRS Transition Costs	1508	$85,421		$85,421		$0	$1,839	$1,256	$3,095		$0	$0		
Other Regulatory Assets - Sub-Account - Incremental Capital Charges	1508	$0				$0	$0				$0	$0		
Other Regulatory Assets - Sub-Account - Financial Assistance Payment and Recovery Variance - Ontario Clean Energy Benefit Act[8]	1508	-$518,401	-$41,973			-$560,374	-$7,076	-$7,836			-$14,911	-$560,374	-$47,307	
Other Regulatory Assets - Sub-Account - Financial Assistance Payment and Recovery Carrying Charges	1508	$0				$0	$0				$0	$0		
Other Regulatory Assets - Sub-Account - Other [4] **- OEB Cost Assessments + Other**	1508	$22,583	-$284	$22,449		-$150	$15,366	$330	$15,696		$0	-$150	-$273	
Retail Cost Variance Account - Retail	1518	$0				$0	$0				$0	$0		
Misc. Deferred Debits	1525	$0				$0	$0				$0	$0		
Board-Approved CDM Variance Account	1567	$0				$0	$0				$0	$0		
Extra-Ordinary Event Costs	1572	$0				$0	$0				$0	$0		
Deferred Rate Impact Amounts	1574	$0				$0	$0				$0	$0		
RSVA - One-time	1582	$0				$0	$0				$0	$0		
Other Deferred Credits	2425	$0				$0	$0				$0	$0		
Group 2 Sub-Total		-$410,397	-$42,257	$107,870	$0	-$560,524	$10,129	-$6,250	$18,791	$0	-$14,911	-$560,524	-$47,579	$0
PILs and Tax Variance for 2006 and Subsequent Years (excludes sub-account and contra account below)	1592	$0				$0	$0				$0	$0	-$95,557	
PILs and Tax Variance for 2006 and Subsequent Years - Sub-Account HST/OVAT Input Tax Credits (ITCs)	1592	$0		-$69,220		$69,220	$0		-$1,772		$1,772	$69,220	-$32,819	
Total of Group 1 and Group 2 Accounts (including 1562 and 1592)		-$410,397	-$42,257	$38,649	$0	-$491,303	$10,129	-$6,250	$17,019	$0	-$13,139	-$491,303	-$175,956	$0

Account Descriptions	Account Number	2012 Opening Principal Amounts as of Jan-1-12	Transactions[2] Debit / (Credit) during 2012	Board-Approved Disposition during 2012	Principal Adjustments[2] during 2012	Closing Principal Balance as of Dec-31-12	Opening Interest Amounts as of Jan-1-12	Interest Jan-1 to Dec-31-12	Board-Approved Disposition during 2012	Interest Adjustments[1] during 2012	Closing Interest Amounts as of Dec-31-12	Opening Principal Amounts as of Jan-1-13	Transactions[2] Debit / (Credit) during 2013	Board-Approved Disposition during 2013
LRAM Variance Account	**1568**	$0				$0	$0				$0	$0		
Total including Account 1568		-$410,397	-$42,257	$38,649	$0	-$491,303	$10,129	-$6,250	$17,019	$0	-$13,139	-$491,303	-$175,956	$0
Renewable Generation Connection Capital Deferral Account	1531	$0				$0	$0				$0	$0		
Renewable Generation Connection OM&A Deferral Account	1532	$0				$0	$0				$0	$0		
Renewable Generation Connection Funding Adder Deferral Account	1533	$0				$0	$0				$0	$0		
Smart Grid Capital Deferral Account	1534	$0				$0	$0				$0	$0		
Smart Grid OM&A Deferral Account	1535	$0				$0	$0				$0	$0		
Smart Grid Funding Adder Deferral Account	1536	$0				$0	$0				$0	$0		
Retail Cost Variance Account - STR	1548	$0				$0	$0				$0	$0		
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Capital[5]	1555	$0				$0	$0				$0	$0		
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Recoveries[5]	1555	$0				$0	$0				$0	$0		
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Stranded Meter Costs[5]	1555	$0				$0	$0				$0	$0	-$594,492	-$1,169,603
Smart Meter OM&A Variance[5]	1556	$0				$0	$0				$0	$0		
IFRS-CGAAP Transition PP&E Amounts Balance + Return Component[6]	1575													
Accounting Changes Under CGAAP Balance + Return Component[6]	1576													

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balances in "Sub account Financial Assistance Payment and Recovery Variance - Ontario Clean Energy Benefit Act" will
Please describe "other" components of 1508 and add more component lines if necessary.

Deferral accounts related to Smart Meter deployment are not to be recovered/refunded through the Deferral and Variance

Guideline: Smart Meter Disposition and Cost Recovery (G-2011-0001)
The Board requires that disposition of Account 1575 and Account 1576 shall require the use of separate rate riders. In the "Adjustments during 2015" column of the continuity schedule, please enter the amounts to be included in the Account 1575 and 1576 rate rider calculation from the applicable Chapter 2 appendices. For Account 1575, please

ntario Energy Board

2016 Deferral/Variance Account Workform

Account Descriptions	Account Number	2013 Principal Adjustments[2] during 2013	2013 Closing Principal Balance as of Dec-31-13	2013 Opening Interest Amounts as of Jan-1-13	2013 Interest Jan-1 to Dec-31-13	2013 Board-Approved Disposition during 2013	2013 Interest Adjustments[1] during 2013	2013 Closing Interest Amounts as of Dec-31-13	2014 Opening Principal Amounts as of Jan-1-14	2014 Transactions[2] Debit / (Credit) during 2014	2014 Board-Approved Disposition during 2014	2014 Principal Adjustments[2] during 2014	2014 Closing Principal Balance as of Dec-31-14	2014 Opening Interest Amounts as of Jan-1-14
Group 1 Accounts														
LV Variance Account	1550		$0	$0				$0	$0			-$15,843	-$15,843	$0
Smart Metering Entity Charge Variance Account	1551		$0	$0				$0	$0			-$7,851	-$7,851	$0
RSVA - Wholesale Market Service Charge	1580		$0	$0				$0	$0			-$1,271,559	-$1,271,559	$0
RSVA - Retail Transmission Network Charge	1584		$0	$0				$0	$0			$793,362	$793,362	$0
RSVA - Retail Transmission Connection Charge	1586		$0	$0				$0	$0			$483,751	$483,751	$0
RSVA - Power (excluding Global Adjustment)	1588		$0	$0				$0	$0			-$907,225	-$907,225	$0
RSVA - Global Adjustment	1589		$0	$0				$0	$0			$819,697	$819,697	$0
Disposition and Recovery/Refund of Regulatory Balances (2009)	1595		$0	$0				$0	$0				$0	$0
Disposition and Recovery/Refund of Regulatory Balances (2010)	1595		$0	$0				$0	$0				$0	$0
Disposition and Recovery/Refund of Regulatory Balances (2011)	1595		$0	$0				$0	$0				$0	$0
Disposition and Recovery/Refund of Regulatory Balances (2012)	1595		$0	$0				$0	$0				$0	$0
Disposition and Recovery/Refund of Regulatory Balances (2013)	1595		$0	$0				$0	$0				$0	$0
Disposition and Recovery/Refund of Regulatory Balances (2014)	1595		$0	$0				$0	$0				$0	$0
Disposition and Recovery/Refund of Regulatory Balances (2015)	1595		$0	$0				$0	$0			$0	$0	$0
Group 1 Sub-Total (including Account 1589 - Global Adjustment)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	-$105,667	-$105,667	$0
Group 1 Sub-Total (excluding Account 1589 - Global Adjustment)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	-$925,365	-$925,365	$0
RSVA - Global Adjustment	**1589**	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$819,697	$819,697	$0
Group 2 Accounts														
Other Regulatory Assets - Sub-Account - Deferred IFRS Transition Costs	1508		$0	$0				$0	$0				$0	$0
Other Regulatory Assets - Sub-Account - Incremental Capital Charges	1508		$0	$0				$0	$0				$0	$0
Other Regulatory Assets - Sub-Account - Financial Assistance Payment and Recovery Variance - Ontario Clean Energy Benefit Act[8]	1508		-$607,681	-$14,911	-$8,157			-$23,069	-$607,681	$11,016			-$596,664	-$23,069
Other Regulatory Assets - Sub-Account - Financial Assistance Payment and Recovery Carrying Charges	1508		$0	$0				$0	$0				$0	$0
Other Regulatory Assets - Sub-Account - Other [4] **- OEB Cost Assessments + Other**	1508		-$423	$0				$0	-$423	$423			-$0	$0
Retail Cost Variance Account - Retail	1518		$0	$0				$0	$0				$0	$0
Misc. Deferred Debits	1525		$0	$0				$0	$0				$0	$0
Board-Approved CDM Variance Account	1567		$0	$0				$0	$0				$0	$0
Extra-Ordinary Event Costs	1572		$0	$0				$0	$0				$0	$0
Deferred Rate Impact Amounts	1574		$0	$0				$0	$0				$0	$0
RSVA - One-time	1582		$0	$0				$0	$0				$0	$0
Other Deferred Credits	2425		$0	$0				$0	$0				$0	$0
Group 2 Sub-Total		$0	-$608,103	-$14,911	-$8,157	$0	$0	-$23,068	-$608,103	$11,439	$0	$0	-$596,664	-$23,068
PILs and Tax Variance for 2006 and Subsequent Years (excludes sub-account and contra account below)	1592		-$95,557	$0	-$12,270			-$12,270	-$95,557	$0			-$95,557	-$12,270
PILs and Tax Variance for 2006 and Subsequent Years - Sub-Account HST/OVAT Input Tax Credits (ITCs)	1592		$36,402	$1,772	$799			$2,571	$36,402	-$33,313			$3,088	$2,571
Total of Group 1 and Group 2 Accounts (including 1562 and 1592)		$0	-$667,259	-$13,139	-$19,629	$0	$0	-$32,768	-$667,259	-$21,874	$0	-$105,667	-$794,801	-$32,768

Account Descriptions	Account Number	2013 Principal Adjustments[2] during 2013	2013 Closing Principal Balance as of Dec-31-13	2013 Opening Interest Amounts as of Jan-1-13	2013 Interest Jan-1 to Dec-31-13	2013 Board-Approved Disposition during 2013	2013 Interest Adjustments[1] during 2013	2013 Closing Interest Amounts as of Dec-31-13	2014 Opening Principal Amounts as of Jan-1-14	2014 Transactions[2] Debit / (Credit) during 2014	2014 Board-Approved Disposition during 2014	2014 Principal Adjustments[2] during 2014	2014 Closing Principal Balance as of Dec-31-14	2014 Opening Interest Amounts as of Jan-1-14
LRAM Variance Account	**1568**		$0	$0				$0	$0	$80,868			$80,868	$0
Total including Account 1568		$0	-$667,259	-$13,139	-$19,629	$0	$0	-$32,768	-$667,259	$58,994	$0	-$105,667	-$713,933	-$32,768
Renewable Generation Connection Capital Deferral Account	1531		$0	$0				$0	$0				$0	$0
Renewable Generation Connection OM&A Deferral Account	1532		$0	$0				$0	$0				$0	$0
Renewable Generation Connection Funding Adder Deferral Account	1533		$0	$0				$0	$0				$0	$0
Smart Grid Capital Deferral Account	1534		$0	$0				$0	$0				$0	$0
Smart Grid OM&A Deferral Account	1535		$0	$0				$0	$0				$0	$0
Smart Grid Funding Adder Deferral Account	1536		$0	$0				$0	$0				$0	$0
Retail Cost Variance Account - STR	1548		$0	$0				$0	$0				$0	$0
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Capital[5]	1555		$0	$0				$0	$0				$0	$0
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Recoveries[5]	1555		$0	$0				$0	$0				$0	$0
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Stranded Meter Costs[5]	1555		$575,111	$0	$11,851			$11,851	$575,111	-$586,445			-$11,334	$11,851
Smart Meter OM&A Variance[5]	1556		$0	$0				$0	$0				$0	$0
IFRS-CGAAP Transition PP&E Amounts Balance + Return Component[6]	1575		$0						$0				$0	
Accounting Changes Under CGAAP Balance + Return Component[6]	1576		$0						$0				$0	

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Ontario Energy Board

2016 Deferral/Variance Account Workform

Account Descriptions	Account Number	Interest Jan-1 to Dec-31-14	Board-Approved Disposition during 2014	Interest Adjustments[1] during 2014	Closing Interest Amounts as of Dec-31-14	2015: Opening Principal Amounts as of Jan-1-15	Transactions[2] Debit / (Credit) during 2015	Board-Approved Disposition during 2015	Principal Adjustments[2] during 2015	Closing Principal Balance as of Dec-31-15	Opening Interest Amounts as of Jan-1-15	Interest Jan-1 to Dec-31-15	Board-Approved Disposition during 2015	Interest Adjustments[1] during 2015	Closing Interest Amounts as of Dec-31-15
Group 1 Accounts															
LV Variance Account	1550			-$60	-$60	-$15,843	$41,015	-$359		$25,531	-$60	-$49	$54		-$163
Smart Metering Entity Charge Variance Account	1551			-$65	-$65	-$7,851	-$3,810	-$6,222	-$9,475	-$14,914	-$65	-$15	-$102	$16,326	$16,348
RSVA - Wholesale Market Service Charge	1580			-$34,447	-$34,447	-$1,271,559	-$861,506	-$1,143,156		-$989,909	-$34,447	-$6,129	-$37,131		-$3,445
RSVA - Retail Transmission Network Charge	1584			$21,401	$21,401	$793,362	-$161,591	$643,882		-$12,111	$21,401	$1,509	$20,717		$2,193
RSVA - Retail Transmission Connection Charge	1586			$12,150	$12,150	$483,751	-$9,153	$328,765		$145,834	$12,150	$1,715	$11,291		$2,574
RSVA - Power (excluding Global Adjustment)	1588			-$31,563	-$31,563	-$907,225	-$570,319	$459,419	$12,490	-$1,924,474	-$31,563	-$20,145	-$12,954		-$38,754
RSVA - Global Adjustment	1589			$28,234	$28,234	$819,697	$1,258,319	-$770,098	-$97,293	$2,750,822	$28,234	$26,742	$9,924		$45,052
Disposition and Recovery/Refund of Regulatory Balances (2009)	1595				$0	$0				$0	$0				$0
Disposition and Recovery/Refund of Regulatory Balances (2010)	1595				$0	$0				$0	$0				$0
Disposition and Recovery/Refund of Regulatory Balances (2011)	1595				$0	$0				$0	$0				$0
Disposition and Recovery/Refund of Regulatory Balances (2012)	1595				$0	$0				$0	$0				$0
Disposition and Recovery/Refund of Regulatory Balances (2013)	1595				$0	$0				$0	$0				$0
Disposition and Recovery/Refund of Regulatory Balances (2014)	1595				$0	$0				$0	$0				$0
Disposition and Recovery/Refund of Regulatory Balances (2015)	1595			$0	$0	$0	-$75,157	-$80,868	$0	$5,711	$0	$565	$0	$0	$565
Group 1 Sub-Total (including Account 1589 - Global Adjustment)		$0	$0	-$4,350	-$4,350	-$105,667	-$382,203	-$568,638	-$94,278	-$13,509	-$4,350	$4,193	-$8,201	$16,326	$24,371
Group 1 Sub-Total (excluding Account 1589 - Global Adjustment)		$0	$0	-$32,584	-$32,584	-$925,365	-$1,640,522	$201,460	$3,015	-$2,764,332	-$32,584	-$22,548	-$18,125	$16,326	-$20,681
RSVA - Global Adjustment	**1589**	$0	$0	$28,234	$28,234	$819,697	$1,258,319	-$770,098	-$97,293	$2,750,822	$28,234	$26,742	$9,924	$0	$45,052
Group 2 Accounts															
Other Regulatory Assets - Sub-Account - Deferred IFRS Transition Costs	1508				$0	$0				$0	$0				$0
Other Regulatory Assets - Sub-Account - Incremental Capital Charges	1508				$0	$0				$0	$0				$0
Other Regulatory Assets - Sub-Account - Financial Assistance Payment and Recovery Variance - Ontario Clean Energy Benefit Act[8]	1508	-$8,893			-$31,962	-$596,664	$49,518		$547,146	$0	-$31,962	-$6,895			-$38,857
Other Regulatory Assets - Sub-Account - Financial Assistance Payment and Recovery Carrying Charges	1508				$0	$0				$0	$0				$0
Other Regulatory Assets - Sub-Account - Other [4] **- OEB Cost Assessments + Other**	1508				$0	-$0	$0			-$0	$0				$0
Retail Cost Variance Account - Retail	1518				$0	$0				$0	$0				$0
Misc. Deferred Debits	1525				$0	$0				$0	$0				$0
Board-Approved CDM Variance Account	1567				$0	$0				$0	$0				$0
Extra-Ordinary Event Costs	1572				$0	$0				$0	$0				$0
Deferred Rate Impact Amounts	1574				$0	$0				$0	$0				$0
RSVA - One-time	1582				$0	$0				$0	$0				$0
Other Deferred Credits	2425				$0	$0				$0	$0				$0
Group 2 Sub-Total		-$8,893	$0	$0	-$31,962	-$596,664	$49,518	$0	$547,146	-$0	-$31,962	-$6,895	$0	$0	-$38,857
PILs and Tax Variance for 2006 and Subsequent Years (excludes sub-account and contra account below)	1592	-$1,405			-$13,675	-$95,557	$0		$33,848	-$61,710	-$13,675	-$1,138		$5,204	-$9,609
PILs and Tax Variance for 2006 and Subsequent Years - Sub-Account HST/OVAT Input Tax Credits (ITCs)	1592	$305			$2,877	$3,088	-$5,998			-$2,910	$2,877	$36		-$3	$2,910
Total of Group 1 and Group 2 Accounts (including 1562 and 1592)		-$9,992	$0	-$4,350	-$47,110	-$794,801	-$338,682	-$568,638	$486,715	-$78,129	-$47,110	-$3,804	-$8,201	$21,528	-$21,185

Account Descriptions	Account Number	Interest Jan-1 to Dec-31-14	Board-Approved Disposition during 2014	Interest Adjustments[1] during 2014	Closing Interest Amounts as of Dec-31-14	2015 Opening Principal Amounts as of Jan-1-15	2015 Transactions[2] Debit / (Credit) during 2015	2015 Board-Approved Disposition during 2015	2015 Principal Adjustments[2] during 2015	2015 Closing Principal Balance as of Dec-31-15	2015 Opening Interest Amounts as of Jan-1-15	2015 Interest Jan-1 to Dec-31-15	2015 Board-Approved Disposition during 2015	2015 Interest Adjustments[1] during 2015	2015 Closing Interest Amounts as of Dec-31-15
LRAM Variance Account	**1568**				$0	$80,868		$80,868	$252,642	$252,642	$0				$0
Total including Account 1568		-$9,992	$0	-$4,350	-$47,110	-$713,933	-$338,682	-$487,770	$739,357	$174,513	-$47,110	-$3,804	-$8,201	$21,528	-$21,185
Renewable Generation Connection Capital Deferral Account	1531				$0	$0				$0	$0				$0
Renewable Generation Connection OM&A Deferral Account	1532				$0	$0				$0	$0				$0
Renewable Generation Connection Funding Adder Deferral Account	1533				$0	$0				$0	$0				$0
Smart Grid Capital Deferral Account	1534				$0	$0				$0	$0				$0
Smart Grid OM&A Deferral Account	1535				$0	$0				$0	$0				$0
Smart Grid Funding Adder Deferral Account	1536				$0	$0				$0	$0				$0
Retail Cost Variance Account - STR	1548				$0	$0				$0	$0				$0
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Capital[5]	1555				$0	$0				$0	$0				$0
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Recoveries[5]	1555				$0	$0				$0	$0				$0
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Stranded Meter Costs[5]	1555	$4,590			$16,441	-$11,334	$1,859		$9,475	$0	$16,441	-$115		-$16,326	$0
Smart Meter OM&A Variance[5]	1556				$0	$0				$0	$0				$0
IFRS-CGAAP Transition PP&E Amounts Balance + Return Component[6]	1575					$0				$0					
Accounting Changes Under CGAAP Balance + Return Component[6]	1576					$0				$0					

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ntario Energy Board

2016 Deferral/Variance Account Workform

Account Descriptions	Account Number	2016 Principal Disposition during 2016 - instructed by Board	Interest Disposition during 2016 - instructed by Board	Closing Principal Balances as of Dec 31-15 Adjusted for Dispositions during 2016	Closing Interest Balances as of Dec 31-15 Adjusted for Dispositions during 2016	Projected Interest on Dec-31-15 Balances: Projected Interest from Jan 1, 2016 to December 31, 2016 on Dec 31 -15 balance adjusted for disposition during 2016 [5]	Projected Interest from January 1, 2017 to April 30, 2017 on Dec 31 -15 balance adjusted for disposition during 2016 [5]	Total Claim	2.1.7 RRR: As of Dec 31-15	Variance RRR vs. 2015 Balance *(Principal + Interest)*
Group 1 Accounts										
LV Variance Account	1550	-$15,484	-$285	$41,015	$122	$451		$41,587	$25,368	$0
Smart Metering Entity Charge Variance Account	1551	-$1,629	$19	-$13,285	$16,329	-$146		$2,898	-$5,417	-$6,851
RSVA - Wholesale Market Service Charge	1580	-$128,403	$1,271	-$861,506	-$4,717	-$9,477		-$875,699	-$993,354	$0
RSVA - Retail Transmission Network Charge	1584	$149,481	$2,329	-$161,591	-$135	-$1,778		-$163,504	-$9,917	$0
RSVA - Retail Transmission Connection Charge	1586	$154,987	$2,564	-$9,153	$10	-$101		-$9,244	$148,408	-$0
RSVA - Power (excluding Global Adjustment)	1588	-$1,366,644	-$33,642	-$557,829	-$5,112	-$6,136		-$569,077	-$1,975,717	-$12,490
RSVA - Global Adjustment	1589	$1,589,796	$35,798	$1,161,026	$9,254	$12,771		$1,183,052	$2,893,167	$97,293
Disposition and Recovery/Refund of Regulatory Balances (2009)	1595			$0	$0	$0		$0		$0
Disposition and Recovery/Refund of Regulatory Balances (2010)	1595			$0	$0	$0		$0		$0
Disposition and Recovery/Refund of Regulatory Balances (2011)	1595			$0	$0	$0		$0		$0
Disposition and Recovery/Refund of Regulatory Balances (2012)	1595			$0	$0	$0		$0		$0
Disposition and Recovery/Refund of Regulatory Balances (2013)	1595			$0	$0	$0		$0		$0
Disposition and Recovery/Refund of Regulatory Balances (2014)	1595			$0	$0	$0		$0		$0
Disposition and Recovery/Refund of Regulatory Balances (2015)	1595	$0	$0	$5,711	$565	$63		$6,339	-$303,032	-$309,309
Group 1 Sub-Total (including Account 1589 - Global Adjustment)		$382,103	$8,054	-$395,612	$16,316	-$4,352	$0	-$383,648	-$220,495	-$231,357
Group 1 Sub-Total (excluding Account 1589 - Global Adjustment)		-$1,207,693	-$27,744	-$1,556,639	$7,062	-$17,123	$0	-$1,566,699	-$3,113,663	-$328,650
RSVA - Global Adjustment	**1589**	$1,589,796	$35,798	$1,161,026	$9,254	$12,771	$0	$1,183,052	$2,893,167	$97,293
Group 2 Accounts										
Other Regulatory Assets - Sub-Account - Deferred IFRS Transition Costs	1508			$0	$0	$0		$0		-$0
Other Regulatory Assets - Sub-Account - Incremental Capital Charges	1508			$0	$0	$0		$0		$0
Other Regulatory Assets - Sub-Account - Financial Assistance Payment and Recovery Variance - Ontario Clean Energy Benefit Act[8]	1508			$0	-$38,857	$0		-$38,857	-$586,003	-$547,146
Other Regulatory Assets - Sub-Account - Financial Assistance Payment and Recovery Carrying Charges	1508			$0	$0	$0		$0		$0
Other Regulatory Assets - Sub-Account - Other [4] **- OEB Cost Assessments + Other**	1508			-$0	$0	$0		$0		-$0
Retail Cost Variance Account - Retail	1518			$0	$0	$0		$0		$0
Misc. Deferred Debits	1525			$0	$0	$0		$0		$0
Board-Approved CDM Variance Account	1567			$0	$0	$0		$0		$0
Extra-Ordinary Event Costs	1572			$0	$0	$0		$0		$0
Deferred Rate Impact Amounts	1574			$0	$0	$0		$0		$0
RSVA - One-time	1582			$0	$0	$0		$0		$0
Other Deferred Credits	2425			$0	$0	$0		$0		$0
Group 2 Sub-Total		$0	$0	-$0	-$38,857	$0	$0	-$38,857	-$586,003	-$547,146
PILs and Tax Variance for 2006 and Subsequent Years (excludes sub-account and contra account below)	1592			-$61,710	-$9,609	-$679		-$71,997	-$71,319	$0
PILs and Tax Variance for 2006 and Subsequent Years - Sub-Account HST/OVAT Input Tax Credits (ITCs)	1592			-$2,910	$2,910			$0		-$0
Total of Group 1 and Group 2 Accounts (including 1562 and 1592)		$382,103	$8,054	-$460,233	-$29,239	-$5,031	$0	-$494,502	-$877,817	-$778,503

		2016				Projected Interest on Dec-31-15 Balances			2.1.7 RRR	
Account Descriptions	Account Number	Principal Disposition during 2016 - instructed by Board	Interest Disposition during 2016 - instructed by Board	Closing Principal Balances as of Dec 31-15 Adjusted for Dispositions during 2016	Closing Interest Balances as of Dec 31-15 Adjusted for Dispositions during 2016	Projected Interest from Jan 1, 2016 to December 31, 2016 on Dec 31 -15 balance adjusted for disposition during 2016 [5]	Projected Interest from January 1, 2017 to April 30, 2017 on Dec 31 -15 balance adjusted for disposition during 2016 [5]	Total Claim	As of Dec 31-15	Variance RRR vs. 2015 Balance *(Principal + Interest)*
LRAM Variance Account	**1568**			$252,642	$0	$2,779		$255,421		-$252,642
Total including Account 1568		$382,103	$8,054	-$207,591	-$29,239	-$2,251	$0	-$239,081	-$877,817	-$1,031,145
Renewable Generation Connection Capital Deferral Account	1531			$0	$0	$0		$0		$0
Renewable Generation Connection OM&A Deferral Account	1532			$0	$0	$0		$0		$0
Renewable Generation Connection Funding Adder Deferral Account	1533			$0	$0	$0		$0		$0
Smart Grid Capital Deferral Account	1534			$0	$0	$0		$0		$0
Smart Grid OM&A Deferral Account	1535			$0	$0	$0		$0		$0
Smart Grid Funding Adder Deferral Account	1536			$0	$0	$0		$0		$0
Retail Cost Variance Account - STR	1548			$0	$0	$0		$0		$0
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Capital[5]	1555			$0	$0	$0		$0		$0
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Recoveries[5]	1555			$0	$0	$0		$0		$0
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Stranded Meter Costs[5]	1555			$0	$0	$0		$0	$6,851	$6,851
Smart Meter OM&A Variance[5]	1556			$0	$0	$0		$0		$0
IFRS-CGAAP Transition PP&E Amounts Balance + Return Component[6]	1575			$0				$0		$0
Accounting Changes Under CGAAP Balance + Return Component[6]	1576			$0				$0		$0

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Ontario Energy Board

2016 Deferral/Variance Account Workform

Accounts that produced a variance on the 2014 continuity schedule are listed below.
Please provide a detailed explanation for each variance below.

Account Descriptions	**Account Number**	**Variance RRR vs. 2014 Balance** ***(Principal + Interest)***	**Explanation**
Group 1 Accounts			

Ontario Energy Board

2016 Deferral/Variance Account Workform

In the green shaded cells, enter the data related to the **proposed** load forecast. Do not enter data for the MicroFit class.

Rate Class (Enter Rate Classes in cells below as they appear on your current tariff of rates and charges)	Units	# of Customers	Total Metered kWh	Total Metered kW	Billed kWh for Non-RPP Customers	Billed kW for Non-RPP Customers	Distribution Revenue [1]	Billed kWh for Wholesale Market Participants (WMP)	Billed kW for Wholesale Market Participants (WMP)	Total Metered kWh less WMP consumption *(if applicable)*	Total Metered kW less WMP Demand *(if applicable)*	GA Allocator for Class A, Non-WMP Customers (if applicable)[3]	Billed kWh for Class A, Non-WMPs Customers (if applicable)	Billed kW for Class A Non-WMP Customers (if applicable)	Billed kWh for Non-RPP Customers LESS Class A Consumption	Billed kW for Non-RPP Customers LESS Class A Demand	1595 Recovery Share Proportion (2008) [2]	1595 Recovery Share Proportion (2009) [2]	1595 Recovery Share Proportion (2010) [2]	1595 Recovery Share Proportion (2011) [2]	1595 Recovery Share Proportion (2012) [2]	1595 Recovery Share Proportion (2013) [2]	1595 Recovery Share Proportion (2014) [2]
RESIDENTIAL SERVICE CLASSIFICATION	kWh	26,074	198,077,803		13,481,818	-				198,077,803	-				13,481,818	-							29%
GENERAL SERVICE LESS THAN 50 KW SERVICE CLASSIFICAT	kWh	2,489	67,907,332		10,889,999	-				67,907,332	-				10,889,999	-							33%
GENERAL SERVICE 50 TO 4,999 KW SERVICE CLASSIFICATIO	kW		184,944,203	593,383	168,230,922	539,759				184,944,203	593,383	8.0%	40,842,903	88,966	127,388,019	450,793							38%
EMBEDDED DISTRIBUTOR	kW		5,129,448	13,717	5,129,448	13,717				5,129,448	13,717				5,129,448	13,717							
UNMETERED SCATTERED LOAD SERVICE CLASSIFICATION	kWh		1,462,761		6,052	-				1,462,761	-				6,052	-							
SENTINEL LIGHTING SERVICE CLASSIFICATION	kW		629,014	1,916	-	-				629,014	1,916				-	-							
STREET LIGHTING SERVICE CLASSIFICATION	kW		2,781,556	8,591	2,721,726	8,406				2,781,556	8,591				2,721,726	8,406							
						-				-	-				-	-							
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						-				-	-				-	-							
Total		**28,563**	**460,932,117**	**617,607**	**200,459,965**	**561,883**	**$ -**	**-**	**-**	**460,932,117**	**617,607**	**8%**	**40,842,903**	**88,966**	**159,617,062**	**472,917**	**0%**	**0%**	**0%**	**0%**	**0%**		**100%**

Balance as per Sheet 2

Variance

[1] For Account 1562, the allocation to customer classes should be performed on the basis of the test year distribution revenue allocation to customer classes found in the Applicant's Cost of Service application that was most recently approved at the time of disposition of the 1562 account balances

[2] Residual Account balance to be allocated to rate classes in proportion to the recovery share as established when rate riders were implemented.

[3] Enter the percentage of the balance in account 1589 allocated to Class A customers. Distributors typically settle GA costs with Class A customers on the basis of actual (i.e. non-estimated) costs. If this is the case, no amount of the balance in 1589 should be allocated to a distributor's Class A customers.

1568 LRAM Variance Account Class Allocation ($ amounts)
67,839
130,786
56,796
$ 255,421
$ 255,421
$ -

Ontario Energy Board

2016 Deferral/Variance Account Workform

		Amounts from Sheet 2	Allocator	RESIDENTIAL SERVICE CLASSIFICATION	GENERAL SERVICE LESS THAN 50 KW SERVICE CLASSIFICATION	GENERAL SERVICE 50 TO 4,999 KW SERVICE CLASSIFICATION	EMBEDDED DISTRIBUTOR	UNMETERED SCATTERED LOAD SERVICE CLASSIFICATION	SENTINEL LIGHTING SERVICE CLASSIFICATION	STREET LIGHTING SERVICE CLASSIFICATION
LV Variance Account	1550	41,587	kWh	17,871	6,127	16,687	463	132	57	251
Smart Metering Entity Charge Variance Account	1551	2,898	# of Customers	2,645	252	0	0	0	0	0
RSVA - Wholesale Market Service Charge	1580	(875,699)	kWh	(376,317)	(129,013)	(351,365)	(9,745)	(2,779)	(1,195)	(5,285)
RSVA - Retail Transmission Network Charge	1584	(163,504)	kWh	(70,263)	(24,088)	(65,604)	(1,820)	(519)	(223)	(987)
RSVA - Retail Transmission Connection Charge	1586	(9,244)	kWh	(3,972)	(1,362)	(3,709)	(103)	(29)	(13)	(56)
RSVA - Power (excluding Global Adjustment)	1588	(569,077)	kWh	(244,551)	(83,840)	(228,336)	(6,333)	(1,806)	(777)	(3,434)
RSVA - Global Adjustment	1589	1,088,407	Non-RPP kWh	91,931	74,257	868,642	34,977	41	0	18,559
Disposition and Recovery/Refund of Regulatory Balances (2008)	1595	0	%	0	0	0	0	0	0	0
Disposition and Recovery/Refund of Regulatory Balances (2009)	1595	0	%	0	0	0	0	0	0	0
Disposition and Recovery/Refund of Regulatory Balances (2010)	1595	0	kWh	0	0	0	0	0	0	0
Disposition and Recovery/Refund of Regulatory Balances (2011)	1595	0	%	0	0	0	0	0	0	0
Disposition and Recovery/Refund of Regulatory Balances (2012)	1595	0	kWh	0	0	0	0	0	0	0
Disposition and Recovery/Refund of Regulatory Balances (2013)	1595	0	%	0	0	0	0	0	0	0
Disposition and Recovery/Refund of Regulatory Balances (2014)	1595	6,339	%	1,824	2,123	2,392	0	0	0	0
Total of Group 1 Accounts (excluding 1589)		**(1,566,699)**		**(672,763)**	**(229,801)**	**(629,936)**	**(17,538)**	**(5,001)**	**(2,151)**	**(9,510)**
Other Regulatory Assets - Sub-Account - Deferred IFRS Transition Costs	1508	0	kWh	0	0	0	0	0	0	0
Other Regulatory Assets - Sub-Account - Incremental Capital Charges	1508	0	kWh	0	0	0	0	0	0	0
Other Regulatory Assets - Sub-Account - Financial Assistance Payment and Recovery Variance - Ontario Clean Energy Benefit Act8	1508	(38,857)	kWh	(16,698)	(5,725)	(15,591)	(432)	(123)	(53)	(234)
Other Regulatory Assets - Sub-Account - Financial Assistance Payment and Recovery Carrying Charges	1508	0	kWh	0	0	0	0	0	0	0
Other Regulatory Assets - Sub-Account - Other 4	1508	0	kWh	0	0	0	0	0	0	0
Retail Cost Variance Account - Retail	1518	0	kWh	0	0	0	0	0	0	0
Misc. Deferred Debits	1525	0	kWh	0	0	0	0	0	0	0
Retail Cost Variance Account - STR	1548	0	kWh	0	0	0	0	0	0	0
Board-Approved CDM Variance Account	1567	0	kWh	0	0	0	0	0	0	0
Extra-Ordinary Event Costs	1572	0	kWh	0	0	0	0	0	0	0
Deferred Rate Impact Amounts	1574	0	kWh	0	0	0	0	0	0	0
RSVA - One-time	1582	0	kWh	0	0	0	0	0	0	0
Other Deferred Credits	2425	0	kWh	0	0	0	0	0	0	0
Total of Group 2 Accounts		**(38,857)**		**(16,698)**	**(5,725)**	**(15,591)**	**(432)**	**(123)**	**(53)**	**(234)**
PILs and Tax Variance for 2006 and Subsequent Years (excludes sub-account and contra account)	1592	(71,997)	kWh	(30,940)	(10,607)	(28,888)	(801)	(228)	(98)	(434)
PILs and Tax Variance for 2006 and Subsequent Years - Sub-Account HST/OVAT Input Tax Credits (ITCs)	1592	0	kWh	0	0	0	0	0	0	0
Total of Account 1562 and Account 1592		**(71,997)**		**(30,940)**	**(10,607)**	**(28,888)**	**(801)**	**(228)**	**(98)**	**(434)**
LRAM Variance Account **(Enter dollar amount for each class)**	1568	**255,421**		67,839	130,786	56,796	0	0	0	0
(Account 1568 - total amount allocated to classes)		255,421								
Variance		**0**								
Total of Group 1 Accounts (1550, 1551, 1584, 1586 and 1595)		**(121,924)**		**(51,895)**	**(16,948)**	**(50,234)**	**(1,460)**	**(416)**	**(179)**	**(792)**
Total of Account 1580 and 1588 (not allocated to WMPs)		**(1,444,776)**		**(620,868)**	**(212,853)**	**(579,701)**	**(16,078)**	**(4,585)**	**(1,972)**	**(8,719)**
Balance of Account 1589 Allocated to Non-WMPs		**1,088,407**		**91,931**	**74,257**	**868,642**	**34,977**	**41**	**0**	**18,559**
Balance of Account 1589 allocated to Class A Non-WMP Customers		**94,644**		**0**	**0**	**94,644**	**0**	**0**	**0**	**0**
Group 2 Accounts - Total balance allocated to each class		**(38,857)**		**(16,698)**	**(5,725)**	**(15,591)**	**(432)**	**(123)**	**(53)**	**(234)**
IFRS-CGAAP Transition PP&E Amounts Balance + Return Component	1575	0	kWh	0	0	0	0	0	0	0
Accounting Changes Under CGAAP Balance + Return Component	1576	0	kWh	0	0	0	0	0	0	0
Total Balance Allocated to each class for Accounts 1575 and 1576		**0**		**0**	**0**	**0**	**0**	**0**	**0**	**0**

Account 1589 reference calculation by customer and consumption	
Account 1589 / Number of Customers	$41.42
1589/total kwh	$0.0026

Ontario Energy Board

2016 Deferral/Variance Account Wo

		Amounts from Sheet 2	Allocator						
LV Variance Account	1550	41,587	kWh	0	0	0	0	0	0
Smart Metering Entity Charge Variance Account	1551	2,898	# of Customers	0	0	0	0	0	0
RSVA - Wholesale Market Service Charge	1580	(875,699)	kWh	0	0	0	0	0	0
RSVA - Retail Transmission Network Charge	1584	(163,504)	kWh	0	0	0	0	0	0
RSVA - Retail Transmission Connection Charge	1586	(9,244)	kWh	0	0	0	0	0	0
RSVA - Power (excluding Global Adjustment)	1588	(569,077)	kWh	0	0	0	0	0	0
RSVA - Global Adjustment	1589	1,088,407	Non-RPP kWh	0	0	0	0	0	0
Disposition and Recovery/Refund of Regulatory Balances (2008)	1595	0	%	0	0	0	0	0	0
Disposition and Recovery/Refund of Regulatory Balances (2009)	1595	0	%	0	0	0	0	0	0
Disposition and Recovery/Refund of Regulatory Balances (2010)	1595	0	kWh	0	0	0	0	0	0
Disposition and Recovery/Refund of Regulatory Balances (2011)	1595	0	%	0	0	0	0	0	0
Disposition and Recovery/Refund of Regulatory Balances (2012)	1595	0	kWh	0	0	0	0	0	0
Disposition and Recovery/Refund of Regulatory Balances (2013)	1595	0	%	0	0	0	0	0	0
Disposition and Recovery/Refund of Regulatory Balances (2014)	1595	6,339	%	0	0	0	0	0	0
Total of Group 1 Accounts (excluding 1589)		**(1,566,699)**		**0**	**0**	**0**	**0**	**0**	**0**
Other Regulatory Assets - Sub-Account - Deferred IFRS Transition Costs	1508	0	kWh	0	0	0	0	0	0
Other Regulatory Assets - Sub-Account - Incremental Capital Charges	1508	0	kWh	0	0	0	0	0	0
Other Regulatory Assets - Sub-Account - Financial Assistance Payment and Recovery Variance - Ontario Clean Energy Benefit Act8	1508	(38,857)	kWh	0	0	0	0	0	0
Other Regulatory Assets - Sub-Account - Financial Assistance Payment and Recovery Carrying Charges	1508	0	kWh	0	0	0	0	0	0
Other Regulatory Assets - Sub-Account - Other 4	1508	0	kWh	0	0	0	0	0	0
Retail Cost Variance Account - Retail	1518	0	kWh	0	0	0	0	0	0
Misc. Deferred Debits	1525	0	kWh	0	0	0	0	0	0
Retail Cost Variance Account - STR	1548	0	kWh	0	0	0	0	0	0
Board-Approved CDM Variance Account	1567	0	kWh	0	0	0	0	0	0
Extra-Ordinary Event Costs	1572	0	kWh	0	0	0	0	0	0
Deferred Rate Impact Amounts	1574	0	kWh	0	0	0	0	0	0
RSVA - One-time	1582	0	kWh	0	0	0	0	0	0
Other Deferred Credits	2425	0	kWh	0	0	0	0	0	0
Total of Group 2 Accounts		**(38,857)**		**0**	**0**	**0**	**0**	**0**	**0**
PILs and Tax Variance for 2006 and Subsequent Years (excludes sub-account and contra account)	1592	(71,997)	kWh	0	0	0	0	0	0
PILs and Tax Variance for 2006 and Subsequent Years - Sub-Account HST/OVAT Input Tax Credits (ITCs)	1592	0	kWh	0	0	0	0	0	0
Total of Account 1562 and Account 1592		**(71,997)**		**0**	**0**	**0**	**0**	**0**	**0**
LRAM Variance Account **(Enter dollar amount for each class)**	1568	**255,421**		0	0	0	0	0	0
(Account 1568 - total amount allocated to classes)		255,421							
Variance		**0**							
Total of Group 1 Accounts (1550, 1551, 1584, 1586 and 1595)		**(121,924)**		**0**	**0**	**0**	**0**	**0**	**0**
Total of Account 1580 and 1588 (not allocated to WMPs)		**(1,444,776)**		**0**	**0**	**0**	**0**	**0**	**0**
Balance of Account 1589 Allocated to Non-WMPs		**1,088,407**		**0**	**0**	**0**	**0**	**0**	**0**
Balance of Account 1589 allocated to Class A Non-WMP Customers		**94,644**		**0**	**0**	**0**	**0**	**0**	**0**
Group 2 Accounts - Total balance allocated to each class		**(38,857)**		**0**	**0**	**0**	**0**	**0**	**0**
IFRS-CGAAP Transition PP&E Amounts Balance + Return Component	1575	0	kWh	0	0	0	0	0	0
Accounting Changes Under CGAAP Balance + Return Component	1576	0	kWh	0	0	0	0	0	0
Total Balance Allocated to each class for Accounts 1575 and 1576		**0**		**0**	**0**	**0**	**0**	**0**	**0**

Account 1589 reference calculation by customer and consumption	
Account 1589 / Number of Customers	$41.42
1589/total kwh	$0.0026

Ontario Energy Board

2016 Deferral/Variance Account Wo

		Amounts from Sheet 2	Allocator							
LV Variance Account	1550	41,587	kWh	0	0	0	0	0	0	0
Smart Metering Entity Charge Variance Account	1551	2,898	# of Customers	0	0	0	0	0	0	0
RSVA - Wholesale Market Service Charge	1580	(875,699)	kWh	0	0	0	0	0	0	0
RSVA - Retail Transmission Network Charge	1584	(163,504)	kWh	0	0	0	0	0	0	0
RSVA - Retail Transmission Connection Charge	1586	(9,244)	kWh	0	0	0	0	0	0	0
RSVA - Power (excluding Global Adjustment)	1588	(569,077)	kWh	0	0	0	0	0	0	0
RSVA - Global Adjustment	1589	1,088,407	Non-RPP kWh	0	0	0	0	0	0	0
Disposition and Recovery/Refund of Regulatory Balances (2008)	1595	0	%	0	0	0	0	0	0	0
Disposition and Recovery/Refund of Regulatory Balances (2009)	1595	0	%	0	0	0	0	0	0	0
Disposition and Recovery/Refund of Regulatory Balances (2010)	1595	0	kWh	0	0	0	0	0	0	0
Disposition and Recovery/Refund of Regulatory Balances (2011)	1595	0	%	0	0	0	0	0	0	0
Disposition and Recovery/Refund of Regulatory Balances (2012)	1595	0	kWh	0	0	0	0	0	0	0
Disposition and Recovery/Refund of Regulatory Balances (2013)	1595	0	%	0	0	0	0	0	0	0
Disposition and Recovery/Refund of Regulatory Balances (2014)	1595	6,339	%	0	0	0	0	0	0	0
Total of Group 1 Accounts (excluding 1589)		**(1,566,699)**		**0**	**0**	**0**	**0**	**0**	**0**	**0**

Other Regulatory Assets - Sub-Account - Deferred IFRS Transition Costs	1508	0	kWh	0	0	0	0	0	0	0
Other Regulatory Assets - Sub-Account - Incremental Capital Charges	1508	0	kWh	0	0	0	0	0	0	0
Other Regulatory Assets - Sub-Account - Financial Assistance Payment and Recovery Variance - Ontario Clean Energy Benefit Act8	1508	(38,857)	kWh	0	0	0	0	0	0	0
Other Regulatory Assets - Sub-Account - Financial Assistance Payment and Recovery Carrying Charges	1508	0	kWh	0	0	0	0	0	0	0
Other Regulatory Assets - Sub-Account - Other 4	1508	0	kWh	0	0	0	0	0	0	0
Retail Cost Variance Account - Retail	1518	0	kWh	0	0	0	0	0	0	0
Misc. Deferred Debits	1525	0	kWh	0	0	0	0	0	0	0
Retail Cost Variance Account - STR	1548	0	kWh	0	0	0	0	0	0	0
Board-Approved CDM Variance Account	1567	0	kWh	0	0	0	0	0	0	0
Extra-Ordinary Event Costs	1572	0	kWh	0	0	0	0	0	0	0
Deferred Rate Impact Amounts	1574	0	kWh	0	0	0	0	0	0	0
RSVA - One-time	1582	0	kWh	0	0	0	0	0	0	0
Other Deferred Credits	2425	0	kWh	0	0	0	0	0	0	0
Total of Group 2 Accounts		**(38,857)**		**0**	**0**	**0**	**0**	**0**	**0**	**0**

PILs and Tax Variance for 2006 and Subsequent Years (excludes sub-account and contra account)	1592	(71,997)	kWh	0	0	0	0	0	0	0
PILs and Tax Variance for 2006 and Subsequent Years - Sub-Account HST/OVAT Input Tax Credits (ITCs)	1592	0	kWh	0	0	0	0	0	0	0
Total of Account 1562 and Account 1592		**(71,997)**		**0**	**0**	**0**	**0**	**0**	**0**	**0**

LRAM Variance Account **(Enter dollar amount for each class)**	1568	**255,421**		0	0	0	0	0	0	0
(Account 1568 - total amount allocated to classes)		255,421								
Variance		**0**								

Total of Group 1 Accounts (1550, 1551, 1584, 1586 and 1595)	**(121,924)**		**0**	**0**	**0**	**0**	**0**	**0**	**0**
Total of Account 1580 and 1588 (not allocated to WMPs)	**(1,444,776)**		**0**	**0**	**0**	**0**	**0**	**0**	**0**
Balance of Account 1589 Allocated to Non-WMPs	**1,088,407**		**0**	**0**	**0**	**0**	**0**	**0**	**0**
Balance of Account 1589 allocated to Class A Non-WMP Customers	**94,644**		**0**	**0**	**0**	**0**	**0**	**0**	**0**
Group 2 Accounts - Total balance allocated to each class	**(38,857)**		**0**	**0**	**0**	**0**	**0**	**0**	**0**

IFRS-CGAAP Transition PP&E Amounts Balance + Return Component	1575	0	kWh	0	0	0	0	0	0	0
Accounting Changes Under CGAAP Balance + Return Component	1576	0	kWh	0	0	0	0	0	0	0
Total Balance Allocated to each class for Accounts 1575 and 1576		**0**		**0**	**0**	**0**	**0**	**0**	**0**	**0**

Account 1589 reference calculation by customer and consumption	
Account 1589 / Number of Customers	$41.42
1589/total kwh	$0.0026

Ontario Energy Board

2016 Deferral/Variance Account Workform

Please indicate the Rate Rider Recovery Period (in years) | **1**

Rate Rider Calculation for Deferral / Variance Accounts Balances (excluding Global Adj.)

1550, 1551, 1584, 1586, 1595

Rate Class (Enter Rate Classes in cells below)	**Units**	**kW / kWh / # of Customers**	**Allocated Balance (excluding 1589)**	**Rate Rider for Deferral/Variance Accounts**	
RESIDENTIAL SERVICE CLASSIFICATION	kWh	198,077,803	-$ 51,895	- 0.0003	$/kWh
GENERAL SERVICE LESS THAN 50 KW SE	kWh	67,907,332	-$ 16,948	- 0.0002	$/kWh
GENERAL SERVICE 50 TO 4,999 KW SER	kW	593,383	-$ 50,234	- 0.0847	$/kW
EMBEDDED DISTRIBUTOR	kW	13,717	-$ 1,460	- 0.1064	$/kW
UNMETERED SCATTERED LOAD SERVICE	kWh	1,462,761	-$ 416	- 0.0003	$/kWh
SENTINEL LIGHTING SERVICE CLASSIFIC	kW	1,916	-$ 179	- 0.0934	$/kW
STREET LIGHTING SERVICE CLASSIFICAT	kW	8,591	-$ 792	- 0.0921	$/kW
		-	$ -	-	
		-	$ -	-	
		-	$ -	-	
		-	$ -	-	
		-	$ -	-	
		-	$ -	-	
		-	$ -	-	
		-	$ -	-	
		-	$ -	-	
		-	$ -	-	
		-	$ -	-	
		-	$ -	-	
		-	$ -	-	
Total			**-$ 121,924**		

Ontario Energy Board

2017 Deferral/Variance Account Workform

Accounts that produced a variance on the 2015 continuity schedule are listed below. Please provide a detailed explanation for each variance below.

	Account Descriptions	Account Number	Variance RRR vs. 2015 Balance *(Principal + Interest)*	Explanation
	Group 1 Accounts			
2	Smart Metering Entity Charge Variance Account	1551	-$6,851	Variance represents the residual balance in OEB 1555 Smart Meter Capital and Recovery Offset Variance - Sub-Account - Stranded Meter Costs. Allocated to OEB 1551 Smart Metering Entity Charge Variance Account in DVA.
6	RSVA - Power (excluding Global Adjustment)	1588	-$12,490	Fixed priced, MicroFIT, and FIT adjustment true-up was performed in 2016 for the 2015 year and recorded in DVA as a Principal Adjustment during 2015 in OEB 1588, but not recorded in financial statements and the RRR filings until 2016.
7	RSVA - Global Adjustment	1589	$97,293	Global adjustment true-up was performed in 2016 for the 2015 year and recorded in DVA as a Principal Adjustment during 2015 in OEB 1589, but not recorded in the financial statements and RRR filings until 2016.
14	Disposition and Recovery/Refund of Regulatory Balances (2015)	1595	-$309,309	Variance represents residual balances in recovery of disposition of Deferral/Variance Accounts (2015) and Global Adjustment (2015); rate riders set to expire December 31, 2016.
	Group 2 Accounts			
17	Other Regulatory Assets - Sub-Account - Financial Assistance Payment and Recovery Variance - Ontario Clean Energy Benefit Act8	1508	-$547,146	Variance represents the principal portion of OEB 1508 Other Regulatory Assets - Sub-Account - Financial Assistance Payment and Recovery Variance - Ontario Clean Energy Benefit Act excluded from DVA.
29	LRAM Variance Account	1568	-$252,642	Variance represents amount quantified and requested for disposition for lost revenues in relation to conservation and demand management ("CDM") activities, up to December 31, 2015. Amount recorded in DVA as a Principal Adjustment during 2015 in OEB 1568, but not recorded in financial statements and the RRR filings until 2016.
39	Smart Meter Capital and Recovery Offset Variance - Sub-Account - Stranded Meter Costs5	1555	$6,851	Variance represents the residual balance in OEB 1555 Smart Meter Capital and Recovery Offset Variance - Sub-Account - Stranded Meter Costs. Allocated to OEB 1551 Smart Metering Entity Charge Variance Account in DVA.

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DEFERRED PILS ACCOUNT – ACCOUNT 1592 PILS AND TAX VARIANCE

CNPI has calculated a December 31, 2015 principal liability amount for Account 1592 – PILS and Tax Variance of $61,710, and carrying charges of $9,609, up to and including December 31, 2015, totaling $71,319 owing to ratepayers, for review and disposition in this rate application.

Please refer to Exhibit 9, Tab 2, Schedule 3 for the detailed calculations of the balance in Account 1592 and Exhibit 9, Tab 2, Schedule 4 for carrying charges calculated on principal balances.

The balance owing has been included in the EDDVAR continuity schedule in Schedule 2 of Tab 1 of this Exhibit.

The guidance provided in the FAQ of July 2007 was followed with respect to Account 1592 – PILs and Tax Variance. CNPI received approved rates in 2006 and then again in 2007, and the tax variances have been calculated based on large corporation tax and Ontario capital tax decreases relative to rates approved within the rate proceedings.

OEB account 1562 was addressed as part of CNPI's last cost of service proceeding (EB-2012-0112). The PILs disposition rate rider relating to account 1562 for the Port Colborne service territory expires December 31, 2016. CNPI will request disposition of any residual balances remaining in that account in a future proceeding.

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Appendix 2-TA
Account 1592, PILs and Tax Variances for 2006 and Subsequent Years

The following table should be completed based on the information requested below, in accordance with the notes following the table. An explanation should be provided for any blank entries.

Tax Item	Principal as of December 31, 2015
Large Corporation Tax decrease for 2007	-$ 55,725
Ontario Capital Tax rate decrease and increase in capital deduction for 2007	-$ 2,993
Ontario Capital Tax rate decrease and increase in capital deduction for 2008	-$ 2,993
Ontario Capital Tax rate decrease and increase in capital deduction for 2009	N/A
Ontario Capital Tax rate decrease and increase in capital deduction for 2010	N/A
Capital Cost Allowance class changes from 2006 EDR application for 2006	N/A
Capital Cost Allowance class changes from 2006 EDR application for 2007	N/A
Capital Cost Allowance class changes from 2006 EDR application for 2008	N/A
Capital Cost Allowance class changes from 2006 EDR application for 2009	N/A
Federal Income Tax Rate change from 2007 EDR to 2008	N/A
Federal Income Tax Rate change from 2007 EDR to 2009	N/A
Carrying charges on above amounts	-$ 9,609
Insert description of additional item(s) and new rows if needed.	
Total	-$ 71,319

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1 Calculations

FORT ERIE, GANANOQUE AND PORT COLBORNE

	2006 EDR	2007 EDR	2008 IRM
Summary - Sharing of Tax Change Forecast Amounts			
1. Tax Related Amounts from Large Corporation Tax Rate Changes	**2006**	**2007**	**2008**
Rate Base from	$ 43,294,336	$ 43,294,336	
Less: Exemption	$ 1,276,770	$ 1,276,770	
Deemed Taxable Capital	$ 42,017,566	$ 42,017,566	
Rate in 2006	0.125%	0.000%	
Gross Amount (Taxable Capital x Rate)	$ 52,522	$ -	
Less: Federal Surtax	$ 873	$ 873	
Net LCT	$ 53,395	$ 873	
Grossed up LCT May 1, 2006 to April 30, 2007	**$ 83,587**	**$ -**	
Grossed up LCT Jan 1, 2006 to April 30, 2006	**$ 27,862**		
2. Tax Related Amounts from Capital Tax Rate Changes	**2006**	**2007**	**2008**
Taxable Capital	$ 41,483,554	$ 41,483,554	$ 41,483,554
Deduction from taxable capital up to $15,000,000	$ 1,581,928	$ 1,581,928	$ 1,581,928
Net Taxable Capital	$ 39,901,626	$ 39,901,626	$ 39,901,626
Rate	0.300%	0.285%	0.285%
Ontario Capital Tax (Deductible, not grossed-up)	**$ 119,705**	**$ 113,720**	**$ 113,720**
Tax Related Amounts from Large Corporations Tax Rate Changes	$ 111,449	$ -	
Incremental Tax Savings		**-$ 111,449**	
Tax Related Amounts from Capital Tax Rate Changes	$ 119,705	$ 113,720	$ 113,720
Incremental Tax Savings		**-$ 5,985**	**-$ 5,985**
Total Tax Related Amounts	**$ 231,154**	**$ 113,720**	**$ 113,720**
Total Incremental Tax Savings		**-$ 117,435**	**-$ 5,985**
Sharing of Tax Savings (50%)		**-$ 58,717**	**-$ 2,993**

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Canadian Niagara Power
1592 Deferred PILS - Continuity Schedule

Year: 2007

	Approved PILS Entitlement	PILS Revenue	True-Up Adjustments (neg = CR)	Variance (neg. = payable) Monthly	Variance (neg. = payable) Cumulative	Interest Improvement (neg = payable) Approved Interest Rate	Interest Improvement Monthly	Interest Improvement Cumulative	Total Variance
January				$ -	$ -	4.59%		$ -	$ -
February				$ -	$ -	4.59%	$ -	$ -	$ -
March				$ -	$ -	4.59%	$ -	$ -	$ -
April				$ -	$ -	4.59%	$ -	$ -	$ -
May			-$ 58,717.29	-$ 58,717.29	-$ 58,717.29	4.59%	$ -	$ -	-$ 58,717.29
June				$ -	-$ 58,717.29	4.59%	-$ 224.59	-$ 224.59	-$ 58,941.88
July				$ -	-$ 58,717.29	4.59%	-$ 224.59	-$ 449.19	-$ 59,166.48
August				$ -	-$ 58,717.29	4.59%	-$ 224.59	-$ 673.78	-$ 59,391.07
September				$ -	-$ 58,717.29	4.59%	-$ 224.59	-$ 898.37	-$ 59,615.66
October				$ -	-$ 58,717.29	5.14%	-$ 251.51	-$ 1,149.88	-$ 59,867.17
November				$ -	-$ 58,717.29	5.14%	-$ 251.51	-$ 1,401.39	-$ 60,118.67
December				$ -	-$ 58,717.29	5.14%	-$ 251.51	-$ 1,652.89	-$ 60,370.18
Total	$ -	$ -	-$ 58,717.29	-$ 58,717.29			-$ 1,652.89		

Year: 2008

	Approved PILS Entitlement	PILS Revenue	True-Up Adjustments (neg = CR)	Variance (neg. = payable) Monthly	Variance (neg. = payable) Cumulative	Interest Improvement (neg = payable) Approved Interest Rate	Interest Improvement Monthly	Interest Improvement Cumulative	Total Variance
January				$ -	-$ 58,717.29	5.14%	-$ 251.51	-$ 1,904.40	-$ 60,621.69
February				$ -	-$ 58,717.29	5.14%	-$ 251.51	-$ 2,155.90	-$ 60,873.19
March				$ -	-$ 58,717.29	5.14%	-$ 251.51	-$ 2,407.41	-$ 61,124.70
April				$ -	-$ 58,717.29	4.08%	-$ 199.64	-$ 2,607.05	-$ 61,324.34
May			-$ 2,992.62	-$ 2,992.62	-$ 61,709.91	4.08%	-$ 199.64	-$ 2,806.69	-$ 64,516.60
June				$ -	-$ 61,709.91	4.08%	-$ 209.81	-$ 3,016.50	-$ 64,726.41
July				$ -	-$ 61,709.91	3.35%	-$ 172.27	-$ 3,188.77	-$ 64,898.68
August				$ -	-$ 61,709.91	3.35%	-$ 172.27	-$ 3,361.05	-$ 65,070.96
September				$ -	-$ 61,709.91	3.35%	-$ 172.27	-$ 3,533.32	-$ 65,243.23
October				$ -	-$ 61,709.91	3.35%	-$ 172.27	-$ 3,705.59	-$ 65,415.50
November				$ -	-$ 61,709.91	3.35%	-$ 172.27	-$ 3,877.87	-$ 65,587.78
December				$ -	-$ 61,709.91	3.35%	-$ 172.27	-$ 4,050.14	-$ 65,760.05
Total	$ -	$ -	-$ 2,992.62	-$ 2,992.62			-$ 2,397.25		

Year: 2009

	Approved PILS Entitlement	PILS Revenue	True-Up Adjustments (neg = CR)	Variance (neg. = payable) Monthly	Variance (neg. = payable) Cumulative	Interest Improvement (neg = payable) Approved Interest Rate	Interest Improvement Monthly	Interest Improvement Cumulative	Total Variance
January				$ -	-$ 61,709.91	2.45%	-$ 125.99	-$ 4,176.13	-$ 65,886.04
February				$ -	-$ 61,709.91	2.45%	-$ 125.99	-$ 4,302.12	-$ 66,012.03
March				$ -	-$ 61,709.91	2.45%	-$ 125.99	-$ 4,428.11	-$ 66,138.02
April				$ -	-$ 61,709.91	1.00%	-$ 51.42	-$ 4,479.54	-$ 66,189.45
May				$ -	-$ 61,709.91	1.00%	-$ 51.42	-$ 4,530.96	-$ 66,240.87
June				$ -	-$ 61,709.91	1.00%	-$ 51.42	-$ 4,582.39	-$ 66,292.30
July				$ -	-$ 61,709.91	0.55%	-$ 28.28	-$ 4,610.67	-$ 66,320.58
August				$ -	-$ 61,709.91	0.55%	-$ 28.28	-$ 4,638.96	-$ 66,348.87
September				$ -	-$ 61,709.91	0.55%	-$ 28.28	-$ 4,667.24	-$ 66,377.15
October				$ -	-$ 61,709.91	0.55%	-$ 28.28	-$ 4,695.52	-$ 66,405.43
November				$ -	-$ 61,709.91	0.55%	-$ 28.28	-$ 4,723.81	-$ 66,433.72
December				$ -	-$ 61,709.91	0.55%	-$ 28.28	-$ 4,752.09	-$ 66,462.00
Total	$ -	$ -	$ -	$ -			-$ 701.95		

Canadian Niagara Power
1592 Deferred PILS - Continuity Schedule

Year: 2010

	Approved PILS Entitlement	PILS Revenue	True-Up Adjustments (neg = CR)	Variance (neg. = payable) Monthly	Variance (neg. = payable) Cumulative	Interest Improvement (neg = payable) Approved Interest Rate	Interest Improvement (neg = payable) Monthly	Interest Improvement (neg = payable) Cumulative	Total Variance
January				$ -	-$ 61,709.91	0.55%	-$ 28.28	-$ 4,780.38	-$ 66,490.29
February				$ -	-$ 61,709.91	0.55%	-$ 28.28	-$ 4,808.66	-$ 66,518.57
March				$ -	-$ 61,709.91	0.55%	-$ 28.28	-$ 4,836.94	-$ 66,546.85
April				$ -	-$ 61,709.91	0.55%	-$ 28.28	-$ 4,865.23	-$ 66,575.14
May				$ -	-$ 61,709.91	0.55%	-$ 28.28	-$ 4,893.51	-$ 66,603.42
June				$ -	-$ 61,709.91	0.55%	-$ 28.28	-$ 4,921.79	-$ 66,631.70
July				$ -	-$ 61,709.91	0.89%	-$ 45.77	-$ 4,967.56	-$ 66,677.47
August				$ -	-$ 61,709.91	0.89%	-$ 45.77	-$ 5,013.33	-$ 66,723.24
September				$ -	-$ 61,709.91	0.89%	-$ 45.77	-$ 5,059.10	-$ 66,769.01
October				$ -	-$ 61,709.91	1.20%	-$ 61.71	-$ 5,120.81	-$ 66,830.72
November				$ -	-$ 61,709.91	1.20%	-$ 61.71	-$ 5,182.52	-$ 66,892.43
December				$ -	-$ 61,709.91	1.20%	-$ 61.71	-$ 5,244.23	-$ 66,954.14
Total	$ -	$ -	$ -	$ -			-$ 492.14		

Year: 2011

	Approved PILS Entitlement	PILS Revenue	True-Up Adjustments (neg = CR)	Variance (neg. = payable) Monthly	Variance (neg. = payable) Cumulative	Interest Improvement (neg = payable) Approved Interest Rate	Interest Improvement (neg = payable) Monthly	Interest Improvement (neg = payable) Cumulative	Total Variance
January				$ -	-$ 61,709.91	1.47%	-$ 75.59	-$ 5,319.82	-$ 67,029.73
February				$ -	-$ 61,709.91	1.47%	-$ 75.59	-$ 5,395.42	-$ 67,105.33
March				$ -	-$ 61,709.91	1.47%	-$ 75.59	-$ 5,471.01	-$ 67,180.92
April				$ -	-$ 61,709.91	1.47%	-$ 75.59	-$ 5,546.61	-$ 67,256.52
May				$ -	-$ 61,709.91	1.47%	-$ 75.59	-$ 5,622.20	-$ 67,332.11
June				$ -	-$ 61,709.91	1.47%	-$ 75.59	-$ 5,697.80	-$ 67,407.71
July				$ -	-$ 61,709.91	1.47%	-$ 75.59	-$ 5,773.39	-$ 67,483.30
August				$ -	-$ 61,709.91	1.47%	-$ 75.59	-$ 5,848.98	-$ 67,558.90
September				$ -	-$ 61,709.91	1.47%	-$ 75.59	-$ 5,924.58	-$ 67,634.49
October				$ -	-$ 61,709.91	1.47%	-$ 75.59	-$ 6,000.17	-$ 67,710.08
November				$ -	-$ 61,709.91	1.47%	-$ 75.59	-$ 6,075.77	-$ 67,785.68
December				$ -	-$ 61,709.91	1.47%	-$ 75.59	-$ 6,151.36	-$ 67,861.27
Total	$ -	$ -	$ -	$ -			-$ 907.14		

Year: 2012

	Approved PILS Entitlement	PILS Revenue	True-Up Adjustments (neg = CR)	Variance (neg. = payable) Monthly	Variance (neg. = payable) Cumulative	Interest Improvement (neg = payable) Approved Interest Rate	Interest Improvement (neg = payable) Monthly	Interest Improvement (neg = payable) Cumulative	Total Variance
January				$ -	-$ 61,709.91	1.47%	-$ 75.59	-$ 6,226.96	-$ 67,936.87
February				$ -	-$ 61,709.91	1.47%	-$ 75.59	-$ 6,302.55	-$ 68,012.46
March				$ -	-$ 61,709.91	1.47%	-$ 75.59	-$ 6,378.15	-$ 68,088.06
April				$ -	-$ 61,709.91	1.47%	-$ 75.59	-$ 6,453.74	-$ 68,163.65
May				$ -	-$ 61,709.91	1.47%	-$ 75.59	-$ 6,529.34	-$ 68,239.25
June				$ -	-$ 61,709.91	1.47%	-$ 75.59	-$ 6,604.93	-$ 68,314.84
July				$ -	-$ 61,709.91	1.47%	-$ 75.59	-$ 6,680.53	-$ 68,390.44
August				$ -	-$ 61,709.91	1.47%	-$ 75.59	-$ 6,756.12	-$ 68,466.03
September				$ -	-$ 61,709.91	1.47%	-$ 75.59	-$ 6,831.72	-$ 68,541.63
October				$ -	-$ 61,709.91	1.47%	-$ 75.59	-$ 6,907.31	-$ 68,617.22
November				$ -	-$ 61,709.91	1.47%	-$ 75.59	-$ 6,982.90	-$ 68,692.82
December				$ -	-$ 61,709.91	1.47%	-$ 75.59	-$ 7,058.50	-$ 68,768.41
Total	$ -	$ -	$ -	$ -			-$ 907.14		

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Canadian Niagara Power
1592 Deferred PILS - Continuity Schedule

Year: 2013

	Approved PILS Entitlement	PILS Revenue	True-Up Adjustments (neg = CR)	Variance (neg. = payable) Monthly	Variance (neg. = payable) Cumulative	Interest Improvement (neg = payable) Approved Interest Rate	Interest Improvement Monthly	Interest Improvement Cumulative	Total Variance
January				$ -	-$ 61,709.91	1.47%	-$ 75.59	-$ 7,134.09	-$ 68,844.00
February				$ -	-$ 61,709.91	1.47%	-$ 75.59	-$ 7,209.69	-$ 68,919.60
March				$ -	-$ 61,709.91	1.47%	-$ 75.59	-$ 7,285.28	-$ 68,995.19
April				$ -	-$ 61,709.91	1.47%	-$ 75.59	-$ 7,360.88	-$ 69,070.79
May				$ -	-$ 61,709.91	1.47%	-$ 75.59	-$ 7,436.47	-$ 69,146.38
June				$ -	-$ 61,709.91	1.47%	-$ 75.59	-$ 7,512.07	-$ 69,221.98
July				$ -	-$ 61,709.91	1.47%	-$ 75.59	-$ 7,587.66	-$ 69,297.57
August				$ -	-$ 61,709.91	1.47%	-$ 75.59	-$ 7,663.26	-$ 69,373.17
September				$ -	-$ 61,709.91	1.47%	-$ 75.59	-$ 7,738.85	-$ 69,448.76
October				$ -	-$ 61,709.91	1.47%	-$ 75.59	-$ 7,814.45	-$ 69,524.36
November				$ -	-$ 61,709.91	1.47%	-$ 75.59	-$ 7,890.04	-$ 69,599.95
December				$ -	-$ 61,709.91	1.47%	-$ 75.59	-$ 7,965.63	-$ 69,675.55
Total	$ -	$ -	$ -	$ -			-$ 907.14		

Year: 2014

	Approved PILS Entitlement	PILS Revenue	True-Up Adjustments (neg = CR)	Variance (neg. = payable) Monthly	Variance (neg. = payable) Cumulative	Interest Improvement (neg = payable) Approved Interest Rate	Interest Improvement Monthly	Interest Improvement Cumulative	Total Variance
January				$ -	-$ 61,709.91	1.47%	-$ 75.59	-$ 8,041.23	-$ 69,751.14
February				$ -	-$ 61,709.91	1.47%	-$ 75.59	-$ 8,116.82	-$ 69,826.73
March				$ -	-$ 61,709.91	1.47%	-$ 75.59	-$ 8,192.42	-$ 69,902.33
April				$ -	-$ 61,709.91	1.47%	-$ 75.59	-$ 8,268.01	-$ 69,977.92
May				$ -	-$ 61,709.91	1.47%	-$ 75.59	-$ 8,343.61	-$ 70,053.52
June				$ -	-$ 61,709.91	1.47%	-$ 75.59	-$ 8,419.20	-$ 70,129.11
July				$ -	-$ 61,709.91	1.47%	-$ 75.59	-$ 8,494.80	-$ 70,204.71
August				$ -	-$ 61,709.91	1.47%	-$ 75.59	-$ 8,570.39	-$ 70,280.30
September				$ -	-$ 61,709.91	1.47%	-$ 75.59	-$ 8,645.99	-$ 70,355.90
October				$ -	-$ 61,709.91	1.47%	-$ 75.59	-$ 8,721.58	-$ 70,431.49
November				$ -	-$ 61,709.91	1.47%	-$ 75.59	-$ 8,797.18	-$ 70,507.09
December				$ -	-$ 61,709.91	1.47%	-$ 75.59	-$ 8,872.77	-$ 70,582.68
Total	$ -	$ -	$ -	$ -			-$ 907.14		

Year: 2015

	Approved PILS Entitlement	PILS Revenue	True-Up Adjustments (neg = CR)	Variance (neg. = payable) Monthly	Variance (neg. = payable) Cumulative	Interest Improvement (neg = payable) Approved Interest Rate	Interest Improvement Monthly	Interest Improvement Cumulative	Total Variance
January				$ -	-$ 61,709.91	1.47%	-$ 75.59	-$ 8,948.37	-$ 70,658.28
February				$ -	-$ 61,709.91	1.47%	-$ 75.59	-$ 9,023.96	-$ 70,733.87
March				$ -	-$ 61,709.91	1.47%	-$ 75.59	-$ 9,099.55	-$ 70,809.47
April				$ -	-$ 61,709.91	1.10%	-$ 56.57	-$ 9,156.12	-$ 70,866.03
May				$ -	-$ 61,709.91	1.10%	-$ 56.57	-$ 9,212.69	-$ 70,922.60
June				$ -	-$ 61,709.91	1.10%	-$ 56.57	-$ 9,269.26	-$ 70,979.17
July				$ -	-$ 61,709.91	1.10%	-$ 56.57	-$ 9,325.82	-$ 71,035.73
August				$ -	-$ 61,709.91	1.10%	-$ 56.57	-$ 9,382.39	-$ 71,092.30
September				$ -	-$ 61,709.91	1.10%	-$ 56.57	-$ 9,438.96	-$ 71,148.87
October				$ -	-$ 61,709.91	1.10%	-$ 56.57	-$ 9,495.53	-$ 71,205.44
November				$ -	-$ 61,709.91	1.10%	-$ 56.57	-$ 9,552.09	-$ 71,262.00
December				$ -	-$ 61,709.91	1.10%	-$ 56.57	-$ 9,608.66	-$ 71,318.57
Total	$ -	$ -	$ -	$ -			-$ 735.89		

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METERING INSIDE THE SETTLEMENT TIMEFRAME (MIST) DEPLOYMENT CAPITAL COSTS

Introduction

In 2014 the OEB made amendments to the DSC such that MIST meters were required to be installed on customers that had a monthly peak demand over 50 kW. This implementation was to be completed by August 21, 2020. CNPI commenced and substantially completed its MIST meter installations on 133 customers during 2015, with a final 12 installations to be completed in 2016.

In the OEB's March 2015 Accounting Procedures Handbook Guidance, the OEB directed distributors to be guided by the various Board documents related to record-keeping and disposition of smart meter costs when accounting for MIST costs. As per OEB direction, account 1557 Meter Cost Deferral Account was established for the tracking of incremental capital and OM&A MIST costs and has been utilized by CNPI.

In this Application, CNPI is proposing MIST Meter Disposition Riders ("MMDRs") for the recovery of costs related to the true-up of revenue requirement up to December 31, 2016. CNPI proposes a five year rate rider from an effective date of January 1, 2017 to December 31, 2021.

Project Background

On January 16, 2014, the Board issued a Notice of Proposal to Amend a Code (the "January Notice") in which it proposed amendments to the DSC (the "January Proposed Amendments"). The January Proposed Amendments set out revisions to the DSC to require a distributor to install an interval meter (i.e., a "MIST meter") on any installation that is forecast by the distributor to have a monthly average peak demand during a calendar year of over 50 kW. The primary driver of this mandate was to address the concern that many customers with a monthly average peak demand during a calendar year of over 50 kW and less than or equal to 500 kW are demand metered and billed based on one or two month usage data mapped to the net system load shape of the distributor, which may have little resemblance to the customers' actual hourly consumption.

The DSC was then amended in May 2014 to establish the requirement for the installation of Metering Inside the Settlement Timeframe ("MIST") meters. The changes came into force on August 21, 2014 and distributors have until August 21, 2020 to install the required meters.

CNPI recognized that some of the benefits of moving all customers with a monthly average peak demand during a calendar year of over 50 kW to interval meters include that it would provide the customer with greater choice, opportunity, ability, and incentive to better manage their electricity consumption and costs through load shifting, pricing options, and/or demand reduction. The amendment would also bring these customers in line with the rest of the electricity customers in Ontario in terms of pricing and, potentially, this could lead to the deferral and mitigation of system investments, lowering overall system costs.

By the end of 2015, CNPI substantially completed the implementation of the MIST program. This project affected various functional areas and systems across CNPI, including metering, customer service, and information technology. However, CNPI was able to leverage the experience that had been gained through the implementation of its Smart Meter program, resulting in an efficient implementation of the MIST meter program.

Project Phases

The CNPI MIST Project can generally be subdivided into the following distinct phases, although there was some overlap between the timing of some phases:

1. Planning
2. Procurement

3. Installation
4. Billing

The project phases are described in the following text.

1. Planning

After the DSC was amended in May 2014 to include the requirement to install MIST meters by August 21, 2020, CNPI staff had several internal meetings to discuss the MIST technical and regulatory requirements. OEB account 1557 was created to allow for the tracking of capital and incremental O&M costs. Operationally, a decision was made to substantially complete the installation of MIST meters by the end of 2015 so that costs may be claimed as part of this proceeding.

2. Procurement

CNPI conducted a comprehensive analysis in selecting a vendor and solution for the implementation of MIST metering. Three meter vendors were considered; Sensus, Itron and Elster. Current infrastructure restrictions excluded Sensus from the selection process. Itron currently operates on a 2G cellular system which will be discontinued in 2017, and did not at the time of consideration have a 3G cellular system available resulting in its elimination as a potential vendor. Although Elster did not have a 3G cellular system yet available, they were able to provide a solution that included an RS232 External Data add-on paired with a Microhard external cellular modem to collect CNP's interval MIST data. This solution offers CNPI increased control of cellular communications and additional access to power quality within the meter.

3. Installation

Once the Elster meters and required accessories were received by CNPI, the meters were readied for installation. A significant amount of effort was required to ready the meters for installation as accessories such as modems, were mounted to the meters prior to on-site installation. During Q4 2015, all but 12 MIST meters had been installed. The remaining MIST meters were forecasted to be installed in 2016.

Concurrently with the installation of the MIST meters, Utilismart; CNPI's third party metering service provider, was engaged to collect the meter read information from each of the MIST meters and to make this metering information available both to CNPI (for billing purposes) and to the customer.

4. Billing

As the majority of MIST meters were installed by the end of 2015, CNPI forecasted approximately $4.5k in expenditures to be incurred in Q1 2016 to ready the system for MIST meter billings.

All customers were notified via letter that their meters would be physically changed and how the change would affect electricity consumption billing. Due to the change in data collection methodology, customers may have received two invoices for a one-month period during the transitional month. Again, affected customers received a letter indicating this possibility and further explaining the transition to MIST meters. If customers contacted CNPI's call centre directly, the Customer Service Supervisor personally spoke to them to address any further questions.

In 2016, all customers will be invited to learn how to access their interval data online. CNPI will provide an overview on how to use the Utilismart web portal and how to interpret the information on the portal.

MIST Meter Program Capital Costs

CNPI installed 133 MIST meters in 2015 and is forecasted to complete the remaining 12 installations in 2016. Cumulative audited costs as at December 31, 2015 were $234,065, with an additional $15,300 forecasted to be spent in 2016. Additionally, CNPI forecasts incremental O&M of $44,300 in 2016 as a result of third party communication costs and costs to make the information available to customers on a website as well as convert the data to be used for billing purposes. CNPI has included any 2017 OM&A costs as part of the Revenue Requirement Work form in Exhibit 6 of this Application.

See Table 9.3.1.1 below for a summary of the MIST meter implementation costs and five year rate rider calculation of $7.05 per month per customer. A five year recovery period was elected so as to calculate a rider that was reasonable within the bill impact models completed in Exhibit 8 of this Application and to ensure alignment with CNPI's IR period. Also, see Exhibit 9, Tab 3, Schedule 2 for a partially completed Smart Meter model.

Table 9.3.1.1 MIST Meter Disposition Rate Rider Calculation

	Total	
MIST Meter Capital Costs (2015 to 2016)	$	249,365
Revenue Requirement		
Total Return on Capital (Deemed Interest Plus Return on Equity)	$	20,844
Amortization	$	23,992
OM&A	$	44,300
Total Before PILs	$	89,136
PILs	$	2,630
Total Revenue Requirement 2015 to 2016	**$**	**91,766**
Metered Customers (Average for 2017 Test)		**217**
Recovery Period in Months		**60**
MIST Meter Disposition Rider ($/Customer/Month)	**$**	**7.05**

Schedule Explanations:

- MIST Meter Capital Costs ties back to Total Smart Meter Capital Costs per '2. Smart_Meter_Costs' tab of E9 T3 S2
- Total Return on Capital ties back to sum of Total Return on Capital per '5. SM_Rev_Reqt' tab of E9 T3 S2 and Interest on Deferred and Forecasted OM&A and Amortization Expense per '9. SMFA_SMDR_SMIRR' tab of E9 T3 S2
- Amortization ties back to Total Amortization Expense per '5. SM_Rev_Reqt' tab of E9 T3 S2
- OM&A ties back to Operating Expenses per '5. SM_Rev_Reqt' tab of E9 T3 S2
- PILS ties back to Grossed-up Taxes/PILs per '5. SM_Rev_Reqt' tab of E9 T3 S2
- Metered Customers ties back to number of customers in GS >50 kW rate class per load forecasting in Exhibit 3
- Recovery Period of 5 years so as to minimize bill impacts completed in Exhibit 8

Relief Sought

CNPI considers its MIST Meter program to be substantially completed. As such, CNPI respectfully submits that the costs incurred in order to fulfill its obligations in accordance with the DSC have been prudently incurred and are in accordance with Board guidelines, and that the proposed MMDR for the five year period from January 1, 2017 to December 31, 2021, is just and reasonable.

Ontario Energy Board

Smart Meter Model for Electricity Distributors

2016 Filers

Version 6.00

Utility Name	Canadian Niagara Power Inc. – Eastern Ontario Power/Fort Erie/Port Colborne
Assigned EB Number	EB-2016-0061
Name and Title	Brian Vander Vloet, Manager Regulatory Accounting
Phone Number	905-871-0330
Email Address	brian.vandervloet@cnpower.com
Date	29-Apr-16
Last COS Re-based Year	2013

Note: Drop-down lists are shaded blue; Input cells are shaded green.

While this model has been provided in Excel format and is required to be filed with the applications, the onus remains on the applicant to ensure the accuracy of the data and the results. The use of any models and spreadsheets does not automatically imply Board approval. The onus is on the distributor to prepare, document and support its application. Board-issued Excel models and spreadsheets are offered to assist parties in providing the necessary information so as to facilitate an expeditious review of an application. The onus remains on the applicant to ensure the accuracy of the data and the results.

Ontario Energy Board

Smart Meter Model for Electricity Distributors

2016 Filers

Distributors must enter all incremental costs related to their smart meter program and all revenues recovered to date in the applicable tabs except for those costs (and associated revenues) for which the Board has approved on a final basis, i.e. capital costs have been included in rate base and OM&A costs in revenue requirement.

For 2014, distributors that have completed their deployments by the end of 2013 are not expected to enter any capital costs. However, for OM&A, regardless of whether a distributor has deployments in 2014, distributors should enter the forecasted OM&A for 2014 for all smart meters in service.

		2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	Total
Smart Meter Capital Cost and Operational Expense Data		Audited Actual	Audited Actual	Audited Actual	Audited Actual	Audited Actual	Audited Actual	Audited Actual	Audited Actual	Audited Actual	Audited Actual	Forecast	
Smart Meter Installation Plan													
Actual/Planned number of Smart Meters installed during the Calendar Year													
Residential													0
General Service < 50 kW													0
Actual/Planned number of Smart Meters installed (Residential and GS < 50 kW only)		0	0	0	0	0	0	0	0	0	0	0	0
Percentage of Residential and GS < 50 kW Smart Meter Installations Completed		0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
Actual/Planned number of GS > 50 kW meters installed													0
Other (please identify)	MIST Customers										133	12	145
Total Number of Smart Meters installed or planned to be installed		0	0	0	0	0	0	0	0	0	133	12	145

1 Capital Costs

1.1 ADVANCED METERING COMMUNICATION DEVICE (AMCD)	**Asset Type** Asset type must be selected to enable calculations	Audited Actual	Audited Actual	Audited Actual	Audited Actual	Audited Actual	Audited Actual	Audited Actual	Audited Actual	Audited Actual	Audited Actual	Forecast	
1.1.1 Smart Meters *(may include new meters and modules, etc.)*	Smart Meter										146,706	8,800	$ 155,506
1.1.2 Installation Costs *(may include socket kits, labour, vehicle, benefits, etc.)*	Smart Meter										87,359	2,000	$ 89,359
1.1.3a Workforce Automation Hardware *(may include fieldwork handhelds, barcode hardware, etc.)*													$ -
1.1.3b Workforce Automation Software *(may include fieldwork handhelds, barcode hardware, etc.)*													$ -
Total Advanced Metering Communications Devices (AMCD)		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 234,065	$ 10,800	$ 244,865

1.2 ADVANCED METERING REGIONAL COLLECTOR (AMRC) (includes LAN)	**Asset Type**	Audited Actual	Audited Actual	Audited Actual	Audited Actual	Audited Actual	Audited Actual	Audited Actual	Audited Actual	Audited Actual	Audited Actual	Forecast	
1.2.1 Collectors													$ -
1.2.2 Repeaters *(may include radio licence, etc.)*													$ -
1.2.3 Installation *(may include meter seals and rings, collector computer hardware, etc.)*													$ -
Total Advanced Metering Regional Collector (AMRC) (Includes LAN)		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -

Ontario Energy Board

Smart Meter Model for Electricity Distributors

2016 Filers

Distributors must enter all incremental costs related to their smart meter program and all revenues recovered to date in the applicable tabs except for those costs (and associated revenues) for which the Board has approved on a final basis, i.e. capital costs have been included in rate base and OM&A costs in revenue requirement.

For 2014, distributors that have completed their deployments by the end of 2013 are not expected to enter any capital costs. However, for OM&A, regardless of whether a distributor has deployments in 2014, distributors should enter the forecasted OM&A for 2014 for all smart meters in service.

	Asset Type	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	Total
1.3 ADVANCED METERING CONTROL COMPUTER (AMCC)	**Asset Type**	Audited Actual	Audited Actual	Audited Actual	Audited Actual	Audited Actual	Audited Actual	Audited Actual	Audited Actual	Audited Actual	Audited Actual	Forecast	
1.3.1 Computer Hardware													$ -
1.3.2 Computer Software													$ -
1.3.3 Computer Software Licences & Installation (includes hardware and software) *(may include AS/400 disk space, backup and recovery computer, UPS, etc.)*													$ -
Total Advanced Metering Control Computer (AMCC)		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1.4 WIDE AREA NETWORK (WAN)	**Asset Type**	Audited Actual	Audited Actual	Audited Actual	Audited Actual	Audited Actual	Audited Actual	Audited Actual	Audited Actual	Audited Actual	Audited Actual	Forecast	
1.4.1 Activiation Fees													$ -
Total Wide Area Network (WAN)		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1.5 OTHER AMI CAPITAL COSTS RELATED TO MINIMUM FUNCTIONALITY	**Asset Type**	Audited Actual	Audited Actual	Audited Actual	Audited Actual	Audited Actual	Audited Actual	Audited Actual	Audited Actual	Audited Actual	Audited Actual	Forecast	
1.5.1 Customer Equipment *(including repair of damaged equipment)*													$ -
1.5.2 AMI Interface to CIS													$ -
1.5.3 Professional Fees													$ -
1.5.4 Integration													$ -
1.5.5 Program Management													$ -
1.5.6 Other AMI Capital													$ -
Total Other AMI Capital Costs Related to Minimum Functionality		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Capital Costs Related to Minimum Functionality		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 234,065	$ 10,800	$ 244,865
1.6 CAPITAL COSTS BEYOND MINIMUM FUNCTIONALITY *(Please provide a descriptive title and identify nature of beyond minimum functionality costs)*	**Asset Type**	Audited Actual	Audited Actual	Audited Actual	Audited Actual	Audited Actual	Audited Actual	Audited Actual	Audited Actual	Audited Actual	Audited Actual	Forecast	
1.6.1 Costs related to technical capabilities in the smart meters or related communications infrastructure that exceed those specified in O.Reg 425/06													$ -
1.6.2 Costs for deployment of smart meters to customers other than residential and small general service													$ -
1.6.3 Costs for TOU rate implementation, CIS system upgrades, web presentation, integration with the MDM/R, etc.	Computer Software											4,500	$ 4,500
Total Capital Costs Beyond Minimum Functionality		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 4,500	$ 4,500
Total Smart Meter Capital Costs		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 234,065	$ 15,300	$ 249,365

Ontario Energy Board

Smart Meter Model for Electricity Distributors

2016 Filers

Distributors must enter all incremental costs related to their smart meter program and all revenues recovered to date in the applicable tabs except for those costs (and associated revenues) for which the Board has approved on a final basis, i.e. capital costs have been included in rate base and OM&A costs in revenue requirement.

For 2014, distributors that have completed their deployments by the end of 2013 are not expected to enter any capital costs. However, for OM&A, regardless of whether a distributor has deployments in 2014, distributors should enter the forecasted OM&A for 2014 for all smart meters in service.

	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	Total
2 OM&A Expenses												
2.1 ADVANCED METERING COMMUNICATION DEVICE (AMCD)	Audited Actual	Audited Actual	Audited Actual	Audited Actual	Audited Actual	Audited Actual	Audited Actual	Audited Actual	Audited Actual	Audited Actual	Forecast	
2.1.1 Maintenance *(may include meter reverification costs, etc.)*												$ -
2.1.2 Other *(please specify)* Communication costs from 3rd party service provider											28,200	$ 28,200
Total Incremental AMCD OM&A Costs	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 28,200	$ 28,200
2.2 ADVANCED METERING REGIONAL COLLECTOR (AMRC) (includes LAN)												
2.2.1 Maintenance												$ -
2.2.2 Other *(please specify)*												$ -
Total Incremental AMRC OM&A Costs	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2.3 ADVANCED METERING CONTROL COMPUTER (AMCC)												
2.3.1 Hardware Maintenance *(may include server support, etc.)*												$ -
2.3.2 Software Maintenance *(may include maintenance support, etc.)*												$ -
2.3.2 Other *(please specify)*												$ -
Total Incremental AMCC OM&A Costs	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2.4 WIDE AREA NETWORK (WAN)												
2.4.1 WAN Maintenance												$ -
2.4.2 Other *(please specify)*												$ -
Total Incremental AMRC OM&A Costs	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2.5 OTHER AMI OM&A COSTS RELATED TO MINIMUM FUNCTIONALITY												
2.5.1 Business Process Redesign												$ -
2.5.2 Customer Communication (may include project communication, etc.)												$ -
2.5.3 Program Management												$ -
2.5.4 Change Management (may include training, etc.)												$ -
2.5.5 Administration Costs												$ -
2.5.6 Other AMI Expenses *(please specify)*												$ -
Total Other AMI OM&A Costs Related to Minimum Functionality	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
TOTAL OM&A COSTS RELATED TO MINIMUM FUNCTIONALITY	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 28,200	$ 28,200
2.6 OM&A COSTS RELATED TO BEYOND MINIMUM FUNCTIONALITY *(Please provide a descriptive title and identify nature of beyond minimum functionality costs)*	Audited Actual	Audited Actual	Audited Actual	Audited Actual	Audited Actual	Audited Actual	Audited Actual	Audited Actual	Audited Actual	Audited Actual	Forecast	
2.6.1 Costs related to technical capabilities in the smart meters or related communications infrastructure that exceed those specified in O.Reg 425/06												$ -
2.6.2 Costs for deployment of smart meters to customers other than residential and small general service												$ -

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Smart Meter Model for Electricity Distributors

2016 Filers

Distributors must enter all incremental costs related to their smart meter program and all revenues recovered to date in the applicable tabs except for those costs (and associated revenues) for which the Board has approved on a final basis, i.e. capital costs have been included in rate base and OM&A costs in revenue requirement.

For 2014, distributors that have completed their deployments by the end of 2013 are not expected to enter any capital costs. However, for OM&A, regardless of whether a distributor has deployments in 2014, distributors should enter the forecasted OM&A for 2014 for all smart meters in service.

	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	Total
2.6.3 Costs for TOU rate implementation, CIS system upgrades, web presentation, integration with the MDM/R, etc.											16,100	$ 16,100
Total OM&A Costs Beyond Minimum Functionality	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 16,100	$ 16,100
Total Smart Meter OM&A Costs	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 44,300	$ 44,300

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Smart Meter Model for Electricity Distributors

2016 Filers

Distributors must enter all incremental costs related to their smart meter program and all revenues recovered to date in the applicable tabs except for those costs (and associated revenues) for which the Board has approved on a final basis, i.e. capital costs have been included in rate base and OM&A costs in revenue requirement.

For 2014, distributors that have completed their deployments by the end of 2013 are not expected to enter any capital costs. However, for OM&A, regardless of whether a distributor has deployments in 2014, distributors should enter the forecasted OM&A for 2014 for all smart meters in service.

3 Aggregate Smart Meter Costs by Category

		2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	Total
3.1	**Capital**												
3.1.1	Smart Meter	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 234,065	$ 10,800	$ 244,865
3.1.2	Computer Hardware	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
3.1.3	Computer Software	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 4,500	$ 4,500
3.1.4	Tools & Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
3.1.5	Other Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
3.1.6	Applications Software	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
3.1.7	**Total Capital Costs**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ 234,065**	**$ 15,300**	**$ 249,365**
3.2	**OM&A Costs**												
3.2.1	**Total OM&A Costs**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ 44,300**	**$ 44,300**

Ontario Energy Board

Smart Meter Model for Electricity Distributors

2016 Filers

	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016
Cost of Capital											
Capital Structure[1]											
Deemed Short-term Debt Capitalization										4.0%	4.0%
Deemed Long-term Debt Capitalization		0.0%	60.0%	60.0%	60.0%	60.0%	60.0%	60.0%	60.0%	56.0%	56.0%
Deemed Equity Capitalization	100.0%	100.0%	40.0%	40.0%	40.0%	40.0%	40.0%	40.0%	40.0%	40.0%	40.0%
Preferred Shares											
Total	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%
Cost of Capital Parameters											
Deemed Short-term Debt Rate										2.08%	2.08%
Long-term Debt Rate (actual/embedded/deemed)[2]	5.80%	5.80%								4.03%	4.03%
Target Return on Equity (ROE)	9.0%	9.00%								8.93%	8.93%
Return on Preferred Shares											
WACC	9.00%	9.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	5.91%	5.91%
Working Capital Allowance											
Working Capital Allowance Rate										13.0%	13.0%
(% of the sum of Cost of Power + controllable expenses)											
Taxes/PILs											
Aggregate Corporate Income Tax Rate	36.12%	36.12%	33.50%	33.00%	31.00%	28.25%	26.25%	26.50%	26.50%	26.50%	26.50%
Capital Tax (until July 1st, 2010)	0.30%	0.225%	0.225%	0.225%	0.075%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%

Ontario Energy Board

Smart Meter Model for Electricity Distributors

2016 Filers

	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016
Depreciation Rates											
(expressed as expected useful life in years)											
Smart Meters - years										15	15
- rate (%)	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	6.67%	6.67%
Computer Hardware - years											
- rate (%)	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Computer Software - years										10	10
- rate (%)	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	10.00%	10.00%
Tools & Equipment - years											
- rate (%)	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Other Equipment - years											
- rate (%)	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
CCA Rates											
Smart Meters - CCA Class										47	47
Smart Meters - CCA Rate										8%	8%
Computer Equipment - CCA Class										50	50
Computer Equipment - CCA Rate										55%	55%
General Equipment - CCA Class											
General Equipment - CCA Rate											
Applications Software - CCA Class											
Applications Software - CCA Rate											

Assumptions

1 *Planned smart meter installations occur evenly throughout the year.*
2 *Fiscal calendar year (January 1 to December 31) used.*
3 *Amortization is done on a striaght line basis and has the "half-year" rule applied.*

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Smart Meter Model for Electricity Distributors

2016 Filers

	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016
Net Fixed Assets - Smart Meters											
Gross Book Value											
Opening Balance		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 234,065
Capital Additions during year (from Smart Meter Costs)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 234,065	$ 10,800
Retirements/Removals (if applicable)											
Closing Balance	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 234,065	$ 244,865
Accumulated Depreciation											
Opening Balance		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-$ 7,802
Amortization expense during year	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-$ 7,802	-$ 15,964
Retirements/Removals (if applicable)											
Closing Balance	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-$ 7,802	-$ 23,767
Net Book Value											
Opening Balance	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 226,263
Closing Balance	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 226,263	$ 221,099
Average Net Book Value	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 113,131	$ 223,681
Net Fixed Assets - Computer Hardware											
Gross Book Value											
Opening Balance		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Capital Additions during year (from Smart Meter Costs)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Retirements/Removals (if applicable)											
Closing Balance	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Accumulated Depreciation											
Opening Balance	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Amortization expense during year	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Retirements/Removals (if applicable)											
Closing Balance	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Net Book Value											
Opening Balance	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Closing Balance	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Average Net Book Value	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -

Ontario Energy Board

Smart Meter Model for Electricity Distributors

2016 Filers

	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016
Net Fixed Assets - Computer Software (including Applications Software)											
Gross Book Value											
Opening Balance		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Capital Additions during year (from Smart Meter Costs)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 4,500
Retirements/Removals (if applicable)											
Closing Balance	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 4,500
Accumulated Depreciation											
Opening Balance	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Amortization expense during year	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-$ 225
Retirements/Removals (if applicable)											
Closing Balance	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-$ 225
Net Book Value											
Opening Balance	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Closing Balance	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 4,275
Average Net Book Value	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 2,138
Net Fixed Assets - Tools and Equipment											
Gross Book Value											
Opening Balance		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Capital Additions during year (from Smart Meter Costs)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Retirements/Removals (if applicable)											
Closing Balance	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Accumulated Depreciation											
Opening Balance	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Amortization expense during year	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Retirements/Removals (if applicable)											
Closing Balance	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Net Book Value											
Opening Balance	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Closing Balance	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Average Net Book Value	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Net Fixed Assets - Other Equipment											
Gross Book Value											
Opening Balance		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Capital Additions during year (from Smart Meter Costs)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Retirements/Removals (if applicable)											
Closing Balance	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Accumulated Depreciation											
Opening Balance	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Amortization expense during year	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Retirements/Removals (if applicable)											
Closing Balance	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Net Book Value											
Opening Balance	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Closing Balance	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Average Net Book Value	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -

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Smart Meter Model for Electricity Distributors

2016 Filers

	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016
Average Net Fixed Asset Values (from Sheet 4)											
Smart Meters	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 113,131	$ 223,681
Computer Hardware	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Computer Software	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 2,138
Tools & Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Other Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Net Fixed Assets	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ 113,131**	**$ 225,818**
Working Capital											
Operating Expenses (from Sheet 2)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 44,300
Working Capital Factor (from Sheet 3)	0%	0%	0%	0%	0%	0%	0%	0%	0%	13%	13%
Working Capital Allowance	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 5,759
Incremental Smart Meter Rate Base	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ 113,131**	**$ 231,577**
Return on Rate Base											
Capital Structure											
Deemed Short Term Debt	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 4,525	$ 9,263
Deemed Long Term Debt	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 63,354	$ 129,683
Equity	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 45,253	$ 92,631
Preferred Shares	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Capitalization	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 113,131	$ 231,577
Return on											
Deemed Short Term Debt	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 94	$ 193
Deemed Long Term Debt	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 2,553	$ 5,226
Equity	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 4,041	$ 8,272
Preferred Shares	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Return on Capital	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 6,688	$ 13,691
Operating Expenses	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 44,300
Amortization Expenses (from Sheet 4)											
Smart Meters	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 7,802	$ 15,964
Computer Hardware	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Computer Software	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 225
Tools & Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Other Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Amortization Expense in Year	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 7,802	$ 16,189
Incremental Revenue Requirement before Taxes/PILs	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 14,490	$ 74,180
Calculation of Taxable Income											
Incremental Operating Expenses	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 44,300
Amortization Expense	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 7,802	$ 16,189
Interest Expense	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 2,647	$ 5,419
Net Income for Taxes/PILs	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 4,041	$ 8,272
Grossed-up Taxes/PILs (from Sheet 7)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 894.37	$ 1,736.23
Revenue Requirement, including Grossed-up Taxes/PILs	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 15,385	$ 75,916

Ontario Energy Board

Smart Meter Model for Electricity Distributors

2016 Filers

For PILs Calculation

UCC - Smart Meters

	2006 Audited Actual	2007 Audited Actual	2008 Audited Actual	2009 Audited Actual	2010 Audited Actual	2011 Audited Actual	2012 Audited Actual	2013 Audited Actual	2014 Audited Actual	2015 Audited Actual	2016 Forecast
Opening UCC	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 224,702.40
Capital Additions	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 234,065.00	$ 10,800.00
Retirements/Removals (if applicable)											
UCC Before Half Year Rule	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 234,065.00	$ 235,502.40
Half Year Rule (1/2 Additions - Disposals)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 117,032.50	$ 5,400.00
Reduced UCC	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 117,032.50	$ 230,102.40
CCA Rate Class	0	0	0	0	0	0	0	0	0	47	47
CCA Rate	0%	0%	0%	0%	0%	0%	0%	0%	0%	8%	8%
CCA	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 9,362.60	$ 18,408.19
Closing UCC	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 224,702.40	$ 217,094.21

UCC - Computer Equipment

	2006 Audited Actual	2007 Audited Actual	2008 Audited Actual	2009 Audited Actual	2010 Audited Actual	2011 Audited Actual	2012 Audited Actual	2013 Audited Actual	2014 Audited Actual	2015 Audited Actual	2016 Forecast
Opening UCC	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Capital Additions Computer Hardware	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Capital Additions Computer Software	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 4,500.00
Retirements/Removals (if applicable)											
UCC Before Half Year Rule	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 4,500.00
Half Year Rule (1/2 Additions - Disposals)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 2,250.00
Reduced UCC	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 2,250.00
CCA Rate Class	0	0	0	0	0	0	0	0	0	50	50
CCA Rate	0%	0%	0%	0%	0%	0%	0%	0%	0%	55%	55%
CCA	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 1,237.50
Closing UCC	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 3,262.50

Ontario Energy Board

Smart Meter Model for Electricity Distributors

2016 Filers

For PILs Calculation

UCC - General Equipment

UCC - General Equipment	2006 Audited Actual	2007 Audited Actual	2008 Audited Actual	2009 Audited Actual	2010 Audited Actual	2011 Audited Actual	2012 Audited Actual	2013 Audited Actual	2014 Audited Actual	2015 Audited Actual	2016 Forecast
Opening UCC	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Capital Additions Tools & Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Capital Additions Other Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Retirements/Removals (if applicable)											
UCC Before Half Year Rule	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Half Year Rule (1/2 Additions - Disposals)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Reduced UCC	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
CCA Rate Class	0	0	0	0	0	0	0	0	0	0	0
CCA Rate	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
CCA	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Closing UCC	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -

UCC - Applications Software

UCC - Applications Software	2006 Audited Actual	2007 Audited Actual	2008 Audited Actual	2009 Audited Actual	2010 Audited Actual	2011 Audited Actual	2012 Audited Actual	2013 Audited Actual	2014 Audited Actual	2015 Audited Actual	2016 Forecast
Opening UCC	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Capital Additions Applications Software	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Retirements/Removals (if applicable)											
UCC Before Half Year Rule	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Half Year Rule (1/2 Additions - Disposals)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Reduced UCC	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
CCA Rate Class	0	0	0	0	0	0	0	0	0	0	0
CCA Rate	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
CCA	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Closing UCC	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -

Ontario Energy Board

Smart Meter Model for Electricity Distributors

2016 Filers

PILs Calculation

	2006 Audited Actual	2007 Audited Actual	2008 Audited Actual	2009 Audited Actual	2010 Audited Actual	2011 Audited Actual	2012 Audited Actual	2013 Audited Actual	2014 Audited Actual	2015 Audited Actual	2016 Forecast
INCOME TAX											
Net Income	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 4,041.05	$ 8,271.94
Amortization	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 7,802.17	$ 16,189.33
CCA - Smart Meters	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-$ 9,362.60	-$ 18,408.19
CCA - Computers	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-$ 1,237.50
CCA - Applications Software	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
CCA - Other Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Change in taxable income	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 2,480.62	$ 4,815.58
Tax Rate (from Sheet 3)	36.12%	36.12%	33.50%	33.00%	31.00%	28.25%	26.25%	26.50%	26.50%	26.50%	26.50%
Income Taxes Payable	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 657.36	$ 1,276.13
ONTARIO CAPITAL TAX											
Smart Meters	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 226,262.83	$ 221,098.50
Computer Hardware	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Computer Software (Including Application Software)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 4,275.00
Tools & Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Other Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Rate Base	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 226,262.83	$ 225,373.50
Less: Exemption											
Deemed Taxable Capital	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 226,262.83	$ 225,373.50
Ontario Capital Tax Rate (from Sheet 3)	0.300%	0.225%	0.225%	0.225%	0.075%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%
Net Amount (Taxable Capital x Rate)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Change in Income Taxes Payable	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 657.36	$ 1,276.13
Change in OCT	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
PILs	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 657.36	$ 1,276.13

Gross Up PILs

	2006 Audited Actual	2007 Audited Actual	2008 Audited Actual	2009 Audited Actual	2010 Audited Actual	2011 Audited Actual	2012 Audited Actual	2013 Audited Actual	2014 Audited Actual	2015 Audited Actual	2016 Forecast
Tax Rate	36.12%	36.12%	33.50%	33.00%	31.00%	28.25%	26.25%	26.50%	26.50%	26.50%	26.50%
Change in Income Taxes Payable	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 894.37	$ 1,736.23
Change in OCT	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
PILs	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 894.37	$ 1,736.23

Ontario Energy Board

Smart Meter Model for Electricity Distributors

2016 Filers

This worksheet calculates the funding adder revenues.

Account 1555 - Sub-account Funding Adder Revenues

Prescribed Interest Rates	Approved Deferral and Variance Accounts	CWIP	Date	Year	Quarter	Opening Balance (Principal)	Funding Adder Revenues	Interest Rate	Interest	Closing Balance	Annual amounts	Board Approved Smart Meter Funding Adder (from Tariff)
2006 Q1			Jan-06	2006	Q1	$ -		0.00%	$ -	$ -		
2006 Q2	4.14%	4.68%	Feb-06	2006	Q1	$ -		0.00%	$ -	$ -		
2006 Q3	4.59%	5.05%	Mar-06	2006	Q1	$ -		0.00%	$ -	$ -		
2006 Q4	4.59%	4.72%	Apr-06	2006	Q2	$ -		4.14%	$ -	$ -		
2007 Q1	4.59%	4.72%	May-06	2006	Q2	$ -		4.14%	$ -	$ -		
2007 Q2	4.59%	4.72%	Jun-06	2006	Q2	$ -		4.14%	$ -	$ -		
2007 Q3	4.59%	5.18%	Jul-06	2006	Q3	$ -		4.59%	$ -	$ -		
2007 Q4	5.14%	5.18%	Aug-06	2006	Q3	$ -		4.59%	$ -	$ -		
2008 Q1	5.14%	5.18%	Sep-06	2006	Q3	$ -		4.59%	$ -	$ -		
2008 Q2	4.08%	5.18%	Oct-06	2006	Q4	$ -		4.59%	$ -	$ -		
2008 Q3	3.35%	5.43%	Nov-06	2006	Q4	$ -		4.59%	$ -	$ -		
2008 Q4	3.35%	5.43%	Dec-06	2006	Q4	$ -		4.59%	$ -	$ -	$ -	
2009 Q1	2.45%	6.61%	Jan-07	2007	Q1	$ -		4.59%	$ -	$ -		
2009 Q2	1.00%	6.61%	Feb-07	2007	Q1	$ -		4.59%	$ -	$ -		
2009 Q3	0.55%	5.67%	Mar-07	2007	Q1	$ -		4.59%	$ -	$ -		
2009 Q4	0.55%	4.66%	Apr-07	2007	Q2	$ -		4.59%	$ -	$ -		
2010 Q1	0.55%	4.34%	May-07	2007	Q2	$ -		4.59%	$ -	$ -		
2010 Q2	0.55%	4.34%	Jun-07	2007	Q2	$ -		4.59%	$ -	$ -		
2010 Q3	0.89%	4.66%	Jul-07	2007	Q3	$ -		4.59%	$ -	$ -		
2010 Q4	1.20%	4.01%	Aug-07	2007	Q3	$ -		4.59%	$ -	$ -		
2011 Q1	1.47%	4.29%	Sep-07	2007	Q3	$ -		4.59%	$ -	$ -		
2011 Q2	1.47%	4.29%	Oct-07	2007	Q4	$ -		5.14%	$ -	$ -		
2011 Q3	1.47%	4.29%	Nov-07	2007	Q4	$ -		5.14%	$ -	$ -		
2011 Q4	1.47%	3.92%	Dec-07	2007	Q4	$ -		5.14%	$ -	$ -	$ -	
2012 Q1	1.47%	3.92%	Jan-08	2008	Q1	$ -		5.14%	$ -	$ -		
2012 Q2	1.47%	3.51%	Feb-08	2008	Q1	$ -		5.14%	$ -	$ -		
2012 Q3	1.47%	3.51%	Mar-08	2008	Q1	$ -		5.14%	$ -	$ -		
2012 Q4	1.47%	3.23%	Apr-08	2008	Q2	$ -		4.08%	$ -	$ -		
2013 Q1	1.47%	3.23%	May-08	2008	Q2	$ -		4.08%	$ -	$ -		
2013 Q2	1.47%	3.23%	Jun-08	2008	Q2	$ -		4.08%	$ -	$ -		
2013 Q3	1.47%	3.23%	Jul-08	2008	Q3	$ -		3.35%	$ -	$ -		
2013 Q4	1.47%	3.70%	Aug-08	2008	Q3	$ -		3.35%	$ -	$ -		

Ontario Energy Board

Smart Meter Model for Electricity Distributors

2016 Filers

This worksheet calculates the funding adder revenues.

Account 1555 - Sub-account Funding Adder Revenues

Prescribed Interest Rates	Approved Deferral and Variance Accounts	CWIP
2014 Q1	1.47%	3.70%
2014 Q2	1.47%	3.17%
2014 Q3	1.47%	3.17%
2014 Q4	1.47%	3.17%
2015 Q1	1.47%	2.89%
2015 Q2	1.10%	2.28%
2015 Q3	1.10%	2.55%
2015 Q4	1.10%	2.55%
2016 Q1	1.10%	2.55%
2016 Q2	1.10%	2.55%
2016 Q3	1.10%	2.55%
2016 Q4	1.10%	2.55%

Date	*Year*	*Quarter*	Opening Balance (Principal)	Funding Adder Revenues	Interest Rate	Interest	Closing Balance	Annual amounts	Board Approved Smart Meter Funding Adder (from Tariff)
Sep-08	*2008*	*Q3*	$ -		3.35%	$ -	$ -		
Oct-08	*2008*	*Q4*	$ -		3.35%	$ -	$ -		
Nov-08	*2008*	*Q4*	$ -		3.35%	$ -	$ -		
Dec-08	*2008*	*Q4*	$ -		3.35%	$ -	$ -	$ -	
Jan-09	*2009*	*Q1*	$ -		2.45%	$ -	$ -		
Feb-09	*2009*	*Q1*	$ -		2.45%	$ -	$ -		
Mar-09	*2009*	*Q1*	$ -		2.45%	$ -	$ -		
Apr-09	*2009*	*Q2*	$ -		1.00%	$ -	$ -		
May-09	*2009*	*Q2*	$ -		1.00%	$ -	$ -		
Jun-09	*2009*	*Q2*	$ -		1.00%	$ -	$ -		
Jul-09	*2009*	*Q3*	$ -		0.55%	$ -	$ -		
Aug-09	*2009*	*Q3*	$ -		0.55%	$ -	$ -		
Sep-09	*2009*	*Q3*	$ -		0.55%	$ -	$ -		
Oct-09	*2009*	*Q4*	$ -		0.55%	$ -	$ -		
Nov-09	*2009*	*Q4*	$ -		0.55%	$ -	$ -		
Dec-09	*2009*	*Q4*	$ -		0.55%	$ -	$ -	$ -	
Jan-10	*2010*	*Q1*	$ -		0.55%	$ -	$ -		
Feb-10	*2010*	*Q1*	$ -		0.55%	$ -	$ -		
Mar-10	*2010*	*Q1*	$ -		0.55%	$ -	$ -		
Apr-10	*2010*	*Q2*	$ -		0.55%	$ -	$ -		
May-10	*2010*	*Q2*	$ -		0.55%	$ -	$ -		
Jun-10	*2010*	*Q2*	$ -		0.55%	$ -	$ -		
Jul-10	*2010*	*Q3*	$ -		0.89%	$ -	$ -		
Aug-10	*2010*	*Q3*	$ -		0.89%	$ -	$ -		
Sep-10	*2010*	*Q3*	$ -		0.89%	$ -	$ -		
Oct-10	*2010*	*Q4*	$ -		1.20%	$ -	$ -		
Nov-10	*2010*	*Q4*	$ -		1.20%	$ -	$ -		
Dec-10	*2010*	*Q4*	$ -		1.20%	$ -	$ -	$ -	
Jan-11	*2011*	*Q1*	$ -		1.47%	$ -	$ -		
Feb-11	*2011*	*Q1*	$ -		1.47%	$ -	$ -		
Mar-11	*2011*	*Q1*	$ -		1.47%	$ -	$ -		
Apr-11	*2011*	*Q2*	$ -		1.47%	$ -	$ -		
May-11	*2011*	*Q2*	$ -		1.47%	$ -	$ -		

Ontario Energy Board

Smart Meter Model for Electricity Distributors

2016 Filers

This worksheet calculates the funding adder revenues.

Account 1555 - Sub-account Funding Adder Revenues

Prescribed Interest Rates	Approved Deferral and Variance Accounts	CWIP	Date	Year	Quarter	Opening Balance (Principal)	Funding Adder Revenues	Interest Rate	Interest	Closing Balance	Annual amounts	Board Approved Smart Meter Funding Adder (from Tariff)
			Jun-11	2011	Q2	$ -		1.47%	$ -	$ -		
			Jul-11	2011	Q3	$ -		1.47%	$ -	$ -		
			Aug-11	2011	Q3	$ -		1.47%	$ -	$ -		
			Sep-11	2011	Q3	$ -		1.47%	$ -	$ -		
			Oct-11	2011	Q4	$ -		1.47%	$ -	$ -		
			Nov-11	2011	Q4	$ -		1.47%	$ -	$ -		
			Dec-11	2011	Q4	$ -		1.47%	$ -	$ -	$ -	
			Jan-12	2012	Q1	$ -		1.47%	$ -	$ -		
			Feb-12	2012	Q1	$ -		1.47%	$ -	$ -		
			Mar-12	2012	Q1	$ -		1.47%	$ -	$ -		
			Apr-12	2012	Q2	$ -		1.47%	$ -	$ -		
			May-12	2012	Q2	$ -		1.47%	$ -	$ -		
			Jun-12	2012	Q2	$ -		1.47%	$ -	$ -		
			Jul-12	2012	Q3	$ -		1.47%	$ -	$ -		
			Aug-12	2012	Q3	$ -		1.47%	$ -	$ -		
			Sep-12	2012	Q3	$ -		1.47%	$ -	$ -		
			Oct-12	2012	Q4	$ -		1.47%	$ -	$ -		
			Nov-12	2012	Q4	$ -		1.47%	$ -	$ -		
			Dec-12	2012	Q4	$ -		1.47%	$ -	$ -	$ -	
			Jan-13	2013	Q1	$ -		1.47%	$ -	$ -		
			Feb-13	2013	Q1	$ -		1.47%	$ -	$ -		
			Mar-13	2013	Q1	$ -		1.47%	$ -	$ -		
			Apr-13	2013	Q2	$ -		1.47%	$ -	$ -		
			May-13	2013	Q2	$ -		1.47%	$ -	$ -		
			Jun-13	2013	Q2	$ -		1.47%	$ -	$ -		
			Jul-13	2013	Q3	$ -		1.47%	$ -	$ -		
			Aug-13	2013	Q3	$ -		1.47%	$ -	$ -		
			Sep-13	2013	Q3	$ -		1.47%	$ -	$ -		
			Oct-13	2013	Q4	$ -		1.47%	$ -	$ -		
			Nov-13	2013	Q4	$ -		1.47%	$ -	$ -		
			Dec-13	2013	Q4	$ -		1.47%	$ -	$ -	$ -	
			Jan-14	2014	Q1	$ -		1.47%	$ -	$ -		
			Feb-14	2014	Q1	$ -		1.47%	$ -	$ -		

Ontario Energy Board

Smart Meter Model for Electricity Distributors

2016 Filers

This worksheet calculates the funding adder revenues.

Account 1555 - Sub-account Funding Adder Revenues

Prescribed Interest Rates	Approved Deferral and Variance Accounts	CWIP	Date	*Year*	*Quarter*	Opening Balance (Principal)	Funding Adder Revenues	Interest Rate	Interest	Closing Balance	Annual amounts	Board Approved Smart Meter Funding Adder (from Tariff)
			Mar-14	*2014*	*Q1*	$ -		1.47%	$ -	$ -		
			Apr-14	*2014*	*Q2*	$ -		1.47%	$ -	$ -		
			May-14	*2014*	*Q2*	$ -		1.47%	$ -	$ -		
			Jun-14	*2014*	*Q2*	$ -		1.47%	$ -	$ -		
			Jul-14	*2014*	*Q3*	$ -		1.47%	$ -	$ -		
			Aug-14	*2014*	*Q3*	$ -		1.47%	$ -	$ -		
			Sep-14	*2014*	*Q3*	$ -		1.47%	$ -	$ -		
			Oct-14	*2014*	*Q4*	$ -		1.47%	$ -	$ -		
			Nov-14	*2014*	*Q4*	$ -		1.47%	$ -	$ -		
			Dec-14	*2014*	*Q4*	$ -		1.47%	$ -	$ -	$ -	
			Jan-15	*2015*	*Q1*	$ -		1.47%	$ -	$ -		
			Feb-15	*2015*	*Q1*	$ -		1.47%	$ -	$ -		
			Mar-15	*2015*	*Q1*	$ -		1.47%	$ -	$ -		
			Apr-15	*2015*	*Q2*	$ -		1.10%	$ -	$ -		
			May-15	*2015*	*Q2*	$ -		1.10%	$ -	$ -		
			Jun-15	*2015*	*Q2*	$ -		1.10%	$ -	$ -		
			Jul-15	*2015*	*Q3*	$ -		1.10%	$ -	$ -		
			Aug-15	*2015*	*Q3*	$ -		1.10%	$ -	$ -		
			Sep-15	*2015*	*Q3*	$ -		1.10%	$ -	$ -		
			Oct-15	*2015*	*Q4*	$ -		1.10%	$ -	$ -		
			Nov-15	*2015*	*Q4*	$ -		1.10%	$ -	$ -		
			Dec-15	*2015*	*Q4*	$ -		1.10%	$ -	$ -	$ -	
			Jan-16	*2016*	*Q1*	$ -		1.10%	$ -	$ -		
			Feb-16	*2016*	*Q1*	$ -		1.10%	$ -	$ -		
			Mar-16	*2016*	*Q1*	$ -		1.10%	$ -	$ -		
			Apr-16	*2016*	*Q2*	$ -		1.10%	$ -	$ -		
			May-16	*2016*	*Q2*	$ -		1.10%	$ -	$ -		
			Jun-16	*2016*	*Q2*	$ -		1.10%	$ -	$ -		
			Jul-16	*2016*	*Q3*	$ -		1.10%	$ -	$ -		
			Aug-16	*2016*	*Q3*	$ -		1.10%	$ -	$ -		
			Sep-16	*2016*	*Q3*	$ -		1.10%	$ -	$ -		
			Oct-16	*2016*	*Q4*	$ -		1.10%	$ -	$ -		
			Nov-16	*2016*	*Q4*	$ -		1.10%	$ -	$ -		

Ontario Energy Board

Smart Meter Model for Electricity Distributors

2016 Filers

This worksheet calculates the funding adder revenues.

Account 1555 - Sub-account Funding Adder Revenues

Prescribed Interest Rates	Approved Deferral and Variance Accounts	CWIP	Date	*Year*	*Quarter*	Opening Balance (Principal)	Funding Adder Revenues	Interest Rate	Interest	Closing Balance	Annual amounts	Board Approved Smart Meter Funding Adder (from Tariff)
			Dec-16	*2016*	*Q4*	$ -		1.10%	$ -	$ -	$ -	
			Total Funding Adder Revenues Collected				**$ -**		**$ -**	**$ -**	**$ -**	

Ontario Energy Board

Smart Meter Model for Electricity Distributors

2016 Filers

This worksheet calculates the interest on OM&A and amortization/depreciation expense, based on monthly data.

Account 1556 - Sub-accounts Operating Expenses, Amortization Expenses, Carrying Charges

Prescribed Interest Rates	Approved Deferral and Variance Accounts	CWIP	Date	Year	Quarter	Opening Balance (Principal)	OM&A Expenses	Amortization / Depreciation Expense	Closing Balance (Principal)	(Annual) Interest Rate	Interest (on opening balance)	Cumulative Interest
2006 Q1	0.00%	0.00%	Jan-06	2006	Q1	$ -			$ -	0.00%	$ -	$ -
2006 Q2	4.14%	4.68%	Feb-06	2006	Q1	$ -			$ -	0.00%	$ -	$ -
2006 Q3	4.59%	5.05%	Mar-06	2006	Q1	$ -			$ -	0.00%	$ -	$ -
2006 Q4	4.59%	4.72%	Apr-06	2006	Q2	$ -			$ -	4.14%	$ -	$ -
2007 Q1	4.59%	4.72%	May-06	2006	Q2	$ -			$ -	4.14%	$ -	$ -
2007 Q2	4.59%	4.72%	Jun-06	2006	Q2	$ -			$ -	4.14%	$ -	$ -
2007 Q3	4.59%	5.18%	Jul-06	2006	Q3	$ -			$ -	4.59%	$ -	$ -
2007 Q4	5.14%	5.18%	Aug-06	2006	Q3	$ -			$ -	4.59%	$ -	$ -
2008 Q1	5.14%	5.18%	Sep-06	2006	Q3	$ -			$ -	4.59%	$ -	$ -
2008 Q2	4.08%	5.18%	Oct-06	2006	Q4	$ -			$ -	4.59%	$ -	$ -
2008 Q3	3.35%	5.43%	Nov-06	2006	Q4	$ -			$ -	4.59%	$ -	$ -
2008 Q4	3.35%	5.43%	Dec-06	2006	Q4	$ -			$ -	4.59%	$ -	$ -
2009 Q1	2.45%	6.61%	Jan-07	2007	Q1	$ -			$ -	4.59%	$ -	$ -
2009 Q2	1.00%	6.61%	Feb-07	2007	Q1	$ -			$ -	4.59%	$ -	$ -
2009 Q3	0.55%	5.67%	Mar-07	2007	Q1	$ -			$ -	4.59%	$ -	$ -
2009 Q4	0.55%	4.66%	Apr-07	2007	Q2	$ -			$ -	4.59%	$ -	$ -
2010 Q1	0.55%	4.34%	May-07	2007	Q2	$ -			$ -	4.59%	$ -	$ -
2010 Q2	0.55%	4.34%	Jun-07	2007	Q2	$ -			$ -	4.59%	$ -	$ -
2010 Q3	0.89%	4.66%	Jul-07	2007	Q3	$ -			$ -	4.59%	$ -	$ -
2010 Q4	1.20%	4.01%	Aug-07	2007	Q3	$ -			$ -	4.59%	$ -	$ -
2011 Q1	1.47%	4.29%	Sep-07	2007	Q3	$ -			$ -	4.59%	$ -	$ -
2011 Q2	1.47%	4.29%	Oct-07	2007	Q4	$ -			$ -	5.14%	$ -	$ -
2011 Q3	1.47%	4.29%	Nov-07	2007	Q4	$ -			$ -	5.14%	$ -	$ -
2011 Q4	1.47%	3.92%	Dec-07	2007	Q4	$ -			$ -	5.14%	$ -	$ -
2012 Q1	1.47%	3.92%	Jan-08	2008	Q1	$ -			$ -	5.14%	$ -	$ -
2012 Q2	1.47%	3.51%	Feb-08	2008	Q1	$ -			$ -	5.14%	$ -	$ -
2012 Q3	1.47%	3.51%	Mar-08	2008	Q1	$ -			$ -	5.14%	$ -	$ -
2012 Q4	1.47%	3.23%	Apr-08	2008	Q2	$ -			$ -	4.08%	$ -	$ -
2013 Q1	1.47%	3.23%	May-08	2008	Q2	$ -			$ -	4.08%	$ -	$ -
2013 Q2	1.47%	3.23%	Jun-08	2008	Q2	$ -			$ -	4.08%	$ -	$ -
2013 Q3	1.47%	3.23%	Jul-08	2008	Q3	$ -			$ -	3.35%	$ -	$ -
2013 Q4	1.47%	3.70%	Aug-08	2008	Q3	$ -			$ -	3.35%	$ -	$ -
2014 Q1	1.47%	3.70%	Sep-08	2008	Q3	$ -			$ -	3.35%	$ -	$ -
2014 Q2	1.47%	3.17%	Oct-08	2008	Q4	$ -			$ -	3.35%	$ -	$ -
2014 Q3	1.47%	3.17%	Nov-08	2008	Q4	$ -			$ -	3.35%	$ -	$ -

Ontario Energy Board

Smart Meter Model for Electricity Distributors

2016 Filers

This worksheet calculates the interest on OM&A and amortization/depreciation expense, based on monthly data.

2014 Q4	1.47%	3.17%	Dec-08	*2008*	*Q4*	$	-			$	-	3.35%	$ -	$ -

Ontario Energy Board

Smart Meter Model for Electricity Distributors

2016 Filers

This worksheet calculates the interest on OM&A and amortization/depreciation expense, based on monthly data.

2015 Q1	1.47%	2.89%
2015 Q2	1.10%	2.28%
2015 Q3	1.10%	2.55%
2015 Q4	1.10%	2.55%
2016 Q1	1.10%	2.55%
2016 Q2	1.10%	2.55%
2016 Q3	1.10%	2.55%
2016 Q4	1.10%	2.55%

Jan-09	2009	Q1	$ -			$ -	2.45%	$ -	$ -
Feb-09	2009	Q1	$ -			$ -	2.45%	$ -	$ -
Mar-09	2009	Q1	$ -			$ -	2.45%	$ -	$ -
Apr-09	2009	Q2	$ -			$ -	1.00%	$ -	$ -
May-09	2009	Q2	$ -			$ -	1.00%	$ -	$ -
Jun-09	2009	Q2	$ -			$ -	1.00%	$ -	$ -
Jul-09	2009	Q3	$ -			$ -	0.55%	$ -	$ -
Aug-09	2009	Q3	$ -			$ -	0.55%	$ -	$ -
Sep-09	2009	Q3	$ -			$ -	0.55%	$ -	$ -
Oct-09	2009	Q4	$ -			$ -	0.55%	$ -	$ -
Nov-09	2009	Q4	$ -			$ -	0.55%	$ -	$ -
Dec-09	2009	Q4	$ -			$ -	0.55%	$ -	$ -
Jan-10	2010	Q1	$ -			$ -	0.55%	$ -	$ -
Feb-10	2010	Q1	$ -			$ -	0.55%	$ -	$ -
Mar-10	2010	Q1	$ -			$ -	0.55%	$ -	$ -
Apr-10	2010	Q2	$ -			$ -	0.55%	$ -	$ -
May-10	2010	Q2	$ -			$ -	0.55%	$ -	$ -
Jun-10	2010	Q2	$ -			$ -	0.55%	$ -	$ -
Jul-10	2010	Q3	$ -			$ -	0.89%	$ -	$ -
Aug-10	2010	Q3	$ -			$ -	0.89%	$ -	$ -
Sep-10	2010	Q3	$ -			$ -	0.89%	$ -	$ -
Oct-10	2010	Q4	$ -			$ -	1.20%	$ -	$ -
Nov-10	2010	Q4	$ -			$ -	1.20%	$ -	$ -
Dec-10	2010	Q4	$ -			$ -	1.20%	$ -	$ -
Jan-11	2011	Q1	$ -			$ -	1.47%	$ -	$ -
Feb-11	2011	Q1	$ -			$ -	1.47%	$ -	$ -
Mar-11	2011	Q1	$ -			$ -	1.47%	$ -	$ -
Apr-11	2011	Q2	$ -			$ -	1.47%	$ -	$ -
May-11	2011	Q2	$ -			$ -	1.47%	$ -	$ -
Jun-11	2011	Q2	$ -			$ -	1.47%	$ -	$ -
Jul-11	2011	Q3	$ -			$ -	1.47%	$ -	$ -
Aug-11	2011	Q3	$ -			$ -	1.47%	$ -	$ -
Sep-11	2011	Q3	$ -			$ -	1.47%	$ -	$ -
Oct-11	2011	Q4	$ -			$ -	1.47%	$ -	$ -
Nov-11	2011	Q4	$ -			$ -	1.47%	$ -	$ -
Dec-11	2011	Q4	$ -			$ -	1.47%	$ -	$ -
Jan-12	2012	Q1	$ -			$ -	1.47%	$ -	$ -
Feb-12	2012	Q1	$ -			$ -	1.47%	$ -	$ -
Mar-12	2012	Q1	$ -			$ -	1.47%	$ -	$ -
Apr-12	2012	Q2	$ -			$ -	1.47%	$ -	$ -
May-12	2012	Q2	$ -			$ -	1.47%	$ -	$ -
Jun-12	2012	Q2	$ -			$ -	1.47%	$ -	$ -
Jul-12	2012	Q3	$ -			$ -	1.47%	$ -	$ -
Aug-12	2012	Q3	$ -			$ -	1.47%	$ -	$ -

Ontario Energy Board

Smart Meter Model for Electricity Distributors

2016 Filers

This worksheet calculates the interest on OM&A and amortization/depreciation expense, based on monthly data.

Sep-12	2012	Q3	$ -			$ -	1.47%	$ -	$ -
Oct-12	2012	Q4	$ -			$ -	1.47%	$ -	$ -
Nov-12	2012	Q4	$ -			$ -	1.47%	$ -	$ -
Dec-12	2012	Q4	$ -			$ -	1.47%	$ -	$ -
Jan-13	2013	Q1	$ -			$ -	1.47%	$ -	$ -
Feb-13	2013	Q1	$ -			$ -	1.47%	$ -	$ -
Mar-13	2013	Q1	$ -			$ -	1.47%	$ -	$ -
Apr-13	2013	Q2	$ -			$ -	1.47%	$ -	$ -
May-13	2013	Q2	$ -			$ -	1.47%	$ -	$ -
Jun-13	2013	Q2	$ -			$ -	1.47%	$ -	$ -
Jul-13	2013	Q3	$ -			$ -	1.47%	$ -	$ -
Aug-13	2013	Q3	$ -			$ -	1.47%	$ -	$ -
Sep-13	2013	Q3	$ -			$ -	1.47%	$ -	$ -
Oct-13	2013	Q4	$ -			$ -	1.47%	$ -	$ -
Nov-13	2013	Q4	$ -			$ -	1.47%	$ -	$ -
Dec-13	2013	Q4	$ -			$ -	1.47%	$ -	$ -
Jan-14	2014	Q1	$ -			$ -	1.47%	$ -	$ -
Feb-14	2014	Q1	$ -			$ -	1.47%	$ -	$ -
Mar-14	2014	Q1	$ -			$ -	1.47%	$ -	$ -
Apr-14	2014	Q2	$ -			$ -	1.47%	$ -	$ -
May-14	2014	Q2	$ -			$ -	1.47%	$ -	$ -
Jun-14	2014	Q2	$ -			$ -	1.47%	$ -	$ -
Jul-14	2014	Q3	$ -			$ -	1.47%	$ -	$ -
Aug-14	2014	Q3	$ -			$ -	1.47%	$ -	$ -
Sep-14	2014	Q3	$ -			$ -	1.47%	$ -	$ -
Oct-14	2014	Q4	$ -			$ -	1.47%	$ -	$ -
Nov-14	2014	Q4	$ -			$ -	1.47%	$ -	$ -
Dec-14	2014	Q4	$ -			$ -	1.47%	$ -	$ -
Jan-15	2015	Q1	$ -			$ -	1.47%	$ -	$ -
Feb-15	2015	Q1	$ -			$ -	1.47%	$ -	$ -
Mar-15	2015	Q1	$ -			$ -	1.47%	$ -	$ -
Apr-15	2015	Q2	$ -			$ -	1.10%	$ -	$ -
May-15	2015	Q2	$ -			$ -	1.10%	$ -	$ -
Jun-15	2015	Q2	$ -			$ -	1.10%	$ -	$ -
Jul-15	2015	Q3	$ -			$ -	1.10%	$ -	$ -
Aug-15	2015	Q3	$ -			$ -	1.10%	$ -	$ -
Sep-15	2015	Q3	$ -			$ -	1.10%	$ -	$ -
Oct-15	2015	Q4	$ -			$ -	1.10%	$ -	$ -
Nov-15	2015	Q4	$ -			$ -	1.10%	$ -	$ -
Dec-15	2015	Q4	$ -			$ -	1.10%	$ -	$ -
Jan-16	2016	Q1	$ -			$ -	1.10%	$ -	$ -
Feb-16	2016	Q1	$ -			$ -	1.10%	$ -	$ -
Mar-16	2016	Q1	$ -			$ -	1.10%	$ -	$ -
Apr-16	2016	Q2	$ -			$ -	1.10%	$ -	$ -
May-16	2016	Q2	$ -			$ -	1.10%	$ -	$ -

Ontario Energy Board

Smart Meter Model for Electricity Distributors

2016 Filers

This worksheet calculates the interest on OM&A and amortization/depreciation expense, based on monthly data.

Jun-16	*2016*	*Q2*	$ -			$ -	1.10%	$ -	$ -
Jul-16	*2016*	*Q3*	$ -			$ -	1.10%	$ -	$ -
Aug-16	*2016*	*Q3*	$ -			$ -	1.10%	$ -	$ -
Sep-16	*2016*	*Q3*	$ -			$ -	1.10%	$ -	$ -
Oct-16	*2016*	*Q4*	$ -			$ -	1.10%	$ -	$ -
Nov-16	*2016*	*Q4*	$ -			$ -	1.10%	$ -	$ -
Dec-16	*2016*	*Q4*	$ -			$ -	1.10%	$ -	$ -
				$ -	$ -	$ -		$ -	$ -

Ontario Energy Board

Smart Meter Model for Electricity Distributors

2016 Filers

This worksheet calculates the interest on OM&A and amortization/depreciation expense, in the absence of monthly data.

Year	**OM&A (from Sheet 5)**	**Amortization Expense (from Sheet 5)**	**Cumulative OM&A and Amortization Expense**	**Average Cumulative OM&A and Amortization Expense**	**Average Annual Prescribed Interest Rate for Deferral and Variance Accounts (from Sheets 8A and 8B)**	**Simple Interest on OM&A and Amortization Expenses**
2006	$ -	$ -	$ -	$ -	4.37%	$ -
2007	$ -	$ -	$ -	$ -	4.73%	$ -
2008	$ -	$ -	$ -	$ -	3.98%	$ -
2009	$ -	$ -	$ -	$ -	1.14%	$ -
2010	$ -	$ -	$ -	$ -	0.80%	$ -
2011	$ -	$ -	$ -	$ -	1.47%	$ -
2012	$ -	$ -	$ -	$ -	1.47%	$ -
2013	$ -	$ -	$ -	$ -	1.47%	$ -
2014	$ -	$ -	$ -	$ -	1.47%	$ -
2015	$ -	$ 7,802.17	$ 7,802.17	$ 3,901.08	1.19%	$ 46.52
2016	$ 44,300.00	$ 16,189.33	$ 68,291.50	$ 38,046.83	1.10%	$ 418.52
Cumulative Interest to 2012						$ -
Cumulative Interest to 2013						$ -
Cumulative Interest to 2014						$ -
Cumulative Interest to 2015						$ 46.52
Cumulative Interest to 2016						$ 465.04

Ontario Energy Board

Smart Meter Model for Electricity Distributors

2016 Filers

This worksheet calculates the Smart Meter Disposition Rider and the Smart Meter Incremental Revenue Requirement Rate Rider, if applicable. This worksheet also calculates any new Smart Meter Funding Adder that a distributor may wish to request. However, please note that in many 2011 IRM decisions, the Board noted that current funding adders will cease on April 30, 2011 and that the Board's expectation is that distributors will file for a final review of prudence at the earliest opportunity. The Board also noted that the SMFA is a tool designed to provide advance funding and to mitigate the anticipated rate impact of smart meter costs when recovery of those costs is approved by the Board. The Board observed that the SMFA was not intended to be compensatory (return on and of capital) on a cumulative basis over the term the SMFA was in effect. The SMFA was initially designed to fund future investment, and not fully fund prior capital investment. Distributors that seek a new SMFA should provide evidence to support its proposal. This would include documentation of where the distributor is with respect to its smart meter deployment program, and reasons as to why the distributor's circumstances are such that continuation of the SMFA is warranted. Press the "UPDATE WORKSHEET" button after choosing the applicable adders/riders.

Check if applicable

	Smart Meter Funding Adder (SMFA)	
X	Smart Meter Disposition Rider (SMDR)	**The SMDR is calculated based on costs to December 31, 2015**
X	Smart Meter Incremental Revenue Requirement Rate Rider (SMIRR)	

The SMIRR is calculated based on the incremental revenue requirement associated with the recovery of capital related costs to December 31, 2016 and associated OM&A.

	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	Total
Deferred and forecasted Smart Meter Incremental Revenue Requirement (from Sheet 5)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 15,384.87	$ 75,916.40	$ 91,301.27
Interest on Deferred and forecasted OM&A and Amortization Expense (Sheet 8A/8B) (Check **one** of the boxes below)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 46.52		$ 46.52
[ ] Sheet 8A (Interest calculated on monthly balances)												
[X] Sheet 8B (Interest calculated on average annual balances)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 46.52	$ 418.52	$ 46.52
SMFA Revenues (from Sheet 8)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
SMFA Interest (from Sheet 8)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Net Deferred Revenue Requirement	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 15,431.39	$ 75,916.40	$ 91,347.79

Number of Metered Customers (average for 2016 test year) → 145

- Number of metered customers for which smart meter were deployed as part of program). Residential and GS < 50 kW customer classes and any other metered classes involved (e.g. GS 50 to 4999 kW for which interval meters were upgraded to utilize AMI and ODS assets)

Calculation of Smart Meter Disposition Rider (per metered customer per month)

Years for collection or refunding		5	
Deferred Incremental Revenue Requirement from 2006 to December 31, 2015 plus Interest on OM&A and Amortization		$ 15,431.39	
SMFA Revenues collected from 2006 to 2015 test year (inclusive) Plus Simple Interest on SMFA Revenues		$ -	
Net Deferred Revenue Requirement		$ 15,431.39	
SMDR	XXX 1, 2016 to XXX 30/31, 201X	$ 1.77	
Check: Forecasted SMDR Revenues		$ 15,399.00	**Match**

Calculation of Smart Meter Incremental Revenue Requirement Rate Rider (per metered customer per month)

Incremental Revenue Requirement for 2016	$ 75,916.40	
SMIRR	$ 43.63	
Check: Forecasted SMIRR Revenues	$ 75,916.20	**Match**

Ontario Energy Board

Smart Meter Model for Electricity Distributors

2016 Filers

This worksheet calculates the class-specific SMDRs according to accepted practice. A distributor may choose to use its own methodology, but should provide analogous support for its allocation and derivation of class-specific SMDRs and SMIRRs.

Class-specific SMDRs

Revenue Requirement for Historical Years	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	Total 2006 to 2015
Return on Capital	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 6,688.33	$ 6,688.33
Depreciation/Amortization expense and related interest	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 7,802.17	
	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 46.52	
	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 7,848.69	$ 7,848.69
Operating Expenses and related interest	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Revenue Requirement before Taxes/PILs											$ 14,537.02
Grossed-up Taxes/PILs	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 894.37	$ 894.37
Total Revenue Requirement plus interest on OM&A and depreciation expense											$ 15,431.39
											$ -

Explanation / Allocator	**Residential**	**GS < 50 kW**	**GS 50 to 4999 kW**	**Other (please specify)**	**Total**
Check Row if SMDR/SMIRR apply to class			X		1
	%	%	%	%	
Weighted Meter Cost - Capital					0%
Allocated per class	$ -	$ -	$ -	$ -	
Weighted Meter Cost - Capital	0%	0%	0%	0%	0%
Allocated per class	$ -	$ -	$ -	$ -	
	#	#	#	#	
Number of Smart Meters installed by Class					
Allocated per class	$ -	$ -	0	0	
	$ -	$ -	$ -	$ -	#######
Revenue Requirement before PILs	0.00%	0.00%	0.00%	0.00%	0%
	$ -	$ -	$ -	$ -	
	$ -	$ -	$ -	$ -	
Percentage of costs allocated to each class	0.00%	0.00%	0.00%	0.00%	
Percentage of costs for classes with SMDR/SMIRR	0.00%	0.00%	0.00%	0.00%	
	0.00%	0.00%	0.00%	0.00%	
	%	%	%	%	
SMFA Revenues directly attributable to class					0%
	0.00%	0.00%	0.00%	0.00%	0.00%
Residual SMFA Revenues (from other metered classes) attributed evenly	0.00%	0.00%	100.00%	0.00%	
Total	0.00%	0.00%	100.00%	0.00%	

	Total		Residential	GS < 50 kW	GS 50 to 4999 kW	Other (please specify)
SMFA Revenues plus interest expense	$ -		$ -	$ -	$ -	$ -
Net Deferred Revenue Requirement to be recovered via SMDR	$ 15,431.39		$ -	$ -	$ -	$ -
Average number of metered customers by class (2015), for customer classes with smart meters deployed		Average number of customers (2015), for applicable classes	0	0	0	0
Number of Years for SMDR recovery		years	0	0	0	0
Smart Meter Disposition Rider ($/month per metered customer in the customer class)						
Estimated SMDR Revenues	$ -		$ -	$ -	$ -	$ -
	$ 15,431.39					

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Smart Meter Model for Electricity Distributors

2016 Filers

This worksheet calculates the class-specific SMIRRs according to accepted practice. A distributor may choose to use its own methodology, but should provide analogous support for its allocation and derivation of class-specific SMDRs and SMIRRs.

Class-specific SMDRs

Revenue Requirement for 2016	**2016**	**Explanation / Allocator**	**Residential**	**GS < 50 kW**	**GS 50 to 4999 kW**	**Other (please specify)**	**Total**
		Check Row if SMDR/SMIRR apply to class			X		1
			%	%	%	%	
		Weighted Meter Cost - Capital	0.00%	0.00%	0.00%	0.00%	0%
Return on Capital	$ 13,690.84	Allocated per class	$ -	$ -	$ -	$ -	
Depreciation/Amortization expense		Weighted Meter Cost - Capital	0.00%	0.00%	0.00%	0.00%	0%
	$ 16,189.33	Allocated per class	$ -	$ -	$ -	$ -	
Operating Expenses	$ 44,300.00						
		Number of Smart Meters installed by Class	# -	# -	# -	# -	
	$ -	Allocated per class	$ -	$ -	$ -	$ -	
Revenue Requirement before Taxes/PILs	$ 74,180.18		$ -	$ -	$ -	$ -	########
		Revenue Requirement before PILs	0.00%	0.00%	0.00%	0.00%	0%
Grossed-up Taxes/PILs	$ 1,736.23		$ -	$ -	$ -	$ -	
Total Revenue Requirement for 2013	$ 75,916.40		$ -	$ -	$ -	$ -	
		Percentage of costs allocated to each clas	0.00%	0.00%	0.00%	0.00%	
	$ -	Percentage of costs for classes with	0.00%	0.00%	0.00%	0.00%	
		SMDR/SMIRR	0.00%	0.00%	0.00%	0.00%	
Average number of metered customers by class (2013)			-	-	-	-	
The SMIRR is recovered as an annualized rate until the effective date of the distributor's next rebased rates resulting from a cost of service application	1	year	1	1	1	1	
Smart Meter Incremental Revenue Requirement Rate Rider ($/month per metered customer in the customer class)							
Estimated SMIRR Revenues	$ -		$ -	$ -	$ -	$ -	
	-$ 75,916.40						

RETAIL SERVICE CHARGES

CNPI has a $0 balance in both OEB accounts 1518 RCVA Retail and 1548 RCVA STR. As stated in Exhibit 1, Tab 4, Schedule 7, due to the non-significant dollars associated with these types of revenues and expenditures, CNPI has not followed the Article 490, Retail Services and Settlement Variances of the Accounting Procedures Handbook for Account 1518 and Account 1548. For example, OEB 4082 had $21,397 and OEB 4084 had $579 in credit revenues recorded in 2015 Actuals (Appendix 2-H in Exhibit 3, Tab 4, Schedule 3), while offsetting debit costs totaling $10,887 were recorded within OEB 5340. The net credit of $11,089 remained in the Profit and Loss Statement for 2015.

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DISPOSITION OF DEFERRAL AND VARIANCE ACCOUNT

Allocators

The allocators used can be found in the continuity schedules provided in Tab 1, Schedule 2 of this Exhibit.

New Rate Riders

CNPI has assumed a one year disposition period for balances noted below. See Table 9.5.1.1 below for consolidated rate rider calculations for disposition of the sum of Group 1 balances (excluding $RSVA_{POWER}$), Group 2 and Other balances, as well as the rate rider calculations for disposition of the Group 1 $RSVA_{GA}$ balance. Per Board direction, CNPI has used the number of customers for the Residential rate class to calculate monthly rate riders for disposition of certain amounts allocated to that class. Also, as discussed in Tab 1 of this Exhibit. CNPI has quantified an amount to be allocated to the two Class A customers in its service territories relating to the $RSVA_{GA}$ balance and CNPI has calculated a rate rider to be assessed on those customer bills. The detailed calculation worksheets can be found in Schedule 2 of Tab 1 of this Exhibit.

Table 9.5.1.1 Calculation of Rate Riders

Please indicate the Rate Rider Recovery Period (in years) 1

Rate Rider Calculation for Deferral / Variance Accounts Balances (excluding Global Adj.) - A

1550, 1551, 1584, 1586, 1595

Rate Class (Enter Rate Classes in cells below)	Units	kW / kWh / # of Customers	Allocated Balance (excluding 1589)	Rate Rider for Deferral/Variance Accounts	
RESIDENTIAL SERVICE CLASSIFICATION	kWh	198,077,803	-$ 51,895	- 0.0003	$/kWh
GENERAL SERVICE LESS THAN 50 KW SERVICE CLASSIFICATION	kWh	67,907,332	-$ 16,948	- 0.0002	$/kWh
GENERAL SERVICE 50 TO 4,999 KW SERVICE CLASSIFICATION	kW	593,383	-$ 50,234	- 0.0847	$/kW
EMBEDDED DISTRIBUTOR	kW	13,717	-$ 1,460	- 0.1064	$/kW
UNMETERED SCATTERED LOAD SERVICE CLASSIFICATION	kWh	1,462,761	-$ 416	- 0.0003	$/kWh
SENTINEL LIGHTING SERVICE CLASSIFICATION	kW	1,916	-$ 179	- 0.0934	$/kW
STREET LIGHTING SERVICE CLASSIFICATION	kW	8,591	-$ 792	- 0.0921	$/kW
Total			**-$ 121,924**		

Rate Rider Calculation for Deferral / Variance Accounts Balances (excluding Global Adj.) - NON-WMP - B

1580 and 1588

Rate Class (Enter Rate Classes in cells below)	Units	kW / kWh / # of Customers	Allocated Balance (excluding 1589)	Rate Rider for Deferral/Variance Accounts	
RESIDENTIAL SERVICE CLASSIFICATION	kWh	198,077,803	-$ 620,868	- 0.0031	$/kWh
GENERAL SERVICE LESS THAN 50 KW SERVICE CLASSIFICATION	kWh	67,907,332	-$ 212,853	- 0.0031	$/kWh
GENERAL SERVICE 50 TO 4,999 KW SERVICE CLASSIFICATION	kW	593,383	-$ 579,701	- 0.9769	$/kW
EMBEDDED DISTRIBUTOR	kW	13,717	-$ 16,078	- 1.1721	$/kW
UNMETERED SCATTERED LOAD SERVICE CLASSIFICATION	kWh	1,462,761	-$ 4,585	- 0.0031	$/kWh
SENTINEL LIGHTING SERVICE CLASSIFICATION	kW	1,916	-$ 1,972	- 1.0290	$/kW
STREET LIGHTING SERVICE CLASSIFICATION	kW	8,591	-$ 8,719	- 1.0149	$/kW
Total			**-$ 1,444,776**		

Table 9.5.1.1 Calculation of Rate Riders

Please indicate the Rate Rider Recovery Period (in years) 1

Rate Rider Calculation for Group 2 Accounts - C

Rate Class (Enter Rate Classes in cells below)	Units	kW / kWh / # of Customers	Allocated Balance (excluding 1589)	Rate Rider for Deferral/Variance Accounts	
RESIDENTIAL SERVICE CLASSIFICATION	# of Customers	26,074	-$ 16,698	- 0.0534	per customer per month
GENERAL SERVICE LESS THAN 50 KW SERVICE CLASSIFICATION	kWh	67,907,332	-$ 5,725	- 0.0001	$/kWh
GENERAL SERVICE 50 TO 4,999 KW SERVICE CLASSIFICATION	kW	593,383	-$ 15,591	- 0.0263	$/kW
EMBEDDED DISTRIBUTOR	kW	13,717	-$ 432	- 0.0315	$/kW
UNMETERED SCATTERED LOAD SERVICE CLASSIFICATION	kWh	1,462,761	-$ 123	- 0.0001	$/kWh
SENTINEL LIGHTING SERVICE CLASSIFICATION	kW	1,916	-$ 53	- 0.0277	$/kW
STREET LIGHTING SERVICE CLASSIFICATION	kW	8,591	-$ 234	- 0.0273	$/kW
Total			**-$ 38,857**		

Rate Rider Calculation for 1592 Account - D

Rate Class (Enter Rate Classes in cells below)	Units	kW / kWh / # of Customers	Allocated Balance (excluding 1589)	Rate Rider for Deferral/Variance Accounts	
RESIDENTIAL SERVICE CLASSIFICATION	# of Customers	26,074	-$ 30,940	- 0.0989	per customer per month
GENERAL SERVICE LESS THAN 50 KW SERVICE CLASSIFICATION	kWh	67,907,332	-$ 10,607	- 0.0002	$/kWh
GENERAL SERVICE 50 TO 4,999 KW SERVICE CLASSIFICATION	kW	593,383	-$ 28,888	- 0.0487	$/kW
EMBEDDED DISTRIBUTOR	kW	13,717	-$ 801	- 0.0584	$/kW
UNMETERED SCATTERED LOAD SERVICE CLASSIFICATION	kWh	1,462,761	-$ 228	- 0.0002	$/kWh
SENTINEL LIGHTING SERVICE CLASSIFICATION	kW	1,916	-$ 98	- 0.0513	$/kW
STREET LIGHTING SERVICE CLASSIFICATION	kW	8,591	-$ 434	- 0.0506	$/kW
Total			**-$ 71,997**		

Addition Of A + B + C + D Calculations per above = New Consolidated Rate Rider

Rate Class (Enter Rate Classes in cells below)	Units	kW / kWh / # of Customers	Allocated Balance (excluding 1589)	Rate Rider for Deferral/Variance Accounts	
RESIDENTIAL SERVICE CLASSIFICATION	kWh	198,077,803	-$ 672,763	- 0.0034	$/kWh
RESIDENTIAL SERVICE CLASSIFICATION	# of Customers	26,074	-$ 47,638	- 0.1523	per customer per month
GENERAL SERVICE LESS THAN 50 KW SERVICE CLASSIFICATION	kWh	67,907,332	-$ 246,133	- 0.0036	$/kWh
GENERAL SERVICE 50 TO 4,999 KW SERVICE CLASSIFICATION	kW	593,383	-$ 674,415	- 1.1366	$/kW
EMBEDDED DISTRIBUTOR	kW	13,717	-$ 18,771	- 1.3685	$/kW
UNMETERED SCATTERED LOAD SERVICE CLASSIFICATION	kWh	1,462,761	-$ 5,353	- 0.0037	$/kWh
SENTINEL LIGHTING SERVICE CLASSIFICATION	kW	1,916	-$ 2,302	- 1.2014	$/kW
STREET LIGHTING SERVICE CLASSIFICATION	kW	8,591	-$ 10,179	- 1.1849	$/kW
Total			**-$ 1,677,554**		

Rate Rider Calculation for RSVA - Power - Global Adjustment

Balance of Account 1589 Allocated to Non-WMPs

Rate Class (Enter Rate Classes in cells below)	Units	kW / kWh / # of Customers	Allocated Balance (excluding 1589)	Rate Rider for Deferral/Variance Accounts	
RESIDENTIAL SERVICE CLASSIFICATION	kWh	13,481,818	$ 91,931	0.0068	per customer per month
GENERAL SERVICE LESS THAN 50 KW SERVICE CLASSIFICATION	kWh	10,889,999	$ 74,257	0.0068	$/kWh
GENERAL SERVICE 50 TO 4,999 KW SERVICE CLASSIFICATION	kW	450,793	$ 868,642	1.9269	$/kW
EMBEDDED DISTRIBUTOR	kW	13,717	$ 34,977	2.5499	$/kW
UNMETERED SCATTERED LOAD SERVICE CLASSIFICATION	kWh	6,052	$ 41	0.0068	$/kWh
SENTINEL LIGHTING SERVICE CLASSIFICATION	kW	-	$ -	-	$/kW
STREET LIGHTING SERVICE CLASSIFICATION	kW	8,406	$ 18,559	2.2078	$/kW
Total			**$ 1,088,407**		

Rate Rider Calculation for RSVA - Power - Global Adjustment - Class A Non-WMP Customers

Balance of Account 1589 allocated to Class A Non-WMP Customers

Rate Class (Enter Rate Classes in cells below)	Units	kW / kWh / # of Customers	Allocated Balance (excluding 1589)	Rate Rider for Deferral/Variance Accounts	
RESIDENTIAL SERVICE CLASSIFICATION	kWh	-	$ -	-	per customer per month
GENERAL SERVICE LESS THAN 50 KW SERVICE CLASSIFICATION	kWh	-	$ -	-	$/kWh
GENERAL SERVICE 50 TO 4,999 KW SERVICE CLASSIFICATION	kW	88,966	$ 94,644	1.0638	$/kW
EMBEDDED DISTRIBUTOR	kW	-	$ -	-	$/kW
UNMETERED SCATTERED LOAD SERVICE CLASSIFICATION	kWh	-	$ -	-	$/kWh
SENTINEL LIGHTING SERVICE CLASSIFICATION	kW	-	$ -	-	$/kW
STREET LIGHTING SERVICE CLASSIFICATION	kW	-	$ -	-	$/kW
Total			**$ 94,644**		

1	**GRAND TOTAL OF ALLOCATED BALANCES**			**-$ 494,502**		agrees to continuity schedule

For the projected debit balance of $255,421 in OEB 1568, LRAM Variance Account, refer to Tab 6 of this Exhibit for the rate rider calculations. Stranded MIST meter rate rider calculations have been discussed in Exhibit 2, Tab 1, Schedule 8, while the MIST capital cost recovery rate rider has been calculated in Tab 3 of this Exhibit.

Harmonization of Existing Rate Riders

As mentioned in Tab 1 of this Exhibit, CNPI is proposing harmonization of its DVA balances and any rate rider calculations for the three service territories effective January 1, 2017. CNPI is proposing to harmonize an existing rate rider with an expiry date of December 31, 2017 that was approved as part of CNPI's 2016 IRM (EB-2015-0058). See table 9.5.1.2 below for calculation of harmonized rate riders to be applied starting January 1, 2017 for the remaining one year of the two year rate riders that were effective January 1, 2016.

Table 9.5.1.2 Calculation of Harmonization of Existing Rate Riders

ORIGINAL COLLECTION PERIOD (# OF MONTHS)	24									
	Unit	Total Metered kWh	Metered kW or kVA	Total Metered kWh less WMP consumption	Total Metered kW less WMP consumption	Allocation of Group 1 Account Balances to All Classes	Deferral/Variance Account Rate Rider	Balance in Account 1589 to Non-Class A Customers	Metered kWh or kW for Non-RPP Customers (less WMP if applicable)	Global Adjustment Rate Rider
PER 2016 IRM										
FORT ERIE A										
RESIDENTIAL SERVICE CLASSIFICATION	kWh	111,371,333	-	111,371,333	-	(87,748)	(0.0004)	56,828	7,602,793	0.0037
GENERAL SERVICE LESS THAN 50 KW SERVICE CLASSIFICATION	kWh	32,703,664	-	32,703,664	-	(37,328)	(0.0006)	39,076	5,227,812	0.0037
GENERAL SERVICE 50 TO 4,999 KW SERVICE CLASSIFICATION	kW	102,618,770	279,552	102,618,770	279,552	(93,823)	(0.1678)	684,046	242,502	1.4104
UNMETERED SCATTERED LOAD SERVICE CLASSIFICATION	kWh	783,108	-	783,108	-	(835)	(0.0005)	17	2,247	0.0038
SENTINEL LIGHTING SERVICE CLASSIFICATION	kW	649,772	1,980	649,772	1,980	(522)	(0.1318)	0	0	0.0000
STREET LIGHTING SERVICE CLASSIFICATION	kW	2,170,391	6,662	2,170,391	6,662	(2,027)	(0.1521)	15,862	6,459	1.2279
						(222,283)		795,829		
PORT COLBORNE B										
RESIDENTIAL SERVICE CLASSIFICATION	kWh	62,544,703	-	62,544,703	-	(158,403)	(0.0013)	17,032	4,395,746	0.0019
GENERAL SERVICE LESS THAN 50 KW SERVICE CLASSIFICATION	kWh	24,123,513	-	24,123,513	-	(60,976)	(0.0013)	17,396	4,489,837	0.0019
GENERAL SERVICE 50 TO 4,999 KW SERVICE CLASSIFICATION	kW	113,386,236	352,778	113,386,236	352,778	(286,025)	(0.4054)	409,335	328,820	0.6224
UNMETERED SCATTERED LOAD SERVICE CLASSIFICATION	kWh	561,391	-	561,391	-	(1,410)	(0.0013)	15	3,971	0.0019
STANDBY POWER SERVICE CLASSIFICATION	kW	-	-	-	-	0	#DIV/0!	0	0	0.0000
SENTINEL LIGHTING SERVICE CLASSIFICATION	kW	13,840	43	13,840	43	(33)	(0.3837)	0	0	0.0000
STREET LIGHTING SERVICE CLASSIFICATION	kW	1,617,772	4,953	1,617,772	4,953	(4,028)	(0.4066)	6,201	4,872	0.6364
						(510,875)		449,979		
EASTERN ONTARIO POWER C										
RESIDENTIAL SERVICE CLASSIFICATION	kWh	28,579,742	-	28,579,742	-	(154,894)	(0.0027)	37,592	1,783,981	0.0105
GENERAL SERVICE LESS THAN 50 KW SERVICE CLASSIFICATION	kWh	12,307,839	-	12,307,839	-	(66,728)	(0.0027)	28,852	1,369,228	0.0105
GENERAL SERVICE 50 TO 4,999 KW SERVICE CLASSIFICATION	kW	16,518,390	44,989	16,518,390	44,989	(89,532)	(0.9950)	302,363	39,229	3.8538
UNMETERED SCATTERED LOAD SERVICE CLASSIFICATION	kWh	158,504	-	158,504	-	(859)	(0.0027)	0	0	0.0000
SENTINEL LIGHTING SERVICE CLASSIFICATION	kW	33,674	102	33,674	102	(180)	(0.8824)	0	0	0.0000
STREET LIGHTING SERVICE CLASSIFICATION	kW	548,610	1,670	548,610	1,670	(2,974)	(0.8904)	10,979	1,586	3.4612
						(315,167)		379,786		
CNPI TOTAL (PER 2016 IRM) = A + B + C										
RESIDENTIAL SERVICE CLASSIFICATION	kWh	202,495,778	-	202,495,778	-	(401,045)	(0.0010)	111,452	13,782,520	0.0040
GENERAL SERVICE LESS THAN 50 KW SERVICE CLASSIFICATION	kWh	69,135,016	-	69,135,016	-	(165,032)	(0.0012)	85,324	11,086,877	0.0038
GENERAL SERVICE 50 TO 4,999 KW SERVICE CLASSIFICATION	kW	232,523,396	677,319	232,523,396	677,319	(469,380)	(0.3465)	1,395,744	610,551	1.1430
UNMETERED SCATTERED LOAD SERVICE CLASSIFICATION	kWh	1,503,003	-	1,503,003	-	(3,104)	(0.0010)	32	6,218	0.0026
SENTINEL LIGHTING SERVICE CLASSIFICATION	kW	697,286	2,125	697,286	2,125	(735)	(0.1729)	0	0	0.0000
STREET LIGHTING SERVICE CLASSIFICATION	kW	4,336,773	13,285	4,336,773	13,285	(9,029)	(0.3398)	33,042	12,917	1.2790
						(1,048,325)		1,625,594		
CNPI REVISED TOTAL (FOR 2017 COS) - TAKE 1/2 OF 2016 IRM APPROVED $ AMOUNT AND APPLY 2017 BILLING DETERMINANTS										
RESIDENTIAL SERVICE CLASSIFICATION	kWh	198,077,803		198,077,803	-	(200,523)	(0.0010)	55,726	13,481,818	0.0041
GENERAL SERVICE LESS THAN 50 KW SERVICE CLASSIFICATION	kWh	67,907,332		67,907,332	-	(82,516)	(0.0012)	42,662	10,889,999	0.0039
GENERAL SERVICE 50 TO 4,999 KW SERVICE CLASSIFICATION	kW	184,944,203	593,383	184,944,203	593,383	(229,387)	(0.3866)	677,264	450,793	1.5024
EMBEDDED DISTRIBUTOR	kW	5,129,448	13,717	5,129,448	13,717	(5,303)	(0.3866)	20,608	13,717	1.5024
UNMETERED SCATTERED LOAD SERVICE CLASSIFICATION	kWh	1,462,761		1,462,761	-	(1,552)	(0.0011)	16	6,052	0.0026
SENTINEL LIGHTING SERVICE CLASSIFICATION	kW	629,014	1,916	629,014	1,916	(368)	(0.1918)	0	0	0.0000
STREET LIGHTING SERVICE CLASSIFICATION	kW	2,781,556	8,591	2,781,556	8,591	(4,515)	(0.5255)	16,521	8,406	1.9654
						(524,163)		812,797		

DISPOSITION OF LRAMVA

CNPI retained Burman Energy Consultants to calculate the value of its LRAMVA claim. The report, at Appendix A, of this schedule, finds that "Canadian Niagara Power's LRAMVA value for the period of 2013 through 2014 to be a total of $252,641.96". With the addition of carrying charges the total amount for disposition in Account 1568 is $255,421. Please see the Burman report for details on lost revenue by rate class.

CNPI proposes to dispose of this balance in 1-year through a rate rider in the 2017 rate year, the calculation of which is provided in Table 9.7.1.1 below:

Table 9.7.1.1

Rate Rider Calculation for Accounts 1568

Please indicate the Rate Rider Recovery Period (in years) | **1**

Rate Class (Enter Rate Classes in cells below)	Units	kW / kWh / # of Customers	Balance of Account 1568	Rate Rider for Account 1568	
RESIDENTIAL SERVICE CLASSIFICATION	kWh	198,077,803	$ 67,839	**0.0003**	***$/kWh***
GENERAL SERVICE LESS THAN 50 KW	kWh	67,907,332	$ 130,786	**0.0019**	***$/kWh***
GENERAL SERVICE 50 TO 4,999 KW SE	kW	593,383	$ 56,796	**0.0957**	**$/kW**

CNPI proposes to amend the application with a claim for 2015 when the information becomes available. The proposed rate riders will be updated at that time.

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Appendix A
Burman Energy Report

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BURMAN ENERGY
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CANADIAN NIAGARA POWER INC.

LRAMVA SUPPORT

October 20, 2015

PREPARED BY: JARRETT URECH, CET

REVIEWED BY: BART BURMAN, MBA BA.SC. P.ENG

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Executive Summary

Burman Energy Consultants group has calculated Canadian Niagara Power's LRAMVA value for the period of 2013 through 2014 to be a total of $252,641.96 . Canadian Niagara Power did not forecast any CDM savings as a component of their 2013 approved cost of service application.

Introduction

Since the completion of Third Tranche CDM programs and reporting, LDCs across Ontario have sought to recover revenues lost to successful CDM programming. The mechanism that enables this recovery is the Lost Revenue Adjustment Mechanism (LRAM).

On April 26, 2012, new Board-issued CDM Guidelines were enacted that provide updated LRAM details. For CDM programs delivered within the 2011 to 2014 term, the Board established the Lost Revenue Adjustment Variance Account (LRAMVA). This account captures the variance between the Board-approved CDM forecast and the actual CDM results.

The variance calculated from this comparison must be recorded in separate sub-accounts per the applicable customer rate classes.

LDCs must apply for the disposition of the balance in the LRAMVA as part of their cost of service (COS) applications or on an annual basis, as part of their IRM rate applications.

The LRAM mechanism determines persistent CDM impacts realized after 2010, for those distributors whose load forecast has not been updated.

Canadian Niagara Power Inc. has requested Burman Energy Consultants Group to propose fees to assist in the calculation of LRAMVA and LRAM amounts to be included in its filing with the OEB.

Terms

Term	Description
Persistence	CDM savings during the subsequent years after the first year savings.
Extension Framework	The conservation period between 2011 and 2015
Conservation First Framework	The conservation period between 2015 and 2020.
CDM	Conservation and Demand Management
LRAM	Lost Revenue Adjustment Mechanism
LRAMVA	Lost Revenue Adjustment Mechanism Variance Account
COS	Cost of Service
IRM	Incentive Regulation Model

About Burman Energy Consultants Group Inc.

Burman Energy is a vibrant, growing company, and has provided energy conservation program planning, administration and delivery services since the inception of OPA programs in 2007. Serving 39 CDM client LDCs in Ontario, we currently have over 30 staff with specialized expertise in CDM planning and program administration, marketing, technical review and support, quality control, and contractor management. In 2013, Bart Burman, President of Burman Energy, was inducted into Worldwide Who's Who for Excellence in Energy Consulting, and in 2014/15, Bart sits as chair of the EDA's Commercial Steering Committee.

Burman Energy has adopted a new structured approach to fulfilling its contracted obligations with our numerous and diverse LDC CDM clients. Recognizing, in practice, the significant peaks and valleys associated with sustaining a consistent high standard of service on time delivery, our organizational focus continues to be to ensure adequate and flexible staff resources. Cross training in several different aspects of program execution has historically enabled us to make this approach extremely effective in meeting our clients' timeliness criteria.

As a process centric organization, our starting point is to use stock, off the shelf, proven process designs, and adjust collaboratively, in discussion with you, our client, for your specific LDC protocols as required. From this common basis for understanding, identification of roles and associated accountabilities can be easily determined. In addition, this work, up front, provides for a more solid basis upon which to convey pricing options.

Burman Energy Consultants Group Inc. is headquartered at

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Scope of Work

Specifically, Burman Energy will perform the following in its work undertaking:

1) Collect and outline savings for the following data sets:
   i. CDM Results for programs as applicable for the LRAMVA period.
   ii. Forecasted savings for Conservation and Demand Management programs (Last Approved).
2) Collect additional data as outlined:
   i. LDC volumetric distribution rates for LRAMVA years.
   ii. Completed Retrofit projects for years for which retrofit savings are reported.
3) Calculate by initiative and year the lost revenue values.
4) Calculate the currently recovered lost revenue from the load forecast.
5) Outline the net LRAMVA values by year and overall.
6) Provide summary report with supporting information.

Lost Revenue Adjustment Mechanism History

From 2005 to the end of 2010, distributors delivered CDM programs either through approved distribution rate funding by way of the third installment of their incremental market adjusted revenue requirement ("MARR"), or through contracts with the OPA. Some distributors received incremental distribution rate funding separate from MARR. To promote the participation in and the delivery of CDM programs by distributors, the Board made available an LRAM regardless of whether the CDM programs were funded by the OPA or through distribution rates.

Lost Revenue Adjustment Mechanism Outline

In preparation of this document, Burman Energy performed this analysis in compliance with Guidelines for Electricity Distributor Conservation and Demand Management EB-2012-0003 with specific reference to the following:

> 13.6 LRAM & Shared Savings Mechanism for Pre-CDM Code Activities
>
> The Board notes that the Filing Requirements for Transmission and Distribution Applications state the following:
>
> > Distributors intending to file an LRAM or SSM application for CDM Programs funded through distribution rates, or an LRAM application for CDM Programs funded by the OPA between 2005 and 2010, shall do so as part of their 2012 rate application filings, either cost-of-service or IRM. If a distributor does not file for the recovery of LRAM or SSM amounts in its 2012 rate application, it will forego the opportunity to recover LRAM or SSM for this legacy period of CDM activity.
>
> The 2008 CDM Guidelines state as follows: "lost revenues are only accruable until new rates (based on a new revenue requirement and load forecast) are set by the Board, as the CDM savings would be assumed to be incorporated in the load forecast at that time". The intent of the LRAM in the 2008 CDM Guidelines was to keep electricity distributors revenue neutral for CDM activities implemented by the distributor during the years in which its rates were set using the incentive regulation mechanism, and that future LRAM claims should be unnecessary once a distributor rebases and updates its load forecast.
>
> The Board therefore expects that LRAM for pre-2011 CDM activities should be completed with the 2012 rate applications, outside of persisting historical CDM impacts realized after 2010 for those distributors whose load forecast has not been updated as part of a cost of service application.

This summary is extracted from the "Guidelines for Electricity Distributor Conservation and Demand Management" (EB-2012-0003). This document can be found at:
http://www.ontarioenergyboard.ca/oeb/_Documents/EB-2012-0003/CDM_Guidelines_Electricity_Distributor.pdf

Lost Revenue Adjustment Mechanism Variance Account Outline

With specific reference to the following:

13.2 LRAM Mechanism for 2011- 2014

The Board will adopt an approach for LRAM for the 2011-2014 CDM period that is similar to that adopted in relation to natural gas distributor DSM activities. The Board will authorize the establishment of an LRAM variance account ("LRAMVA") to capture, at the customer rate-class level, the difference between the following:

i. The results of actual, verified impacts of authorized CDM activities undertaken by electricity distributors between 2011-2014 for both Board-Approved CDM programs and OPA-Contracted Province-Wide CDM programs in relation to activities undertaken by the distributor and/or delivered for the distributor by a third party under contract (in the distributor's franchise area); and

ii. The level of CDM program activities included in the distributor's load forecast (i.e. the level embedded into rates).

Distributors will generally be expected to include a CDM component in their load forecast in cost of service proceedings to ensure that its customers are realizing the true effects of conservation at the earliest date possible date and to mitigate the variance between forecasted revenue losses and actual revenue losses. If the distributor has included a CDM load reduction in its distribution rates, the amount of the forecast that was adjusted for CDM at the rate class level would be compared to the actual DCM results verified by an independent third part for each year of the CDM program (i.e., 2011 to 2014) in accordance with the OPA's EM&V Protocols as set out in Section 6.1 of the CDM Code. The variance calculated from this comparison result in a credit or a debit to the ratepayers at the customer rate class level in the LRAMVA. The LRAM amount is determined by applying, by customer class, the distributor's Board-approved variable distribution charge applicable to the class to the volumetric variance (positive or negative) described in the paragraph above. The calculated lost revenues will be recorded in the LRAMVA. Distributors will be expected to report the balance in the LRAMVA as part of the reporting and record-keeping requirements on an annual basis.

This summary is extracted from the "Guidelines for Electricity Distributor Conservation and Demand Management" (EB-2012-0003). This document can be found at:
http://www.ontarioenergyboard.ca/oeb/_Documents/EB-2012-0003/CDM_Guidelines_Electricity_Distributor.pdf

Summary Of Lost Revenue Adjustments

LRAMVA Summary

Burman Energy Consultants Group Inc. (Burman Energy) has prepared the following LRAMVA tables, representing the variance amount to be recorded in the LRAM Variance Account. The amount is the calculated result of the lost revenues by customer class based on the volumetric impact of the load reductions arising from the CDM measures implemented, multiplied by Canadian Niagara Power's Board-approved variable distribution changes applicable to the customer rate class in which the volumetric variance occurred. The calculations provided by Burman Energy do not include carrying charges or adjustments based on CDM reductions as included in any CDM Load reduction forecast.

Results Year	Lost Revenue Adjustment Mechanism Year					
	2013	2014				
2014	$ -	$ 42,050				
2013	$ 40,393	$ 40,213				
2012	$ 24,892	$ 24,640				
2011	$ 40,427	$ 40,027				
Total	$ 105,712	$ 146,930				
Forecast	$ -	$ -				
Net	$ 105,712	$ 146,930				
Variance			$ 252,642			

Reference Material

The following OPA documents were used to prepare the LRAMVA calculations:

i. [2006-2014]_RATES_DATABASE_FROM TARIFFS.xls
ii. 2011-2014 Canadian Niagara Power Results with Persistence.xls
iii. Canadian Niagara Power [2013-2014] Retrofit Project Lists

Methodology

Burman Energy would like to present a summary of the methodology used to calculate the LRAMVA figures in this report for the purposes of auditing.

Burman Energy collects the following information as the sources for the values calculated in this report:

- Rate Database documents from the Ontario Energy Board (OEB) website for all years that are being calculated.
- Final CDM results and their persistence into future years received directly from the IESO or from the Local Distributor.
- Retrofit & High Performance New Construction (HPNC) project data with kW, kWh and Rate Class information for each project.
- The forecasted CDM results from the distributors most recently approved Cost of Service application (COS).

Burman Energy takes the results of each initiative where the savings for the LRAMVA report period are not equal to zero and enters the figures into the report. The values entered into the report are organized by results year, rate class, and then initiative.

Results from 2013
Residential
HVAC Incentives
RESIDIENTIAL TOTAL
GS Less Than 50 kW
Retrofit
GS LESS THAN 50 KW TOTAL
GS Greater Than 50 kW
Retrofit
GS GREATER THAN 50 KW TOTAL
Large Use
Retrofit
LARGE USE TOTAL
RESULTS FROM 2013 TOTAL

The results for Retrofit and HPNC items are initially collected for all rate classes then using verified project savings the result savings are divided into the appropriate rate classes.

Year	Application Type	LDC	Demand Savings	Energy Savings	Rate Class	Sector
2014	Retrofit	Canadian Ni	9.53	68,384	GS>50	Industrial
2014	Retrofit	Canadian Ni	3.58	2,502	GS<50	Business
2014	Retrofit	Canadian Ni	49.534627	279445.35	Large Use	LargeUse

kW	GS>50	15.22%	GS<50	5.71%	Large Use	79.07%
kWh		19.52%		0.71%		79.77%

Volumetric distribution rates are derived by using the rate database provided on the OEB website directly as they appear. These volumetric distribution rates are collected for each rate class for the years during the LRAMVA reporting period and one year prior are entered into the report along with their effective date. Burman Energy uses the effective date to create a weighted volumetric rate for each of the calendar years (Jan1st through Dec 31st) years in the reporting period. A summary of the calculation is presented below:

$$Weighted\ Rate\ (kWh) = \left(\frac{Old\ Rate}{\left(\frac{Months\ at\ Old\ Rate}{12}\right)}\right) + \left(\frac{New\ Rate}{\left(\frac{Months\ at\ New\ Rate}{12}\right)}\right)$$

The weighted volumetric rate is multiplied by the savings metric selected by rate class (the Residential and GS<50 metric is kWh and the GS>50 and Large Use metric is kW). The resulting figure is then subject to global modifiers based on initiative (eg. Demand Response 3 is taken at a factor of 0% due to the type of savings it provides).

$$LRAM(kW) = Weighted\ Rate * Modifier\%_{If\ Applicable} * \left((kW_{Per\ Month} * Months\ at\ old\ Rate) + (kW_{Per\ Month} * Months\ at\ New\ Rate)\right)$$

$$LRAM\ (kWh) = Weighted\ Rate * Modifier\%_{If\ Applicable} * kWh_{Annual}$$

The totals are outlined at the bottom of each section with a summary by rate class presented near the bottom of the table for comparison to the forecasted figures.

If the distributor had forecasted CDM savings Burman Energy takes the values and applies same methods outlined for the savings results to calculate the total lost revenue that has already been recovered for the reporting period.

The recovered lost revenue is subtracted from the calculated LRAM resulting in the net figures or Variance. These figures are outlined by reporting period year and as an overall.

Supporting Attachments

Canadian Niagara Power Inc. LRAMVA CALCULATIONS
OPA Conservation & Demand Management Programs
Initiative Results at End-User Level

	2012	2013				2014			
Initiative Name	**Volumetric Rate**	**Net Summer Peak Demand Savings (kW)**	**Net Energy Savings (kWh)**	**Distribution Volumetric Rate (Effective Date: Jan 1)**	**2013 LRAMVA**	**Net Summer Peak Demand Savings (kW)**	**Net Energy Savings (kWh)**	**Distribution Volumetric Rate (Effective Date: Jan 1)**	**2014 LRAMVA**
LRAM CDM Results and Persistence									
Results from 2014									
Residential									
Appliance Exchange	0.017467			0.021433		15.13	26,969.11	0.021	$ 566.35
Appliance Retirement	0.017467			0.021433		3.51	24,563.49	0.021	$ 515.83
HAP	0.017467			0.021433		12.16	83,903.70	0.021	$ 1,761.98
HVAC	0.017467			0.021433		169.16	317,113.91	0.021	$ 6,659.39
RESIDENTIAL TOTAL		**0.00**	**0**		**$ -**	**199.96**	**452,550**		**$ 9,503.55**
GS Less Than 50 kW									
Audit Funding	0.0199			0.022967		1.65	8,186.30	0.022967	$ 188.01
New Construction	0.0199			0.022967		133.51	441,275.21	0.022967	$ 10,134.62
Retrofit	0.0199			0.022967		26.28	146,911.92	0.022967	$ 3,374.08
SBL	0.0199			0.022967		85.88	307,005.44	0.022967	$ 7,050.89
GS LESS THAN 50 KW TOTAL		**0.00**	**0**		**$ -**	**247.33**	**903,379**		**$ 20,747.60**
GS Greater Than 50 kW									
Retrofit	5.761133			6.4157		85.26	502,094.46	6.4808	$ 6,630.78
High Performance New Construction	5.761133			6.4157		66.45	183,094.00	6.4808	$ 5,167.79
GS GREATER THAN 50 KW TOTAL		**0.00**	**0**		**$ -**	**151.71**	**685,188**		**$ 11,798.57**
RESULTS FROM 2014 TOTAL		**0.00**	**0**		**$ -**	**598.99**	**2,041,118**		**$ 42,049.73**
Results from 2013									
Residential									
Annual Coupons	0.017467	2.64	39,385.98	0.021433	$ 844.17	2.64	39,385.98	0.021	$ 827.11
Appliance Exchange	0.017467	12.64	22,535.83	0.021433	$ 483.02	12.64	22,535.83	0.021	$ 473.25
Appliance Retirement	0.017467	3.58	23,949.59	0.021433	$ 513.32	3.58	23,949.59	0.021	$ 502.94
Bi-Annual Retailer Events	0.017467	6.05	87,789.62	0.021433	$ 1,881.62	6.05	87,789.62	0.021	$ 1,843.58
Home Assistance Program	0.017467	8.92	128,967.63	0.021433	$ 2,764.21	8.79	126,391.89	0.021	$ 2,654.23
HVAC	0.017467	135.45	239,553.40	0.021433	$ 5,134.43	135.45	239,553.40	0.021	$ 5,030.62
peaksaverPLUS	0.017467	49.22	6.09	0.021433	$ 0.13	0.00	0.00	0.021	$ -
RESIDENTIAL TOTAL		**218.49**	**542,188**		**$ 11,620.90**	**169.13**	**539,606**		**$ 11,331.73**
GS Less Than 50 kW									
peaksaverPLUS	0.0199	0.64	0.00	0.022967	$ -	0.00	0.00	0.022967	$ -
Retrofit	0.0199	50.93	295,052.53	0.022967	$ 6,776.37	50.91	295,005.71	0.022967	$ 6,775.30
Small Business Lighting	0.0199	130.87	469,871.70	0.022967	$ 10,791.39	130.87	469,871.70	0.022967	$ 10,791.39
GS LESS THAN 50 KW TOTAL		**182.44**	**764,924**		**$ 17,567.76**	**181.79**	**764,877**		**$ 17,566.68**
GS Greater Than 50 kW									
DR-3	5.761133	1,147.41	26,127.11	6.4157	$ -	0.00	0.00	6.4808	$ -
Retrofit	5.761133	145.54	847,978.13	6.4157	$ 11,204.55	145.49	847,843.55	6.4808	$ 11,314.91
GS GREATER THAN 50 KW TOTAL		**1,292.94**	**874,105**		**$ 11,204.55**	**145.49**	**847,844**		**$ 11,314.91**
RESULTS FROM 2013 TOTAL		**1,693.87**	**2,181,218**		**$ 40,393.21**	**496.41**	**2,152,327**		**$ 40,213.32**
Results from 2012									
Residential									
Appliance Exchange	0.017467	5.50	9,652.62	0.021433	$ 206.89	5.50	9,652.62	0.021	$ 202.70
Appliance Retirement	0.017467	5.72	38,455.01	0.021433	$ 824.22	5.72	38,455.01	0.021	$ 807.56
Bi-Annual Retailer Event	0.017467	7.56	136,855.34	0.021433	$ 2,933.27	7.56	136,855.34	0.021	$ 2,873.96
Conservation Instant Coupon Booklet	0.017467	1.18	7,144.86	0.021433	$ 153.14	1.18	7,144.86	0.021	$ 150.04
Home Assistance Program	0.017467	0.63	4,982.79	0.021433	$ 106.80	0.63	4,982.79	0.021	$ 104.64
HVAC	0.017467	1.76	3,282.39	0.021433	$ 70.35	1.76	3,282.39	0.021	$ 68.93
HVAC Incentives	0.017467	64.23	111,564.36	0.021433	$ 2,391.20	64.23	111,564.36	0.021	$ 2,342.85
RESIDENTIAL TOTAL		**86.58**	**311,937**		**$ 6,685.86**	**86.58**	**311,937**		**$ 6,550.68**
GS Less Than 50 kW									
Direct Install Lighting	0.0199	132.75	492,449.34	0.022967	$ 11,309.92	131.65	487,178.07	0.022967	$ 11,188.86
Energy Audit	0.0199	5.18	25,176.25	0.022967	$ 578.21	5.18	25,176.25	0.022967	$ 578.21
Retrofit	0.0199	47.20	218,081.47	0.022967	$ 5,008.60	47.17	218,010.46	0.022967	$ 5,006.97
Small Business Lighting	0.0199	1.54	8,717.71	0.022967	$ 200.22	1.50	8,480.85	0.022967	$ 194.78
GS LESS THAN 50 KW TOTAL		**186.67**	**744,425**		**$ 17,096.96**	**185.50**	**738,846**		**$ 16,968.82**
GS Greater Than 50 kW									
Retrofit	5.761133	13.83	169,207.33	6.4157	$ 1,065.06	13.83	169,152.24	6.4808	$ 1,075.19
High Performance New Construction	5.761133	0.58	559.44	6.4157	$ 44.46	0.58	559.44	6.4808	$ 44.91
GS GREATER THAN 50 KW TOTAL		**14.41**	**169,767**		**$ 1,109.52**	**14.40**	**169,712**		**$ 1,120.09**
RESULTS FROM 2012 TOTAL		**287.66**	**1,226,129**		**$ 24,892.33**	**286.48**	**1,220,495**		**$ 24,639.60**
Results from 2011									
Residential									
Appliance Exchange	0.017467	6.36	7,024.50	0.021433	$ 150.56	1.50	2,674.64	0.021	$ 56.17
Appliance Retirement	0.017467	13.21	93,880.72	0.021433	$ 2,012.18	13.09	93,778.81	0.021	$ 1,969.35
Bi-Annual Retailer Event	0.017467	9.14	161,328.25	0.021433	$ 3,457.80	9.14	161,328.25	0.021	$ 3,387.89
Conservation Instant Coupon Booklet	0.017467	6.09	98,867.10	0.021433	$ 2,119.05	6.09	98,867.10	0.021	$ 2,076.21
HVAC Incentives	0.017467	78.18	145,617.26	0.021433	$ 3,121.06	78.18	145,617.26	0.021	$ 3,057.96
RESIDENTIAL TOTAL		**112.99**	**506,718**		**$ 10,860.65**	**108.01**	**502,266**		**$ 10,547.59**
GS Less Than 50 kW									
Direct Install Lighting	0.0199	15.39	37,405.51	0.022967	$ 859.08	13.00	29,313.43	0.022967	$ 673.23
Energy Audit	0.0199	31.06	151,057.53	0.022967	$ 3,469.29	31.06	151,057.53	0.022967	$ 3,469.29
Retrofit	0.0199	126.57	673,683.83	0.022967	$ 15,472.27	126.57	673,683.83	0.022967	$ 15,472.27
GS LESS THAN 50 KW TOTAL		**173.03**	**862,147**		**$ 19,800.64**	**170.63**	**854,055**		**$ 19,614.79**
GS Greater Than 50 kW									
Retrofit	5.761133	126.57	673,683.83	6.4157	$ 9,744.48	126.57	673,683.83	6.4808	$ 9,843.36
High Performance New Construction	5.761133	0.27	1,402.47	6.4157	$ 21.02	0.27	1,402.47	6.4808	$ 21.24
GS GREATER THAN 50 KW TOTAL		**126.84**	**675,086**		**$ 9,765.50**	**126.84**	**675,086**		**$ 9,864.59**
RESULTS FROM 2011 TOTAL		**412.86**	**2,043,951**		**$ 40,426.79**	**405.48**	**2,031,407**		**$ 40,026.97**
Summary By Rate Class									
Residential	0.017467	418.06	1,360,843.33	0.021433	$ 29,167.41	563.68	1,806,359.93	0.021	$ 37,933.56
General Service Less Than 50 kW	0.0199	542.14	2,371,495.89	0.022967	$ 54,465.36	785.24	3,261,156.70	0.022967	$ 74,897.90
General Service Greater Than 50 kW	5.761133	1,434.20	1,718,958.32	6.4157	$ 22,079.57	438.45	2,377,829.99	6.4808	$ 34,098.17
SUMMARY BY RATE CLASS TOTAL		**2,394.39**	**5,451,298**		**$ 105,712.34**	**1,787.37**	**7,445,347**		**$ 146,929.62**
LRAM CDM RESULTS AND PERSISTENCE TOTAL		**2,394.39**	**5,451,297.53**		**$ 105,712.34**	**1,787.37**	**7,445,346.62**		**$ 146,929.62**
Lost Revenue Adjustment Mechanism Variance									$252,641.96

METHODOLOGY

All results are at the end-user level (not including transmission and distribution losses)

EQUATIONS:

PRESCRIPTIVE MEASURES/PROJECTS:

Gross Savings = Activity * Per Unit Assumption

Net Savings = Gross Savings * Net-to-Gross Ratio

All savings are annualized (i.e. the savings are the same regardless of time of year a project was completed or measure installed)

ENGINEERED/CUSTOM PROJECTS:

Gross Savings = Reported Savings * Realization Rate

Net Savings = Gross Savings * Net-to-Gross Ratio

All savings are annualized (i.e. the savings are the same regardless of time of year a project was completed or measure installed)

DEMAND RESPONSE:

Peak Demand: Gross Savings = Net Savings = contracted MW at contributor level * Provincial contracted to ex ante ratio

Energy: Gross Savings = Net Savings = provincial ex post energy savings * LDC proportion of total provincial contracted MW

All savings are annualized (i.e. the savings are the same regardless of the time of year a participant began offering DR)

#	Initiative	Attributing Savings to LDCs	Savings 'start' Date	Calculating Resource Savings
Consumer Program				
1	Appliance Retirement	Includes both retail and home pickup stream; Retail stream allocated based on average of residential throughput; Home pickup stream directly attributed by postal code or customer selection	Savings are considered to begin in the year the appliance is picked up.	**Peak demand and energy savings** are determined using the verified measure level per unit assumption multiplied by the uptake in the market (gross) taking into account net-to-gross factors such as free-ridership and spillover (net) at the measure level.
2	Appliance Exchange	When postal code information is provided by customer, results are directly attributed to the LDC. When postal code is not available, results allocated based on average of residential throughput	Savings are considered to begin in the year that the exchange event occurred	
3	HVAC Incentives	Results directly attributed to LDC based on customer postal code	Savings are considered to begin in the year that the installation occurred	
4	Conservation Instant Coupon Booklet	LDC-coded coupons directly attributed to LDC; Otherwise results are allocated based on average of residential throughput	Savings are considered to begin in the year in which the coupon was redeemed.	**Peak demand and energy savings** are determined using the verified measure level per unit assumption multiplied by the uptake in the market (gross) taking into account net-to-gross factors such as free-ridership and spillover (net) at the measure level. Reported results are presented with verified per unit assumptions and net-to-gross ratio from Bi-Annual Retailer Event and Conservation Instant Coupon Booklet initiatives.
5	Bi-Annual Retailer Event	Results are allocated based on average of residential throughput	Savings are considered to begin in the year in which the event occurs.	
6	Retailer Co-op	When postal code information is provided by the customer, results are directly attributed. If postal code information is not available, results are allocated based on average of residential throughput.	Savings are considered to begin in the year of the home visit and installation date.	**Peak demand and energy savings** are determined using the verified measure level per unit assumption multiplied by the uptake in the market (gross) taking into account net-to-gross factors such as free-ridership and spillover (net) at the measure level. Reported results are presented with verified per unit assumptions and net-to-gross ratio from Bi-Annual Retailer Event and Conservation Instant Coupon Booklet initiatives.
7	Residential Demand Response	Results are directly attributed to LDC based on data provided to OPA through project completion reports and continuing participant lists	Savings are considered to begin in the year the device was installed and/or when a customer signed a ***peaksaver*** PLUS™ participant agreement.	**Peak demand savings** are based on an ex ante estimate assuming a 1 in 10 weather year and represents the "insurance value" of the initiative. **Energy savings** are based on an ex post estimate which reflects the savings that occurred as a result of activations in the year and accounts for any “snapback” in energy consumption experienced after the event. Savings are assumed to **persist** for only 1 year, reflecting that savings will only occur if the resource is activated.

#	Initiative	Attributing Savings to LDCs	Savings 'start' Date	Calculating Resource Savings
8	Residential New Construction	Results are directly attributed to LDC based on LDC identified in application in the saveONenergy CRM system; Reported results are presented with forecast assumptions as per the business case.	Savings are considered to begin in the year of the project completion date.	**Peak demand and energy savings** are determined using a measure level per unit assumption multiplied by the uptake in the market (gross) taking into account net-to-gross factors such as free-ridership and spillover (net) at the measure level.
Business Program				
9	Efficiency: Equipment Replacement	Results are directly attributed to LDC based on LDC identified at the facility level in the saveONenergy CRM; Projects in the Application Status: "Post-Stage Submission" are included (excluding "Payment denied by LDC"); Please see "Reference Tables" tab for Building type to Sector mapping	Savings are considered to begin in the year of the actual project completion date on the iCON CRM system.	**Peak demand and energy savings** are determined by the total savings for a given project as reported in the iCON CRM system (reported). A realization rate is applied to the reported savings to ensure that these savings align with EM&V protocols and reflect the savings that were actually realized (i.e. how many light bulbs were actually installed vs. what was reported) (gross). Net savings takes into account net-to-gross factors such as free-ridership and spillover (net). Both realization rate and net-to-gross ratios can differ for energy and demand savings and depend on the mix of projects within an LDC territory (i.e. lighting or non-lighting project, engineered/custom/prescriptive track).
10	Direct Installed Lighting	Results are directly attributed to LDC based on the LDC specified on the work order	Savings are considered to begin in the year of the actual project completion date.	**Peak demand and energy savings** are determined using the verified measure level per unit assumptions multiplied by the uptake of each measure accounting for the realization rate for both peak demand and energy to reflect the savings that were actually realized (i.e. how many light bulbs were actually installed vs. what was reported) (gross). Net savings take into account net-to-gross factors such as free-ridership and spillover for both peak demand and energy savings at the program level (net).
11	Existing Building Commissioning Incentive	Results are directly attributed to LDC based on LDC identified in the application.	Savings are considered to begin in the year of the actual project completion date.	**Peak demand and energy savings** are determined by the total savings for a given project as reported (reported). A realization rate is applied to the reported savings to ensure that these savings align with EM&V protocols and reflect the savings that were actually realized (i.e. how many light bulbs were actually installed vs. what was reported) (gross). Net savings takes into account net-to-gross factors such as free-ridership and spillover (net).
12	New Construction and Major Renovation Incentive	Results are directly attributed to LDC based on LDC identified in the application; Initiative was not evaluated, reported results are presented with reported assumptions.	Savings are considered to begin in the year of the actual project completion date.	
13	Energy Audit	Projects are directly attributed to LDC based on LDC identified in the application	Savings are considered to begin in the year of the audit date.	**Peak demand and energy savings** are determined by the total savings resulting from an audit as reported (reported). A realization rate is applied to the reported savings to ensure that these savings align with EM&V protocols and reflect the savings that were actually realized (i.e. how many light bulbs were actually installed vs. what was reported) (gross). Net savings takes into account net-to-gross factors such as free-ridership and spillover (net)

#	Initiative	Attributing Savings to LDCs	Savings 'start' Date	Calculating Resource Savings
14	Commercial Demand Response (part of the Residential program schedule)	Results are directly attributed to LDC based on data provided to OPA through project completion reports and continuing participant lists	Savings are considered to begin in the year the device was installed and/or when a customer signed a ***peaksaver*** PLUS™ participant agreement.	**Peak demand savings** are based on an ex ante estimate assuming a 1 in 10 weather year and represents the "insurance value" of the initiative. **Energy savings** are based on an ex post estimate which reflects the savings that occurred as a result of activations in the year. Savings are assumed to **persist** for only 1 year, reflecting that savings will only occur if the resource is activated.
15	Demand Response 3 (part of the Industrial program schedule)	Results are attributed to LDCs based on the total contracted megawatts at the contributor level as of December 31st of the relevant year, applying the provincial ex ante to contracted ratio (ex ante estimate/contracted megawatts); Ex post energy savings are attributed to the LDC based on their proportion of the total contracted megawatts at the contributor level.	Savings are considered to begin in the year in which the contributor signed up to participate in demand response.	**Peak demand savings** are ex ante estimates based on the load reduction capability that can be expected for the purposes of planning. The ex ante estimates factor in both scheduled non-performances (i.e. maintenance) and historical performance. **Energy savings** are based on an ex post estimate which reflects the savings that actually occurred as a results of activations in the year. Savings are assumed to persist for 1 year, reflecting that savings will not occur if the resource is not activated and additional costs are incurred to activate the resource.
Industrial Program				
16	Process & System Upgrades	Results are directly attributed to LDC based on LDC identified in application in the saveONenergy CRM system.	Savings are considered to begin in the year in which the incentive project was completed.	**Peak demand and energy savings** are determined by the total savings from a given project as reported (reported). A realization rate is applied to the reported savings to ensure that these savings align with EM&V protocols and reflect the savings that were actually realized (i.e. how many light bulbs were actually installed vs. what was reported) (gross). Net savings takes into account net-to-gross factors such as free-ridership and spillover (net).
17	Monitoring & Targeting	Results are directly attributed to LDC based on LDC identified in the application.	Savings are considered to begin in the year in which the incentive project was completed.	**Peak demand and energy savings** are determined by the total savings from a given project as reported (reported). A realization rate is applied to the reported savings to ensure that these savings align with EM&V protocols and reflect the savings that were actually realized (i.e. how many light bulbs were actually installed vs. what was reported) (gross). Net savings takes into account net-to-gross factors such as free-ridership and spillover (net).
18	Energy Manager	Results are directly attributed to LDC based on LDC identified in the application.	Savings are considered to begin in the year in which the project was completed by the energy manager. If no date is specified the savings will begin the year of the Quarterly Report submitted by the energy manager.	**Peak demand and energy savings** are determined by the total savings from a given project as reported (reported). A realization rate is applied to the reported savings to ensure that these savings align with EM&V protocols and reflect the savings that were actually realized (i.e. how many light bulbs were actually installed vs. what was reported) (gross). Net savings takes into account net-to-gross factors such as free-ridership and spillover (net).

#	Initiative	Attributing Savings to LDCs	Savings 'start' Date	Calculating Resource Savings
19	Efficiency: Equipment Replacement Incentive (part of the C&I program schedule)	Results are directly attributed to LDC based on LDC identified at the facility level in the saveONenergy CRM; Projects in the Application Status: "Post-Stage Submission" are included (excluding "Payment denied by LDC"); Please see "Reference Tables" tab for Building type to Sector mapping	Savings are considered to begin in the year of the actual project completion date on the iCON CRM system.	**Peak demand and energy savings** are determined by the total savings for a given project as reported in the iCON CRM system (reported). A realization rate is applied to the reported savings to ensure that these savings align with EM&V protocols and reflect the savings that were actually realized (i.e. how many light bulbs were actually installed vs. what was reported) (gross). Net savings takes into account net-to-gross factors such as free-ridership and spillover (net). Both realization rate and net-to-gross ratios can differ for energy and demand savings and depend on the mix of projects within an LDC territory (i.e. lighting or non-lighting project, engineered/custom/prescriptive track).
20	Demand Response 3	Results are attributed to LDCs based on the total contracted megawatts at the contributor level as of December 31st of the relevant year, applying the provincial ex ante to contracted ratio (ex ante estimate/contracted megawatts); Ex post energy savings are attributed to the LDC based on their proportion of the total contracted megawatts at the contributor level.	Savings are considered to begin in the year in which the contributor signed up to participate in demand response.	**Peak demand savings** are ex ante estimates based on the load reduction capability that can be expected for the purposes of planning. The ex ante estimates factor in both scheduled non-performances (i.e. maintenance) and historical performance. **Energy savings** are based on an ex post estimate which reflects the savings that actually occurred as a results of activations in the year. Savings are assumed to persist for 1 year, reflecting that savings will not occur if the resource is not activated and additional costs are incurred to activate the resource.
Home Assistance Program				
21	Home Assistance Program	Results are directly attributed to LDC based on LDC identified in the application; reported results are presented with forecast assumptions as per the business case.	Savings are considered to begin in the year in which the measures were installed.	**Peak demand and energy savings** are determined using the measure level per unit assumption multiplied by the uptake of each measure (gross) taking into account net-to-gross factors such as free-ridership and spillover (net) at the measure level.
Legacy Programs Completed in Current Year				
22	Electricity Retrofit Incentive Program	Results are directly attributed to LDC based on LDC identified in the application.	Savings are considered to begin in the year in which a project was completed.	**Peak demand and energy savings** are determined by the total savings from a given project as reported (reported). A realization rate is applied to the reported savings to ensure that these savings align with EM&V protocols and reflect the savings that were actually realized (i.e. how many light bulbs were actually installed vs. what was reported) (gross). Net savings takes into account net-to-gross factors such as free-ridership and spillover (net). **If energy savings are not available,** an estimate is made based on the kWh to kW ratio in the provincial results (http://www.powerauthority.on.ca/evaluation-measurement-and-verification/evaluation-reports).
23	High Performance New Construction	Results are directly attributed to LDC based on customer data provided to the OPA from the gas utility.	Savings are considered to begin in the year in which a project was completed.	
24	Toronto Comprehensive	Program run exclusively in Toronto Hydro-Electric System Limited service territory		

#	Initiative	Attributing Savings to LDCs	Savings 'start' Date	Calculating Resource Savings
25	Multifamily Energy Efficiency Rebates	Results are directly attributed to LDC based on LDC identified in the application	Savings are considered to begin in the year in which a project was completed.	**Peak demand and energy savings** are determined by the total savings from a given project as reported (reported). A realization rate is applied to the reported savings to ensure that these savings align with EM&V protocols and reflect the savings that were actually realized (i.e. how many light bulbs were actually installed vs. what was reported) (gross). Net savings takes into account net-to-gross factors such as free-ridership and spillover (net). **If energy savings are not available,** an estimate is made based on the kWh to kW ratio in the provincial results (http://www.powerauthority.on.ca/evaluation-measurement-and-verification/evaluation-reports).
26	Data Centre Incentive Program	Program run exclusively in PowerStream Inc. service territory		
27	EnWin Green Suites	Program run exclusively in ENWIN Utilities Ltd. service territory		

REPLACE WITH LDC RESULTS PDFS

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Appendix B
OPA 2014 CDM Year End Report

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Message from the Vice President:

The IESO is pleased to provide the enclosed 2011-2014 Final Results Report. This report is designed to help populate LDC Annual Reports that will be submitted to the Ontario Energy Board (OEB) in September 2015.

2011-2014 Conservation Framework Highlights:

- LDCs have made significant achievements against dual energy and peak demand savings targets. Collectively, the LDCs have achieved 109% of the energy target and 70% of the peak demand target.
- Momentum has built as we transition to the Conservation First Framework. 2014 demonstrated an achievement of over 1 TWh of net incremental energy savings, positioning us well for average net incremental energy savings of 1.2 TWh required in the new framework to meet our 2020 CDM targets.
- Throughout the past framework, program results have become more predictable year over year as noted in the increasingly smaller variance between quarterly preliminary results and verified final results.
- Customer engagement continued to increase in both the Consumer and Business Programs. Between 2011 - 2014 consumers have purchased over 10 million energy efficient products through the saveONenergy COUPONS program. Customers in RETROFIT continue to declare a positive experience participating in the program with 86% likely to recommend.
- saveONenergy has seen a steady and significant increase in unaided brand awareness by 33% from 2011-2014
- Conservation is becoming even more cost-effective as programs become more efficient and effective. 2014 proved early investments in long lead time projects will pay off with the high savings now being realized in programs like PROCESS & SYSTEMS and RETROFIT. Within 4 cents per kWh, Conservation programs continue to be a valuable and cost effective resource for customers across the province.

The 2011-2014 Final Results within this report vary from the Draft 2011-2014 Final Results Report for the following reasons:

- Savings from Time of Use pricing are included in the Final Results Report. Overall the province saved 55 MWs from Time-of-Use pricing in 2014, or 0.73% of residential summer peak demand.
- Between August 4th and August 28th, the IESO and LDCs have worked collaboratively to reconcile projects from 2011-2014 Final Results Report to ensure every eligible project was captured and accurately reported.
- Verified savings from Innovation Fund pilots are also included for participating LDCs.

All results will be considered final for the 2011-2014 Conservation Framework. Any additional program activity not captured in the 2011-2014 Final Results Report will not be included as part of a future adjustment process.

Please continue to monitor saveONenergy E-blasts for future updates and should you have any other questions or comments please contact LDC.Support@ieso.ca.

We appreciate your collaboration and cooperation throughout the reporting and evaluation process and we look forward to the success ahead in the Conservation First Framework.

Sincerely,

Terry Young

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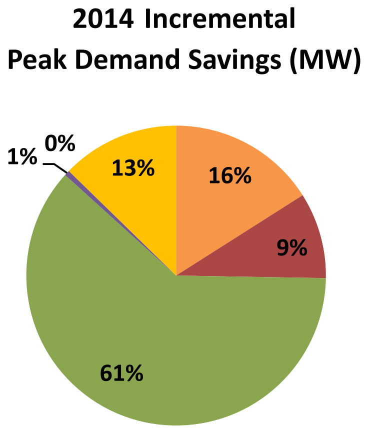
IESO-Contracted Province-Wide CDM Programs: 2011-2014 Final Results Report

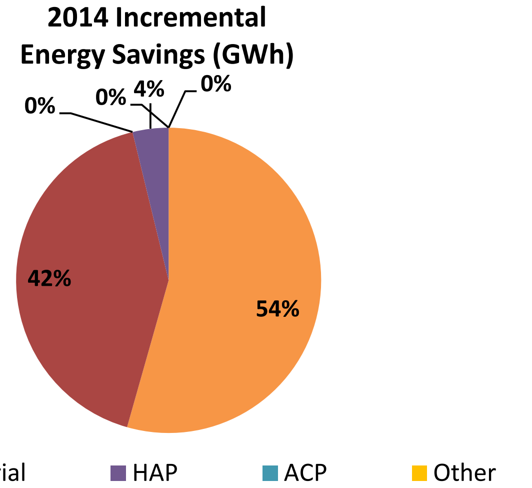
LDC: Canadian Niagara Power Inc.

Final 2014 Achievement Against Targets	2014 Incremental	2011-2014 Achievement Against Target	% of Target Achieved
Net Annual Peak Demand Savings (MW)	2.3	3.5	**54.6%**
Net Energy Savings (GWh)	3.0	20.7	**82.6%**

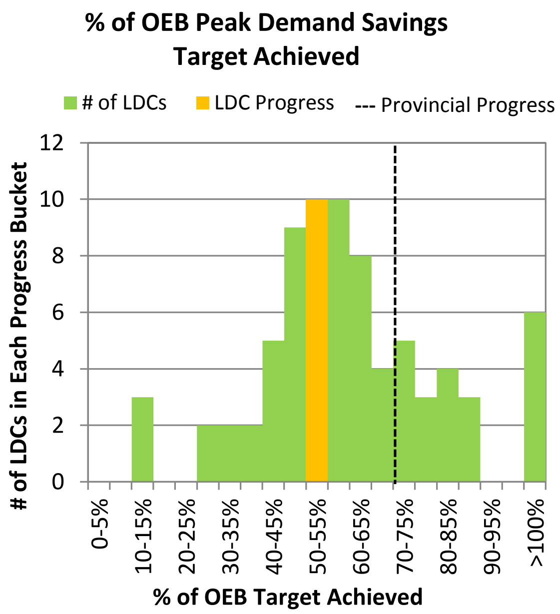
Unless otherwise noted, results are presented using scenario 1 which assumes that demand response resources have a persistence of 1 year

Achievement by Sector





Comparison: LDC Achievement vs. LDC Community Achievement (Progress to Target)



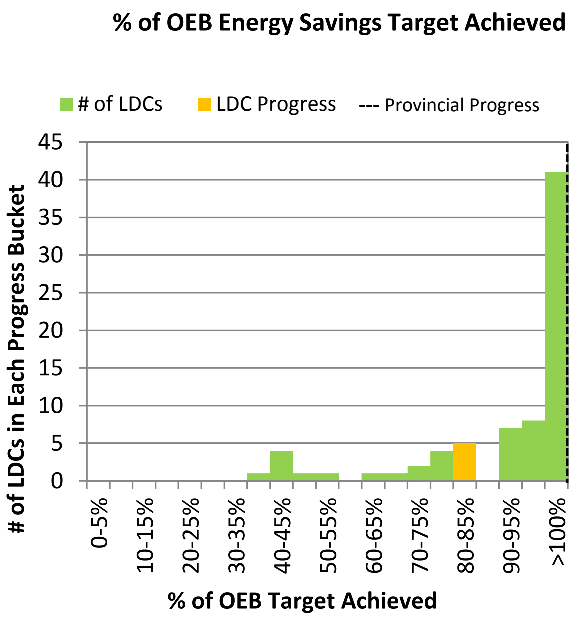


Table 1: Canadian Niagara Power Inc. Initiative and Program Level Net Savings by Year

Initiative	Unit	Incremental Activity (new program activity occurring within the specified reporting period)				Net Incremental Peak Demand Savings (kW) (new peak demand savings from activity within the specified reporting period)				Net Incremental Energy Savings (kWh) (new energy savings from activity within the specified reporting period)				Program-to-Date Verified Progress to Target (excludes DR)	
														2014 Net Annual Peak Demand Savings (kW)	2011-2014 Net Cumulative Energy Savings (kWh)
		2011*	2012*	2013*	2014	2011	2012	2013	2014	2011	2012	2013	2014	2014	2014
Consumer Program															
Appliance Retirement	Appliances	219	97	56	56	13	6	4	4	93,881	38,455	23,950	25,003	26	563,688
Appliance Exchange	Appliances	67	38	61	73	6	6	13	15	7,024	9,653	22,536	26,969	35	124,747
HVAC Incentives	Equipment	269	293	624	908	94	64	135	196	173,523	111,564	239,553	367,484	489	1,875,375
Conservation Instant Coupon Booklet	Items	2,618	158	1,778	5,559	6	1	3	11	97,458	7,145	39,386	151,935	21	641,975
Bi-Annual Retailer Event	Items	4,866	5,421	4,828	24,655	9	8	6	41	150,171	136,855	87,790	628,038	63	1,814,867
Retailer Co-op	Items	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Residential Demand Response	Devices	0	0	114	173	0	0	49	65	0	0	6	0	65	6
Residential Demand Response (IHD)	Devices	0	0	113	167	0	0	0	0	0	0	0	0	0	0
Residential New Construction	Homes	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Consumer Program Total						**128**	**84**	**210**	**332**	**522,058**	**303,672**	**413,221**	**1,199,428**	**699**	**5,020,658**
Business Program															
Retrofit	Projects	8	23	48	30	13	53	196	89	114,842	306,302	1,143,031	531,324	352	4,195,353
Direct Install Lighting	Projects	14	140	97	68	15	133	131	86	37,406	492,449	469,872	307,005	361	2,860,356
Building Commissioning	Buildings	0	0	0	0	0	0	0	0	0	0	0	0	0	0
New Construction	Buildings	0	1	0	1	0	0	0	3	0	0	0	18,103	3	18,103
Energy Audit	Audits	6	1	0	1	0	5	0	13	0	25,176	0	65,274	19	140,802
Small Commercial Demand Response	Devices	0	0	1	2	0	0	1	2	0	0	0	0	2	0
Small Commercial Demand Response (IHD)	Devices	0	0	1	2	0	0	0	0	0	0	0	0	0	0
Demand Response 3	Facilities	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Business Program Total						**29**	**191**	**328**	**193**	**152,247**	**823,928**	**1,612,902**	**921,706**	**736**	**7,214,614**
Industrial Program															
Process & System Upgrades	Projects	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Monitoring & Targeting	Projects	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Energy Manager	Projects	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Retrofit	Projects	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Demand Response 3	Facilities	1	3	5	4	126	218	1,147	1,276	7,420	5,260	26,127	0	1,276	38,807
Industrial Program Total						**126**	**218**	**1,147**	**1,276**	**7,420**	**5,260**	**26,127**	**0**	**1,276**	**38,807**
Home Assistance Program															
Home Assistance Program	Homes	0	2	350	100	0	1	9	12	0	4,983	128,968	83,904	22	354,212
Home Assistance Program Total						**0**	**1**	**9**	**12**	**0**	**4,983**	**128,968**	**83,904**	**22**	**354,212**
Aboriginal Program															
Home Assistance Program	Homes	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Direct Install Lighting	Projects	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Aboriginal Program Total						**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
Pre-2011 Programs completed in 2011															
Electricity Retrofit Incentive Program	Projects	32	0	0	0	240	0	0	0	1,232,526	0	0	0	240	4,930,103
High Performance New Construction	Projects	1	0	0	0	0	1	0	0	1,402	559	0	0	1	7,288
Toronto Comprehensive	Projects	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Multifamily Energy Efficiency Rebates	Projects	0	0	0	0	0	0	0	0	0	0	0	0	0	0
LDC Custom Programs	Projects	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Pre-2011 Programs completed in 2011 Total						**240**	**1**	**0**	**0**	**1,233,928**	**559**	**0**	**0**	**241**	**4,937,391**
Other															
Program Enabled Savings	Projects	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Time-of-Use Savings	Homes	0	0	0	n/a	0	0	0	264	0	0	0	0	264	0
LDC Pilots	Projects	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Other Total						**0**	**0**	**0**	**264**	**0**	**0**	**0**	**0**	**264**	**0**
Adjustments to 2011 Verified Results							**16**	**0**	**68**		**135,718**	**0**	**190,426**	**84**	**1,304,576**
Adjustments to 2012 Verified Results								**11**	**131**			**92,986**	**424,026**	**142**	**1,550,800**
Adjustments to 2013 Verified Results									**29**				**139,041**	**29**	**282,409**
Energy Efficiency Total						**396**	**277**	**497**	**734**	**1,908,233**	**1,133,142**	**2,155,084**	**2,205,038**	**1,895**	**17,526,868**
Demand Response Total (Scenario 1)						**126**	**218**	**1,197**	**1,342**	**7,420**	**5,260**	**26,133**	**0**	**1,342**	**38,813**
Adjustments to Previous Years' Verified Results Total						**0**	**16**	**11**	**227**	**0**	**135,718**	**92,986**	**753,493**	**255**	**3,137,785**
OPA-Contracted LDC Portfolio Total (inc. Adjustments)						**523**	**511**	**1,705**	**2,304**	**1,915,654**	**1,274,120**	**2,274,204**	**2,958,531**	**3,492**	**20,703,467**
													Full OEB Target:	**6,400**	**25,080,000**
													% of Full OEB Target Achieved to Date (Scenario 1):	**54.6%**	**82.5%**

Activity and savings for Demand Response resources for each year represent the savings from all active facilities or devices contracted since January 1, 2011 (reported cumulatively).

*Includes adjustments after Final Reports were issued

Results presented using scenario 1 which assumes that demand response resources have a persistence of 1 year

Table 2: Adjustments to Canadian Niagara Power Inc. Net Verified Results due to Variances

Initiative	Unit	Incremental Activity (new program activity occurring within the specified reporting period)				Net Incremental Peak Demand Savings (kW) (new peak demand savings from activity within the specified reporting period)				Net Incremental Energy Savings (kWh) (new energy savings from activity within the specified reporting period)				Program-to-Date Verified Progress to Target (excludes DR): 2014 Net Annual Peak Demand Savings (kW)	Program-to-Date Verified Progress to Target (excludes DR): 2011-2014 Net Cumulative Energy Savings (kWh)
		2011*	2012*	2013*	2014	2011	2012	2013	2014	2011	2012	2013	2014	2014	2014
Consumer Program															
Appliance Retirement	Appliances	0	0	0		0	0	0		0	0	0		0	0
Appliance Exchange	Appliances	0	0	0		0	0	0		0	0	0		0	0
HVAC Incentives	Equipment	-55	9	9		-15	2	2		-27,905	3,282	3,418		-12	-94,938
Conservation Instant Coupon Booklet	Items	42	0	5		0	0	0		1,409	0	120		0	5,874
Bi-Annual Retailer Event	Items	418	0	0		1	0	0		11,157	0	0		1	44,629
Retailer Co-op	Items	0	0	0		0	0	0		0	0	0		0	0
Residential Demand Response	Devices	0	0	0		0	0	0		0	0	0		0	0
Residential Demand Response (IHD)	Devices	0	0	0		0	0	0		0	0	0		0	0
Residential New Construction	Homes	0	0	0		0	0	0		0	0	0		0	0
Consumer Program Total						**-15**	**2**	**2**		**-15,340**	**3,282**	**3,538**		**-11**	**-44,435**
Business Program															
Retrofit	Projects	0	4	6		0	8	24		0	80,986	121,855		30	482,497
Direct Install Lighting	Projects	0	3	0		0	2	0		0	8,718	0		1	25,916
Building Commissioning	Buildings	0	0	0		0	0	0		0	0	0		0	0
New Construction	Buildings	0	1	0		0	131	0		0	423,172	0		131	1,269,516
Energy Audit	Audits	6	0	0		33	0	0		158,390	854	0		33	636,121
Small Commercial Demand Response	Devices	0	0	0		0	0	0		0	0	0		0	0
Small Commercial Demand Response (IHD)	Devices	0	0	0		0	0	0		0	0	0		0	0
Demand Response 3	Facilities	0	0	0		0	0	0		0	0	0		0	0
Business Program Total						**33**	**140**	**24**		**158,390**	**513,730**	**121,855**		**195**	**2,414,050**
Industrial Program															
Process & System Upgrades	Projects	0	0	0		0	0	0		0	0	0		0	0
Monitoring & Targeting	Projects	0	0	0		0	0	0		0	0	0		0	0
Energy Manager	Projects	0	0	0		0	0	0		0	0	0		0	0
Retrofit	Projects	0	0	0		0	0	0		0	0	0		0	0
Demand Response 3	Facilities	0	0	0		0	0	0		0	0	0		0	0
Industrial Program Total						**0**	**0**	**0**		**0**	**0**	**0**		**0**	**0**
Home Assistance Program															
Home Assistance Program	Homes	0	0	14		0	0	4		0	0	17,974		4	35,794
Home Assistance Program Total						**0**	**0**	**4**		**0**	**0**	**17,974**		**4**	**35,794**
Aboriginal Program															
Home Assistance Program	Homes	0	0	0		0	0	0		0	0	0		0	0
Direct Install Lighting	Projects	0	0	0		0	0	0		0	0	0		0	0
Aboriginal Program Total						**0**	**0**	**0**		**0**	**0**	**0**		**0**	**0**
Pre-2011 Programs completed in 2011															
Electricity Retrofit Incentive Program	Projects	0	0	0		0	0	0		0	0	0		0	0
High Performance New Construction	Projects	1	0	0		66	0	0		183,094	0	0		66	732,376
Toronto Comprehensive	Projects	0	0	0		0	0	0		0	0	0		0	0
Multifamily Energy Efficiency Rebates	Projects	0	0	0		0	0	0		0	0	0		0	0
LDC Custom Programs	Projects	0	0	0		0	0	0		0	0	0		0	0
Pre-2011 Programs completed in 2011 Total						**66**	**0**	**0**		**183,094**	**0**	**0**		**66**	**732,376**
Other															
Program Enabled Savings	Projects	0	0	0		0	0	0		0	0	0		0	0
Time-of-Use Savings	Homes	0	0	0		0	0	0		0	0	0		0	0
LDC Pilots	Projects	0	0	0		0	0	0		0	0	0		0	0
Other Total						**0**	**0**	**0**		**0**	**0**	**0**		**0**	**0**
Adjustments to 2011 Verified Results						**84**				**326,144**				**84**	**1,304,576**
Adjustments to 2012 Verified Results							**142**				**517,012**			**142**	**1,550,800**
Adjustments to 2013 Verified Results								**30**				**143,368**		**29**	**282,409**
Total Adjustments to Previous Years' Verified Results						**84**	**142**	**30**		**326,144**	**517,012**	**143,368**		**255**	**3,137,785**

Activity and savings for Demand Response resources for each year represent the savings from all active facilities or devices contracted since January 1, 2011 (reported cumulatively).

Adjustments to previous years' results shown in this table will not align to adjustments shown in Table 1 as the information presented above is presented in the implementation year. Adjustements in Table 1 reflect persisted savings in the year in which that adjustment is verified.

Table 3: Canadian Niagara Power Inc. Realization Rate & NTG

Initiative	Peak Demand Savings								Energy Savings							
	Realization Rate				Net-to-Gross Ratio				Realization Rate				Net-to-Gross Ratio			
	2011	2012	2013	2014	2011	2012	2013	2014	2011	2012	2013	2014	2011	2012	2013	2014
Consumer Program																
Appliance Retirement	1.00	1.00	n/a	n/a	0.51	0.46	0.42	0.42	1.00	1.00	n/a	n/a	0.52	0.47	0.44	0.44
Appliance Exchange	1.00	1.00	1.00	1.00	0.52	0.52	0.53	0.53	1.00	1.00	1.00	1.00	0.52	0.52	0.53	0.53
HVAC Incentives	1.00	1.00	n/a	1.00	0.60	0.50	0.48	0.51	1.00	1.00	n/a	1.00	0.60	0.49	0.48	0.51
Conservation Instant Coupon Booklet	1.00	1.00	1.00	1.00	1.14	1.00	1.11	1.69	1.00	1.00	1.00	1.00	1.11	1.05	1.13	1.74
Bi-Annual Retailer Event	1.00	1.00	1.00	1.00	1.13	0.91	1.04	1.74	1.00	1.00	1.00	1.00	1.10	0.92	1.04	1.75
Retailer Co-op	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
Residential Demand Response	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
Residential Demand Response (IHD)	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
Residential New Construction	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
Business Program																
Retrofit	0.90	0.93	0.92	0.40	0.73	0.75	0.73	0.36	1.05	1.05	1.05	0.52	0.76	0.74	0.75	0.36
Direct Install Lighting	1.08	0.69	0.81	0.78	0.93	0.94	0.94	0.94	0.90	0.85	0.84	0.83	0.93	0.94	0.94	0.94
Building Commissioning	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
New Construction	n/a	n/a	n/a	0.77	n/a	n/a	n/a	0.54	n/a	n/a	n/a	1.00	n/a	n/a	n/a	0.54
Energy Audit	n/a	n/a	n/a	0.96	n/a	n/a	n/a	0.68	n/a	n/a	n/a	1.00	n/a	n/a	n/a	0.67
Small Commercial Demand Response	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
Small Commercial Demand Response (IHD)	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
Demand Response 3	0.76	n/a	n/a	n/a	n/a	n/a	n/a	n/a	1.00	n/a	n/a	n/a	n/a	n/a	n/a	n/a
Industrial Program																
Process & System Upgrades	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
Monitoring & Targeting	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
Energy Manager	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
Retrofit																
Demand Response 3	0.84	n/a	n/a	n/a	n/a	n/a	n/a	n/a	1.00	n/a	n/a	n/a	n/a	n/a	n/a	n/a
Home Assistance Program																
Home Assistance Program	n/a	0.98	1.16	0.90	n/a	1.00	1.00	1.00	n/a	0.99	0.87	0.81	n/a	1.00	1.00	1.00
Aboriginal Program																
Home Assistance Program	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
Direct Install Lighting	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
Pre-2011 Programs completed in 2011																
Electricity Retrofit Incentive Program	0.77	n/a	n/a	n/a	0.52	n/a	n/a	n/a	0.77	n/a	n/a	n/a	0.52	n/a	n/a	n/a
High Performance New Construction	1.00	1.00	1.00	1.00	0.50	0.50	0.50	0.50	1.00	1.00	1.00	1.00	0.50	0.50	0.50	0.50
Toronto Comprehensive	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
Multifamily Energy Efficiency Rebates	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
LDC Custom Programs	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
Other																
Program Enabled Savings	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
Time-of-Use Savings	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
LDC Pilots	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a

Summary Achievement Against CDM Targets

Results are recognized using current IESO reporting policies. Energy efficiency resources persist for the duration of the effective useful life. Any upcoming code changes are taken into account. Demand response resources persist for 1 year (Scenario 1). Please see methodology tab for more detailed information.

Table 4: Net Peak Demand Savings at the End User Level (MW) (Scenario 1)

Implementation Period	Annual			
	2011	2012	2013	2014
2011 - Verified	0.5	0.4	0.4	0.4
2012 - Verified†	0.0	0.5	0.3	0.3
2013 - Verified†	0.0	0.0	1.7	0.5
2014 - Verified†	0.1	0.2	0.2	2.3
Verified Net Annual Peak Demand Savings Persisting in 2014:				**3.5**
Canadian Niagara Power Inc. 2014 Annual CDM Capacity Target:				**6.4**
Verified Portion of Peak Demand Savings Target Achieved in 2014 (%):				**54.6%**

Table 5: Net Energy Savings at the End User Level (GWh)

Implementation Period	Annual				Cumulative
	2011	2012	2013	2014	2011-2014
2011 - Verified	1.9	1.9	1.9	1.9	7.6
2012 - Verified†	0.1	1.3	1.3	1.3	3.9
2013 - Verified†	0.0	0.1	2.3	2.2	4.6
2014 - Verified†	0.2	0.6	0.76	3.0	4.5
Verified Net Cumulative Energy Savings 2011-2014:					**20.7**
Canadian Niagara Power Inc. 2011-2014 Annual CDM Energy Target:					**25.1**
Verified Portion of Cumulative Energy Target Achieved in 2014 (%):					**82.5%**

†Includes adjustments to previous years' verified results

Results presented using scenario 1 which assumes that demand response resources have a persistence of 1 year

Table 6: Province-Wide Initiatives and Program Level Net Savings by Year (Scenario 1)

Initiative	Unit	Incremental Activity (new program activity occurring within the specified reporting period)				Net Incremental Peak Demand Savings (kW) (new peak demand savings from activity within the specified reporting period)				Net Incremental Energy Savings (kWh) (new energy savings from activity within the specified reporting period)				Program-to-Date Verified Progress to Target (excludes DR)	
														2014 Net Annual Peak Demand Savings (kW)	2011-2014 Net Cumulative Energy Savings (kWh)
		2011*	2012*	2013*	2014	2011	2012	2013	2014	2011	2012	2013	2014	2014	2014
Consumer Program															
Appliance Retirement	Appliances	56,110	34,146	20,952	22,563	3,299	2,011	1,433	1,617	23,005,812	13,424,518	8,713,107	9,497,343	8,221	159,100,415
Appliance Exchange	Appliances	3,688	3,836	5,337	5,685	371	556	1,106	1,178	450,187	974,621	1,971,701	2,100,266	2,973	10,556,192
HVAC Incentives	Equipment	92,748	87,540	96,286	113,002	32,037	19,060	19,552	23,106	59,437,670	32,841,283	33,923,592	42,888,217	93,755	447,009,930
Conservation Instant Coupon Booklet	Items	567,678	30,891	347,946	1,208,108	1,344	230	517	2,440	21,211,537	1,398,202	7,707,573	32,802,537	4,531	137,258,436
Bi-Annual Retailer Event	Items	952,149	1,060,901	944,772	4,824,751	1,681	1,480	1,184	8,043	29,387,468	26,781,674	17,179,841	122,902,769	12,389	355,157,348
Retailer Co-op	Items	152	0	0	0	0	0	0	0	2,652	0	0	0	0	10,607
Residential Demand Response	Devices	19,550	98,388	171,733	241,381	10,947	49,038	93,076	117,513	24,870	359,408	390,303	8,379	117,513	782,960
Residential Demand Response (IHD)	Devices	0	49,689	133,657	188,577	0	0	0	0	0	0	0	0	0	0
Residential New Construction	Homes	27	21	279	2,367	0	2	18	369	743	17,152	163,690	2,330,865	390	2,712,676
Consumer Program Total						**49,681**	**72,377**	**116,886**	**154,267**	**133,520,941**	**75,796,859**	**70,049,807**	**212,530,376**	**239,772**	**1,112,588,565**
Business Program															
Retrofit	Projects	2,828	6,481	9,746	10,925	24,467	61,147	59,678	70,662	136,002,258	314,922,468	345,346,008	462,903,521	213,493	2,631,401,223
Direct Install Lighting	Projects	20,741	18,691	17,833	23,784	23,724	15,284	18,708	23,419	61,076,701	57,345,798	64,315,558	84,503,302	73,304	604,196,658
Building Commissioning	Buildings	0	0	0	5	0	0	0	988	0	0	0	1,513,377	988	1,513,377
New Construction	Buildings	25	98	158	226	123	764	1,584	6,432	411,717	1,814,721	4,959,266	20,381,204	8,904	37,390,767
Energy Audit	Audits	222	357	589	473	0	1,450	2,811	6,323	0	7,049,351	15,455,795	30,874,399	10,583	82,934,042
Small Commercial Demand Response	Devices	132	294	1,211	3,652	84	187	773	2,116	157	1,068	373	319	2,116	1,916
Small Commercial Demand Response (IHD)	Devices	0	0	378	820	0	0	0	0	0	0	0	0	0	0
Demand Response 3	Facilities	145	151	175	180	16,218	19,389	23,706	23,380	633,421	281,823	346,659	0	23,380	1,261,903
Business Program Total						**64,617**	**98,221**	**107,261**	**133,319**	**198,124,253**	**381,415,230**	**430,423,659**	**600,176,121**	**332,769**	**3,358,699,887**
Industrial Program															
Process & System Upgrades	Projects	0	0	5	10	0	0	294	9,692	0	0	2,603,764	72,053,255	9,986	77,260,782
Monitoring & Targeting	Projects	0	1	3	5	0	0	0	102	0	0	0	502,517	102	502,517
Energy Manager	Projects	1	132	306	379	0	1,086	3,558	5,191	0	7,372,108	21,994,263	40,436,427	8,384	95,324,998
Retrofit	Projects	433	0	0	0	4,615	0	0	0	28,866,840	0	0	0	4,613	115,462,282
Demand Response 3	Facilities	124	185	281	336	52,484	74,056	162,543	166,082	3,080,737	1,784,712	4,309,160	0	166,082	9,174,609
Industrial Program Total						**57,098**	**75,141**	**166,395**	**181,066**	**31,947,577**	**9,156,820**	**28,907,187**	**112,992,199**	**189,168**	**297,725,188**
Home Assistance Program															
Home Assistance Program	Homes	46	5,920	29,654	25,424	2	566	2,361	2,466	39,283	5,442,232	20,987,275	19,582,658	5,370	77,532,571
Home Assistance Program Total						**2**	**566**	**2,361**	**2,466**	**39,283**	**5,442,232**	**20,987,275**	**19,582,658**	**5,370**	**77,532,571**
Aboriginal Program															
Home Assistance Program	Homes	0	0	717	1,125	0	0	267	549	0	0	1,609,393	3,101,207	816	6,319,993
Direct Install Lighting	Projects	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Aboriginal Program Total						**0**	**0**	**267**	**549**	**0**	**0**	**1,609,393**	**3,101,207**	**816**	**6,319,993**
Pre-2011 Programs completed in 2011															
Electricity Retrofit Incentive Program	Projects	2,028	0	0	0	21,662	0	0	0	121,138,219	0	0	0	21,662	484,552,876
High Performance New Construction	Projects	182	73	19	3	5,098	3,251	772	134	26,185,591	11,901,944	3,522,240	688,738	9,255	148,181,415
Toronto Comprehensive	Projects	577	15	4	5	15,805	0	0	281	86,964,886	0	0	2,479,840	16,086	350,339,385
Multifamily Energy Efficiency Rebates	Projects	110	0	0	0	1,981	0	0	0	7,595,683	0	0	0	1,981	30,382,733
LDC Custom Programs	Projects	8	0	0	0	399	0	0	0	1,367,170	0	0	0	399	5,468,679
Pre-2011 Programs completed in 2011 Total						**44,945**	**3,251**	**772**	**415**	**243,251,550**	**11,901,944**	**3,522,240**	**3,168,578**	**49,382**	**1,018,925,088**
Other															
Program Enabled Savings	Projects	33	71	46	43	0	2,304	3,692	5,500	0	1,188,362	4,075,382	19,035,337	11,496	30,751,187
Time-of-Use Savings	Homes	0	0	0	n/a	0	0	0	54,795	0	0	0	0	54,795	0
LDC Pilots	Projects	0	0	0	1,174	0	0	0	1,170	0	0	0	5,061,522	1,170	5,061,522
Other Total						**0**	**2,304**	**3,692**	**61,466**	**0**	**1,188,362**	**4,075,382**	**24,096,859**	**67,462**	**35,812,709**
Adjustments to 2011 Verified Results							**1,406**	**641**	**1,418**		**18,689,081**	**1,736,381**	**7,319,857**	**3,215**	**110,143,550**
Adjustments to 2012 Verified Results								**6,260**	**9,221**			**41,947,840**	**37,080,215**	**15,401**	**238,780,637**
Adjustments to 2013 Verified Results									**24,391**				**150,785,808**	**24,391**	**296,465,211**
Energy Efficiency Total						**136,610**	**109,191**	**117,536**	**224,457**	**603,144,419**	**482,474,435**	**554,528,447**	**975,639,300**	**575,647**	**5,896,382,612**
Demand Response Total (Scenario 1)						**79,733**	**142,670**	**280,099**	**309,091**	**3,739,185**	**2,427,011**	**5,046,495**	**8,698**	**309,091**	**11,221,389**
Adjustments to Previous Years' Verified Results Total						**0**	**1,406**	**6,901**	**35,030**	**0**	**18,689,081**	**43,684,221**	**195,185,880**	**43,006**	**645,389,397**
OPA-Contracted LDC Portfolio Total (inc. Adjustments)						**216,343**	**253,267**	**404,536**	**568,578**	**606,883,604**	**503,590,526**	**603,259,163**	**1,170,833,878**	**927,745**	**6,552,993,397**
													Full OEB Target:	**1,330,000**	**6,000,000,000**
													% of Full OEB Target Achieved to Date (Scenario 1):	**70%**	**109%**

Activity and savings for Demand Response resources for each year represent the savings from all active facilities or devices contracted since January 1, 2011 (reported cumulatively).

*Includes adjustments after Final Reports were issued

Results presented using scenario 1 which assumes that demand response resources have a persistence of 1 year

Table 7: Adjustments to Province-Wide Net Verified Results due to Variances

Initiative	Unit	Incremental Activity (new program activity occurring within the specified reporting period)				Net Incremental Peak Demand Savings (kW) (new peak demand savings from activity within the specified reporting period)				Net Incremental Energy Savings (kWh) (new energy savings from activity within the specified reporting period)				Program-to-Date Verified Progress to Target (excludes DR) 2014 Net Annual Peak Demand Savings (kW)	Program-to-Date Verified Progress to Target (excludes DR) 2011-2014 Net Cumulative Energy Savings (kWh)
		2011*	2012*	2013*	2014	2011	2012	2013	2014	2011	2012	2013	2014	2014	2014
Consumer Program															
Appliance Retirement	Appliances	0	0	0		0	0	0		0	0	0		0	0
Appliance Exchange	Appliances	0	0	0		0	0	0		0	0	0		0	0
HVAC Incentives	Equipment	-18,839	2,319	4,705		-5,270	479	1,037		-9,707,002	955,512	1,838,408		-3,754	-32,284,656
Conservation Instant Coupon Booklet	Items	8,216	0	1,050		16	0	2		275,655	0	23,571		18	1,149,763
Bi-Annual Retailer Event	Items	81,817	0	0		108	0	0		2,183,391	0	0		108	8,733,563
Retailer Co-op	Items	0	0	0		0	0	0		0	0	0		0	0
Residential Demand Response	Devices	0	0	0		0	0	0		0	0	0		0	0
Residential Demand Response (IHD)	Devices	0	0	0		0	0	0		0	0	0		0	0
Residential New Construction	Homes	20	2	193		1	1	72		14,667	985	441,938		74	945,497
Consumer Program Total						**-5,145**	**480**	**1,111**		**-7,233,290**	**956,497**	**2,303,917**		**-3,555**	**-21,664,975**
Business Program															
Retrofit	Projects	312	876	961		3,208	7,233	11,961		16,266,129	42,498,052	78,146,280		22,056	347,545,386
Direct Install Lighting	Projects	444	197	51		501	204	46		1,250,388	736,541	164,667		620	7,158,143
Building Commissioning	Buildings	0	0	0		0	0	0		0	0	0		0	0
New Construction	Buildings	15	29	72		850	1,304	2,241		3,604,553	4,825,774	8,636,179		4,401	46,187,216
Energy Audit	Audits	119	77	270		604	439	2,383		2,945,189	2,145,367	13,100,635		3,426	44,418,129
Small Commercial Demand Response	Devices	0	0	0		0	0	0		0	0	0		0	0
Small Commercial Demand Response (IHD)	Devices	0	0	0		0	0	0		0	0	0		0	0
Demand Response 3	Facilities	0	0	0		0	0	0		0	0	0		0	0
Business Program Total						**5,162**	**9,181**	**16,631**		**24,066,259**	**50,205,734**	**100,047,761**		**30,503**	**385,148,444**
Industrial Program															
Process & System Upgrades	Projects	0	0	2		0	0	324		0	0	968,659		324	1,937,318
Monitoring & Targeting	Projects	0	1	3		0	0	54		0	528,000	639,348		54	2,862,696
Energy Manager	Projects	1	93	101		27	1,067	2,395		241,515	8,266,841	25,814,853		4,345	81,853,489
Retrofit	Projects	0	0	0		0	0	0		0	0	0		0	0
Demand Response 3	Facilities	0	0	0		0	0	0		0	0	0		0	0
Industrial Program Total						**27**	**1,067**	**2,774**		**241,515**	**8,794,841**	**27,422,860**		**4,723**	**61,215,516**
Home Assistance Program															
Home Assistance Program	Homes	0	887	2,898		0	222	791		0	1,316,749	4,321,794		1,009	12,515,300
Home Assistance Program Total						**0**	**222**	**791**		**0**	**1,316,749**	**4,321,794**		**1,009**	**8,581,177**
Aboriginal Program															
Home Assistance Program	Homes	0	0	133		0	0	134		0	0	563,715		134	1,127,430
Direct Install Lighting	Projects	0	0	0		0	0	0		0	0	0		0	0
Aboriginal Program Total						**0**	**0**	**134**		**0**	**0**	**563,715**		**134**	**1,127,430**
Pre-2011 Programs completed in 2011															
Electricity Retrofit Incentive Program	Projects	12	0	0		138	0	0		545,536	0	0		138	2,182,145
High Performance New Construction	Projects	37	4	15		1,507	363	-184		2,398,941	2,832,533	-993,596		1,686	16,106,171
Toronto Comprehensive	Projects	0	15	4		0	672	185		0	4,523,517	1,324,388		857	16,219,327
Multifamily Energy Efficiency Rebates	Projects	0	0	0		0	0	0		0	0	0		0	0
LDC Custom Programs	Projects	0	0	0		0	0	0		0	0	0		0	0
Pre-2011 Programs completed in 2011 Total						**1,645**	**1,035**	**2**		**2,944,477**	**7,356,050**	**330,792**		**2,682**	**11,104,528**
Other															
Program Enabled Savings	Projects	33	55	33		1,776	3,712	2,020		7,727,573	11,481,687	10,688,564		7,509	86,732,481
Time-of-Use Savings	Homes	0	0	0		0	0	0		0	0	0		0	0
LDC Pilots	Projects	0	0	0		0	0	0		0	0	0		0	0
Other Total						**1,776**	**3,712**	**2,020**		**7,727,573**	**11,481,687**	**10,688,564**		**7,509**	**86,732,481**
Adjustments to 2011 Verified Results						**3,465**				**27,746,535**				**3,215**	**110,143,550**
Adjustments to 2012 Verified Results							**15,697**				**80,111,558**			**15,401**	**238,780,637**
Adjustments to 2013 Verified Results								**23,463**				**145,679,403**		**24,391**	**296,465,211**
Adjustments to Previous Years' Verified Results Total						**3,465**	**15,697**	**23,463**		**27,746,535**	**80,111,558**	**145,679,403**		**43,006**	**645,389,397**

Activity and savings for Demand Response resources for each year represent the savings from all active facilities or devices contracted since January 1, 2011 (reported cumulatively).

Adjustments to previous years' results shown in this table will not align to adjustments shown in Table 1 as the information presented above is presented in the implementation year. Adjustements in Table 1 reflect persisted savings in the year in which that adjustment is verified.

Table 8: Province-Wide Realization Rate & NTG

Initiative	Peak Demand Savings								Energy Savings							
	Realization Rate				Net-to-Gross Ratio				Realization Rate				Net-to-Gross Ratio			
	2011	2012	2013	2014	2011	2012	2013	2014	2011	2012	2013	2014	2011	2012	2013	2014
Consumer Program																
Appliance Retirement	1.00	1.00	1.00	1.00	0.51	0.46	0.42	0.45	1.00	1.00	1.00	1.00	0.46	0.47	0.44	0.47
Appliance Exchange	1.00	1.00	1.00	1.00	0.51	0.52	0.53	0.53	1.00	1.00	1.00	1.00	0.52	0.52	0.53	0.53
HVAC Incentives	1.00	1.00	1.00	1.00	0.60	0.50	0.48	0.48	1.00	1.00	1.00	1.00	0.50	0.49	0.48	0.48
Conservation Instant Coupon Booklet	1.00	1.00	1.00	1.00	1.14	1.00	1.11	1.69	1.00	1.00	1.00	1.00	1.00	1.05	1.13	1.73
Bi-Annual Retailer Event	1.00	1.00	1.00	1.00	1.12	0.91	1.04	1.74	1.00	1.00	1.00	1.00	0.91	0.92	1.04	1.75
Retailer Co-op	1.00	n/a	n/a	n/a	0.68	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
Residential Demand Response	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
Residential Demand Response (IHD)	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
Residential New Construction	1.00	3.65	0.78	1.03	0.41	0.49	0.63	0.63	3.65	7.17	3.09	0.62	0.49	0.49	0.63	0.63
Business Program																
Retrofit	1.06	0.93	0.92	0.84	0.72	0.75	0.73	0.71	0.93	1.05	1.01	0.98	0.75	0.76	0.73	0.72
Direct Install Lighting	1.08	0.69	0.82	0.78	1.08	0.94	0.94	0.94	0.69	0.85	0.84	0.83	0.94	0.94	0.94	0.94
Building Commissioning	n/a	n/a	n/a	1.97	n/a	n/a	n/a	1.00	n/a	n/a	n/a	1.16	n/a	n/a	n/a	1.00
New Construction	0.50	0.98	0.68	0.71	0.50	0.49	0.54	0.54	0.98	0.99	0.76	0.79	0.49	0.49	0.54	0.54
Energy Audit	n/a	n/a	1.02	0.96	n/a	n/a	0.66	0.68	n/a	n/a	0.97	1.00	n/a	n/a	0.66	0.67
Small Commercial Demand Response	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
Small Commercial Demand Response (IHD)	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
Demand Response 3	0.76	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
Industrial Program																
Process & System Upgrades	n/a	n/a	0.85	0.96	n/a	n/a	0.94	0.79	n/a	n/a	0.87	0.96	n/a	n/a	0.93	0.80
Monitoring & Targeting	n/a	n/a	n/a	0.59	n/a	n/a	n/a	1.00	n/a	n/a	n/a	0.36	n/a	n/a	n/a	1.00
Energy Manager	n/a	1.16	0.90	0.91	n/a	0.90	0.90	0.90	1.16	1.16	0.90	0.96	0.90	0.90	0.90	0.85
Retrofit	1.11	n/a	n/a	n/a	0.72	n/a	n/a	n/a	0.91	n/a	n/a	n/a	0.75	n/a	n/a	n/a
Demand Response 3	0.84	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
Home Assistance Program																
Home Assistance Program	1.00	0.32	0.26	0.49	0.70	1.00	1.00	1.00	0.32	0.99	0.88	0.78	1.00	1.00	1.00	1.00
Aboriginal Program																
Home Assistance Program	n/a	n/a	0.05	0.15	n/a	n/a	1.00	1.00	n/a	n/a	0.95	0.97	n/a	n/a	1.00	1.00
Direct Install Lighting	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
Pre-2011 Programs completed in 2011																
Electricity Retrofit Incentive Program	0.80	n/a	n/a	n/a	0.54	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
High Performance New Construction	1.00	1.00	1.00	n/a	0.49	0.50	0.50	0.50	1.00	1.00	1.00	n/a	0.50	0.50	0.50	0.50
Toronto Comprehensive	1.13	n/a	n/a	n/a	0.50	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
Multifamily Energy Efficiency Rebates	0.93	n/a	n/a	n/a	0.78	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
LDC Custom Programs	1.00	n/a	n/a	n/a	1.00	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
Other																
Program Enabled Savings	n/a	1.06	1.00	0.86	n/a	1.00	1.00	1.00	n/a	2.26	1.00	0.98	n/a	1.00	1.00	1.00
Time-of-Use Savings	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
LDC Pilots	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a

Summary Provincial Progress Towards CDM Targets

Table 9: Province-Wide Net Peak Demand Savings at the End User Level (MW)

Implementation Period	Annual			
	2011	2012	2013	2014
2011	216.3	136.6	135.8	129.0
2012†	1.4	253.3	109.8	108.2
2013†	0.6	7.0	404.5	122.0
2014†	1.4	10.8	34.2	568.6
Verified Net Annual Peak Demand Savings in 2014:				**927.7**
2014 Annual CDM Capacity Target:				**1,330**
Verified Portion of Peak Demand Savings Target Achieved in 2014 (%):				**69.8%**

Table 10: Province-Wide Net Energy Savings at the End-User Level (GWh)

Implementation Period	Annual				Cumulative
	2011	2012	2013	2014	2011-2014
2011	606.9	603.0	601.0	582.3	2,393.1
2012†	18.7	503.6	498.4	492.6	1,513.3
2013†	1.7	44.4	603.3	583.4	1,232.8
2014†	7.3	44.8	191.0	1,170.8	1,413.9
Verified Net Cumulative Energy Savings 2011-2014:					**6,553.0**
2011-2014 Cumulative CDM Energy Target:					**6,000**
Verified Portion of Cumulative Energy Target Achieved in 2014 (%):					**109.2%**

†Includes adjustments to previous years' verified results

Results presented using scenario 1 which assumes that demand response resources have a persistence of 1 year

METHODOLOGY

All results are at the end-user level (not including transmission and distribution losses)

EQUATIONS	
Prescriptive Measures and Projects	**Gross Savings = Activity * Per Unit Assumption** **Net Savings = Gross Savings * Net-to-Gross Ratio** **All savings are annualized (i.e. the savings are the same regardless of time of year a project was completed or measure installed)**
Engineered and Custom Projects	**Gross Savings = Reported Savings * Realization Rate** **Net Savings = Gross Savings * Net-to-Gross Ratio** **All savings are annualized (i.e. the savings are the same regardless of time of year a project was completed or measure installed)**
Demand Response	**Peak Demand: Gross Savings = Net Savings = contracted MW at contributor level * Provincial contracted to ex ante ratio** **Energy: Gross Savings = Net Savings = provincial ex post energy savings * LDC proportion of total provincial contracted MW** **All savings are annualized (i.e. the savings are the same regardless of the time of year a participant began offering DR)**
Adjustments to Previous Years' Verified Results	All variances from the Final Annual Results Reports from prior years will be adjusted within this report. Any variances with regards to projects counts, data lag, and calculations etc., will be made within this report. Considers the cumulative effect of energy savings.

Initiative	Attributing Savings to LDCs	Savings 'start' Date	Calculating Resource Savings
Consumer Program			
Appliance Retirement	Includes both retail and home pickup stream. Retail stream allocated based on average of 2008 & 2009 residential throughput; Home pickup stream directly attributed by postal code or customer selection.	Savings are considered to begin in the year the appliance is picked up.	Peak demand and energy savings are determined using the verified measure level per unit assumption multiplied by the uptake in the market (gross) taking into account net-to-gross factors such as free-ridership and spillover (net) at the measure level.
Appliance Exchange	When postal code information is provided by customer, results are directly attributed to the LDC. When postal code is not available, results allocated based on average of 2008 & 2009 residential throughput.	Savings are considered to begin in the year that the exchange event occurred.	
HVAC Incentives	Results directly attributed to LDC based on customer postal code.	Savings are considered to begin in the year that the installation occurred.	

Initiative	Attributing Savings to LDCs	Savings 'start' Date	Calculating Resource Savings
Conservation Instant Coupon Booklet	LDC-coded coupons directly attributed to LDC. Otherwise results are allocated based on average of 2008 & 2009 residential throughput.	Savings are considered to begin in the year in which the coupon was redeemed.	Peak demand and energy savings are determined using the verified measure level per unit assumption multiplied by the uptake in the market (gross) taking into account net-to-gross factors such as free-ridership and spillover (net) at the measure level.
Bi-Annual Retailer Event	Results are allocated based on average of 2008 & 2009 residential throughput.	Savings are considered to begin in the year in which the event occurs.	
Retailer Co-op	When postal code information is provided by the customer, results are directly attributed. If postal code information is not available, results are allocated based on average of 2008 & 2009 residential throughput.	Savings are considered to begin in the year of the home visit and installation date.	Peak demand and energy savings are determined using the verified measure level per unit assumption multiplied by the uptake in the market (gross) taking into account net-to-gross factors such as free-ridership and spillover (net) at the measure level.
Residential Demand Response	Results are directly attributed to LDC based on data provided to IESO through project completion reports and continuing participant lists.	Savings are considered to begin in the year the device was installed and/or when a customer signed a peaksaver PLUS™ participant agreement.	Peak demand savings are based on an ex ante estimate assuming a 1 in 10 weather year and represents the "insurance value" of the initiative. Energy savings are based on an ex post estimate which reflects the savings that occurred as a result of activations in the year and accounts for any "snapback" in energy consumption experienced after the event. Savings are assumed to persist for only 1 year, reflecting that savings will only occur if the resource is activated.

Initiative	Attributing Savings to LDCs	Savings 'start' Date	Calculating Resource Savings
Residential New Construction	Results are directly attributed to LDC based on LDC identified in application in the iCon system. Initiative was not evaluated in 2011, reported results are presented with forecast assumptions as per the business case.	Savings are considered to begin in the year of the project completion date.	Peak demand and energy savings are determined using the verified measure level per unit assumption multiplied by the uptake in the market (gross) taking into account net-to-gross factors such as free-ridership and spillover (net) at the measure level.
Business Program			
Efficiency: Equipment Replacement	Results are directly attributed to LDC based on LDC identified at the facility level in the iCon system. Projects in the Application Status: "Post-Stage Submission" are included (excluding "Payment denied by LDC"); Please see page for Building type to Sector mapping.	Savings are considered to begin in the year of the actual project completion date in the iCON system.	Peak demand and energy savings are determined by the total savings for a given project as reported in the iCON system (reported). A realization rate is applied to the reported savings to ensure that these savings align with EM&V protocols and reflect the savings that were actually realized (i.e. how many light bulbs were actually installed vs. what was reported) (gross). Net savings takes into account net-to-gross factors such as free-ridership and spillover (net). Both realization rate and net-to-gross ratios can differ for energy and demand savings and depend on the mix of projects within an LDC territory (i.e. lighting or non-lighting project, engineered/custom/prescriptive track).
	Additional Note: project counts were derived by filtering out invalid statuses (e.g. Post-Project Submission - Payment denied by LDC) and only including projects with an "Actual Project Completion Date" in 2014)		

Initiative	Attributing Savings to LDCs	Savings 'start' Date	Calculating Resource Savings
Direct Installed Lighting	Results are directly attributed to LDC based on the LDC specified on the work order.	Savings are considered to begin in the year of the actual project completion date.	Peak demand and energy savings are determined using the verified measure level per unit assumptions multiplied by the uptake of each measure accounting for the realization rate for both peak demand and energy to reflect the savings that were actually realized (i.e. how many light bulbs were actually installed vs. what was reported) (gross). Net savings take into account net-to-gross factors such as free-ridership and spillover for both peak demand and energy savings at the program level (net).
Existing Building Commissioning Incentive	Results are directly attributed to LDC based on LDC identified in the application.	Savings are considered to begin in the year of the actual project completion date.	Peak demand and energy savings are determined by the total savings for a given project as reported (reported). A realization rate is applied to the reported savings to ensure that these savings align with EM&V protocols and reflect the savings that were actually realized (i.e. how many light bulbs were actually installed vs. what was reported) (gross). Net savings takes into account net-to-gross factors such as free-ridership and spillover (net).
New Construction and Major Renovation Incentive	Results are directly attributed to LDC based on LDC identified in the application.	Savings are considered to begin in the year of the actual project completion date.	
Energy Audit	Projects are directly attributed to LDC based on LDC identified in the application.	Savings are considered to begin in the year of the audit date.	Peak demand and energy savings are determined by the total savings resulting from an audit as reported (reported). A realization rate is applied to the reported savings to ensure that these savings align with EM&V protocols and reflect the savings that were actually realized (i.e. how many light bulbs were actually installed vs. what was reported) (gross). Net savings takes into account net-to-gross factors such as free-ridership and spillover (net).

Initiative	Attributing Savings to LDCs	Savings 'start' Date	Calculating Resource Savings
Commercial Demand Response (part of the Residential program schedule)	Results are directly attributed to LDC based on data provided to IESO through project completion reports and continuing participant lists	Savings are considered to begin in the year the device was installed and/or when a customer signed a peaksaver PLUS™ participant agreement.	Peak demand savings are based on an ex ante estimate assuming a 1 in 10 weather year and represents the "insurance value" of the initiative. Energy savings are based on an ex post estimate which reflects the savings that occurred as a result of activations in the year. Savings are assumed to persist for only 1 year, reflecting that savings will only occur if the resource is activated.
Demand Response 3 (part of the Industrial program schedule)	Results are attributed to LDCs based on the total contracted megawatts at the contributor level as of December 31st, applying the provincial ex ante to contracted ratio (ex ante estimate/contracted megawatts); Ex post energy savings are attributed to the LDC based on their proportion of the total contracted megawatts at the contributor level.	Savings are considered to begin in the year in which the contributor signed up to participate in demand response.	Peak demand savings are ex ante estimates based on the load reduction capability that can be expected for the purposes of planning. The ex ante estimates factor in both scheduled non-performances (i.e. maintenance) and historical performance. Energy savings are based on an ex post estimate which reflects the savings that actually occurred as a results of activations in the year. Savings are assumed to persist for 1 year, reflecting that savings will not occur if the resource is not activated and additional costs are incurred to activate the resource.
Industrial Program			
Process & System Upgrades	Results are directly attributed to LDC based on LDC identified in application.	Savings are considered to begin in the year in which the incentive project was completed.	Peak demand and energy savings are determined by the total savings from a given project as reported (reported). A realization rate is applied to the reported savings to ensure that these savings align with EM&V protocols and reflect the savings that were actually realized (i.e. how many light bulbs were actually installed vs. what was reported) (gross). Net savings takes into account net-to-gross factors such as free-ridership and spillover (net).

Initiative	Attributing Savings to LDCs	Savings 'start' Date	Calculating Resource Savings
Monitoring & Targeting	Results are directly attributed to LDC based on LDC identified in the application.	Savings are considered to begin in the year in which the incentive project was completed.	Peak demand and energy savings are determined by the total savings from a given project as reported (reported). A realization rate is applied to the reported savings to ensure that these savings align with EM&V protocols and reflect the savings that were actually realized (i.e. how many light bulbs were actually installed vs. what was reported) (gross). Net savings takes into account net-to-gross factors such as free-ridership and spillover (net).
Energy Manager	Results are directly attributed to LDC based on LDC identified in the application.	Savings are considered to begin in the year in which the project was completed by the energy manager. If no date is specified the savings will begin the year of the Quarterly Report submitted by the energy manager.	Peak demand and energy savings are determined by the total savings from a given project as reported (reported). A realization rate is applied to the reported savings to ensure that these savings align with EM&V protocols and reflect the savings that were actually realized (i.e. how many light bulbs were actually installed vs. what was reported) (gross). Net savings takes into account net-to-gross factors such as free-ridership and spillover (net).

Initiative	Attributing Savings to LDCs	Savings 'start' Date	Calculating Resource Savings
Efficiency: Equipment Replacement Incentive (part of the C&I program schedule)	Results are directly attributed to LDC based on LDC identified at the facility level in the saveONenergy CRM; Projects in the Application Status: "Post-Stage Submission" are included (excluding "Payment denied by LDC"); Please see "Reference Tables" tab for Building type to Sector mapping.	Savings are considered to begin in the year of the actual project completion date on the iCON CRM system.	Peak demand and energy savings are determined by the total savings for a given project as reported in the iCON CRM system (reported). A realization rate is applied to the reported savings to ensure that these savings align with EM&V protocols and reflect the savings that were actually realized (i.e. how many light bulbs were actually installed vs. what was reported) (gross). Net savings takes into account net-to-gross factors such as free-ridership and spillover (net). Both realization rate and net-to-gross ratios can differ for energy and demand savings and depend on the mix of projects within an LDC territory (i.e. lighting or non-lighting project, engineered/custom/prescriptive track).
Demand Response 3	Results are attributed to LDCs based on the total contracted megawatts at the contributor level as of December 31st, applying the provincial ex ante to contracted ratio (ex ante estimate/contracted megawatts); Ex post energy savings are attributed to the LDC based on their proportion of the total contracted megawatts at the contributor level.	Savings are considered to begin in the year in which the contributor signed up to participate in demand response.	Peak demand savings are ex ante estimates based on the load reduction capability that can be expected for the purposes of planning. The ex ante estimates factor in both scheduled non-performances (i.e. maintenance) and historical performance. Energy savings are based on an ex post estimate which reflects the savings that actually occurred as a results of activations in the year. Savings are assumed to persist for 1 year, reflecting that savings will not occur if the resource is not activated and additional costs are incurred to activate the resource.

Initiative	Attributing Savings to LDCs	Savings 'start' Date	Calculating Resource Savings
Home Assistance Program			
Home Assistance Program	Results are directly attributed to LDC based on LDC identified in the application.	Savings are considered to begin in the year in which the measures were installed.	Peak demand and energy savings are determined using the measure level per unit assumption multiplied by the uptake of each measure (gross), taking into account net-to-gross factors such as free-ridership and spillover (net) at the measure level.
Aboriginal Program			
Aboriginal Program	Results are directly attributed to LDC based on LDC identified in the application.	Savings are considered to begin in the year in which the measures were installed.	Peak demand and energy savings are determined using the measure level per unit assumption multiplied by the uptake of each measure (gross), taking into account net-to-gross factors such as free-ridership and spillover (net) at the measure level.

Initiative	Attributing Savings to LDCs	Savings 'start' Date	Calculating Resource Savings
Pre-2011 Programs completed in 2011			
Electricity Retrofit Incentive Program	Results are directly attributed to LDC based on LDC identified in the application; Initiative was not evaluated in 2011, 2012, 2013 or 2014 assumptions as per 2010 evaluation.	Savings are considered to begin in the year in which a project was completed.	Peak demand and energy savings are determined by the total savings from a given project as reported. A realization rate is applied to the reported savings to ensure that these savings align with EM&V protocols and reflect the savings that were actually realized (i.e. how many light bulbs were actually installed vs. what was reported) (gross). Net savings takes into account net-to-gross factors such as free-ridership and spillover (net). If energy savings are not available, an estimate is made based on the kWh to kW ratio in the provincial results from the 2010 evaluated results (http://www.powerauthority.on.ca/evaluation-measurement-and-verification/evaluation-reports).
High Performance New Construction	Results are directly attributed to LDC based on customer data provided to the OPA from Enbridge; Initiative was not evaluated in 2011, 2012, 2013 or 2014, assumptions as per 2010 evaluation.	Savings are considered to begin in the year in which a project was completed.	
Toronto Comprehensive	Program run exclusively in Toronto Hydro-Electric System Limited service territory; Initiative was not evaluated in 2011, 2012, 2013 or 2014, assumptions as per 2010 evaluation.		

Initiative	Attributing Savings to LDCs	Savings 'start' Date	Calculating Resource Savings
Multifamily Energy Efficiency Rebates	Results are directly attributed to LDC based on LDC identified in the application; Initiative was not evaluated in 2011, 2012, 2013 or 2014, assumptions as per 2010 evaluation.	Savings are considered to begin in the year in which a project was completed.	Peak demand and energy savings are determined by the total savings from a given project as reported (reported). A realization rate is applied to the reported savings to ensure that these savings align with EM&V protocols and reflect the savings that were actually realized (i.e. how many light bulbs were actually installed vs. what was reported) (gross). Net savings takes into account net-to-gross factors such as free-ridership and spillover (net). If energy savings are not available, an estimate is made based on the kWh to kW ratio in the provincial results from the 2010 evaluated results (http://www.powerauthority.on.ca/evaluation-measurement-and-verification/evaluation-reports).
Data Centre Incentive Program	Program run exclusively in PowerStream Inc. service territory; Initiative was not evaluated in 2011, assumptions as per 2009 evaluation.		
EnWin Green Suites	Program run exclusively in ENWIN Utilities Ltd. service territory; Initiative was not evaluated in 2011 or 2012, assumptions as per 2010 evaluation.		

Consumer Program Allocation Methodology

Results can be allocated based on average of 2008 & 2009 residential throughput for each LDC (below) when additional information is not available. Source: OEB Yearbook Data 2008 & 2009

Local Distribution Company	Allocation
Algoma Power Inc.	0.2%
Atikokan Hydro Inc.	0.0%
Attawapiskat Power Corporation	0.0%
Bluewater Power Distribution Corporation	0.6%
Brant County Power Inc.	0.2%
Brantford Power Inc.	0.7%
Burlington Hydro Inc.	1.4%
Cambridge and North Dumfries Hydro Inc.	1.0%
Canadian Niagara Power Inc.	0.5%
Centre Wellington Hydro Ltd.	0.1%
Chapleau Public Utilities Corporation	0.0%
COLLUS Power Corporation	0.3%
Cooperative Hydro Embrun Inc.	0.0%
E.L.K. Energy Inc.	0.2%
Enersource Hydro Mississauga Inc.	3.9%
ENTEGRUS	0.6%
ENWIN Utilities Ltd.	1.6%
Erie Thames Powerlines Corporation	0.4%
Espanola Regional Hydro Distribution Corporation	0.1%
Essex Powerlines Corporation	0.7%
Festival Hydro Inc.	0.3%
Fort Albany Power Corporation	0.0%
Fort Frances Power Corporation	0.1%
Greater Sudbury Hydro Inc.	1.0%
Grimsby Power Inc.	0.2%
Guelph Hydro Electric Systems Inc.	0.9%
Haldimand County Hydro Inc.	0.4%
Halton Hills Hydro Inc.	0.5%
Hearst Power Distribution Company Limited	0.1%
Horizon Utilities Corporation	4.0%
Hydro 2000 Inc.	0.0%
Hydro Hawkesbury Inc.	0.1%
Hydro One Brampton Networks Inc.	2.8%
Hydro One Networks Inc.	30.0%
Hydro Ottawa Limited	5.6%
Innisfil Hydro Distribution Systems Limited	0.4%
Kashechewan Power Corporation	0.0%
Kenora Hydro Electric Corporation Ltd.	0.1%
Kingston Hydro Corporation	0.5%
Kitchener-Wilmot Hydro Inc.	1.6%
Lakefront Utilities Inc.	0.2%

Lakeland Power Distribution Ltd.	0.2%
London Hydro Inc.	2.7%
Middlesex Power Distribution Corporation	0.1%
Midland Power Utility Corporation	0.1%
Milton Hydro Distribution Inc.	0.6%
Newmarket - Tay Power Distribution Ltd.	0.7%
Niagara Peninsula Energy Inc.	1.0%
Niagara-on-the-Lake Hydro Inc.	0.2%
Norfolk Power Distribution Inc.	0.3%
North Bay Hydro Distribution Limited	0.5%
Northern Ontario Wires Inc.	0.1%
Oakville Hydro Electricity Distribution Inc.	1.5%
Orangeville Hydro Limited	0.2%
Orillia Power Distribution Corporation	0.3%
Oshawa PUC Networks Inc.	1.2%
Ottawa River Power Corporation	0.2%
Parry Sound Power Corporation	0.1%
Peterborough Distribution Incorporated	0.7%
PowerStream Inc.	6.6%
PUC Distribution Inc.	0.9%
Renfrew Hydro Inc.	0.1%
Rideau St. Lawrence Distribution Inc.	0.1%
Sioux Lookout Hydro Inc.	0.1%
St. Thomas Energy Inc.	0.3%
Thunder Bay Hydro Electricity Distribution Inc.	0.9%
Tillsonburg Hydro Inc.	0.1%
Toronto Hydro-Electric System Limited	12.8%
Veridian Connections Inc.	2.4%
Wasaga Distribution Inc.	0.2%
Waterloo North Hydro Inc.	1.0%
Welland Hydro-Electric System Corp.	0.4%
Wellington North Power Inc.	0.1%
West Coast Huron Energy Inc.	0.1%
Westario Power Inc.	0.5%
Whitby Hydro Electric Corporation	0.9%
Woodstock Hydro Services Inc.	0.3%

Reporting Glossary

Annual: the peak demand or energy savings that occur in a given year (includes resource savings from new program activity and resource savings persisting from previous years).

Cumulative Energy Savings: represents the sum of the annual energy savings that accrue over a defined period (in the context of this report the defined period is 2011 - 2014). This concept does not apply to peak demand savings.

End-User Level: resource savings in this report are measured at the customer level as opposed to the generator level (the difference being line losses).

Free-ridership: the percentage of participants who would have implemented the program measure or practice in the absence of the program.

Incremental: the new resource savings attributable to activity procured in a particular reporting period based on when the savings are considered to 'start'.

Initiative: a Conservation & Demand Management offering focusing on a particular opportunity or customer end-use (i.e. Retrofit, Fridge & Freezer Pickup).

Net-to-Gross Ratio: The ratio of net savings to gross savings, which takes into account factors such as free-ridership and spillover

Net Energy Savings (MWh): energy savings attributable to conservation and demand management activities net of free-riders, etc.

Net Peak Demand Savings (MW): peak demand savings attributable to conservation and demand management activities net of free-riders, etc.

Program: a group of initiatives that target a particular market sector (e.g. Consumer, Industrial).

Realization Rate: A comparison of observed or measured (evaluated) information to original reported savings which is used to adjust the gross savings estimates.

Settlement Account: the grouping of demand response facilities (contributors) into one contractual agreement

Spillover: Reductions in energy consumption and/or demand caused by the presence of the energy efficiency program, beyond the program-related gross savings of the participants. There can be participant and/or non-participant spillover.

Unit: for a specific initiative the relevant type of activity acquired in the market place (i.e. appliances picked up, projects completed, coupons redeemed).

Table 11: Canadian Niagara Power Inc. Initiative and Program Level Gross Savings by Year

Initiative	Unit	Gross Incremental Peak Demand Savings (kW) (new peak demand savings from activity within the specified reporting period)				Gross Incremental Energy Savings (kWh) (new energy savings from activity within the specified reporting period)			
		2011	2012	2013	2014	2011	2012	2013	2014
Consumer Program									
Appliance Retirement**	Appliances	26	6	8	8	182,793	38,455	50,971	52,783
Appliance Exchange**	Appliances	12	6	24	29	13,630	9,653	42,817	51,240
HVAC Incentives	Equipment	155	129	281	412	290,070	227,635	504,431	773,852
Conservation Instant Coupon Booklet	Items	5	1	2	7	88,378	6,775	34,964	88,046
Bi-Annual Retailer Event	Items	8	8	6	24	137,456	149,326	84,016	359,003
Retailer Co-op	Items	0	0	0	0	0	0	0	0
Residential Demand Response	Devices	0	0	49	65	0	0	6	0
Residential Demand Response (IHD)	Devices	0	0	0	0	0	0	0	0
Residential New Construction	Homes	0	0	0	0	0	0	0	0
Consumer Program Total		**207**	**150**	**371**	**543**	**712,326**	**431,844**	**717,204**	**1,324,924**
Business Program									
Retrofit	Projects	18	70	273	119	152,574	384,518	1,563,830	690,482
Direct Install Lighting	Projects	14	178	139	91	40,284	591,641	497,814	325,262
Building Commissioning	Buildings	0	0	0	0	0	0	0	0
New Construction	Buildings	0	0	0	5	0	0	0	33,525
Energy Audit	Audits	0	5	0	20	0	25,176	0	97,278
Small Commercial Demand Response	Devices	0	0	1	2	0	0	0	0
Small Commercial Demand Response (IHD)	Devices	0	0	0	0	0	0	0	0
Demand Response 3	Facilities	0	0	0	0	0	0	0	0
Business Program Total		**32**	**253**	**413**	**237**	**192,858**	**1,001,336**	**2,061,644**	**1,146,547**
Industrial Program									
Process & System Upgrades	Projects	0	0	0	0	0	0	0	0
Monitoring & Targeting	Projects	0	0	0	0	0	0	0	0
Energy Manager	Projects	0	0	0	0	0	0	0	0
Retrofit	Projects	0	0	0	0	0	0	0	0
Demand Response 3	Facilities	126	218	1,147	1,276	7,420	5,260	26,127	0
Industrial Program Total		**126**	**218**	**1,147**	**1,276**	**7,420**	**5,260**	**26,127**	**0**
Home Assistance Program									
Home Assistance Program	Homes	0	1	9	12	0	5,046	128,968	83,904
Home Assistance Program Total		**0**	**1**	**9**	**12**	**0**	**5,046**	**128,968**	**83,904**
Aboriginal Program									
Home Assistance Program	Homes	0	0	0	0	0	0	0	0
Direct Install Lighting	Projects	0	0	0	0	0	0	0	0
Aboriginal Program Total		**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
Pre-2011 Programs completed in 2011									
Electricity Retrofit Incentive Program	Projects	462	0	0	0	2,370,242	0	0	0
High Performance New Construction	Projects	1	1	0	0	2,805	1,119	0	0
Toronto Comprehensive	Projects	0	0	0	0	0	0	0	0
Multifamily Energy Efficiency Rebates	Projects	0	0	0	0	0	0	0	0
LDC Custom Programs	Projects	0	0	0	0	0	0	0	0
Pre-2011 Programs completed in 2011 Total		**462**	**1**	**0**	**0**	**2,373,047**	**1,119**	**0**	**0**
Other									
Program Enabled Savings	Projects	0	0	0	0	0	0	0	0
Time-of-Use Savings	Homes	0	0	0	264	0	0	0	0
LDC Pilots	Projects	0	0	0	0	0	0	0	0
Other Total		**0**	**0**	**0**	**264**	**0**	**0**	**0**	**0**
Adjustments to 2011 Verified Results			**6**	**0**	**135**		**117,942**	**0**	**376,993**
Adjustments to 2012 Verified Results				**15**	**267**			**126,484**	**864,875**
Adjustments to 2013 Verified Results					**38**				**208,535**
Energy Efficiency Total		**701**	**405**	**742**	**989**	**3,278,231**	**1,439,345**	**2,907,810**	**2,555,375**
Demand Response Total		**126**	**218**	**1,197**	**1,342**	**7,420**	**5,260**	**26,133**	**0**
Adjustments to Previous Years' Verified Results Total		**0**	**6**	**15**	**440**	**0**	**117,942**	**126,484**	**1,450,402**
OPA-Contracted LDC Portfolio Total (inc. Adjustments)		**828**	**630**	**1,954**	**2,771**	**3,285,651**	**1,562,546**	**3,060,427**	**4,005,777**

Activity and savings for Demand Response resources for each year represent the savings from all active facilities or devices contracted since January 1, 2011 (reported cumulatively).

*Includes adjustments after Final Reports were issued

Results presented using scenario 1 which assumes that demand response resources have a persistence of 1 year

Gross results are presented for informational purposes only and are not considered official 2014 Final Verified Results

**Net results substituted for gross results due to unavailability of data

Table 12: Adjustments to Canadian Niagara Power Inc. Gross Verified Results due to Variances

Initiative	Unit	Gross Incremental Peak Demand Savings (kW) (new peak demand savings from activity within the specified reporting period)				Gross Incremental Energy Savings (kWh) (new energy savings from activity within the specified reporting period)			
		2011	2012	2013	2014	2011	2012	2013	2014
Consumer Program									
Appliance Retirement	Appliances	0	0	0		0	0	0	
Appliance Exchange	Appliances	0	0	0		0	0	0	
HVAC Incentives	Equipment	-25	4	4		-46,553	6,617	7,164	
Conservation Instant Coupon Booklet	Items	0	0	0		1,308	0	106	
Bi-Annual Retailer Event	Items	1	0	0		12,129	0	0	
Retailer Co-op	Items	0	0	0		0	0	0	
Residential Demand Response	Devices	0	0	0		0	0	0	
Residential Demand Response (IHD)	Devices	0	0	0		0	0	0	
Residential New Construction	Homes	0	0	0		0	0	0	
Consumer Program Total		**-25**	**4**	**4**		**-33,115**	**6,617**	**7,270**	
Business Program									
Retrofit	Projects	0	9	36		0	110,612	189,950	
Direct Install Lighting	Projects	0	2	0		0	9,254	0	
Building Commissioning	Buildings	0	0	0		0	0	0	
New Construction	Buildings	0	0	0		0	863,616	0	
Energy Audit	Audits	31	0	0		151,058	1,259	0	
Small Commercial Demand Response	Devices	0	0	0		0	0	0	
Small Commercial Demand Response (IHD)	Devices	0	0	0		0	0	0	
Demand Response 3	Facilities	0	0	0		0	0	0	
Business Program Total		**31**	**11**	**36**		**151,058**	**984,741**	**189,950**	
Industrial Program									
Process & System Upgrades	Projects	0	0	0		0	0	0	
Monitoring & Targeting	Projects	0	0	0		0	0	0	
Energy Manager	Projects	0	0	0		0	0	0	
Retrofit	Projects	0	0	0		0	0	0	
Demand Response 3	Facilities	0	0	0		0	0	0	
Industrial Program Total		**0**	**0**	**0**		**0**	**0**	**0**	
Home Assistance Program									
Home Assistance Program	Homes	0	0	4		0	0	17,974	
Home Assistance Program Total		**0**	**0**	**4**		**0**	**0**	**17,974**	
Aboriginal Program									
Home Assistance Program	Homes	0	0	0		0	0	0	
Direct Install Lighting	Projects	0	0	0		0	0	0	
Aboriginal Program Total		**0**	**0**	**0**		**0**	**0**	**0**	
Pre-2011 Programs completed in 2011									
Electricity Retrofit Incentive Program	Projects	0	0	0		0	0	0	
High Performance New Construction	Projects	0	0	0		0	0	0	
Toronto Comprehensive	Projects	0	0	0		0	0	0	
Multifamily Energy Efficiency Rebates	Projects	0	0	0		0	0	0	
LDC Custom Programs	Projects	0	0	0		0	0	0	
Pre-2011 Programs completed in 2011 Total		**0**	**0**	**0**		**0**	**0**	**0**	
Other									
Program Enabled Savings	Projects	0	0	0		0	0	0	
Time-of-Use Savings	Homes	0	0	0		0	0	0	
LDC Pilots	Projects	0	0	0		0	0	0	
Other Total		**0**	**0**	**0**		**0**	**0**	**0**	
Adjustments to 2011 Verified Results		**6**				**117,942**			
Adjustments to 2012 Verified Results			**15**				**991,358**		
Adjustments to 2013 Verified Results				**44**				**215,194**	
Total Adjustments to Previous Years' Verified Results		**6**	**15**	**44**		**117,942**	**991,358**	**215,194**	

Activity and savings for Demand Response resources for each year represent the savings from all active facilities or devices contracted since January 1, 2011 (reported cumulatively).

Gross results are presented for informational purposes only and are not considered official 2014 Final Verified Results

Table 13: Province-Wide Initiatives and Program Level Gross Savings by Year

Initiative	Unit	Gross Incremental Peak Demand Savings (kW) (new peak demand savings from activity within the specified reporting period)				Gross Incremental Energy Savings (kWh) (new energy savings from activity within the specified reporting period)			
		2011	2012	2013	2014	2011	2012	2013	2014
Consumer Program									
Appliance Retirement**	Appliances	6,750	2,011	3,151	3,579	45,971,627	13,424,518	18,616,239	20,315,770
Appliance Exchange**	Appliances	719	556	2,101	2,238	873,531	974,621	3,746,106	3,990,372
HVAC Incentives	Equipment	53,209	38,346	40,418	48,467	99,413,430	66,929,213	71,225,037	90,274,814
Conservation Instant Coupon Booklet	Items	1,184	231	464	1,442	19,192,453	1,325,898	6,842,244	19,000,254
Bi-Annual Retailer Event	Items	1,504	1,622	1,142	4,626	26,899,265	29,222,072	16,441,329	70,254,471
Retailer Co-op	Items	0	0	0	0	3,917	0	0	0
Residential Demand Response	Devices	10,390	49,038	93,076	117,513	23,597	359,408	390,303	8,379
Residential Demand Response (IHD)	Devices	0	0	0	0	0	0	0	0
Residential New Construction	Homes	0	1	29	587	1,813	4,884	259,826	3,699,786
Consumer Program Total		**73,757**	**91,805**	**140,380**	**178,452**	**192,379,633**	**112,240,615**	**117,521,084**	**207,543,846**
Business Program									
Retrofit	Projects	34,201	78,965	82,896	98,849	184,070,265	387,817,248	478,410,896	642,515,421
Direct Install Lighting	Projects	22,155	20,469	19,807	24,794	65,777,197	68,896,046	68,140,249	89,528,509
Building Commissioning	Buildings	0	0	0	988	0	0	0	1,513,377
New Construction	Buildings	247	1,596	2,934	11,911	823,434	3,755,869	9,183,826	37,742,970
Energy Audit	Audits	0	1,450	4,283	9,367	0	7,049,351	23,386,108	46,012,517
Small Commercial Demand Response	Devices	55	187	773	2,116	131	1,068	373	319
Small Commercial Demand Response (IHD)	Devices	0	0	0	0	0	0	0	0
Demand Response 3	Facilities	21,390	19,389	23,706	23,380	633,421	281,823	346,659	0
Business Program Total		**78,048**	**122,056**	**134,399**	**171,405**	**251,304,448**	**467,801,406**	**579,468,111**	**817,313,113**
Industrial Program									
Process & System Upgrades	Projects	0	0	313	12,287	0	0	2,799,746	90,463,617
Monitoring & Targeting	Projects	0	0	0	102	0	0	0	502,517
Energy Manager	Projects	0	1,034	3,953	5,767	0	7,067,535	24,438,070	44,929,364
Retrofit	Projects	6,372	0	0	0	38,412,408	0	0	0
Demand Response 3	Facilities	176,180	74,056	162,543	166,082	4,243,958	1,784,712	4,309,160	0
Industrial Program Total		**182,552**	**75,090**	**166,809**	**184,238**	**42,656,366**	**8,852,247**	**31,546,976**	**135,895,498**
Home Assistance Program									
Home Assistance Program	Homes	4	1,777	2,361	2,466	56,119	5,524,230	20,987,275	19,582,658
Home Assistance Program Total		**4**	**1,777**	**2,361**	**2,466**	**56,119**	**5,524,230**	**20,987,275**	**19,582,658**
Aboriginal Program									
Home Assistance Program	Homes	0	0	267	549	0	0	1,609,393	3,101,207
Direct Install Lighting	Projects	0	0	0	0	0	0	0	0
Aboriginal Program Total		**0**	**0**	**267**	**549**	**0**	**0**	**1,609,393**	**3,101,207**
Pre-2011 Programs completed in 2011									
Electricity Retrofit Incentive Program	Projects	40,418	0	0	0	223,956,390	0	0	0
High Performance New Construction	Projects	10,197	6,501	772	268	52,371,183	23,803,888	3,522,240	1,377,475
Toronto Comprehensive	Projects	33,467	0	0	802	174,070,574	0	0	7,085,257
Multifamily Energy Efficiency Rebates	Projects	2,553	0	0	0	9,774,792	0	0	0
LDC Custom Programs	Projects	534	0	0	0	649,140	0	0	0
Pre-2011 Programs completed in 2011 Total		**87,169**	**6,501**	**772**	**1,070**	**460,822,079**	**23,803,888**	**3,522,240**	**8,462,733**
Other									
Program Enabled Savings	Projects	0	2,177	3,692	5,500	0	525,011	4,075,382	19,035,337
Time-of-Use Savings	Homes	0	0	0	54,795	0	0	0	0
LDC Pilots	Projects	0	0	0	1,170	0	0	0	5,061,522
Other Total		**0**	**2,177**	**3,692**	**60,296**	**0**	**525,011**	**4,075,382**	**19,035,337**
Adjustments to 2011 Verified Results			**13,266**	**645**	**1,601**		**48,705,294**	**20,581**	**6,028**
Adjustments to 2012 Verified Results				**8,632**	**13,449**			**54,301,893**	**59,098,939**
Adjustments to 2013 Verified Results					**34,727**				**206,413,158**
Energy Efficiency Total		**213,515**	**156,735**	**168,583**	**289,384**	**942,317,539**	**616,320,385**	**753,683,966**	**1,210,925,694**
Demand Response Total		**208,015**	**142,670**	**280,099**	**309,091**	**4,901,107**	**2,427,011**	**5,046,495**	**8,698**
Adjustments to Previous Years' Verified Results Total		**0**	**13,266**	**9,277**	**49,777**	**0**	**48,705,294**	**54,322,474**	**265,518,125**
OPA-Contracted LDC Portfolio Total (inc. Adjustments)		**421,530**	**312,671**	**457,958**	**648,252**	**947,218,646**	**667,452,690**	**813,052,934**	**1,476,452,516**

Activity and savings for Demand Response resources for each year represent the savings from all active facilities or devices contracted since January 1, 2011 (reported cumulatively).

Gross results are presented for informational purposes only and are not considered official 2014 Final Verified Results

**Net results substituted for gross results due to unavailability of data

Table 14: Adjustments to Province-Wide Gross Verified Results due to Variances

Initiative	Unit	Gross Incremental Peak Demand Savings (kW) (new peak demand savings from activity within the specified reporting period)				Gross Incremental Energy Savings (kWh) (new energy savings from activity within the specified reporting period)			
		2011	2012	2013	2014	2011	2012	2013	2014
Consumer Program									
Appliance Retirement	Appliances	0	0	0		0	0	0	
Appliance Exchange	Appliances	0	0	0		0	0	0	
HVAC Incentives	Equipment	-8,759	1,091	2,157		-16,241,086	1,952,473	3,873,449	
Conservation Instant Coupon Booklet	Items	15	0	1		255,975	0	20,668	
Bi-Annual Retailer Event	Items	117	0	0		2,373,616	0	0	
Retailer Co-op	Items	0	0	0		0	0	0	
Residential Demand Response	Devices	0	0	0		0	0	0	
Residential Demand Response (IHD)	Devices	0	0	0		0	0	0	
Residential New Construction	Homes	1	1	115		330,093	2,009	701,488	
Consumer Program Total		**-8,628**	**1,092**	**2,273**		**-13,281,402**	**1,954,483**	**4,595,605**	
Business Program									
Retrofit	Projects	4,511	10,114	16,584		22,046,931	58,528,789	108,677,566	
Direct Install Lighting	Projects	541	217	49		1,346,618	781,858	174,460	
Building Commissioning	Buildings	0	0	0		0	0	0	
New Construction	Buildings	3,287	2,673	4,151		11,323,593	9,884,305	15,992,924	
Energy Audit	Audits	656	488	3,631		2,391,744	2,386,374	19,822,524	
Small Commercial Demand Response	Devices	0	0	0		0	0	0	
Small Commercial Demand Response (IHD)	Devices	0	0	0		0	0	0	
Demand Response 3	Facilities	0	0	0		0	0	0	
Business Program Total		**8,996**	**13,491**	**24,414**		**37,108,886**	**71,581,326**	**144,667,473**	
Industrial Program									
Process & System Upgrades	Projects	0	0	426		0	0	1,232,785	
Monitoring & Targeting	Projects	0	0	54		0	528,000	639,348	
Energy Manager	Projects	29	1,071	2,687		0	8,968,007	28,893,596	
Retrofit	Projects	0	0	0		0	0	0	
Demand Response 3	Facilities	0	0	0		0	0	0	
Industrial Program Total		**29**	**1,071**	**3,168**		**0**	**9,496,007**	**30,765,729**	
Home Assistance Program									
Home Assistance Program	Homes	0	222	791		0	1,316,749	4,321,794	
Home Assistance Program Total		**0**	**222**	**791**		**0**	**1,316,749**	**4,321,794**	
Aboriginal Program									
Home Assistance Program	Homes	0	0	134		0	0	563,715	
Direct Install Lighting	Projects	0	0	0		0	0	0	
Aboriginal Program Total		**0**	**0**	**134**		**0**	**0**	**563,715**	
Pre-2011 Programs completed in 2011									
Electricity Retrofit Incentive Program	Projects	266	0	0		1,049,108	0	0	
High Performance New Construction	Projects	13,072	727	405		23,905,663	5,665,066	1,535,048	
Toronto Comprehensive	Projects	0	1,920	529		0	12,924,335	3,783,965	
Multifamily Energy Efficiency Rebates	Projects	0	0	0		0	0	0	
LDC Custom Programs	Projects	0	0	0		0	0	0	
Pre-2011 Programs completed in 2011 Total		**13,337**	**2,647**	**934**		**24,954,771**	**18,589,400**	**5,319,013**	
Other									
Program Enabled Savings	Projects	1,776	3,712	2,020		1,673,712	11,481,687	10,688,564	
Time-of-Use Savings	Homes	0	0	0		0	0	0	
LDC Pilots	Projects	0	0	0		0	0	0	
Other Total		**1,776**	**3,712**	**2,020**		**1,673,712**	**11,481,687**	**10,688,564**	
Adjustments to 2011 Verified Results		**15,511**				**50,455,967**			
Adjustments to 2012 Verified Results			**22,235**				**114,419,652**		
Adjustments to 2013 Verified Results				**33,734**				**200,921,892**	
Adjustments to Previous Years' Verified Results Total		**15,511**	**22,235**	**33,734**		**50,455,967**	**114,419,652**	**200,921,892**	

Activity and savings for Demand Response resources for each year represent the savings from all active facilities or devices contracted since January 1, 2011 (reported cumulatively).

*Includes adjustments after Final Reports were issued

Results presented using scenario 1 which assumes that demand response resources have a persistence of 1 year

Gross results are presented for informational purposes only and are not considered official 2014 Final Verified Results