A medium voltage circuit breaker could also be applied in this application and would have a few advantages over fused loadbreaks. The main advantages of a breaker would be the following:

- Very sensitive protection can be applied, including phase and ground fault protection.
- Other sophisticated protection can be applied, as well as sequence of events records, waveform captures, and metering within the relays
- A breaker can be quickly re-closed after a fault is cleared, unlike fuses which must have their link replaced.

However, a circuit breaker would also cost substantially more than a fused loadbreak, typically about $50,000 versus $15,000 for a single feeder (initial construction costs, not retrofit), with other potential costs such as a battery bank for stored tripping energy and other requirements. Therefore, while there are some advantages to applying this protection, it would not currently be recommended based on the costs involved and the potential future configuration of the system.

Exhibit 3 – Operating Revenues

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EXHIBIT 3 – OPERATING REVENUE

The evidence presented in this exhibit provides information supporting the revenues derived from activities regulated by the OEB. Actual operating revenues from the regulated operations come mainly from fixed and variable tariff charges as well as pass through charges and specific service charges. The evidence herein is organized according to the following topics;

1) Load and Revenue Forecast
2) Variance Analysis
3) Other Revenues

Tab 1 – Load and Revenue Forecasts

E3.T1.S1 OVERVIEW

The schedules included in this Exhibit outline and describe CHEI's load, customer, and distribution revenue forecasts. The load forecast methodology and assumptions are described in detail at E3.T1.S3. CHEI's purchase forecast is based on a regression model. The load forecasting model relates monthly historical purchases to monthly weather conditions (measured in cooling-degree-days ("CDD") and heating-degree days (HDD)), and other variables such as which are discussed in detail at E3.T1.S3. Further adjustments for projected Conservation and Demand Management ("CDM") reductions and estimated distribution losses are made to derive distribution sales. CHEI has applied current approved rates to the test year customer and sales forecast in order to derive the test year distribution revenue. Projected Revenues at current and proposed rates are presented at Tab 2 of this Exhibit. Other Revenues are discussed at Tab 3 of this Exhibit and the derivation of the Power Supply Expense is presented at E3.T3.S8.

E3.T1.S2 HISTORICAL AND FORECAST VOLUME TABLE

Table 1 below shows the actual and forecast trends for customer/connection counts, kWh consumption and billed kW demand. The derivation of forecast for the Test Year can be found at E3.T1.S4.

Table 1: Proposed 2014 Load Forecast

	Year	2008	2009	2010	2011	2012	2013	2014
Residential	Cust	1743	1757	1777	1785	1788	1798	1998
	kWh	19785629	19972762	19782134	19491847	19634780	19627850	21785963
GS<50	Cust	162	153	151	158	157	160	168
	kWh	4950298	4834611	4708938	4513395	4742923	4804973	5064745
GS>50	Cust	12	11	11	11	11	11	11
	kWh	3966528	4158758	4070817	3990329	4403739	4267511	4284025
	kW	12578.21	12094.6	11793.3	11860.8	12485.5	12607.32	12656.11
Streetlight	Cust	409	409	409	409	409	415	425
	kWh	388273.7	350654	381018	357291	355537	374201.7	383218.6
	kW	1006.8	1003.2	1003.2	1003.2	1003.2	1000.331	1024.435
USL	Conn.	19	19	19	19	19	20	20
	Energy	93535.68	92676	89786	89208	89208	91611.8	91611.8

In the past, the Residential class has shown stable but slow growth in customers. Historically slow growth of new residential attachments reflects the lack of new development occurring in CHEI's service area however CHEI expects a new subdivision to be built and energized sometime in 2014 and 2015. The new subdivision is expected to bring 300 new customers by 2018. Several other development projects have been discussed however no concrete plans have been formed. The forecasted consumption for 2014 reflects the addition of this new subdivision. Table 2 below shows the yearly change in consumption for the Residential class. The utility expects that approximately 200 customers out of the 300 expected connections will be in service by end of 2014.

Table 2: Residential Variance

	Residential			
Year	Cust	%chg	kWh	%chg
2003	1,417		18,102,240	
2004	1,522	7%	17,954,498	-1%
2005	1,593	5%	17,941,596	0%
2006	1,634	3%	18,422,749	3%
2007	1,689	3%	19,179,493	4%
2008	1,743	3%	19,785,629	3%
2009	1,757	1%	19,972,762	1%
2010	1,777	1%	19,782,134	-1%
2011	1,785	0%	19,491,847	-1%
2012	1,788	0%	20,141,761	3%
2013	1,798	1%	19,627,850	-3%
2014	1,998	11%	21,785,963	11%

The number of customers for GS<50 kW have been growing slowly but steadily since 2003. This increase in GS<50 is proportional to the residential growth in CHEI's service area.

Table 3: GS<50 Variance

	GS<50			
Year	Cust	%chg	kWh	%chg
2003	165		5,429,033	
2004	167	1%	4,893,895	-10%
2005	169	1%	4,651,271	-5%
2006	170	1%	4,792,364	3%
2007	162	-5%	4,740,664	-1%
2008	162	0%	4,950,298	4%
2009	153	-6%	4,834,611	-2%
2010	151	-1%	4,708,938	-3%
2011	158	5%	4,513,395	-4%
2012	157	-1%	4,865,388	8%
2013	160	2%	4,804,973	-1%
2014	168	5%	5,064,745	5%

The customer count for the GS>50 kW class has not changed since 2008 and therefore, no change is anticipated for both count and consumption, in 2014.

Table 4: GS>50 Variance

	GS>50					
Year	Cust	%chg	kWh	%chg	kW	%chg
2003	12		4,444,344		13,228	
2004	12	0%	4,539,809	2%	14,510	10%
2005	12	0%	4,231,851	-7%	14,289	-2%
2006	12	0%	4,190,122	-1%	12,990	-9%
2007	12	0%	6,439,475	54%	13,560	4%
2008	12	0%	3,966,528	-38%	12,578	-7%
2009	11	-8%	4,158,758	5%	12,095	-4%
2010	11	0%	4,070,817	-2%	11,793	-2%
2011	11	0%	3,990,329	-2%	11,861	1%
2012	11	0%	4,403,739	10%	12,486	5%
2013	11	0%	4,267,511	-3%	12,607	1%
2014	11	0%	4,284,025	0%	12,656	0%

Street Lighting connections have also been historically stable however an increase in 2014 is expected as a result of the new subdivision. Only a slight increase is expected in USL connections, again, as a result of the new subdivision.

Table 5: Streetlights and USL Variance

	Non-Weather Sensitive								
Year	Streetlight						USL		
2003	Cust	%chg	kWh	%chg	kW		Conn.		Energy
2004	381		310,985		856		15		66,312
2005	387	2%	344,131	11%	908	6%	15	0%	66,312
2006	395	2%	370,312	8%	951	5%	15	0%	66,312
2007	395	0%	381,159	3%	955	0%	15	0%	66,312
2008	409	4%	379,503	0%	987	3%	21	40%	88,330
2009	409	0%	388,274	2%	1,007	2%	19	-10%	93,536
2010	409	0%	350,654	-10%	1,003	0%	19	0%	92,676
2011	409	0%	381,018	9%	1,003	0%	19	0%	89,786
2012	409	0%	357,291	-6%	1,003	0%	19	0%	89,208
2013	409	0%	355,537	0%	1,003	0%	19	0%	89,208
2014	415	1%	374,202	5%	1,000	0%	20	5%	91,612
	425	2%	383,219	2%	1,024	2%	20	0%	91,612

The utility load has been relatively stable over the historical period, with average wholesale deliveries (on an actual weather basis) increasing by eight per cent from 2003 to 2012. The bulk of the increase occurred prior to 2008 and have since then plateaued mainly due to the fact that additional energy usage typical of more air conditioners, computers, TVs and, pool heaters will be offset by the additional transitioning to energy efficient lighting, appliances and other energy efficient changes.

Table 6: Wholesale Purchases VS Weather Adjusted

Year	kWh Purchased	%chg	Adjusted	%chg	Purch. VS Adj.
2003	27,517,169.79		28,940,124.94		5.17%
2004	28,610,973.26	3.97%	28,643,728.07	-1.02%	0.11%
2005	30,335,823.58	6.03%	28,946,696.92	1.06%	-4.58%
2006	28,814,681.00	-5.01%	28,650,683.79	-1.02%	-0.57%
2007	30,020,517.00	4.18%	29,699,765.60	3.66%	-1.07%
2008	29,993,741.00	-0.09%	30,209,951.99	1.72%	0.72%
2009	30,079,505.00	0.29%	30,115,120.16	-0.31%	0.12%
2010	30,067,541.00	-0.04%	29,936,865.95	-0.59%	-0.43%
2011	30,249,028.00	0.60%	29,778,753.10	-0.53%	-1.55%
2012	29,716,224.00	-1.76%	30,483,513.13	2.37%	2.58%

E3.T1.S3 APPROACH TO WEATHER NORMALIZED LOAD FORECAST

The load forecast was developed based on monthly wholesale purchased kWh from January 2003 to December 2012 as measured at the wholesale point of delivery (exclusive of losses; i.e., not loss adjusted). CHEI purchases wholesale energy from Hydro One Networks. While it may be desirable to isolate demand determinants related to individual rate classes, such as residential, commercial, and industrial, it is not always possible nor is it necessary to do so especially for small utilities such as CHEI. Therefore the decision was made to continue working with the same approach as the last cost of service, thus using total monthly energy. Many other LDC distribution rate applications considered by the Board have also used this approach and that this approach has been approved by the Board in the past.

The methodology predicts wholesale consumption using a multiple regression analysis that relates historical monthly wholesale kWh usage to monthly historical heating degree days and cooling degree days. Heating degree-day figures come with a "base temperature", and provide a measure of how much (in degrees), and for how long (in days), the outside temperature was below that base temperature. The most readily available heating degree days come with a base temperature of 18°C. Cooling degree-day figures also come with a base temperature, and provide a measure of how much, and for how long, the outside temperature was above that base temperature. Historical monthly full-time employment levels are also used to account for regional economic patterns that may influence consumption of electricity within the LDC. For degree days, daily observations as reported at Ottawa (Macdonald-Cartier) International Airport are used. For employment levels, monthly full-time employment for the Ottawa Economic Region, as reported in Statistics Canada's Monthly Labour Force Survey (CANSIM) has been used.

The number of days in the month did not yield meaningful results in predicting CHEI's load. Therefore, these were not included as explanatory variables.

The resulting regression equation yields an adjusted R-squared of 0.87. When actual annual wholesale values are compared to annual values predicted by the regression equation, the mean absolute percentage error (MAPE) is 1.69 per cent. More detailed model statistics can be found in the next section.

Weather normalized values are determined by using the regression equation with a 10-year average monthly degree days (2003-2012). The 10-year average is consistent with recent years' weather and has been used in other electricity distribution rate applications and has been accepted by the Board.

Allocation to specific weather sensitive rate classes (Residential, GS<50, GS>50) is based on the share of each classes' actual retail kWh (exclusive of distribution losses) share of actual wholesale kWh. Weather normalized wholesale kWh, for historical years, are allocated to these classes based on these historical shares. Forecast values for 2013 and 2014 are allocated based on the most recent year's (2012) actual share.

For those rate classes that use kW consumption as a billing determinant, sales for these customer classes are then converted to kW based on the historical volumetric relationship between kWh and kW

E3.T1.S4 LOAD FORECAST

The load forecast presented in this application uses a similar approach as CHEI's last Cost of Service application (2010).

CHEI's energy purchase forecast is based on a multiple regression model. Distribution sales/consumption is derived from purchases Distribution consumption is then allocated to the rate classes based on historical billing trends (% share). For those rate classes that use kW consumption as a billing determinant, sales for these customer classes are then converted to kW based on the historical volumetric relationship between kWh and kW.

The following table (Table 7) outlines monthly wholesale deliveries to CHEI from May 2003 to December 2012.

Table 7: Monthly Actual Energy (kWh), Embrun

	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012
Jan	3008989	3495133	3511603	2859069	2933130	2903498	3471299	3346358	3172720	2957782
Feb	3102648	3073437	2868848	2903021	3050867	2894816	3176832	2797322	2843398	2892266
Mar	2380957	2416349	2697718	2493981	2640192	3010275	2521443	2325101	2504442	2251469
Apr	2142317	2177357	2159485	2194198	2362019	2071600	2269610	2291130	2466547	2187562
May	1730327	1886182	1938928	1942547	1935667	2040573	1873661	2175578	1968798	2131898
Jun	1865251	1787184	2493888	2089418	2205766	2260592	2167539	2196483	2491606	2480451
Jul	1894675	2074106	2317110	2576915	2341590	2253245	2119197	2489155	2591069	2534698
Aug	2203712	2076848	2263837	2079187	2353395	2455939	2556038	2428634	2294906	2727376
Sep	1778506	1907258	2168726	1957587	2217226	2068726	2062813	2096810	2274531	2031747
Oct	2007117	1918701	2044269	2285037	2001734	2121728	2387786	2280842	2106445	1791846
Nov	2444314	2496704	2385523	2380630	2542576	2661923	2341130	2479104	2280768	2592355
Dec	2958358	3301715	3485888	3053091	3436355	3250826	3132157	3161024	3253798	3136774

The purpose of a multiple regression equation is to predict a single dependent variable from multiple independent variables. Several variables and the interactions among each variables, affects overall electricity purchases. Various combination of economic drivers were tested using different model specifications and while adding and removing independent variable at a time. Results from these various scenarios can be found in the excel model filed in conjunction with this application. The decision to add/delete a variable is made on the basis of whether that variable improves the accuracy of the model. The variables listed below were used as initial inputs for the purpose of regression analysis.

- Heating Degree Days (included)
- Cooling Degree Days (included)
- Spring Fall Flag (included)
- Days/month (excluded)
- Full Time Employment for Ottawa Region (urban) (included)
- Full Time Employment for Kingston Pembroke (rural) (excluded)

Variation in monthly electricity consumption is influenced by three main factors – weather (e.g. heating and cooling), which is by far the most dominant effect for most systems; employment factors (increases or decreases in economic activity leads to changes in employment); and a seasonality, in this case, a spring/fall factors.

Heating and Cooling:

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

CHEI has adopted the 10 year average from 2003 to 2012 as the definition of weather normal. Our view is that a ten-year average based on the most recent ten calendar years available is a reasonable compromise that likely reflects the "average" weather experienced in recent years. Many other LDCs have also adopted this definition for the purposes of cost-of-service rebasing. The following table (Table 8) outlines the monthly weather data used in the regression analysis.

Table 8: HDD and CDD as reported at Ottawa International Airport

	2003		**2004**		**2005**		**2006**		**2007**		**2008**		**2009**		**2010**		**2011**		**2012**	
	HDD	CDD	HDD	CDD	HDD	CDD	HDD	CDD	HDD	CDD	HDD	CDD	HDD	CDD	HDD	CDD	HDD	CDD	HDD	CDD
Jan	977	0	1045	0	921	0	734	0	797	0	754	0	980	0	789	0	893	0	831	0
Feb	842	0	750	0	701	0	721	0	820	0	774	0	712	0	656	0	729	0	671	0
Mar	675	0	559	0	669	0	600	0	643	0	721	0	598	0	461	0	636	0	460	0
Apr	425	0	378	2	325	0	322	0	361	0	300	0	334	0	258	0	347	0	363	3
May	154	0	166	4	205	2	128	17	157	0	185	0	182	3	112	2	143	17	96	21
Jun	39	55	54	27	16	112	28	48	34	17	22	0	50	3	38	38	19	59	0	70
Jul	2	90	2	87	3	129	0	131	12	67	0	61	13	45	5	33	0	138	0	142
Aug	13	106	30	48	8	115	18	68	20	65	14	79	26	43	15	151	2	82	8	98
Sep	60	24	67	11	59	33	121	5	76	79	95	50	107	82	112	93	55	33	127	21
Oct	337	0	287	0	270	6	336	0	228	26	322	25	356	5	311	26	259	1	243	0
Nov	469	0	484	0	484	0	417	0	517	2	503	0	417	0	492	0	393	0	542	0
Dec	722	0	815	0	762	0	610	0	788	0	797	0	759	0	731	0	415	0	681	0

Employment Factor:

In order to measure the change in economic activity, a data series must be chosen which represents, as much as possible, regional economic activity. Although full-time employment levels for the Pembroke-Kingston region are available, a decision was made to use the monthly full-time employment levels for the Ottawa economic region, as reported in Statistics Canada's Monthly Labour Force Survey (CANSIM). The reason for using Ottawa instead of Kingston-Pembroke is that Embrun tends to be a "commuter town" or "bedroom community" defined as an urban community that is primarily residential, from which most of the workforce commutes out to create their livelihood. In this case, many of CHEI's residents work in the Ottawa. Employments levels in Ottawa tend to have a more relevant impact on Embrun's load forecast.

The following table (Table 9) outlines the full-time employment levels for the Ottawa economic region.

Table 9: full-time employment levels for the Ottawa economic region

	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012
Jan	486.50	490.70	497.90	505.30	495.50	545.40	537.90	548.80	540.80	552.80
Feb	481.80	486.10	494.80	506.30	497.40	537.90	528.30	544.40	539.90	549.50
Mar	484.30	481.80	485.30	505.90	501.90	533.30	520.10	540.20	542.70	554.50
Apr	483.50	478.30	488.30	513.50	508.20	536.00	520.70	540.60	546.20	562.70
May	491.40	487.10	494.80	524.40	524.30	542.90	529.20	547.20	555.90	573.70
Jun	496.10	500.50	506.80	532.80	538.00	552.90	544.10	564.30	564.00	580.30
Jul	510.20	513.30	517.10	542.10	556.90	568.40	563.80	577.50	571.90	586.50
Aug	519.90	517.00	521.10	544.50	563.70	578.50	577.30	581.00	576.40	588.90
Sep	516.10	513.30	514.50	535.20	562.70	571.40	577.10	571.30	568.50	584.00
Oct	513.70	511.20	509.00	518.80	558.60	559.40	570.00	562.10	560.00	575.00
Nov	502.10	505.60	502.80	501.30	553.60	546.50	561.70	550.90	552.70	570.40
Dec	500.20	505.80	508.80	497.50	553.80	546.00	556.30	546.50	551.80	567.50

Spring/Fall Flag:

The forecast equation for Embrun's monthly wholesale kWh also contains a seasonal factor, specifically a spring/fall flag to account for the seasonal increase in consumption in the summer and winter months.

Using these variables, an excel based multiple regression analysis was used to develop an equation describing the relationship between monthly actual wholesale kWh and the explanatory variables. CHEI also used a correlation function to examine the relationship between the variables included in the analysis.

The following table (Table 10) presents the regression results used to determine the load forecast

Table 10: Correlation/Regression Results

CORRELATION RESULTS - Scenario 4

	Purchased kWh	*HDD*	*CDD*	*Spring Fall*	
Purchased kWh	1				
HDD	0.78736102	1			
CDD	-0.2323335	-0.6465083	1		
Spring Fall	-0.5367908	-0.1137436	-0.3507276	1	
Full Time Employment for Ottawa Region	-0.0795182	-0.3767558	0.36169899	-0.0722688	1

REGRESSION ANALYSIS _SUMMARY OUTPUT - Scenario 4

Regression Statistics	
Multiple R	0.93145591

R Square	0.86761012
Adjusted R Square	0.86300525
Standard Error	166181.331
Observations	120

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	4	2.0813E+13	5.2032E+12	188.411614	1.634E-49
Residual	115	3.1759E+12	2.7616E+10		
Total	119	2.3989E+13			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*
Intercept	638908.828	305403.261	2.09201704	0.0386375	33964.0014
HDD	1367.19524	75.6901878	18.0630446	2.2612E-35	1217.26761
CDD	2102.52206	630.185754	3.33635288	0.00114366	854.245892
Spring Fall	-317016.17	36880.3331	-8.5958055	4.7561E-14	-390068.98
Full Time Employment for Ottawa Region	2698.28884	555.313312	4.85903863	3.7615E-06	1598.3205

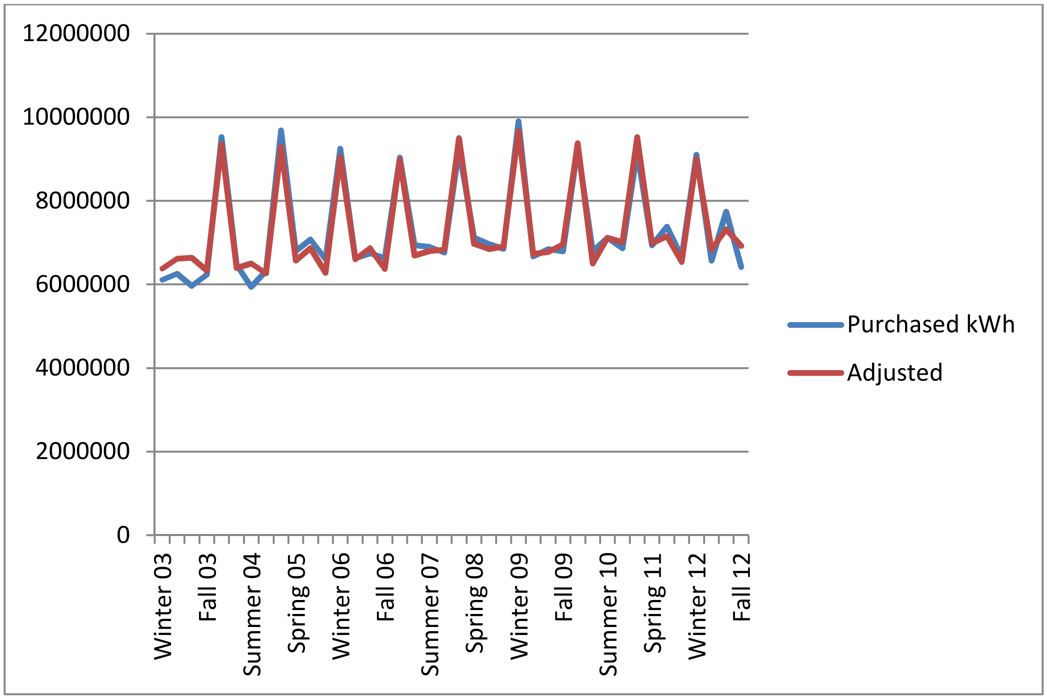
Table 11 below provides a comparison of the forecasted, actual and weather-normalized purchases kWhs over the past ten years. In accordance with the Filing Requirements, CHEI has also provided a 2013 forecast assuming twenty-year normal weather conditions. Following table 11 is a Chart 1 which plots Actual Purchases vs Adjusted.

Table 11: Purchased VS Adjusted

Year	kWh Purchased	year over year	Adjusted	year over year	Purch. VS Adj.
2003	27,517,169.79		28,940,124.94		5.17%
2004	28,610,973.26	3.97%	28,643,728.07	-1.02%	0.11%
2005	30,335,823.58	6.03%	28,946,696.92	1.06%	-4.58%
2006	28,814,681.00	-5.01%	28,650,683.79	-1.02%	-0.57%
2007	30,020,517.00	4.18%	29,699,765.60	3.66%	-1.07%
2008	29,993,741.00	-0.09%	30,209,951.99	1.72%	0.72%
2009	30,079,505.00	0.29%	30,115,120.16	-0.31%	0.12%
2010	30,067,541.00	-0.04%	29,936,865.95	-0.59%	-0.43%
2011	30,249,028.00	0.60%	29,778,753.10	-0.53%	-1.55%
2012	29,716,224.00	-1.76%	30,483,513.13	2.37%	2.58%

As shown in the table above, 2012 adjusted wholesale purchases are up 2.37% from 2011 and 2.58% higher than the Actual Wholesale Purchases.

Chart 1: Purchased VS Adjusted



Annual estimates using actual weather are compared to actual values in the table 12 below. Mean absolute percentage error (MAPE is a measure of how high or low are the differences between the predictions and actual data) of annual estimates for the period is 1.69%. On a monthly basis, the MAPE was calculated as 5.6%. Although the MAPE calculated on a monthly basis is higher than the MAPE calculated on a yearly basis, this forecast is intended for determination of annual load; therefore, an annual MAPE is an appropriate measure for predictive accuracy. The median is calculated at 0.89%.

Table 12 – Actual vs. Predicted Wholesale kWh

Year	kWh Purchased	Adjusted	Purch. VS Adj.	MAPE
2003	27517169.79	28940124.94	5.17%	5.17%
2004	28610973.26	28643728.07	0.11%	0.11%
2005	30335823.58	28946696.92	-4.58%	4.58%
2006	28814681.00	28650683.79	-0.57%	0.57%
2007	30020517.00	29699765.60	-1.07%	1.07%
2008	29993741.00	30209951.99	0.72%	0.72%
2009	30079505.00	30115120.16	0.12%	0.12%
2010	30067541.00	29936865.95	-0.43%	0.43%
2011	30249028.00	29778753.10	-1.55%	1.55%
2012	29716224.00	30483513.13	2.58%	2.58%
MAPE				**1.69%**
Median				**0.89%**

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Customer Forecast

CHEI has used a simple geometric mean function to determine the forecasted number of customers of 2013 and 2014. Geometric mean is more appropriate to use when dealing with percentages and rates of change. Although the formula is somewhat simplistic, it is reasonably representative of CHEI's natural customer growth. Residential customers grew steadily from 2003 up until 2008. However, growth in the residential class has tapered off since 2008, the reason being that most developed areas have currently been filled close to capacity. As mentioned earlier in the application, the utility is in the process of upgrading its distribution system to accommodate new development. It is estimated that the natural growth of the residential class will increase by 1.26% over 2012 for both 2013 and 2014. However, as mentioned in the earlier CHEI anticipates that a new subdivision will be energized sometime in 2014-2015. This subdivision would include approximately 300 houses. The utility, the municipality and board members are of the opinion that it is unlikely that all 300 units will be completed, sold and energized in 2014. For this reason, CHEI has adjusted its proposed customer count to add in 200 new customers in the residential class.

An increase in inhabitants usually results in an increase in commercial or municipal services (i.e. new fire station). CHEI anticipates an increase of 11 customers in General Services <50 from 2012 to 2014. Additional Streetlights connections are also anticipated as a result of the new subdivision.

Historic customer counts and projected customer counts for 2013 and 2014 are presented in Table 13 below.

Table 13 – Customer Forecast

	Residential		GS<50		GS>50		Street Lights		USL	
Date	Connections	Growth Rate	Connections	Growth Rate	Connections	Growth Rate	Connections	Growth Rate	Connections	Growth Rate
2003	1417		165		12		381		15	
2004	1522	1.0741	167	1.0121	12	1.0000	387	1.0157	15	1.0000
2005	1593	1.0466	169	1.0120	12	1.0000	395	1.0207	15	1.0000
2006	1634	1.0257	170	1.0059	12	1.0000	395	1.0000	15	1.0000
2007	1689	1.0337	162	0.9529	12	1.0000	409	1.0354	21	1.4000
2008	1743	1.0320	162	1.0000	12	1.0000	409	1.0000	19	0.9048
2009	1757	1.0080	153	0.9444	11	0.9167	409	1.0000	19	1.0000
2010	1777	1.0114	151	0.9869	11	1.0000	409	1.0000	19	1.0000
2011	1785	1.0045	158	1.0464	11	1.0000	409	1.0000	19	1.0000
2012	1788	1.0017	157	0.9937	11	1.0000	409	1.0000	19	1.0000
Geomean		*1.0262*		*0.9945*		*0.9904*		*1.0079*		*1.0266*
2013	1835		156		11		412		20	
2014	1883		155		11		415		20	

CHE adjusted										
2013	1798		160		11		415		20	
2014	1998		168		11		425		20	

Class specific weather normalization and consumption

The following section presents class specific weather normal historic and forecast values for those classes that have weather sensitive load. Historic class specific kWh consumption is allocated based on each class' share in wholesale kWh, exclusive of distribution losses. Forecast class values are allocated based on the class share for 2012.

CHEI estimates that the natural load usage growth of existing customers will be no more than 1% per year. Additional energy usage typical of more air conditioners, computers, TVs and, pool will be offset by the additional transitioning to energy efficient lighting, appliances and other energy efficient changes.

The natural forecasted load for the Residential and GS<50 class has been adjusted to factor in additional load from the anticipated subdivision. As most commercial units are heated with natural gas, the increase in load for the GS<50 and GS>50 classes is marginal.

Tables 14-15-16 show historical and forecasted details for each of the weather sensitive classes.

Table 14 – Annual Residential Forecast

Residential						
Year	Actual residential kWh	Wholesale Purchases	Adjusted Purchases	*Share%*	Weather Normal	Per customer
2003	17,212,172	27,517,170	28,940,125	62.55%	18,102,240	12,775
2004	17,933,967	28,610,973	28,643,728	62.68%	17,954,498	11,797
2005	18,802,598	30,335,824	28,946,697	61.98%	17,941,596	11,263
2006	18,528,201	28,814,681	28,650,684	64.30%	18,422,749	11,275
2007	19,386,628	30,020,517	29,699,766	64.58%	19,179,493	11,356
2008	19,644,024	29,993,741	30,209,952	65.49%	19,785,629	11,351
2009	19,949,142	30,079,505	30,115,120	66.32%	19,972,762	11,368
2010	19,868,483	30,067,541	29,936,866	66.08%	19,782,134	11,132
2011	19,799,668	30,249,028	29,778,753	65.46%	19,491,847	10,920
2012	19,634,780	29,716,224	30,483,513	66.07%	20,141,761	11,265
2013			29,540,520	66.07%	19,518,685	10,916
2014			29,654,833	66.07%	19,594,217	10,959

* consumption is further adjusted below

Load corrected based on CHE input

Residential						
Year	Actual residential kWh	Wholesale Purchases	Adjusted Purchases	*Share%*	Weather Normal	Per customer
2012	19,634,780	29,716,224	30,483,513	66.07%	20,141,761	11,265
2013	0	0	29,540,520	66.07%	19,518,685	10,916
2014	0	0	29,654,833	66.07%	19,594,217	10,959

Residential				
Year	New Customer	Per Customer Weather Normalized (based on 2012 Cust count)	Added Load	Total
2013	10	10,916	109,165	**19,627,850**
2014	200	10,959	2,191,747	**21,785,963**

Table 15 – Annual General Service <50 Consumption

GS<50						
Year	Actual GS<50 kWh	Wholesale Purchases	Adjusted Purchases	*Share%*	Weather Normal	Per customer
2003	5,162,093	27,517,170	28,940,125	18.76%	5,429,033	32,903
2004	4,888,299	28,610,973	28,643,728	17.09%	4,893,895	29,305
2005	4,874,481	30,335,824	28,946,697	16.07%	4,651,271	27,522
2006	4,819,795	28,814,681	28,650,684	16.73%	4,792,364	28,190
2007	4,791,862	30,020,517	29,699,766	15.96%	4,740,664	29,263
2008	4,914,869	29,993,741	30,209,952	16.39%	4,950,298	30,557
2009	4,828,893	30,079,505	30,115,120	16.05%	4,834,611	31,599
2010	4,729,493	30,067,541	29,936,866	15.73%	4,708,938	31,185
2011	4,584,672	30,249,028	29,778,753	15.16%	4,513,395	28,566
2012	4,742,923	29,716,224	30,483,513	15.96%	4,865,388	30,990
2013			29,540,520	15.96%	4,714,879	30,031
2014			29,654,833	15.96%	4,733,125	30,147

* consumption is further adjusted below

Load corrected based on CHE input

GS<50						
Year	Actual GS<50 kWh			*Share%*	Weather Normal	Per customer
2012	4,742,923	29,716,224	30,483,513	15.96%	4,865,388	30,990
2013	0	0	29,540,520	15.96%	4,714,879	30,031
2014	0	0	29,654,833	15.96%	4,733,125	30,147

GS<50				
Year	New Customer	Per Customer Weather Normalized	Added Load	Total
2013	3	30,031	90,093	**4,804,973**
2014	11	30,147	331,620	**5,064,745**

Table 16 – Annual General Service >50 Consumption

GS>50						
Year	Actual GS>50 kWh	Wholesale Purchases	Adjusted Purchases	*Share%*	Weather Normal	Per customer
2003	4,225,820	27,517,170	28,940,125	15.36%	4,444,344	370,362
2004	4,534,618	28,610,973	28,643,728	15.85%	4,539,809	378,317
2005	4,434,933	30,335,824	28,946,697	14.62%	4,231,851	352,654
2006	4,214,106	28,814,681	28,650,684	14.62%	4,190,122	349,177
2007	6,509,020	30,020,517	29,699,766	21.68%	6,439,475	536,623
2008	3,938,140	29,993,741	30,209,952	13.13%	3,966,528	330,544
2009	4,153,840	30,079,505	30,115,120	13.81%	4,158,758	378,069
2010	4,088,586	30,067,541	29,936,866	13.60%	4,070,817	370,074
2011	4,053,345	30,249,028	29,778,753	13.40%	3,990,329	362,757
2012	4,292,894	29,716,224	30,483,513	14.45%	4,403,739	400,340
2013			29,540,520	14.45%	4,267,511	387,956
2014			29,654,833	14.45%	4,284,025	389,457

Note that the GS>50 is not affected by the new subdivision therefore little change is expected in this class.

Actual, normalized and forecast kW for the weather sensitive GS>50 class are summarized in Table 17 below. Similarly the kWh, the demand (or kW) for the GS>50 class is not affected by the new subdivision therefore little change is expected in this class.

Historical normalized values are calculated based on the annual ratio of class kW to class kWh. Forecast kW is based on the class kW to class kWh ratio in 2008.

Table 17 – Annual General Service >50 Demand (kW)

	GS>50			
Year	Energy	Weather Ad	Demand	KW/kWh Ratio
2003	4,225,820		13,228	0.00313
2004	4,534,618		14,510	0.00320
2005	4,434,933		14,289	0.00322
2006	4,214,106		12,990	0.00308
2007	6,509,020		13,560	0.00208
2008	3,938,140		12,578	0.00319
2009	4,153,840		12,095	0.00291
2010	4,088,586		11,793	0.00288
2011	4,053,345		11,861	0.00293
2012	4,292,894		12,486	0.00291
2013		4,267,511	12,607	
2014		4,284,025	12,656	
Avg				*0.00295*

Table 18 presents actual and forecast kWh and kW for the non-weather sensitive Street Lighting, and kWh for non-weather sensitive USL. The forecast throughput for USL classes is not expected to change as no changes to the number of customer connections is anticipated in 2013 or 2014. Street Lighting is affected by the new subdivision and as such, the forecast has used a simple average to determine the forecasted load and adjusted the 2013 and 2014 accordingly.

Table 18- non-weather sensitive Street Lighting, USL

Streetlight						USL		
Energy	Demand	Connection	kWh per connection	KW per connection	KW/kWh Ratio	Energy	Connection	kWh per connection
310,985	856	381	816	2.2467	0.00275	66,312	15	4,421
344,131	908	387	889	2.3466	0.00264	66,312	15	4,421
370,312	951	395	937	2.4084	0.00257	66,312	15	4,421
381,159	955	395	965	2.4173	0.00251	66,312	15	4,421
379,503	987	409	928	2.4125	0.00260	88,330	21	4,206
388,274	1,007	409	949	2.4616	0.00259	93,536	19	4,923
350,654	1,003	409	857	2.4528	0.00286	92,676	19	4,878
381,018	1,003	409	932	2.4528	0.00263	89,786	19	4,726
357,291	1,003	409	874	2.4528	0.00281	89,208	19	4,695
355,537	1,003	409	869	2.4528	0.00282	89,208	19	4,695
374,202	1,000	415				91,612	20	
383,219	1,024	425				91,612	20	
Avg			*902*	*2.4104*	*0.00268*			*4,581*

Table 19 below presents the results for class specific historic actual and historic normalized kWh and kW (where applicable), and normalized forecast values for bridge year (2009) and test year (2010).

Table 19 – Load Forecast (Historical, Bridge and Test Years).

	Weather Adjusted							Non-Weather Sensitive				
	Residential		GS<50		GS>50			Streetlight			USL	
Year	Cust	kWh	Cust	kWh	Cust	kWh	kW	Cust	kWh	kW	Conn.	Energy
2003	1,417	18,102,240	165	5,429,033	12	4,444,344	13,228	381	310,985	856	15	66,312
2004	1,522	17,954,498	167	4,893,895	12	4,539,809	14,510	387	344,131	908	15	66,312
2005	1,593	17,941,596	169	4,651,271	12	4,231,851	14,289	395	370,312	951	15	66,312
2006	1,634	18,422,749	170	4,792,364	12	4,190,122	12,990	395	381,159	955	15	66,312
2007	1,689	19,179,493	162	4,740,664	12	6,439,475	13,560	409	379,503	987	21	88,330
2008	1,743	19,785,629	162	4,950,298	12	3,966,528	12,578	409	388,274	1,007	19	93,536
2009	1,757	19,972,762	153	4,834,611	11	4,158,758	12,095	409	350,654	1,003	19	92,676
2010	1,777	19,782,134	151	4,708,938	11	4,070,817	11,793	409	381,018	1,003	19	89,786
2011	1,785	19,491,847	158	4,513,395	11	3,990,329	11,861	409	357,291	1,003	19	89,208
2012	1,788	20,141,761	157	4,865,388	11	4,403,739	12,486	409	355,537	1,003	19	89,208
2013	1,798	19,627,850	160	4,804,973	11	4,267,511	12,607	415	374,202	1,000	20	91,612
2014	1,998	21,785,963	168	5,064,745	11	4,284,025	12,656	425	383,219	1,024	20	91,612

Average use

Table 20 below presents the actual average use per customer, by customer class, and historical and adjusted forecast average use per customer generated using our load forecast. As can be seen from the results below, the predicted use per customer is in line with historical usage per customer.

Table 20 – Average use per customer (Historical, Bridge and Test Years).

	Residential	GS<50	GS>50		Streetlights		USL
Year	per cust	per cust	per cust kWh	per cust kWh	per cust kWh	per cust kWh	per cust kWh
2003	12,147	31,285	352,152	1,102	816	2	4,421
2004	11,783	29,271	377,885	1,209	889	2	4,421
2005	11,803	28,843	369,578	1,191	937	2	4,421
2006	11,339	28,352	351,176	1,082	965	2	4,421
2007	11,478	29,579	542,418	1,130	928	2	4,206
2008	11,270	30,339	328,178	1,048	949	2	4,923
2009	11,354	31,561	377,622	1,100	857	2	4,878
2010	11,181	31,321	371,690	1,072	932	2	4,726
2011	11,092	29,017	368,486	1,078	874	2	4,695
2012	10,981	30,210	390,263	1,135	869	2	4,695
2013	10,916	30,031	387,956	1,146	902	2	4,581
2014	10,904	30,147	389,457	1,151	902	2	4,581

E3.T1.S5 PERSISTENCE FROM HISTORICAL CDM PROGRAMS

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

The schedule to achieve CDM targets are presented at Table 21 below.

Table 21 – Utility specific 2011-2014 CDM target

4 Year (2011-2014) kWh Target:	**1,120,000**

	2011	2012	2013	2014	Total
	%				
2011 CDM Programs	6.33%	6.33%	6.33%	6.31%	25.30%
2012 CDM Programs		21.43%	21.43%	21.43%	64.29%
2013 CDM Programs			3.47%	3.47%	6.94%
2014 CDM Programs				3.47%	3.47%
Total in Year	**6.33%**	**18.78%**	**31.23%**	**43.66%**	**100.00%**

	kWh				
2011 CDM Programs	70,951	70,849	70,849	70,709	283,358
2012 CDM Programs		240,000	240,000	240,000	720,000
2013 CDM Programs			38,881	38,881	77,762
2014 CDM Programs				38,881	38,881
Total in Year	**70,951**	**310,849**	**349,729**	**388,471**	**1,120,000**
				Check	1,120,000

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

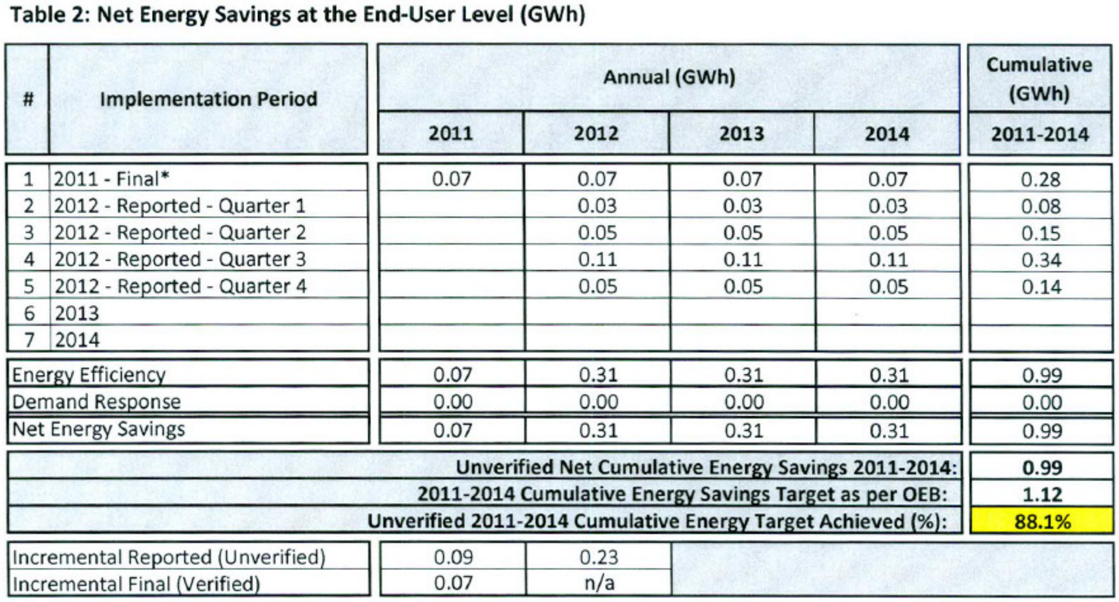

Table 2: Net Energy Savings at the End-User Level (GWh)

#	Implementation Period	Annual (GWh)				Cumulative (GWh)
		2011	2012	2013	2014	2011-2014
1	2011 - Final*	0.07	0.07	0.07	0.07	0.28
2	2012 - Reported - Quarter 1		0.03	0.03	0.03	0.08
3	2012 - Reported - Quarter 2		0.05	0.05	0.05	0.15
4	2012 - Reported - Quarter 3		0.11	0.11	0.11	0.34
5	2012 - Reported - Quarter 4		0.05	0.05	0.05	0.14
6	2013					
7	2014					
	Energy Efficiency	0.07	0.31	0.31	0.31	0.99
	Demand Response	0.00	0.00	0.00	0.00	0.00
	Net Energy Savings	0.07	0.31	0.31	0.31	0.99
	Unverified Net Cumulative Energy Savings 2011-2014:					**0.99**
	2011-2014 Cumulative Energy Savings Target as per OEB:					**1.12**
	Unverified 2011-2014 Cumulative Energy Target Achieved (%):					**88.1%**
	Incremental Reported (Unverified)	0.09	0.23			
	Incremental Final (Verified)	0.07	n/a			

Table 22 – Calculation of adjustment to the Load Forecast

Net-to-Gross Conversion kWh					
		"Gross"	"Net"	Difference	"Net-to-Gross" Conversion Factor ("g")
2006		207,000	186,000	21,000	11.29%
2007		869,000	332,000	537,000	161.75%
2008		605,000	360,000	245,000	68.06%
2009		685,000	416,000	269,000	64.66%
2010		606,000	322,000	284,000	88.20%
2011		589,000	304,000	285,000	93.75%
2012		555,000	216,000	339,000	156.94%
2013		548,000	286,000	262,000	91.61%
2014		499,000	261,000	238,000	91.19%
2006 to 2011 OPA CDM programs: Persistence to 2014		**5,163,000**	**2,683,000**	**2,480,000**	**92.43%**

	2011	**2012**	**2013**	**2014**	**Total for 2014**
Amount used for CDM threshold for LRAMVA	70,709	240,000	38,881	38,881	388,471
Manual Adjustment for 2014 Load Forecast	136,069	461,841	74,820	37,410	710,140
Manual adjustment uses "gross" versus "net" (i.e. numbers multiplied by (1 + g)					

E3.T1.S6 CLASS SPECIFIC CDM COMPONENT

The overall CDM adjustment for 2014, as calculated above, is allocated on pro-rata basis (using kWh forecast) per class.

CDM Adjusted energy forecast

kWh	Year	2013	2014
Residential	kWh	19,627,850	21,785,963
GS<50	kWh	4,804,973	5,064,745
GS>50	kWh	4,267,511	4,284,025
Streetlight	kWh	374,202	383,219
USL	kWh	91,612	91,612
Total			31,609,564

Share	Target	CDM Adj.
68.92%	489,442.98	21,296,520.49
16.02%	113,784.45	4,950,960.38
13.55%	96,244.82	4,187,780.52
1.21%	8,609.38	374,609.24
0.29%	2,058.15	89,553.65
100.00%	710,139.77	30,899,424.28

CDM Adjusted demand forecast

kW	Year	2013	2014
GS>50	kW	12,607	12,656
Streetlight	kW	1,000	1,024
Total			13,681

CDM Adj
12,372
1,001
13,373

Tab 2 – Variance Analysis of Proposed Revenues

E3.T2.S1 OVERVIEW

CHEI’s 2013 forecasted revenues recovered through its currently approved distribution rates will be $781,348 (exclusive of all rate riders). This amount is determined by applying the currently approved distribution rates to the forecasted consumption and customer counts. When the same formula is applied to the 2014 consumption, resulting revenues are $837,820. The forecasted 2014 distribution revenues are $56,440 higher the 2013 actual amounts.

E3.T2.S2 PROJECTED REVENUES AT CURRENT AND PROPOSED RATES

These following tables show CHEI’s projected revenues for both the Bridge and Test Year at current and proposed rates.

Table 23 – Revenues at Current and Proposed Rates

Bridge Year

	Bridge Year Projected Revenue from Existing Variable Charges							
Customer Class Name	**Variable Distribution Rate**	**per**	**Bridge Year Volume**	**Gross Variable Revenue**	**Transform. Allowance Rate**	**Transform. Allowance kW's**	**Transform. Allowance $'s**	**Net Variable Revenue**
Residential	$0.0128	kWh	19,627,850	251,236			0	251,236
General Service < 50 kW	$0.0168	kWh	4,804,973	80,724			0	80,724
General Service > 50 to 4999 kW	$4.5445	kW	12,607	57,293	($0.60)		0	57,293
Unmetered Scattered Load	$0.0104	kWh	91,612	953			0	953
Street Lighting	$6.5145	kW	1,000	6,515	($0.60)		0	6,515
MicroFit	$5.4000	Monthly	6	32			0	32
Total Variable Revenue			**24,538,047**	**396,752**		**0**	**0**	**396,752**

Bridge Year

	Bridge Year Projected Revenue from Existing Fixed Charges							
Customer Class Name	**Fixed Rate**	**Customers (Connections)**	**Fixed Charge Revenue**	**Variable Revenue**	**TOTAL**	**% Fixed Revenue**	**% Variable Revenue**	**% Total Revenue**
Residential	$13.7000	1,798	295,591	251,236	546,828	54.06%	45.94%	69.99%
General Service < 50 kW	$20.3400	160	39,053	80,724	119,776	32.60%	67.40%	15.33%
General Service > 50 to 4999 kW	$245.2700	11	32,376	57,293	89,668	36.11%	63.89%	11.48%
Unmetered Scattered Load	$40.0100	20	9,602	953	10,555	90.97%	9.03%	1.35%
Street Lighting	$1.6000	415	7,968	6,515	14,483	55.02%	44.98%	1.85%
MicroFit	$5.4000	0	6	32	38	0.00%	0.00%	0.00%
Total Fixed Revenue		**2,404**	**384,596**	**396,752**	**781,348**			

Test Year

	Test Year Projected Revenue from Existing Variable Charges							
Customer Class Name	**Variable Distribution Rate**	**per**	**Test Year Volume**	**Gross Variable Revenue**	**Transform. Allowance Rate**	**Transform. Allowance kW's**	**Transform. Allowance $'s**	**Net Variable Revenue**
Residential	$0.0128	kWh	21,296,520	272,595			0	272,595
General Service < 50 kW	$0.0168	kWh	4,950,960	83,176			0	83,176
General Service > 50 to 4999 kW	$4.5445	kW	12,372	56,225	($0.60)		0	56,225
Unmetered Scattered Load	$0.0104	kWh	89,554	931			0	931
Street Lighting	$6.5145	kW	1,001	6,521	($0.60)			6,521
MicroFit	$5.4000	Monthly	11	59			0	59
Total Variable Revenue			**26,350,418**	**419,508**		**0**	**0**	**419,508**

Test Year

	Test Year Projected Revenue from Existing Fixed Charges							
Customer Class Name	**Fixed Rate**	**Customers (Connections)**	**Fixed Charge Revenue**	**Variable Revenue**	**TOTAL**	**% Fixed Revenue**	**% Variable Revenue**	**% Total Revenue**
Residential	$13.7000	1,998	328,471	272,595	601,067	54.65%	45.35%	71.63%
General Service < 50 kW	$20.3400	168	41,005	83,176	124,182	33.02%	66.98%	14.80%
General Service > 50 to 4999 kW	$245.2700	11	32,376	56,225	88,600	36.54%	63.46%	10.56%
Unmetered Scattered Load	$40.0100	20	9,602	931	10,534	91.16%	8.84%	1.26%
Street Lighting	$1.6000	425	8,160	6,521	14,681	55.58%	44.42%	1.75%
MicroFit	$5.4000	0	11	59	70	0.00%	0.00%	0.01%
Total Fixed Revenue		**2,622**	**419,626**	**419,508**	**839,134**			

E3.T2.S2 VARIANCE ANALYSIS BY CLASS

The bulk of the increase is in the Residential Class which is expected since nearly 70% of the utility's load is attributed to the Residential Class. The main reasons for this variance, as explained in the load forecast, is due primarily to the lack of new development in the service area over the last several years. Secondly, additional energy consumption that does not depend on the weather (often referred to as "baseload" energy consumption) is often offset by the additional transitioning to energy efficient lighting, appliances and other energy efficient changes. Revenue Deficiency is discussed further in Exhibit 6.

Table 24 – Variance Analysis by Class

Variance Analysis

	Bridge Year to Test Year Variance			
Customer Class Name	**2,013.00**	**2,014.00**	**Variance**	**% change**
Residential	$546,827.68	$600,213.08	53,385	9.76%
General Service < 50 kW	$119,776.34	$123,921.12	4,145	3.46%
General Service > 50 to 4999 kW	$89,668.15	$88,422.96	-1,245	-1.39%
Unmetered Scattered Load	$10,555.16	$10,530.84	-24	-0.23%
Street Lighting	$14,482.50	$14,661.47	179	1.24%
MicroFit	$38.40	$70.40		
Total Fixed Revenue	**781,348**	**837,820**	**56,440**	7.23%

Tab 3 – Other Revenues

E3.T3.S1 OVERVIEW

Other Distribution Revenues are revenues that are distribution related but that are sourced from means other than distribution rates. It includes items such as

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

Details of these revenues are provided at the next section E3.T3.S2. Variances on the revenue items will be explained at E3.T3.S3.

E3.T3.S2 BREAKDOWN BY ACCOUNT – APPENDIX 2-F

Appendix 2-F is presented at the next page.

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Appendix 2-F
Other Operating Revenue

USoA #	USoA Description	2010 Actual	2011 Actual	2012 Actual[2]	2012 Actual[2]	Bridge Year[3]	Bridge Year[3]	Test Year
						2013	2013	2014
	Reporting Basis					CGAAP	MIFRS	CGAAP
4235	**Specific Service Charges**	$ 9,280	$ 12,870	$ 12,605		$ 13,250		$ 14,200
4225	**Late Payment Charges**	$ 5,764	$ 7,109	$ 5,208		$ 5,800		$ 6,000
4082	**Retail Services Revenues**	$ 3,817	$ 3,713	$ 3,614		$ 3,975		$ 4,130
4080	Admin Charge	$ 5,395	$ 5,519	$ 5,598		$ 5,750		$ 5,938
4084	Service Transaction Request	$ 54	$ 12	$ 8		$ 10		$ 13
Specific Service Charges		$ 9,280	$ 12,870	$ 12,605	$ -	$ 13,250	$ -	$ 14,200
Late Payment Charges		$ 5,764	$ 7,109	$ 5,208	$ -	$ 5,800	$ -	$ 6,000
Other Operating Revenues		$ 9,266	$ 9,244	$ 9,220		$ 9,735		$ 10,081
Other Income or Deductions								
Total		$ 24,310	$ 29,223	$ 27,033	$ -	$ 28,785	$ -	$ 30,281

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

Note: Add all applicable accounts listed above to the table and include all relevant information.
The above table assumes adoption of MIFRS as of January 1, 2013. If the adoption year differs, please adjust the table accordingly.

Account Breakdown Details

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

Account 4405 - Interest and Dividend Income

	2010 Actual	2011 Actual	2012 Actual[2]	2012 Actual[2]	Bridge Year	Bridge Year	Test Year
Reporting Basis					CGAAP	MIFRS	CGAAP
Short-term Investment Interest							
Bank Deposit Interest							
Miscellaneous Interest Revenue							
etc.[1]							
Total	$ -	$ -	$ -	$ -	$ -	$ -	$ -

Notes:
1 List and specify any other interest revenue

Breakdown of Other Service Charges

		2010 Actual			2011 Actual			2012 Actual			2013 Actual			2014 Actual		
	2010 Actual Total			0			0			0			0			0
Service	***USoA***	**Quantiy**	**Rate**	**Total**	**Quantiy**	**Rate**	**Total**	**Quantiy**	**Rate**	**Total**	**Quantiy**	**Rate**	**Total**	**Quantiy**	**Rate**	**Total**
Standard Supply Service -- Administrative Charge	4080	21580	$ 0.25	$ 5,395	22075	$ 0.25	$ 5,519	22391	$ 0.25	$ 5,598	23000	$ 0.25	$ 5,750	23750	$ 0.25	$ 5,938
	4080 Total			$ 5,395			$ 5,519			$ 5,598			$ 5,750			$ 5,938
Retailer Service Agreement -- standard charge	4082	1	$ 100.00	$ 100	2	$ 100.00	$ 200	2	$ 100.00	$ 200	2	$ 100.00	$ 200	2	$ 100.00	$ 200
Retailer Service Agreement -- monthly fixed charge (per retailer)	4082	98	$ 20.00	$ 1,960	110	$ 20.00	$ 2,200	117	$ 20.00	$ 2,340	125	$ 20.00	$ 2,500	130	$ 20.00	$ 2,600
Retailer Service Agreement -- monthly variable charge (per customer)	4082	2249	$ 0.50	$ 1,125	1641	$ 0.50	$ 821	1343	$ 0.50	$ 672	1650	$ 0.50	$ 825	1700	$ 0.50	$ 850
Distributor-Consolidated Billing -- monthly charge (per customer)	4082	2107	$ 0.30	$ 632	1641	$ 0.30	$ 492	1342	$ 0.30	$ 403	1500	$ 0.30	$ 450	1600	$ 0.30	$ 480
Retailer-Consolidated Billing -- monthly credit (per customer)	4082	0	-$ 0.30	$ -		-$ 0.30	$ -		-$ 0.30	$ -		-$ 0.30	$ -		-$ 0.30	$ -
	4082 Total			$ 3,817			$ 3,713			$ 3,614			$ 3,975			$ 4,130
Service Transaction Request - request fee,per request, applied to the requesting party	4084	216	$ 0.25	$ 54.00	46	$ 0.25	$ 12	30	$ 0.25	$ 8	40	$ 0.25	$ 10	50	$ 0.25	$ 13
Service Transaction Request - processing fee,per request, applied to the requesting party	4084	0	$ 0.50	$ -		$ 0.50	$ -		$ 0.50	$ -		$ 0.50	$ -		$ 0.50	$ -
Arrears Certificate	4084	0	$ 15.00	$ -		$ 15.00	$ -		$ 15.00	$ -		$ 15.00	$ -		$ 15.00	$ -
Statement of Account	4084	0	$ 15.00	$ -		$ 15.00	$ -		$ 15.00	$ -		$ 15.00	$ -		$ 15.00	$ -
Pulling post-dated cheques	4084	0		$ -			$ -			$ -			$ -			$ -
Duplicate invoices for previous billing	4084	0	$ 15.00	$ -		$ 15.00	$ -		$ 15.00	$ -		$ 15.00	$ -		$ 15.00	$ -
Request for other billing information	4084	0	$ 15.00	$ -		$ 15.00	$ -		$ 15.00	$ -		$ 15.00	$ -		$ 15.00	$ -
Easement Letter	4084	0		$ -			$ -			$ -			$ -			$ -
Income tax letter	4084	0	$ 15.00	$ -		$ 15.00	$ -		$ 15.00	$ -		$ 15.00	$ -		$ 15.00	$ -
Notification Charge	4084	0		$ -			$ -			$ -			$ -			$ -
Legal letter charge	4084	0	$ 15.00	$ -		$ 15.00	$ -		$ 15.00	$ -		$ 15.00	$ -		$ 15.00	$ -
Service Transaction Request -- request fee (per request)	4084	0	$ -	$ -			$ -			$ -			$ -			$ -
Service Transaction Request -- processing fee (per processed request)	4084	0	$ -	$ -			$ -			$ -			$ -			$ -
Customer Information request -- non-EBT (more than twice a year, per request)	4084		$ -	$ -			$ -			$ -			$ -			$ -
	4084 Total			$ 54			$ 12			$ 8			$ 10			$ 13
Late Payment - per month	4225		1.50%	$ 5,764		1.50%	$ 7,109		1.50%	$ 5,208		1.50%	$ 5,800		1.50%	$ 6,000
Collection of account charge – no disconnection – after regular hours	4225		$ 50.00	$ -		$ 50.00	$ -		$ 50.00	$ -		$ 50.00	$ -		$ 50.00	$ -
	4225 Total			$ 5,764			$ 7,109			$ 5,208			$ 5,800			$ 6,000
Account history	4235		$ 15.00	$ -		$ 15.00	$ -		$ 15.00	$ -		$ 15.00	$ -		$ 15.00	$ -
Credit reference/credit check (plus credit agency costs)	4235		$ 25.00	$ -		$ 25.00	$ -		$ 25.00	$ -		$ 25.00	$ -		$ 25.00	$ -
Returned Cheque charge (plus bank charges)	4235	51	$ 15.00	$ 765	53	$ 15.00	$ 795	44	$ 15.00	$ 660	50	$ 15.00	$ 750	55	$ 15.00	$ 825
Charge to certify cheque	4235			$ -			$ -			$ -			$ -			$ -
Account set up charge / change of occupancy charge	4235	333	$ 15.00	$ 4,995	305	$ 15.00	$ 4,575	287	$ 15.00	$ 4,305	300	$ 15.00	$ 4,500	325	$ 15.00	$ 4,875
Special Meter reads	4235		$ 20.00	$ -		$ 20.00	$ -		$ 20.00	$ -		$ 20.00	$ -		$ 20.00	$ -
Meter dispute charge plus Measurement Canada fees (if meter found correct)	4235		$ 30.00	$ -		$ 30.00	$ -		$ 30.00	$ -		$ 30.00	$ -		$ 30.00	$ -
Disconnect/Reconnect at meter – during regular hours	4235		$ 25.00	$ -		$ 25.00	$ -		$ 25.00	$ -		$ 25.00	$ -		$ 25.00	$ -
Disconnect/Reconnect at meter – after regular hours	4235		$ 50.00	$ -		$ 50.00	$ -		$ 50.00	$ -		$ 50.00	$ -		$ 50.00	$ -
Disconnect/Reconnect at pole – during regular hours	4235		$ 185.00	$ -		$ 185.00	$ -		$ 185.00	$ -		$ 185.00	$ -		$ 185.00	$ -
Disconnect/Reconnect at pole – after regular hours	4235		$ 415.00	$ -		$ 415.00	$ -		$ 415.00	$ -		$ 415.00	$ -		$ 415.00	$ -
Install / remove load control device – during regular hours	4235		$ 25.00	$ -		$ 25.00	$ -		$ 25.00	$ -		$ 25.00	$ -		$ 25.00	$ -
Install / remove load control device – after regular hours	4235		$ 50.00	$ -		$ 50.00	$ -		$ 50.00	$ -		$ 50.00	$ -		$ 50.00	$ -
Service call – customer-owned equipment	4235		$ 30.00	$ -		$ 30.00	$ -		$ 30.00	$ -		$ 30.00	$ -		$ 30.00	$ -
Service call – after regular hours	4235		$ 165.00	$ -		$ 165.00	$ -		$ 165.00	$ -		$ 165.00	$ -		$ 165.00	$ -
Temporary service install and remove – overhead – no transformer	4235		$ 500.00	$ -		$ 500.00	$ -		$ 500.00	$ -		$ 500.00	$ -		$ 500.00	$ -
Temporary service install and remove – underground – no transformer	4235		$ 300.00	$ -		$ 300.00	$ -		$ 300.00	$ -		$ 300.00	$ -		$ 300.00	$ -
Temporary service install and remove – overhead – with transformer	4235		$ 1,000.00	$ -		$ 1,000.00	$ -		$ 1,000.00	$ -		$ 1,000.00	$ -		$ 1,000.00	$ -
Administrative Billing Charge	4235			$ -			$ -			$ -			$ -			$ -
Collection of account charge – no disconnection	4235	176	$ 20.00	$ 3,520	375	$ 20.00	$ 7,500	382	$ 20.00	$ 7,640	400	$ 20.00	$ 8,000	425	$ 20.00	$ 8,500
Interval Meter Load Management Tool	4235			$ -			$ -			$ -			$ -			$ -
Miscellaneous Service Revenue	4235			$ -			$ -			$ -			$ -			$ -
	4235 Total			**$ 9,280**			**$ 12,870**			**$ 12,605**			**$ 13,250**			**$14,200**
				$ -			$ -			$ -			$ -			$ -
	Grand Total			$ 24,310			$ 29,222			$ 27,032			$ 28,785			$30,280

E3.T3.S3 VARIANCE ANALYSIS

Table 25 below presents the summary and year over year variances of other operating revenues. Account 4235 and 4225 saw a spike from 2010-2011 due to the increase in the amount of collection that occurred in that particular year. The increase in these two accounts coincides with the utility abolishing its security deposit policy. The number of collections and late payment charges show no signs of slowing down in the test year and beyond.

Table 25 – Variance Analysis of Other Operating Revenues

USoA #	USoA Description	2010	2011	2012	2013	2014
4235	Specific Service Charges	$ 9,280	$ 12,870	$ 12,605	$ 13,250	$ 14,200
4225	Late Payment Charges	$ 5,764	$ 7,109	$ 5,208	$ 5,800	$ 6,000
4082	Retail Services Revenues	$ 3,817	$ 3,713	$ 3,614	$ 3,975	$ 4,130
4080	Admin Charge	$ 5,395	$ 5,519	$ 5,598	$ 5,750	$ 5,938
4084	Service Transaction Request	$ 54	$ 12	$ 8	$ 10	$ 13

USoA #	USoA Description		2011-2010	2012-2011	2013-2012	2014-2013
4235	Specific Service Charges		39%	-2%	5%	7%
4225	Late Payment Charges		23%	-27%	11%	3%
4082	Retail Services Revenues		-3%	-3%	10%	4%
4080	Admin Charge		2%	1%	3%	3%

The percentage increase in other accounts is misleading due to the relatively small dollar amounts being compared.

E3.T3.S4 SPECIFIC SERVICE CHARGES

A Specific Service Charge is an approved fixed rate charged to a customer for a specific activity or service, or as a penalty. Activities include services that are only available from, or under the control of, the distributor. There are also special or extra services that a distributor chooses to provide. Such services may be those that are of benefit to the distributor or to other customers, and that are provided at a customer's request or as the result of a customer's action or inaction. Specific Service Charges are established for activities that are over and above the distributor's standard level of service. The costs of providing the standard level of service are recovered in the regular distribution rates. The proposed list of specific service charges is presented at the next page.

Customer Administration

Arrears Certificate	$	15.00
Statement of Account	$	15.00
Duplicate invoices for pervious billing	$	15.00
Request for other billing information	$	15.00
Income tax eltter	$	15.00
Account history	$	15.00
Credit reference/credit check (plus credit agency costs)	$	25.00
Returned cheques charge (plus bank charges)	$	15.00
Legal letter charge	$	15.00
Account set up charge/change of occupancy chrage (plus credit agency costs of applicable)	$	15.00
Special meter reads	$	20.00
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	$	20.00
Collection of account charge - no disconnection - after regular hours	$	50.00
Disconnect/Reconnect Charge - At Meter during Regular Hours	$	25.00
Disconnect/Reconnect Charge - At Meter after Regular Hours	$	50.00
Disconnect/Reconnect at pole - during regular hours	$	185.00
Disconnect/Reconnect at pole - after regular hours	$	415.00

Install/Remove load control device - during regular hours	$	25.00
Install/Remove load control device - after regular hours	$	50.00
service call - customer owned equipment	$	30.00
service call - after regular hours	$	165.00
Temporary service installation and removal - overhead - no transformer	$	500.00
Temporary service installation and removal - underground - no transformer	$	300.00
Temporary service installation and removal - overhead - with transformer	$	1,000.00
Specific charge for access to power poles $/pole/year	$	22.35

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

E3.T3.S5 PROPOSED CHANGES TO SPECIFIC SERVICE REVENUES

Please note that CHEI is not proposing to change its specific service revenues.

E3.T3.S6 REVENUES FOR AFFILIATE TRANSACTIONS

CHEI does not have affiliates and as such does not engage in affiliate transactions.

E3.T3.S7 PASS THROUGH REVENUES

CHEI is an embedded distributor of Hydro One Networks Inc. ("HONI") and is charged monthly by HONI for its power supply expenses.

Pass-through charges for power supply include commodity, retail transmission services, wholesale market service, rural rate protection and low voltage service. Debt retirement charges are not included. A total loss factor applies to forecast retail volumes for all pass-through charges other than low voltage service, when the billing determinant is kWh.

Commodity Price

The assumed commodity prices are based on the Regulated Price Plan ("RPP") Report issued by the OEB on April 5, 2013. The estimated price for RPP customers corresponds to the average supply cost for RPP customers specified in the report's Table ES-1 as indicated in the excerpt below.

Table ES-1: Average RPP Supply Cost Summary (for the 12 months from May 1, 2013)

RPP Supply Cost Summary
for the period from May 1, 2013 through April 30, 2014

		Current
Forecast Wholesale Electricity Price		$19.33
Load-Weighted Price for RPP Consumers ($ / MWh)		$21.05
Impact of the Global Adjustment ($ / MWh)	+	$66.12
Adjustment to Address Bias Towards Unfavourable Variance ($ / MWh)	+	$1.00
Adjustment to Clear Existing Variance ($ / MWh)	+	($4.21)
Average Supply Cost for RPP Consumers ($ / MWh)	=	**$83.95**

CHEI reserves the right to update its commodity price based on updated prices are they become available.

Retail Transmission Service ("RTSR") Rates

Proposed RTSRs for Network Service and Line and Transformation Connection Service are described in E8.T2.S1.

Wholesale Market Service ("WMS") Rate

WPI proposes to maintain its cuurent WMS rate of $0.0044 per kWh, as prescribed by the OEB.

Rural Rate Protection

The existing Rural Rate Protection charge of $0.0011 per kWh has been maintained.

Low Voltage ("LV") Service

CHEI estimates total charges of $40,000 in 2013 for LV service. Proposed retail rates for LV are described in E8.T5.S1

E3.T3.S8 POWER SUPPLY EXPENSES

The next page presents the utility’s power supply expense for both the Bridge Year and Test Year.

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TESI-7
Power Supply Expense

Determination of Commodity

		2012 Actual kWh's		
Customer Class Name		**2012 Actual kWh's**	**non-RPP**	**RPP**
Residential		19,634,780	911,692	18,723,088
General Service < 50 kW		4,742,923	312,122	4,430,801
General Service > 50 to 4999 kW		4,292,894	4,292,844	50
Unmetered Scattered Load		89,208	14,167	75,041
Street Lighting		355,537	355,537	0
MicroFit				
TOTAL		**29,115,342**	**5,886,362**	**23,228,980**
%		*100.00%*	*20.22%*	*79.78%*

Forecast Price

HOEP ($/MWh)				$21.05		Note: Table ES-1 from current RPP report - Load Weighted price for RPP Consumers
Global Adjustment ($/MWh)				$66.12		Note: Table ES-1 from current RPP report - Impact of Global Adjustment
TOTAL ($/MWh)				**$87.17**	**$83.95**	Note: Table ES-1 from current RPP report -Avg Supply Cost of RPP Consumers
$/kWh				***$0.08717***	***$0.08395***	
%				20.22%	79.78%	
WEIGHTED AVERAGE PRICE		**$0.0846**		**$0.0176**	**$0.0670**	

Electricity Projections

(loss adjusted)

				Bridge Year 2013			**Test Year 2014**		
Customer		**Revenue**	**Expense**						
Class Name		USA #	USA #	Volume	rate ($/kWh):	Amount	Volume	rate ($/kWh):	Amount
Residential	kWh	4006	4705	20,929,014	0.07932	$1,660,089	22,708,303	$0.08460	$1,921,145
General Service < 50 kW	kWh	4010	4705	5,123,503	0.07932	$406,396	5,279,168	$0.08460	$446,623
General Service > 50 to 4999 kW	kWh	4035	4705	4,550,412	0.07932	$360,939	4,465,396	$0.08460	$377,777
Unmetered Scattered Load	kWh	4010	4705	97,685	0.07932	$7,748	95,491	$0.08460	$8,079
Street Lighting	kWh	4025	4705	399,008	0.07932	$31,649	399,442	$0.08460	$33,793
MicroFit									
TOTAL				**31,099,622**		**$2,466,822**	**32,947,800**		**$2,787,417**

Transmission - Network

(loss adjusted)

				Bridge Year 2013			**Test Year 2014**		
Customer		**Revenue**	**Expense**						
Class Name		USA #	USA #	Volume	Rate	Amount	Volume	Rate	Amount
Residential	kWh	4066	4714	20,929,014	0.0069	$144,410	22,708,303	0.0057	$129,437
General Service < 50 kW	kWh	4066	4714	5,123,503	0.0064	$32,790	5,279,168	0.0053	$27,980
General Service > 50 to 4999 kW	kW	4066	4714	12,607	2.5726	$32,433	12,372	2.1331	$26,391
Unmetered Scattered Load	kWh	4066	4714	97,685	0.0064	$625	95,491	0.0053	$506
Street Lighting	kW	4066	4714	1,000	1.9403	$1,940	1,001	1.6088	$1,610
MicroFit									
TOTAL				**26,163,808**		**$212,199**	**28,096,334**		**$185,924**

Transmission - Connection

(loss adjusted)

				Bridge Year 2013			**Test Year 2014**		
Customer		**Revenue**	**Expense**						
Class Name		USA #	USA #	Volume	Rate	Amount	Volume	Rate	Amount
Residential	kWh	4068	4716	20,929,014	0.0052	$108,831	22,708,303	0.0048	$109,000
General Service < 50 kW	kWh	4068	4716	5,123,503	0.0046	$23,568	5,279,168	0.0042	$22,173
General Service > 50 to 4999 kW	kW	4068	4716	12,607	1.8286	$23,053	12,372	1.6823	$20,813
Unmetered Scattered Load	kWh	4068	4716	97,685	0.0046	$449	95,491	0.0042	$401
Street Lighting	kW	4068	4716	1,000	1.4136	$1,414	1,001	1.3005	$1,302
MicroFit									
TOTAL		**0**	**0**	**26,163,808**		**$157,315**	**28,096,334**		**$153,689**

Wholesale Market Service

(loss adjusted)

				Bridge Year 2013			**Test Year 2014**		
Customer		**Revenue**	**Expense**		**rate ($/kWh):**	**0.0052**		**rate ($/kWh):**	**0.0052**
Class Name		USA #	USA #	Volume		Amount	Volume		Amount
Residential	kWh	4062	4708	20,929,014	0.00440	$92,088	22,708,303	0.00440	$99,917
General Service < 50 kW	kWh	4062	4708	5,123,503	0.00440	$22,543	5,279,168	0.00440	$23,228
General Service > 50 to 4999 kW	kWh	4062	4708	4,550,412	0.00440	$20,022	4,465,396	0.00440	$19,648
Unmetered Scattered Load	kWh	4062	4708	97,685	0.00440	$430	95,491	0.00440	$420
Street Lighting	kWh	4062	4708	399,008	0.00440	$1,756	399,442	0.00440	$1,758
MicroFit									
TOTAL		**0**	**0**	**31,099,622**		**$136,838**	**32,947,800**		**$144,970**

File Number:	EB-20130122
Exhibit:	3
Tab:	3
Schedule:	8
Page:	
Date:	

TESI-7

Power Supply Expense

Rural Rate Protection

(loss adjusted)

				Bridge Year 2013			**Test Year 2014**		
Customer		**Revenue**	**Expense**		**rate ($/kWh):**			**rate ($/kWh):**	
Class Name		USA #	USA #	Volume		Amount	Volume		Amount
Residential	kWh	4062	4730	20,929,014	0.00110	$23,022	22,708,303	0.00110	$24,979
General Service < 50 kW	kWh	4062	4730	5,123,503	0.00110	$5,636	5,279,168	0.00110	$5,807
General Service > 50 to 4999 kW	kWh	4062	4730	4,550,412	0.00110	$5,005	4,465,396	0.00110	$4,912
Unmetered Scattered Load	kWh	4062	4730	97,685	0.00110	$107	95,491	0.00110	$105
Street Lighting	kWh	4062	4730	399,008	0.00110	$439	399,442	0.00110	$439
MicroFit	kWh								
TOTAL		**0**	**0**	**31,099,622**		**$34,210**	**32,947,800**		**$36,243**

Low Voltage Charges

	Current Low Voltage Rates		**2013 PROJECTED TRANSMISSION-CONNECTION REVENUE**				
Customer Class Name	**Rate**	**per**	**Rate**	**per**	**Uplifted Volumes**	**Revenue**	**%**
Residential	$0.0014	kWh	**$0.0048**	kWh	22,708,303	$109,000	70.92%
General Service < 50 kW	$0.0013	kWh	**$0.0042**	kWh	5,279,168	$22,173	14.43%
General Service > 50 to 4999 kW	$0.4778	kW	**$1.6823**	kW	12,372	$20,813	13.54%
Unmetered Scattered Load	$0.0013	kWh	**$0.0042**	kWh	95,491	$401	0.26%
Street Lighting	$0.3694	kW	**$1.3005**	kW	1,001	$1,302	0.85%
MicroFit							
TOTAL	**0**	**0**		**$0**	**28,096,334**	**$153,689**	**100%**

Low Voltage Charges

(not loss adjusted)

	2013 PROPOSED LOW VOLTAGE CHARGES & RATES				
Customer Class Name	**% Allocation**	**Charges**	**Not Uplifted Volumes**	**Rate**	**per**
Residential	70.92%	39,717	21,296,520	$0.0019	kWh
General Service < 50 kW	14.43%	8,079	4,950,960	$0.0016	kWh
General Service > 50 to 4999 kW	13.54%	7,584	12,372	$0.6130	kW
Unmetered Scattered Load	0.26%	146	89,554	$0.0016	kWh
Street Lighting	0.85%	474	1,001	$0.4739	kW
MicroFit					
TOTAL	**100.00%**	**56,000**	**26,350,407**		

				Bridge Year 2013			**Test Year 2014**		
Customer		**Revenue**	**Expense**		**2013**			**2014**	
Class Name		USA #	USA #	Volume	Rate	Amount	Volume	Rate	Amount
Residential	kWh	4075	4750	19,627,850	$0.0014	$27,479	21,296,520	$0.0019	$40,463.39
General Service < 50 kW	kWh	4075	4750	4,804,973	$0.0013	$6,246	4,950,960	$0.0016	$7,921.54
General Service > 50 to 4999 kW	kW	4075	4750	12,607	$0.4778	$6,024	12,372	$0.6130	$7,584.04
Unmetered Scattered Load	kWh	4075	4750	91,612	$0.0013	$119	89,554	$0.0016	$143.29
Street Lighting	kW	4075	4750	1,000	$0.3694	$369	1,001	$0.4739	$474.37
MicroFit									
TOTAL		**0**	**0**	**24,538,041**		**$40,238**	**26,350,407**		**$56,586.62**

Projected Power Supply Expense					**$3,047,621**			**$3,364,829**

Appendix A – CHEI 2006-2010 OPA results

OPA Conservation & Demand Management Programs

Annual Results at the End-User Level

For: Cooperative Hydro Embrun Inc.

Net Summer Peak Demand Savings (MW)

#	Program Year	Results Status	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
1	2006 Programs	Final	0.0435	0.0090	0.0090	0.0090	0.0090	0.0090	0.0084	0.0084	0.0065	0.0065	0.0065	0.0065	0.0065	0.0065	0.0040	0.0027	0.0027	0.0027	0.0001	0.0001	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
2	2007 Programs	Final	0.0000	0.0854	0.0210	0.0153	0.0153	0.0153	0.0148	0.0148	0.0148	0.0131	0.0127	0.0115	0.0115	0.0115	0.0115	0.0064	0.0012	0.0012	0.0012	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
3	2008 Programs	Final	0.0000	0.0000	0.0766	0.0118	0.0118	0.0118	0.0114	0.0114	0.0108	0.0106	0.0097	0.0083	0.0082	0.0082	0.0077	0.0077	0.0076	0.0063	0.0058	0.0058	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
4	2009 Programs	Final	0.0000	0.0000	0.0000	0.0729	0.0144	0.0144	0.0142	0.0137	0.0125	0.0123	0.0123	0.0117	0.0117	0.0114	0.0114	0.0106	0.0106	0.0106	0.0097	0.0097	0.0097	0.0072	0.0005	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
5	2010 Programs	Final	0.0000	0.0000	0.0000	0.0000	0.0775	0.0318	0.0318	0.0318	0.0312	0.0291	0.0291	0.0291	0.0291	0.0289	0.0270	0.0270	0.0270	0.0026	0.0026	0.0024	0.0024	0.0024	0.0021	0.0015	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Total			**0.0435**	**0.0944**	**0.1065**	**0.1090**	**0.1280**	**0.0823**	**0.0806**	**0.0801**	**0.0758**	**0.0716**	**0.0703**	**0.0672**	**0.0671**	**0.0666**	**0.0616**	**0.0544**	**0.0492**	**0.0234**	**0.0194**	**0.0179**	**0.0120**	**0.0096**	**0.0026**	**0.0015**	**0.0000**	**0.0000**	**0.0000**	**0.0000**	**0.0000**	**0.0000**

Net Energy Savings (MWh)

#	Program Year	Results Status	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
1	2006 Programs	Final	186	186	186	186	32	32	29	29	28	28	26	26	26	26	24	21	21	21	11	11	6	6	6	6	6	11	11	11	11	11
2	2007 Programs	Final	0	146	92	85	85	85	82	82	82	26	23	13	13	13	13	11	2	1	1	0	0	0	0	0	0	0	0	0	0	0
3	2008 Programs	Final	0	0	83	83	83	83	74	74	65	58	43	32	28	28	27	27	27	24	9	9	0	0	0	0	0	0	0	0	0	0
4	2009 Programs	Final	0	0	0	63	52	52	52	48	38	34	34	27	27	24	24	21	21	21	18	16	15	13	2	0	0	0	0	0	0	0
5	2010 Programs	Final	0	0	0	0	70	52	52	52	47	29	28	28	28	9	7	7	7	7	7	6	5	5	4	3	0	0	0	0	0	0
Total			**186**	**332**	**360**	**416**	**322**	**304**	**290**	**286**	**261**	**175**	**154**	**126**	**122**	**101**	**95**	**87**	**77**	**73**	**46**	**42**	**27**	**24**	**13**	**10**	**6**	**11**	**11**	**11**	**11**	**11**

Gross Summer Peak Demand Savings (MW)

#	Program Year	Results Status	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
1	2006 Programs	Final	0.0451	0.0106	0.0106	0.0106	0.0106	0.0106	0.0100	0.0100	0.0079	0.0079	0.0079	0.0079	0.0079	0.0079	0.0051	0.0031	0.0031	0.0031	0.0001	0.0001	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
2	2007 Programs	Final	0.0000	0.3617	0.1096	0.0627	0.0627	0.0627	0.0593	0.0593	0.0593	0.0568	0.0558	0.0542	0.0542	0.0542	0.0542	0.0111	0.0021	0.0021	0.0021	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
3	2008 Programs	Final	0.0000	0.0000	0.0876	0.0225	0.0225	0.0225	0.0216	0.0216	0.0203	0.0197	0.0181	0.0154	0.0151	0.0151	0.0139	0.0139	0.0139	0.0115	0.0101	0.0101	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
4	2009 Programs	Final	0.0000	0.0000	0.0000	0.0916	0.0328	0.0328	0.0325	0.0314	0.0292	0.0288	0.0288	0.0276	0.0276	0.0268	0.0268	0.0253	0.0253	0.0252	0.0223	0.0222	0.0222	0.0179	0.0009	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
5	2010 Programs	Final	0.0000	0.0000	0.0000	0.0000	0.0859	0.0402	0.0402	0.0402	0.0390	0.0351	0.0351	0.0351	0.0351	0.0347	0.0318	0.0318	0.0317	0.0047	0.0047	0.0041	0.0040	0.0040	0.0036	0.0021	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Total			**0.0451**	**0.3723**	**0.2079**	**0.1875**	**0.2146**	**0.1689**	**0.1636**	**0.1625**	**0.1557**	**0.1483**	**0.1457**	**0.1402**	**0.1399**	**0.1387**	**0.1318**	**0.0852**	**0.0761**	**0.0466**	**0.0393**	**0.0365**	**0.0262**	**0.0219**	**0.0045**	**0.0021**	**0.0000**	**0.0000**	**0.0000**	**0.0000**	**0.0000**	**0.0000**

Gross Energy Savings (MWh)

#	Program Year	Results Status	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
1	2006 Programs	Final	207	207	207	207	37	37	34	34	32	32	30	30	30	30	27	23	23	23	12	12	7	7	7	7	7	12	12	12	12	12
2	2007 Programs	Final	0	661	209	153	153	153	145	145	145	62	53	41	41	41	41	19	3	2	2	0	0	0	0	0	0	0	0	0	0	0
3	2008 Programs	Final	0	0	188	188	188	188	165	165	145	127	98	77	68	68	66	66	66	61	16	16	0	0	0	0	0	0	0	0	0	0
4	2009 Programs	Final	0.0000	0.0000	0.0000	137.7195	121.3706	121.3706	121.0306	113.2772	94.9248	86.1476	85.9192	71.0134	71.0134	61.3721	61.3596	56.4718	56.4718	55.0472	44.1578	40.3846	37.7905	33.8674	4.9426	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
5	2010 Programs	Final	0	0	0	0	107	91	91	91	82	44	42	42	42	17	13	13	12	12	12	10	8	8	7	5	0	0	0	0	0	0
Total			**207**	**869**	**605**	**685**	**606**	**589**	**555**	**548**	**499**	**351**	**309**	**261**	**252**	**218**	**209**	**177**	**161**	**153**	**86**	**79**	**53**	**49**	**20**	**12**	**7**	**12**	**12**	**12**	**12**	**12**

Appendix B – Q4 2012 OPA Report

Ontario Power Authority
Conservation & Demand Management Status Report
Q4 2012 Preliminary Results Update
Cooperative Hydro Embrun Inc.

Unverified OPA-Contracted Province-Wide CDM Program Progress at a Glance

Unverified Progress to Targets	Incremental Q4 2012	Program-to-Date Progress Towards OEB Target				Rank (of 76)
		Scenario 1		Scenario 2		
		Savings	%	Savings	%	Scenario 2
Net Peak Demand Savings (MW)	**0.1**	**0.1**	29.3%	**0.1**	40.5%	**9**
Net Energy Savings (GWh)	**0.0**	**1.0**	88.1%	**1.0**	88.1%	**8**

Program-to-Date towards Target: *Combination of 2011 verified and 2012 preliminary results. To align with savings accounted towards OEB targets, peak Demand is represented by annual savings in 2014 and energy is represented by the cumulative savings from 2011-2014.*

Scenario 1: *Assumes that demand response resources have a persistence of 1 year. Official reporting policy for demand response resources.*

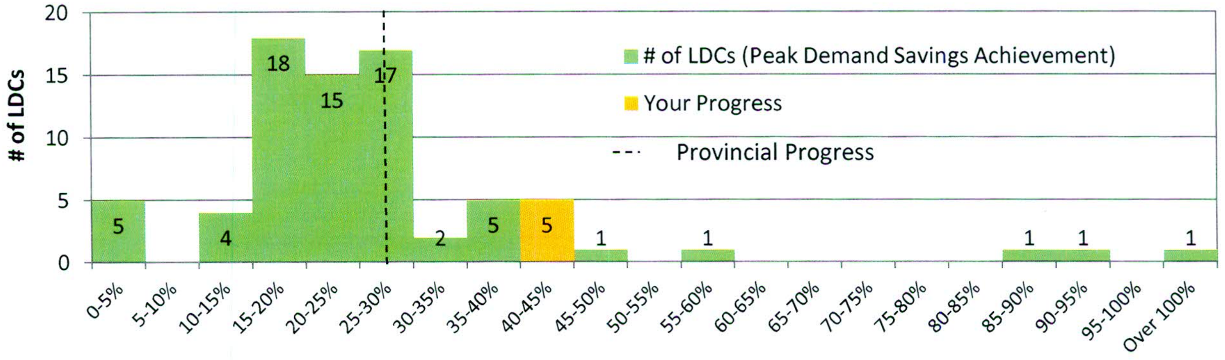
Scenario 2: *Assumes that demand response resources remain in your territory until 2014. Used to better assess progress to demand targets.*

Rank: *Sorts each LDC by % of peak demand or energy target achieved as of the current reporting period using scenario 2.*

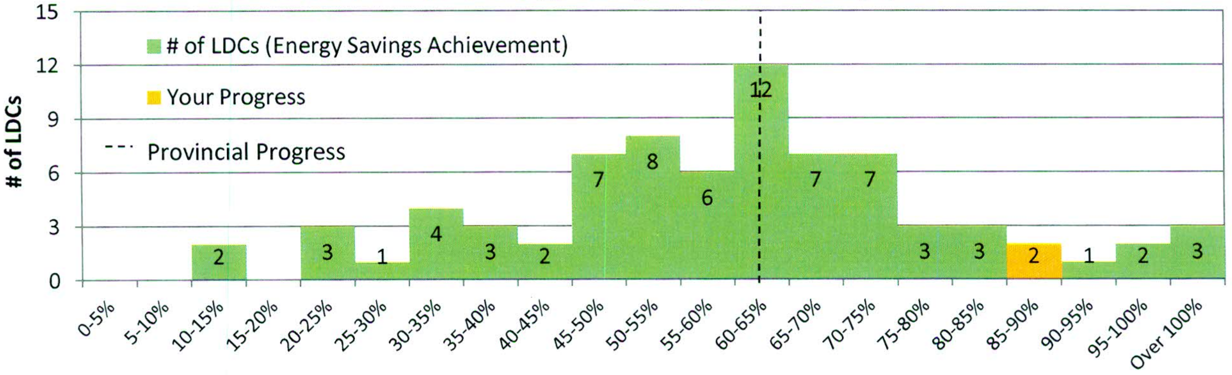
Comparison: Your Achievement vs. LDC Community Achievement

The following graphs assume that demand response resources remain in your territory until 2014 (aligns with Scenario 2)

2014 Annual Peak Demand Savings Target Achieved (%)



2011-2014 Cumulative Energy Savings Target Achieved (%)



Questions? Please check the "About this Report" Section on page 2, Table 5 on page 9 and "Reporting Methodology" on page 10.
More Questions? Please contact LDC.Support@powerauthority.on.ca

Message from the Vice President

I am pleased to present our Q4 2012 LDC report. We continue to achieve great success across all sectors and provincially our progress to date continues to rise for both energy and demand. In Q4, 62% of the cumulative 6,000 GWh energy target was achieved and progress towards the 1,330 MW demand target increased from last quarter at 28%.

In Q4 we received the Minister's directive to extend the programs to December 31st, 2015. This is great news for our customers and we continue to work towards identifying additional tools, training, and information that will help LDCs achieve their targets.

Programs are being enhanced through LDC feedback to further drive participation in conservation and channel partners are being engaged to build stronger relationships across all sectors. A few highlights of our efforts so far include:

- 7 regionally-located Energy Efficiency Service Providers are now available to help engage Municipalities and capture more projects for the municipal sector
- Retrofit projects are moving beyond commercial lighting and capturing more peak demand savings relative to energy savings
- Partnerships between LDCs and retailers resulted in 130 in-store events in 2012
- The Home Assistance Program is ramping up in 2012 with over 3,000 basic and extended audits completed for income eligible homes resulting in the installation of almost 40,000 energy efficient products

We encourage you to continue to share your success stories to learn from best practices and share our experiences across the province.

Please contact the OPA Conservation Business Development team at ldc.support@powerauthority.on.ca with any questions regarding this report.

Congratulations on another successful quarter!

Sincerely,

Andrew Pride

About this Report

This report contains:

- Peak demand and energy savings for OPA-Contracted Province-Wide programs (does not include Ontario Energy Board (OEB) approved CDM programs or other LDC conservation efforts)
- Progress as of the end of Q4 2012 using unverified quarterly results for 2012 and final results for 2011
- Program activity data (i.e. projects completed, appliances picked up) completed on or before December 31, 2012 and received and entered into the OPA processing systems as per the dates specified in Table 5
- Updates to the previous quarter's participation as a result of further data received
- Information to assist the LDC in reconciling internal data sources with the data contained in this report. Table 5 (page 9) contains:
  1. The date in which savings are considered to 'start';
  2. At what point the data becomes available to the OPA;
  3. The expected probability and magnitude of updates to the data as more information becomes available.
- iCON CRM Post Stage Retrofit Report data queried on **January 31, 2013**
  - Retrofit projects completed after December 31, 2011 will be tracked as part of the Business program only
- Preliminary results for ***peaksaver* PLUS®** representing customers that have signed a Participant Agreement and information has been successfully uploaded into the RDR settlement system

New this quarter based on LDC feedback:

- ***peaksaver* PLUS** reporting is now split into two line items: switch/thermostat and IHD

2011-2014 Summary: Net Peak Demand Savings Achieved (MW)

This section provides a portfolio level view of net peak demand savings procured to date through Tier 1 programs.
Table 1 presents:

- Net peak demand savings results from 2011 to Q4 2012 listed by implementation period, status (i.e. final or reported) and summarized by resource type (i.e. energy efficiency or demand response)
- Net annual peak demand savings that are expected to persist through to 2014 from program activity completed as of Q4 2012 using both Scenarios 1 and 2
- A comparison between reported, unverified results (as of Q4 2011) and final, verified 2011 results
- Energy efficiency resources reported with persistence according to the effective useful life of the technology

Figure 1 presents:

- Net peak demand savings results from 2011 to date using scenario 1 for demand response resources (persistence of 1 year)

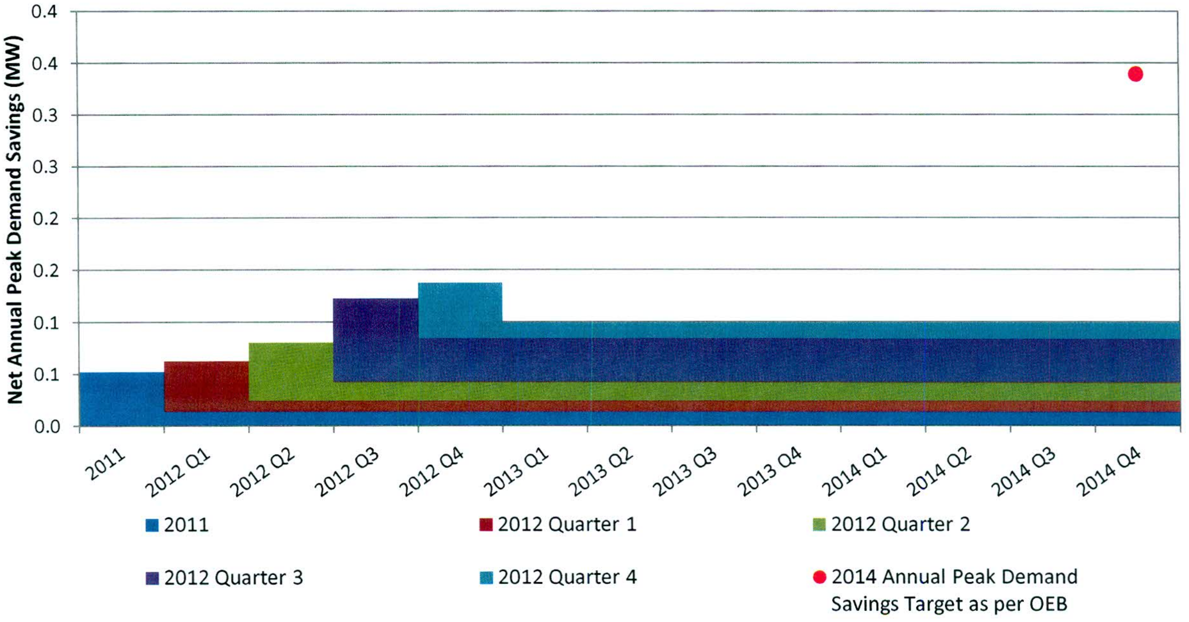
Please note: demand response resources are only presented in the final quarter of each year and the current reporting quarter (i.e. quarter 4 2011 and quarter 4 2012) to correctly aggregate the annual savings in the table below. However, the figure below and tables 3B and 4B present Demand Response in each quarter to display any changes that may have occurred quarter over quarter.

Table 1: Net Peak Demand Savings at the End-User Level (MW)

#	Implementation Period	Annual (MW)				
		Scenario 1				Scenario 2
		2011	2012	2013	2014	2014
1	2011 - Final*	0.05	0.01	0.01	0.01	0.01
2	2012 - Reported - Quarter 1		0.01	0.01	0.01	0.01
3	2012 - Reported - Quarter 2		0.02	0.02	0.02	0.02
4	2012 - Reported - Quarter 3		0.04	0.04	0.04	0.04
5	2012 - Reported - Quarter 4		0.05	0.02	0.02	0.05
6	2013					
7	2014					
Energy Efficiency		0.01	0.10	0.10	0.10	0.10
Demand Response		0.04	0.04	0.00	0.00	0.04
Net Annual Peak Demand Savings		0.05	0.14	0.10	0.10	0.14
Unverified Net Annual Peak Demand Savings in 2014:					**0.10**	**0.14**
2014 Annual Peak Demand Savings Target as per OEB:					**0.34**	**0.34**
Unverified 2014 Peak Demand Savings Target Achieved (%):					**29.3%**	**40.5%**
Incremental Reported (Unverified)		0.05	0.12			
Incremental Final (Verified)		0.05	n/a			

* Drop from 2011 to 2012 due to demand response persistence assumption (scenario 1)

Figure 1: Net Peak Demand Savings (MW)



2011-2014 Summary: Net Energy Savings Achieved (GWh)

This section provides a portfolio level view of net energy savings procured to date through Tier 1 programs.

Table 2 presents net annual energy savings results from 2011 to date listed by implementation period, status (i.e. final or reported) and summarized by resource type. This table aligns with scenario 1 and presents 2011-2014 net cumulative energy savings expected in 2014 from program activity completed to date. At the bottom of the table a comparison is made between reported (as of Q4 2011) and final 2011 results.

Table 2: Net Energy Savings at the End-User Level (GWh)

#	Implementation Period	Annual (GWh)				Cumulative (GWh)
		2011	2012	2013	2014	2011-2014
1	2011 - Final*	0.07	0.07	0.07	0.07	0.28
2	2012 - Reported - Quarter 1		0.03	0.03	0.03	0.08
3	2012 - Reported - Quarter 2		0.05	0.05	0.05	0.15
4	2012 - Reported - Quarter 3		0.11	0.11	0.11	0.34
5	2012 - Reported - Quarter 4		0.05	0.05	0.05	0.14
6	2013					
7	2014					
Energy Efficiency		0.07	0.31	0.31	0.31	0.99
Demand Response		0.00	0.00	0.00	0.00	0.00
Net Energy Savings		0.07	0.31	0.31	0.31	0.99
Unverified Net Cumulative Energy Savings 2011-2014:						**0.99**
2011-2014 Cumulative Energy Savings Target as per OEB:						**1.12**
Unverified 2011-2014 Cumulative Energy Target Achieved (%):						**88.1%**
Incremental Reported (Unverified)		0.09	0.23			
Incremental Final (Verified)		0.07	n/a			

Figure 2: Net Cumulative Energy Savings (GWh)

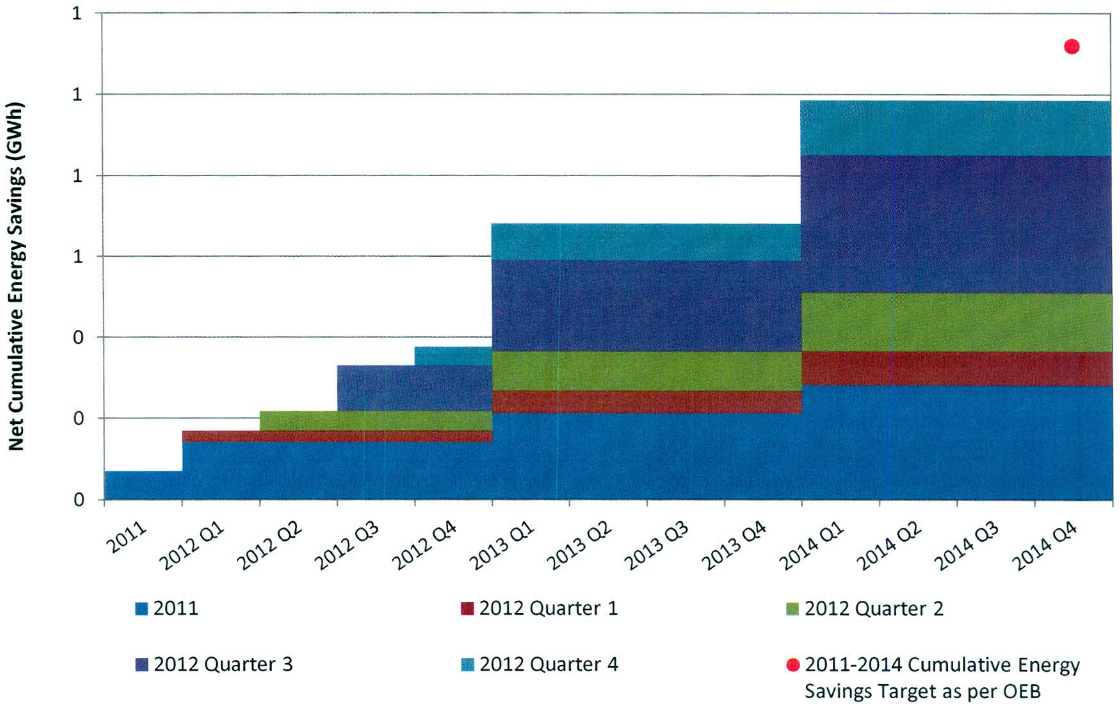


Table 3A: **Cooperative Hydro Embrun Inc.** Initiative and Program Level Savings by Year (Scenario 1)

#	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 Unverified Progress to Target** (excludes DR)	
			2011	**2012**	**2013**	**2014**	**2011**	**2012**	**2013**	**2014**	**2011**	**2012**	**2013**	**2014**	**2014 Net Annual Peak Demand Savings (kW) 2014**	**2011-2014 Net Cumulative Energy Savings (kWh) 2014**
Consumer Program																
1	Appliance Retirement	Appliances	31	6			2	0			12,946	2,672			2	59,700
2	Appliance Exchange	Appliances	1	0			0	0			66	11			0	260
3	HVAC Incentives	Equipment	20	18			6	6			10,853	12,629			12	81,299
4	Conservation Instant Coupon Booklet	Coupons	278	1			1	0			9,926	54			1	39,865
5	Bi-Annual Retailer Event	Coupons	430	156			1	0			14,524	6,067			1	76,296
6	Retailer Co-op	Items	0	0			0	0			0	0			0	0
7	Residential Demand Response (switch/pstat)*	Devices	64	64			36	36			93	138			0	230
8	Residential Demand Response (IHD)	Devices	0	0			0	0			0	0			0	0
9	Residential New Construction	Homes	0	0			0	0			0	0			0	0
Consumer Program Total							**45**	**43**			**48,408**	**21,571**			**16**	**257,652**
Business Program																
10	Retrofit	Projects	1	0			5	0			20,655	0			5	82,621
11	Direct Install Lighting	Projects	0	57			0	79			0	213,054			79	639,162
12	Building Commissioning	Buildings	0	0			0	0			0	0			0	0
13	New Construction	Buildings	0	0			0	0			0	0			0	0
14	Energy Audit	Audits	0	0			0	0			0	0			0	0
15	Small Commercial Demand Response (switch/pstat)*	Devices	4	4			3	2			9	8			0	17
16	Small Commercial Demand Response (IHD)	Devices	0	0			0	0			0	0			0	0
17	Demand Response 3*	Facilities	0	0			0	0			0	0			0	0
Business Program Total							**7**	**81**			**20,665**	**213,062**			**83**	**721,800**
Industrial Program																
18	Process & System Upgrades	Projects	0	0			0	0			0	0			0	0
19	Monitoring & Targeting	Projects	0	0			0	0			0	0			0	0
20	Energy Manager	Projects	0	0			0	0			0	0			0	0
21	Retrofit	Projects	0				0				0				0	0
22	Demand Response 3*	Facilities	0	0			0	0			0	0			0	0
Industrial Program Total							**0**	**0**			**0**	**0**			**0**	**0**
Home Assistance Program																
23	Home Assistance Program	Homes	0	0			0	0			0	0			0	0
Home Assistance Program Total							**0**	**0**			**0**	**0**			**0**	**0**
Pre-2011 Programs completed in 2011																
24	Electricity Retrofit Incentive Program	Projects	1	0			0	0			1,838	0			0	7,352
25	High Performance New Construction	Projects	0	0			0	0			40	0			0	161
26	Toronto Comprehensive	Projects	0	0			0	0			0	0			0	0
27	Multifamily Energy Efficiency Rebates	Projects	0	0			0	0			0	0			0	0
28	LDC Custom Programs	Projects	0	0			0	0			0	0			0	0
Pre-2011 Programs completed in 2011 Total							**0**	**0**			**1,878**	**0**			**0**	**7,513**
Energy Efficiency Total							**14**	**86**			**70,849**	**234,487**			**99**	**986,717**
Demand Response Total (Scenario 1)							**38**	**38**			**102**	**145**			**0**	**247**
OPA-Contracted LDC Portfolio Total							**52**	**124**			**70,951**	**234,632**			**99**	**986,964**
														Full OEB Target:	**340**	**1,120,000**
														Preliminary % of Full OEB Target Achieved to Date (Scenario 1):	**29.3%**	**88.1%**

* Activity & savings for Demand Response resources for each year and quarter represent the savings from all active facilities or devices contracted since January 1, 2011.

Table 3B: Cooperative Hydro Embrun Inc. Initiative and Program Level Savings by Quarter for current reporting 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)			
			Q1 2012	Q2 2012	Q3 2012	Q4 2012	Q1 2012	Q2 2012	Q3 2012	Q4 2012	Q1 2012	Q2 2012	Q3 2012	Q4 2012
Consumer Program														
1	Appliance Retirement	Appliances	2	2	0	2	0	0	0	0	919	854	20	879
2	Appliance Exchange	Appliances	0	0	0	0	0	0	0	0	0	11	0	0
3	HVAC Incentives	Equipment	1	7	3	7	0	2	1	3	827	4,753	1,654	5,395
4	Conservation Instant Coupon Booklet	Coupons	0	0	0	1	0	0	0	0	0	0	0	54
5	Bi-Annual Retailer Event	Coupons	0	45	0	110	0	0	0	0	0	1,709	0	4,358
6	Retailer Co-op	Items	0	0	0	0	0	0	0	0	0	0	0	0
7	Residential Demand Response (switch/pstat)*	Devices	64	64	64	64	36	36	36	36	138	138	138	138
8	Residential Demand Response (IHD)	Devices	0	0	0	0	0	0	0	0	0	0	0	0
9	Residential New Construction	Homes	0	0	0	0	0	0	0	0	0	0	0	0
Consumer Program Total							**36**	**39**	**37**	**39**	**1,884**	**7,465**	**1,811**	**10,824**
Business Program														
10	Retrofit	Projects	0	0	0	0	0	0	0	0	0	0	0	0
11	Direct Install Lighting	Projects	8	11	31	7	10	15	41	12	26,124	41,126	111,218	34,586
12	Building Commissioning	Buildings	0	0	0	0	0	0	0	0	0	0	0	0
13	New Construction	Buildings	0	0	0	0	0	0	0	0	0	0	0	0
14	Energy Audit	Audits	0	0	0	0	0	0	0	0	0	0	0	0
15	Small Commercial Demand Response (switch/pstat)*	Devices	4	4	4	4	2	2	2	2	8	8	8	8
16	Small Commercial Demand Response (IHD)	Devices	0	0	0	0	0	0	0	0	0	0	0	0
17	Demand Response 3*	Facilities	0	0	0	0	0	0	0	0	0	0	0	0
Business Program Total							**12**	**17**	**44**	**14**	**26,132**	**41,133**	**111,225**	**34,594**
Industrial Program														
18	Process & System Upgrades	Projects	0	0	0	0	0	0	0	0	0	0	0	0
19	Monitoring & Targeting	Projects	0	0	0	0	0	0	0	0	0	0	0	0
20	Energy Manager	Projects	0	0	0	0	0	0	0	0	0	0	0	0
21	Retrofit	Projects												
22	Demand Response 3*	Facilities	0	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														
23	Home Assistance Program	Homes	0	0	0	0	0	0	0	0	0	0	0	0
Home Assistance Program Total							**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
Pre-2011 Programs completed in 2011														
24	Electricity Retrofit Incentive Program	Projects	0	0	0	0	0	0	0	0	0	0	0	0
25	High Performance New Construction	Projects	0	0	0	0	0	0	0	0	0	0	0	0
26	Toronto Comprehensive	Projects	0	0	0	0	0	0	0	0	0	0	0	0
27	Multifamily Energy Efficiency Rebates	Projects	0	0	0	0	0	0	0	0	0	0	0	0
28	LDC Custom Programs	Projects	0	0	0	0	0	0	0	0	0	0	0	0
Pre-2011 Programs completed in 2011 Total							**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
Energy Efficiency Total							**11**	**18**	**42**	**15**	**27,871**	**48,453**	**112,891**	**45,272**
Demand Response Total (Scenario 1)							**38**	**38**	**38**	**38**	**145**	**145**	**145**	**145**
OPA-Contracted LDC Portfolio Total							**49**	**56**	**80**	**53**	**28,016**	**48,598**	**113,036**	**45,418**

* Activity & savings for Demand Response resources for each year and quarter represent the savings from all active facilities or devices contracted since January 1, 2011.

**** Updates to the previous quarter's participation may occur as a result of further data received**

Table 4A: Province-Wide Initiative and Program Level Savings by Year (Scenario 1)

#	Initiative	Unit	Incremental Activity (new program activity occuring 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 Unverified Progress to Target (excluding DR)	
			2011	2012	2013	2014	2011	2012	2013	2014	2011	2012	2013	2014	2014 Net Annual Peak Demand Savings (kW) 2014	2011-2014 Net Cumulative Energy Savings (kWh) 2014
Consumer Program																
1	Appliance Retirement	Appliances	56,110	34,155			3,299	2,144			23,005,812	14,479,436			5,304	135,341,610
2	Appliance Exchange	Appliances	3,688	2,243			371	311			450,187	526,845			444	3,169,198
3	HVAC Incentives	Equipment	111,587	84,668			32,037	23,927			59,437,670	44,084,702			55,964	370,004,787
4	Conservation Instant Coupon Booklet	Coupons	559,462	2,604			1,344	8			21,211,537	109,679			1,352	85,175,185
5	Bi-Annual Retailer Event	Coupons	870,332	315,023			1,681	667			29,387,468	12,276,249			2,349	154,378,622
6	Retailer Co-op	Items	152	0			0	0			2,652	0			0	10,607
7	Residential Demand Response (switch/pstat)*	Devices	19,550	59,408			10,947	33,268			24,870	127,144			0	152,014
8	Residential Demand Response (IHD)	Devices	0	35,388			0	1,399			0	9,320,016			1,399	9,320,016
9	Residential New Construction	Homes	7	26			0	0			743	2,703			0	11,081
Consumer Program Total							**49,681**	**61,725**			**133,520,941**	**80,926,773**			**66,813**	**757,563,120**
Business Program																
10	Retrofit	Projects	2,516	5,033			24,467	53,009			136,002,258	270,478,412			77,453	1,355,349,569
11	Direct Install Lighting	Projects	20,297	16,257			23,724	28,455			61,076,701	72,747,089			44,942	439,762,244
12	Building Commissioning	Buildings	0	0			0	0			0	0			0	0
13	New Construction	Buildings	10	21			123	853			411,717	1,355,405			976	5,713,083
14	Energy Audit	Audits	103	221			0	0			0	0			0	0
15	Small Commercial Demand Response (switch/pstat)*	Devices	132	363			84	203			157	698			0	854
16	Small Commercial Demand Response (IHD)	Devices	124	43			0	1			0	9,288			1	9,288
17	Demand Response 3*	Facilities	0	150			16,224	19,283			633,421	755,205			0	1,388,625
Business Program Total							**64,623**	**101,805**			**198,124,253**	**345,346,095**			**123,373**	**1,802,223,663**
Industrial Program																
18	Process & System Upgrades	Projects	0	0			0	0			0	0			0	0
19	Monitoring & Targeting	Projects	0	0			0	0			0	0			0	0
20	Energy Manager	Projects	0	37			0	828			0	7,587,760			828	22,763,281
21	Retrofit	Projects	433	0			4,615				28,866,840				4,613	115,462,282
22	Demand Response 3*	Facilities	124	186			52,484	71,353			3,080,737	4,188,340			0	7,269,078
Industrial Program Total							**57,098**	**72,181**			**31,947,577**	**11,776,101**			**5,442**	**145,494,640**
Home Assistance Program																
23	Home Assistance Program	Homes	46	3,036			2	204			39,283	2,051,762			207	6,312,419
Home Assistance Program Total							**2**	**204**			**39,283**	**2,051,762**			**207**	**6,312,419**
Pre-2011 Programs completed in 2011																
24	Electricity Retrofit Incentive Program	Projects	2,016	0			21,662	0			121,138,219	0			21,662	484,552,876
25	High Performance New Construction	Projects	145	20			5,098	1,869			26,185,591	9,936,694			6,968	134,552,447
26	Toronto Comprehensive	Projects	577	0			15,805	0			86,964,886	0			15,805	347,859,545
27	Multifamily Energy Efficiency Rebates	Projects	110	0			1,981	0			7,595,683	0			1,981	30,382,733
28	LDC Custom Programs	Projects	8	0			399	0			614,310	0			399	2,457,238
Pre-2011 Programs completed in 2011 Total							**44,945**	**1,869**			**242,498,689**	**9,936,694**			**46,814**	**999,804,839**
Energy Efficiency Total							**136,610**	**113,677**			**602,391,559**	**444,966,038**			**242,648**	**3,702,588,109**
Demand Response Total (Scenario 1)							**79,739**	**124,107**			**3,739,185**	**5,071,387**			**0**	**8,810,572**
OPA-Contracted LDC Portfolio Total							**216,349**	**237,785**			**606,130,744**	**450,037,425**			**242,648**	**3,711,398,681**
														Full OEB Target:	**1,330,000**	**6,000,000,000**
														Preliminary % of Full OEB Target Achieved to Date (Scenario 1):	**18.2%**	**61.9%**

* Activity & savings for Demand Response resources for each year and quarter represent the savings from all active facilities or devices contracted since January 1, 2011.

Table 4B: Province-Wide Initiative and Program Level Savings by Quarter for current reporting 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)			
			Q1 2012	Q2 2012	Q3 2012	Q4 2012	Q1 2012	Q2 2012	Q3 2012	Q4 2012	Q1 2012	Q2 2012	Q3 2012	Q4 2012
Consumer Program														
1	Appliance Retirement	Appliances	7,344	8,668	9,193	8,950	458	548	579	560	3,083,758	3,681,924	3,909,570	3,804,184
2	Appliance Exchange	Appliances	0	2,243	0	0	0	311	0	0	0	526,845	0	0
3	HVAC Incentives	Equipment	20,185	21,956	22,624	19,903	6,206	5,407	5,977	6,337	11,795,155	9,344,736	10,695,218	12,249,593
4	Conservation Instant Coupon Booklet	Coupons	0	0	0	2,604	0	0	0	8	0	0	0	109,679
5	Bi-Annual Retailer Event	Coupons	0	91,968	0	223,055	0	312	0	355	0	3,457,870	0	8,818,379
6	Retailer Co-op	Items	0	0	0	0	0	0	0	0	0	0	0	0
7	Residential Demand Response (switch/pstat)*	Devices	24,159	24,257	46,008	59,408	13,529	13,584	25,764	33,268	51,359	51,570	98,334	127,144
8	Residential Demand Response (IHD)	Devices	0	251	20,319	14,818	0	10	695	695	0	60,240	4,870,872	4,388,904
9	Residential New Construction	Homes	4	19	1	2	0	0	0	0	373	1,622	123	585
Consumer Program Total							**20,193**	**20,171**	**33,015**	**41,224**	**14,930,644**	**17,124,807**	**19,574,118**	**29,498,467**
Business Program														
10	Retrofit	Projects	1,080	1,264	1,530	1,159	12,614	13,581	14,250	12,564	68,920,271	70,484,025	71,179,848	59,894,268
11	Direct Install Lighting	Projects	4,743	4,563	4,063	2,888	7,965	7,958	7,146	5,385	20,335,190	20,331,442	18,339,284	13,741,172
12	Building Commissioning	Buildings	0	0	0	0	0	0	0	0	0	0	0	0
13	New Construction	Buildings	2	9	7	3	22	559	201	70	64,503	355,782	732,990	202,131
14	Energy Audit	Audits	48	98	51	24	0	0	0	0	0	0	0	0
15	Small Commercial Demand Response (switch/pstat)*	Devices	188	188	337	363	105	105	189	203	361	361	648	698
16	Small Commercial Demand Response (IHD)	Devices	0	0	26	17	0	0	1	1	0	0	5,616	3,672
17	Demand Response 3*	Facilities	149	153	153	150	16,390	20,623	19,573	19,283	641,918	807,681	766,575	755,205
Business Program Total							**37,097**	**42,826**	**41,361**	**37,506**	**89,962,243**	**91,979,291**	**91,024,961**	**74,597,145**
Industrial Program														
18	Process & System Upgrades	Projects	0	0	0	0	0	0	0	0	0	0	0	0
19	Monitoring & Targeting	Projects	0	0	0	0	0	0	0	0	0	0	0	0
20	Energy Manager	Projects	8	8	14	7	16	332	201	280	726,093	3,441,901	1,296,676	2,123,089
21	Retrofit	Projects												
22	Demand Response 3*	Facilities	132	145	177	186	56,120	62,864	63,239	71,353	3,294,157	3,690,043	3,712,034	4,188,340
Industrial Program Total							**56,135**	**63,196**	**63,440**	**71,633**	**4,020,250**	**7,131,944**	**5,008,710**	**6,311,430**
Home Assistance Program														
23	Home Assistance Program	Homes	135	1,018	954	929	20	76	89	20	171,593	751,230	735,013	393,925
Home Assistance Program Total							**20**	**76**	**89**	**20**	**171,593**	**751,230**	**735,013**	**393,925**
Pre-2011 Programs completed in 2011														
24	Electricity Retrofit Incentive Program	Projects	0	0	0	0	0	0	0	0	0	0	0	0
25	High Performance New Construction	Projects	13	6	1	0	1,654	201	14	0	8,794,790	1,069,101	72,803	0
26	Toronto Comprehensive	Projects	0	0	0	0	0	0	0	0	0	0	0	0
27	Multifamily Energy Efficiency Rebates	Projects	0	0	0	0	0	0	0	0	0	0	0	0
28	LDC Custom Programs	Projects	0	0	0	0	0	0	0	0	0	0	0	0
Pre-2011 Programs completed in 2011 Total							**1,654**	**201**	**14**	**0**	**8,794,790**	**1,069,101**	**72,803**	**0**
Energy Efficiency Total							**28,955**	**29,294**	**29,154**	**26,275**	**113,891,726**	**113,506,718**	**111,838,014**	**105,729,580**
Demand Response Total (Scenario 1)							**86,144**	**97,176**	**108,765**	**124,107**	**3,987,795**	**4,549,655**	**4,577,591**	**5,071,387**
OPA-Contracted LDC Portfolio Total							**115,099**	**126,469**	**137,919**	**150,383**	**117,879,521**	**118,056,373**	**116,415,605**	**110,800,967**

* Activity & savings for Demand Response resources for each year and quarter represent the savings from all active facilities or devices contracted since January 1, 2011.

**** Updates to the previous quarter's participation may occur as a result of further data received**

Table 5: Data Qualifiers for Initiatives Currently In-Market & Likelihood of Additional Data

Data included in the Q4 2012 report includes all program activity completed (as per the savings 'start' date) on or before December 31, 2012.

Initiative	**Savings 'start' Date**	**Data Available**	**Additional Data Likely**
Consumer Program			
Appliance Retirement	Pick-up date	When database is queried (Q3 Report Date: January 17, 2013). Typically up-to-date.	Moderate
Appliance Exchange	Exchange event date	Once data is submitted to the OPA by retailers and undergoes QA/QC by OPA staff. Typically 3 - 6 months to receive and process all data.	High
HVAC Incentives	Installation date^1	Rebate Status = Approved, Cheque Issued/Cashed, Pending, Under Review (Q3 Report Date: January 17, 2013). Typically 1 - 4 months delay.	High
Conservation Instant Coupon Booklet	Coupon redemption year	Once data is submitted to the OPA by retailers and undergoes QA/QC by OPA staff. Typically 3 - 6 months to receive and process all data.	High
Bi-Annual Retailer Event	Year and quarter of the event		High
Retailer co-op activities	Will vary by specific project	Will vary by specific project	Low
Residential Demand Response	Device installation date	Data successfully uploaded into RDR settlement system as of January 24, 2013.	High
Residential New Construction	Project completion	Preliminary Billing Report submitted to OPA as of January 17, 2013.	Low
Business (Commercial & Institutional) Program			
Retrofit	Actual project completion date	In the "Post Project Submission" Stage (excluding "Payment Denied by LDC") within iCON CRM as of January 31, 2013.	Low
Direct Installed Lighting	Retrofit date	Work-order: invoiced, approved and paid to LDC as of January 17, 2013. Typically 1.5 - 2 months delay. Any projects that are flagged as duplicates will not appear in reports until duplicates have been resolved.	High
Building Commissioning	Hand off date	Preliminary Billing Report submitted to OPA and reviewed as of January 17, 2013.	Moderate
New Construction	Actual project completion date	Preliminary Billing Report submitted to OPA and reviewed as of January 17, 2013.	Moderate
Energy Audit	Audit completion date	Preliminary Billing Report submitted to OPA and reviewed as of January 17, 2013.	Moderate
Small Commercial Demand Response	Device installation date	Data successfully uploaded into RDR settlement system as of January 24, 2013.	Moderate
Demand Response 3	Facility is available under contract	Facility available under contract with aggregator	Low
Industrial Program			
Process & System Upgrades	In-service date	Preliminary Billing Report submitted to OPA and reviewed as of January 17, 2013.	Low
Monitoring & Targeting	Project completion date	Preliminary Billing Report submitted to OPA and reviewed as of January 17, 2013.	Low
Energy Manager (EEM or REM)	Project completion date	Completed, non-incented projects submitted quarterly by Energy Manager.	High
Retrofit	All Retrofit projects are now reported under the Business Program		
Demand Response 3	Facility is available under contract	Facility available under contract with aggregator.	Low
Home Assistance Program			
Home Assistance Program	Project completion date	Preliminary Billing Report submitted to OPA and reviewed as of January 17, 2013.	High
Pre-2011 Projects Completed in 2011			
High Performance New Construction	Project completion date	Reviewed and processed from delivery agent, quarterly	Moderate

1: Monthly reports split savings into months using the approval date

Reporting Glossary

Annual: the peak demand or energy savings that occur in a given year (includes resource savings from new program activity in a given year and resource savings persisting from previous years). Annual savings for Demand Response resources represent the savings from all active facilities contracted since January 1, 2011.

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.

Current Reporting Period: the calendar quarter specified on page 1 of this report.

Effective Useful Life: detemines the persistence of savings for a given technology or initiative. Factors that may effect the useful life of a technology are typical use and operating hours, upcoming code changes, etc. Demand response resources are assumed to have a persistence of 1 year.

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). All savings presented in this report are at the end-user level.

Final or Verified Savings: savings achieved that have undergone annual Evaluation, Measurement & Verification (EM&V) and thus have had activity audited and savings assumptions measured and verified.

Implementation Period: the particular calendar quarter or calendar year that conservation activity is achieved based on when the savings are considered to 'start' (please see table 5).

Incremental: the new resource savings attributable to activity procured in a particular reporting period based on when the savings are considered to 'start' (please see table 5). Incremental savings for Demand Response resources represent the savings from all active facilities contracted since January 1, 2011 (i.e. Incremental = Annual for demand response only).

Initiative: a Conservation & Demand Management offering focusing on a particular opportunity or customer end-use (i.e. Retrofit, Fridge & Freezer Pickup).

Net Energy Savings (MWh): energy savings attributable to conservation and demand management activities net of free-riders, etc. Please refer to the webinars in the "Reporting Methodology" section for more information.

Net Peak Demand Savings (MW): peak demand savings attributable to conservation and demand management activities net of free-riders, etc. Please refer to the webinars in the "Reporting Methodology" section for more information.

Program-to-Date: the reporting period from January 1, 2011 until the end of the Current Reporting Period.

Program: a group of initiatives that target a particular market sector (i.e. Consumer, Industrial).

Reported or Unverified Savings: savings achieved that are based on reported activity and forecasted or best available savings assumptions. These savings are not verified, i.e. have not undergone the Evaluation, Measurement & Verification processes.

Unit: for a specific initiative the relevant type of activity acquired in the market place (i.e. appliances picked up, projects completed, coupons redeemed).

Reporting Methodology (Quarterly, Unverified results):

There are several resources on reporting that are available to LDCs:

- Reporting Policy & FAQ Document found on the iCON Portal in the "Other Program Materials" under "Reporting Tools"
- LDC Consumer Program Tracking Tool found on the iCON Portal in "Other Program Materials" under "Reporting Tools"
- Webinars (available at the following link: http://www.snwebcastcenter.com/custom_events/opa-20111781/site/index.php)
  - Understanding your Q4 2011 Report (April 11, 2012)
  - Tools from the Reporting WG (April 25, 2012)
  - A Deeper Look at: ***peaksaver* PLUS®** (May 23, 2012)
  - A Deeper Look at: Demand Response 3 (June 6, 2012)
  - Revisiting Reporting (June 20, 2012)
  - Quarterly CDM Status Report update (October 24, 2012) http://powerauthority.webex.com; password: DCx2012

Exhibit 4 – Operation Cost

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EXHIBIT 4 – OPERATING COST

The purpose of this Appendix is to provide an analysis of The Applicant's Operating, Maintenance and Administrative (OM&A) costs on an actual and forecast basis. The evidence herein is organized according to the following topics;

1) Manager 'Summary
2) Employee Compensation
3) Shared Services and Corporate Allocation
4) Purchases of Non-Affiliate Services
5) Depreciation/Amortization/Depletion
6) PILs and Property Taxes
7) GEA Plan
8) CDM Costs
9) Patronage Dividends

Tab 1 – Manager ‘Summary

E4.T1.S1 OVERVIEW OF OPERATING COSTS

Table 1 below shows a summary of CHEI’s Operations, Maintenance and Administrative (“OM&A”) costs as required by the OEB’s filing guidelines.

Table 1 - Summary of Operating Costs

	Last Rebasing Year (2010 BA)	**Last Rebasing Year (2010 Actuals)**	**2011 Actuals**	**2012 Actuals**	**2013 Bridge Year**	**2014 Test Year**
Reporting Basis	**CGAAP**	**CGAAP**	**CGAAP**	**CGAAP**	**CGAAP**	**CGAAP**
Operations	$33,860.00	$20,826.84	$20,964.95	$16,298.22	$15,550.00	$20,900.00
Maintenance	$37,425.00	$36,633.34	$39,318.88	$48,628.27	$39,800.00	$40,300.00
SubTotal	**$71,285.00**	**$57,460.18**	**$60,283.83**	**$64,926.49**	**$55,350.00**	**$61,200.00**
%Change (year over year)	▨	▨	4.9%	7.7%	-14.7%	10.6%
%Change (Test Year vs Last Rebasing Year - Actual)						6.5%
Billing and Collecting	$155,247.00	$146,428.90	$163,138.56	$151,426.27	$134,057.15	$170,174.00
Community Relations	$3,000.00	$2,182.16	$1,316.25	$6,709.95	$3,100.00	$4,000.00
Administrative and General	$265,695.00	$268,698.04	$313,599.01	$301,533.57	$320,278.16	$320,905.00
SubTotal	**$423,942.00**	**$417,309.10**	**$478,053.82**	**$459,669.79**	**$457,435.31**	**$495,079.00**
%Change (year over year)	▨	▨	14.6%	-3.8%	-0.5%	8.2%
%Change (Test Year vs Last Rebasing Year - Actual)						18.6%
Total	**$495,227.00**	**$474,769.28**	**$538,337.65**	**$524,596.28**	**$512,785.31**	**$556,279.00**
%Change (year over year)	▨	▨	13.4%	-2.6%	-2.3%	8.5%

As indicated at Exhibit 1 section E1.T1.S5 CHEI has followed the Canadian Generally Accepted Accounting Principles (CGAAP) in preparation of its forecasted years. In a January 1, 2013, the Board instructed utilities to change their capitalization policy which meant expensing certain costs rather than applying them as burdens to capital projects. For most utilities, this change has had the effect of significantly increasing OM&A. However, In CHEI's case, burdens were never applied prior to the change in capitalization consequently the effects on OM&A are nonexistent.

CHEI's increase in OM&A spending from its 2010 Cost of Service to the 2014 Test Year amounts to approximately $65,000. The increase can be attributed to several factors related to the operating and maintenance of the distribution system and administrative costs. The costs related to maintenance of the distribution system are for the most part aimed at specific projects to accommodate future load or the inflationary increase in administration. These projects are discussed in detail at Exhibit 2. Another significant contributor to the increase in OM&A is the on-going costs associated with supporting smart metering. These costs, at $34,500, account for more than half of the overall increase. If CHEI were to remove these costs, the overall increase from 2010 to 2014 would be approximately $26,500 or 10% as seen in Table 2 below.

Table 2 -Summary of Operating Costs

	Last Rebasing Year (2010 BA)	**Last Rebasing Year (2010 Actuals)**	**2011 Actuals**	**2012 Actuals**	**2013 Bridge Year**	**2014 Test Year**
Reporting Basis	**CGAAP**	**CGAAP**	**CGAAP**	**CGAAP**	**CGAAP**	**CGAAP**
SubTotal	**$423,942.00**	**$417,309.10**	**$478,053.82**	**$459,669.79**	**$457,435.31**	**$460,579.00**
%Change (year over year)	▨	▨	14.6%	-3.8%	-0.5%	0.7%
%Change (Test Year vs Last Rebasing Year - Actual)						10.4%
Total	**$495,227.00**	**$474,769.28**	**$538,337.65**	**$524,596.28**	**$512,785.31**	**$521,779.00**
%Change (year over year)	▨	▨	13.4%	-2.6%	-2.3%	1.8%

Financial pressures in specific areas, such as bad debts, have also influenced the spending in the OM&A. Staff and management salaries are adjusted yearly to reflect inflation and cost of living. The cost of living is based on an inflation rate of 2% as published by the Bank of Canada [footnote to RRFE report].

CHEI’s approach to budgeting and managing its OM&A costs is that whenever possible, CHEI attempts to keep its operating cost within the boundaries of the last board approved OM&A costs. If unexpected costs arise, the utility makes every effort to reduce costs elsewhere in order to stay within the board approved budget. Reasonableness of OM&A costs are scrutinized with particular care and consideration of the needs and requirement of the organization, its members, employees, and clients, the public at large, and the regulators.

E4.T1.S2 Summary of Recoverable OM&A Expenses – Appendix 2-I

The following Table (3) summarizes CHEI’s recoverable OM&A expenses.

Table 3 – Summary of recoverable OM&A expenses

	Last Rebasing Year (2010 BA)	Last Rebasing Year (2010 Actuals)	2011 Actuals	2012 Actuals	2013 Bridge Year	2014 Test Year
Operations	$33,860.00	$20,826.84	$20,964.95	$16,298.22	$15,550.00	$20,900.00
Maintenance	$37,425.00	$36,633.34	$39,318.88	$48,628.55	$39,800.00	$40,300.00
Billing and Collecting	$155,247.00	$146,428.90	$163,138.56	$135,426.27	$134,057.15	$170,174.00
Community Relations	$3,000.00	$2,182.16	$1,316.25	$6,709.95	$3,100.00	$4,000.00
Administrative and General	$265,695.00	$268,698.04	$313,599.01	$317,533.57	$320,278.16	$320,905.00
Total	**$495,227.00**	**$474,769.28**	**$538,337.65**	**$524,596.56**	**$512,785.31**	**$556,279.00**
%Change (year over year)	▨	▨	13.4%	-2.6%	-2.3%	8.5%

E4.T1.S3 Detailed OM&A Expenses by Account – Appendix 2-H

A more detailed breakdown of CHEI’s year over year OM&A is presented at the next page (Appendix 2-H)

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Appendix 2-H
OM&A Detailed Variance Analysis
(excluding Depreciation and Amortization)

Account	Description	Last Board-approved Rebasing Year (2010 Year)	Most Current Actuals Year 2012	Test Year 2014	Test Year Versus Last Rebasing		Test Year Versus Most Current Actuals	
					Variance ($)	Percentage	Variance ($)	Percentage
Reporting Basis		CGAAP	CGAAP	CGAAP	▨	▨	▨	▨
Operations								
5005	Operation Supervision and Engineering	$ -	$ -	$ -	$ -		$ -	
5010	Load Dispatching	$ -	$ -	$ -	$ -		$ -	
5012	Station Buildings and Fixtures Expense	$ 1,860	$ 1,451	$ 1,900	$ 40	2.15%	$ 449	30.91%
5014	Transformer Station Equipment - Operation Labour	$ -	$ -	$ -	$ -		$ -	
5015	Transformer Station Equipment - Operation Supplies and Expenses	$ -	$ -	$ -	$ -		$ -	
5016	Distribution Station Equipment - Operation Labour	$ -	$ -	$ -	$ -		$ -	
5017	Distribution Station Equipment - Operation Supplies and Expenses	$ -	$ -	$ -	$ -		$ -	
5020	Overhead Distribution Lines and Feeders - Operation Labour	$ -	$ -	$ -	$ -		$ -	
5025	Overhead Distribution Lines and Feeders - Operation Supplies and Expenses	$ -	$ -	$ -	$ -		$ -	
5030	Overhead Sub-transmission Feeders - Operation	$ -	$ -	$ -	$ -		$ -	
5035	Overhead Distribution Transformers - Operation	$ -	$ 605	$ 6,000	$ 6,000		$ 5,395	891.74%
5040	Underground Distribution Lines and Feeders - Operation Labour	$ -	$ -	$ -	$ -		$ -	
5045	Underground Distribution Lines and Feeders - Operation Supplies and Expenses	$ -	$ -	$ -	$ -		$ -	
5050	Underground Sub-transmission Feeders - Operation	$ -	$ -	$ -	$ -		$ -	
5055	Underground Distribution Transformers - Operation	$ 12,000	$ -	$ -	-$ 12,000	-100.00%	$ -	
5060	Street Lighting and Signal System Expense	$ -	$ -	$ -	$ -		$ -	
5065	Meter Expense	$ 2,000	$ -	$ 2,000	$ -	0.00%	$ 2,000	
5070	Customer Premises - Operation Labour	$ -	$ -	$ -	$ -		$ -	
5075	Customer Premises - Operation Materials and Expenses	$ 6,000	$ 7,031	$ 6,000	$ -	0.00%	-$ 1,031	-14.66%
5085	Miscellaneous Distribution Expenses	$ 12,000	$ 7,211	$ 5,000	-$ 7,000	-58.33%	-$ 2,211	-30.66%
5090	Underground Distribution Lines and Feeders - Rental Paid	$ -	$ -	$ -	$ -		$ -	
5095	Overhead Distribution Lines and Feeders - Rental Paid	$ -	$ -	$ -	$ -		$ -	
5096	Other Rent	$ -	$ -	$ -	$ -		$ -	
Total - Operations		$ 33,860	$ 16,298	$ 20,900	-$ 12,960	-38.28%	$ 4,602	28.23%
Account	**Description**							
Maintenance								
5105	Maintenance Supervision and Engineering	$ 2,500	$ -	$ -	-$ 2,500	-100.00%	$ -	
5110	Maintenance of Buildings and Fixtures - Distribution Stations	$ 2,425	$ 8,538	$ 9,600	$ 7,175	295.88%	$ 1,062	12.44%
5112	Maintenance of Transformer Station Equipment	$ -	$ -	$ -	$ -		$ -	
5114	Maintenance of Distribution Station Equipment	$ 12,000	$ 19,003	$ 5,200	-$ 6,800	-56.67%	-$ 13,803	-72.64%
5120	Maintenance of Poles, Towers and Fixtures	$ 2,500	$ 2,524	$ 6,000	$ 3,500	140.00%	$ 3,477	137.77%
5125	Maintenance of Overhead Conductors and Devices	$ 6,000	$ 6,033	$ 6,000	$ -	0.00%	-$ 33	-0.55%
5130	Maintenance of Overhead Services	$ -	$ -	$ -	$ -		$ -	
5135	Overhead Distribution Lines and Feeders - Right of Way	$ 7,000	$ 4,303	$ 7,500	$ 500	7.14%	$ 3,198	74.32%
5145	Maintenance of Underground Conduit	$ -	$ 5,775	$ -	$ -		-$ 5,775	-100.00%
5150	Maintenance of Underground Conductors and Devices	$ -	$ -	$ -	$ -		$ -	
5155	Maintenance of Underground Services	$ -	$ -	$ -	$ -		$ -	
5160	Maintenance of Line Transformers	$ 5,000	$ 2,453	$ 6,000	$ 1,000	20.00%	$ 3,547	144.60%
5165	Maintenance of Street Lighting and Signal Systems	$ -	$ -	$ -	$ -		$ -	
5170	Sentinel Lights - Labour	$ -	$ -	$ -	$ -		$ -	
5172	Sentinel Lights - Materials and Expenses	$ -	$ -	$ -	$ -		$ -	
5175	Maintenance of Meters	$ -	$ -	$ -	$ -		$ -	
5178	Customer Installations Expenses - Leased Property	$ -	$ -	$ -	$ -		$ -	
5195	Maintenance of Other Installations on Customer Premises	$ -	$ -	$ -	$ -		$ -	
Total - Maintenance		$ 37,425	$ 48,629	$ 40,300	$ 2,875	7.68%	-$ 8,329	-17.13%
Account	**Description**							
Billing and Collecting								
5305	Supervision	$ -	$ -	$ -	$ -		$ -	
5310	Meter Reading Expense	$ 11,600	$ -	$ -	-$ 11,600	-100.00%	$ -	
5315	Customer Billing	$ 141,547	$ 132,060	$ 161,174	$ 19,627	13.87%	$ 29,114	22.05%
5320	Collecting	$ -	$ -	$ -	$ -		$ -	
5325	Collecting - Cash Over and Short	$ -	$ -	$ -	$ -		$ -	
5330	Collection Charges	$ 1,500	$ 3,366	$ 4,000	$ 2,500	166.67%	$ 634	18.82%
5335	Bad Debt Expense	$ 600	$ -	$ 5,000	$ 4,400	733.33%	$ 5,000	
5340	Miscellaneous Customer Accounts Expenses		$ -	$ -	$ -		$ -	
Total - Billing and Collecting		$ 155,247	$ 135,426	$ 170,174	$ 14,927	9.62%	$ 34,748	25.66%
Account	**Description**							
Community Relations								
5405	Supervision	$ -	$ -	$ -	$ -		$ -	
5410	Community Relations - Sundry	$ 3,000	$ 6,710	$ 4,000	$ 1,000	33.33%	-$ 2,710	-40.39%
5415	Energy Conservation	$ -	$ -	$ -	$ -		$ -	
5420	Community Safety Program	$ -	$ -	$ -	$ -		$ -	
5425	Miscellaneous Customer Service and Informational Expenses	$ -	$ -	$ -	$ -		$ -	
5505	Supervision	$ -	$ -	$ -	$ -		$ -	
5510	Demonstrating and Selling Expense	$ -	$ -	$ -	$ -		$ -	
5515	Advertising Expenses	$ -	$ -	$ -	$ -		$ -	
5520	Miscellaneous Sales Expense	$ -	$ -	$ -	$ -		$ -	
Total - Community Relations		$ 3,000	$ 6,710	$ 4,000	$ 1,000	33.33%	-$ 2,710	-40.39%
Account	**Description**							
Administrative and General Expenses								
5605	Executive Salaries and Expenses	$ 21,200	$ 25,148	$ 28,000	$ 6,800	32.08%	$ 2,852	11.34%
5610	Management Salaries and Expenses	$ 82,000	$ 77,598	$ 84,000	$ 2,000	2.44%	$ 6,402	8.25%
5615	General Administrative Salaries and Expenses	$ 37,000	$ 62,114	$ 67,405	$ 30,405	82.18%	$ 5,291	8.52%
5620	Office Supplies and Expenses	$ 17,000	$ 35,738	$ 46,600	$ 29,600	174.12%	$ 10,862	30.39%
5625	Administrative Expense Transferred - Credit	$ -	$ -	$ -	$ -		$ -	
5630	Outside Services Employed	$ 82,350	$ 87,916	$ 58,800	-$ 23,550	-28.60%	-$ 29,116	-33.12%

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Appendix 2-H
OM&A Detailed Variance Analysis
(excluding Depreciation and Amortization)

5635 Property Insurance	$ 5,400	$ 4,960	$ 3,000	-$ 2,400	-44.44%	-$ 1,960	-39.52%
5640 Injuries and Damages	$ 1,500	$ 1,571	$ 2,800	$ 1,300	86.67%	$ 1,229	78.19%
5645 OMERS Pensions and Benefits	$ -	$ -	$ -	$ -		$ -	
5646 Employee Pensions and OPEB	$ -	$ -	$ -	$ -		$ -	
5647 Employee Sick Leave	$ -	$ -	$ -	$ -		$ -	
5650 Franchise Requirements	$ -	$ -	$ -	$ -		$ -	
5655 Regulatory Expenses	$ 5,450	$ 5,452	$ 10,600	$ 5,150	94.50%	$ 5,148	94.41%
5660 General Advertising Expenses	$ -	$ -	$ -	$ -		$ -	
5665 Miscellaneous General Expenses	$ -	$ -	$ -	$ -		$ -	
5670 Rent	$ 12,000	$ 13,200	$ 15,600	$ 3,600	30.00%	$ 2,400	18.18%
5672 Lease Payment Charge	$ -	$ -	$ -	$ -		$ -	
5675 Maintenance of General Plant	$ -	$ -	$ -	$ -		$ -	
5680 Electrical Safety Authority Fees	$ 1,795	$ 1,836	$ 2,100	$ 305	16.99%	$ 264	14.37%
5681 Special Purpose Charge Expense	$ -	$ -	$ -	$ -		$ -	
5685 Independent Electricity System Operator Fees and Penalties	$ -	$ -	$ -	$ -		$ -	
5695 OM&A Contra Account	$ -	$ -	$ -	$ -		$ -	
6205 Donations	$ -	$ -	$ -	$ -		$ -	
6205 Donations, Sub-account LEAP Funding	$ 2,000	$ 2,000	$ 2,000	$ -	0.00%	$ -	0.00%
Total - Administrative and General Expenses	$ 267,695	$ 317,534	$ 320,905	$ 53,210	19.88%	$ 3,371	1.06%
Total OM&A	$ 497,227	$ 524,597	$ 556,279	$ 59,052	11.88%	$ 31,682	6.04%
Adjustments for non-recoverable items							
5681 Special Purpose Charge Expense		$ -	$ -	$ -		$ -	
6205 Donations[1]				$ -		$ -	
				$ -		$ -	
				$ -		$ -	
				$ -		$ -	
Total Recoverable OM&A	$ 497,227	$ 524,597	$ 556,279	$ 59,052	11.88%	$ 31,682	6.04%

[1] Account 6205 - Donations is generally non-recoverable. However, the sub-account LEAP funding of account 6205 is generally recoverable.

Note:

1 If the applicant is adopting IFRS or an alternate accounting standard as of January 1, 2013 for financial reporting purposes, Column D "Most Current Actual Year" must be provided on CGAAP.

2 If the applicant is adopting IFRS or an alternate accounting standard as of January 1, 2012 for financial reporting purposes, Column D "Most Current Actual Year" must be provided on that standard.

E4.T1.S4 OM&A COST DRIVERS – APPENDIX 2-J

In accordance with the OEB's minimum filing requirements, Table 4, below, outlines the key drivers of OM&A costs over the 2010 to 2014 period. The key cost driver's discussions follow Table 4.

Table 4 - OM&A Cost Drivers – Appendix 2-J

OM&A	**Last Rebasing Year (2010 Actuals)**	**2011 Actuals**	**2012 Actuals**	**2013 Bridge Year**	**2014 Test Year**
Reporting Basis	**CGAAP**	**CGAAP**	**CGAAP**	**CGAAP**	**CGAAP**
Opening Balance	$495,227.00	$467,199.00	$531,003.00	$522,596.00	$510,784.00
3500-Distribution Expenses - Operations	$7,580.00	$2,650.00	$20,725.00	$3,895.00	$4,550.00
3500-Distribution Expenses - Maintenance	$13,809.00	$10,509.00		$6,721.00	$5,500.00
3650-Billing and Collecting	$2,572.00	$16,980.00	$1,326.00	$5,000.00	$35,317.00
3700-Community Relations			$5,394.00		
3800-Administrative and General Expenses	$6,186.00	$46,400.00	$22,496.00	$12,328.00	$39,327.00
other	$3,305.00	$3,249.00	$1,753.00	$1,060.00	$3,200.00
Cost Reduction	-$61,480.00	-$15,984.00	-$60,101.00	-$40,816.00	-$42,400.00
Closing Balance	**$467,199.00**	**$531,003.00**	**$522,596.00**	**$510,784.00**	**$556,278.00**
Net Change	-$28,028.00	$63,804.00	-$8,407.00	-$11,812.00	$45,494.00

Table 5 - 2010 Cost Drivers

OEB	Description	2010 Cost Drivers	
3550-Distribution Expenses - Maintenance	5160-Maintenance of Line Transformers	$7,480.75	1
3550-Distribution Expenses - Maintenance	5110-Maintenance of Buildings and Fixtures - Distribution Stations	$6,328.54	2
3500-Distribution Expenses - Operation	5035-Overhead Distribution Transformers-Operation	$5,812.37	3
3800-Administrative and General Expenses	5681-Special Purpose Charge Expense	$5,570.36	4
3800-Administrative and General Expenses	5620-Office Supplies and Expenses	$3,992.41	5
3650-Billing and Collecting	5315-Customer Billing	$2,571.90	6
3800-Administrative and General Expenses	6205-Donations, Sub-account LEAP Funding	$2,000.00	7
3500-Distribution Expenses - Operation	5075-Customer Premises - Materials and Expenses	$1,767.50	8
3800-Administrative and General Expenses	5610-Management Salaries and Expenses	$1,144.94	9
3800-Administrative and General Expenses	5615-General Administrative Salaries and Expenses	$1,048.79	10
Other (< $1000)		$3,505.00	

5160-Maintenance of Line Transformers: $7,480 increase (Over 2010BA-2010Actual period)

These costs are attributed to maintenance done on several pad-mounted transformers. A number of transformers showed signs of deterioration and required additional maintenance to get them back into working order. A properly maintained distribution system is important for ensuring that the utility can: dependably provide electricity to its customers, minimize outages or continue operating in the event of an emergency. A properly maintained distribution system can also extend equipment life-cycles and minimize problems related to minor or major equipment failures.

5110-Maintenance of Buildings and Fixtures - Distribution Stations: $6,328.54 increase (Over 2010BA-2010Actual period)

These costs are related to a new office cleaning contract in the amount of $4,800 as well as $1,400 for carpet cleaning. This is necessary in order to keep CHEI's office looking professional and also enhances the health and well-being of the staff.

5035-Overhead Distribution Transformers- Operation: $5,812.37 increase (Over 2010BA-2010Actual period)

These costs are for oil sampling and repair of a defective transformer. The repairs were in the amount of $3,275$, oil sampling in the amount of $1500 and service call charge of $1,000. As mentioned above, a properly maintained distribution system can also extend equipment life-cycles and minimize problems related to minor or major equipment failures

5681-Special Purpose Charge Expense: $5,570.36.54 increase (Over 2010BA-2010Actual period)

These costs were mandated by the OEB.

5620-Office Supplies and Expenses: $3,992.41increase (Over 2010BA-2010Actual period)

These costs include a new phone line collector for $2,400 and new cost associated with in-house bill print $1,500

5315-Customer Billing: $2,571.90 increase (Over 2010BA-2010Actual period)

These costs include a new collector for meter reading for $1,600 and the balance accounts for an inflationary increase in wages.

6205-Donations, Sub-account LEAP Funding: $2,000.00 increase (Over 2010BA-2010Actual period)

These costs were mandated and approved by the OEB in CHEI's previous cost of service (EB-2009-0132).

5075-Customer Premises - Materials and Expenses: $1,767.50 increase (Over 2010BA-2010Actual period)

This increase in cost can be attributed to additional locates done in 2010.

5610-Management Salaries and Expenses: $1,144.94 increase (Over 2010BA-2010Actual period)

This increase in cost can be attributed to adjustment to management salaries for cost of living.

5615-General Administrative Salaries and Expenses: $1,048.79 increase (Over 2010BA-2010Actual period)

This cost is for an increase in benefits / insurance group premium (Great West Life Insurance).

Table 6 - 2011 Cost Drivers

		2011	
OEB	**Description**	**Cost Drivers**	
3800-Administrative and General Expenses	5630-Outside Services Employed	$19,131.30	1
3650-Billing and Collecting	5315-Customer Billing	$16,979.66	2
3800-Administrative and General Expenses	5615-General Administrative Salaries and Expenses	$10,013.30	3
3550-Distribution Expenses - Maintenance	5125-Maintenance of Overhead Conductors and Devices	$8,005.40	4
3800-Administrative and General Expenses	5620-Office Supplies and Expenses	$7,500.46	5
3800-Administrative and General Expenses	5605-Executive Salaries and Expenses	$5,890.12	6
3800-Administrative and General Expenses	5610-Management Salaries and Expenses	$3,864.92	7
3500-Distribution Expenses - Operation	5065-Meter Expense	$2,650.00	8
3550-Distribution Expenses - Maintenance	5120-Maintenance of Poles, Towers and Fixtures	$2,503.75	9
Other (< $1000)		$3,249.00	

5630-Outside Services Employed: $19,131.30 increase (Over 2011-2010)

These costs are associated with the reclassification (for comparative purposes) of regulatory costs from account 5655 – Regulatory Expenses to 5630 - Outside Services Employed. This increase is offset by a reduction in account 5655. Regulatory Costs are discussed in detail at E4.T1.S8

5315-Customer Billing $16,979.66 increase (Over 2011-2010)

These costs are associated with $10,000 in incentive pay and $7,000 in increased employee benefits. The $10,000 in incentive pay is considered to be one-time costs and as such have been removed in the following year. Further details on one-time costs can be found at E4.T1.S7

5615-General Administrative Salaries and Expenses: $10,013.30 increase (Over 2011-2010)

Prior to 2010, CHEI would allocated 6% of salaries to RRSP. In 2011, CHEI opted to contribute the equivalent amount in DPSP ("Differed Profit Share Plan") instead. The increase of $6,000 is account 5615-General Administrative Salaries and Expenses is offset by an equivalent reduction in 5610-Management Salaries and Expenses.

This cost in the amount of $4,000 is for an increase in benefits / insurance group premium (Great West Life Insurance).

5125-Maintenance of Overhead Conductors and Devices: $8,005.40 increase (Over 2011-2010)

These costs are associated with various repairs done following a severe thunderstorm and are considered necessary for the safety of its customers.

5620-Office Supplies and Expenses: $7,500.46 increase (Over 2011-2010)

This cost is for an increase in benefits / insurance group premium (Great West Life Insurance).

5605-Executive Salaries and Expenses: $5,890.12 increase (Over 2011-2010)

These costs are associated with an increase in Board of Director fees.

5610-Management Salaries and Expenses: $3,864.92 increase (Over 2011-2010)

This increase in cost can be attributed to adjustment to management salaries for cost of living and overtime.

5065-Meter Expense: $2,650.00 increase (Over 2011-2010)

This increase in cost is for engaging a contract meter specialist to oversee the installation and verification of general services over 50KW and insure its compliance with Measurement Canada.

5120-Maintenance of Poles, Towers and Fixtures: $2,503.75 increase (Over 2011-2010)

These costs are associated with additional maintenance and repair on the overhead distribution system in order to increase reliability.

Table 7 - 2012 Cost Drivers

		2012	
OEB	**Description**	**Cost Drivers**	
3550-Distribution Expenses - Maintenance	5110-Maintenance of Buildings and Fixtures - Distribution Stations	$19,303.76	1
3800-Administrative and General Expenses	5615-General Administrative Salaries and Expenses	$14,051.58	2
3700-Community Relations	5410-Community Relations - Sundry	$5,393.70	3
3550-Distribution Expenses - Maintenance	5145-Maintenance of Underground Conduit	$4,429.25	4
3650-Billing and Collecting	5330-Collection Charges	$1,326.36	5
3800-Administrative and General Expenses	5670-Rent	$1,200.00	6
Other (< $1000)		$1,452.00	

5114-Maintenance Distribution Stations: $19,303 increase (Over 2012-2011)

These costs are for in advance of enhancements needed for the substation in order to accommodate future load. Based on a load flow study conducted by Stantec, CHEI has determined that the substation is operating at near full capacity. This issue is discussed in detail throughout Exhibit 2 but to summarize the need for this expenditure, a 4th Feeder was added to reduce emergency switching overload conditions. General Electric was hired do some preliminary analysis on the substation. The work included the following;

44KV Liquid Filled Transformers:
- Visual inspection
- Insulation resistance measurement
- Turns ratio measurement
- Winding resistance measurement
- Verification of auxiliary devices/alarm
- Oil sample analysis

15KV Loadbreak Switches
- Visual inspection
- Mechanical check
- Electrical check
- Contract resistance (main contact/fuse and holders)

5615-General Administrative Salaries and Expenses: $14,051.58 increase (Over 2012-2011)

This increase represents year over year increases in normal operating costs. The increase can be broken down as follows;

- Increase in Bank Charges; $2,500
- Increase in transportation: $300
- Annual meeting of the Coop: $1,200
- Increase in Great West benefits: $2,500
- Increase in DPSP (differed profit share plan) $8500
- Increase in EDA membership: $300
- Remitance to the Government: $1,000

5410-Community Relations - Sundry: $5,393.70 increase (Over 2012-2011)

The United Nations declared 2012 as the International Year of Cooperatives. The intent was to raise public awareness of the invaluable contributions of cooperative enterprises to poverty reduction, employment generation and social integration. Five local cooperatives banded together to organize activities and events in recognition of this declaration. Activities included contests, special publication on the cooperatives, partaking in a summer festival and a special evening gala with dignitaries. The purpose of these activities was to promote cooperatives in the region and encourage membership.

5145-Maintenance of Underground Conduit: $4,429.25 increase (Over 2012-2011)

These costs are associated with repairs on an underground conduit caused by a faulty wire. This type of maintenance in necessary in order to maintain reliability and continuity of service.

5330-Collection Charges: $1,326.36 increase (Over 2012-2011)

These costs are associated with additional delivery of disconnection letter.

5670-Rent: $1,200.00 increase (Over 2012-2011)

These costs are associated with an increase of 100/month for rent.

Table 8 - 2013 Cost Drivers

		2013	
OEB	**Description**	**Cost Drivers**	
3800-Administrative and General Expenses	5620-Office Supplies and Expenses	$20,044.33	1
3650-Billing and Collecting	5335-Bad Debt Expense	$5,000.00	2
3550-Distribution Expenses - Maintenance	5120-Maintenance of Poles, Towers and Fixtures	$2,476.50	5
3500-Distribution Expenses - Operation	5035-Overhead Distribution Transformers-Operation	$2,395.00	3
3550-Distribution Expenses - Maintenance	5135-Overhead Distribution Lines and Feeders - Right of Way	$1,697.50	4
3550-Distribution Expenses - Maintenance	5160-Maintenance of Line Transformers	$1,547.00	5
3500-Distribution Expenses - Operation	5065-Meter Expense	$1,500.00	6
Other (< $1000)		$1,238.00	

5620-Office Supplies and Expenses: $20,044.33 increase (Over 2013-2012)

In January of 2011, CHEI opted to terminate its Bill-Print contract with ORPC and print the bills in-house instead. Under ORPC's contract, the cost per bill was $3.85. On a bi-monthly billing cycle, the annual costs totaled approximately $46,000/year. When CHEI changed its billing cycle from bi-monthly to monthly, the cost doubled increasing the yearly total to $92,000. In the interest of reducing costs, CHEI opted to print the utility's bill in-house thus cutting costs by half. Comparatives are presented in Table 9 below.

Table 9 - 2013 Billing Cost Analysis

	ORPC			In-House		
Before 2011	**bills**	**per bill**	**total**	**bills**	**per bill**	**total**
By-monthly billing	12000	$3.85	$46,200.00	12000	$0.85	$10,200.00
SubTotal	**12000**		**$46,200.00**			**$10,200.00**
Since 2011						
ORPC Monthly billing	24000	$3.85	$92,400.00	24000	$0.85	$20,400.00
Stamps						$17,000.00
Envelop						$1,600.00
Invoice						$1,000.00
Meter Rental						$575.00
Ink/Sealer						$100.00
NeoPost Maintenance						$1,807.00
Total	**24000**		**$92,400.00**			**$42,482.00**
%Change (year over year)						-54%

The increase in materials is offset by the dismissal of the per/bill contract with ORPC. Below is a breakdown of the above yearly increases.

- Stamps: $17000
- Envelops: $1,600
- Invoice: $1,000
- Meter Rental: $575
- Sealer/Ink: $375
- NeoPost maintenance: $1,550

5335-Bad Debt Expense $5,000.00 increase (Over 2013-2012)

Following the changes in the OEB’s disconnection rules and rules related to issuing bills and collecting security deposits which took effect January 1, 2011, CHEI decided to refund all deposits and no longer collect security deposits form its customer. The reason was that managing security deposits had become too much of an administrative burden for a small utility such as CHEI. The disadvantage of abolishing security deposits is an increase in bad debt. The increase in costs is still the best option considering the alternative of hiring additional resources to manage security deposits.

5120-Maintenance of Poles, Towers and Fixtures: Title: $2,476.50 increase (Over 2013-2012)

These costs are associated with additional maintenance and repair on the overhead distribution system in order to increase reliability.

5035-Overhead Distribution Transformers- Operation Title: $2,395.00 increase (Over 2013-2012)

These costs are associated with additional maintenance and repair on the overhead distribution system in order to increase reliability.

5135-Overhead Distribution Lines and Feeders - Right of Way $1,697.50 increase (Over 2013-2012)

These costs are associated with additional maintenance and repair on the overhead distribution system in order to increase reliability.

5160-Maintenance of Line Transformers: $1,547.00 increase (Over 2013-2012)

These costs are associated with additional maintenance and repair on the overhead distribution system in order to increase reliability.

5065-Meter Expense $1,500.00 increase (Over 2013-2012)

These costs are associated with anticipated interval meter changes.

Table 10 -2014 Cost Drivers

		2014	
OEB	**Description**	**Cost Drivers**	
3650-Billing and Collecting	5315-Customer Billing	$35,316.85	1
3800-Administrative and General Expenses	5615-General Administrative Salaries and Expenses	$13,116.00	2
3800-Administrative and General Expenses	5620-Office Supplies and Expenses	$6,018.00	3
3800-Administrative and General Expenses	5610-Management Salaries and Expenses	$6,016.84	4
3550-Distribution Expenses - Maintenance	5160-Maintenance of Line Transformers	$6,000.00	5
3800-Administrative and General Expenses	5605-Executive Salaries and Expenses	$3,000.00	6
3500-Distribution Expenses - Operation	5035-Overhead Distribution Transformers-Operation	$3,000.00	7
3800-Administrative and General Expenses	5670-Rent	$2,400.00	8
3500-Distribution Expenses – Operation	5085-Miscellaneous Distribution Expense	$1,550.00	9
Other (< $1000)		$7,476.00	

5315-Customer Billing: $35,316 increase (Over 2014-2013)

This area has increased significantly due to the inclusion of smart meter related on-going costs in the amount of $31,400. This additional cost constitutes the majority of the overall increase in OM&A, with the balance of the expense being attributed to increase in wages ($4,000). The increase apportioned to smart meters is broken down further below.

• MDMR/Training/Conference	$ 5,000.00
• Harris-MDMR Support	$ 2,000.00
• Harris-Meter Sense	$ 5,000.00
• Util-Assist	$14,400.00
• Web Presentment	$ 5,000.00
	$31,400.00

5615-General Administrative Salaries and Expenses: $13,116 increase (Over 2014- 2013)

The increase in this specific account is attributed to an increase of $5000 in the employer's portion of group insurance. The manager budgets for himself and his employees to attended several conferences at a total cost of $5000. The balance of the increase is due to additional banking fees and EDA membership.

5620-Office Supplies and Expenses: $6,818.00 increase (Over 2014-2013)

CHEI anticipates an addition of approximately 300 residential customer over the next several years and as such, is budgeting a slight increase in billing supplies and general office expenses in order to service these additional customers.

• Billing supplies	$ 3,000.00
• Regular office supplies and Expenses	$ 3,800.00

5610-Management Salaries and Expenses: $6,016 increase (Over 2014-2013)

This increase in cost can be attributed to adjustment to management salaries for cost of living and overtime.

5035-Overhead Distribution Transformers- Operation: $3,000 increase (Over 2014-2013)

These costs are associated with additional maintenance and repair on the overhead distribution system in order to increase reliability.

5605-Executive Salaries and Expenses: $3,000 increase (Over 2014-2013)

These costs are associated with an increase in Board of Director fees.

5670-Rent: $2400 increase (Over 2014-2013)

With the lease expiring in 2013, CHEI's projects an increase of $200 in monthly lease payments.

5085-Miscellaneous Distribution Expense $1,550 increase (Over 2014-2013)

CHEI projects increases in miscellaneous expenses such as local meeting expenses (coffee, lunches).

E4.T1.S5 OM&A COST PER CUSTOMER AND PER FTE - APPENDIX 2-L

Table 11, below, outlines the cost per customer per full time employee. This information is provided for the 2010 to 2014 period, in accordance with the OEB's minimum filing requirements, discussions of cost per customer follow Table 11 below.

Table 11 –Recoverable OM&A Cost per Customer and per FTEE

	Last Rebasing Year (2010 Board-Approved)	Last Rebasing Year (2010 Actuals)	2011 Actuals	2012 Actuals	2013 Bridge Year	2014 Test Year
Reporting Basis						
Number of Customers	2,008	1,777	1,785	1,788	1,798	1,998
Total Recoverable OM&A from Appendix 2-I	495,227	474,769	538,338	524,597	512,785	556,279
OM&A cost per customer	247	267	302	293	285	278
Number of FTEEs	3	3	3	3	3	3
Customers/FTEEs	669	592	595	596	599	666
OM&A Cost per FTEE	165,076	158,256	179,446	174,866	170,928	185,426

As shown in the Table above, the OM&A costs per customer in the Test Year have dropped 2% over the previous period to land at similar levels as 2010. When Smart Meter related costs are removed from the equation, the reduction further drops to 19% per customer.

E4.T1.S6 VARIANCE ANALYSIS

CHE does not have any variances in excess of the materiality threshold of $50,000. Variances above $1,000 are explained in detail in the Cost Driver section of the application.

E4.T1.S7 ONE-TIME COSTS

Two one-time costs have been identified in CHEI's OM&A. In 2011, $10,000 in incentive was disbursed. This is a non-recurring cost and as such, was removed in subsequent years. All costs associated with 2014 Cost of Service application are amortized over a period of 5 years. Regulatory costs are discussed at the next section.

E4.T1.S8 REGULATORY COSTS – APPENDIX 2-M

For ease of comparison, CHEI has reclassified historical costs associated with its 2010 Cost of Service to 5630-Outside services.

The Table below shows the reclassified historical and projected costs for 5630-outside services and 5655 - Regulatory Expenses. For the details on the specific amounts, please refer to the reconciliation to financial statements and RRR at E1.T3.S3.

Table 12 –Outside Services and Regulatory Cost

		2014	2013	2012	2011	2010	2010BA	2009
5630-Outside Services Employed	PL	58,800	92,200	83,916	87,994	68,863	82,350	20,337
5655-Regulatory Expenses	PL	10,600	9,724	9,452	8,952	10,229	5,450	6,113

Costs associated with external consultants and Accounting firms are reported in account 5630-Outside Services while OEB Assessment Costs and Intervener Costs are reporting in account 5655 – Regulatory Expenses. Costs directly associated with the Cost of Service application are amortized over a period of 5 years. Such costs include $28,000 for BDO and $20,500 for Intervener cost.

CHEI has reduced its overall regulatory cost by entering into a fixed yearly contract agreement with Tandem Energy Services Inc. ("TESI") to assist the utility with its regulatory needs. The fixed fee include regulatory services such as; Preparing various documentation and submissions required to meet the regulatory requirements of the utility; Provide advice so that the utility operates in continuous compliance with OEB regulations; Preparation and defense of rate applications; Assist in creating a work environment that facilitates the utility's understanding the regulatory requirements.

CHEI has also budgeted $28,000 for BDO's involvement in the rate application. This amount is amortized over a period of 5 years.

The projected amount of $58,800 in Outside Services can be broken down into the following on-going expenses.

TESI	$30,000
BDO:	$18,000
QUASAR (ESA Audit)	$2,200
Other (computer services)	$3,000
BDO (CoS)	$5,600 ($28,000/5)

The projected amount of $10,600 in Regulatory Services can be broken down into the following expenses.

OEB Assessment fee	$6,500
Intervener:	$4,100 ($20,500/5)

E4.T1.S9 LEAP

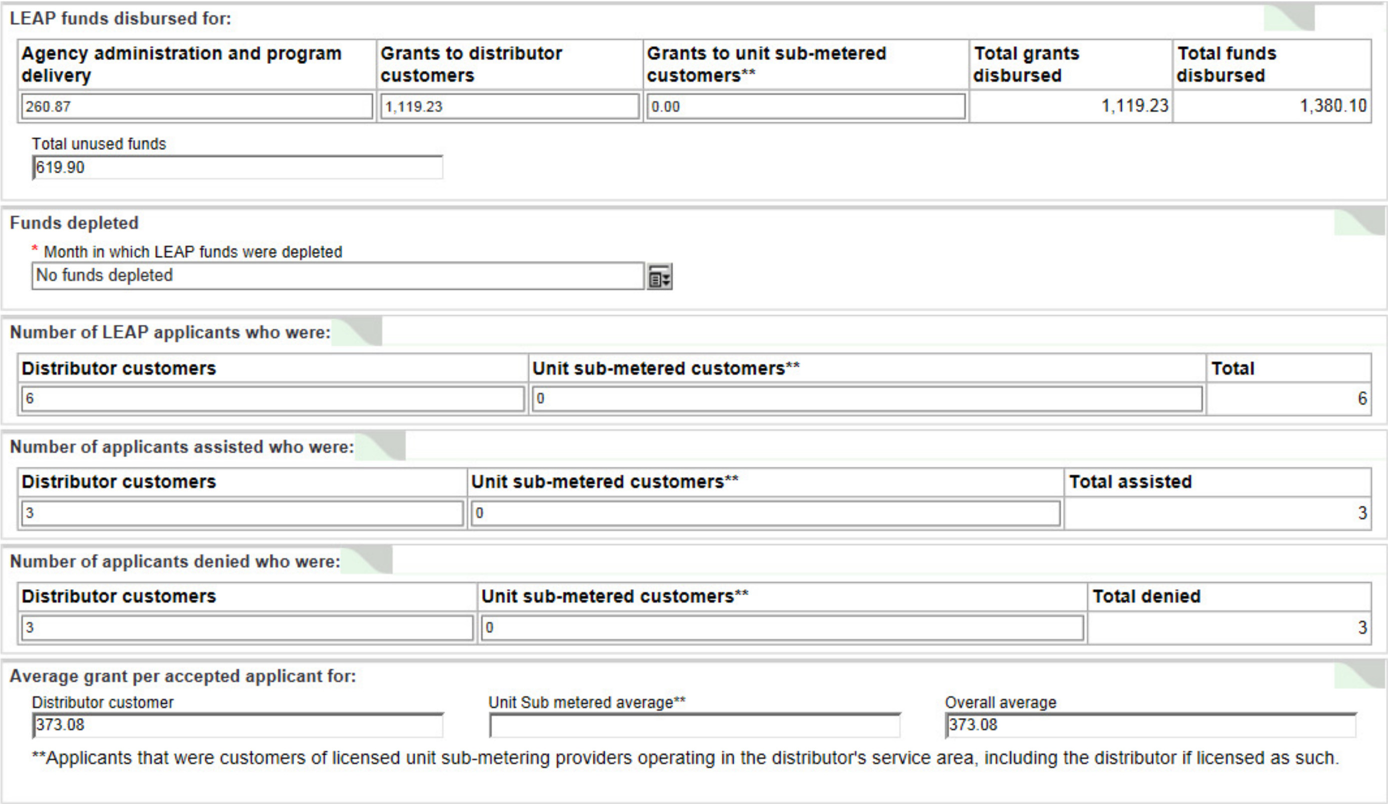
CHEI has included $2,000 of expense for the Low Income Assistance Program (LEAP) under Collection Expenses (USoA #5320). This amount is based on the Board's determination that the greater of 0.12% of a distributor's Board-approved distribution revenue requirement, or $2,000 should be included in the utility's costs.

CHEI has partnered with United Way- Centraide / Prescott Russell to assist in program intended to provide emergency relief to eligible low-income customers who may be experiencing difficulty paying current arrears be our lead agency.

The United Way of Prescott-Russell will pre-screen customers to see if they meet the household low-income guidelines, and other eligibility criteria, including if the customer is in threat of disconnection for non-payment.

Filings 2.1.16 of CHEI's RRR filings are presented at the next page.

2013 LEAP CONTRIBUTION



LEAP funds disbursed for:

Agency administration and program delivery	Grants to distributor customers	Grants to unit sub-metered customers**	Total grants disbursed	Total funds disbursed
260.87	1,119.23	0.00	1,119.23	1,380.10

Total unused funds
619.90

Funds depleted

* Month in which LEAP funds were depleted
No funds depleted

Number of LEAP applicants who were:

Distributor customers	Unit sub-metered customers**	Total
6	0	6

Number of applicants assisted who were:

Distributor customers	Unit sub-metered customers**	Total assisted
3	0	3

Number of applicants denied who were:

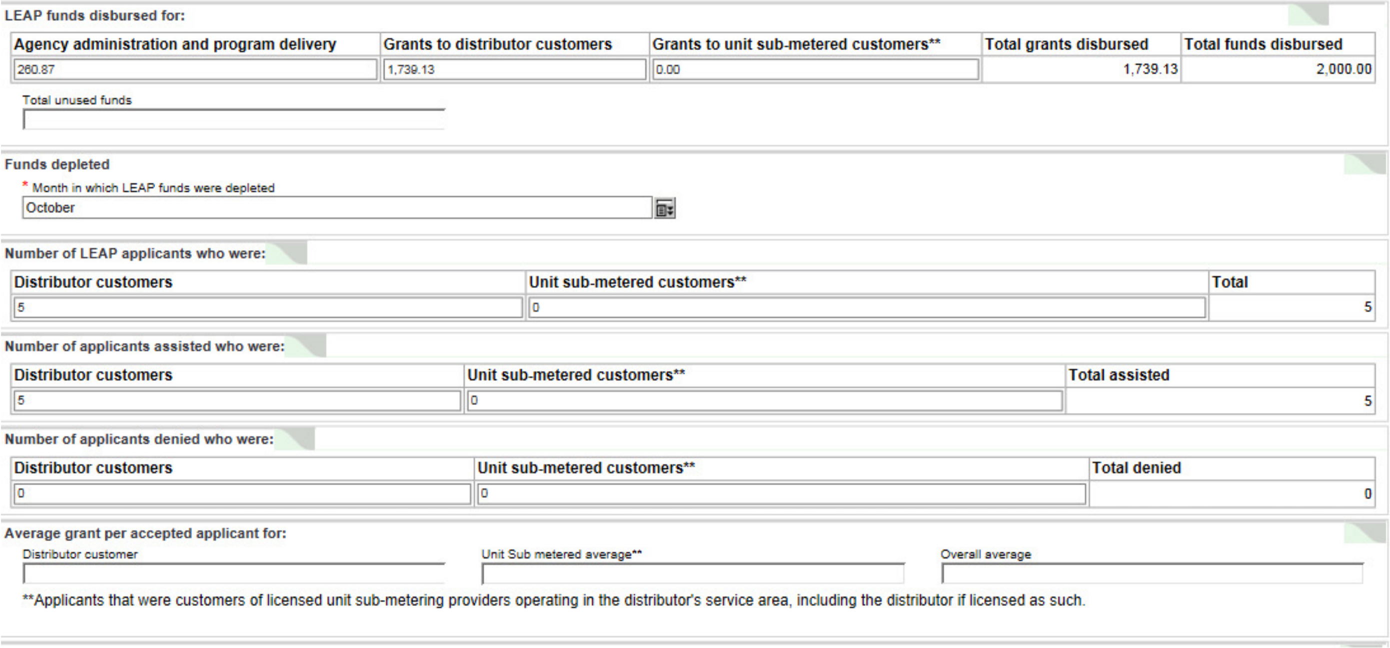
Distributor customers	Unit sub-metered customers**	Total denied
3	0	3

Average grant per accepted applicant for:

Distributor customer	Unit Sub metered average**	Overall average
373.08		373.08

**Applicants that were customers of licensed unit sub-metering providers operating in the distributor's service area, including the distributor if licensed as such.

2012 LEAP CONTRIBUTION



LEAP funds disbursed for:

Agency administration and program delivery	Grants to distributor customers	Grants to unit sub-metered customers**	Total grants disbursed	Total funds disbursed
260.87	1,739.13	0.00	1,739.13	2,000.00

Total unused funds

Funds depleted

* Month in which LEAP funds were depleted
October

Number of LEAP applicants who were:

Distributor customers	Unit sub-metered customers**	Total
5	0	5

Number of applicants assisted who were:

Distributor customers	Unit sub-metered customers**	Total assisted
5	0	5

Number of applicants denied who were:

Distributor customers	Unit sub-metered customers**	Total denied
0	0	0

Average grant per accepted applicant for:

Distributor customer	Unit Sub metered average**	Overall average

**Applicants that were customers of licensed unit sub-metering providers operating in the distributor's service area, including the distributor if licensed as such.

E4.T1.S10 CHARITABLE DONATIONS

Audited financial statements the years 2010, 2011 and 2012 included charitable contributions, however in compliance with the filling requirement, CHEI has not included charitable donations in OM&A expenses for 2014 other than the $2000 for LEAP funding.

Tab 2 – Employee Compensation

E4.T2.S1 OVERVIEW OF EMPLOYEE COMPENSATION

In accordance with Board policy which states that: “*Where there are three, or fewer, full-time equivalents (FTEs) in any category, CHE may aggregate this category with the category to which it is most closely related. This higher level of aggregation may be continued, if required, to ensure that no category contains three, or fewer, FTEs*”, CHEI has aggregated information relating to its 3 full time employees in the FTE class.

CHEI has 3 employees, a General Manager, and two customer service representatives.

Both non-union employees’ compensation levels are reviewed by the general manager and the Board of Directors. The increase in total compensation paid to employees in non-union and management position are attributable to cost of living increase and a provision for benefit coverage. A percentage of the staff’s annual salary is invested in DSPS in lieu of a pension plan.

Revised June 13, 2013. CHEI does not use specific benchmarking studies to determine salary ranges. However CHEI and its shareholder are well aware of the salary ranges in neighbouring utilities and use the neighbouring salaries as a guideline. CHEI is also aware of recently published surveys and attests that current salaries are well below those suggested salary range. Periodically, the utility’s Board of Director along with management input will readjust employee salary to be in line with it neighbouring cohorts.

Year over year variances are shown below. The average increase in the over the past 4 years is 3%.

Table 12 –Variance Analysis of Salary and Wages

	Last Rebasing Year (2010 Board-Approved)	**Last Rebasing Year (2010 Actuals)**	**2011 Actuals**	**2012 Actuals**	**2013 Bridge Year**	**2014 Test Year**
		$153,772	$159,574	$164,202	$166,172	$176,106
Variance Analysis of Salary and Wages		-17,583	5,802	4,628	1,970	9,934
		-10%	4%	3%	1%	6%
					Average	3%

E4.T2.S2 EMPLOYEE COMPENSATION – APPENDIX 2-K

Appendix 2-K presented at the next page details CHEI’s employee compensation. As a rule, the utility applies the inflation rate to salaries and wages. The incentive pays and bonuses have been removed from OM&A.

File Number:	EB-20130122
Exhibit:	4
Tab:	2
Schedule:	2
Page:	
Date:	

Appendix 2-K
Employee Costs

	Last Rebasing Year (2010 Board-Approved)	Last Rebasing Year (2010 Actuals)	2011 Actuals	2012 Actuals	2013 Bridge Year	2014 Test Year
Reporting Basis						
Number of Employees (FTEs including Part-Time)[1]						
Executive						
Management	3.00	3.00	3.00	3.00	3.00	3.00
Non-Union						
Union						
Total	3	3	3	3	3	3
Number of Part-Time Employees						
Executive						
Management						
Non-Union						
Union						
Total	-	-	-	-	-	-
Total Salary and Wages						
Executive						
Management	$ 171,355	$ 167,537	$ 165,617	$ 169,303	$ 166,172	$ 176,106
Non-Union						
Union						
Total	$ 171,355	$ 167,537	$ 165,617	$ 169,303	$ 166,172	$ 176,106
Current Benefits						
Executive						
Management	$ 10,000	$ 12,012	$ 13,441	$ 15,826	$ 16,000	$ 18,000
Non-Union						
Union						
Total	$ 10,000	$ 12,012	$ 13,441	$ 15,826	$ 16,000	$ 18,000
Accrued Pension and Post-Retirement Benefits						
Executive						
Management			$ 5,566	$ 13,981	$ 9,089	$ 9,405
Non-Union						
Union						
Total	$ -	$ -	$ 5,566	$ 13,981	$ 9,089	$ 9,405
Total Benefits (Current + Accrued)						
Executive	$ -	$ -	$ -	$ -	$ -	$ -
Management	$ 10,000	$ 12,012	$ 19,007	$ 29,806	$ 25,089	$ 27,405
Non-Union	$ -	$ -	$ -	$ -	$ -	$ -
Union	$ -	$ -	$ -	$ -	$ -	$ -
Total	$ 10,000	$ 12,012	$ 19,007	$ 29,806	$ 25,089	$ 27,405
Total Compensation (Salary, Wages, & Benefits)						
Executive	$ -	$ -	$ -	$ -	$ -	$ -
Management	$ 181,355	$ 179,548	$ 184,624	$ 199,109	$ 191,261	$ 203,511
Non-Union	$ -	$ -	$ -	$ -	$ -	$ -
Union	$ -	$ -	$ -	$ -	$ -	$ -
Total	$ 181,355	$ 179,548	$ 184,624	$ 199,109	$ 191,261	$ 203,511
Compensation - Average Yearly Base Wages						
Executive						
Management						
Non-Union						
Union						
Total						
Compensation - Average Yearly Overtime						
Executive						
Management						
Non-Union						
Union						
Total						
Compensation - Average Yearly Incentive Pay						
Executive						
Management			$ 15,957	$ 19,000		
Non-Union						
Union						
Total						
Compensation - Average Yearly Benefits						
Executive						
Management						
Non-Union						
Union						
Total						
Total Compensation	$ 181,355	$ 179,548	$ 184,624	$ 199,109	$ 191,261	$ 203,511
Total Compensation Capitalized (CGAAP)						
Total Compensation Charged to OM&A (CGAAP)	$ 181,355.00	$ 179,548.12	$ 184,623.50	$ 199,109.37	$ 191,261.31	
Total Compensation Capitalized (MIFRS)						
Total Compensation Charged to OM&A (MIFRS)				$ 199,109.37	$ 191,261.31	$ 203,511.00

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[1] If an applicant wishes to use headcount, it must also file the same schedule on an FTE basis.

Note:

Tab 3 –Shared Services and Corporate Cost Allocation

E4.T3.S1 OVERVIEW OF SHARED SERVICES AND CORPORATE COST ALLOCATION

CHEI does not have any affiliates and therefore is not subject to shared services or corporate cost allocation.

Tab 4 –Purchases of Non-Affiliate Services

E4.T4.S1 OVERVIEW OF PURCHASES OF SUPPLIER PURCHASES.

CHEI's purchases equipment, materials, and services in a cost effective manner with full consideration given to price as well as product quality, the ability to deliver on time, reliability, compliance with engineering specifications and quality of service. Vendors are screened to ensure knowledge, reputation, and the capability to meet CHEI's needs. The procurement of goods and/or services for CHEI is carried out with highest of ethical standards and consideration to the public nature of the expenditures.

Purchase Authorization: The General Manager, with the input of board members, approves all purchases of goods and/or services.

Tendering: When goods or services are tendered, a Tender/Request for Proposal/Request for Quote will be issued to a minimum of three vendors, if availability permits. Once again, the General Manager, along with the input of the board members, shall authorize the acceptance of the proposals.

Revised June 13, 2013. Although tendering processes provide essential information to potential suppliers and ensure a fair chance for businesses, the tendering process is not always possible in small towns where there is a limited supply of skilled services that can provide support to utilities. The utility does not have a written procurement policy per se however as described above, the General

Manager, with the input of board members, approves all purchases of goods and/or services.

Hydro One, SFIEO, Ottawa River Power and Sproule Powerline Const. Ltd have consistent yearly transactions in excess of the materiality threshold of $50,000. These specific suppliers offer services that are not commonly found in the service area or general surrounding area or offer efficiencies due to their intimate knowledge of CHEI's distribution system, (i.e, Sproule Powerline Construction Ltd).

On a regular basis, CHEI's manager will review how well the current outsource contracts support the overall sourcing strategy. Some contracts may not be as relevant as they once were and may have to be modified to fine-tune the services delivered. Other contracts may need to be expanded to meet additional requirements or changes in internal staffing. Key considerations include: Flexibility for service delivery, Staffing complement and expertise, Management skills, Operational efficiency and financial benefits and finally cost consciousness:

CHEI's 2012 Vendor list is presented at the next page.

Name of Company	2010	2011	2012	Summary of Nature of Activity	Cost or Contract Approach
Annis, O'Sullivan, Vollebekk		$2,672.45			
BDO Dunwoody	$35,207.46	$36,602.96	$21,969.46	Accounting services	cost approach
Bell Canada	$6,931.33	$6,414.97	$7,219.39	Telephone service	cost approach
Bell Canada			$4,567.84	pole rentals	cost approach
Bell Mobility	$4,834.90	$735.40	$1,220.93	Cellular telephone	cost approach
Christie & Walther	$1,935.51	$2,800.83	$2,048.76	Telephone Messaging	cost approach
EDA	$4,935.00	$7,489.17	$5,785.60	Membership fees	cost approach
Elenchus Research Assoc. Inc.	$38,852.21	$11,935.63	$9,037.43	Consultant Rebasing	cost approach
Elster	$12,612.17	$4,396.78	$2,268.45	Meter reading software	cost approach
Harris		$7,362.34	$6,752.99	Metersense fees	contract
Hydro One	$2,702,817.02	2.743.262.78	3.258.565.52	Hydro supplier	contract
Imperial Coffee	$513.96	$1,069.59	$580.77	Office supplies	cost approach
Impressions Printing		$4,520.00	$2,228.36	Printing and advertising	cost approach
Imprimerie Serge	$2,284.87		$1,761.82	Printing supplies	contract
Lakeport	$27,294.87	$16,910.45	$39,962.45	Transformers etc.	cost approach
Le Reflet	$1,827.75	$2,881.50	$10,117.00	Classified ads	cost approach
Mathieu Murphy	$4,780.00	$5,424.00	$5,876.00	Office Cleaning	contract
Mearie Insurance			$1,571.40	Liability insurance	cost approach
Nedco			$88,559.52	Direct lighting program	contract
Neopost		$30,926.11	$22,039.16	Billing and mailing hardware	cost approach
The News	$183.75	$621.50	$0.00	Advertising	cost approach
OEB	$5,418.85	$4,952.27	$5,452.40	Membership fees	cost approach
Ontario Electricity Financial	$30,161.00	$18,934.00	$24,300.00	Income tax	cost approach
Ottawa River Power	$59,997.39	$82,513.20	$79,564.35	Billing - ORPC	contract
Pana Electric	$6,033.06	$1,683.70	$2,408.43	Electrician	contract
Papeterie Germain	$16,617.56	$17,344.67	$20,773.84	Office Rent & Supplies	cost approach
Blackiron/Primus	$1,967.83	$1,941.31	$1,729.44	Internet-Wireless Magma	cost approach
Purolator	$1,012.76	$1,060.83	$547.34	Courrier	cost approach
SFIEO	$204,914.07	$210,454.43	$203,011.96	RLD	cost approach
Silicon Valley Computers	$8,050.00	$4,075.71	$3,032.92	Computer hardware etc.	cost approach
Societe Can. Des Postes	$1,969.92	$528.84	$275.72	Postage	cost approach
Sproule Powerline Const. Ltd.	$203,991.47	$96,429.49	$60,693.64	U/G Transformer Operations	contract
Stantec	$12,689.90	$4,734.48	$29,633.50	Engineer consultant	contract
Tandem			$5,650.00	Rebasing Consultant	contract
Unifirst	$1,556.07	$1,342.13	$1,353.30	Office supplies	contract
Util-Assist	$42,838.72	$75,909.71	$24,548.09	MDMR and OPA consultant	contract

Tab 5 –Depreciation, Amortization and Depletion

E4.T5.S1 OVERVIEW OF DEPRECIATION

CHEI's depreciation policy is described in Exhibit 2. The depreciation continuity schedule presented at the next section shows the calculation of annual depreciation expense with the half-year rule applied for rate-setting purposes, in accordance with the form prescribed in the Board' filing requirements. These expense amounts were used throughout Exhibit 2, in determining the net fixed asset values included in the rate base.

E4.T5.S2 DETAILS BY ASSET

The following pages show the depreciation calculation for 2012, 2013 Bridge Year and 2014 Test Year.

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Exhibit:	2
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Appendix 2-CE

Depreciation and Amortization Expense

Assumes the applicant adopted IFRS for financial reporting purposes January 1, 2015

Year **2010** **CGAAP**

Account	Description	Opening Regulatory Gross PP&E as at Jan 1, 2010 (a)	Less Fully Depreciated (b)	Net for Depreciation (c)	Additions (d)	Total for Depreciation (e) = (c) + ½ x (d) [1]	Years (f)	Depreciation Rate (g) = 1 / (f)	2010 Depreciation Expense (h) = (e) / (f)	2010 Depreciation Expense per Appendix 2-B Fixed Assets, Column K (l)	Variance [2] (m) = (h) - (l)
1611	Computer Software (Formally known as Account 1925)	$ 22,086.00		$ 22,086.00	$ 61,341.00	$ 52,756.50	5.00	20.00%	$ 10,551.30	$ 12,612.74	-$ 2,061.44
1612	Land Rights (Formally known as Account 1906)			$ -		$ -			$ -		$ -
1805	Land	$ 50,000.00		$ 50,000.00		$ 50,000.00	-		$ -		$ -
1808	Buildings			$ -		$ -			$ -		$ -
1810	Leasehold Improvements			$ -		$ -			$ -		$ -
1815	Transformer Station Equipment >50 kV			$ -		$ -			$ -		$ -
1820	Distribution Station Equipment <50 kV	$ 197,522.00		$ 197,522.00	$ 24,966.00	$ 210,005.00	30.00	3.33%	$ 7,000.17	$ 7,000.17	-$ 0.00
1825	Storage Battery Equipment			$ -		$ -			$ -		$ -
1830	Poles, Towers & Fixtures	$ 480,083.00		$ 480,083.00	$ 62,256.00	$ 511,211.00	25.00	4.00%	$ 20,448.44	$ 20,448.44	$ -
1835	Overhead Conductors & Devices	$ 541,906.00		$ 541,906.00	$ 856.00	$ 542,334.00	25.00	4.00%	$ 21,693.36	$ 21,693.36	$ -
1840	Underground Conduit			$ -		$ -			$ -		$ -
1845	Underground Conductors & Devices	$ 952,146.00		$ 952,146.00		$ 952,146.00	25.00	4.00%	$ 38,085.84	$ 38,085.84	$ -
1850	Line Transformers	$ 661,053.00		$ 661,053.00	$ 28,328.00	$ 675,217.00	25.00	4.00%	$ 27,008.68	$ 27,008.68	$ -
1855	Services (Overhead & Underground)	$ 161,465.00		$ 161,465.00	$ 12,637.00	$ 167,783.50	25.00	4.00%	$ 6,711.34	$ 6,711.34	$ -
1860	Meters	$ 79,072.00		$ 79,072.00		$ 79,072.00	25.00	4.00%	$ 3,162.88	$ 3,162.88	$ -
1860	Meters (Smart Meters)			$ -		$ -	25.00	4.00%	$ -		$ -
1905	Land			$ -		$ -			$ -		$ -
1908	Buildings & Fixtures			$ -		$ -			$ -		$ -
1910	Leasehold Improvements			$ -		$ -			$ -		$ -
1915	Office Furniture & Equipment (10 years)	$ 31,696.00		$ 31,696.00	$ 3,013.00	$ 33,202.50	10.00	10.00%	$ 3,320.25	$ 3,320.25	$ -
1915	Office Furniture & Equipment (5 years)			$ -		$ -			$ -		$ -
1920	Computer Equipment - Hardware	$ 16,392.00		$ 16,392.00	$ 3,080.00	$ 17,932.00	5.00	20.00%	$ 3,586.40	$ 1,466.00	$ 2,120.40
1920	Computer Equip.-Hardware(Post Mar. 22/04)			$ -		$ -			$ -		$ -
1920	Computer Equip.-Hardware(Post Mar. 19/07)			$ -		$ -			$ -		$ -
1930	Transportation Equipment			$ -		$ -			$ -		$ -
1935	Stores Equipment	$ 4,320.00		$ 4,320.00		$ 4,320.00	10.00	10.00%	$ 432.00	$ 432.00	$ -
1940	Tools, Shop & Garage Equipment			$ -		$ -	10.00	10.00%	$ -		$ -
1945	Measurement & Testing Equipment	$ 4,281.00		$ 4,281.00		$ 4,281.00	10.00	10.00%	$ 428.10	$ 383.10	$ 45.00
1950	Power Operated Equipment			$ -		$ -			$ -		$ -
1955	Communications Equipment			$ -		$ -			$ -		$ -
1955	Communication Equipment (Smart Meters)			$ -		$ -			$ -		$ -
1960	Miscellaneous Equipment			$ -		$ -			$ -		$ -
1975	Load Management Controls Utility Premises			$ -		$ -			$ -		$ -
1980	System Supervisor Equipment			$ -		$ -			$ -		$ -
1985	Miscellaneous Fixed Assets			$ -		$ -			$ -		$ -
1995	Contributions & Grants	-$ 532,166.00	$ 11,423.00	-$ 543,589.00		-$ 543,589.00	25.00	4.00%	-$ 21,743.56	-$ 21,515.10	-$ 228.46
etc.				$ -		$ -			$ -		$ -
				$ -		$ -			$ -		$ -
	Total	$ 2,669,856.00	$ 11,423.00	$ 2,658,433.00	$ 196,477.00	$ 2,756,671.50			$ 120,685.20	$ 120,809.70	-$ 124.50

Notes:

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

2 The applicant must provide an explanation of material variances in evidence

General: **Applicants must provide a breakdown of depreciation and amortization expense in the above format for all relevant accounts. Asset Retirement Obligations (AROs), depreciation and accretion expense should be disclosed separately consistent with the Notes of historical Audited Financial Statements.**

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Appendix 2-CE
Depreciation and Amortization Expense

Assumes the applicant adopted IFRS for financial reporting purposes January 1, 2015

Year 2011 CGAAP

Account	Description	Opening Regulatory Gross PP&E as at Jan 1, 2011 (a)	Less Fully Depreciated (b)	Net for Depreciation (c)	Additions (d)	Total for Depreciation (e) = (c) + ½ x (d) ^{1}	Years (f)	Depreciation Rate (g) = 1 / (f)	2011 Depreciation Expense (h) = (e) / (f)	2011 Depreciation Expense per Appendix 2-B Fixed Assets, Column K (l)	Variance ^{2} (m) = (h) - (l)
1611	Computer Software (Formally known as Account 1925)	$ 83,427.00		$ 83,427.00	$ 1,500.00	$ 84,177.00	5.00	20.00%	$ 16,835.40	$ 13,706.74	$ 3,128.66
1612	Land Rights (Formally known as Account 1906)	$ -		$ -		$ -			$ -		$ -
1805	Land	$ 50,000.00		$ 50,000.00		$ 50,000.00	-		$ -		$ -
1808	Buildings	$ -		$ -		$ -			$ -		$ -
1810	Leasehold Improvements	$ -		$ -		$ -			$ -		$ -
1815	Transformer Station Equipment >50 kV	$ -		$ -		$ -			$ -		$ -
1820	Distribution Station Equipment <50 kV	$ 222,488.00		$ 222,488.00		$ 222,488.00	30.00	3.33%	$ 7,416.27	$ 7,416.27	-$ 0.00
1825	Storage Battery Equipment	$ -		$ -		$ -			$ -		$ -
1830	Poles, Towers & Fixtures	$ 542,339.00		$ 542,339.00	$ 18,097.00	$ 551,387.50	25.00	4.00%	$ 22,055.50	$ 22,055.50	$ -
1835	Overhead Conductors & Devices	$ 542,762.00		$ 542,762.00	$ 4,224.00	$ 544,874.00	25.00	4.00%	$ 21,794.96	$ 21,794.96	$ -
1840	Underground Conduit	$ -		$ -		$ -			$ -		$ -
1845	Underground Conductors & Devices	$ 952,146.00		$ 952,146.00		$ 952,146.00	25.00	4.00%	$ 38,085.84	$ 38,085.84	$ -
1850	Line Transformers	$ 689,381.00		$ 689,381.00	$ 21,553.00	$ 700,157.50	25.00	4.00%	$ 28,006.30	$ 28,006.32	-$ 0.02
1855	Services (Overhead & Underground)	$ 174,102.00		$ 174,102.00	$ 4,036.00	$ 176,120.00	25.00	4.00%	$ 7,044.80	$ 7,044.80	$ -
1860	Meters	$ 79,072.00		$ 79,072.00		$ 79,072.00	25.00	4.00%	$ 3,162.88	$ 3,162.88	$ -
1860	Meters (Smart Meters)	$ -		$ -		$ -	25.00	4.00%	$ -		$ -
1905	Land	$ -		$ -		$ -			$ -		$ -
1908	Buildings & Fixtures	$ -		$ -		$ -			$ -		$ -
1910	Leasehold Improvements	$ -		$ -		$ -			$ -		$ -
1915	Office Furniture & Equipment (10 years)	$ 34,709.00		$ 34,709.00	$ 14,694.00	$ 42,056.00	10.00	10.00%	$ 4,205.60	$ 3,855.60	$ 350.00
1915	Office Furniture & Equipment (5 years)	$ -		$ -		$ -			$ -		$ -
1920	Computer Equipment - Hardware	$ 19,472.00		$ 19,472.00	$ 2,320.00	$ 20,632.00	5.00	20.00%	$ 4,126.40	$ 1,703.38	$ 2,423.02
1920	Computer Equip.-Hardware(Post Mar. 22/04)	$ -		$ -		$ -			$ -		$ -
1920	Computer Equip.-Hardware(Post Mar. 19/07)	$ -		$ -		$ -			$ -		$ -
1930	Transportation Equipment	$ -		$ -		$ -			$ -		$ -
1935	Stores Equipment	$ 4,320.00		$ 4,320.00		$ 4,320.00	10.00	10.00%	$ 432.00	$ 432.00	$ -
1940	Tools, Shop & Garage Equipment	$ -		$ -		$ -	10.00	10.00%	$ -		$ -
1945	Measurement & Testing Equipment	$ 4,281.00		$ 4,281.00		$ 4,281.00	10.00	10.00%	$ 428.10	$ 158.10	$ 270.00
1950	Power Operated Equipment	$ -		$ -		$ -			$ -		$ -
1955	Communications Equipment	$ -		$ -		$ -			$ -		$ -
1955	Communication Equipment (Smart Meters)	$ -		$ -		$ -			$ -		$ -
1960	Miscellaneous Equipment	$ -		$ -		$ -			$ -		$ -
1975	Load Management Controls Utility Premises	$ -		$ -		$ -			$ -		$ -
1980	System Supervisor Equipment	$ -		$ -		$ -			$ -		$ -
1985	Miscellaneous Fixed Assets	$ -		$ -		$ -			$ -		$ -
1995	Contributions & Grants	-$ 543,589.00		-$ 543,589.00	-$ 7,774.00	-$ 547,476.00	25.00	4.00%	-$ 21,899.04	-$ 21,889.04	-$ 10.00
etc.				$ -		$ -			$ -		$ -
				$ -		$ -			$ -		$ -
	Total	$ 2,854,910.00	$ -	$ 2,854,910.00	$ 58,650.00	$ 2,884,235.00			$ 131,695.01	$ 125,533.35	$ 6,161.66

Notes:

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

2 The applicant must provide an explanation of material variances in evidence

General: Applicants must provide a breakdown of depreciation and amortization expense in the above format for all relevant accounts. Asset Retirement Obligations (AROs), depreciation and accretion expense should be disclosed separately consistent with the Notes of historical Audited Financial Statements.

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Appendix 2-CE
Depreciation and Amortization Expense

Assumes the applicant adopted IFRS for financial reporting purposes January 1, 2015

Year **2012** **CGAAP**

Account	Description	Opening Regulatory Gross PP&E as at Jan 1, 2012 (a)	Less Fully Depreciated (b)	Net for Depreciation (c)	Additions (d)	Total for Depreciation (e) = (c) + ½ x (d) [1]	Years (f)	Depreciation Rate (g) = 1 / (f)	2011 Depreciation Expense (h) = (e) / (f)	2011 Depreciation Expense per Appendix 2-B Fixed Assets, Column K (l)	Variance [2] (m) = (h) - (l)
1611	Computer Software (Formally known as Account 1925)	$ 84,927.00	$ 15,643.30	$ 69,283.70	$ -	$ 69,283.70	5.00	20.00%	$ 13,856.74	$ 13,856.74	$ -
1612	Land Rights (Formally known as Account 1906)	$ -		$ -	$ -	$ -			$ -	$ -	$ -
1805	Land	$ 50,000.00		$ 50,000.00	$ -	$ 50,000.00	-		$ -	$ -	$ -
1808	Buildings	$ -		$ -	$ -	$ -			$ -	$ -	$ -
1810	Leasehold Improvements	$ -		$ -	$ -	$ -			$ -	$ -	$ -
1815	Transformer Station Equipment >50 kV	$ -		$ -	$ -	$ -			$ -	$ -	$ -
1820	Distribution Station Equipment <50 kV	$ 222,488.00		$ 222,488.00	$ -	$ 222,488.00	30.00	3.33%	$ 7,416.27	$ 7,416.27	$ -
1825	Storage Battery Equipment	$ -		$ -	$ -	$ -			$ -	$ -	$ -
1830	Poles, Towers & Fixtures	$ 560,436.00		$ 560,436.00	$ 3,098.00	$ 561,985.00	25.00	4.00%	$ 22,479.40	$ 22,479.40	$ 0.00
1835	Overhead Conductors & Devices	$ 546,986.00		$ 546,986.00	$ -	$ 546,986.00	25.00	4.00%	$ 21,879.44	$ 21,879.44	$ -
1840	Underground Conduit	$ -		$ -	$ -	$ -			$ -	$ -	$ -
1845	Underground Conductors & Devices	$ 952,146.00		$ 952,146.00	$ 5,841.00	$ 955,066.50	25.00	4.00%	$ 38,202.66	$ 38,202.66	$ 0.00
1850	Line Transformers	$ 710,935.00		$ 710,935.00	$ 36,088.00	$ 728,979.00	25.00	4.00%	$ 29,159.16	$ 29,159.16	$ -
1855	Services (Overhead & Underground)	$ 178,138.00		$ 178,138.00	$ 5,074.00	$ 180,675.00	25.00	4.00%	$ 7,227.00	$ 7,227.00	$ -
1860	Meters	$ 79,072.00	$ 79,072.00	$ -	$ -	$ -	25.00	4.00%	$ -		$ -
1860	Meters (Smart Meters)	$ -		$ -	$ 310,212.00	$ 155,106.00	25.00	4.00%	$ 6,204.24	$ 6,204.24	$ -
1905	Land	$ -		$ -	$ -	$ -			$ -	$ -	$ -
1908	Buildings & Fixtures	$ -		$ -	$ -	$ -			$ -	$ -	$ -
1910	Leasehold Improvements	$ -		$ -	$ -	$ -			$ -	$ -	$ -
1915	Office Furniture & Equipment (10 years)	$ 49,403.00	$ 3,155.55	$ 46,247.45	$ -	$ 46,247.45	10.00	10.00%	$ 4,624.75	$ 4,624.70	$ 0.05
1915	Office Furniture & Equipment (5 years)	$ -		$ -	$ -	$ -			$ -	$ -	$ -
1920	Computer Equipment - Hardware	$ 21,791.00	$ 14,197.89	$ 7,593.11	$ 2,746.00	$ 8,966.11	5.00	20.00%	$ 1,793.22	$ 1,793.22	$ -
1920	Computer Equip.-Hardware(Post Mar. 22/04)	$ -		$ -	$ -	$ -			$ -	$ -	$ -
1920	Computer Equip.-Hardware(Post Mar. 19/07)	$ -		$ -	$ -	$ -			$ -	$ -	$ -
1930	Transportation Equipment	$ -		$ -	$ -	$ -			$ -	$ -	$ -
1935	Stores Equipment	$ 4,320.00		$ 4,320.00	$ -	$ 4,320.00	10.00	10.00%	$ 432.00	$ 432.00	$ -
1940	Tools, Shop & Garage Equipment	$ -		$ -	$ 4,205.00	$ 2,102.50	10.00	10.00%	$ 210.25	$ 210.25	$ -
1945	Measurement & Testing Equipment	$ 4,281.00	$ 2,700.00	$ 1,581.00	$ -	$ 1,581.00	10.00	10.00%	$ 158.10	$ 158.10	$ -
1950	Power Operated Equipment	$ -		$ -	$ -	$ -			$ -	$ -	$ -
1955	Communications Equipment	$ -		$ -	$ -	$ -			$ -	$ -	$ -
1955	Communication Equipment (Smart Meters)	$ -		$ -	$ -	$ -			$ -	$ -	$ -
1960	Miscellaneous Equipment	$ -		$ -	$ -	$ -			$ -	$ -	$ -
1975	Load Management Controls Utility Premises	$ -		$ -	$ -	$ -			$ -	$ -	$ -
1980	System Supervisor Equipment	$ -		$ -	$ -	$ -			$ -	$ -	$ -
1985	Miscellaneous Fixed Assets	$ -		$ -	$ -	$ -			$ -	$ -	$ -
1995	Contributions & Grants	-$ 551,363.00		-$ 551,363.00	-$ 1,600.00	-$ 552,163.00	25.00	4.00%	-$ 22,086.52	-$ 22,086.52	$ -
etc.		$ -		$ -	$ -	$ -			$ -		$ -
				$ -		$ -			$ -		$ -
	Total	$ 2,913,560.00	$ 114,768.74	$ 2,798,791.26	$ 365,664.00	$ 2,981,623.26			$ 131,556.70	$ 131,556.66	$ 0.05

Notes:

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

[2] The applicant must provide an explanation of material variances in evidence

General: **Applicants must provide a breakdown of depreciation and amortization expense in the above format for all relevant accounts. Asset Retirement Obligations (AROs), depreciation and accretion expense should be disclosed separately consistent with the Notes of historical Audited Financial Statements.**

File Number:	EB-20130122
Exhibit:	2
Tab:	1
Schedule:	5
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Appendix 2-CF
Depreciation and Amortization Expense

Assumes the applicant adopted IFRS for financial reporting purposes January 1, 2015

Year **2013** **CGAAP**

Account	Description	Opening Regulatory Gross PP&E as at Jan 1, 2013 (a)	Less Fully Depreciated (b)	Net for Depreciation (c)	Additions (d)	Total for Depreciation (e) = (c) + ½ x (d) [1]	Years (f)	Depreciation Rate (g) = 1 / (f)	2013 Depreciation Expense (h) = (e) / (f)	2013 Depreciation Expense per Appendix 2-B Fixed Assets, Column K (l)	Variance [2] (m) = (h) - (l)
1611	Computer Software (Formally known as Account 1925)	$ 84,927.00	$ 15,643.30	$ 69,283.70	$ 26,500.00	$ 82,533.70	5.00	20.00%	$ 16,506.74	$ 16,506.79	-$ 0.05
1612	Land Rights (Formally known as Account 1906)	$ -		$ -		$ -		0.00%	$ -	$ -	$ -
1805	Land	$ 50,000.00		$ 50,000.00		$ 50,000.00		0.00%	$ -	$ -	$ -
1808	Buildings	$ -		$ -		$ -		0.00%	$ -	$ -	$ -
1810	Leasehold Improvements	$ -		$ -		$ -		0.00%	$ -	$ -	$ -
1815	Transformer Station Equipment >50 kV	$ -		$ -		$ -		0.00%	$ -	$ -	$ -
1820	Distribution Station Equipment <50 kV	$ 222,488.00		$ 222,488.00	$ 62,400.00	$ 253,688.00	55.00	1.82%	$ 4,612.51	$ 4,612.50	$ 0.01
1825	Storage Battery Equipment	$ -		$ -		$ -		0.00%	$ -	$ -	$ -
1830	Poles, Towers & Fixtures	$ 563,534.00		$ 563,534.00	$ 83,850.00	$ 605,459.00	40.00	2.50%	$ 15,136.48	$ 15,136.46	$ 0.02
1835	Overhead Conductors & Devices	$ 546,986.00		$ 546,986.00	$ 58,750.00	$ 576,361.00	60.00	1.67%	$ 9,606.02	$ 9,606.03	-$ 0.01
1840	Underground Conduit	$ -		$ -		$ -		0.00%	$ -	$ -	$ -
1845	Underground Conductors & Devices	$ 957,987.00		$ 957,987.00	$ 52,400.00	$ 984,187.00	35.00	2.86%	$ 28,119.63	$ 28,119.62	$ 0.01
1850	Line Transformers	$ 747,023.00		$ 747,023.00	$ 12,000.00	$ 753,023.00	40.00	2.50%	$ 18,825.58	$ 18,825.55	$ 0.03
1855	Services (Overhead & Underground)	$ 183,212.00		$ 183,212.00	$ 5,000.00	$ 185,712.00	40.00	2.50%	$ 4,642.80	$ 4,642.76	$ 0.04
1860	Meters	$ -		$ -		$ -	25.00	4.00%	$ -		$ -
1860	Meters (Smart Meters)	$ 310,212.00		$ 310,212.00		$ 310,212.00	15.00	6.67%	$ 20,680.80	$ 20,680.80	$ -
1905	Land	$ -		$ -		$ -		0.00%	$ -	$ -	$ -
1908	Buildings & Fixtures	$ -		$ -		$ -		0.00%	$ -	$ -	$ -
1910	Leasehold Improvements	$ -		$ -		$ -		0.00%	$ -	$ -	$ -
1915	Office Furniture & Equipment (10 years)	$ 49,403.00	$ 4,750.24	$ 44,652.76	$ 1,500.00	$ 45,402.76	10.00	10.00%	$ 4,540.28	$ 4,540.27	$ 0.01
1915	Office Furniture & Equipment (5 years)	$ -		$ -		$ -		0.00%	$ -	$ -	$ -
1920	Computer Equipment - Hardware	$ 24,537.00	$ 16,392.44	$ 8,144.56	$ 1,500.00	$ 8,894.56	5.00	20.00%	$ 1,778.91	$ 1,779.19	-$ 0.28
1920	Computer Equip.-Hardware(Post Mar. 22/04)	$ -		$ -		$ -		0.00%	$ -	$ -	$ -
1920	Computer Equip.-Hardware(Post Mar. 19/07)	$ -		$ -		$ -		0.00%	$ -	$ -	$ -
1930	Transportation Equipment	$ -		$ -		$ -		0.00%	$ -	$ -	$ -
1935	Stores Equipment	$ 4,320.00		$ 4,320.00		$ 4,320.00	10.00	10.00%	$ 432.00	$ 432.00	$ -
1940	Tools, Shop & Garage Equipment	$ 4,205.00		$ 4,205.00		$ 4,205.00	10.00	10.00%	$ 420.50	$ 420.50	$ -
1945	Measurement & Testing Equipment	$ 4,281.00	$ 2,700.00	$ 1,581.00		$ 1,581.00	10.00	10.00%	$ 158.10	$ 158.10	$ -
1950	Power Operated Equipment	$ -		$ -		$ -		0.00%	$ -	$ -	$ -
1955	Communications Equipment	$ -		$ -		$ -		0.00%	$ -	$ -	$ -
1955	Communication Equipment (Smart Meters)	$ -		$ -		$ -		0.00%	$ -	$ -	$ -
1960	Miscellaneous Equipment	$ -		$ -		$ -		0.00%	$ -	$ -	$ -
1975	Load Management Controls Utility Premises	$ -		$ -		$ -		0.00%	$ -	$ -	$ -
1980	System Supervisor Equipment	$ -		$ -		$ -		0.00%	$ -	$ -	$ -
1985	Miscellaneous Fixed Assets	$ -		$ -		$ -		0.00%	$ -	$ -	$ -
1995	Contributions & Grants	-$ 552,963.00		-$ 552,963.00	-$ 8,000.00	-$ 556,963.00	40.00	2.50%	-$ 13,924.08	-$ 13,924.08	$ 0.00
etc.				$ -		$ -		0.00%	$ -		$ -
				$ -		$ -		0.00%	$ -		$ -
	Total	$ 3,200,152.00	$ 39,485.98	$ 3,160,666.02	$ 295,900.00	$ 3,308,616.02			$ 111,536.26	$ 111,536.49	-$ 0.23

Notes:

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

2 The applicant must provide an explanation of material variances in evidence

General: **Applicants must provide a breakdown of depreciation and amortization expense in the above format for all relevant accounts. Asset Retirement Obligations (AROs), depreciation and accretion expense should be disclosed separately consistent with the Notes of historical Audited Financial Statements.**

File Number:	EB-20130122
Exhibit:	2
Tab:	1
Schedule:	5
Page:	3
Date:	

Appendix 2-CF
Depreciation and Amortization Expense

Assumes the applicant adopted IFRS for financial reporting purposes January 1, 2015

Year **2014** **CGAAP**

Account	Description	Opening Regulatory Gross PP&E as at Jan 1, 2013 (a)	Less Fully Depreciated (b)	Net for Depreciation (c)	Additions (d)	Total for Depreciation (e) = (c) + ½ x (d) [1]	Years (f)	Depreciation Rate (g) = 1 / (f)	2014 Depreciation Expense (h) = (e) / (f)	2014 Depreciation Expense per Appendix 2-B Fixed Assets, Column K (l)	Variance [2] (m) = (h) - (l)
1611	Computer Software (Formally known as Account 1925)	$ 111,427.00	$ 18,864.54	$ 92,562.46	$ 35,000.00	$ 110,062.46	5.00	20.00%	$ 22,012.49	$ 22,013.00	-$ 0.51
1612	Land Rights (Formally known as Account 1906)	$ -		$ -		$ -		0.00%	$ -	$ -	$ -
1805	Land	$ 50,000.00		$ 50,000.00		$ 50,000.00		0.00%	$ -	$ -	$ -
1808	Buildings	$ -		$ -		$ -		0.00%	$ -	$ -	$ -
1810	Leasehold Improvements	$ -		$ -		$ -		0.00%	$ -	$ -	$ -
1815	Transformer Station Equipment >50 kV	$ -		$ -		$ -		0.00%	$ -	$ -	$ -
1820	Distribution Station Equipment <50 kV	$ 284,888.00		$ 284,888.00		$ 284,888.00	55.00	1.82%	$ 5,179.78	$ 5,179.77	$ 0.01
1825	Storage Battery Equipment	$ -		$ -		$ -		0.00%	$ -	$ -	$ -
1830	Poles, Towers & Fixtures	$ 647,384.00		$ 647,384.00	$ 60,220.00	$ 677,494.00	40.00	2.50%	$ 16,937.35	$ 16,937.35	$ -
1835	Overhead Conductors & Devices	$ 605,736.00		$ 605,736.00	$ 19,375.00	$ 615,423.50	60.00	1.67%	$ 10,257.06	$ 10,257.06	-$ 0.00
1840	Underground Conduit	$ -		$ -		$ -		0.00%	$ -	$ -	$ -
1845	Underground Conductors & Devices	$ 1,010,387.00		$ 1,010,387.00	$ 398,000.00	$ 1,209,387.00	35.00	2.86%	$ 34,553.91	$ 34,553.91	$ 0.00
1850	Line Transformers	$ 759,023.00		$ 759,023.00	$ 87,500.00	$ 802,773.00	40.00	2.50%	$ 20,069.33	$ 20,069.30	$ 0.03
1855	Services (Overhead & Underground)	$ 188,212.00		$ 188,212.00	$ 4,000.00	$ 190,212.00	40.00	2.50%	$ 4,755.30	$ 4,755.26	$ 0.04
1860	Meters	$ -		$ -		$ -	25.00	4.00%	$ -		$ -
1860	Meters (Smart Meters)	$ 310,212.00		$ 310,212.00	$ 30,500.00	$ 325,462.00	15.00	6.67%	$ 21,697.47	$ 21,697.47	-$ 0.00
1905	Land	$ -		$ -		$ -		0.00%	$ -	$ -	$ -
1908	Buildings & Fixtures	$ -		$ -		$ -		0.00%	$ -	$ -	$ -
1910	Leasehold Improvements	$ -		$ -		$ -		0.00%	$ -	$ -	$ -
1915	Office Furniture & Equipment (10 years)	$ 50,903.00	$ 7,592.64	$ 43,310.36		$ 43,310.36	10.00	10.00%	$ 4,331.04	$ 4,331.05	-$ 0.01
1915	Office Furniture & Equipment (5 years)	$ -		$ -		$ -		0.00%	$ -	$ -	$ -
1920	Computer Equipment - Hardware	$ 26,037.00	$ 16,392.44	$ 9,644.56		$ 9,644.56	5.00	20.00%	$ 1,928.91	$ 1,929.19	-$ 0.28
1920	Computer Equip.-Hardware(Post Mar. 22/04)	$ -		$ -		$ -		0.00%	$ -	$ -	$ -
1920	Computer Equip.-Hardware(Post Mar. 19/07)	$ -		$ -		$ -		0.00%	$ -	$ -	$ -
1930	Transportation Equipment	$ -		$ -		$ -		0.00%	$ -	$ -	$ -
1935	Stores Equipment	$ 4,320.00	$ 2,808.00	$ 1,512.00		$ 1,512.00	10.00	10.00%	$ 151.20	$ 151.20	$ -
1940	Tools, Shop & Garage Equipment	$ 4,205.00		$ 4,205.00		$ 4,205.00	10.00	10.00%	$ 420.50	$ 420.50	$ -
1945	Measurement & Testing Equipment	$ 4,281.00	$ 2,700.00	$ 1,581.00		$ 1,581.00	10.00	10.00%	$ 158.10	$ 158.10	$ -
1950	Power Operated Equipment	$ -		$ -		$ -		0.00%	$ -	$ -	$ -
1955	Communications Equipment	$ -		$ -		$ -		0.00%	$ -	$ -	$ -
1955	Communication Equipment (Smart Meters)	$ -		$ -		$ -		0.00%	$ -	$ -	$ -
1960	Miscellaneous Equipment	$ -		$ -		$ -		0.00%	$ -	$ -	$ -
1975	Load Management Controls Utility Premises	$ -		$ -		$ -		0.00%	$ -	$ -	$ -
1980	System Supervisor Equipment	$ -		$ -		$ -		0.00%	$ -	$ -	$ -
1985	Miscellaneous Fixed Assets	$ -		$ -		$ -		0.00%	$ -	$ -	$ -
1995	Contributions & Grants	-$ 560,963.00	-$160,000.00	-$ 400,963.00		-$ 400,963.00	40.00	2.50%	-$ 10,024.08	-$ 10,024.08	$ 0.00
etc.				$ -		$ -		0.00%	$ -	$ -	$ -
				$ -		$ -		0.00%	$ -		$ -
	Total	$ 3,496,052.00	-$111,642.38	$ 3,607,694.38	$ 634,595.00	$ 3,924,991.88			$ 132,428.36	$ 132,429.08	-$ 0.72

Notes:

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

2 The applicant must provide an explanation of material variances in evidence

General: **Applicants must provide a breakdown of depreciation and amortization expense in the above format for all relevant accounts. Asset Retirement Obligations (AROs), depreciation and accretion expense should be disclosed separately consistent with the Notes of historical Audited Financial Statements.**

E4.T5.S3 COMPONENTIZATION .

In accordance with Board policy, CHEI has adopted Kinectrics proposed useful lives and componentization (where applicable). CHEI will continue to adopt CGAAP in and beyond 2014 and as such, there is not a requirement to re-state prior year balances as the change in accounting policy is made prospectively, not retroactively.

Table 13 –Depreciation Rates

Account	Description	Pre 2013	2013 and beyond
1611	Computer Software (Formally known as Account 1925)	5	5
1820	Distribution Station Equipment <50 kV	30	55
1830	Poles, Towers & Fixtures	25	40
1835	Overhead Conductors & Devices	25	60
1845	Underground Conductors & Devices	25	35
1850	Line Transformers	25	40
1855	Services (Overhead & Underground)	25	40
1860	Meters	25	25
1860	Meters (Smart Meters)	25	15
1915	Office Furniture & Equipment (10 years)	10	10
1920	Computer Equipment - Hardware	5	5
1935	Stores Equipment	10	10
1940	Tools, Shop & Garage Equipment	10	10
1945	Measurement & Testing Equipment	10	10
1995	Contributions & Grants	25	40

E4.T5.S4 ADOPTION OF HALF YEAR RULE

Board’s general policy for electricity distribution rate setting is that capital additions would normally attract six months of depreciation expense when they enter service in the test year (referred to as the “half-year” rule). Although CHEI was aware of this policy, the accounting firm responsible for year-end audits and financial statements omitted to apply the half year rule in its calculation of the depreciation. CHEI has rectified the error in this application and confirms that the half year rule was applied for the purpose of determining the Rate Base. The resulting discrepancy between CHEI's audited financial statements and RRR filing and the information filed in this application are explained at E1.T3.S3

E4.T5.S5 DEPRECIATION/AMORTIZATION POLICY, OR EQUIVALENT WRITTEN DESCRIPTION

CHEI uses the straight line method of amortization which reflects a constant expense to the bottom line for the service as a function of time, based on the estimated average useful life of the asset. The estimated average useful lives of various asset categories are consistent with Board policy under CGAAP.

Table 14: Depreciation Rates prior to 2013

USoA Account	Account Description	Straight Line Life - Years	Straight Line Rate
1805	Distribution Plant - Land	N/A	N/A
1806	Distribution Plant - Land Rights/Easements	25	4.0%
1820	Distribution Plant - Distribution Stn. Equip. < 50KV	30	3.3%
1830	Distribution Plant - Poles, Towers and Fixtures	25	4.0%
1835	Distribution Plant - Overhead Conductors, Devices	25	4.0%
1840	Distribution Plant - Underground Conduit	25	4.0%
1845	Distribution Plant - Underground Conductors, Devices	25	4.0%
1850	Distribution Plant - Line Transformers	25	4.0%
1855	Distribution Plant - Services Underground	25	4.0%
1860	Distribution Plant - Meters	25	4.0%
1908	General Plant - Building/Fixtures	60	1.7%
1915	General Plant - Office Furniture/Equipment	10	10.0%
1920	Computer Equipment Hardware	5	20.0%
1925	Computer Software	5	20.0%
1930	General Plant - Transportation Equipment - heavy	8	12.5%
1930	General Plant - Transportation Equipment - light	5	20.0%
1935	General Plant - Stores Equipment	10	10.0%
1940	General Plant - Tools and Garage Equipment	10	10.0%
1945	General Plant - Measure and Testing Equipment	10	10.0%
1955	General Plant - Communication Equipment - FM	10	10.0%
1960	General Plant - Miscellaneous Equipment	5	20.0%
1970	General Plant - Load Mgt Customer Premises	10	10.0%
1980	General Plant - System Supervisory Equipment	25	4.0%

For all historical years up to 2012, the amortization rates used were the same as the rates found in Appendix B of the 2006 Distribution Rate Handbook. They reflected a rational and systematic allocation of cost over future periods appropriate to the nature of the property, plant and equipment. Acquisitions made during the year were amortized at half the normal rate.

E4.T5.S6 SUMMARY OF CHANGES TO DEPRECIATION/AMORTIZATION POLICY SINCE LAST CoS

In accordance with the July 17, 2012 letter from the Board on Regulatory accounting policy direction regarding changes to depreciation expense and capitalization policies in 2012 and 2013, CHEI completed an internal analysis which supports the revised average useful lives of various asset categories based on historical evidence and is within the typical useful life bands outlined in the Kinectrics Report "Asset Depreciation Study for the Ontario Energy Board". The impact of on the utility's net assets is discussed at Exhibit 2

E4.T5.S7 USEFUL LIVES STUDY

In accordance with Board policy, CHEI has adopted Kinectrics proposed useful lives and componentization of certain asset categories as suggested in the report where applicable.

Tab 6 –PILs and Property Taxes

E4.T6.S1 OVERVIEW OF PILS

CHEI is subject to the PILs regime, and therefore remits payments in lieu of corporate taxes to the Ontario Energy Financial Corporation.

CHEI files Federal and Provincial tax returns annually. There have been no special circumstances that would require specific tax planning measures to minimize taxes payable.

There are no non-utility activities included in CHEI's financial results, therefore the entire amount of PILs payable is considered in the proposed allowance to be included in the revenue requirement.

There are no outstanding audits, reassessments or disputes relating the tax returns filed by CHEI.

E4.T5.S2 of this tab addresses the allowance for PILs to be included in the proposed revenue requirement for the 2014 test year. Please note that CHEI is not claiming any Apprenticeship Training Tax Credits, education tax credits in its PILs calculation.

BDO reviewed the PILs model on behalf of CHEI and confirms that it complies with the filing requirements

E4.T6.S2 PILS MODEL

The income tax sheet from the Revenue Requirement Workform is presented at the next page and the PILs model is being filed in conjunction with this application

E4.T6.S3 MOST RECENT FEDERAL AND ONTARIO TAX RETURN

The latest tax returns are presented in the following pages,

Revenue Requirement Workform

Utility Income

Line No.	Particulars		Initial Application				Per Board Decision
	Operating Revenues:						
1	Distribution Revenue (at Proposed Rates)		$832,235	($832,235)	$ -	$ -	$ -
2	Other Revenue	(1)	$30,281	($30,281)	$ -	$ -	$ -
3	Total Operating Revenues		$862,516	($862,516)	$ -	$ -	$ -
	Operating Expenses:						
4	OM+A Expenses		$556,279	$ -	$556,279	$ -	$556,279
5	Depreciation/Amortization		$132,429	$ -	$132,429	$ -	$132,429
6	Property taxes		$ -	$ -		$ -	
7	Capital taxes		$ -	$ -	$ -	$ -	$ -
8	Other expense		$ -	$ -		$ -	
9	Subtotal (lines 4 to 8)		$688,708	$ -	$688,708	$ -	$688,708
10	Deemed Interest Expense		$68,890	($68,890)	$ -	$ -	$ -
11	Total Expenses (lines 9 to 10)		$757,598	($68,890)	$688,708	$ -	$688,708
12	Adjustment to Return on Rate Base associated with Deferred PP&E balance as a result of transition from CGAAP to MIFRS		$ -	$ -	$ -	$ -	$ -
13	**Utility income before income taxes**		$104,918	($793,626)	($688,708)	$ -	($688,708)
14	Income taxes (grossed-up)		$7,943	$ -	$7,943	$ -	$7,943
15	**Utility net income**		$96,975	($793,626)	($696,651)	$ -	($696,651)

Notes

Other Revenues / Revenue Offsets

(1)	Specific Service Charges	$14,200		$ -		$ -
	Late Payment Charges	$6,000		$ -		$ -
	Other Distribution Revenue	$10,081		$ -		$ -
	Other Income and Deductions	$ -		$ -		$ -
	Total Revenue Offsets	$30,281	$ -	$ -	$ -	$ -

Agence du revenu du Canada | Canada Revenue Agency

Formulaire de consentement de l'entreprise

Remplir ce formulaire pour autoriser la divulgation des renseignements confidentiels concernant vos comptes de programme au représentant nommé ci-dessous ou pour annuler un consentement existant d'un représentant. **Envoyez ce formulaire dûment rempli à votre centre fiscal (lisez les instructions)**. Assurez-vous de remplir ce formulaire correctement puisque nous ne pouvons pas modifier l'information que vous nous présentez. Vous pouvez aussi donner **ou** annuler un consentement en ligne en fournissant les renseignements demandés par l'entremise de « Mon dossier d'entreprise » à **www.arc.gc.ca/mondossierentreprise**.

Remarque : Veuillez lire toutes les instructions de la première page avant de remplir ce formulaire.

Partie 1 – Renseignement sur l'entreprise

Remplissez cette partie pour identifier votre entreprise (tous les champs doivent être remplis)

Nom de l'entreprise : Cooperative Hydro Embrun inc.

NE : 891479412 Numéro de téléphone : (613) 443-5110

Partie 2 – Autoriser un représentant – Remplir la partie a) ou b)

a) Autoriser l'accès par téléphone, par fax, par la poste ou par rendez-vous

Si vous donnez le consentement pour un individu, inscrivez le nom complet. Si vous donnez le consentement pour une firme, inscrivez son nom et son NE. Si vous souhaitez que nous traitions avec un individu en particulier de cette firme, inscrivez son nom **ainsi** que le nom et le NE de l'entreprise. Si vous n'identifiez pas un individu en particulier, vous autorisez l'ARC à traiter avec toute personne de cette firme.

Remarque : Si vous autorisez un représentant (individu ou firme) qui n'est pas enregistré au service « Représenter un client », vous devez inscrire le numéro de téléphone.

Nom de l'individu :

Nom de la firme :

Numéro de téléphone : Poste : NE :

ou

b) Autoriser l'accès en ligne (qui comprend l'accès par téléphone, fax, la poste ou par rendez-vous)

Vous pouvez autoriser votre représentant à traiter avec nous au moyen de notre service en ligne pour les représentants. Le NE doit être enregistrés avec notre service en ligne « Représenter un client » pour être un représentant en ligne. Nos services en ligne ne permettent pas de restreindre l'accès aux renseignements pour une année précise donc votre représentant aura donc accès à **toutes les années**. Veuillez fournir le nom et le numéro d'identification (ID Rep) de l'individu, ou le nom du Group et l'IDGroup **ou** le nom et le NE de l'entreprise.

Nom de l'individu : **et** ID Rep :

ou

Nom du groupe : **et** ID Group : G

ou

Nom de la firme : BDO CANADA LLP **et** NE : 131585366

ou

Numéro de téléphone : (613) 443-5201 Poste :

Partie 3 – Sélectionnez les comptes de programme, les années et le niveau d'autorisation

a) Comptes de programme – Cochez les comptes de programme auxquels vous autorisez l'accès au représentant ou à la firme mentionnés ci-dessus (cochez la case A **ou** B).

A. ☒ Cette autorisation s'applique à tous les comptes de programme et à toutes les années.

Date d'expiration :

et

Niveau d'autorisation (cochez niveau 1 ou 2)

☐ Niveau 1 permet à l'ARC de divulguer l'information sur vos comptes de programme seulement; **ou**

☒ Niveau 2 permet à l'ARC de divulguer l'information **et** effectuer des modifications à vos comptes de programme.

ou

B. ☐ L'autorisation s'applique seulement à vos comptes de programme et périodes énumérées dans la partie 3b). Si vous cochez cette option, vous devez remplir la partie 3b).

RC59 F (11)

Canada

Formulaire de consentement de l'entreprise

Partie 3 – Selectionnez les comptes de programme, les années et le niveau d'autorisation (suite)

b) Détails des comptes de programme et périodes fiscales – Remplir cette partie seulement si vous avez coché la case B de la partie 3a) de la page 1.

Si vous avez coché la case B dans la partie 3a), vous devez fournir au moins un identificateur de programme. Vous pouvez alors cocher la case « tous les comptes de programme » pour l'identification de programme **ou** inscrire un numéro de référence. Inscrivez le niveau d'autorisation (cochez la case 1 pour permettre à l'ARC de divulguer des informations **ou** la case 2 pour divulguer des informations **et** effectuer des modifications à votre compte de programme).

Vous pouvez aussi cocher la case « Toutes les années » pour permettre un accès illimité pour toutes les années fiscales **ou** indiquer une période spécifique (l'autorisation d'une periode spécifique **n'est pas disponible** pour l'accès en ligne). Vous pouvez aussi entrer une date d'expiration pour annuler automatiquement une autorisation. Pour ajouter d'autres autorisations ou si vous avez plus de quatre comptes de programme, remplissez un nouveau formulaire RC59.

Identificateur de programme	Tous les comptes de programme		Numéro de référence	Niveau d'autorisation		Toutes les années	ou	Fin d'année fiscale (non disponible pour l'accès en ligne)	Date d'expiration
				1	2			Fin d'année	
	☐	ou		☐	☐	☐	ou		
	☐	ou		☐	☐	☐	ou		
	☐	ou		☐	☐	☐	ou		
	☐	ou		☐	☐	☐	ou		

Partie 4 – Annuler une ou plusieurs autorisations

Remplissez cette section **seulement** pour annuler des consentements

A. ☐ Annuler **tous** les consentements.

B. ☐ Annuler les consentements qui ont été donnés à la personne ou à la firme identifiée ci-dessous.

C. ☐ Annuler l'autorisation pour des comptes de programme spécifique(s) ________

Nom de l'individu : ________ **et** **ID Rep :**

ou

Nom du groupe : ________ **et** **ID Group :** G

ou

Nom de la firme : ________ **et** **NE :**

Numéro de téléphone : ________

Partie 5 – Attestation

Ce formulaire doit être signé par une personne autorisée de l'entreprise tel un propriétaire, un associé d'une société de personnes, un directeur d'une société, un agent d'une organisation à but non lucratif ou un fiduciaire d'une succession. En signant et en datant ce formulaire, vous autorisez l'ARC à traiter avec la personne, le groupe, ou la firme figurant à la partie 2 de ce formulaire ou à annuler les consentements indiqués à la partie 4.

Prénom : Benoit

Nom de famille : Lamarche

Signature : ▶ ________

Date : 2013-02-27

Ce formulaire ne sera pas traité à moins qu'il soit signé et daté par une personne autorisée de l'entreprise.

Loi sur la protection de renseignements personnels. Fichiers de renseignements personnels ARC PPU 175 et ARC PPU 223.

Agence du revenu du Canada Canada Revenue Agency

DÉCLARATION DE RENSEIGNEMENTS DES SOCIÉTÉS POUR LA TRANSMISSION ÉLECTRONIQUE

- Vous devez remplir cette déclaration pour permettre à votre spécialiste en transmission de transmettre à l'Agence du revenu du Canada votre déclaration de revenus des sociétés par voie électronique. Remplissez cette déclaration pour chaque année d'imposition visée.
- En remplissant la partie B et en signant la partie C, vous reconnaissez que, selon la *Loi de l'impôt sur le revenu,* vous devez conserver tous les documents utilisés pour remplir votre déclaration de revenus des sociétés et nous les fournir sur demande.
- La partie D doit être remplie par vous ou par le spécialiste en transmission qui transmet votre déclaration de revenus des sociétés.
- Donnez l'original signé de cette déclaration à votre spécialiste en transmission et conservez-en une copie. Selon la *Loi*, vous devez conserver votre copie pendant six ans.
- Nous sommes responsables du caractère confidentiel des renseignements fiscaux produits par voie électronique seulement lorsque nous acceptons ces renseignements.

Conservez cette déclaration dans vos dossiers. Ne l'envoyez pas à moins que nous vous la demandions.

Partie A – Identification

Nom de la société: Cooperative Hydro Embrun inc.

Numéro d'entreprise 89147 9412 RC0001	Année d'imposition ▶	De A M J 2012-01-01	À A M J 2012-12-31

Partie B – Déclaration

Inscrivez les montants suivants, tels qu'ils figurent, selon le cas, dans votre déclaration de revenus des sociétés pour l'année d'imposition mentionnée ci-dessus :

Revenu net ou perte nette aux fins de l'impôt sur le revenu, selon l'annexe 1, les états financiers ou l'IGRF (ligne 300)	261 813
Impôt de la partie I à payer (ligne 700)	29 817
Surtaxe de la partie II à payer (ligne 708)	
Impôt de la partie III.1 à payer (ligne 710)	
Impôt de la partie IV à payer (ligne 712)	
Impôt de la partie IV.1 à payer (ligne 716)	
Impôt de la partie VI à payer (ligne 720)	
Impôt de la partie VI.1 à payer (ligne 724)	
Impôt de la partie XIV à payer (ligne 728)	
Impôt provincial ou territorial net à payer (ligne 760)	13 560
Impôt provincial des grandes sociétés (ligne 765)	

Partie C – Attestation et autorisation

Je, Lamarche (Nom en lettres moulées), Benoit (Prénom en lettres moulées), Manager (Poste ou titre),

suis un signataire autorisé de la société. J'atteste que j'ai examiné la déclaration de revenus T2 de la société, y compris les annexes et les états ci-joints, et que les renseignements fournis dans la déclaration T2 et cette déclaration de renseignements T183 Corp sont, à ma connaissance, exacts et complets. De plus, j'atteste que la méthode utilisée pour calculer le revenu de l'année d'imposition visée est la même que celle qui a été utilisée l'année précédente, sauf exceptions expressément mentionnées dans un état joint à la présente.

J'autorise le spécialiste en transmission indiqué dans la partie D à transmettre par voie électronique la déclaration de revenus de la société indiquée dans la partie A et à modifier les renseignements produits initialement en réponse à toute erreur décelée par l'Agence du revenu du Canada. Cette autorisation expire lorsque le ministre du Revenu national accepte la déclaration transmise par voie électronique telle que produite.

Date (aaaa/mm/jj): 2013-02-27

Signature du signataire autorisé de la société:

Numéro de téléphone: (613) 443-5110

Partie D – Identification du spécialiste en transmission

Le spécialiste en transmission nommé ci-dessous a transmis par voie électronique la déclaration de revenus de la société indiquée dans la partie A.

Nom de la personne ou de l'entreprise: BDO CANADA LLP

Numéro du déclarant par voie électronique: A3590

Loi sur la protection des renseignements personnels, Fichier de renseignements personnels CRA PPU 047.

Canada

Agence du revenu du Canada
Canada Revenue Agency

200

T2 – DÉCLARATION DE REVENUS DES SOCIÉTÉS

Utilisez ce formulaire comme déclaration de revenus fédérale et provinciale ou territoriale, sauf si la société est située au Québec ou en Alberta. Si la société est située dans l'une de ces provinces, vous devez produire une déclaration de revenus provinciale distincte.

Les renvois législatifs mentionnés dans cette déclaration visent la *Loi de l'impôt sur le revenu*. Il se peut que cette déclaration tienne compte de modifications qui n'avaient pas été adoptées au moment de la publication.

Faites parvenir une copie dûment remplie de cette déclaration, y compris les annexes et l'*Index général des renseignements financiers (IGRF)*, à votre centre fiscal ou bureau des services fiscaux. Vous devez produire la déclaration dans les six mois suivant la fin de l'année d'imposition de la société.

Pour en savoir plus, visitez le **www.arc.gc.ca** ou consultez le guide T4012, *Guide T2 - Déclaration de revenus des sociétés*.

055 **N'inscrivez rien ici**

Identification

Numéro d'entreprise (NE) **001** 89147 9412 RC0001

Nom de la société

002 Cooperative Hydro Embrun inc.

Adresse du siège social

L'adresse a-t-elle changé depuis la dernière fois que nous avons été avisés? . . . . **010** 1 Oui ☐ 2 Non ☒

(Si **oui**, remplissez les lignes 011 à 018.)

011 821 Notre-Dame

012 Suite 200

Ville **015** Embrun

Province, territoire ou État **016** ON

Pays (autre que le Canada) **017**

Code postal **018** K0A 1W1

Adresse postale (si elle diffère de l'adresse du siège social)

L'adresse a-t-elle changé depuis la dernière fois que nous avons été avisés? . . . . **020** 1 Oui ☐ 2 Non ☒

(Si **oui**, remplissez les lignes 021 à 028.)

021 a/s de

022 821 Notre-Dame

023 Suite 200

Ville **025** Embrun

Province, territoire ou État **026** ON

Pays (autre que le Canada) **027**

Code postal **028** K0A 1W1

Emplacement des livres comptables

L'emplacement des livres comptables a-t-il changé depuis la dernière fois que nous avons été avisés? . . . . **030** 1 Oui ☐ 2 Non ☒

(Si **oui**, remplissez les lignes 031 à 038.)

031 821 Notre-Dame

032 Suite 200

Ville **035** Embrun

Province, territoire ou État **036** ON

Pays (autre que le Canada) **037**

Code postal **038** K0A 1W1

040 **Genre de société à la fin de l'année d'imposition**

1 ☐ Société privée sous contrôle canadien (SPCC)

2 ☐ Autre société privée

3 ☐ Société publique

4 ☐ Société contrôlée par une société publique

5 ☒ Autre société (précisez, ci-dessous)

Coopérative

Si le genre de société a changé durant l'année d'imposition, indiquez la date d'entrée en vigueur du changement. . . . . **043** AAAA MM JJ

Quelle est l'année d'imposition visée par cette déclaration?

Début de l'année d'imposition **060** 2012-01-01 AAAA MM JJ

Fin de l'année d'imposition **061** 2012-12-31 AAAA MM JJ

Y a-t-il eu acquisition de contrôle visée par le paragraphe 249(4) depuis l'année d'imposition précédente? . . . . **063** 1 Oui ☐ 2 Non ☒

Si **oui**, donnez la date d'acquisition de contrôle . . . . **065** AAAA MM JJ

La date à la ligne 061 est-elle une fin d'année d'imposition réputée selon :

le sous-alinéa 88(2)*a*)(iv)? . . . . **064** 1 Oui ☐ 2 Non ☒

le paragraphe 249(3.1)? . . . . **066** 1 Oui ☐ 2 Non ☒

S'agit-il d'une société professionnelle associée d'une société de personnes? . **067** 1 Oui ☐ 2 Non ☒

Est-ce la première année pour laquelle une déclaration est produite après une :

constitution en société? . . . . **070** 1 Oui ☐ 2 Non ☒

fusion? . . . . **071** 1 Oui ☐ 2 Non ☒

Si **oui**, remplissez les lignes 030 à 038 et joignez l'annexe 24.

Y a-t-il eu liquidation d'une filiale selon l'article 88 durant l'année d'imposition courante? . . . . **072** 1 Oui ☐ 2 Non ☒

Si **oui**, remplissez et joignez l'annexe 24.

Est-ce la dernière année d'imposition avant une fusion? . . . . **076** 1 Oui ☐ 2 Non ☒

Est-ce la dernière déclaration jusqu'à la dissolution de la société? . . . . **078** 1 Oui ☐ 2 Non ☒

Si un choix a été fait selon l'article 261, inscrivez la monnaie fonctionnelle utilisée **079**

La société est-elle résidente du Canada?

080 1 Oui ☒ 2 Non ☐ Si **non**, indiquez le pays de résidence à la ligne 081 et remplissez et joignez l'annexe 97.

081

Est-ce que la société non-résidente demande une exonération d'impôt selon une convention fiscale? . . . . **082** 1 Oui ☐ 2 Non ☒

Si **oui**, remplissez et joignez l'annexe 91.

Si la société est exonérée selon l'article 149, cochez une des cases suivantes :

085

1 ☐ Exonérée selon l'alinéa 149(1)*e*) ou *l*)

2 ☐ Exonérée selon l'alinéa 149(1)*j*)

3 ☐ Exonérée selon l'alinéa 149(1)*t*)

4 ☐ Exonérée selon un autre alinéa de l'article 149

N'inscrivez rien ici

095 **096**

Annexes et formulaires à joindre

Renseignements des états financiers : utilisez les annexes 100, 125 et 141 de l'IGRF.

Annexes – Répondez aux questions suivantes. Pour chaque réponse affirmative, **joignez** l'annexe indiquée, à moins d'avis contraire.

		Oui	annexe
La société est-elle liée à une autre société?	150	☐	9
La société est-elle une SPCC associée?	160	☐	23
La société est-elle une SPCC associée qui demande la limite de dépenses?	161	☐	49
La société a-t-elle au moins un actionnaire non-résident qui détient des actions avec droit de vote?	151	☐	19
La société a-t-elle effectué des opérations, y compris des transferts selon l'article 85, avec ses actionnaires, ses cadres ou ses employés, sauf les opérations effectuées dans le cours normal des activités de l'entreprise? N'incluez pas les opérations avec lien de dépendance effectuées avec des non-résidents	162	☐	11
Si vous avez répondu **oui** à la question ci-dessus et que l'opération a été effectuée entre sociétés ayant un lien de dépendance, la société cédante a-t-elle disposé de la totalité ou presque des biens en faveur de la société cessionnaire?	163	☐	44
La société a-t-elle versé des redevances, des honoraires de gestion ou d'autres paiements semblables à des résidents du Canada?	164	☐	14
La société demande-t-elle une déduction pour les paiements versés à un régime de prestations aux employés?	165	☐	15
La société déduit-elle une perte ou une somme relative à un abri fiscal acquis après le 31 août 1989?	166	☐	T5004
La société est-elle associée d'une société de personnes à laquelle un numéro d'identification a été attribué?	167	☐	T5013
La société, une société étrangère affiliée contrôlée par la société, une autre société ou une fiducie avec laquelle la société avait un lien de dépendance a-t-elle eu un droit de bénéficiaire sur une fiducie non-résidente à pouvoir discrétionnaire (sans tenir compte de l'article 94)?	168	☐	22
La société a-t-elle été affiliée, pendant l'année, à des sociétés étrangères?	169	☐	25
La société a-t-elle fait des paiements à des non-résidents du Canada selon les paragraphes 202(1) et/ou 105(1) du *Règlement de l'impôt sur le revenu* fédéral?	170	☐	29
La société a-t-elle effectué des opérations ayant un lien de dépendance avec des non-résidents?	171	☐	T106
Pour les sociétés privées : la société a-t-elle au moins un actionnaire qui détient 10 % ou plus des actions ordinaires et/ou privilégiées de la société?	173	☐	50
La société a-t-elle fait des paiements ou reçu des montants provenant d'une convention de retraite au cours de l'année?	172	☐	
Le revenu net (perte nette) indiqué dans les états financiers diffère-t-il du revenu net (perte nette) pour l'impôt sur le revenu?	201	☒	1
La société a-t-elle fait des dons de bienfaisance, des dons à l'État, des dons de biens culturels, écosensibles ou de médicaments?	202	☐	2
La société a-t-elle reçu des dividendes ou payé des dividendes imposables pour un remboursement au titre de dividendes?	203	☐	3
La société déduit-elle des pertes quelconques?	204	☐	4
La société demande-t-elle un crédit d'impôt provincial ou territorial ou a-t-elle un établissement stable dans plus d'une administration?	205	☒	5
La société a-t-elle réalisé des gains en capital ou subi des pertes en capital durant l'année d'imposition?	206	☐	6
(i) La société demande-t-elle la déduction accordée aux petites entreprises et déclare-t-elle des revenus tirés de : a) biens (autres que les dividendes déductibles à la ligne 320), b) une société de personnes, c) une entreprise à l'étranger ou d) une entreprise de prestation de services personnels; ou (ii) la société a-t-elle inscrit un revenu de placement total à la ligne 440?	207	☒	7
La société a-t-elle des biens qui donnent droit à la déduction pour amortissement?	208	☒	8
La société a-t-elle des biens qui sont des immobilisations admissibles?	210	☒	10
La société demande-t-elle des déductions pour ressources?	212	☐	12
La société demande-t-elle des réserves déductibles (autres que la provision transitoire selon l'article 34.2)?	213	☒	13
La société demande-t-elle une déduction pour ristournes?	216	☐	16
La société est-elle une caisse de crédit qui demande une déduction pour répartitions proportionnelles à l'importance des emprunts ou un crédit supplémentaire pour caisses de crédit?	217	☐	17
La société est-elle une société de placement ou une société de placement à capital variable?	218	☐	18
La société a-t-elle exploité une entreprise au Canada pendant qu'elle était une société non-résidente?	220	☐	20
La société demande-t-elle un crédit fédéral ou provincial pour impôt étranger ou pour impôt sur les opérations forestières?	221	☐	21
La société a-t-elle des bénéfices de fabrication et de transformation au Canada?	227	☐	27
La société demande-t-elle un crédit d'impôt à l'investissement?	231	☐	31
La société demande-t-elle une déduction pour des dépenses de recherche scientifique et de développement expérimental (RS&DE)?	232	☐	T661
Est-ce que le total du capital imposable utilisé au Canada d'une société et de ses sociétés liées est de plus de 10 000 000 $?	233	☐	
Est-ce que le total du capital imposable utilisé au Canada d'une société et de ses sociétés associées est de plus de 10 000 000 $?	234	☐	
La société demande-t-elle un crédit de surtaxe?	237	☐	37
La société est-elle assujettie à l'impôt brut de la partie VI sur le capital des institutions financières?	238	☐	38
La société demande-t-elle un crédit d'impôt de la partie I?	242	☐	42
La société est-elle assujettie à l'impôt de la partie IV.1 sur les dividendes reçus sur des actions privilégiées ou à l'impôt de la partie VI.1 sur les dividendes payés?	243	☐	43
La société a-t-elle conclu un accord concernant l'obligation de payer l'impôt de la partie VI.1?	244	☐	45
La société est-elle assujettie à l'impôt de la partie II, c.-à-d. à la surtaxe des fabricants de tabac?	249	☐	46
Pour les institutions financières : la société est-elle membre d'un groupe lié d'institutions financières dont un ou plusieurs membres sont assujettis à l'impôt brut de la partie VI?	250	☐	39
La société demande-t-elle un remboursement du crédit d'impôt pour production cinématographique ou magnétoscopique canadienne?	253	☐	T1131
La société demande-t-elle un remboursement du crédit d'impôt pour services de production cinématographique ou magnétoscopique?	254	☐	T1177

Annexes et formulaires à joindre – suite de la page 2

		Oui	annexe
La société est-elle assujettie à l'impôt de la partie XIII.1? (Démontrez vos calculs sur une feuille que vous intitulerez Annexe 92.)	**255**	☐	92
La société est-elle affiliée à des sociétés étrangères qui ne sont pas des sociétés étrangères affiliées contrôlées?	**256**	☐	T1134-A
La société est-elle affiliée à des sociétés étrangères affiliées contrôlées?	**258**	☐	T1134-B
La société a-t-elle détenu, au cours de l'année, des biens étrangers déterminés dont le coût indiqué a dépassé 100 000 $?	**259**	☐	T1135
La société a-t-elle transféré ou prêté des biens à une fiducie non-résidente?	**260**	☐	T1141
La société a-t-elle reçu, au cours de l'année, un intérêt dans une fiducie non-résidente ou a-t-elle été débitrice d'une telle fiducie?	**261**	☐	T1142
La société a-t-elle une convention pour attribuer de l'aide pour la RS&DE effectuée au Canada?	**262**	☐	T1145
La société a-t-elle une convention pour transférer des dépenses admissibles engagées dans le cadre de contrats de RS&DE?	**263**	☐	T1146
La société a-t-elle une convention avec des sociétés associées pour attribuer les salaires d'employés déterminés pour la RS&DE?	**264**	☐	T1174
La société a-t-elle payé des dividendes imposables (autres que des dividendes sur les gains en capital) durant l'année d'imposition?	**265**	☐	55
La société a-t-elle fait un choix selon le paragraphe 89(11) de ne pas être une SPCC?	**266**	☐	T2002
La société a-t-elle révoqué un choix précédent fait selon le paragraphe 89(11)?	**267**	☐	T2002
La société [SPCC ou compagnie d'assurance dépôts (CAD)] a-t-elle payé des dividendes déterminés ou son compte de revenu à taux général (CRTG) a-t-il changé au cours de l'année d'imposition?	**268**	☐	53
La société (autre qu'une SPCC ou CAD) a-t-elle payé des dividendes déterminés ou son compte de revenu à taux réduit (CRTR) a-t-il changé au cours de l'année d'imposition?	**269**	☐	54

Renseignements supplémentaires

La société a-t-elle utilisé les normes internationales d'information financière (IFRS) dans la préparation de ses états financiers?	**270**	1 Oui ☐	2 Non ☒
La société est-elle inactive?	**280**	1 Oui ☐	2 Non ☒

Quelle est la principale activité productive de recettes commerciales de la société? 221122 Distribution d'électricité ÉU

Précisez les principaux produits qui sont extraits d'une mine, fabriqués, vendus ou construits, ou les services fournis. Indiquez le pourcentage approximatif que chaque produit ou service représente par rapport au total des recettes.

284	Hydro distribution	**285**	100,000 %
286		**287**	%
288		**289**	%

La société a-t-elle immigré au Canada au cours de l'année d'imposition?	**291**	1 Oui ☐	2 Non ☒
La société a-t-elle émigré du Canada au cours de l'année d'imposition?	**292**	1 Oui ☐	2 Non ☒
Désirez-vous verser des acomptes provisionnels trimestriels, si vous êtes admissible?	**293**	1 Oui ☐	2 Non ☒
Si la société était admissible à verser des acomptes provisionnels trimestriels pour une partie de l'année d'imposition, indiquez la date à partir de laquelle la société n'était plus admissible	**294**	AAAA MM JJ	
Si l'activité principale de votre société est la construction, avez-vous eu des sous-traitants pendant l'année d'imposition?	**295**	1 Oui ☐	2 Non ☐

Revenu imposable

Revenu net ou perte nette aux fins de l'impôt sur le revenu, selon l'annexe 1, les états financiers ou l'IGRF			**300** 261 813	A
Moins : Dons de bienfaisance (annexe 2)	**311**			
Dons à l'État (annexe 2)	**312**			
Dons de biens culturels (annexe 2)	**313**			
Dons de biens écosensibles (annexe 2)	**314**			
Dons de médicaments (annexe 2)	**315**			
Dividendes imposables déductibles selon les articles 112 ou 113 ou le paragraphe 138(6) (annexe 3)	**320**			
Déduction de l'impôt de la partie VI.1*	**325**			
Pertes autres que des pertes en capital des années d'imposition précédentes (annexe 4)	**331**			
Pertes en capital nettes des années d'imposition précédentes (annexe 4)	**332**			
Pertes agricoles restreintes des années d'imposition précédentes (annexe 4)	**333**			
Pertes agricoles des années d'imposition précédentes (annexe 4)	**334**			
Pertes comme commanditaire des années d'imposition précédentes (annexe 4)	**335**			
Gains en capital imposables ou dividendes imposables répartis par une caisse de crédit centrale	**340**			
Actions de prospecteur ou de commanditaire en prospection	**350**			
Total partiel			▶	B
Total partiel (montant A **moins** montant B) (si négatif, inscrivez « 0 »)			261 813	C
Plus : Ajouts selon l'article 110.5 ou le sous-alinéa 115(1)*a*)(vii)			**355**	D
Revenu imposable (montant C **plus** montant D)			**360** 261 813	
Revenu exonéré selon l'alinéa 149(1)*t*)			**370**	
Revenu imposable pour les sociétés ayant un revenu exonéré selon l'alinéa 149(1)*t*) (ligne 360 **moins** ligne 370)			261 813	Z

* Ce montant est égal à 3,5 fois l'impôt de la partie VI.1 à payer (ligne 724, page 8). Utilisez 3,2 pour les années d'imposition qui se terminent avant 2012.

Déduction accordée aux petites entreprises

Société qui, pendant toute l'année d'imposition, était une société privée sous contrôle canadien (SPCC)

Revenu provenant d'une entreprise exploitée activement au Canada (annexe 7) . . . . **400** 236 395 A

Revenu imposable de la ligne 360 (page 3), **moins** 100/28* 3,57143 du montant de la ligne 632** (page 7), **moins** 1/(0,38 - X***) 4 fois le montant de la ligne 636**** (page 7), et **moins** tout montant exonéré de l'impôt de la partie I selon une loi fédérale . . . . **405** 261 813 B

Plafond des affaires (lisez les remarques 1 et 2 ci-dessous) . . . . **410** 500 000 C

Remarques : 1. S'il s'agit d'une SPCC qui n'était pas associée, inscrivez 500 000 $. Toutefois, si l'année d'imposition de la société compte moins de 51 semaines, multipliez ce montant par le nombre de jours dans l'année d'imposition divisé par 365. Inscrivez le résultat à la ligne 410.

2. Si la SPCC était associée à d'autres sociétés, utilisez l'annexe 23 pour calculer le montant à inscrire à la ligne 410.

Réduction du plafond des affaires :

Montant C 500 000 x **415** ***** ______ D / 11 250 = ... ______ E

Plafond des affaires réduit (montant C **moins** montant E) (si négatif, inscrivez « 0 ») . . . . **425** 500 000 F

Déduction accordée aux petites entreprises

Le moins élevé des montants A, B, C ou F 236 395 x 17 % = ... **430** 40 187 G

Inscrivez le montant G à la ligne 1, page 7.

* 10/3 pour les années d'imposition qui se terminent au plus tard le 31 octobre 2011. Le résultat de la multiplication par la ligne 632 doit être calculé proportionnellement au nombre de jours de l'année d'imposition dans chaque période : avant le 1er novembre 2011 et après le 31 octobre 2011.

** Calculez le montant du crédit pour impôt étranger sur le revenu non tiré d'une entreprise qui serait déductible à la ligne 632, sans tenir compte de l'impôt remboursable sur le revenu de placements des SPCC (ligne 604) ni des réductions de l'impôt des sociétés (article 123.4).

*** Pourcentage de réduction d'impôt générale pour l'année d'imposition. Il doit être calculé proportionnellement au nombre de jours de l'année d'imposition dans chaque année civile. Lisez la page 5.

**** Calculez le montant du crédit pour impôt étranger qui s'applique au revenu d'entreprise et qui serait déductible à la ligne 636, sans tenir compte des réductions de l'impôt des sociétés (article 123.4).

***** **Les grandes sociétés**

- Si la société n'était pas associée à d'autres sociétés dans l'année d'imposition courante et qu'elle ne l'était pas dans l'année d'imposition précédente, le montant à inscrire à la ligne 415 est (le total du capital imposable utilisé au Canada pour son année d'imposition **précédente** moins 10 000 000 $) x 0,225 %.
- Si la société n'est pas associée à d'autres sociétés dans l'année d'imposition courante, mais qu'elle l'était dans l'année d'imposition précédente, le montant à inscrire à la ligne 415 est (le total du capital imposable utilisé au Canada pour son année d'imposition **courante** moins 10 000 000 $) x 0,225 %.
- Si la société est associée à d'autres sociétés dans l'année d'imposition courante, reportez-vous aux règles spéciales indiquées à l'annexe 23.

Réduction d'impôt générale pour les sociétés privées sous contrôle canadien

Société privée sous contrôle canadien pendant toute l'année d'imposition

Revenu imposable (ligne 360, page 3)*				261 813	A
Le moins élevé des montants V et Y (ligne Z1) de la section 9 de l'annexe 27			B		
Montant QQ de la section 13 de l'annexe 27			C		
Revenu provenant d'une entreprise de prestation de services personnels**	432		D		
Montant utilisé pour calculer la déduction pour caisse de crédit (annexe 17)			E		
Montant le moins élevé : ligne 400, 405, 410 ou 425 (page 4)		236 395	F		
Revenu de placements total (ligne 440, page 6)***			G		
Total des montants B à G		236 395	▶	236 395	H
Montant A **moins** montant H (si négatif, inscrivez « 0 »)				25 418	I

Montant I	25 418	x	Nombre de jours dans l'année d'imposition avant le 1er janvier 2011 Nombre de jours dans l'année d'imposition	 366	x	10 %	=		J
Montant I	25 418	x	Nombre de jours dans l'année d'imposition après le 31 décembre 2010 et avant le 1er janvier 2012 Nombre de jours dans l'année d'imposition	 366	x	11,5 %	=		K
Montant I	25 418	x	Nombre de jours dans l'année d'imposition après le 31 décembre 2011 Nombre de jours dans l'année d'imposition	366 366	x	13 %	=	3 304	L

Réduction d'impôt générale pour les sociétés privées sous contrôle canadien – Total des montants J à L 3 304 M

Inscrivez le montant M à la ligne 638, page 7.

* Pour les années d'imposition qui se terminent après le 31 octobre 2011, ligne 360 ou montant Z, selon le cas.

** Pour les années d'imposition qui commencent après le 31 octobre 2011.

*** Sauf pour une société qui est, tout au long de l'année, une société coopérative [selon le paragraphe 136(2)] ou une caisse de crédit.

Réduction d'impôt générale

Ne remplissez pas cette section si vous êtes une société privée sous contrôle canadien, une société de placement, une société de placement hypothécaire, une société de placement à capital variable ou une société qui a un revenu imposable non assujetti au taux d'impôt de 38 %.

Revenu imposable de la page 3 (ligne 360 ou montant Z, selon le cas)					N
Le moins élevé des montants V et Y (ligne Z1) de la section 9 de l'annexe 27			O		
Montant QQ de la section 13 de l'annexe 27			P		
Revenu provenant d'une entreprise de prestation de services personnels*	434		Q		
Montant utilisé pour calculer la déduction pour caisse de crédit (annexe 17)			R		
Total des montants O à R			▶		S
Montant N **moins** montant S (si négatif, inscrivez « 0 »)					T

Montant T		x	Nombre de jours dans l'année d'imposition avant le 1er janvier 2011 Nombre de jours dans l'année d'imposition	 366	x	10 %	=		U
Montant T		x	Nombre de jours dans l'année d'imposition après le 31 décembre 2010 et avant le 1er janvier 2012 Nombre de jours dans l'année d'imposition	 366	x	11,5 %	=		V
Montant T		x	Nombre de jours dans l'année d'imposition après le 31 décembre 2011 Nombre de jours dans l'année d'imposition	366 366	x	13 %	=		W

Réduction d'impôt générale – Total des montants U à W X

Inscrivez le montant X à la ligne 639, page 7.

* Pour les années d'imposition qui commencent après le 31 octobre 2011.

Fraction remboursable de l'impôt de la partie I

Société privée sous contrôle canadien durant toute l'année d'imposition

Revenu de placements total (annexe 7) . . . . **440** × 26 2 / 3 % = ... A

Crédit pour impôt étranger sur le revenu non tiré d'une entreprise (ligne 632, page 7) . . . .

Moins :

Revenu de placements à l'étranger (annexe 7) . . . . . . **445** × 9 1 / 3 % =

(si négatif, inscrivez « 0 ») ▶ B

Montant A **moins** montant B (si négatif, inscrivez « 0 ») C

Revenu imposable (ligne 360, page 3) . . . .

Moins :

Montant le moins élevé : ligne 400, 405, 410 ou 425 (page 4) . . . . . .

Crédit pour impôt étranger sur le revenu non tiré d'une entreprise (ligne 632, page 7) × 25/9* 100 / 35 =

Crédit pour impôt étranger sur le revenu d'entreprise (ligne 636, page 7) . . . . . . × 1/(0,38 - X**) 4 =

▶

× 26 2 / 3 % = D

Impôt de la partie I à payer moins le remboursement du crédit d'impôt à l'investissement (ligne 700 **moins** ligne 780, page 8) . . . . E

Fraction remboursable de l'impôt de la partie I – Montant le moins élevé : C, D ou E . . . . **450** F

* 100/35 pour les années d'imposition qui commencent après le 31 octobre 2011.

** Pourcentage de réduction d'impôt générale pour l'année d'imposition. Il doit être calculé proportionnellement au nombre de jours de l'année d'imposition dans chaque année civile. Lisez la page 5.

Impôt en main remboursable au titre de dividendes

Impôt en main remboursable au titre de dividendes à la fin de l'année d'imposition précédente . . **460**

Moins : remboursement au titre de dividendes pour l'année d'imposition précédente **465**

▶ G

Plus le total des montants suivants :

Fraction remboursable de l'impôt de la partie I (ligne 450 ci-dessus) . . . .

Total de l'impôt de la partie IV à payer (annexe 3) . . . .

Montant net de l'impôt en main remboursable au titre de dividendes transféré d'une société remplacée après une fusion ou la liquidation d'une filiale **480**

▶ H

Impôt en main remboursable au titre de dividendes à la fin de l'année d'imposition – Montant G **plus** montant H **485**

Remboursement au titre de dividendes

Société privée ou assujettie au moment du paiement des dividendes imposables dans l'année d'imposition

Dividendes imposables payés dans l'année d'imposition (ligne 460, page 2 de l'annexe 3) . . . . . × 1 / 3 I

Impôt en main remboursable au titre de dividendes à la fin de l'année d'imposition (ligne 485 ci-dessus) . . . . J

Remboursement au titre de dividendes – Montant le moins élevé : I ou J (inscrivez ce montant à la ligne 784, page 8) . . . .

Impôt de la partie I

Montant de base de l'impôt de la partie I : revenu imposable de la page 3 (ligne 360 ou montant Z, selon le cas) **multiplié** par 38 %	550	99 489	A
Récupération du crédit d'impôt à l'investissement (annexe 31)	602		B

Calcul de l'impôt remboursable sur le revenu de placements des sociétés privées sous contrôle canadien (SPCC)
(pour les sociétés qui, durant toute l'année d'imposition, étaient des SPCC)

Revenu de placements total (ligne 440, page 6)			i
Revenu imposable (ligne 360, page 3)			
Moins :			
montant le moins élevé : lignes 400, 405, 410 ou 425 (page 4)			
Montant net		►	ii

Impôt remboursable sur le revenu de placements pour les sociétés privées sous contrôle canadien :

6 2/3 % multiplié par le montant le moins élevé, i ou ii	604		C
Total partiel (**additionnez** les lignes A à C)		99 489	D

Moins :

Déduction accordée aux petites entreprises (ligne 430, page 4)		40 187	1		
Abattement d'impôt fédéral	608	26 181			
Déduction pour bénéfices de fabrication et de transformation (annexe 27)	616				
Déduction pour société de placement	620				
Gains en capital imposés 624					
Déduction supplémentaire – caisses de crédit (annexe 17)	628				
Crédit fédéral pour impôt étranger sur le revenu non tiré d'une entreprise (annexe 21)	632				
Crédit fédéral pour impôt étranger sur le revenu d'entreprise (annexe 21)	636				
Réduction d'impôt générale pour les SPCC (montant M, page 5)	638	3 304			
Réduction d'impôt générale (montant X, page 5)	639				
Crédit fédéral pour impôt sur les opérations forestières (annexe 21)	640				
Crédit d'impôt fédéral d'une fiducie pour l'environnement admissible	648				
Crédit d'impôt à l'investissement (annexe 31)	652				
Total partiel		69 672	►	69 672	E
Impôt de la partie I à payer – Ligne D **moins** ligne E				29 817	F

Inscrivez le montant F à la ligne 700, page 8.

Sommaire de l'impôt et des crédits

Impôt fédéral

Impôt de la partie I à payer (page 7)			700	29 817
Surtaxe de la partie II à payer (annexe 46)			708	
Impôt de la partie III.1 à payer (annexe 55)			710	
Impôt de la partie IV à payer (annexe 3)			712	
Impôt de la partie IV.1 à payer (annexe 43)			716	
Impôt de la partie VI à payer (annexe 38)			720	
Impôt de la partie VI.1 à payer (annexe 43)			724	
Impôt de la partie XIII.1 à payer (annexe 92)			727	
Impôt de la partie XIV à payer (annexe 20)			728	
			Total de l'impôt fédéral	29 817

Plus l'impôt provincial ou territorial :

Administration provinciale ou territoriale . . . **750** ON
(s'il y en a plus d'une, inscrivez « multiples » et remplissez l'annexe 5)

Impôt provincial ou territorial net à payer (sauf Québec et Alberta)	760	13 560		
Impôt provincial des grandes sociétés (annexe 342 – Nouvelle-Écosse)	765			
(L'impôt des grandes sociétés de la Nouvelle-Écosse est éliminé à compter de juillet 2012.)		13 560 ►		13 560
			Total de l'impôt à payer 770	43 377 A

Moins autres crédits :

Remboursement du crédit d'impôt à l'investissement (annexe 31)		780		
Remboursement au titre de dividendes (page 6)		784		
Remboursement fédéral au titre des gains en capital (annexe 18)		788		
Remboursement du crédit d'impôt fédéral d'une fiducie pour l'environnement admissible		792		
Remboursement du crédit d'impôt pour production cinématographique ou magnétoscopique canadienne (formulaire T1131)		796		
Remboursement du crédit d'impôt pour services de production cinématographique ou magnétoscopique (formulaire T1177)		797		
Impôt retenu à la source		800		
Montant total sur lequel l'impôt a été retenu	801			
Remboursement provincial ou territorial au titre des gains en capital (annexe 18)		808		
Remboursement des crédits d'impôt provinciaux et territoriaux (annexe 5)		812		
Impôt payé par acomptes provisionnels		840	24 000	
		Total des crédits 890	24 000 ►	24 000 B

Code de remboursement **894** ☐ Trop-payé ________ ◄

Solde (ligne A **moins** ligne B) 19 377

Si le résultat est négatif, vous avez un **trop-payé**.
Si le résultat est positif, vous avez un **solde impayé**.
Inscrivez le montant à l'endroit approprié.
En général, une différence de 2 $ ou moins n'est ni exigée, ni remboursée.

Demande de dépôt direct

Pour que le remboursement soit déposé directement dans le compte bancaire de la société au Canada, ou pour corriger les renseignements déjà fournis, veuillez fournir les renseignements suivants :

☐ Commencer ☐ Corriger les renseignements **910** ________ Numéro de succursale

914 ________ Numéro de l'institution **918** ________ Numéro de compte

Solde impayé 19 377

Paiement ci-joint **898** 19 377

Si la société était une société privée sous contrôle canadien durant toute l'année d'imposition, a-t-elle droit au délai d'un mois suivant la date d'exigibilité du solde? . . . **896** 1 Oui ☒ 2 Non ☐

L'INFORMATION A ÉTÉ ÉTABLIE UNIQUEMENT À DES FINS FISCALES À PARTIR DES RENSEIGNEMENTS FOURNIS PAR LE CONTRIBUABLE. ELLE N'A PAS FAIT L'OBJET D'UNE VÉRIFICATION OU D'UN EXAMEN.

Attestation

Je, **950** Lamarche (Nom en lettres moulées) **951** Benoit (Prénom en lettres moulées) **954** Manager (Poste ou titre),

suis un signataire autorisé de la société. J'atteste que j'ai examiné cette déclaration, y compris les annexes et les états ci-joints, et que les renseignements fournis sont, à ma connaissance, exacts et complets. De plus, j'atteste que la méthode utilisée pour calculer le revenu de l'année d'imposition visée par cette déclaration est la même que celle qui a été utilisée l'année précédente, sauf exceptions expressément mentionnées dans un état joint à la présente.

955 2013-02-27 Date (aaaa/mm/jj) ________ Signature du signataire autorisé de la société **956** (613) 443-5110 Numéro de téléphone

La personne à contacter est-elle la même que le signataire autorisé? Si **non**, fournissez les renseignements ci-dessous **957** 1 Oui ☒ 2 Non ☐

958 ________ Nom en lettres moulées **959** ________ Numéro de téléphone

Langue de correspondance – Language of correspondence

Indiquez votre langue de correspondance en inscrivant **2** pour français ou **1** pour anglais.
Indicate your language of correspondence by entering **2** for French or **1** for English. **990** 2

Loi sur la protection des renseignements personnels, Fichier de renseignements personnels CRA PPU 047

Tab 7 –GEA Plan

E4.T7.S1 GEA PLAN

There is no proposed budget with respect to connection of renewable generation under the FIT program. CHEI's GEA plan is presented at Exhibit 2.

Revised June 13, 2013.

E4.T7.S2 LRAMVA (2011-2014)

The Minimum Filing Requirement state that distributors must apply for the disposition of the balance in the LRAMVA as part of their COS applications. In compliance with the filing requirements, CHEI is filing for LRAMVA related to the CDM programs delivered within the 2011 to 2014 term. In this proceeding, CHEI seeks recovery of its 2011 LRAM with persistence up to 2012.

	2011	2012	2013	2014	Total
%					
2011 CDM Programs	6.33%	6.33%	6.33%	6.31%	25.30%
2012 CDM Programs		21.43%	21.43%	21.43%	64.29%
2013 CDM Programs			3.47%	3.47%	6.94%
2014 CDM Programs				3.47%	3.47%
Total in Year	6.33%	27.75%	31.23%	34.68%	100.00%
kWh					
2011 CDM Programs	70,951	70,849	70,849	70,709	283,358
2012 CDM Programs		240,000	240,000	240,000	720,000
2013 CDM Programs			38,881	38,881	77,762
2014 CDM Programs				38,881	38,881
Total in Year	70,951	310,849	349,729	388,471	1,120,000
				Check	1,120,000

LRAMVA					
2011 CDM Programs	70,951	70,849			141,800

CHEI attests that it has used the most recent input assumptions available at the time of the program evaluation when calculating its LRAM amount;

CHEI attests that has relied on the most recent and appropriate final evaluation report from the OPA in support of its LRAM calculation;

CHEI has separate tables for each rate class that shows the LRAM amounts requested by the year they are associated with and the year the lost revenues took place; in Exhibit 9 Tab 1 Schedule 8.

In Exhibit 9 Tab 1 Schedule 8 KWHI has included LRAM calculations, determined by calculating the energy savings by customer class and valuing those energy savings using the distributor's Board-approved variable distribution charge appropriate to the class;

CHEI is not requesting carrying charges on the LRAM amount;

Lastly, CHEI attests that it does not have any Board approved programs

CHEI is filing its final OPA Report on Contracted Province-Wide Programs in conjunction with this revision.

The following table shows each rate class by year the loss revenue took place and the derivations of the entry in account 1568.

LRAMVA Calculations

	2011	2012	
LRAM Claim (kW):	52	14	tab 3.1.1 of Final OPA report
LRAM Claim (kWh):	70,951	70,849	tab 3.1.1 of Final OPA report

Per class allocation (kWh)	2011 Alloc by Class	2012 Alloc by Class	2011 LRAM (kWh)	2012 LRAM (kWh)	Total
Residential	69%	67%	48,624	47,779	96,403
General Service < 50 kW	16%	16%	11,259	11,541	22,800
General Service > 50 to 4999 kW	14%	15%	9,954	10,446	20,400
Unmetered Scattered Load	0%	0%	223	217	440
Street Lighting	1%	1%	891	865	1,756
	100%	100%	70,951	70,849	141,800

Per class allocation (kW)	2011 Alloc by Class	2012 Alloc by Class	kW	kW	Total
General Service > 50 to 4999 kW	92%	93%	48	13	
Street Lighting	8%	7%	4	1	
			52	14	

LRAMVA Rate Rider	2011 Volumetric Rate	2012 Volumetric Rate	2011 LRAM	2012 LRAM	Entry to 1568
Residential	0.0126	0.0128	$612.66	$611.57	$1,224.23
General Service < 50 kW	0.0166	0.0168	$186.90	$193.89	$380.79
General Service > 50 to 4999 kW	4.4833	4.5445	$216.55	$58.84	$275.39
Unmetered Scattered Load	0.0103	0.0104	$2.29	$2.26	$4.55
Street Lighting	6.4268	6.5145	$26.25	$6.78	$33.03
			$1,044.66	$873.33	$1,917.99

The entry to account 1568 is being made in 2012. CHEI is seeking to recover carrying charges on the above LRAM total claim up until December 31, 2013. Details of carrying charges and derivation of the rate rider is determined in the EDDVAR model and is detailed at Exhibit 9.

CHEI attest that it does not use CDM Board-approved programs and as such, does not need a third party report.

Tab 8 –CDM

E4.T8.S1 CDM COSTS

In the Board's Decision and Order issued on November 12, 2010 in the matter of the EB-2010-0215/0216 proceedings, CHEI was assigned the following CDM targets for the 2011-2014 timeframe:

Peak Demand:	0.034 MW
Electricity Consumption:	0.112 MW

CHEI is currently relying solely on Ontario Power Authority ("OPA") contracted Province Wide CDM programs to achieve its mandatory CDM targets. As a part of the planning process, CHEI utilized the OPA's Resource Planning Tool, taking into consideration CHEI's service territory's residential profile and past CDM program results, to forecast its reductions in Peak Demand and Electricity Consumption. CDM related OM&A costs are currently covered through the available Program Administration Budget ("PAB") provided by the OPA.

To market the residential customers' programs, CHEI will continue to utilize a customer-centric marketing approach, including elements ranging from bill inserts to attending community events. CHEI's strategy for Commercial and Industrial customers will further build on developing and maintaining strong customer relationships in addition to traditional marketing approaches

At this time, CHEI does not contemplate employing any Board-Approved programs. The intent is to meet demand and energy reduction requirements by delivering OPA-Contracted Province-Wide programs. CHEI will not be applying for any OM&A costs related to the administration and delivery of CDM programs to be recovered through the revenue requirement.

CHEI may, in the future, turn to Board-Approved CDM Programs, should the prescribed OPA funding model prove insufficient to deliver OPA-Contracted Province-Wide programs or the net results do not meet intended demand and energy savings.

Tab 9 –Patronage Dividends

Cooperative Hydro Embrun Inc. is fully owned and controlled by its members, in this case, the utility's customers. The cooperative's main objective is to; first and foremost, meet the needs of its members. The advantages of the cooperative business model derive from its democratic model of governance. In general, members of cooperative businesses pay lower (or stabilized) prices for its electricity if you take into account the remittance of dividends to its members. Benefits are distributed in a form of patronage dividend to members based on a proportion of profit made by the business. Dividends are refunded to each member in a form of a credit on the customers' invoice.

Since 2001, the utility has remitted over $300,000 to its customers of which $100,000 was in the last 3 years. This amount of dividends more than offsets the increase in costs from 2010 to the proposed Test Year.

Table 15 –Patronage Dividends

Year	Dividend
2001	$8,025.00
2002	$53,250.00
2003	$31,350.00
2004	$16,820.00
2005	$12,775.00
2006	$0.00
2007	$34,155.00
2008	$22,370.00
2009	$24,610.00
2010	$19,705.00
2011	$24,018.00
2012	$55,915.00
Total	**$302,993.00**

Exhibit 5 – Cost of Capital

TABLE OF CONTENTS

EXHIBIT 5 – COST OF CAPITAL AND CAPITAL STRUCTURE

The evidence presented in this exhibit provides information supporting the various elements of CHEI’s proposed capital structure. The evidence herein is organized according to the following topics;

1) Capital Structure
2) Cost of Debt

Tab 1 – Capital Structure

E5.T1.S1 OVERVIEW OF CAPITAL STRUCTURE

CHEI has followed the Report of the Board on Cost of Capital for Ontario's Regulated Utilities, December 11, 2009 in determining the cost of capital.

In calculating the cost of capital, CHEI has used the deemed capital structure of 56% long-term debt, 4% short-term debt, and 40% equity, and the Cost of Capital parameters in the OEB letter of November 15, 2012, for the allowed return on equity and where appropriate for debt. CHEI understands that the OEB will most likely update the ROE for 2014 at a later date, therefore the Applicant commits to updating its Capital Structure accordingly and as new information is issued.

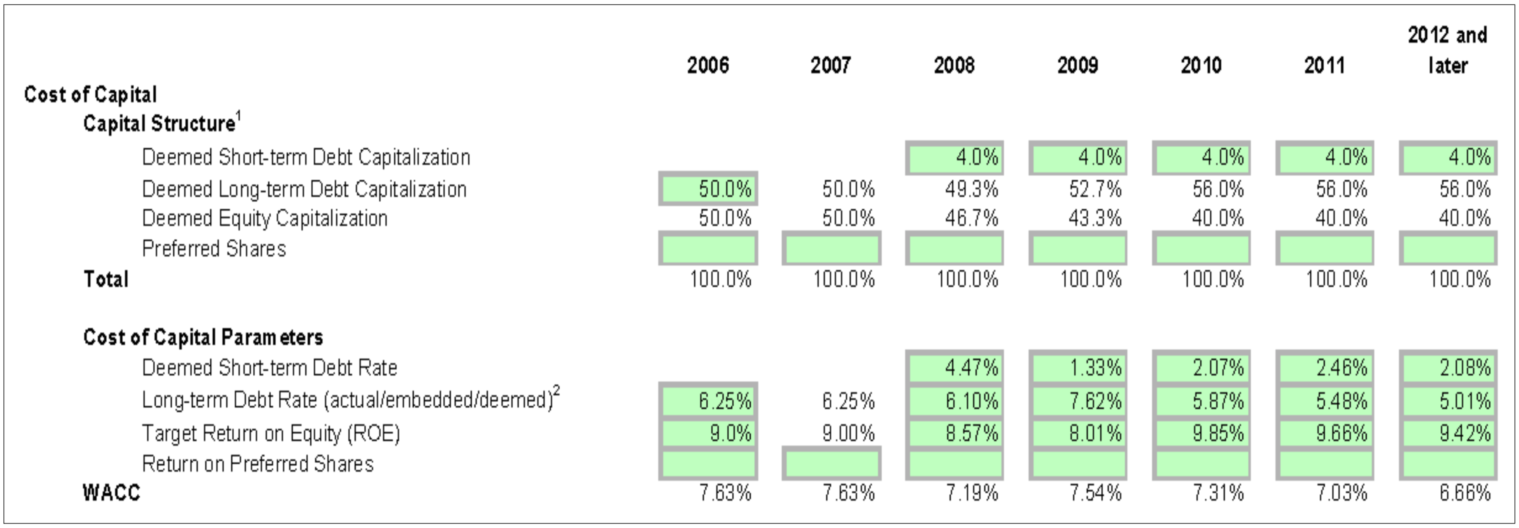
CHEI's cost of capital for 2014 has been calculated as 5.91%, as shown in Table 5.1.1 below.

Table 5.1.1 – Overview of Capital Structure

		2010 Board Approved			**2014 Test Year**	
	Deemed Capital Structure	**Rate**			**Rate**	
Short Term Debt	4%	2.07%			2.07%	
Long Term Debt	56%	5.87%			4.12%	
Equity	40%	9.85%			8.98%	
Total	100%		**7.31%**			**5.98%**

E5.T1.S2 CAPITAL STRUCTURE / COST OF CAPITAL - APPENDIX 2-OA

The following table shows the capital structure for historical years. Appendix 2-OA can be found at the next page



	2006	2007	2008	2009	2010	2011	2012 and later
Cost of Capital							
Capital Structure[1]							
Deemed Short-term Debt Capitalization			4.0%	4.0%	4.0%	4.0%	4.0%
Deemed Long-term Debt Capitalization	50.0%	50.0%	49.3%	52.7%	56.0%	56.0%	56.0%
Deemed Equity Capitalization	50.0%	50.0%	46.7%	43.3%	40.0%	40.0%	40.0%
Preferred Shares							
Total	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%
Cost of Capital Parameters							
Deemed Short-term Debt Rate			4.47%	1.33%	2.07%	2.46%	2.08%
Long-term Debt Rate (actual/embedded/deemed)[2]	6.25%	6.25%	6.10%	7.62%	5.87%	5.48%	5.01%
Target Return on Equity (ROE)	9.0%	9.00%	8.57%	8.01%	9.85%	9.66%	9.42%
Return on Preferred Shares							
WACC	7.63%	7.63%	7.19%	7.54%	7.31%	7.03%	6.66%

E5.T1.S2 PROMISSORY NOTES

CHEI does not hold any debt or affiliate debt instrument and as such, does not hold any promissory notes.

Revised June 13, 2013. CHEI does not hold any debt, has not held any debt or affiliate debt instruments in historical years. Therefore, Appendix 2-OB is not applicable in this case.

File Number:	EB-20130122
Exhibit:	6
Tab:	1
Schedule:	1
Page:	
Date:	

Appendix 2-OA
Capital Structure and Cost of Capital

This table must be completed for the required years of all historical years, the bridge year and the test year.

Line No.	**Particulars**	**Capitalization Ratio**			**Cost Rate**	**Return**
				2014		
				Application		
		(%)		($)	(%)	($)
	Debt					
1	Long-term Debt	56.00%		$1,614,159	4.12%	$66,503
2	Short-term Debt	4.00%	(1)	$115,297	2.07%	$2,387
3	**Total Debt**	60.0%		$1,729,456	3.98%	$68,890
	Equity					
4	Common Equity	40.00%		$1,152,971	8.98%	$103,537
5	Preferred Shares	0.00%		$ -	0.00%	$ -
6	**Total Equity**	40.0%		$1,152,971	8.98%	$103,537
7	**Total**	100.0%		$2,882,427	5.98%	$172,427
	**Cost of Capital Parameter Updates for 2013 Cost of Service Applications for Rates Effective May 1, 2013*					
				2013		
				Application		
		(%)		($)	(%)	($)
	Debt					
1	Long-term Debt	56.00%		$1,480,348	5.87%	$86,896
2	Short-term Debt	4.00%	(1)	$105,739	2.07%	$2,189
3	**Total Debt**	60.0%		$1,586,088	5.62%	$89,085
	Equity					
4	Common Equity	40.00%		$1,057,392	9.85%	$104,153
5	Preferred Shares	0.00%		$ -	0.00%	$ -
6	**Total Equity**	40.0%		$1,057,392	9.85%	$104,153
7	**Total**	100.0%		$2,643,479	7.31%	$193,238
	** Cost of Capital Parameter Updates for 2012 Cost of Service Applications for Rates Effective May 1, 2012*					
				2012		
				Application		
		(%)		($)	(%)	($)
	Debt					
1	Long-term Debt	56.00%		$1,353,326	5.87%	$79,440
2	Short-term Debt	4.00%	(1)	$96,666	2.07%	$2,001
3	**Total Debt**	60.0%		$1,449,993	5.62%	$81,441

	Equity					
4	Common Equity	40.00%		$966,662	9.85%	$95,216
5	Preferred Shares	0.00%		$ -	0.00%	$ -
6	**Total Equity**	40.0%		$966,662	9.85%	$95,216
7	**Total**	100.0%		$2,416,654	7.31%	$176,657

**Cost of Capital Parameter Updates for 2011 Cost of Service Applications for Rates Effective May 1 2011*

2011

Application

		(%)		($)	(%)	($)
	Debt					
1	Long-term Debt	56.00%		$1,308,391	5.87%	$76,803
2	Short-term Debt	4.00%	(1)	$93,456	2.07%	$1,935
3	**Total Debt**	60.0%		$1,401,847	5.62%	$78,737
	Equity					
4	Common Equity	40.00%		$934,565	9.85%	$92,055
5	Preferred Shares	0.00%		$ -	0.00%	$ -
6	**Total Equity**	40.0%		$934,565	9.85%	$92,055
7	**Total**	100.0%		$2,336,412	7.31%	$170,792

2010

Application

		(%)		($)	(%)	($)
	Debt					
1	Long-term Debt	56.00%		$1,285,993	5.87%	$75,488
2	Short-term Debt	4.00%	(1)	$91,857	2.07%	$1,901
3	**Total Debt**	60.0%		$1,377,850	5.62%	$77,389
	Equity					
4	Common Equity	40.00%		$918,567	9.85%	$90,479
5	Preferred Shares	0.00%		$ -	0.00%	$ -
6	**Total Equity**	40.0%		$918,567	9.85%	$90,479
7	**Total**	100.0%		$2,296,417	7.31%	$167,868

Tab 2 – Cost of Debt

E5.T2.S1 OVERVIEW OF EXISTING AND NEW DEBT

CHEI does not hold any debt

E5.T2.S2 COST OF DEBT - APPENDIX 2-OB

Appendix 2-OB is none applicable is CHEI’s case

Exhibit 6 – Revenue Deficit

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EXHIBIT 6 – REVENUE DEFICIT

The evidence presented in this exhibit provides information supporting the utility’s expected deficit at existing rates for the 2014 Test year. The evidence herein is organized according to the following topics;

1) Utility Revenue at Existing Rates
2) Revenue Deficit

Tab 1 – Utility Revenue

E6.T1.S1 REVENUE FROM EXISTING RATES

The current rates are based on Board approved rates effective May 1, 2013 through an IRM proceeding (EB-2012-0117). Existing and projected revenues based on existing Board approved rates, which are used in calculating utility income, are comprised of distribution revenue and other revenues.

Details on existing and projected distribution revenue at existing rates are presented in Exhibit 3, Tab 1. Other revenue is presented in Exhibit 3, Tab 2.

E6.T1.S2 OVERVIEW OF REVENUE REQUIREMENT

A utility's revenue requirement represents the amount of money that a utility must receive from its customers to cover its costs, operating expenses, taxes, interest paid on debts owed to investors and, if applicable, a deemed return (profit).

The proposed Base Revenue Requirement, representing the revenue to be recovered from base distribution rates, is equal to the total Service Revenue Requirement, less Revenue Offsets derived from other revenue sources in 2014. Table 2 below shows the proposed revenue requirement for the 2014 test year.

Revenue Requirement Workform

Revenue Requirement

Line No.	Particulars	Application				Per Board Decision	
1	OM&A Expenses	$556,279		$556,279		$556,279	
2	Amortization/Depreciation	$132,429		$132,429		$132,429	
3	Property Taxes	$ -					
5	Income Taxes (Grossed up)	$7,943		$7,943		$7,943	
6	Other Expenses	$ -					
7	Return						
	Deemed Interest Expense	$68,890		$ -		$ -	
	Return on Deemed Equity	$103,537		$ -		$ -	
	Adjustment to Return on Rate Base associated with Deferred PP&E balance as a result of transition from CGAAP to MIFRS	$ -		$ -		$ -	
8	**Service Revenue Requirement (before Revenues)**	$869,078		$696,651		$696,651	
9	Revenue Offsets	$30,281		$ -		$ -	
10	**Base Revenue Requirement (excluding Tranformer Owership Allowance credit adjustment)**	$838,797		$696,651		$696,651	
11	Distribution revenue	$832,235		$ -		$ -	
12	Other revenue	$30,281		$ -		$ -	
13	**Total revenue**	$862,516		$ -		$ -	
14	**Difference (Total Revenue Less Distribution Revenue Requirement before Revenues)**	($6,562)	**(1)**	($696,651)	**(1)**	($696,651)	**(1)**

Notes

(1) Line 11 - Line 8

Tab 2 – Utility Deficit

E6.T2.S1 CALCULATION OF REVENUE DEFICIT

CHEI's net revenue deficiency under the proposed rates is $68,498. This deficiency is calculated as the difference between the 2014 Test Year Revenue Requirement and the Forecast 2014 Test Year Revenue Requirement at the Applcant's 2013 approved distribution rates.

The Table of Revenue Deficit presented at E6.T2.S2 shows the revenue deficiency calculations for the 2014 Test Year at Existing 2013 rates.

The drivers of the revenue deficiency are detailed in E6.T2.S3.

E6.T2.S2 TABLE OF REVENUE DEFICIT

The Revenue Deficiency sheet from the Revenue Requirement Work Form is presented at the next page.

Revenue Requirement Workform

Revenue Deficiency/Sufficiency

Line No.	Particulars	Initial Application				Per Board Decision	
		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		$68,498		($92,640)		$688,708
2	Distribution Revenue	$781,348	$763,738	$781,348	$924,875	$ -	($688,708)
3	Other Operating Revenue Offsets - net	$30,281	$30,281	$ -	$ -	$ -	$ -
4	**Total Revenue**	$811,629	$862,516	$781,348	$832,235	$ -	$ -
5	Operating Expenses	$688,708	$688,708	$688,708	$688,708	$688,708	$688,708
6	Deemed Interest Expense	$68,890	$68,890	$ -	$ -	$ -	$ -
7	Adjustment to Return on Rate Base associated with Deferred PP&E balance as a result of transition from CGAAP to MIFRS	$ - **(2)**	$ -	$ - **(2)**	$ -	$ - **(2)**	$ -
8	**Total Cost and Expenses**	$757,598	$757,598	$688,708	$688,708	$688,708	$688,708
9	**Utility Income Before Income Taxes**	$54,031	$104,918	$92,640	$143,527	($688,708)	($688,708)
10	Tax Adjustments to Accounting Income per 2013 PILs model	$ -	$ -	$ -	$ -	$ -	$ -
11	**Taxable Income**	$54,031	$104,918	$92,640	$143,527	($688,708)	($688,708)
12	Income Tax Rate	15.50%	15.50%	15.50%	15.50%	15.50%	15.50%
13	**Income Tax on Taxable Income**	$8,375	$16,262	$14,359	$22,247	($106,750)	($106,750)
14	**Income Tax Credits**	$ -	$ -	$ -	$ -	$ -	$ -
15	**Utility Net Income**	$45,656	$96,975	$78,281	($696,651)	($581,958)	($696,651)
16	**Utility Rate Base**	$2,882,427	$2,882,427	$2,882,427	$2,882,427	$2,882,427	$2,882,427
17	Deemed Equity Portion of Rate Base	$1,152,971	$1,152,971	$ -	$ -	$ -	$ -
18	Income/(Equity Portion of Rate Base)	3.96%	8.41%	0.00%	0.00%	0.00%	0.00%
19	Target Return - Equity on Rate Base	8.98%	8.98%	0.00%	0.00%	0.00%	0.00%
20	Deficiency/Sufficiency in Return on Equity	-5.02%	-0.57%	0.00%	0.00%	0.00%	0.00%
21	Indicated Rate of Return	3.97%	5.75%	2.72%	0.00%	-20.19%	0.00%
22	Requested Rate of Return on Rate Base	5.98%	5.98%	0.00%	0.00%	0.00%	0.00%
23	Deficiency/Sufficiency in Rate of Return	-2.01%	-0.23%	2.72%	0.00%	-20.19%	0.00%
24	Target Return on Equity	$103,537	$103,537	$ -	$ -	$ -	$ -
25	Revenue Deficiency/(Sufficiency)	$57,880	($6,562)	($78,281)	$ -	$581,958	$ -
26	**Gross Revenue Deficiency/(Sufficiency)**	$68,498 **(1)**		($92,640) **(1)**		$688,708 **(1)**	

Notes:

(1)	Revenue Deficiency/Sufficiency divided by (1 - Tax Rate)
(2)	Treated as an adjustment pre-tax to avoid an impact on taxes/PILs and hence on revenue sufficiency deficiency

E6.T2.S3 CAUSES OF REVENUE DEFICIT

CHEI's existing rates are based on the Board-approved rates in 2010 following a cost of service rate application, and adjustments to its base distribution rates in 2011-2013 under the Board's third Generation Incentive Regulation Mechanism.

As shown in Table of Revenue Deficit at the previous section, the Revenue Deficiency is $68K. The deficiency is due primarily to the increase in the rate base. The proposed rate base for 2014 is $457,000K higher than the 2010 Board-approved amount, an increase of 16%. Based on a 5.98% overall cost of capital, the increase in the rate base drives an increase to the revenue requirement. The factors contributing to the change in the rate base are discussed in detail at Exhibit 2 but for the most part, are due to investments in the distribution system to accommodate growth and the inclusion to smart meters into rate base.

The increased expense for Operations, Maintenance and Administration (OM&A) is another reason for the revenue deficiency. Projected OM&A for 2014 is $61,000 higher than the 2010 Board-approved amount, an increase of 12%. The cost drivers underlying this increase are presented in Exhibit 4.

Exhibit 7 – Cost Allocation

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EXHIBIT 7 – COST ALLOCATION

The evidence presented in this exhibit provides information supporting the various elements of CHE's proposed cost allocation. The evidence herein is organized according to the following topics;

1) Cost Allocation

Tab 1 – Cost Allocation

E5.T1.S1 OVERVIEW OF COST ALLOCATION

CHEI has prepared and is filling a cost allocation information filing consistent with the utility's understanding of the Directions, the Guidelines, the Model and the Instructions issued by the Board back in November of 2006 and all subsequent updates.

The main objectives of the original information filing back in 2006, was to provide information on any apparent cross-subsidization among a distributor's rate classifications and to eventually be used in future rate applications. As part of its 2010 Cost of Service Rate Application, CHEI updated the cost allocation revenue to cost ratios with 2010 base revenue requirement information. The revenue to cost ratios from the 2010 application are presented below.

Table 1: Previously Approved Ratios

	%
Residential	103.00
GS < 50 kW	0.91
GS > 50	121.00
Street Lighting	120.00
Unmetered Scattered Load (USL)	120.00

CHEI has prepared a Cost Allocation Study for 2014 based on an allocation of the 2014 test year costs (i.e., the 2014 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.

CHEI has used the updated Board-approved Cost Allocation Model and followed the instructions and guidelines issued by the Board to enter the 2014 data into this model.

CHEI populated the information on Sheet I3, Trial Balance Data with the 2014 forecasted data, Target Net Income, PILs, Deemed interest on long term debt, and the targeted Revenue Requirement and Rate Base.

On Sheet I4, Break-out of Assets, CHEI updated the allocation of the accounts based on 2014 values.

In Sheet I5.1, Miscellaneous data, CHEI updated the deemed equity component of rate base, km of roads where distribution lines exist, working capital allowance, the proportion of pole rent revenue from secondary poles, and the monthly service charges.

In Sheet I5.2, Weighting Factors, CHEI has used LDC specific factors versus the use of default factors as instructed by the Board. The utility has applied service and billing &collecting weightings for each customer classification. These weightings are based upon costs incurred servicing these particular customer class:

- Residential: weighted for services and for billing and collecting as “1” per Cost Allocation instruction sheet

- General Service less than 50 kW: weighted “1” for billing & collecting. CHEI feels that no more time, attention and costs are spent on these customers as the residential class. The weighting factor for services requires slightly more planning and monitoring for general service class than the residential class.

- The Weighted factor for the General Service greater than 50 kW also resulted in 1 for billing and collecting: These customer are billed from a file and require no more time, effort and cost than any other class. Weighting for services is “2” as the time and cost of the installations require additional planning and preparation time due to the complexity of the metering equipment. Additional time is also required to ensure the demand data is programmed and monitored appropriately.

- A Weighting factor of 1 is also used for the billing and collecting of the Streetlighting class and Unmetered Scattered Load as it requires no more time and effort to bill than the residential class. Services Weighting factors is not applicable for each of these classes.

In Sheet I6.1 Revenue has been populated with the 2014 Test year forecast data as well as existing rates.

Sheet I6.2 has been updated with the required Bad Debt and Late Payment revenue data as well as customer/connection number information devices.

CHEI updated the capital cost meter information on Sheet I7.1 and the meter reading information on I7.2 in accordance with the recent update to smart meters.

On sheet I8, Demand data is based on the output of CHEI's load forecast model.

No Direct Allocations on Sheet I9 were used.

The revenue to cost ratios calculated on Sheet O1 of the Cost Allocation model for the 2014 updated study is provided at the next page.

2014 Cost Allocation Model

Sheet O1 Revenue to Cost Summary Worksheet - Initial Submission

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	9
Rate Base Assets		**Total**	**Residential**	**GS <50**	**GS>50-Regular**	**Street Light**	**Unmetered Scattered Load**
crev	Distribution Revenue at Existing Rates	**$837,749**	$600,213	$123,921	$88,423	$14,661	$10,531
mi	Miscellaneous Revenue (mi)	**($30,281)**	($26,262)	($2,599)	($193)	($1,023)	($204)
		Miscellaneous Revenue Input Does Not Equal Output					
	Total Revenue at Existing Rates	**$807,468**	**$573,951**	**$121,322**	**$88,230**	**$13,639**	**$10,327**
	Factor required to recover deficiency (1 + D)	**1.0733**					
	Distribution Revenue at Status Quo Rates	**$899,173**	$644,221	$133,007	$94,906	$15,736	$11,303
	Miscellaneous Revenue (mi)	**($30,281)**	($26,262)	($2,599)	($193)	($1,023)	($204)
	Total Revenue at Status Quo Rates	**$868,892**	**$617,958**	**$130,408**	**$94,714**	**$14,714**	**$11,099**
	Expenses						
di	Distribution Costs (di)	**$53,200**	$39,213	$7,514	$4,430	$1,927	$116
cu	Customer Related Costs (cu)	**$178,174**	$161,273	$13,369	$936	$1,048	$1,549
ad	General and Administration (ad)	**$324,905**	$281,241	$29,489	$7,599	$4,254	$2,322
dep	Depreciation and Amortization (dep)	**$132,428**	$102,407	$19,602	$5,269	$4,873	$277
INPUT	PILs (INPUT)	**$7,944**	$6,114	$1,157	$356	$299	$17
INT	Interest	**$68,890**	$53,024	$10,034	$3,090	$2,592	$149
	Total Expenses	**$765,541**	**$643,274**	**$81,165**	**$21,680**	**$14,992**	**$4,430**
	Direct Allocation	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**
NI	Allocated Net Income (NI)	**$103,537**	$79,692	$15,081	$4,644	$3,895	$224
	Revenue Requirement (includes NI)	**$868,892**	$722,823	$96,219	$26,316	$18,880	$4,654
		Revenue Requirement Input Does Not Equal Output					
	Rate Base Calculation						
	Net Assets						
dp	Distribution Plant - Gross	**$4,155,640**	$3,202,147	$599,230	$176,844	$167,821	$9,597
gp	General Plant - Gross	**$218,673**	$168,356	$31,748	$9,649	$8,436	$485
accum dep	Accumulated Depreciation	**($1,559,384)**	($1,203,294)	($222,291)	($62,288)	($67,666)	($3,845)
co	Capital Contribution	**($442,246)**	($340,954)	($63,101)	($17,794)	($19,300)	($1,097)
	Total Net Plant	**$2,372,683**	**$1,826,255**	**$345,586**	**$106,410**	**$89,291**	**$5,140**
	Directly Allocated Net Fixed Assets	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**
COP	Cost of Power (COP)	**$3,364,829**	$2,319,110	$539,141	$456,033	$40,793	$9,752
	OM&A Expenses	**$556,279**	$481,727	$50,371	$12,965	$7,228	$3,987
	Directly Allocated Expenses	**$0**	$0	$0	$0	$0	$0
	Subtotal	***$3,921,108***	***$2,800,837***	***$589,512***	***$468,998***	***$48,022***	***$13,739***
	Working Capital	**$509,744**	**$364,109**	**$76,637**	**$60,970**	**$6,243**	**$1,786**
	Total Rate Base	**$2,882,427**	**$2,190,364**	**$422,223**	**$167,380**	**$95,534**	**$6,926**
		Rate Base Input equals Output					
	Equity Component of Rate Base	**$1,152,971**	**$876,146**	**$168,889**	**$66,952**	**$38,213**	**$2,771**
	Net Income on Allocated Assets	**$103,351**	**($25,315)**	**$49,243**	**$73,034**	**($278)**	**$6,669**
	Net Income on Direct Allocation Assets	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**
	Net Income	**$103,351**	**($25,315)**	**$49,243**	**$73,034**	**($278)**	**$6,669**
	RATIOS ANALYSIS						
	REVENUE TO EXPENSES STATUS QUO%	**100.00%**	**85.49%**	**135.53%**	**359.91%**	**77.93%**	**238.47%**
	EXISTING REVENUE MINUS ALLOCATED COSTS	**($61,424)**	($148,872)	$25,103	$61,914	($5,241)	$5,672
		Deficiency Input Does Not Equal Output					
	STATUS QUO REVENUE MINUS ALLOCATED COSTS	**$0**	($104,865)	$34,189	$68,398	($4,166)	$6,445
	RETURN ON EQUITY COMPONENT OF RATE BASE	8.96%	-2.89%	29.16%	109.08%	-0.73%	240.71%

2014 Cost Allocation Model

Sheet O2 Monthly Fixed Charge Min. & Max. Worksheet - Initial Submission

Output sheet showing minimum and maximum level for Monthly Fixed Charge

	1	2	3	7	9
Summary	**Residential**	**GS <50**	**GS>50-Regular**	**Street Light**	**Unmetered Scattered Load**
Customer Unit Cost per month - Avoided Cost	$8.27	$10.99	$21.42	$0.22	$6.58
Customer Unit Cost per month - Directly Related	$17.49	$20.58	$32.24	$0.51	$15.58
Customer Unit Cost per month - Minimum System with PLCC Adjustment	$20.30	$23.47	$36.20	$3.70	$16.45
Existing Approved Fixed Charge	$13.70	$20.34	$245.27	$1.60	$40.01

Per the Filing Requirements for Transmission and Distribution Applications dated June 22, 2011, CHEI has completed OEB Appendix 2-P with the results of the 2014 cost allocation study and proposed adjustments. The Allocated cost table (2), calculated class revenues (2) and Rebalancing Revenue-to-Cost (R/C) Ratios (3) are summarized at the next few pages.

Table 2: Allocated Costs

Classes	**Costs Allocated from Previous Study**	**%**	**Costs Allocated in Test Year Study (Column 7A)**	**%**
Residential	$ 557,055	67.51%	$ 722,823	83.19%
GS < 50 kW	$ 140,228	16.99%	$ 96,219	11.07%
GS > 50 kW	$ 78,850	9.56%	$ 26,316	3.03%
GS > xxx kW, if applicable		0.00%		0.00%
Large User, if applicable		0.00%		0.00%
Street Lighting	$ 25,794	3.13%	$ 18,880	2.17%
Sentinel Lighting		0.00%		0.00%
Unmetered Scattered Load (USL)	$ 23,212	2.81%	$ 4,654	0.54%
Other class, if applicable		0.00%		0.00%
		0.00%		0.00%
Embedded distributor class		0.00%		0.00%
Total	$ 825,139	100.00%	$ 868,892	100.00%

Table 3: Class Revenues

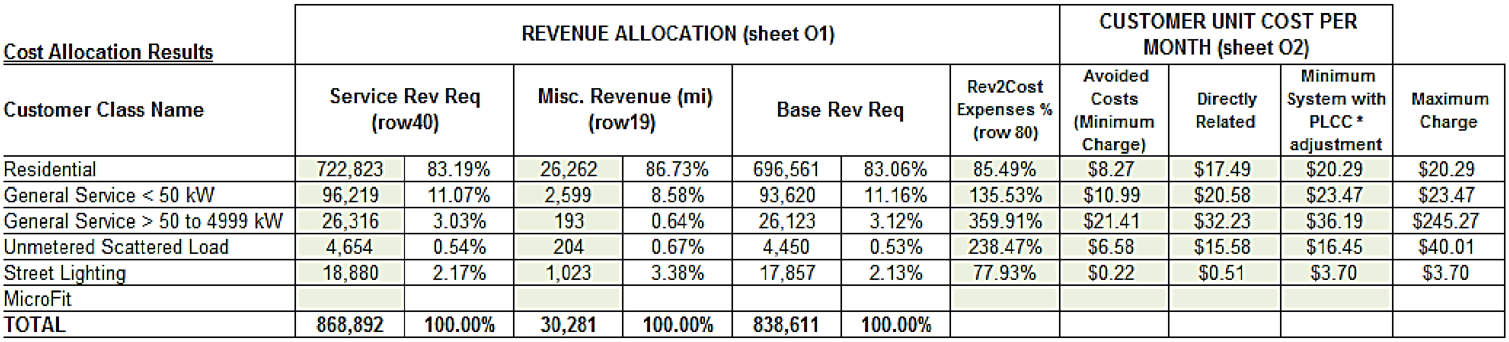
Classes (same as previous table)	Column 7B Load Forecast (LF) X current approved rates	Column 7C L.F. X current approved rates X (1 + d)	Column 7D LF X proposed rates	Column 7E Miscellaneous Revenue
Residential	$601,066.66	$600,826.18	$671,725.80	$26,262.00
GS < 50 kW	$124,181.57	$124,131.89	$112,420.64	$2,599.00
GS > 50 kW)	$88,600.19	$88,564.75	$31,393.19	$193.00
GS > xxx kW, if applicable				
Large User, if applicable				
Street Lighting	$14,681.01	$14,675.14	$17,880.49	$1,023.00
Sentinel Lighting				$204.00
Unmetered Scattered Load (USL)	$10,533.76	$10,529.55	$5,377.76	
Other class, if applicable				
Embedded distributor class				
Total	$839,063.19	$838,727.50	$838,797.87	$30,281.00

Table 4: Rebalancing Revenue to Cost Ratios

Class	Previously Approved Ratios	Status Quo Ratios	Proposed Ratios	Policy Range
	Most Recent Year: 20XX	(7C + 7E) / (7A)	(7D + 7E) / (7A)	
	%	%	%	%
Residential	103.00	86.76	96.56	85 - 115
GS < 50 kW	0.91	131.71	119.54	80 - 120
GS > 50	121.00	337.28	120.03	80 - 120
GS > xxx kW, if applicable				80 - 120
Large User, if applicable				85 - 115
Street Lighting	120.00	83.15	100.12	70 - 120
Sentinel Lighting				80 - 120
Unmetered Scattered Load (USL)	120.00	226.25	115.55	80 - 120
Other class, if applicable				
Embedded distributor class				▨

Table 5 below provides a breakdown of the proposed revenue allocation based on the results of the updated Cost Allocation Study (Sheet O2). The first column shows the allocated costs from the proposed service revenue requirement while the second column shows the per class allocation of the proposed service revenue requirement. The third and fourth column show the breakdown of the revenue offsets as calculated in the cost allocation model. Columns 7-8-9-10 show the results of the cost allocation model and the last column calculates the maximum charge per class.

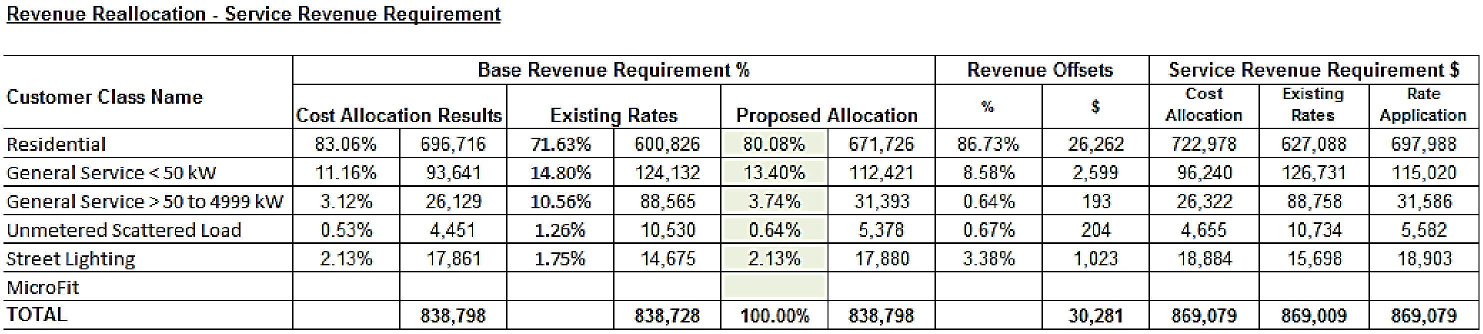
Table 5: Cost Allocation Results



Cost Allocation Results

Customer Class Name	REVENUE ALLOCATION (sheet O1)							CUSTOMER UNIT COST PER MONTH (sheet O2)			
	Service Rev Req (row40)		Misc. Revenue (mi) (row19)		Base Rev Req		Rev2Cost Expenses % (row 80)	Avoided Costs (Minimum Charge)	Directly Related	Minimum System with PLCC * adjustment	Maximum Charge
Residential	722,823	83.19%	26,262	86.73%	696,561	83.06%	85.49%	$8.27	$17.49	$20.29	$20.29
General Service < 50 kW	96,219	11.07%	2,599	8.58%	93,620	11.16%	135.53%	$10.99	$20.58	$23.47	$23.47
General Service > 50 to 4999 kW	26,316	3.03%	193	0.64%	26,123	3.12%	359.91%	$21.41	$32.23	$36.19	$245.27
Unmetered Scattered Load	4,654	0.54%	204	0.67%	4,450	0.53%	238.47%	$6.58	$15.58	$16.45	$40.01
Street Lighting	18,880	2.17%	1,023	3.38%	17,857	2.13%	77.93%	$0.22	$0.51	$3.70	$3.70
MicroFit											
TOTAL	**868,892**	**100.00%**	**30,281**	**100.00%**	**838,611**	**100.00%**					

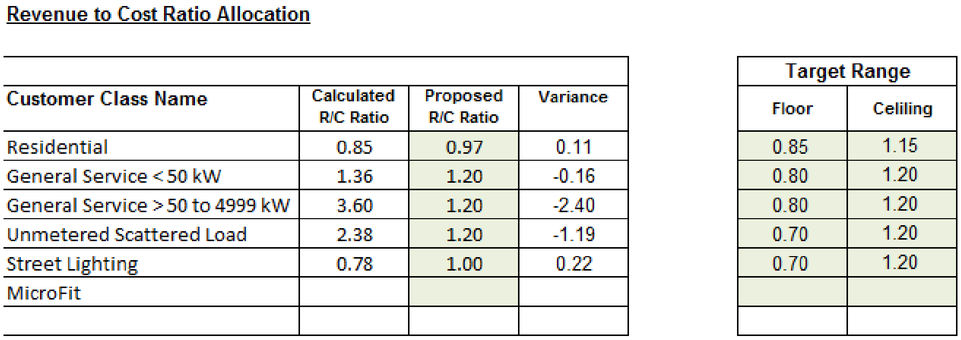
Table 6: Cost Allocation of Revenue Requirement



Revenue Reallocation - Service Revenue Requirement

Customer Class Name	Base Revenue Requirement %						Revenue Offsets		Service Revenue Requirement $		
	Cost Allocation Results		Existing Rates		Proposed Allocation		%	$	Cost Allocation	Existing Rates	Rate Application
Residential	83.06%	696,716	71.63%	600,826	80.08%	671,726	86.73%	26,262	722,978	627,088	697,988
General Service < 50 kW	11.16%	93,641	14.80%	124,132	13.40%	112,421	8.58%	2,599	96,240	126,731	115,020
General Service > 50 to 4999 kW	3.12%	26,129	10.56%	88,565	3.74%	31,393	0.64%	193	26,322	88,758	31,586
Unmetered Scattered Load	0.53%	4,451	1.26%	10,530	0.64%	5,378	0.67%	204	4,655	10,734	5,582
Street Lighting	2.13%	17,861	1.75%	14,675	2.13%	17,880	3.38%	1,023	18,884	15,698	18,903
MicroFit											
TOTAL		**838,798**		**838,728**	**100.00%**	**838,798**		**30,281**	**869,079**	**869,009**	**869,079**

Table 7: Revenue to Cost Ratios



Revenue to Cost Ratio Allocation

Customer Class Name	Calculated R/C Ratio	Proposed R/C Ratio	Variance
Residential	0.85	0.97	0.11
General Service < 50 kW	1.36	1.20	-0.16
General Service > 50 to 4999 kW	3.60	1.20	-2.40
Unmetered Scattered Load	2.38	1.20	-1.19
Street Lighting	0.78	1.00	0.22
MicroFit			

Target Range	
Floor	Ceiling
0.85	1.15
0.80	1.20
0.80	1.20
0.70	1.20
0.70	1.20

The reason for the significant difference in the calculated ratios and proposed ratios is due to the utility specific weighting factors. The default factors used in the previous cost allocation did not accurately reflect the actual billing, collecting and services at CHEI. How the proposed revenues to cost ratios are used to determine rates is discussed in detail at Exhibit 8.

2014 Cost Allocation Model

Sheet I4 Break Out Worksheet - Initial Submission

Instructions:
This is an input sheet for the Break Out of Distribution Assets, Contributed Capital, Amortization, and Amortization Expenses.
*****Please see Instructions tab for detailed instructions*****

Enter Net Fixed Assets from the Revenue Requirement Work Form, Rate Base sheet, cell G15	**$2,372,684**

RATE BASE AND DISTRIBUTION ASSETS		BALANCE SHEET ITEMS									EXPENSE ITEMS			
											5705	5710	5715	5720
Account	Description	Break out Functions	BREAK OUT (%)	BREAK OUT ($)	After BO	Contributed Capital - 1995	Accumulated Depreciation - 2105 Capital Contribution	Accumulated Depreciation - 2105 Fixed Assets Only	Accumulated Depreciation - 2120	Asset net of Accumulated Depreciation and Contributed Capital	Amortization Expense - Property, Plant, and Equipment	Amortization of Limited Term Electric Plant	Amortization of Intangibles and Other Electric Plant	Amortization of Electric Plant Acquisition Adjustments
1565	Conservation and Demand Management	$0		-	-					-				
1805	Land	$50,000		($50,000)	-									
1805-1	Land Station >50 kV			$0	-					-				
1805-2	Land Station <50 kV		100.00%	$50,000	50,000					50,000				
1806	Land Rights	$0		$0	-									
1806-1	Land Rights Station >50 kV			$0	-					-				
1806-2	Land Rights Station <50 kV		100.00%	$0	-					-				
1808	Buildings and Fixtures	$0		$0	-									
1808-1	Buildings and Fixtures > 50 kV			$0	-					-				
1808-2	Buildings and Fixtures < 50 KV		100.00%	$0	-					-				
1810	Leasehold Improvements	$0		$0	-									
1810-1	Leasehold Improvements >50 kV			$0	-					-				
1810-2	Leasehold Improvements <50 kV		100.00%	$0	-					-				
1815	Transformer Station Equipment - Normally Primary above 50 kV	$0		$0	-					-				
1820	Distribution Station Equipment - Normally Primary below 50 kV	$284,888		($284,888)	-					-				
1820-1	Distribution Station Equipment - Normally Primary below 50 kV (Bulk)			$0	-					-				
1820-2	Distribution Station Equipment - Normally Primary below 50 kV Primary)		100.00%	$284,888	284,888	($25,297)	$0	$ (88,644)		170,947	$5,180			
1820-3	Distribution Station Equipment - Normally Primary below 50 kV (Wholesale Meters)		0.00%	$0	-					-				
1825	Storage Battery Equipment	$0		$0	-									
1825-1	Storage Battery Equipment > 50 kV			$0	-					-				
1825-2	Storage Battery Equipment <50 kV		100.00%	$0	-					-				
1830	Poles, Towers and Fixtures	$677,494		($677,494)	-									
1830-3	Poles, Towers and Fixtures - Subtransmission Bulk Delivery			$0	-					-				
1830-4	Poles, Towers and Fixtures - Primary		0.00%	$0	-			$ -		-				
1830-5	Poles, Towers and Fixtures - Secondary		100.00%	$677,494	677,494	($66,352)	$0	$ (232,503)		378,639	$16,937			
1835	Overhead Conductors and Devices	$615,424		($615,424)	-									
1835-3	Overhead Conductors and Devices - Subtransmission Bulk Delivery			$0	-					-				
1835-4	Overhead Conductors and Devices - Primary		0.00%	$0	-			$ -		-				
1835-5	Overhead Conductors and Devices - Secondary		100.00%	$615,424	615,424	($69,148)	$0	$ (242,301)		303,975	$10,257			
1840	Underground Conduit	$0		$0	-									
1840-3	Underground Conduit - Bulk Delivery			$0	-					-				
1840-4	Underground Conduit - Primary			$0	-			$ -		-				
1840-5	Underground Conduit - Secondary		100.00%	$0	-					-				
1845	Underground Conductors and Devices	$1,209,387		($1,209,387)	-									
1845-3	Underground Conductors and Devices - Bulk Delivery			$0	-					-				
1845-4	Underground Conductors and Devices - Primary			$0	-			$ -		-				
1845-5	Underground Conductors and Devices - Secondary		100.00%	$1,209,387	1,209,387	($129,392)		$ (453,403)		626,592	$34,554			
1850	Line Transformers	$802,773		$0	802,773	($84,758)		$ (297,001)		421,013	$20,069			
1855	Services	$190,212		$0	190,212	($13,153)		$ (60,544)		116,514	$4,755			
1860	Meters	$325,462		$0	325,462	($12,384)		$ (37,734)		275,344	$21,697			
9999	IFRS Placeholder Account	$0		$0	-					-				
	Total	**$4,155,640**		**$0**	**$4,155,640**	**($400,485)**	**$0**	**($1,412,131)**	**$0**	**2,343,024**	**$113,449**	**$0**	**$0**	**$0**
	SUB TOTAL from I3	**$4,155,640**												

5705	5710	5715	5720

2014 Cost Allocation Model

Sheet I4 Break Out Worksheet - Initial Submission

Instructions:
This is an input sheet for the Break Out of Distribution Assets, Contributed Capital, Amortization, and Amortization Expenses.
*****Please see Instructions tab for detailed instructions*****

Enter Net Fixed Assets from the Revenue Requirement Work Form, Rate Base sheet, cell G15	$2,372,684

RATE BASE AND DISTRIBUTION ASSETS		BALANCE SHEET ITEMS									EXPENSE ITEMS			
											5705	5710	5715	5720
Account	Description	Break out Functions	BREAK OUT (%)	BREAK OUT ($)	After BO	Contributed Capital - 1995	Accumulated Depreciation - 2105 Capital Contribution	Accumulated Depreciation - 2105 Fixed Assets Only	Accumulated Depreciation - 2120	Asset net of Accumulated Depreciation and Contributed Capital	Amortization Expense - Property, Plant, and Equipment	Amortization of Limited Term Electric Plant	Amortization of Intangibles and Other Electric Plant	Amortization of Electric Plant Acquisition Adjustments
General Plant		Break out Functions				Contributed Capital - 1995	Accumulated Depreciation - 2105 Capital Contribution	Accumulated Depreciation - 2105 Fixed Assets Only	Accumulated Depreciation - 2120	Net Asset	Amortization Expense - Property, Plant, and Equipment	Amortization of Limited Term Electric Plant	Amortization of Intangibles and Other Electric Plant	Amortization of Electric Plant Acquisition Adjustments
1905	Land	$0			-					$ -				
1906	Land Rights	$0			-					$ -				
1908	Buildings and Fixtures	$0			-					$ -				
1910	Leasehold Improvements	$0			-					$ -				
1915	Office Furniture and Equipment	$50,903			50,903	($9,353)		$ (32,978)		$ 8,572	$4,331			
1920	Computer Equipment - Hardware	$26,037			26,037	($6,139)		$ (21,646)		-$ 1,748	$1,929			
1925	Computer Software	$128,927			128,927	($23,678)		$ (83,491)		$ 21,758	$22,013			
1930	Transportation Equipment	$0			-					$ -	$0			
1935	Stores Equipment	$4,320			4,320	($1,161)		$ (4,094)		-$ 935	$151			
1940	Tools, Shop and Garage Equipment	$4,205			4,205	($239)		$ (841)		$ 3,125	$421			
1945	Measurement and Testing Equipment	$4,281			4,281	($1,192)		$ (4,202)		-$ 1,113	$158			
1950	Power Operated Equipment	$0			-					$ -				
1955	Communication Equipment	$0			-					$ -				
1960	Miscellaneous Equipment	$0			-					$ -				
1970	Load Management Controls - Customer Premises	$0			-					$ -				
1975	Load Management Controls - Utility Premises	$0			-					$ -				
1980	System Supervisory Equipment	$0			-					$ -				
1990	Other Tangible Property	$0			-					$ -	($10,024)			
2005	Property Under Capital Leases	$0			-					$ -				
2010	Electric Plant Purchased or Sold	$0			-					$ -				
	Total	$218,673		$0	$218,673	($41,761)	$0	($147,253)	$0	$29,659	$18,979	$0	$0	$0
	SUB TOTAL from I3	$218,673												
	I3 Directly Allocated	$0												
	Grand Total	$4,374,313		$0	$4,374,313	($442,246)	$0	($1,559,384)	$0	$2,372,683	$132,428	$0	$0	$0

2014 Cost Allocation Model

Sheet I4 Break Out Worksheet - Initial Submission

Instructions:
This is an input sheet for the Break Out of Distribution Assets, Contributed Capital, Amortization, and Amortization Expenses.
*****Please see Instructions tab for detailed instructions*****

Enter Net Fixed Assets from the Revenue Requirement Work Form, Rate Base sheet, cell G15	**$2,372,684**

RATE BASE AND DISTRIBUTION ASSETS		**BALANCE SHEET ITEMS**									**EXPENSE ITEMS**				
											5705	**5710**	**5715**	**5720**	
Account	**Description**	**Break out Functions**	**BREAK OUT (%)**	**BREAK OUT ($)**	**After BO**	**Contributed Capital - 1995**	**Accumulated Depreciation - 2105 Capital Contribution**	**Accumulated Depreciation - 2105 Fixed Assets Only**	**Accumulated Depreciation - 2120**	**Asset net of Accumulated Depreciation and Contributed Capital**	**Amortization Expense - Property, Plant, and Equipment**	**Amortization of Limited Term Electric Plant**	**Amortization of Intangibles and Other Electric Plant**	**Amortization of Electric Plant Acquisition Adjustments**	
To be Prorated															
1995	Contributed Capital - 1995	($442,246)				$442,246	**Balanced**								
2105	Accumulated Depreciation - 2105	($1,559,383)						$1,559,384	**Balanced**						
2120	Accumulated Depreciation - 2120	$0							$0	**Balanced**					
	Total	**($2,001,629)**													
	Net Assets	**$2,372,684**	**Net Fixed Assets Match**												
Amortization Expenses															
5705	Amortization Expense - Property, Plant, and Equipment	$132,429									($132,428)	**Balanced**			
5710	Amortization of Limited Term Electric Plant	$0										$0	**Balanced**		
5715	Amortization of Intangibles and Other Electric Plant	$0											$0	**Balanced**	
5720	Amortization of Electric Plant Acquisition Adjustments	$0												$0	**Balanced**
	Total Amortization Expense	**$132,429**													

2014 Cost Allocation Model

Sheet I6.1 Revenue Worksheet - Initial Submission

Total kWhs from Load Forecast	30,802,669
Total kWs from Load Forecast	13,331
Deficiency from RRWF	144,681
Miscellaneous Revenue	30,281

			1	2	3	7	9
	ID	**Total**	**Residential**	**GS <50**	**GS>50-Regular**	**Street Light**	**Unmetered Scattered Load**
Billing Data							
Forecast kWh	**CEN**	30,802,669	21,229,835	4,935,457	4,174,667	373,436	89,274
Forecast kW	**CDEM**	13,331			12,333	998	
Forecast kW, included in CDEM, of customers receiving line transformer allowance		-					
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**	30,802,669	21,229,835	4,935,457	4,174,667	373,436	89,274
kWh - 30 year weather normalized amount		30,802,669	21,229,835	4,935,457	4,174,667	373,436	89,274
Existing Monthly Charge			$13.70	$20.34	$245.27	$1.60	$40.01
Existing Distribution kWh Rate			$0.0128	$0.0168			$0.0104
Existing Distribution kW Rate					$4.5445	$6.5145	
Existing TFOA Rate			$0.60	$0.60	$0.60	$0.60	$0.60
Additional Charges							
Distribution Revenue from Rates		$837,749	$600,213	$123,921	$88,423	$14,661	$10,531
Transformer Ownership Allowance		$0	$0	$0	$0	$0	$0
Net Class Revenue	**CREV**	$837,749	$600,213	$123,921	$88,423	$14,661	$10,531
Data Mismatch Analysis							
Revenue with 30 year weather normalized kWh		837,749	600,213	123,921	88,423	14,661	10,531

Weather Normalized Data from Hydro One

	Total	**Residential**	**GS <50**	**GS>50-Regular**	**Street Light**	**Unmetered Scattered Load**
kWh - 30 year weather normalized amount	32,844,886	22,637,373	5,262,678	4,451,447	398,195	95,193
Loss Factor		**1.0663**	**1.0663**	**1.0663**	**1.0663**	**1.0663**

2014 Cost Allocation Model

Sheet I8 Demand Data Worksheet - Initial Submission

This is an input sheet for demand allocators.

CP TEST RESULTS	4 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

			1	2	3	7	9
Customer Classes		Total	Residential	GS <50	GS>50-Regular	Street Light	Unmetered Scattered Load
CO-INCIDENT PEAK							
1 CP							
Transformation CP	TCP1	7,103	5,145	794	1,060	94	10
Bulk Delivery CP	BCP1	7,103	5,145	794	1,060	94	10
Total Sytem CP	DCP1	7,103	5,145	794	1,060	94	10
4 CP							
Transformation CP	TCP4	26,287	18,316	3,390	4,224	315	42
Bulk Delivery CP	BCP4	26,287	18,316	3,390	4,224	315	42
Total Sytem CP	DCP4	26,287	18,316	3,390	4,224	315	42
12 CP							
Transformation CP	TCP12	64,956	45,979	8,760	9,373	715	129
Bulk Delivery CP	BCP12	64,956	45,979	8,760	9,373	715	129
Total Sytem CP	DCP12	64,956	45,979	8,760	9,373	715	129
NON CO_INCIDENT PEAK							
1 NCP							
Classification NCP from Load Data Provider	DNCP1	7,896	5,497	1,060	1,209	118	12
Primary NCP	PNCP1	7,896	5,497	1,060	1,209	118	12
Line Transformer NCP	LTNCP1	7,896	5,497	1,060	1,209	118	12
Secondary NCP	SNCP1	6,687	5,497	1,060		118	12
4 NCP							
Classification NCP from Load Data Provider	DNCP4	29,020	19,904	4,016	4,655	399	46
Primary NCP	PNCP4	29,020	19,904	4,016	4,655	399	46
Line Transformer NCP	LTNCP4	29,020	19,904	4,016	4,655	399	46
Secondary NCP	SNCP4	24,365	19,904	4,016		399	46
12 NCP							
Classification NCP from Load Data Provider	DNCP12	70,511	47,874	10,681	10,726	1,101	129
Primary NCP	PNCP12	70,511	47,874	10,681	10,726	1,101	129
Line Transformer NCP	LTNCP12	70,511	47,874	10,681	10,726	1,101	129
Secondary NCP	SNCP12	59,785	47,874	10,681		1,101	129

Exhibit 8 – Rate Design

TABLE OF CONTENTS

EXHIBIT 8 – RATE DESIGN

The evidence presented in this exhibit provides information supporting the utility's development of electricity prices for various customer classes to meet revenue requirements dictated by operating needs and costs. The evidence herein is organized according to the following topics;

1) Fixed/Variable Proportions
2) Retail Transmission Service Rates
3) Retail Service Charges
4) Wholesale Market Service Charges
5) Specific Service Charges
6) Low voltage Charges
7) Loss Adjustment Factor
8) Rate Schedule
9) Bill Impacts

Tab 1 – Fixed Variable Proportion

E8.T1.S1 OVERVIEW OF EXISTING RATES

The existing rate schedule is presented at E8.T1.S2. The current rates were approved as part of the proceeding EB-2012-0117. CHEI applied for distribution rate adjustments pursuant to the IRM process. Notice of CHEI's rate application was given through newspaper publication in CHEI's service area, and advising how interested parties may intervene in the proceeding or comment on the application. No intervention requests or comments were received.

The Board found that CHEI's rate application was filed in compliance with Chapter 3 of the Board's Filing Requirements for Transmission and Distribution Applications (the "Filing Requirements"), which outlines the application filing requirements for IRM applications based on the policies in the Reports.

The following matters were addressed in the decision.

- Rates were adjusted by a price escalator less a productivity factor. The Board established the price escalator to be 1.60% with a stretch factor of 0.4%.
- On March 28, 2013, the Board 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 for those distributors identified in the Board's annual Yearbook of Electricity Distributors.

The following matters were addressed in the decision.

- Rate Riders and Rate Adders;
- Low Voltage Service Charges;
- Retail Transmission Service Rates;
- Wholesale Market Service Rate;
- Rural or Remote Rate Protection Charge;
- Standard Supply Service – Administrative Charge;
- Transformation and Primary Metering Allowances;
- Loss Factors;

CHEI's rates were approved by the Board and rendered effective May 1, 2013

Table 1 below summarizes these revenue projections, showing the proportions attributable to fixed (monthly service) charges and variable (distribution volumetric) charges. Table 2 which follows the Revenues from Existing Fixed and Variable Charges shows the current customer classes. CHEI is not proposing any changes to its customer class at this time.

Table 1: Revenues from Existing Fixed and Variable Charges

Bridge Year

	Bridge Year Projected Revenue from Existing Variable Charges							
Customer Class Name	**Variable Distribution Rate**	**per**	**Bridge Year Volume**	**Gross Variable Revenue**	**Transform. Allowance Rate**	**Transform. Allowance kW's**	**Transform. Allowance $'s**	**Net Variable Revenue**
Residential	$0.0128	kWh	19,627,850	251,236			0	251,236
General Service < 50 kW	$0.0017	kWh	4,804,973	8,072			0	8,072
General Service > 50 to 4999 kW	$4.5445	kW	12,607	57,293	($0.60)		0	57,293
Unmetered Scattered Load	$0.0104	kWh	91,612	953			0	953
Street Lighting	$6.5145	kW	1,000	6,515	($0.60)		0	6,515
MicroFit	$5.4000	Monthly	6	32			0	32
Total Variable Revenue			**24,538,047**	**324,101**		**0**	**0**	**324,101**

Bridge Year

	Bridge Year Projected Revenue from Existing Fixed Charges							
Customer Class Name	**Fixed Rate**	**Customers (Connections)**	**Fixed Charge Revenue**	**Variable Revenue**	**TOTAL**	**% Fixed Revenue**	**% Variable Revenue**	**% Total Revenue**
Residential	$13.7000	1,798	295,591	251,236	546,828	54.06%	45.94%	77.16%
General Service < 50 kW	$20.3400	160	39,053	8,072	47,125	82.87%	17.13%	6.65%
General Service > 50 to 4999 kW	$245.2700	11	32,376	57,293	89,668	36.11%	63.89%	12.65%
Unmetered Scattered Load	$40.0100	20	9,602	953	10,555	90.97%	9.03%	1.49%
Street Lighting	$1.6000	415	7,968	6,515	14,483	55.02%	44.98%	2.04%
MicroFit	$5.4000	0	6	32	38	0.00%	0.00%	0.01%
Total Fixed Revenue		**2,404**	**384,596**	**324,101**	**708,697**			

Table 2: Revenues from Existing Fixed and Variable Charges

Customer Class Name	Existing	Proposed	Status	MSC Metric	Usage Metric	USA #
Residential	YES	YES	Continued	Customer	kWh	
General Service < 50 kW	YES	YES	Continued	Customer	kWh	
General Service > 50 to 4999 kW	YES	YES	Continued	Customer	kW	
Unmetered Scattered Load	YES	YES	Continued	Connection	kWh	
Street Lighting	YES	YES	Continued	Connection	kW	
MicroFit	YES	YES	Continued	Customer	Monthly	

E8.T1.S2 CURRENT RATE SCHEDULE

The current rates is presented at the next page

Precedent: CustomerClass

File Number: EB-20130122
Exhibit:
Tab:
Schedule:
Page:

Date:

TESI-2
Current Tariff Sheet

Loss Factor	
Total Loss Factor – Secondary Metered Customer < 5,000 kW	1.0788
Total Loss Factor – Secondary Metered Customer > 5,000 kW	
Total Loss Factor – Primary Metered Customer < 5,000 kW	1.0680
Total Loss Factor – Primary Metered Customer > 5,000 KW	

Residential	Effective Until mm/dd/yy	rate	Connection Type
Service Charge		13.70	$
Distribution Volumetric Rate		0.0128	kWh
Rate Rider for Recovery of Smart Meter Incremental Revenue Requirement – in effect until the effective date of the next cost of service application		1.44	$
Rate Rider For Smart Metering Entity Charge - effective until October 31, 2018		0.79	$
Low Voltage Service Rate		0.0014	kWh
Rate Rider for Disposition of Deferral/Variance Account (2012) – effective until April 30, 2014		-0.0021	kWh
Rate Rider for Disposition of Global Adjustment Sub-Account (2012) – effective until April 30, 2014 Applicable only for Non-RPP Customers		0.0014	kWh
Rate Rider for Recovery of Lost Revenue Adjustment Mechanism (LRAM) – effective until April 30, 2014		0.0004	kWh
Rate Rider for Disposition of Deferred PILs Variance Account 1562 - effective until April 30, 2015		-0.008	kWh
Retail Transmission Rate – Network Service Rate		0.0069	kWh
Retail Transmission Rate – Line and Transformation Connection Service Rate		0.0052	kWh
Wholesale Market Service Rate		0.0044	kWh
Rural Rate Protection Charge		0.0012	kWh
Standard Supply Service – Administrative Charge (if applicable)		0.25	$

General Service < 50 kW	Effective Until mm/dd/yy	rate	Connection Type
Service Charge		20.34	$
Distribution Volumetric Rate		0.0168	kWh
Rate Rider for Recovery of Smart Meter Incremental Revenue Requirement – in effect until the effective date of the next cost of service application		4.20	$
Rate Rider For Smart Metering Entity Charge - effective until October 31, 2018		0.79	$
Low Voltage Service Rate		0.0013	kWh
Rate Rider for Disposition of Deferral/Variance Account (2012) – effective until April 30, 2014		-0.0021	kWh
Rate Rider for Disposition of Global Adjustment Sub-Account (2012) – effective until April 30, 2014 Applicable only for Non-RPP Customers		0.0014	kWh
Rate Rider for Disposition of Deferred PILs Variance Account 1562 - effective until April 30, 2015		-0.0008	kWh
Retail Transmission Rate – Network Service Rate		0.0064	kWh
Retail Transmission Rate – Line and Transformation Connection Service Rate		0.0046	kWh
Wholesale Market Service Rate		0.0044	kWh
Rural Rate Protection Charge		0.0012	kWh
Standard Supply Service – Administrative Charge (if applicable)		0.25	$

General Service > 50 to 4999 kW	Effective Until mm/dd/yy	rate	Connection Type
Service Charge		245.27	$
Distribution Volumetric Rate		4.5445	kW
Rate Rider for Recovery of Smart Meter Incremental Revenue Requirement – in effect until the effective date of the next cost of service application		14.30	kW
Low Voltage Service Rate		0.4778	kW
Rate Rider for Disposition of Deferral/Variance Account (2012) – effective until April 30, 2014		-0.7109	kW
Rate Rider for Disposition of Global Adjustment Sub-Account (2012) – effective until April 30, 2014 Applicable only for Non-RPP Customers		0.4834	kW
Rate Rider for Disposition of Deferred PILs Variance Account 1562 - effective until April 30, 2014		-0.2605	kW
Rate Rider for Recovery of Lost Revenue Adjustment Mechanism (LRAM) – effective until April 30, 2014		0.0284	kW

Retail Transmission Rate – Network Service Rate		**2.5726**	**kW**
Retail Transmission Rate – Line and Transformation Connection Service Rate		**1.8286**	**kW**
Wholesale Market Service Rate		**0.0044**	**kWh**
Rural Rate Protection Charge		**0.0012**	**kWh**
Standard Supply Service – Administrative Charge (if applicable)			**$**

Unmetered Scattered Load	**Effective Until mm/dd/yy**	**rate**	**Connection Type**
Service Charge		**40.01**	**$**
Distribution Volumetric Rate		**0.0104**	**kWh**
Low Voltage Service Rate		**0.0013**	**kWh**
Rate Rider for Disposition of Deferral/Variance Account (2012) – effective until April 30, 2014		**-0.0021**	**kWh**
Rate Rider for Disposition of Global Adjustment Sub-Account (2012) – effective until April 30, 2014 Applicable only for Non-RPP Customers		**0.0014**	**kWh**
Rate Rider for Disposition of Deferred PILs Variance Account 1562 - effective until April 30, 2014		**-0.0051**	**kWh**
Retail Transmission Rate – Network Service Rate		**0.0064**	**kWh**
Retail Transmission Rate – Line and Transformation Connection Service Rate		**0.0046**	**kWh**
Wholesale Market Service Rate		**0.0044**	**kWh**
Rural Rate Protection Charge		**0.0012**	**kWh**
Standard Supply Service – Administrative Charge (if applicable)		**0.25**	**$**

Street Lighting	**Effective Until mm/dd/yy**	**rate**	**Connection Type**
Service Charge		**1.6**	**$**
Distribution Volumetric Rate		**6.5145**	**kW**
Low Voltage Service Rate		**0.3694**	**kW**
Rate Rider for Disposition of Deferral/Variance Account (2012) – effective until April 30, 2014		**-0.7349**	**kW**
Rate Rider for Disposition of Deferred PILs Variance Account 1562 - effective until April 30, 2014		**-0.5708**	**kW**
Retail Transmission Rate – Network Service Rate		**1.9403**	**kW**
Retail Transmission Rate – Line and Transformation Connection Service Rate		**1.4136**	**kW**
Wholesale Market Service Rate		**0.0044**	**kWh**
Rural Rate Protection Charge		**0.0012**	**kWh**
Standard Supply Service – Administrative Charge (if applicable)		**0.25**	**$**

MicroFit	**Effective Until mm/dd/yy**	**rate**	**Connection Type**
Service Charge		**5.40**	**$**
Distribution Volumetric Rate			**kWh**
Retail Transmission Rate – Network Service Rate			**kWh**
Retail Transmission Rate – Line and Transformation Connection Service Rate			**kWh**
Wholesale Market Service Rate			**kWh**
Rural Rate Protection Charge			**kWh**
Standard Supply Service – Administrative Charge (if applicable)			**$**

Cooperative Hydro Embrun Inc.

TARIFF OF RATES AND CHARGES

Effective and Implementation Date May 1, 2013

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

EB-2012-0117

RESIDENTIAL SERVICE CLASSIFICATION

This classification applies to an account taking electricity at 750 volts or less where the electricity is used exclusively in a separate metered living accommodation. Customers shall be residing in single-dwelling units that consist of a detached house or one unit of a semi-detached, duplex, triplex or quadruplex house, with a residential zoning. Separately metered dwellings within a town house complex or apartment building also qualify as residential customers. All customers are single-phase. 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 Board, and amendments thereto as approved by the 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 Board, and amendments thereto as approved by the 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 Board approval, such as the Debt Retirement Charge, the Global Adjustment, the Ontario Clean Energy Benefit and the HST.

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge	$	13.70
Rate Rider for Recovery of Smart Meter Incremental Revenue Requirement – in effect until the effective date of the next cost of service application	$	1.44
Rate Rider For Smart Metering Entity Charge - effective until October 31, 2018	$	0.79
Distribution Volumetric Rate	$/kWh	0.0128
Low Voltage Service Rate	$/kWh	0.0014
Rate Rider for Disposition of Deferral/Variance Account (2012) – effective until April 30, 2014	$/kWh	(0.0021)
Rate Rider for Disposition of Global Adjustment Sub-Account (2012) – effective until April 30, 2014 Applicable only for Non-RPP Customers	$/kWh	0.0014
Rate Rider for Recovery of Lost Revenue Adjustment Mechanism (LRAM) – effective until April 30, 2014	$/kWh	0.0004
Rate Rider for Disposition of Deferred PILs Variance Account 1562 - effective until April 30, 2014	$/kWh	(0.0008)
Retail Transmission Rate - Network Service Rate	$/kWh	0.0069
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kWh	0.0052

MONTHLY RATES AND CHARGES - Regulatory Component

Wholesale Market Service Rate	$/kWh	0.0044
Rural Rate Protection Charge	$/kWh	0.0012
Standard Supply Service - Administrative Charge (if applicable)	$	0.25

Cooperative Hydro Embrun Inc.

TARIFF OF RATES AND CHARGES

Effective and Implementation Date May 1, 2013

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EB-2012-0117

GENERAL SERVICE LESS THAN 50 KW SERVICE CLASSIFICATION

This classification applies to a non residential account taking electricity at 750 volts or less whose average monthly maximum demand is less than, or is forecast to be 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 Board, and amendments thereto as approved by the 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 Board, and amendments thereto as approved by the 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 Board approval, such as the Debt Retirement Charge, the Global Adjustment, the Ontario Clean Energy Benefit and the HST.

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge	$	20.34
Rate Rider for Recovery of Smart Meter Incremental Revenue Requirement – in effect until the effective date of the next cost of service application	$	4.20
Rate Rider For Smart Metering Entity Charge - effective until October 31, 2018	$	0.79
Distribution Volumetric Rate	$/kWh	0.0168
Low Voltage Service Rate	$/kWh	0.0013
Rate Rider for Disposition of Deferral/Variance Account (2012) – effective until April 30, 2014	$/kWh	(0.0021)
Rate Rider for Disposition of Global Adjustment Sub-Account (2012) – effective until April 30, 2014 Applicable only for Non-RPP Customers	$/kWh	0.0014
Rate Rider for Disposition of Deferred PILs Variance Account 1562 - effective until April 30, 2014	$/kWh	(0.0008)
Retail Transmission Rate - Network Service Rate	$/kWh	0.0064
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kWh	0.0046

MONTHLY RATES AND CHARGES - Regulatory Component

Wholesale Market Service Rate	$/kWh	0.0044
Rural Rate Protection Charge	$/kWh	0.0012
Standard Supply Service - Administrative Charge (if applicable)	$	0.25

Cooperative Hydro Embrun Inc.

TARIFF OF RATES AND CHARGES

Effective and Implementation Date May 1, 2013

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EB-2012-0117

GENERAL SERVICE 50 TO 4,999 KW SERVICE CLASSIFICATION

This classification applies to a non residential account whose average monthly maximum demand used for billing purposes is equal to or greater than, or is forecast to be equal to or greater than, 50 kW but less than 5,000 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 Board, and amendments thereto as approved by the 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 Board, and amendments thereto as approved by the 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 Board approval, such as the Debt Retirement Charge, the Global Adjustment, the Ontario Clean Energy Benefit and the HST.

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge	$	245.27
Rate Rider for Recovery of Smart Meter Incremental Revenue Requirement – in effect until the effective date of the next cost of service application	$	14.30
Distribution Volumetric Rate	$/kW	4.5445
Low Voltage Service Rate	$/kW	0.4778
Rate Rider for Disposition of Deferral/Variance Account (2012) – effective until April 30, 2014	$/kW	(0.7109)
Rate Rider for Disposition of Global Adjustment Sub-Account (2012) – effective until April 30, 2014 Applicable only for Non-RPP Customers	$/kW	0.4834
Rate Rider for Disposition of Deferred PILs Variance Account 1562 - effective until April 30, 2014	$/kW	(0.2605)
Rate Rider for Recovery of Lost Revenue Adjustment Mechanism (LRAM) – effective until April 30, 2014	$/kW	0.0284
Retail Transmission Rate - Network Service Rate	$/kW	2.5726
Retail Transmission Rate - Line Connection Service Rate	$/kW	1.8286

MONTHLY RATES AND CHARGES - Regulatory Component

Wholesale Market Service Rate	$/kWh	0.0044
Rural Rate Protection Charge	$/kWh	0.0012
Standard Supply Service - Administrative Charge (if applicable)	$	0.25

Cooperative Hydro Embrun Inc.

TARIFF OF RATES AND CHARGES

Effective and Implementation Date May 1, 2013

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approved schedules of Rates, Charges and Loss Factors**

EB-2012-0117

UNMETERED SCATTERED LOAD SERVICE CLASSIFICATION

This classification applies to an account taking electricity at 750 volts or less whose average monthly maximum demand is less than, or is forecast to be less than, 50 kW and the consumption is unmetered. Such connections include cable TV power packs, bus shelters, telephone booths, traffic lights, railway crossings, etc. The level of the consumption will be agreed to by the distributor and the customer, based on detailed manufacturer information/ documentation with regard to electrical consumption of the unmetered load or periodic monitoring of actual consumption. 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 Board, and amendments thereto as approved by the 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 Board, and amendments thereto as approved by the 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 Board approval, such as the Debt Retirement Charge, the Global Adjustment, the Ontario Clean Energy Benefit and the HST.

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge (per customer)	$	40.01
Distribution Volumetric Rate	$/kWh	0.0104
Low Voltage Service Rate	$/kWh	0.0013
Rate Rider for Disposition of Deferral/Variance Account (2012) – effective until April 30, 2014	$/kWh	(0.0021)
Rate Rider for Disposition of Global Adjustment Sub-Account (2012) – effective until April 30, 2014		
Applicable only for Non-RPP Customers	$/kWh	0.0014
Rate Rider for Disposition of Deferred PILs Variance Account 1562 - effective until April 30, 2014	$/kWh	(0.0051)
Retail Transmission Rate - Network Service Rate	$/kWh	0.0064
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kWh	0.0046

MONTHLY RATES AND CHARGES - Regulatory Component

Wholesale Market Service Rate	$/kWh	0.0044
Rural Rate Protection Charge	$/kWh	0.0012
Standard Supply Service - Administrative Charge (if applicable)	$	0.25

Cooperative Hydro Embrun Inc.

TARIFF OF RATES AND CHARGES

Effective and Implementation Date May 1, 2013

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EB-2012-0117

STREET LIGHTING SERVICE CLASSIFICATION

This classification applies to an account for roadway lighting with a Municipality, Regional Municipality, Ministry of Transportation and private roadway lighting, controlled by photo cells. The consumption for these customers will be based on the calculated connected load times the required lighting times established in the approved OEB street lighting load shape template. 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 Board, and amendments thereto as approved by the 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 Board, and amendments thereto as approved by the 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 Board approval, such as the Debt Retirement Charge, the Global Adjustment, the Ontario Clean Energy Benefit and the HST.

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge (per connection)	$	1.60
Distribution Volumetric Rate	$/kW	6.5145
Low Voltage Service Rate	$/kW	0.3694
Rate Rider for Disposition of Deferral/Variance Account (2012) – effective until April 30, 2014	$/kW	(0.7349)
Rate Rider for Disposition of Deferred PILs Variance Account 1562 - effective until April 30, 2014	$/kW	(0.5708)
Retail Transmission Rate - Network Service Rate	$/kW	1.9403
Retail Transmission Rate - Line Connection Service Rate	$/kW	1.4136

MONTHLY RATES AND CHARGES - Regulatory Component

Wholesale Market Service Rate	$/kWh	0.0044
Rural Rate Protection Charge	$/kWh	0.0012
Standard Supply Service - Administrative Charge (if applicable)	$	0.25

Cooperative Hydro Embrun Inc.

TARIFF OF RATES AND CHARGES

Effective and Implementation Date May 1, 2013

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

EB-2012-0117

MICROFIT SERVICE CLASSIFICATION

This classification applies to an electricity generation facility contracted under the Ontario Power Authority'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 Board, and amendments thereto as approved by the 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 Board, and amendments thereto as approved by the 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 Board approval, such as the Debt Retirement Charge, the Global Adjustment, the Ontario Clean Energy Benefit and the HST.

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge	$	5.40

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)

Cooperative Hydro Embrun Inc.

TARIFF OF RATES AND CHARGES

Effective and Implementation Date May 1, 2013

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EB-2012-0117

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 Board, and amendments thereto as approved by the 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 Orderof the Board, and amendments thereto as approved by the 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 Board approval, such as the Debt Retirement Charge, charges forthe Ministry of Energy Conservation and Renewable Energy Program, the Global Adjustment, the Ontario Clean Energy Benefit and the HST.

Customer Administration

Arrears Certificate	$	15.00
Statement of Account	$	15.00
Duplicate invoices for pervious billing	$	15.00
Request for other billing information	$	15.00
Income tax eltter	$	15.00
Account history	$	15.00
Credit reference/credit check (plus credit agency costs)	$	25.00
Returned cheques charge (plus bank charges)	$	15.00
Legal letter charge	$	15.00
Account set up charge/change of occupancy chrage (plus credit agency costs of applicable)	$	15.00
Special meter reads	$	20.00
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	$	20.00
Collection of account charge - no disconnection - after regular hours	$	50.00
Disconnect/Reconnect Charge - At Meter during Regular Hours	$	25.00
Disconnect/Reconnect Charge - At Meter after Regular Hours	$	50.00
Disconnect/Reconnect at pole - during regular hours	$	185.00
Disconnect/Reconnect at pole - after regular hours	$	415.00

Install/Remove load control device - during regular hours	$	25.00
Install/Remove load control device - after regular hours	$	50.00
service call - customer owned equipment	$	30.00
service call - after regular hours	$	165.00
Temporary service installation and removal - overhead - no transformer	$	500.00
Temporary service installation and removal - underground - no transformer	$	300.00
Temporary service installation and removal - overhead - with transformer	$	1,000.00
Specific charge for access to power poles $/pole/year	$	22.35

Cooperative Hydro Embrun Inc.

TARIFF OF RATES AND CHARGES

Effective and Implementation Date May 1, 2013

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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 Board, and amendments thereto as approved by the 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 Board, and amendments thereto as approved by the 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 Board approval, such as the Debt Retirement Charge, charges for the Ministry of Energy Conservation and Renewable Energy Program, the Global Adjustment, the Ontario Clean Energy Benefit 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 < 5,000 kW	1.0579
Total Loss Factor – Primary Metered Customer < 5,000 kW	1.0473

E8.T1.S3 OVERVIEW OF FIXED AND VARIABLE CHARGES

Table 2 below shows the proposed monthly service charge for each customer class, the resulting splits of base revenue from fixed and variable charges, and the ensuing usage rates. The existing splits at current rates all fell within the minimum and maximum boundaries therefore the focus of this exercise was to align the split to what the utility considers to be a fair and equitable split, one of 50% fixed and 50% variable.

Under the current rates and split, the fixed charge rates for the Unmetered Scattered Load resulted in a 91% fixed to 9% variable. The utility felt that the split should be rebalanced so as to get as close as possible to a 50% fixed to 50% split. The resulting Monthly Service Charge ("MSC") of $12 instead of $40 fall within the boundaries produced by the 2014 Cost Allocation ("CA") model.

The fixed charge rates for the Street Lighting classes were set so as to get as close as possible to a 50% fixed to 50% variable split. The resulting Monthly Service Charge ("MSC") is a slight increase from the currently approved rates and fall well within the boundaries produced by the 2014 Cost Allocation ("CA") model. The MSC was set at $1.75

Because of the utility specific weighting factors used in this Cost Allocation Study versus the default weighting factors used in the previously approved Cost Allocation Study, the revenue recovered from the GS> 50 has dropped considerably. The split at current rates is for the General Service 50 – 4,999 kW rate class is 37% fixed to 63% variable. In the interest of fairness, CHEI proposes a split that is closer to a 50/50 split.

For the General Service less than 50kW rate class, the split at current rates is 33% fixed to 67% variable. Again, in the interest of fairness, CHEI proposes a split that is closer to a 50/50 split.

The existing split for the Residential rate class falls within the minimum and maximum boundaries and resulted in a split of 55% fixed to 45% variable. If CHEI were to keep the existing split, the resulting MSC would have resulted in an increase of $1.61 per month. Instead, the utility opted to increase the variable split and reduce the fixed split. The resulting MSC is $0.75 higher than the currently approved fixed rate.

E8.T1.S4 FIXED/VARIABLE REVENUE SPLIT

Table 3 at the next page shows the Current fixed/variable proportion for each rate class, along with the Proposed fixed/variable proportion for each rate class.

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TESI-12
Rate Design

Cost Allocation Results

	Cost Allocation - Minimum Fixed Rate (b)			Cost Allocation - Maximun Fixed Rate (b)		
Customer Class Name	**Rate**	**Fixed %**	**Variable %**	**Rate**	**Fixed %**	**Variable %**
Residential	$8.27	29.52%	70.48%	$20.29	72.42%	27.58%
General Service < 50 kW	$10.99	19.71%	80.29%	$23.47	42.09%	57.91%
General Service > 50 to 4999 kW	$21.41	9.00%	91.00%	$245.27	103.13%	-3.13%
Unmetered Scattered Load	$6.58	29.35%	70.65%	$40.01	178.56%	-78.56%
Street Lighting	$0.22	6.16%	93.84%	$3.70	105.53%	-5.53%
MicroFit						

Existing Rates

	Current Rates and Split			Calculated Rates at Current Split		
Customer Class Name	**Rate**	**Fixed %**	**Variable %**	**Rate**	**Fixed %**	**Variable %**
Residential	$13.70	54.65%	45.35%	$15.31	54.65%	45.35%
General Service < 50 kW	$20.34	33.02%	66.98%	$18.41	33.02%	66.98%
General Service > 50 to 4999 kW	$245.27	36.54%	63.46%	$86.91	36.54%	63.46%
Unmetered Scattered Load	$40.01	91.16%	8.84%	$20.43	91.16%	8.84%
Street Lighting	$1.60	55.58%	44.42%	$1.95	55.58%	44.42%
MicroFit						

Rate Design

	Proposed Fixed Charge			Resulting Variable		
Customer Class Name	Fixed Rate	Fixed %	Variable %	**Variable (h)**	**Rate (i)**	**per**
Residential	**$13.75**	47.23%	52.77%	368,318	**$0.0173**	kWh
General Service < 50 kW	**$23.47**	41.14%	58.86%	67,704	**$0.0137**	kWh
General Service > 50 to 4999 kW	**$130.00**	54.33%	45.67%	14,426	**$1.1660**	kW
Unmetered Scattered Load	**$12.00**	51.60%	48.40%	2,702	**$0.0302**	kWh
Street Lighting	**$1.75**	47.21%	52.79%	9,978	**$9.9685**	kW
MicroFit						
				463,128		

	Transf. Allowance ($/kW):		**($0.60)**	Base Revenue Requirement $		
Customer Class Name	**kW**	**Rate**	**Total $ (g)**	Total (d)	Fixed	Variable
Residential	0	$0.00	0	697,988	329,670	368,318
General Service < 50 kW	0	$0.00	0	115,020	47,316	67,704
General Service > 50 to 4999 kW	0	$0.00	0	31,586	17,160	14,426
Unmetered Scattered Load	0	$0.00	0	5,582	2,880	2,702
Street Lighting	0	$0.00	0	18,903	8,925	9,978
MicroFit						
				869,079	**405,951**	**463,128**

Rate Design

		Exisitng Rates		Proposed Rates	
Customer Class Name		Fixed	Variable	Fixed	Variable
Residential		**$13.70**	**0.0128**	**$13.75**	**$0.0173**
General Service < 50 kW		**$20.34**	**0.0168**	**$23.47**	**$0.0137**
General Service > 50 to 4999 kW		**$245.27**	**4.5445**	**$130.00**	**$1.1660**
Unmetered Scattered Load		**$40.01**	**0.0104**	**$12.00**	**$0.0302**
Street Lighting		**$1.60**	**6.5145**	**$1.75**	**$9.9685**
MicroFit					

E8.T1.S5 RECONCILIATION TO BASE REVENUE REQUIREMENT APPENDIX 2-V

Appendix 2-V presented at the next page, shows the reconciliation of the revenues from fixed and variable distribution charges to the Base Revenue Requirement.

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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						
								kWh	kW					
Residential	Customers	1,998.00	1,998.00	1,998.00	21,296,520		$ 13.75	$ 0.0173		$ 697,987.80	$ 697,988		$ 697,988	$ -
GS < 50 kW	Customers	168.00	168.00	168.00	4,950,960		$ 23.47	$ 0.0137		$ 115,019.64	$ 115,020		$ 115,020	$ -
GS > 50 to 4,999 kW	Customers	11.00	11.00	11.00	4,187,781	12,372	$ 130.00		$ 1.1660	$ 31,586.19	$ 31,586		$ 31,586	$ -
Unmetered Scattered Load	Connections	20.00	20.00	20.00	89,554	-	$ 12.00	$ 0.0302		$ 5,581.76	$ 5,582			
StreetLights	Connections	425.00	425.00	425.00	374,609	1,001	$ 1.75		$ 9.9685	$ 18,903.49	$ 18,903		$ 18,903	$ -
				-						$ -			$ -	$ -
				-						$ -			$ -	$ -
				-						$ -			$ -	$ -
				-						$ -			$ -	$ -
Total										$ 869,078.87	$ 869,079	$ -	$ 869,079	$ -

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

Tab 2 – Retail Transmission Service Rates

E8.T2.S1 RETAIL TRANSMISSION SERVICE RATES (RTSR)

Electricity distributors are charged for transmission costs at the wholesale level and subsequently pass these charges on to their distribution customers through the RTSRs. Variance accounts are used to capture timing differences and differences in the rate that a distributor pays for wholesale transmission service compared to the retail rate that the distributor is authorized to charge when billing its customers

CHEI completed its 2014 proposed RTSR in accordance with the Guideline G-2008-0001: Electricity Distribution Retail Transmission Service Rates, October 22, 2008 (and any subsequent updates). The RTSR model provided by the Board is being filed in conjunction with this application.

The trend indicates that the current rates result in over-collection of transmission charges for both Network Service and Connection Service. This conclusion is consistent with the accumulation of credit balances in variance accounts 1584-RSVA/NW and 1586-RSVA/CN during the last year period. CHEI therefore proposes to adjust its RTSRs to offset the over-collection bias in its existing retail rates.

As an embedded distributor, the Applicant pays Hydro One Networks Inc. (“HONI”) retail transmission service rates for the supply of transmission services, rather than the Uniform Transmission Rates (“UTRs”) paid by market participants.

E8.T2.S2 Proposed Retail Transmission Service Rates (RTSR)

Table 1 below presents the Applicant’s proposed RTSR for the Test Year. The proposed rates are reflected in the Applicant’s projected power supply expense for 2014 as shown in Exhibit 3.

Table 2 Proposed RTSR

Rate Class	Unit	Proposed RTSR Network	Proposed RTSR Connection
Residential	kWh	0.0057	0.0048
General Service Less Than 50 kW	kWh	0.0053	0.0042
General Service 50 to 4,999 kW	kW	2.1331	1.6823
Unmetered Scattered Load	kWh	0.0053	0.0042
Street Lighting	kW	1.6088	1.3005

Table 3: Adjusted Network to Current WS

Rate Class	Unit	Current RTSR-Network	Loss Adjusted Billed kWh	Loss Adjusted Billed kW	Billed Amount	Billed Amount %	Current Wholesale Billing	Proposed RTSR Network
Residential	kWh	0.0069	20,771,633.76	0.00	143,324.27	0.68	118,840.23	0.0057
General Service Less Than 50 kW	kWh	0.0064	5,017,157.40	0.00	32,109.81	0.15	26,624.50	0.0053
General Service 50 to 4,999 kW	kW	2.5726	0.00	13,273.00	34,146.12	0.16	28,312.95	2.1331
Unmetered Scattered Load	kWh	0.0064	94,373.14	0.00	603.99	0.00	500.81	0.0053
Street Lighting	kW	1.9403	0.00	1,060.00	2,056.72	0.01	1,705.37	1.6088
					212,240.91			

Table 4: Adjusted Network to Forecasted WS

Rate Class	*Unit*	*Adjusted RTSR-Network*	*Loss Adjusted Billed kWh*	*Loss Adjusted Billed kW*	*Billed Amount*	*Billed Amount %*	*Forecast Wholesale Billing*	*Proposed RTSR Network*
Residential	kWh	0.0057	20,771,633.76	0.00	118,840.23	0.68	118,840.23	0.0057
General Service Less Than 50 kW	kWh	0.0053	5,017,157.40	0.00	26,624.50	0.15	26,624.50	0.0053
General Service 50 to 4,999 kW	kW	2.1331	0.00	13,273.00	28,312.95	0.16	28,312.95	2.1331
Unmetered Scattered Load	kWh	0.0053	94,373.14	0.00	500.81	0.00	500.81	0.0053
Street Lighting	kW	1.6088	0.00	1,060.00	1,705.37	0.01	1,705.37	1.6088
					175,983.85			

Table 5: Adjusted Connection to Current WS

Rate Class	**Unit**	**Current RTSR-Network**	**Loss Adjusted Billed kWh**	**Loss Adjusted Billed kW**	**Billed Amount**	**Billed Amount %**	**Current Wholesale Billing**	**Proposed RTSR Network**
Residential	kWh	0.0052	20,771,633.76	0.00	108,012.50	0.69	99,369.83	0.0048
General Service Less Than 50 kW	kWh	0.0046	5,017,157.40	0.00	23,078.92	0.15	21,232.25	0.0042
General Service 50 to 4,999 kW	kW	1.8286	0.00	13,273.00	24,271.01	0.15	22,328.95	1.6823
Unmetered Scattered Load	kWh	0.0046	94,373.14	0.00	434.12	0.00	399.38	0.0042
Street Lighting	kW	1.4136	0.00	1,060.00	1,498.42	0.01	1,378.52	1.3005
					157,294.96			

Table 6: Adjusted Connection to Forecasted WS

Rate Class	Unit	Adjusted RTSR-Network	Loss Adjusted Billed kWh	Loss Adjusted Billed kW	Billed Amount	Billed Amount %	Forecast Wholesale Billing	Proposed RTSR Network
Residential	kWh	0.0048	20,771,633.76	0.00	99,369.83	0.69	99,369.83	0.0048
General Service Less Than 50 kW	kWh	0.0042	5,017,157.40	0.00	21,232.25	0.15	21,232.25	0.0042
General Service 50 to 4,999 kW	kW	1.6823	0.00	13,273.00	22,328.95	0.15	22,328.95	1.6823
Unmetered Scattered Load	kWh	0.0042	94,373.14	0.00	399.38	0.00	399.38	0.0042
Street Lighting	kW	1.3005	0.00	1,060.00	1,378.52	0.01	1,378.52	1.3005
					144,708.94			

Tab 3 – Retail Service Charges and Specific Service Charges

E8.T3.S1 OVERVIEW OF RETAIL AND SPECIFIC SERVICE CHARGE

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 (“RSC”). CHEI is proposing to maintain its current RCS in this application. CHEI is proposing to maintain its existing retail service charges which are consistent with the OEB’s Standard Rates. The retail service charges the following; The proposed RSC charges are consistent with all other utilities in Ontario. CHEI anticipates no material changes to the following Specific Service Charge revenue and proposes to maintain the current rates for the following:

E8.T3.S2 PROPOSED RETAIL AND SPECIFIC SERVICE CHARGES

Customer Administration

Arrears Certificate	$	15.00
Statement of Account	$	15.00
Duplicate invoices for pervious billing	$	15.00
Request for other billing information	$	15.00
Income tax eltter	$	15.00
Account history	$	15.00
Credit reference/credit check (plus credit agency costs)	$	25.00
Returned cheques charge (plus bank charges)	$	15.00
Legal letter charge	$	15.00
Account set up charge/change of occupancy chrage (plus credit agency costs of applicable)	$	15.00
Special meter reads	$	20.00
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	$	20.00
Collection of account charge - no disconnection - after regular hours	$	50.00
Disconnect/Reconnect Charge - At Meter during Regular Hours	$	25.00
Disconnect/Reconnect Charge - At Meter after Regular Hours	$	50.00
Disconnect/Reconnect at pole - during regular hours	$	185.00
Disconnect/Reconnect at pole - after regular hours	$	415.00
Install/Remove load control device - during regular hours	$	25.00
Install/Remove load control device - after regular hours	$	50.00
service call - customer owned equipment	$	30.00
service call - after regular hours	$	165.00
Temporary service installation and removal - overhead - no transformer	$	500.00
Temporary service installation and removal - underground - no transformer	$	300.00
Temporary service installation and removal - overhead - with transformer	$	1,000.00
Specific charge for access to power poles $/pole/year	$	22.35

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

Tab 4 – Wholesale Market Service Charges

E8.T4.S1 OVERVIEW OF WHOLESALE MARKET SERVICE CHARGES

On March 21, 2013, the Board issued a Decision with Reasons and Rate Order (EB-2013-0067) establishing that the Wholesale Market Service rate ("WMS rate") used by rate regulated distributors to bill their customers shall be $0.0044 per kilowatt hour effective May 1, 2013. CHEI is proposing to maintain its existing Wholesale Market Service Charges at $0.0044.

Tab 5 – Low Voltage Charges

E8.T5.S1 OVERVIEW OF LOW VOLTAGE CHARGES

Table 1 presents the derivation of proposed retail rates for Low Voltage ("LV") service. The 2013-2014 estimates of total LV charges were calculated based on an average of the last 2 years and adjusted upwards to reflect the projected load growth in 2014.

The projections were allocated to customer classes, according to each class' share of projected Transmission-Connection revenue, in accordance with Board policy. The resulting allocated LV charges for each class were divided by the applicable 2014 volumes from the load forecast, as presented in Exhibit 3.

Current LV revenues are recovered through a separate rate adder and therefore are not embedded within the approved Distribution Volumetric rate. 2014 LV rates appear on a distinct line item on the proposed schedule of rates.

E8.T5.S2 DERIVATION OF PROPOSED LOW VOLTAGE CHARGES

Table 7: Derivation of Low Voltage Charges

Low Voltage Charges

(not loss adjusted)

	2013 PROPOSED LOW VOLTAGE CHARGES & RATES				
Customer Class Name	**% Allocation**	**Charges**	**Not Uplifted Volumes**	**Rate**	**per**
Residential	70.92%	39,717	21,229,835	$0.0019	kWh
General Service < 50 kW	14.43%	8,079	4,935,457	$0.0016	kWh
General Service > 50 to 4999 kW	13.54%	7,584	12,333	$0.6149	kW
Unmetered Scattered Load	0.26%	146	89,273	$0.0016	kWh
Street Lighting	0.85%	474	998	$0.4754	kW
MicroFit					
TOTAL	**100.00%**	**56,000**	**26,267,896**		

				Bridge Year 2013			**Test Year 2014**		
Customer		**Revenue**	**Expense**		**2013**			**2014**	
Class Name		USA #	USA #	Volume	Rate	Amount	Volume	Rate	Amount
Residential	kWh	4075	4750	19,627,850	$0.0014	$27,479	21,229,835	$0.0019	$40,336.69
General Service < 50 kW	kWh	4075	4750	4,804,973	$0.0013	$6,246	4,935,457	$0.0016	$7,896.73
General Service > 50 to 4999 kW	kW	4075	4750	12,607	$0.4778	$6,024	12,333	$0.6149	$7,583.56
Unmetered Scattered Load	kWh	4075	4750	91,612	$0.0013	$119	89,273	$0.0016	$142.84
Street Lighting	kW	4075	4750	1,000	$0.3694	$369	998	$0.4754	$474.45
MicroFit									
TOTAL		**0**	**0**	**24,538,041**		**$40,238**	**26,267,896**		**$56,434.27**

Tab 6 – Loss Adjustment Factors

E8.T6.S1 OVERVIEW OF LOSS ADJUSTMENT FACTOR

Table 1 at the next page presents the determination of the Applicant's loss adjustment factor.

CHEI proposes a Total Loss Factor ("TLF") 1.0663, using the historical average of the last five years as presented at Table 1. The proposed TLF represents a marginal increase from CHEI's currently approved TLF of 1.0632.

CHEI is an embedded distributor with Hydro One Networks Inc. ("HONI") as its host distributor. As reflected in Attachment 1 (Appendix 2-R, Loss Factor) the total losses in CHEI's distribution system are only 1.0271 while the supply facility loss represents 1.03812. CHEI is committed to continuing its effort to minimize its distribution system losses.

In anticipation of the upgrades to the Applicant's distribution system to accommodate the new subdivision, the Applicant hired Stantec to conduct a System Load-Flow and Optimization Study. This study is appended to Exhibit 2. Part of the study included an assessment of the utility'system loss. The results of the study showed some unbalanced currents on all feeders. Once the utility completes its upgrade to accommodate the new load, it plans on addressing the rebalancing of the current.

E8.T6.S2 DERIVATION OF PROPOSED LOSS ADJUSTMENT FACTOR

Appendix 2-R Loss Factor is presented at the next page.

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Appendix 2-R
Loss Factors

		Historical Years					5-Year Average
		2008	**2009**	**2010**	**2011**	**2012**	
	Losses Within Distributor's System						
A(1)	"Wholesale" kWh delivered to distributor (higher value)						-
A(2)	"Wholesale" kWh delivered to distributor (lower value)	29,993,741.00	30,079,505.00	30,067,541.00	30,249,028.00	29,716,224.00	30,021,207.80
B	Portion of "Wholesale" kWh delivered to distributor for its Large Use Customer(s)						-
C	Net "Wholesale" kWh delivered to distributor = **A(2) - B**	29,993,741.00	30,079,505.00	30,067,541.00	30,249,028.00	29,716,224.00	30,021,207.80
D	"Retail" kWh delivered by distributor	29,483,564.00	29,448,752.00	29,135,811.00	28,883,868.00	29,188,202.00	29,228,039.40
E	Portion of "Retail" kWh delivered by distributor to its Large Use Customer(s)						-
F	Net "Retail" kWh delivered by distributor = **D - E**	29,483,564.00	29,448,752.00	29,135,811.00	28,883,868.00	29188202	29,228,039.40
G	Loss Factor in Distributor's system = **C** / **F**	1.0173	1.0214	1.0320	1.0473	1.0181	1.0271
	Losses Upstream of Distributor's System						
H	Supply Facilities Loss Factor	1.034	1.034	1.034	1.0443	1.0443	1.03812
	Total Losses						
I	Total Loss Factor = **G x H**	1.0519	1.0561	1.0671	1.0937	1.0632	1.0663

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 higher 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 higher 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 lower of the two kWh values provided by MV-WEB.

If fully embedded with the host distributor, kWh pertains to an actual or virtual meter 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 lower 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.

Tab 7 – Stranded Meter Rate Rider

E8.T7.S1 CALCULATION OF STRANDED METER RATE RIDER

In the minimum filing requirements , The Board’s states that the Smart Meter Funding and Cost Recovery (G-2008-0002) provides two options to distributors regarding the accounting treatment for stranded meters related to the installation of smart meters:

- (Scenario A) If the stranded meter costs were transferred to "Sub-account Stranded Meter Costs" of Account 1555;.or
- (Scenario B) If the stranded meter costs remained recorded in Account 1860.

CHEI attests that its utility falls under Scenario B as the stranded meters have, until now, resided in Account 1860 - Meters.

The table below (excerpt from Appendix 2-R of the Board’s Appendices) shows the net book value of CHEI’s stranded smart meters.

Table 8: Net Book Value of Stranded Meters

Year	Notes	Gross Asset Value	Accumulated Amortization	Contributed Capital (Net of Amortization)	Net Asset	Proceeds on Disposition	Residual Net Book Value
		(A)	(B)	(C)	(D) = (A) - (B) - (C)	(E)	(F) = (D) - (E)
2006					$0.00		$0.00
2007					$0.00		$0.00
2008					$0.00		$0.00
2009					$0.00		$0.00
2010		$79,072.00	$29,822.00		$49,250.00		$49,250.00
2011		$79,072.00	$32,985.00		$46,087.00		$46,087.00
2012	(1)	$79,072.00	$36,148.00		$42,924.00		$42,924.00

Appendix 2-S requests that utilities complete the following information relating to the treatment of the utility's stranded meters.

1. A description of the accounting treatment followed by the applicant on stranded meter costs for financial accounting and reporting purposes.

Thus far, stranded meters were included in account 1860 and therefore were treated accordance with CGAAP with the same accounting rules as standard meters.

CHEI transferred net balances as 2012, when the bulk of the smart meters were installed. $42,924 was removed from Account 1860-Meters

2. The amount of the pooled residual net book value of the removed from service stranded meters, less any contributed capital (net of accumulated amortization), and less any net proceeds from sales, as of December 31, 2012.

The amount of pooled residual net book value as of December 31st, 2012 is in the amount of $42,924

3. A statement as to whether or not the recording of depreciation expenses continued in order to reduce the net book value through accumulated depreciation. If so, provision of the total (cumulative) depreciation expense for the period from the time that the meters became stranded to December 31, 2012.

Smart meters were fully installed by the end of 2011. The 2010 depreciation expense was $3,163.

4. If no depreciation expenses were recorded to reduce the net book value of stranded meters through accumulated depreciation, the total (cumulative) depreciation expense amount that would have been applicable for the period from the time that the meters became stranded to December 31, 2012.

N/A Please see question #3 above.

5. The estimated amount of the pooled residual net book value of the removed from service meters, less any net proceeds from sales and contributed capital, at the time when smart meters will have been fully deployed. If the smart meters have been fully deployed, please provide the actual amount.

The estimated net amount at end of 2011 was $42,924

6. A description as to how the applicant intends to recover in rates the costs for stranded meters, including the proposed accounting treatment, the proposed disposition period and the associated bill impacts.

The applicant intends to recover the cost of the Stranded Meters through a Rate Rider. The proposed recovery period is 2 years. Calculations of the proposed rate rider are presented at Table 1 below.

Table 9: Stranded Meter Rate Rider

Customer Class Name	**Net Book Value**	**% share**	**Annual $**	**Customer**	**Rate**	**per month**
Residential	$39,490.08	92.00%	19745.04	1998	$ 9.88	$ 0.82
General Service < 50 kW	$3,433.92	8.00%	1716.96	168	$ 10.22	$ 0.85
enter classes						
	TOTAL					

Total for Recovery			**42,924**
Recovery Period (years)		**2**	
Annual Recovery			**21,462**

Tab 8 – Rate Schedule

E8.T7.S1 OVERVEW OF PROPOSED RATE SCHEDULE

The schedule at the next page shows the current and proposed 2014 tariff rates.

E8.T7.S2 PROPOSED RATE SCHEDULE

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TESI-14
Summary Sheet

Current Rates

Residential	**rate**	**Connection Type**
Service Charge	13.70	$
Distribution Volumetric Rate	0.0128	kWh
Rate Rider for Recovery of Smart Meter Incremental Revenue Requirement – in effect until the effective date of the next cost of service application	1.44	$
Rate Rider For Smart Metering Entity Charge - effective until October 31, 2018	0.79	$
Low Voltage Service Rate	0.0014	kWh
Rate Rider for Disposition of Deferral/Variance Account (2012) – effective until April 30, 2014	-0.0021	kWh
Rate Rider for Disposition of Global Adjustment Sub-Account (2012) – effective until April 30, 2014 Applicable only for Non-RPP Customers	0.0014	kWh
Rate Rider for Recovery of Lost Revenue Adjustment Mechanism (LRAM) – effective until April 30, 2014	0.0004	kWh
Rate Rider for Disposition of Deferred PILs Variance Account 1562 - effective until April 30, 2015	-0.008	kWh
Retail Transmission Rate – Network Service Rate	0.0069	kWh
Retail Transmission Rate – Line and Transformation Connection Service Rate	0.0052	kWh
Wholesale Market Service Rate	0.0044	kWh
Rural Rate Protection Charge	0.0012	kWh
Standard Supply Service – Administrative Charge (if applicable)	0.25	$

General Service < 50 kW	**rate**	**Connection Type**
Service Charge	20.34	$
Distribution Volumetric Rate	0.0168	kWh
Rate Rider for Recovery of Smart Meter Incremental Revenue Requirement – in effect until the effective date of the next cost of service application	4.20	$
Rate Rider For Smart Metering Entity Charge - effective until October 31, 2018	0.79	$
Low Voltage Service Rate	0.0013	kWh
Rate Rider for Disposition of Deferral/Variance Account (2012) – effective until April 30, 2014	-0.0021	kWh
Rate Rider for Disposition of Global Adjustment Sub-Account (2012) – effective until April 30, 2014 Applicable only for Non-RPP Customers	0.0014	kWh
Rate Rider for Disposition of Deferred PILs Variance Account 1562 - effective until April 30, 2015	-0.0008	kWh
Retail Transmission Rate – Network Service Rate	0.0064	kWh
Retail Transmission Rate – Line and Transformation Connection Service Rate	0.0046	kWh
Wholesale Market Service Rate	0.0044	kWh
Rural Rate Protection Charge	0.0012	kWh
Standard Supply Service – Administrative Charge (if applicable)	0.25	$

General Service > 50 to 4999 kW	**rate**	**Connection Type**
Service Charge	245.27	$
Distribution Volumetric Rate	4.5445	kW

Proposed Rates

Residential	**rate**	**Connection Type**
Service Charge	13.75	$
Distribution Volumetric Rate	0.0173	kWh
Rate Rider For Smart Metering Entity Charge - effective until October 31, 2018	0.79	$
Low Voltage Service Rate	0.0019	kWh
Rate Rider for Disposition of Deferral/Variance Account (2012) – effective until December 31, 2016	-0.0011	kWh
Rate Rider for Disposition of Global Adjustment Sub-Account (2012) – effective until December 31, 2016 Applicable only for Non-RPP Customers	-0.0007	kWh
Stranded Meter Rate Rider	0.82	$
Retail Transmission Rate – Network Service Rate	0.0057	kWh
Retail Transmission Rate – Line and Transformation Connection Service Rate	0.0048	kWh
Wholesale Market Service Rate	0.0044	kWh
Rural Rate Protection Charge	0.0011	kWh
Standard Supply Service – Administrative Charge (if applicable)	0.25	$

General Service < 50 kW	**rate**	**Connection Type**
Service Charge	23.47	$
Distribution Volumetric Rate	0.0137	kWh
Rate Rider For Smart Metering Entity Charge - effective until October 31, 2018	0.79	$
Low Voltage Service Rate	0.0016	kWh
Rate Rider for Disposition of Deferral/Variance Account (2012) – effective until December 31, 2016	-0.0010	kWh
Rate Rider for Disposition of Global Adjustment Sub-Account (2012) – effective until December 31, 2016 Applicable only for Non-RPP Customers	-0.0007	kWh
Stranded Meter Rate Rider	0.85	$
Retail Transmission Rate – Network Service Rate	0.0053	kWh
Retail Transmission Rate – Line and Transformation Connection Service Rate	0.0042	kWh
Wholesale Market Service Rate	0.0044	kWh
Rural Rate Protection Charge	0.0011	kWh
Standard Supply Service – Administrative Charge (if applicable)	0.25	$

General Service > 50 to 4999 kW	**rate**	**Connection Type**
Service Charge	130.00	$
Distribution Volumetric Rate	1.166	kW

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Rate Rider for Recovery of Smart Meter Incremental Revenue Requirement – in effect until the effective date of the next cost of service application	14.3	kW
Low Voltage Service Rate	0.4778	kW
Rate Rider for Disposition of Deferral/Variance Account (2012) – effective until April 30, 2014	-0.7109	kW
Rate Rider for Disposition of Global Adjustment Sub-Account (2012) – effective until April 30, 2014 Applicable only for Non-RPP Customers	0.4834	kW
Rate Rider for Disposition of Deferred PILs Variance Account 1562 - effective until April 30, 2014	-0.2605	kW
Rate Rider for Recovery of Lost Revenue Adjustment Mechanism (LRAM) – effective until April 30, 2014	0.0284	kW
Retail Transmission Rate – Network Service Rate	2.5726	kW
Retail Transmission Rate – Line and Transformation Connection Service Rate	1.8286	kW
Wholesale Market Service Rate	0.0044	kWh
Rural Rate Protection Charge	0.0012	kWh
Standard Supply Service – Administrative Charge (if applicable)	0.25	$

Low Voltage Service Rate	0.613	kW
Rate Rider for Disposition of Deferral/Variance Account (2012) – effective until December 31, 2016	-0.3534	kW
Rate Rider for Disposition of Global Adjustment Sub-Account (2012) – effective until December 31, 2016 Applicable only for Non-RPP Customers	-0.2425	kW
		$
Retail Transmission Rate – Network Service Rate	2.1331	kW
Retail Transmission Rate – Line and Transformation Connection Service Rate	1.6823	kW
Wholesale Market Service Rate	0.0044	kWh
Rural Rate Protection Charge	0.0012	kWh
Standard Supply Service – Administrative Charge (if applicable)	0.25	$

Unmetered Scattered Load	**rate**	**Connection Type**
Service Charge	40.01	$
Distribution Volumetric Rate	0.0104	kWh
Low Voltage Service Rate	0.0013	kWh
Rate Rider for Disposition of Deferral/Variance Account (2012) – effective until April 30, 2014	-0.0021	kWh
Rate Rider for Disposition of Global Adjustment Sub-Account (2012) – effective until April 30, 2014 Applicable only for Non-RPP Customers	0.0014	kWh
Rate Rider for Disposition of Deferred PILs Variance Account 1562 - effective until April 30, 2014	-0.0051	kWh
Retail Transmission Rate – Network Service Rate	0.0064	kWh
Retail Transmission Rate – Line and Transformation Connection Service Rate	0.0046	kWh
Wholesale Market Service Rate	0.0044	kWh
Rural Rate Protection Charge	0.0012	kWh
Standard Supply Service – Administrative Charge (if applicable)	0.25	$

Unmetered Scattered Load	**rate**	**Connection Type**
Service Charge	12.00	$
Distribution Volumetric Rate	0.0302	kWh
Low Voltage Service Rate	0.0016	
Rate Rider for Disposition of Deferral/Variance Account (2012) – effective until December 31, 2016	-0.0011	kWh
Rate Rider for Disposition of Global Adjustment Sub-Account (2012) – effective until December 31, 2016 Applicable only for Non-RPP Customers	-0.0007	kWh
		kWh
		$
Retail Transmission Rate – Network Service Rate	0.0053	kWh
Retail Transmission Rate – Line and Transformation Connection Service Rate	0.0042	kWh
Wholesale Market Service Rate	0.0044	kWh
Rural Rate Protection Charge	0.0012	kWh
Standard Supply Service – Administrative Charge (if applicable)	0.25	$

Street Lighting	**rate**	**Connection Type**
Service Charge	1.6	$
Distribution Volumetric Rate	6.5145	kW
Low Voltage Service Rate	0.3694	kW
Rate Rider for Disposition of Deferral/Variance Account (2012) – effective until April 30, 2014	-0.7349	kW
Rate Rider for Disposition of Deferred PILs Variance Account 1562 - effective until April 30, 2014	-0.5708	kW

Street Lighting	**rate**	**Connection Type**
Service Charge	1.75	$
Distribution Volumetric Rate	9.9685	kW
Low Voltage Service Rate	0.4739	kW
Rate Rider for Disposition of Deferral/Variance Account (2012) – effective until December 31, 2016	-0.4921	kW
Rate Rider for Disposition of Global Adjustment Sub-Account (2012) – effective until December 31, 2016 Applicable only for Non-RPP Customers	-0.2501	kW
		$

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Retail Transmission Rate – Network Service Rate	1.9403	kW
Retail Transmission Rate – Line and Transformation Connection Service Rate	1.4136	kW
Wholesale Market Service Rate	0.0044	kWh
Rural Rate Protection Charge	0.0012	kWh
Standard Supply Service – Administrative Charge (if applicable)	0.25	$

Retail Transmission Rate – Network Service Rate	1.6088	kW
Retail Transmission Rate – Line and Transformation Connection Service Rate	1.3005	kW
Wholesale Market Service Rate	0.0044	kWh
Rural Rate Protection Charge	0.0012	kWh
Standard Supply Service – Administrative Charge (if applicable)	0.25	$

Tab 9 – Bill Impact

E8.T8.S1 OVERVEW OF BILL IMPACTS

Total bill impacts vary by customer class, ranging from a decrease of 18.10% for Unmetered Scattered Load, to an increase of 35.07% for Street Lighting. Due to the use of utility specific weighting factors, the GS>50 class is seeing the largest drop in rates at -45.03%. Under the default factors from the previous cost allocation, the GS>50 class is was subsidizing the other classes. Under the new utility specific weighting factors, the class is forgoing $57,172 in revenues. The residential class is recovering $70,900 in added revenues causing its distribution rates to increase by 11.94%. While the base distribution rates are showing an increase, this increase is offset by credit rate riders to dispose of the significant balances owed to ratepayers that have accumulated in certain variance accounts. Decreases in rates for retail transmission service and wholesale market service also contribute to offset the increase in base distribution rates. The overall bill impact for the residential class is 1.20%.

A large portion of CHEI's bill impacts can be attributed to Rate Riders which are for the most part related to either government mandated costs or spending (i.e. smart meters), or Pass-through Charges (i.e. DVA and LV Charges) which CHEI considers to be beyond the utility's control.

CHEI needs the proposed rates to remain in compliance with its regulators and meet its mandate and commitment to provide safe, reliable cost-effective services and products achieving sustainable growth while respecting the community and the environment.

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Appendix 2-W
Bill Impacts

Customer Class: **Residential**

Consumption 800 **kWh** ● May 1 - October 31 ○ November 1 - April 30 (Select this radio button for applications filed after C

		Current Board-Approved			Proposed			Impact	
	Charge Unit	**Rate ($)**	**Volume**	**Charge ($)**	**Rate ($)**	**Volume**	**Charge ($)**	**$ Change**	**% Change**
Monthly Service Charge	Monthly	$ 13.70	1	$ 13.70	$ 13.75	1	$ 13.75	$ 0.05	0.36%
Smart Meter Rate Adder	Monthly	$ 1.44	1	$ 1.44		1	$ -	-$ 1.44	-100.00%
Stranded Meter Rate Rider	Monthly		1	$ -	$ 0.82	1	$ 0.82	$ 0.82	
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
Distribution Volumetric Rate	per kWh	$ 0.0128	800	$ 10.24	$ 0.0173	800	$ 13.84	$ 3.60	35.16%
Smart Meter Disposition Rider	per kWh		800	$ -		800	$ -	$ -	
LRAM & SSM Rate Rider	per kWh	$ 0.0004	800	$ 0.32		800	$ -	-$ 0.32	-100.00%
			800	$ -		800	$ -	$ -	
			800	$ -		800	$ -	$ -	
LRAM	per kWh	$ 0.0004	800	$ 0.32		800	$ -	-$ 0.32	-100.00%
Deferred PILs 1562	per kWh	-$ 0.0008	800	-$ 0.64		800	$ -	$ 0.64	-100.00%
			800	$ -		800	$ -	$ -	
			800	$ -		800	$ -	$ -	
			800	$ -		800	$ -	$ -	
Sub-Total A				$ 25.38			$ 28.41	**$ 3.03**	**11.94%**
Deferral/Variance Account Disposition Rate Rider	per kWh	-$ 0.0021	800	-$ 1.68	-$ 0.0011	800	-$ 0.88	$ 0.80	-47.62%
Global Adj DVA	per kWh	$ 0.0014	800	$ 1.12	-$ 0.0007	800	-$ 0.56	-$ 1.68	-150.00%
			800	$ -		800	$ -	$ -	
			800	$ -		800	$ -	$ -	
Low Voltage Service Charge	per kWh	$ 0.0014	800	$ 1.12	$ 0.0019	800	$ 1.52	$ 0.40	35.71%
Smart Meter Entity Charge	Monthly	$ 0.7900	1	$ 0.79	$ 0.7900	800	$ 632.00	$ 631.21	
Sub-Total B - Distribution (includes Sub-Total A)				**$ 25.94**			**$ 28.49**	**$ 2.55**	**9.83%**
RTSR - Network	per kWh	$ 0.0069	808	$ 5.58	$ 0.0057	809	$ 4.61	-$ 0.97	-17.38%
RTSR - Line and Transformation Connection	per kWh	$ 0.0052	808	$ 4.20	$ 0.0048	809	$ 3.88	-$ 0.32	-7.68%
Sub-Total C - Delivery (including Sub-Total B)				**$ 35.72**			**$ 36.98**	**$ 1.26**	**3.52%**
Wholesale Market Service Charge (WMSC)	per kWh	$ 0.0044	808	$ 3.56	$ 0.0044	809	$ 3.56	$ 0.00	0.01%
Rural and Remote Rate Protection (RRRP)	per kWh	$ 0.0012	808	$ 0.97	$ 0.0012	809	$ 0.97	$ 0.00	0.01%
Standard Supply Service Charge	Monthly	$ 0.2500	1	$ 0.25	$ 0.2500	1	$ 0.25	$ -	0.00%
Debt Retirement Charge (DRC)			808	$ -		809	$ -	$ -	
Energy - RPP - Tier 1		$ 0.0750	600	$ 45.00	$ 0.0750	600	$ 45.00	$ -	0.00%
Energy - RPP - Tier 2		$ 0.0880	208	$ 18.34	$ 0.0880	209	$ 18.35	$ 0.01	0.03%
TOU - Off Peak		$ 0.0650	517	$ 33.63	$ 0.0650	517	$ 33.63	$ 0.00	0.01%
TOU - Mid Peak		$ 0.1000	146	$ 14.55	$ 0.1000	146	$ 14.55	$ 0.00	0.01%
TOU - On Peak		$ 0.1170	146	$ 17.03	$ 0.1170	146	$ 17.03	$ 0.00	0.01%
Total Bill on RPP (before Taxes)				**$ 103.84**			**$ 105.11**	**$ 1.26**	**1.22%**
HST		13%		$ 13.50	13%		$ 13.66	$ 0.16	1.22%
Total Bill (including HST)				$ 117.34			$ 118.77	$ 1.43	1.22%
Ontario Clean Energy Benefit [1]				-$ 11.73			-$ 11.88	-$ 0.15	1.28%
Total Bill on RPP (including OCEB)				**$ 105.61**			**$ 106.89**	**$ 1.28**	**1.21%**
Total Bill on TOU (before Taxes)				**$ 105.71**			**$ 106.97**	**$ 1.26**	**1.19%**
HST		13%		$ 13.74	13%		$ 13.91	$ 0.16	1.19%
Total Bill (including HST)				$ 119.45			$ 120.88	$ 1.43	1.19%
Ontario Clean Energy Benefit [1]				-$ 11.95			-$ 12.09	-$ 0.14	1.17%
Total Bill on TOU (including OCEB)				**$ 107.50**			**$ 108.79**	**$ 1.29**	**1.20%**

Loss Factor (%)	1.06%	1.07%

[1] Applicable to eligible customers only. Refer to the *Ontario Clean Energy Benefit Act, 2010.*

Note that the "Charge $" columns provide breakdowns of the amounts that each bill component contributes to the total monthly bill at the referenced consumption level at existing and proposed rates.

Applicants must provide bill impacts for residential at 800 kWh and GS<50kW at 2000 kWh. In addition, their filing should cover the range that is relevant to their service territory, class by class. A general guideline of consumption levels follows:

Residential (kWh) - 100, 250, 500, 800, 1000, 1500, 2000
GS<50kW (kWh) - 1000, 2000, 5000, 10000, 15000
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.

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Appendix 2-W
Bill Impacts

Customer Class: **GS<50**

Consumption **2000** **kWh** ● May 1 - October 31 ○ November 1 - April 30 (Select this radio button for applications filed after O

		Current Board-Approved			Proposed			Impact	
	Charge Unit	**Rate ($)**	**Volume**	**Charge ($)**	**Rate ($)**	**Volume**	**Charge ($)**	**$ Change**	**% Change**
Monthly Service Charge	Monthly	$ 20.34	1	$ 20.34	$ 23.47	1	$ 23.47	$ 3.13	15.39%
Smart Meter Rate Adder	Monthly	$ 4.20	1	$ 4.20		1	$ -	-$ 4.20	-100.00%
Stranded Meter Rate Rider	Monthly		1	$ -	$ 0.85	1	$ 0.85	$ 0.85	
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
Distribution Volumetric Rate	per kWh	$ 0.0168	2000	$ 33.60	$ 0.0137	2000	$ 27.40	-$ 6.20	-18.45%
Smart Meter Disposition Rider			2000	$ -		2000	$ -	$ -	
LRAM & SSM Rate Rider			2000	$ -		2000	$ -	$ -	
			2000	$ -		2000	$ -	$ -	
			2000	$ -		2000	$ -	$ -	
LRAM			2000	$ -		2000	$ -	$ -	
Deferred PILs 1562	per kWh	-$ 0.0008	2000	-$ 1.60		2000	$ -	$ 1.60	-100.00%
			2000	$ -		2000	$ -	$ -	
			2000	$ -		2000	$ -	$ -	
			2000	$ -		2000	$ -	$ -	
Sub-Total A				$ 56.54			$ 51.72	**-$ 4.82**	**-8.52%**
Deferral/Variance Account Disposition Rate Rider	per kWh	-$ 0.0021	2000	-$ 4.20	-$ 0.0010	2000	-$ 2.00	$ 2.20	-52.38%
Global Adj DVA	per kWh	$ 0.0014	2000	$ 2.80	-$ 0.0007	2000	-$ 1.40	-$ 4.20	-150.00%
			2000	$ -		2000	$ -	$ -	
			2000	$ -		2000	$ -	$ -	
Low Voltage Service Charge	per kWh	$ 0.0013	2000	$ 2.60	$ 0.0016	2000	$ 3.20	$ 0.60	23.08%
Smart Meter Entity Charge	Monthly	$ 0.7900	1	$ 0.79	$ 0.7900	2000	$ 1,580.00	$ 1,579.21	
Sub-Total B - Distribution (includes Sub-Total A)				**$ 57.74**			**$ 51.52**	**-$ 6.22**	**-10.77%**
RTSR - Network	per kWh	$ 0.0064	2021	$ 12.94	$ 0.0053	2021	$ 10.71	-$ 2.22	-17.18%
RTSR - Line and Transformation Connection	per kWh	$ 0.0046	2021	$ 9.30	$ 0.0042	2021	$ 8.49	-$ 0.81	-8.69%
Sub-Total C - Delivery (including Sub-Total B)				**$ 79.97**			**$ 70.72**	**-$ 9.25**	**-11.57%**
Wholesale Market Service Charge (WMSC)	per kWh	$ 0.0044	2021	$ 8.89	$ 0.0044	2021	$ 8.89	$ 0.00	0.01%
Rural and Remote Rate Protection (RRRP)	per kWh	$ 0.0012	2021	$ 2.43	$ 0.0012	2021	$ 2.43	$ 0.00	0.01%
Standard Supply Service Charge	Monthly	$ 0.2500	1	$ 0.25	$ 0.2500	1	$ 0.25	$ -	0.00%
Debt Retirement Charge (DRC)			2021	$ -		2021	$ -	$ -	
Energy - RPP - Tier 1		$ 0.0750	600	$ 45.00	$ 0.0750	600	$ 45.00	$ -	0.00%
Energy - RPP - Tier 2		$ 0.0880	1421	$ 125.06	$ 0.0880	1421	$ 125.08	$ 0.01	0.01%
TOU - Off Peak		$ 0.0650	1294	$ 84.08	$ 0.0650	1294	$ 84.09	$ 0.01	0.01%
TOU - Mid Peak		$ 0.1000	364	$ 36.38	$ 0.1000	364	$ 36.38	$ 0.00	0.01%
TOU - On Peak		$ 0.1170	364	$ 42.57	$ 0.1170	364	$ 42.57	$ 0.00	0.01%
Total Bill on RPP (before Taxes)				**$ 261.60**			**$ 252.37**	**-$ 9.23**	**-3.53%**
HST		13%		$ 34.01	13%		$ 32.81	-$ 1.20	-3.53%
Total Bill (including HST)				$ 295.61			$ 285.18	-$ 10.44	-3.53%
Ontario Clean Energy Benefit [1]				-$ 29.56			-$ 28.52	$ 1.04	-3.52%
Total Bill on RPP (including OCEB)				**$ 266.05**			**$ 256.66**	**-$ 9.40**	**-3.53%**
Total Bill on TOU (before Taxes)				**$ 254.57**			**$ 245.33**	**-$ 9.24**	**-3.63%**
HST		13%		$ 33.09	13%		$ 31.89	-$ 1.20	-3.63%
Total Bill (including HST)				$ 287.66			$ 277.23	-$ 10.44	-3.63%
Ontario Clean Energy Benefit [1]				-$ 28.77			-$ 27.72	$ 1.05	-3.65%
Total Bill on TOU (including OCEB)				**$ 258.89**			**$ 249.51**	**-$ 9.39**	**-3.63%**

Loss Factor (%)	1.06%	1.07%

[1] Applicable to eligible customers only. Refer to the *Ontario Clean Energy Benefit Act, 2010.*

Note that the "Charge $" columns provide breakdowns of the amounts that each bill component contributes to the total monthly bill at the referenced consumption level at existing and proposed rates.

Applicants must provide bill impacts for residential at 800 kWh and GS<50kW at 2000 kWh. In addition, their filing should cover the range that is relevant to their service territory, class by class. A general guideline of consumption levels follows:

Residential (kWh) - 100, 250, 500, 800, 1000, 1500, 2000
GS<50kW (kWh) - 1000, 2000, 5000, 10000, 15000
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.

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Appendix 2-W
Bill Impacts

Customer Class: **GS>50**

Consumption 100 **kW** ● May 1 - October 31 ○ November 1 - April 30 (Select this radio button for applications filed after Oc

		Current Board-Approved			Proposed			Impact	
	Charge Unit	**Rate ($)**	**Volume**	**Charge ($)**	**Rate ($)**	**Volume**	**Charge ($)**	**$ Change**	**% Change**
Monthly Service Charge		$ 245.2700	1	$ 245.27	$ 130.0000	1	$ 130.00	-$ 115.27	-47.00%
Smart Meter Rate Adder		$ 14.3000	1	$ 14.30		1	$ -	-$ 14.30	-100.00%
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
Distribution Volumetric Rate		$ 4.5445	100	$ 454.45	$ 1.1660	100	$ 116.60	-$ 337.85	-74.34%
Smart Meter Disposition Rider			100	$ -		100	$ -	$ -	
LRAM & SSM Rate Rider			100	$ -		100	$ -	$ -	
			100	$ -		100	$ -	$ -	
LRAM		$ 0.0284	100	$ 2.84		100	$ -	-$ 2.84	-100.00%
Deferred PILs 1562		-$ 0.2605	100	-$ 26.05		100	$ -	$ 26.05	-100.00%
			100	$ -		100	$ -	$ -	
			100	$ -		100	$ -	$ -	
			100	$ -		100	$ -	$ -	
			100	$ -		100	$ -	$ -	
Sub-Total A				$ 690.81			$ 246.60	**-$ 444.21**	**-64.30%**
Deferral/Variance Account Disposition Rate Rider		-$ 0.7109	100	-$ 71.09	-$ 0.3534	100	-$ 35.34	$ 35.75	-50.29%
Global Adj DVA		$ 0.4834	100	$ 48.34	-$ 0.2425	100	-$ 24.25	-$ 72.59	-150.17%
			100	$ -		100	$ -	$ -	
			100	$ -		100	$ -	$ -	
Low Voltage Service Charge		$ 0.4778	100	$ 47.78	$ 0.6130	100	$ 61.30	$ 13.52	28.30%
Smart Meter Entity Charge		$ 0.7900	1	$ 0.79	$ 0.7900	100	$ 79.00	$ 78.21	
Sub-Total B - Distribution (includes Sub-Total A)				**$ 715.84**			**$ 248.31**	**-$ 467.53**	**-65.31%**
RTSR - Network		$ 2.5726	101	$ 259.98	$ 2.1331	101	$ 215.58	-$ 44.40	-17.08%
RTSR - Line and Transformation Connection		$ 1.8286	101	$ 184.79	$ 1.6823	101	$ 170.02	-$ 14.77	-7.99%
Sub-Total C - Delivery (including Sub-Total B)				**$1,160.62**			**$ 633.92**	**-$ 526.70**	**-45.38%**
Wholesale Market Service Charge (WMSC)		$ 0.0044	101	$ 0.44	$ 0.0044	101	$ 0.44	$ 0.00	0.01%
Rural and Remote Rate Protection (RRRP)		$ 0.0012	101	$ 0.12	$ 0.0012	101	$ 0.12	$ 0.00	0.01%
Standard Supply Service Charge		$ 0.2500	1	$ 0.25	$ 0.2500	1	$ 0.25	$ -	0.00%
Debt Retirement Charge (DRC)			101	$ -		101	$ -	$ -	
Energy - RPP - Tier 1		$ 0.0750	101	$ 7.58	$ 0.0750	101	$ 7.58	$ 0.00	0.01%
Energy - RPP - Tier 2		$ 0.0880	0	$ -	$ 0.0880	0	$ -	$ -	
TOU - Off Peak		$ 0.0650	65	$ 4.20	$ 0.0650	65	$ 4.20	$ 0.00	0.01%
TOU - Mid Peak		$ 0.1000	18	$ 1.82	$ 0.1000	18	$ 1.82	$ 0.00	0.01%
TOU - On Peak		$ 0.1170	18	$ 2.13	$ 0.1170	18	$ 2.13	$ 0.00	0.01%
Total Bill on RPP (before Taxes)				**$ 1,169.01**			**$ 642.31**	**-$ 526.70**	**-45.05%**
HST		13%		$ 151.97	13%		$ 83.50	-$ 68.47	-45.05%
Total Bill (including HST)				$ 1,320.98			$ 725.81	-$ 595.17	-45.05%
Ontario Clean Energy Benefit [1]				-$ 132.10			-$ 72.58	$ 59.52	-45.06%
Total Bill on RPP (including OCEB)				**$ 1,188.88**			**$ 653.23**	**-$ 535.65**	**-45.05%**
Total Bill on TOU (before Taxes)				**$ 1,169.58**			**$ 642.89**	**-$ 526.70**	**-45.03%**
HST		13%		$ 152.05	13%		$ 83.58	-$ 68.47	-45.03%
Total Bill (including HST)				$ 1,321.63			$ 726.46	-$ 595.17	-45.03%
Ontario Clean Energy Benefit [1]				-$ 132.16			-$ 72.65	$ 59.51	-45.03%
Total Bill on TOU (including OCEB)				**$ 1,189.47**			**$ 653.81**	**-$ 535.66**	**-45.03%**
Loss Factor (%)		1.06%			1.07%				

[1] Applicable to eligible customers only. Refer to the *Ontario Clean Energy Benefit Act, 2010.*

Note that the "Charge $" columns provide breakdowns of the amounts that each bill component contributes to the total monthly bill at the referenced consumption level at existing and proposed rates.

Applicants must provide bill impacts for residential at 800 kWh and GS<50kW at 2000 kWh. In addition, their filing should cover the range that is relevant to their service territory, class by class. A general guideline of consumption levels follows:

Residential (kWh) - 100, 250, 500, 800, 1000, 1500, 2000
GS<50kW (kWh) - 1000, 2000, 5000, 10000, 15000
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.

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Bill Impacts

Customer Class: **Unmetered Scatterred Load**

Consumption 500 **kWh** ● May 1 - October 31 ○ November 1 - April 30 (Select this radio button for applications filed after C

		Current Board-Approved			Proposed			Impact	
	Charge Unit	**Rate ($)**	**Volume**	**Charge ($)**	**Rate ($)**	**Volume**	**Charge ($)**	**$ Change**	**% Change**
Monthly Service Charge		$ 40.01	1	$ 40.01	$ 12.00	1	$ 12.00	-$ 28.01	-70.01%
Smart Meter Rate Adder			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
Distribution Volumetric Rate		$ 0.0104	500	$ 5.20	$ 0.0302	500	$ 15.10	$ 9.90	190.38%
Smart Meter Disposition Rider			500	$ -		500	$ -	$ -	
LRAM & SSM Rate Rider			500	$ -		500	$ -	$ -	
			500	$ -		500	$ -	$ -	
			500	$ -		500	$ -	$ -	
Deferred PILs 1562		-$ 0.0051	500	-$ 2.55		500	$ -	$ 2.55	-100.00%
			500	$ -		500	$ -	$ -	
			500	$ -		500	$ -	$ -	
			500	$ -		500	$ -	$ -	
			500	$ -		500	$ -	$ -	
Sub-Total A				$ 42.66			$ 27.10	**-$ 15.56**	**-36.47%**
Deferral/Variance Account Disposition Rate Rider		-$ 0.0021	500	-$ 1.05	-$ 0.0011	500	-$ 0.55	$ 0.50	-47.62%
Global Adj DVA		$ 0.0014	500	$ 0.70	-$ 0.0007	500	-$ 0.35	-$ 1.05	-150.00%
			500	$ -		500	$ -	$ -	
			500	$ -		500	$ -	$ -	
Low Voltage Service Charge		$ 0.0013	500	$ 0.65	$ 0.0016	500	$ 0.80	$ 0.15	23.08%
Smart Meter Entity Charge		$ 0.7900	1	$ 0.79	$ 0.7900	500	$ 395.00	$ 394.21	
Sub-Total B - Distribution (includes Sub-Total A)				**$ 42.96**			**$ 27.00**	**-$ 15.96**	**-37.15%**
RTSR - Network		$ 0.0064	505	$ 3.23	$ 0.0053	505	$ 2.68	-$ 0.56	-17.18%
RTSR - Line and Transformation Connection		$ 0.0046	505	$ 2.32	$ 0.0042	505	$ 2.12	-$ 0.20	-8.69%
Sub-Total C - Delivery (including Sub-Total B)				**$ 48.52**			**$ 31.80**	**-$ 16.72**	**-34.46%**
Wholesale Market Service Charge (WMSC)		$ 0.0044	505	$ 2.22	$ 0.0044	505	$ 2.22	$ 0.00	0.01%
Rural and Remote Rate Protection (RRRP)		$ 0.0012	505	$ 0.61	$ 0.0012	505	$ 0.61	$ 0.00	0.01%
Standard Supply Service Charge		$ 0.2500	1	$ 0.25	$ 0.2500	1	$ 0.25	$ -	0.00%
Debt Retirement Charge (DRC)			505	$ -		505	$ -	$ -	
Energy - RPP - Tier 1		$ 0.0750	505	$ 37.90	$ 0.0750	505	$ 37.90	$ 0.00	0.01%
Energy - RPP - Tier 2		$ 0.0880	0	$ -	$ 0.0880	0	$ -	$ -	
TOU - Off Peak		$ 0.0650	323	$ 21.02	$ 0.0650	323	$ 21.02	$ 0.00	0.01%
TOU - Mid Peak		$ 0.1000	91	$ 9.10	$ 0.1000	91	$ 9.10	$ 0.00	0.01%
TOU - On Peak		$ 0.1170	91	$ 10.64	$ 0.1170	91	$ 10.64	$ 0.00	0.01%
Total Bill on RPP (before Taxes)				**$ 89.49**			**$ 72.78**	**-$ 16.71**	**-18.68%**
HST		13%		$ 11.63	13%		$ 9.46	-$ 2.17	-18.68%
Total Bill (including HST)				$ 101.13			$ 82.24	-$ 18.89	-18.68%
Ontario Clean Energy Benefit [1]				-$ 10.11			-$ 8.22	$ 1.89	-18.69%
Total Bill on RPP (including OCEB)				**$ 91.02**			**$ 74.02**	**-$ 17.00**	**-18.67%**
Total Bill on TOU (before Taxes)				**$ 92.35**			**$ 75.64**	**-$ 16.71**	**-18.10%**
HST		13%		$ 12.01	13%		$ 9.83	-$ 2.17	-18.10%
Total Bill (including HST)				$ 104.36			$ 85.47	-$ 18.89	-18.10%
Ontario Clean Energy Benefit [1]				-$ 10.44			-$ 8.55	$ 1.89	-18.10%
Total Bill on TOU (including OCEB)				**$ 93.92**			**$ 76.92**	**-$ 17.00**	**-18.10%**

Loss Factor (%)		1.06%			1.07%				

[1] Applicable to eligible customers only. Refer to the *Ontario Clean Energy Benefit Act, 2010*.

Note that the "Charge $" columns provide breakdowns of the amounts that each bill component contributes to the total monthly bill at the referenced consumption level at existing and proposed rates.

Applicants must provide bill impacts for residential at 800 kWh and GS<50kW at 2000 kWh. In addition, their filing should cover the range that is relevant to their service territory, class by class. A general guideline of consumption levels follows:

Residential (kWh) - 100, 250, 500, 800, 1000, 1500, 2000
GS<50kW (kWh) - 1000, 2000, 5000, 10000, 15000
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.

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Bill Impacts

Customer Class: **StreetLights**

Consumption 1 **kW** ● May 1 - October 31 ○ November 1 - April 30 (Select this radio button for applications filed after O

	Charge Unit	Current Board-Approved Rate ($)	Current Board-Approved Volume	Current Board-Approved Charge ($)	Proposed Rate ($)	Proposed Volume	Proposed Charge ($)	Impact $ Change	Impact % Change
Monthly Service Charge	Monthly	$ 1.60	1	$ 1.60	$ 1.75	1	$ 1.75	$ 0.15	9.37%
Smart Meter Rate Adder			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
Distribution Volumetric Rate		$ 6.5145	1	$ 6.51	$ 9.9685	1	$ 9.97	$ 3.45	53.02%
Smart Meter Disposition Rider			1	$ -		1	$ -	$ -	
LRAM & SSM Rate Rider			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
Deferred PILs 1562		-$ 0.5708	1	-$ 0.57		1	$ -	$ 0.57	-100.00%
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
Sub-Total A				$ 7.54			$ 11.72	**$ 4.17**	**55.34%**
Deferral/Variance Account Disposition Rate Rider		-$ 0.7349	1	-$ 0.73	-$ 0.4921	1	-$ 0.49	$ 0.24	-33.04%
Global Adj DVA			1	$ -	-$ 0.2501	1	-$ 0.25	-$ 0.25	
			1	$ -		1	$ -	$ -	
			1	$ -		1	$ -	$ -	
Low Voltage Service Charge		$ 0.3694	1	$ 0.37	$ 0.4739	1	$ 0.47	$ 0.10	28.29%
Smart Meter Entity Charge		$ 0.7900	1		$ 0.7900	1	$ 0.79	$ 0.79	
Sub-Total B - Distribution (includes Sub-Total A)				**$ 7.18**			**$ 11.45**	**$ 4.27**	**59.51%**
RTSR - Network		$ 1.9403	1	$ 1.96	$ 1.6088	1	$ 1.63	-$ 0.33	-17.08%
RTSR - Line and Transformation Connection		$ 1.4136	1	$ 1.43	$ 1.3005	1	$ 1.31	-$ 0.11	-7.99%
Sub-Total C - Delivery (including Sub-Total B)				**$ 10.57**			**$ 14.39**	**$ 3.82**	**36.18%**
Wholesale Market Service Charge (WMSC)		$ 0.0044	1	$ 0.00	$ 0.0044	1	$ 0.00	$ 0.00	0.01%
Rural and Remote Rate Protection (RRRP)		$ 0.0012	1	$ 0.00	$ 0.0012	1	$ 0.00	$ 0.00	0.01%
Standard Supply Service Charge		$ 0.2500	1	$ 0.25	$ 0.2500	1	$ 0.25	$ -	0.00%
Debt Retirement Charge (DRC)			1	$ -		1	$ -	$ -	
Energy - RPP - Tier 1		$ 0.0750	1	$ 0.08	$ 0.0750	1	$ 0.08	$ 0.00	0.01%
Energy - RPP - Tier 2		$ 0.0880	0	$ -	$ 0.0880	0	$ -	$ -	
TOU - Off Peak		$ 0.0650	1	$ 0.04	$ 0.0650	1	$ 0.04	$ 0.00	0.01%
TOU - Mid Peak		$ 0.1000	0	$ 0.02	$ 0.1000	0	$ 0.02	$ 0.00	0.01%
TOU - On Peak		$ 0.1170	0	$ 0.02	$ 0.1170	0	$ 0.02	$ 0.00	0.01%
Total Bill on RPP (before Taxes)				**$ 10.90**			**$ 14.72**	**$ 3.82**	**35.08%**
HST		13%		$ 1.42	13%		$ 1.91	$ 0.50	35.08%
Total Bill (including HST)				$ 12.32			$ 16.64	$ 4.32	35.08%
Ontario Clean Energy Benefit [1]				-$ 1.23			-$ 1.66	-$ 0.43	34.96%
Total Bill on RPP (including OCEB)				**$ 11.09**			**$ 14.98**	**$ 3.89**	**35.09%**
Total Bill on TOU (before Taxes)				**$ 10.90**			**$ 14.73**	**$ 3.82**	**35.06%**
HST		13%		$ 1.42	13%		$ 1.91	$ 0.50	35.06%
Total Bill (including HST)				$ 12.32			$ 16.64	$ 4.32	35.06%
Ontario Clean Energy Benefit [1]				-$ 1.23			-$ 1.66	-$ 0.43	34.96%
Total Bill on TOU (including OCEB)				**$ 11.09**			**$ 14.98**	**$ 3.89**	**35.07%**
Loss Factor (%)		1.06%			1.07%				

[1] Applicable to eligible customers only. Refer to the *Ontario Clean Energy Benefit Act, 2010.*

Note that the "Charge $" columns provide breakdowns of the amounts that each bill component contributes to the total monthly bill at the referenced consumption level at existing and proposed rates.

Applicants must provide bill impacts for residential at 800 kWh and GS<50kW at 2000 kWh. In addition, their filing should cover the range that is relevant to their service territory, class by class. A general guideline of consumption levels follows:

Residential (kWh) - 100, 250, 500, 800, 1000, 1500, 2000
GS<50kW (kWh) - 1000, 2000, 5000, 10000, 15000
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.

Exhibit 9 – Deferral and Variance Acct

Exhibit 9 – Deferral and Variance Acct

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EXHIBIT 9 – DEFERRAL AND VARIANCE ACCOUNT

The evidence presented in this exhibit provides information supporting the utility's expected deficit at existing rates for the 2014 Test year. The evidence herein is organized according to the following topics;

1) Status and Disposition of Deferral and Variance Accounts

Tab 1 – Status and disposition of Deferral and Variance Accounts

E9.T1.S1 DESCRIPTION OF DVA USED BY THE APPLICANT

CHEI follows and is in compliance with the OEB's Uniform System of Accounts for electricity distributors. All accounts are used in accordance with the Accounting Procedures Handbook.

CHEI used the cash method to calculate carrying charges. Effective July 1, 2012 CHEI has transitioned to the accrual method in accordance with the Board's directive. The Board prescribed interest rates are used to calculate the carrying charges and the interest is recorded in a sub-account.

At December 31, 2012, CHEI has balances in the following Board-approved deferral and variance accounts:

Group 1 Accounts

1550 – LV Variance Account

Account Description: This account is used to record the variances arising from low voltage transactions which are not part of the electricity wholesale market.

Account 1550: Low Voltage (LV) Variance Account

This account captures the difference between the amounts included in rates and billed to customers and the cost to CHEI of Hydro One's charges for using its LV lines to transmit electricity from its transformer stations to CHEI's distribution system. The low voltage costs forecast for 2014 are proposed to be collected through a rate rider consistent with past practice. The details supporting this calculation can be found in Exhibit 8.

For 2014, CHEI is requesting disposition of the December 31, 2012 audited balance, plus the forecasted interest through December 30, 2013 for account 1550.

The balance requested for disposal, including carrying charges is a debit of $21,533.

1580 – Retail Settlement Variance Account 1 – Wholesale Market Service Charges (“RSVAWMS”)

Account Description: The Retail Settlement Variance Account is used to record net differences in Wholesale Market Service Charges, including accruals.

RSVAWMS is used to record the difference between the amount of wholesale market services charges paid to the IESO or host distributor and the amounts billed to customers for wholesale market services 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 RSVA account.

For 2014, CHEI is requesting disposition of the December 31, 2012 audited balance, plus the forecasted interest through December 30, 2013 for account 1580.

The balance requested for disposal, including carrying charges is a credit of $40,812.

1584 – Retail Settlement Variance Account – Retail Transmission Network Charges ("RSVA$_{NW}$")

Account Description: The Retail Settlement Variance Account is used to record net differences in Retail Transmission Network Charges, including accruals.

RSVANW 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 for retail transmission network costs. 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.

For 2014, CHEI is requesting disposition of the December 31, 2012 audited balance, plus the forecasted interest through December 30, 2013 for account 1584. The December 31, 2011 audited balance of $-2,564 reconciles with filing 2.1.7 of the RRR.

The balance requested for disposal, including carrying charges is a credit of $-2,643.

1586 – Retail Settlement Variance Account – Retail Transmission Connection Charges ("RSVA$_{CN}$")

Account Description: The Retail Settlement Variance Account is used to record net differences in Retail Transmission Connection Charges, including accruals.

RSVACN 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 for retail transmission connection costs. 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.

For 2014, CHEI is requesting disposition of the December 31, 2012 audited balance, plus the forecasted interest through December 30, 2013 for account 1586. The December 31, 2011 audited balance of $2,018 reconciles with filing 2.1.7 of the RRR.

The balance requested for disposal, including carrying charges is a debit of $2,107.

1588 – Retail Settlement Variance Account– Power (“RSVAPOWER”)

Account Description: The Retail Settlement Variance Account is used to record net differences between the energy amount charged to customers, including accruals AND the energy charge to a distributor using the settlement invoice received from the IESO, host distributor or embedded generator

The RSVAPOWER account is to be 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.

The RSVA power account is designed to capture variances due to billing timing differences (i.e. electricity charged by IESO to LDCs vs. electricity billed by LDCs to their customers), price and quantity differences (i.e. arising from final vs. preliminary

IESO settlement invoices), and line loss differences (i.e. actual vs. estimated line loss factors).

This account is not designed to capture any price differences between the regulated price plan (RPP) and spot prices applicable to RPP customers. This is the function of the Ontario Power Authority (OPA) RPP variance account which is trued-up in accordance with the terms established by the Board for the RPP.

Accordingly, since the RSVA power account is generic to all customers of an LDC, disposition of the account balance in rates is attributable to all its customers.

For 2014, CHEI is requesting disposition of the December 31, 2012 audited balance, plus the forecasted interest through December 30, 2013 for account 1588 RSVA. The December 31, 2012 audited balance of $-21,123 reconciles with filing 2.1.7 of the RRR.

The balance requested for disposal, including carrying charges is a credit of $-21,851.

1588 – Retail Settlement Variance Account – Global Adjustment (“RSVA$_{GA}$”)

Account Description: The Retail Settlement Variance Account is used to record the Global Adjustment net differences between the global adjustment amounts billed to non-RPP customers, including accruals AND the global adjustment charge to a distributor using the settlement invoice received from the IESO, host distributor or embedded generator.

The RSVAGA 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, host distributor or embedded generator. 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.

The 1588 RSVA power - Sub-account Global Adjustments is designed for the global adjustments applicable to non-RPP customers. Hence, the disposition of the account balance should be attributable to non-RPP customers.

For 2014, CHEI is requesting disposition of the December 31, 2012 audited balance, plus the forecasted interest through December 30, 2013 for account 1588GA. The December 31, 2012 audited balance of $-8,004 reconciles with filing 2.1.7 of the RRR.

The balance requested for disposal, including carrying charges is a credit of $-8,305.

1595 – Recovery/Disposition of Regulatory Asset Balances (Recovery or Refund Period completed)

Account Description: This account is used to record the disposition and recoveries of deferral and variance account balances for electricity distributors receiving *approval to recover (or refund) account balances in rates as part of the regulatory process.*

This account includes the regulatory asset or liability balances authorized by the Board for recovery in rates or payments/credits made to customers. Separate sub-accounts are maintained for expenses, interest, and recovery amounts for each Board-approved recovery. CHEI only filed for disposition of actual year-end total balance for Group 1 Accounts including projected interest in 2012. Other years' year end balances did not exceed the preset disposition threshold.

1595 - Disposition and Recovery/Refund of Regulatory Balances (2010)

For 2014, CHEI is requesting disposition of the December 31, 2012 audited balance. The December 31, 2012 audited balance of $-111,523 reconciles with filing 2.1.7 of the RRR.

The balance requested for disposal, including carrying charges is a credit of $-37,178.

Group 2 Accounts

1508 – Other Regulatory Assets – OEB Cost Assessment/Pension Contribution

OEB Cost Assessment; This account is used to record the difference between OEB costs assessments invoiced to the distributor for the Board's 2004/05 and 2005/06 (up to April 30, 2006) fiscal years and OEB costs assessments previously included the distributor's rates. For 2014, CHEI is requesting disposition of the December 31, 2012 audited balance, plus forecasted interest through December 30, 2013. The requested amount is a debit balance of $604.

Pension Contributions; A distributor shall use this account to record the pension costs associated with the cash contributions paid to Ontario Municipal Employees Retirement Savings (“OMERS”) for the period from January 1, 2005 to April 30, 2006 or where the distributor receives approval through an order of the Board to record pension costs in a deferral account for a specified period. For 2014, CHEI is requesting disposition of the December 31, 2012 audited balance, plus forecasted interest through December 30, 2013. The requested amount is a debit balance of $685.

The total of $1,289 recoverable from ratepayers is included for review and final disposition for this sub-account in this rate application.

1592- PILs and Tax Variance for 2006 and Subsequent Years (excludes sub-account and contra account)

For 2014, CHEI is requesting disposition of the December 31, 2012 audited balance, plus forecasted interest through December 30, 2013. The requested amount is a credit balance of $-2,847.

1592- PILs and Tax Variance for 2006 and Subsequent Years - Sub-Account HST/OVAT Input Tax Credits (ITCs)

For 2014, CHEI is requesting disposition of the December 31, 2012 audited balance, plus forecasted interest through December 30, 2013. The requested amount is a debit balance of $3,816.

CHEI intends to continue all accounts identified above on an ongoing basis that are listed in Group 1. In Group 2, with the exception of 1508 and 1592, remaining accounts balances are subject to review from BDO and the OEB and as such, CHEI does not propose to dispose of these other balances at this time.

All other deferral and variance accounts in Group 2 are not sought for disposition as they require a prudence review and lend themselves to a disposition threshold

E9.T1.S2 DVA BALANCES AND CONTINUITY SCHEDULE

Table 1 below presents the list of deferral and variance accounts, with the proposed selection of balances for disposition. All account balances selected for disposition are as at December 31, 2012 being the most recent date the balances was subject to audit.

Board policy states: at the time of rebasing, all Account balances should be disposed of unless otherwise justified by the distributor or as required by a specific Board decision or guideline. In accordance with the above statement, CHEI proposes to dispose of all its balances

The 2013_EDDVAR_Continuity_Schedule_CoS_v2_20120706 detailing each account is being filed in conjunction with this application

Table 1: Deferral and Variance Balances proposed for disposition

		Amounts from Sheet 2
LV Variance Account	1550	21,533
RSVA - Wholesale Market Service Charge	1580	(23,665)
RSVA - Retail Transmission Network Charge	1584	(2,643)
RSVA - Retail Transmission Connection Charge	1586	2,107
RSVA - Power (excluding Global Adjustment)	1588	(21,851)
RSVA - Power - Sub-account - Global Adjustment	1588	(8,305)
Recovery of Regulatory Asset Balances	1590	0
Disposition and Recovery/Refund of Regulatory Balances (2008)	1595	(0)
Disposition and Recovery/Refund of Regulatory Balances (2009)	1595	0
Disposition and Recovery/Refund of Regulatory Balances (2010)	1595	(37,178)
Total of Group 1 Accounts (excluding 1588 sub-account)		**(61,697)**

Other Regulatory Assets - Sub-Account - OEB Cost Assessments	1508	604
Other Regulatory Assets - Sub-Account - Pension Contributions	1508	685
Other Regulatory Assets - Sub-Account - Deferred IFRS Transition Costs	1508	0
Other Regulatory Assets - Sub-Account - Incremental Capital Charges	1508	0
Other Regulatory Assets - Sub-Account - Financial Assistance Payment and Recovery Variance - Ontario Clean Energy Benefit Act	1508	0
Other Regulatory Assets - Sub-Account - Financial Assistance Payment and Recovery Carrying Charges	1508	0
Other Regulatory Assets - Sub-Account - Other	1508	0
Retail Cost Variance Account - Retail	1518	0
Misc. Deferred Debits	1525	0
Renewable Generation Connection Capital Deferral Account	1531	0
Renewable Generation Connection OM&A Deferral Account	1532	0
Renewable Generation Connection Funding Adder Deferral Account	1533	0
Smart Grid Capital Deferral Account	1534	0
Smart Grid OM&A Deferral Account	1535	
Smart Grid Funding Adder Deferral Account	1536	0
Retail Cost Variance Account - STR	1548	0
Board-Approved CDM Variance Account	1567	0
Extra-Ordinary Event Costs	1572	0
Deferred Rate Impact Amounts	1574	0
RSVA - One-time	1582	0
Other Deferred Credits	2425	0
Total of Group 2 Accounts		**1,289**

Deferred Payments in Lieu of Taxes	1562	0
PILs and Tax Variance for 2006 and Subsequent Years (excludes sub-account and contra account)	1592	(2,847)

PILs and Tax Variance for 2006 and Subsequent Years - Sub-Account HST/OVAT Input Tax Credits (ITCs)	1592	0
Total of Account 1562 and Account 1592		**(2,847)**

Special Purpose Charge Assessment Variance Account	1521	0
LRAM Variance Account **(Enter dollar amount for each class)**	1568	1,946
(Account 1568 - total amount allocated to classes)		1,946
Variance		0

Total Balance Allocated to each class (excluding 1588 sub-account)	**(61,309)**
Total Balance in Account 1588 - sub account	**(8,305)**
Total Balance Allocated to each class (including 1588 sub-account)	**(69,615)**

E9.T1.S3 INTEREST RATES APPLIED

Table 2 below provides the interest rates by quarter that are applied to calculate actual and forecast carrying charges for each regulatory and variance account.

Table 2: Interest Rates Applied to Deferral and Variance Accounts (%)

Q2 2013	1.47		Q4 2009	0.55
Q1 2013	1.47		Q3 2009	0.55
Q4 2012	1.47		Q2 2009	1
Q3 2012	1.47		Q1 2009	2.45
Q2 2012	1.47		Q3 2008	3.35
Q1 2012	1.47		Q4 2008	3.35
Q4 2011	1.47		Q2 2008	4.08
Q3 2011	1.47		Q1 2008	5.14
Q2 2011	1.47		Q4 2007	5.14
Q1 2011	1.47		Q3 2007	4.59
Q4 2010	1.2		Q2 2007	4.59
Q3 2010	0.89		Q1 2007	4.59
Q2 2010	0.55		Q4 2006	4.59
Q1 2010	0.55		Q3 2006	4.59

E9.T1.S4 CALCULATION OF RATE RIDER

CHEI is proposing to dispose of these balances over a period of two years instead of one year. The only reason for choosing a two year disposal period instead of one year disposal period is to try to minimize the rate shock that would occur if the balances rate rider were to expire after a single year. The rate rider calculations are presented at the next page.

Deferral/Variance Account Workform for 2013 Filers

		Amounts from Sheet 2	Allocator	Residential	General Service < 50 kW	General Service > 50 to 4999 kW	Unmetered Scattered Load	Street Lighting
LV Variance Account	1550	21,533	kWh	14,522	3,508	3,175	66	263
RSVA - Wholesale Market Service Charge	1580	(23,665)	kWh	(15,959)	(3,855)	(3,489)	(73)	(289)
RSVA - Retail Transmission Network Charge	1584	(2,643)	kWh	(1,783)	(431)	(390)	(8)	(32)
RSVA - Retail Transmission Connection Charge	1586	2,107	kWh	1,421	343	311	6	26
RSVA - Power (excluding Global Adjustment)	1588	(21,851)	kWh	(14,736)	(3,560)	(3,222)	(67)	(267)
RSVA - Power - Sub-account - Global Adjustment	1588	(8,305)	Non-RPP kWh	(1,286)	(440)	(6,057)	(20)	(502)
Recovery of Regulatory Asset Balances	1590	0	kWh	0	0	0	0	0
Disposition and Recovery/Refund of Regulatory Balances (2008)	1595	(0)	kWh	(0)	(0)	(0)	(0)	(0)
Disposition and Recovery/Refund of Regulatory Balances (2009)	1595	0	kWh	0	0	0	0	0
Disposition and Recovery/Refund of Regulatory Balances (2010)	1595	(37,178)	kWh	(25,072)	(6,056)	(5,482)	(114)	(454)
Total of Group 1 Accounts (excluding 1588 sub-account)		**(61,697)**		**(41,607)**	**(10,051)**	**(9,097)**	**(189)**	**(753)**
Other Regulatory Assets - Sub-Account - OEB Cost Assessments	1508	604		453	40	3	5	104
Other Regulatory Assets - Sub-Account - Pension Contributions	1508	685		514	45	3	5	118
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	1508	0		0	0	0	0	0
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	1508	0		0	0	0	0	0
Retail Cost Variance Account - Retail	1518	0		0	0	0	0	0
Misc. Deferred Debits	1525	0		0	0	0	0	0
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
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
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
Total of Group 2 Accounts		**1,289**		**967**	**85**	**6**	**10**	**221**
Deferred Payments in Lieu of Taxes	1562	0		0	0	0	0	0
PILs and Tax Variance for 2006 and Subsequent Years (excludes sub-account and contra account)	1592	(2,847)		(2,135)	(187)	(13)	(23)	(488)
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 Account 1562 and Account 1592		**(2,847)**		**(2,135)**	**(187)**	**(13)**	**(23)**	**(488)**
Special Purpose Charge Assessment Variance Account	1521	0		0	0	0	0	0
LRAM Variance Account **(Enter dollar amount for each class)**	1568	1,946		1,242	386	279	5	34
(Account 1568 - total amount allocated to classes)		1,946						
Variance		0						
Total Balance Allocated to each class (excluding 1588 sub-account)		**(61,309)**		**(41,534)**	**(9,767)**	**(8,825)**	**(197)**	**(987)**
Total Balance in Account 1588 - sub account		**(8,305)**		**(1,286)**	**(440)**	**(6,057)**	**(20)**	**(502)**
Total Balance Allocated to each class (including 1588 sub-account)		**(69,615)**		**(42,820)**	**(10,207)**	**(14,882)**	**(217)**	**(1,489)**

E9.T1.S5 DEPARTURE FROM BOARD APPROVED BALANCES

CHEI has not made any adjustments to deferral and variance account balances that were previously approved by the Board on a final basis in either cost of service or IRM proceedings

E9.T1.S6 RECONCILIATION OF ENERGY SALES AND COST OF POWER EXPENSES TO FINANCIAL STATEMENTS

The filing requirements state that a breakdown of energy sales and cost of power expenses, as reported in the 2011 audited financial statements is requested. Please refer to Table 2 below for an excerpt from the model that CHEI used to calculate its projected rates.

Table 2: Energy Sales and Cost of Power Expenses

	2012	2011	2010	2010BA	2009
4006-Residential Energy Sales	-1,726,518.90	-1,905,409.86	-1,360,848.95	-1,625,781.00	-943,579.86
4010-Commercial Energy Sales	-345,026.98		-347,619.56		
4015-Industrial Energy Sales	-38,294.88	-48,532.39	-47,656.84		
4020-Energy Sales to Large Users					
4025-Street Lighting Energy Sales		-6,366.72	-12,402.91	-25,528.00	-21,770.39
4030-Sentinel Lighting Energy Sales					
4035-General Energy Sales	-49,771.71	-79,644.90	-114,738.06	-288,494.00	-26,550.15
4040-Other Energy Sales to Public Authorities					
4050-Revenue Adjustment					
4055-Energy Sales for Resale	-64,564.40	-63,129.99	-76,047.70		-57,260.30
	-2,224,176.87	-2,103,083.86	-1,959,314.02	-1,939,803.00	-1,049,160.70
4705-Power Purchased	2,224,176.87	2,103,083.86	1,959,314.02	1,939,803.00	1,049,160.69

As can be seen above, there is no difference between energy sales and cost of power expense reported numbers.

E9.T1.S7 PRO-RATA OF GLOBAL ADJUSTMENT INTO RPP/NON-RPP

CHEI confirms that it pro-rated the IESO Global Adjustment Charge into the RPP and non-RPP portions.

E9.T1.S8 REQUEST FOR NEW VARIANCE ACCOUNT

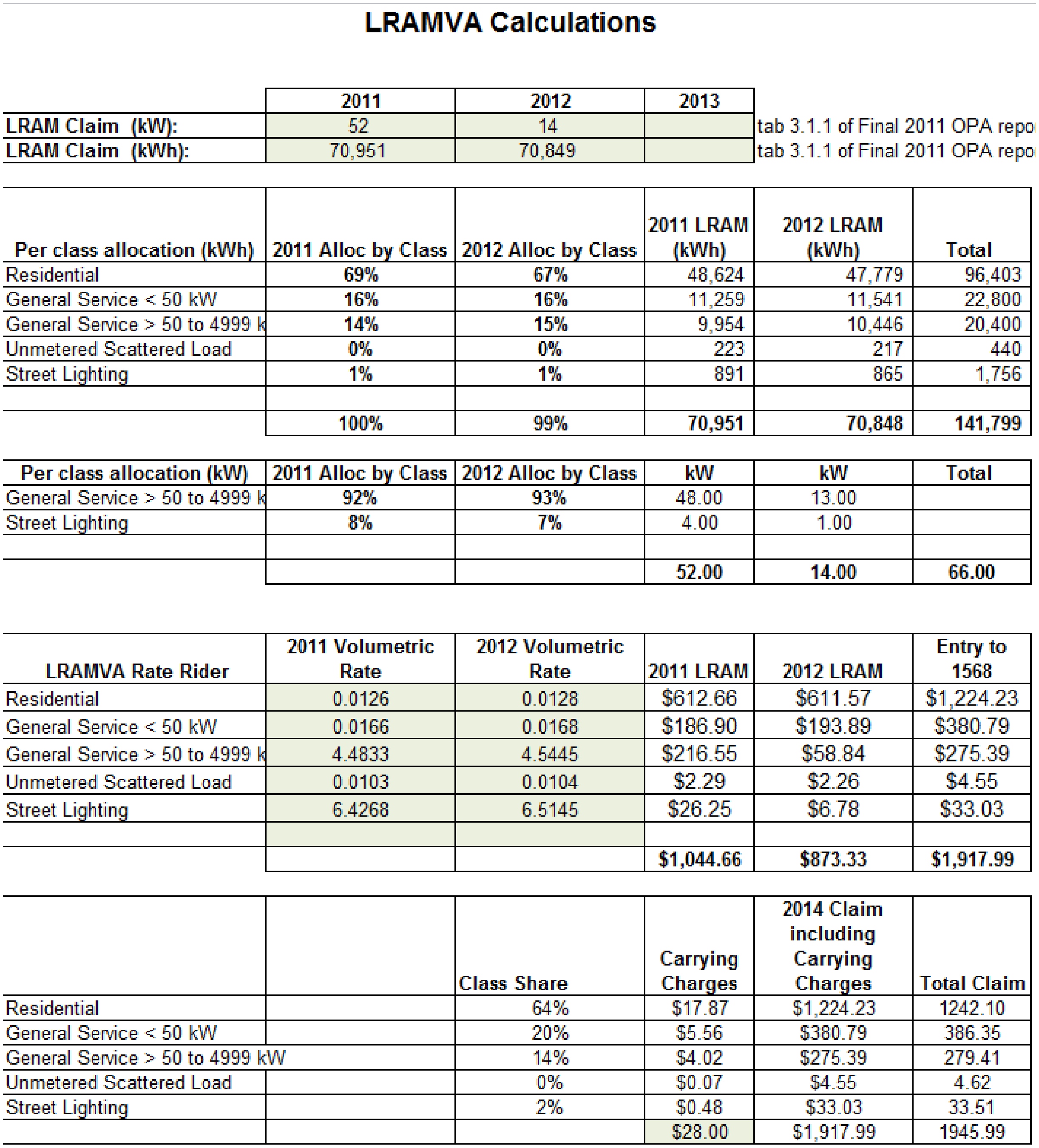
The applicant is not requesting any new accounts or sub-accounts at this time. CHEI will continue to monitor OEB directives and implement new accounts as set out by the OEB and identified in the Accounting Procedures Handbook or other sources of information as required complying with regulation.

E9.T1.S9 LRAMVA

At this time, the applicant is not including an LRAM Variance Account (LRAMVA); however, CHEI may request for application of this account in a future application. This is consistent with the information disclosed in the "Ontario Energy Board Accounting Procedures Handbook Frequently Asked Questions" dated July 2012.

Revised June 13, 2014: For 2014, HHI is requesting disposition of the December 31, 2012 un-audited balance, plus forecasted interest through December 30, 2013. The requested amount is a debit balance of $ 1,916 as detailed at Section

E4.T7.S2 of Exhibit 4. Carrying charges up to December 31, 2013 are calculated at $28. The determination of the class specific rate rider is presented below.



LRAMVA Calculations

	2011	2012	2013	
LRAM Claim (kW):	52	14		tab 3.1.1 of Final 2011 OPA repo
LRAM Claim (kWh):	70,951	70,849		tab 3.1.1 of Final 2011 OPA repo

Per class allocation (kWh)	**2011 Alloc by Class**	**2012 Alloc by Class**	**2011 LRAM (kWh)**	**2012 LRAM (kWh)**	**Total**
Residential	**69%**	**67%**	48,624	47,779	96,403
General Service < 50 kW	**16%**	**16%**	11,259	11,541	22,800
General Service > 50 to 4999 k	**14%**	**15%**	9,954	10,446	20,400
Unmetered Scattered Load	**0%**	**0%**	223	217	440
Street Lighting	**1%**	**1%**	891	865	1,756
	100%	**99%**	**70,951**	**70,848**	**141,799**

Per class allocation (kW)	**2011 Alloc by Class**	**2012 Alloc by Class**	**kW**	**kW**	**Total**
General Service > 50 to 4999 k	**92%**	**93%**	48.00	13.00	
Street Lighting	**8%**	**7%**	4.00	1.00	
			52.00	**14.00**	**66.00**

LRAMVA Rate Rider	**2011 Volumetric Rate**	**2012 Volumetric Rate**	**2011 LRAM**	**2012 LRAM**	**Entry to 1568**
Residential	0.0126	0.0128	$612.66	$611.57	$1,224.23
General Service < 50 kW	0.0166	0.0168	$186.90	$193.89	$380.79
General Service > 50 to 4999 k	4.4833	4.5445	$216.55	$58.84	$275.39
Unmetered Scattered Load	0.0103	0.0104	$2.29	$2.26	$4.55
Street Lighting	6.4268	6.5145	$26.25	$6.78	$33.03
			$1,044.66	**$873.33**	**$1,917.99**

		Class Share	**Carrying Charges**	**2014 Claim including Carrying Charges**	**Total Claim**
Residential		64%	$17.87	$1,224.23	1242.10
General Service < 50 kW		20%	$5.56	$380.79	386.35
General Service > 50 to 4999 kW		14%	$4.02	$275.39	279.41
Unmetered Scattered Load		0%	$0.07	$4.55	4.62
Street Lighting		2%	$0.48	$33.03	33.51
			$28.00	$1,917.99	1945.99