Chapleau Public Utilities Corporation

2012 Rate Rebasing Application

EB-2011-0322

Response to Board Staff Interrogatories

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Interrogatories

<u>Appendices</u>

Pursuant to Procedural Order No. 1, the following are Board staff's interrogatories in Chapleau Public Utilities Corporation ("CPUC") 2012 Cost of Service Application, EB-2011-0322.

1. Letters of Comment

Reference: Notice of Application and Hearing

Following publication of the Notice of Application and Hearing, the Board has received no letters of comment to date.

a. Please confirm whether CPUC has received any letters of comment, and if so, please file a copy of the letters of comment.

Response

CPUC confirms that no letters of comment have been received to date.

b. Please confirm whether a reply was sent from CPUC for each. If confirmed, please file the reply with the Board. Please ensure that the author's contact information except for the name is **redacted**.

Response - Not Applicable

c. If not confirmed, please explain why a response was not sent and confirm if CPUC intends to respond.

Response - Not Applicable

2. Effective Date for New Rates

Reference: Exhibit 1 page 13

CPUC filed its 2012 rate rebasing application on January 30, 2012. In its Application, CPUC requested rates to be effective May 1, 2012. In a letter dated March 1, 2011, the Board stated that applicants should file no later than August 26, 2011 for rates to become effective May 1, 2012. Please explain why CPUC is late, and why rates should be effective May 1, 2012.

Response

CPUC was late in filing its 2012 rate rebasing application due to the enormous amount of detail required to complete the application and to ensure its accuracy.

CPUC is one of the smallest distribution utilities in Ontario with only two administrative employees; the Secretary Treasurer and a secretary/clerk who are responsible for all office activities that include billing and collecting, accounts payable, payroll, bookkeeping, customer inquiries, RRR filings, etc. and find that the rate rebasing application requires a tremendous amount of detailed information and is very onerous on their time.

CPUC does not expect rates to be effective May 1, 2012 due to the lateness of the application. Based on the Boards experience, approval of CPUCs rates may not be approved until October 1, 2012. This late approval will impact CPUCs revenue requirement for 2012 by an estimated $78,700 for the 5 months, May 1, 2012 to September 30, 2012, and therefore requests that the Board consider a "Lost Revenue Rider" to recover the lost revenue.

CPUC requests approval of the 2012 rate rebasing application at the earliest opportunity so as to minimize the impact lower rates will have on CPUC and its customers.

3. Financial Reporting

Reference: Exhibit 1 page 15 & 26

2010 Audited Financial Statements page 8

Board letter April 30, 2012

Chapter 2 of the Filing Requirements for Transmission and Distribution Applications Section 2.4.3

CPUC did not file using the International Financial Reporting Standard ("IFRS"). The Board, in a letter dated April 30, 2012, provided guidance to all electricity utilities on the impacts of a decision by the Canadian Accounting Standards Board to defer the mandatory changeover to IFRS to January 1, 2013. The Board stated that it will not require regulatory accounting and reporting for 2012 to be in Modified IFRS ("MIFRS") if a distributor is not required to adopt IFRS for financial reporting and opts to remain on Canadian Generally Accepted Accounting Principles ("CGAAP").

On page 8 of its 2010 Audited Financial statement in note 1 (i), it states: "The Corporation has launched an internal initiative to govern the conversion process and is currently in the process of evaluating the potential impact of the conversion to IFRS on its financial statements." While CPUC is not required to file the 2012 test year or report to the Board based on the Board established MIFRS, CPUC will be required to do so in 2013.

a. Please state the steps and the timelines that CPUC has and will be taking to prepare itself for MIFRS.

<u>Response</u>

Based on the letter issued by the Board dated April 30, 2012 that provided guidance to all electricity utilities on the impacts of a decision by the Canadian Accounting Standards Board to defer the mandatory changeover to IFRS to January 1, 2013, CPUC will opt to remain on the Canadian Generally Accepted Accounting Principles ("CGAAP") for 2012 and will changeover to IFRS on January 1, 2013.

Based on the deferral to 2013, CPUC will complete internal work on the transition to IFRS including a detailed listing of assets by September, 2012 for componentization purposes. Our auditors, KPMG, will be involved with the work required for the transition to IFRS in 2013.

b. Please state whether CPUC is planning to prepare its 2012 audited financial statements under MIFRS.

Response

CPUC is not planning to prepare its 2012 audited financial statements under MIFRS.

c. Please provide the estimated costs for CPUC to transition to MIFRS.

Response

The total estimated costs for the transition to IFRS will be $29,500. CPUC has incurred expenses to date of $19,500 in account 1508 - sub-account - deferred transition costs.

d. Has CPUC included in its OM&A the forecasted costs of the transition to MIFRS? If so, please provide the total amount and the breakdown of the costs.

Response

CPUC has not included any costs for the transition to IFRS in its OM&A

e. Please provide a breakdown of the costs recorded in the one-time incremental IFRS costs under Account 1508– Other Regulatory Assets - Sub-Account Deferred IFRS Transition Costs account and provide an explanation for each category of the cost recorded in this account and demonstrate how the costs recorded meet the criteria of one-time IFRS administrative incremental costs.

Response

CPUC engaged its auditors KPMG in 2009 for the transition to IFRS and recorded IFRS Costs incurred to-date in account 1508 - Other Regulatory Assets - Sub-Account - Deferred IFRS Transition Costs.

Costs Incurred in 2009 of $5,000 for the initial assessment to conduct a high level of CPUCs business/accounting and disclosure policies and identify primary differences between current accounting treatment and IFRS.

Costs incurred in 2010 of $10,000 for the detailed assessment of potential impacts by work function based on priorities and assist in the development of work plans, budgets and timelines and identification of required resources.

Costs incurred in March 2012 of $4,500 for the development of all IFRS accounting policies.

Estimated costs of $10,000 to be incurred for the implementation to IFRS in 2013.

In Section 2.4.3 the Board states that an application should contain a:

> "Detailed reconciliation of the financial results shown in the Annual Reports/ Audited Financial Statements with the regulatory financial results filed in the application including a reconciliation of the fixed assets, for example in order to separate non-utility businesses. This should include the identification of any deviations between the Annual Reports/Audited Financial Statements and the regulatory financial statements that are being proposed including the identification of any prior Board approvals for such deviations that may exist."

f. Please provide a detailed reconciliation as described for 2008, 2009, and 2010 describing detailed explanations for the variances.

<u>Response</u>

See attached excel worksheet "CPUC Interrogatories Question # 3" Sheet "Reconciliation 2008, 2009, 2010" found in Appendix G

2008 - OM&A

Operations Variance between Audited Financials and Rate Application of $63,193 is employee benefits included in Audited Financials that should be in Admin and General Expenses.

Variance of $587 is for Community Relations that is included in Audited Financials in Admin and General Expenses.

2009 - OM&A

Operations Variance between Audited Financials and Rate Application of $82,119 is employee benefits of $66,321 included in Audited Financials that should be in Admin and General Expenses and Low Voltage Charges of $15,798 that should be included with Purchased Power.

Variance of $665 is for Community Relations that is included in Audited Financials in Admin and General Expenses.

2010 - OM&A

Operations Variance between Audited Financials and Rate Application of $82,844 is employee benefits of $74,190 included in Audited Financials that should be in Admin and General Expenses and Low Voltage Charges of $8,654 that should be included with Purchased Power.

Variance of $715 is for Community Relations that is included in Audited Financials in Admin and General Expenses.

g. If audited financial statements are available for 2011, please provide the statements with a detailed reconciliation to the regulatory financial results filed in CPUC's year end RRR filing. Please describe in detail any variances.

Response

See attached excel worksheet "CPUC Interrogatories Question # 3" sheet "Actual Pro Forma Comparisons"

Balance Sheet - Net increase of $112,552

Cash is lower than pro-forma by $53,211 mainly due to lower revenues and increase in Regulatory Assets of $158,087 due to under estimate in pro-forma statements.

Property Plant and Equipment expenditures are higher than pro-forma estimate by $3,239 and Accumulated Depreciation for meters should be $6,963 not $1,705 as shown in Audited Financial Statements - an adjustment will be made in 2012 for 2011 to correct this.

-53,211+158,087+3,239+5,258 = 113,373

Income Statement - Net increase of $28,100

Increase in Distribution Revenue by $6,558 and a decrease in Other Income (Expenses) by $6,474.

OM&A Expenses are lower than estimated by $37,149 after adjustment of the Low Voltage charge ($14,368) included in Operations and Maintenance. This reduction is mainly due to lower OH Distribution lines and Feeders - Operation Supplies (a/c 5025) were overestimated by $13,470 and lower Outside Services Employed (a/c 5620) by $25,757 for the delay of the Asset Management Plan till 2012.

Depreciation Expense lower by $5,236 mainly due to the above adjustment to be made in 2012 for 2011.

+6558-6474-37149+5236 = -31,829

h. Please provide a detailed reconciliation of the 2012 Pro Forma Statements with CPUC's Application.

<u>Response</u>

Reconciliation of 2012 Pro-Forma Statements with the 2012 Application. See - Appendix G

<u>Rate Base - $1,518,609</u>

Application - Pages 25, 175 and 176

Revenue Requirement Form - Sheet "3 - Data Input Sheet" and Sheet "4 Rate Base" $1,518,609 reconcilable to Pro-Forma Statements as follows:

Fixed Gross Assets and Accumulated Depreciation average of opening and closing balances from Filing Requirements Worksheets, sheet "App. 2-B Fixed Asset Cont. (12)" Line 55 Columns F, I, K and N and pages 80 and 81 in Application.

	Opening	***Pro-Forma Closing***	***Application Average***
Fixed Gross assets	***2,525,380***	***2,583,670***	***2,554,525***
Accumulated Depr'n	***1,480,055***	***1,555,631***	***1,517,843***
Net Assets	***1,045,325***	***1,028,039***	***1,036,682***

Allowance for Working Capital - $481,927

	Pro-Forma	***Rate***	***Application***
Controllable Expenses;			
- Oper'n & Maintenance	***215,590***		
- Admin & General	***364,700***		
- Billing & Collection	***84,200***		
	664,490		
Cost of Power	***2,548,354***		
Working Capital Base	***3,212,844***	***15 %***	***481,927***
Total Rate Base			***1,518,609***

Distribution Revenue $823,030

Application - Pages 25 and 174 and Pro-Forma Statements

Distribution Revenue generated in Revenue Requirement Work Form Sheet "5. Utility income line 13 column F, Sheet "8. Rev Deff Suff" lines 16 and 17 column H and sheet "9. Rev Reqt" line 27 column F. and appears in CPUCs application page 25.

Other Income (Expenses) Net $38,735

Application - Pages 25 and 174, and Pro-Forma Statements

Other Income in the application $41, 735 was generated in Filing Requirements Sheet "App 2. Other Oper. Rev" and appears in the application on pages 25 and 174.

Expenses (other Interest) of $3,000 appears in the application on page 174.

4. Conservation and Demand Management

Reference: Decision and Order EB-2010-0215, EB-2010-0216

In Appendix A of the Board's Decision and Order on CDM Targets, EB-2010-0215, EB-2010-0216, CPUC was given the following CDM targets: a 2014 Net Annual Peak Demand Savings of 0.170 MW, and a 2011-2014 Net Cumulative Energy Savings of 1.210 GWh.

a. What plans and programmes/projects does CPUC have to achieve these targets?

Response

In accordance with the Board's direction and letter dated February 18, 2011, Chapleau PUC submitted their CDM Strategy that contains estimated, prospective budgets for each of the funding components for planned OPA Contracted Province-Wide CDM Programs in April 2011. Chapleau PUC will continue to execute OPA Contracted work toward achievement of prescribed reduction targets.

b. If any costs associated with these plans and programmes/projects are included in the 2012 test year revenue requirement please state the amount(s), describe the programme(s)/project(s), and state why they should be included in the revenue requirement.

Response

No costs associated with the plans and programmes/projects have been included in the 2012 test year revenue requirement.

5. Volumetric Forecast

References: Exhibit 3 pages 104 – 111

Decision Chapleau PUC EB-2007-0755

Decision and Order on Licence Amendments and CDM Targets, EB-201-0215/EB2010-0216

The Board noted in CPUC's 2008 costs of service Decision that CPUC is to clearly present and fully substantiate its customer number forecast and a weather normalized load forecast in its application. The Board went on to say that it expects CPUC's next application to show substantial improvement in this area.

Board staff is having difficulties understanding CPUC's forecast. CPUC states on page 102 that the load forecast for the 2012 Test Year is the average of actual historical data from 2006 to 2010 was used. CPUC also stated that, for the Bridge Year, actual data to August 2011 was used and September to December was forecast based on the average monthly consumptions 2008 to 2010. Board staff would like to understand this forecast better. Table 1 is a summary of the monthly average demand per customer/connection.

a. When CPUC states that the average of actual historical data from 2006 to 2010 was used, Board staff would like to clarify that the 2012 forecast was built up from the granular level of average monthly volumes by customer/connection. Please confirm that this is correct. If this is not correct, please explain how the forecast was developed.

Table 1
Average Customer Monthly Demand (kWh/Cust/Mos)
Chapleau PUC EB-2011-0322

		2006	2007	2008	2009	2010	2011	2012
1	Residential	1,075	1,080	1,046	1,093	1,112	1,061	1,072
2	GS,50 kW	2,905	2,851	2,750	2,629	2,675	2,643	2,720
3	GS > 50 kW	43,928	46,074	46,345	47,192	46,854	43,851	45,589
4	USL	101	101	97	101	100	101	101
5	Sentinel Lights	81	79	83	84	101	94	94
6	Street Lightnig.	59	72	72	72	73	72	72
7	Total	1,407	1,394	1,370	1,400	1,414	1,352	1,383

Board staff has developed the following tables based on the data.

Table 2
Variance
Average Customer Monthly Demand (kWh/Cust/Mos)
Chapleau PUC EB-2011-0322

		Col. 1	Col. 2	Col. 3	Col. 4	Col. 5	Col. 6	Col. 7	Col. 8	Col. 9	Col. 10
		07/08	**08/07**	**09/08**	**10/09**	**11/10**	**12/11**	**Avg.**	**Max.**	**Min**	**Range**
1	Residential	5	-34	47	20	-51	11	-1	47	-51	98
2	GS,50 kW	-54	-101	-120	45	-31	77	-31	77	-120	197
3	GS > 50 kW	2,146	271	847	-338	-3,003	1,738	277	2,146	-3,003	5,149
4	USL	1	-4	4	-1	0	0	0	4	-4	8
5	Sentinel Lights	-2	3	1	17	-7	0	2	17	-7	24
6	Street Lightnig.	13	0	0	0	-1	0	2	13	-1	14

Table 3

Variance
Average Customer Monthly Demand (%)
Chapleau PUC EB-2011-0322

		Col. 1	Col. 2	Col. 3	Col. 4	Col. 5	Col. 6	Col. 7	Col. 8	Col. 9	Col. 10
		07/06	**08/07**	**09/08**	**10/09**	**11/10**	**12/11**	**Avg.**	**Max.**	**Min**	**Range**
1	Residential	0.5%	-3.1%	4.5%	1.8%	-4.6%	1.0%	0.0%	4.5%	-4.6%	9.1%
2	GS,50 kW	-1.9%	-3.5%	-4.4%	1.7%	-1.2%	2.9%	-1.1%	2.9%	-4.4%	7.3%
3	GS > 50 kW	4.9%	0.6%	1.8%	-0.7%	-6.4%	4.0%	0.7%	4.9%	-6.4%	11.3%
4	USL	0.5%	-4.0%	4.4%	-1.2%	0.4%	0.4%	0.1%	4.4%	-4.0%	8.5%
5	Sentinel Lights	-1.9%	4.3%	1.2%	20.4%	-6.6%	-0.3%	2.8%	20.4%	-6.6%	27.0%
6	Street Lightnig.	22.3%	0.1%	0.3%	0.2%	-1.0%	0.3%	3.7%	22.3%	-1.0%	23.3%

Table 2 is the year over year variance in the average monthly kWh by class found on Table 1. Table 3 expresses the variances in Table 2 as a percentage. In both tables, Col. 7 – Col. 10 are descriptive statistics on the variability of the variances. Col. 7 is the average of the observed variance in Col. 1 - 6. Col. 10 is the range in which the actual value varies, and is calculated from the Maximums and Minimums in Col. 8 and 9.

Board staff feels that the year over year variability seen in the data is large.

<u>Response</u>

In order to determine the most accurate data for the Bridge Year (2011), CPUC used actual data to August 2011 and the average monthly consumptions from 2008 to 2010 for the September to December forecast. The 2011 forecast data was used for comparison purposes only and was not used in the development of data for 2012

CPUC confirms that the 2012 forecast was built up from the granular level of average monthly volumes by customer/connection for the years 2006 to 2010.

CPUC feels that the year over year variability is very normal given the fact that the town of Chapleau is located 790 kilometers North-North West of Toronto and that

most of Chapleaus residents (approximately 70 to 75%) and businesses (approximately 40 to 45%) heat their homes, shops or premises by electricity. Variability of the weather during winter months could account for much larger variables than those shown above.

It must also be noted that CPUC is a winter peaking utility.

b. Please confirm that CPUC agrees with the variances in tables, and provide an explanation for the variability of the average monthly kWh per customer/connect.

<u>Response</u>

The above table uses average consumption data from the 2008 Board Approved instead of 2008 actual, 2008 actual is in 2009 and 2009 actual is in 2010. As these will not impact Tables 2 and 3 adversely, CPUC agrees with the variances as presented and responses will be made, where possible, on the basis of the data used in Table 1 above.

Residential and General Service < 50 kW Customer usage from year over year will be impacted by the weather through-out the year. Data collected for monthly peak times, proves this variability. Comparison of the average monthly peak with the kWh % variability (table 3) year over year is:

	kWh% Residential		***kWh % GS < 50 kW***		***Ave. Monthly***	
	Table 3	***Actual***	***Table 3***	***Actual***	***Peak***	***%***
2006	***N/A***	***N/A***		***N/A***	***4810***	
2007/6	***0.5***	***0.5***	***-1.9***	***-1.9***	***4760***	***-1.0***
2008/7	***-3.1***	***1.2***	***-3.5***	***-4.4***	***4629***	***-2.8***
2009/8	***4.5***	***1.7***	***-4.4***	***1.7***	***4678***	***1.1***
2010/9	***1.8***	***-10.0***	***1.7***	***-5.1***	***4430***	***-5.3***
2011/10	***-4.6***	***6.1***	***-1.2***	***4.1***	***N/A***	
2012/11	***1.0***	***1.0***	***2.9***	***N/A***	***N/A***	

Min. Max. Range of average monthly Peaks 6.4%

Min. Max. Range per Table 3 - Residential		***9.1%***
	- <50 kW	***7.3%***

Comparisons from table 3 above do not compare with changes in the average winter peak, therefore actual variances are also used.

General Service > 50 kW customer electricity use is mostly dependant on the Ontario economy, and on their ability to operate continually. In 2011/10 average customer consumptions were reduced by 6.4%. The major reason for this is due a partial reduction in workload by the biggest of the general service customers reducing to one shift instead of 2 for over a 4 week period. This consumption loss represents approximately 2.0% of the total.

The range of 8.5% for the Unmetered Scattered Load class is due to the use of 2008 Board approved consumptions instead of the 2008 actual consumptions which would have the range at 2.0%.

Sentinel Lighting range is 27.0% For a such a small group that consumes approximately 26,000 kWh in a year a reduction by 2 very low use customers (average of 14 kWh per month) in 2009 increased average consumption for the other 23 customers. This would make the range at 8.6%.

It appears that Street Lighting class in 2006 average consumption of 59 kWh may be an anomaly. All future years consumptions are consistently averaging 72 to 73 kWh. Removing 2006 would make the range at 2.8%.

c. Please file a weather normalized kWh forecast.

<u>Response</u>

Weather Normalization worksheet - Appendix A

Weather Normalization Load and Customer/Connection Forecast

The purpose of this evidence is to present the process used by CPUC to prepare the weather normalized load and customer/connection forecast for 2012.

CPUC has used the same regression analysis methodology used by a number of other distributors in their 2009, 2010 and 2011 cost of service rate applications to determine a prediction model. With regard to the overall process of load forecasting, CPUC submits that conducting a regression analysis on historical electricity purchases to produce an equation that will predict purchases is appropriate. CPUC has the data for the amount of monthly electricity (in kWh) purchases from the IESO for use by CPUC's customers. With a regression analysis, these purchases can be related to other monthly explanatory variables such as heating degree days and cooling degree days which occur in the same month. The results of the regression analysis produce an equation that predicts the purchases based on the explanatory variables. This prediction model is then used as the basis to forecast the total level of weather normalized purchases for CPUC for the Bridge Year and the Test Year which is converted to billed kWh by rate class. A detailed explanation of the process is provided later in this evidence.

To increase the accuracy of the regression analysis and to achieve reasonable results for the purpose of weather normalized load forecasting for this application, CPUC utilized the regression analysis based on historical electricity purchases.

Based on the OEB's approval of this methodology in a number of cost of service applications, and based on the discussion that follows, CPUC submits that its load forecasting methodology using power purchases is reasonable at this time for the purposes of this Application.

The following provides the material to support the weather normalized load forecast that may be used by CPUC in this Application.

Table A - Summary of Load and Customer/Connection Forecast

Summary of Load and Customer/Connection Forecast						
Year	Billed kWh	Change	% change	Customer/ Connection Count	Change	% change
2003 Actual	32,559,118			1,747		
2004 Actual	31,044,406	-1,514,713	-4.88%	1,734	-13	-0.75%
2005 Actual	29,513,664	-1,530,742	-5.19%	1,730	-4	-0.23%
2006 Actual	28,429,027	-1,084,638	-3.82%	1,681	-49	-2.91%
2007 Actual	28,525,074	96,048	0.34%	1,705	24	1.41%
2008 Actual	28,582,032	56,958	0.20%	1,701	-4	-0.24%
2009 Actual	28,674,687	92,655	0.32%	1,690	-11	-0.65%
2010 Actual	26,167,966	-2,506,721	-9.58%	1,676	-14	-0.84%
2011 Normalized	27,813,437	1,645,471	5.92%	1,666	-10	-0.60%
2012 Normalized	27,864,645	51,208	0.18%	1,656	-10	-0.60%

Note that 2003 to 2010 are weather actual, while 2011 and 2012 are weather normalized. CPUC does not have a process to adjust weather actual data to weather normal basis. However, based on the process outlined in this Exhibit, a process to forecast energy on a weather normalized basis has been developed and used in this application.

The total Customers and Connections are on a year average basis. Sentinel Lights and Streetlights are measured as connections.

Actual and Forecast Billed Amounts and Number of Customers are shown in Table B per customer usage is shown in Table C on a rate class basis below:

Table B - Billed Energy and Number of Customer/Connections by Rate Class

Year	Residential	General Service < 50	General Service >50	USL	Sentinel Lights	Street Lights	Total
Billed Energy							
2003 Actual	16,533,903	6,027,416	9,668,139	7,248	27,506	294,906	32,559,118
2004 Actual	15,978,327	5,940,345	8,798,182	7,239	23,670	296,643	31,044,406
2005 Actual	15,211,690	5,825,357	8,150,335	7,248	23,346	295,688	29,513,664
2006 Actual	14,654,854	5,541,938	7,907,099	7,286	23,346	294,504	28,429,027
2007 Actual	15,018,918	5,438,894	7,740,511	7,286	24,801	294,664	28,525,074
2008 Actual	15,056,531	5,269,211	7,928,332	7,301	24,659	295,998	28,582,032
2009 Actual	15,273,442	5,200,927	7,871,532	7,212	24,861	296,713	28,674,687
2010 Actual	13,587,676	4,877,032	7,374,502	7,391	25,021	296,344	26,167,966
2011 Normalized	14,501,285	5,120,806	7,861,839	7,417	25,284	296,806	27,813,437
2012 Normalized	14,299,797	4,968,022	7,785,786	7,372	25,300	294,372	27,380,649
Number of Customer/Connections							
2003 Actual	1,189	169	16	6	26	341	1,747
2004 Actual	1,179	169	14	6	25	341	1,734
2005 Actual	1,176	169	14	6	24	341	1,730
2006 Actual	1,136	159	15	6	24	341	1,681
2007 Actual	1,159	159	14	6	26	341	1,705
2008 Actual	1,148	167	14	6	25	341	1,701
2009 Actual	1,144	162	14	6	23	341	1,690
2010 Actual	1,132	160	14	6	23	341	1,676
2011 Normalized	1,124	159	14	6	23	341	1,666
2012 Normalized	1,116	158	13	6	22	341	1,656

Table C - Annual Usage per Customer/Connection by Rate Class

Total Billed	Residential	General Service < 50	General Service >50	USL	Sentinel Lights	Street Lights
Energy Usage per Customer/Connections by Rate Class kWh						
2003 Actual	13,906	35,665	604,259	1,208	1,058	865
2004 Actual	13,552	35,150	628,442	1,207	947	870
2005 Actual	12,935	34,470	582,167	1,208	973	867
2006 Actual	12,900	34,855	527,140	1,214	973	864
2007 Actual	12,959	34,207	552,894	1,214	954	864
2008 Actual	13,115	31,552	566,309	1,217	986	868
2009 Actual	13,351	32,104	562,252	1,202	1,081	870
2010 Actual	12,003	30,481	526,750	1,232	1,088	869
2011 Normalized	11,789	29,477	526,750	1,236	1,119	870
2012 Normalized	11,578	28,505	526,653	1,241	1,151	872
Annual Growth Rate in Usage per Customer/Connection						
2003 Actual						
2004 Actual	-0.0254	-0.0144	0.0400	-0.0012	-0.1050	0.0059
2005 Actual	-0.0456	-0.0194	-0.0736	0.0012	0.0274	-0.0032
2006 Actual	-0.0027	0.0112	-0.0945	0.0052	0.0000	-0.0040
2007 Actual	0.0045	-0.0186	0.0489	0.0000	-0.0194	0.0005
2008 Actual	0.0121	-0.0776	0.0243	0.0021	0.0340	0.0045
2009 Actual	0.0180	0.0175	-0.0072	-0.0122	0.0959	0.0024
2010 Actual	-0.1009	-0.0506	-0.0631	0.0248	0.0064	-0.0012
2011 Normalized	-0.0178	-0.0330	0.0000	0.0034	0.0286	0.0011
2012 Normalized	-0.0179	-0.0330	-0.0002	0.0040	0.0286	0.0023

LOAD FORECAST AND METHODOLOGY

CPUC's weather normalized load forecast is developed by using a three step process. First total system weather normalized purchased energy forecast is developed based on a multifactor regression model that incorporates historical load, weather and calendar related events. Second, the weather normalized purchases energy forecast is adjusted by a historical loss factor to produce a

weather normalized billed energy forecast. Finally, the forecast of billed energy by rate class is developed based on a forecast of customer number and historical usage patterns per customer. For the rate classes that have weather sensitive load their forecasted billed energy is adjusted to ensure that the total billed energy forecast by rate class is equivalent to the total weather normalized billed energy forecast that has been determined from the regression model. The forecast customer numbers by rate class is determined using a geometric mean analysis. For those rate classes that use kW for the distribution volumetric billing determinant, an adjustment factor is applied to the class energy forecast based on the historical relationship between kW and kWh.

A detailed explanation of the load forecasting process follows.

Purchases kWh Load Forecast:

An equation to predict total system purchased energy is developed using a multifactor regression model with the following independent variables: weather (heating and cooling degree days) and calendar variables (number of days in the month). The regression model uses monthly kWh and monthly values of independent variables from January 2003 to December 2010 to determine the monthly regression coefficients. This provides 96 monthly data points - this represents a reasonable data set for use in a regression analysis. Based on the recent global activity surrounding climate change, historical weather data is showing that there is a warming of the global climate system. In this regard, CPUC submits that it is appropriate to review the impact of weather since 2003 on the energy usage and then determine the average weather conditions from January 2003 to December 2010 which would be applied in the forecasting process to determine a weather normalized forecast.

The multifactor regression model has determined drivers of year-over-year changes in CPUC's load growth; these include weather and "calendar" factors. These factors are captured within the multifactor regression model.

CPUC conducted the regression analysis using the Heating Degree Days, Cooling Degree Days, Ontario Real GDP Monthly Index, Number of Customers, Number of Days in the month and Spring Fall Flag and Number of Peak Hours. After completing the regression analysis CPUC eliminated the Number of Customers, Ontario Real Gross Domestic Product% and the spring/fall flag variables from the regression analysis since they did not have a t-stat value above the absolute value of 2 and are not statistically significant to the analysis.

The following outlines the prediction model used by CPUC to predict weather normal purchases for 2011 and 2012:

CPUC's Monthly Predicted kWh Purchases

Intercept	**-4329780.327**
Heating Degree Days	**2527.105379**
Cooling Degree Days	**1639.788116**
Number of Peak Hours	**1118.577441**
Number of Customers	**3429.53786**
Number of Days in Month	**27029.76583**

The monthly data used in the regression model and the resulting monthly prediction for the actual and forecasted years are provided in Appendix A.

The sources of data for the various data points are:

a) ***Environment Canada website for monthly heating degree day and cooling degree day information. Weather data from the Chapleau Station was used.***

b) ***The calendar provided information related to the spring/fall flag.***

The prediction formula has the following statistical results:

Table D - Statistical Results and T-Stat Coefficients

Statistical Results

Statistic	Value
R Square	99%

Adjusted R Square	99%
F Test	1798.87
T-Stats by Coefficient	
Intercept	-8.08
Heating Degree Days	75.82
Cooling Degree Days	3.27

T-Stat Coefficients

Intercept	-8.083694703
Heating Degree Days	75.81558445
Cooling Degree Days	3.266389882
Number of Peak Hours	2.028218132
Number of Customers	10.91278787
Number of Days in Month	2.381763389

The following table outlines the data that supports the above chart. In addition, the predicted total system purchases for CPUC are provided for 2011 and 2012. For 2011 and 2012 the system purchases reflect a weather normalized forecast for the full year.

Table E - Total System Purchases

Purchased Energy (kWh)

Year	Actual	Predicted	Difference	% Difference
2003	33,611,224	33,144,680	(466,544)	-1.4%
2004	32,654,946	32,568,940	(86,006)	-0.3%
2005	31,058,652	31,416,472	357,820	1.2%
2006	29,569,274	28,776,483	(792,791)	-2.7%
2007	29,857,234	29,839,536	(17,698)	-0.1%
2008	30,257,407	30,580,875	323,468	1.1%
2009	29,917,187	30,273,856	356,669	1.2%
2010	27,909,701	28,234,783	325,082	1.2%
2011 Normalized		29,175,800		
2012 Normalized		29,229,517		

The weather normalized amount for 2012 is determined by using 2012 dependent variables in the prediction formula on a monthly basis together with the average monthly heating degree days and cooling degree days that occurred from January 2003 to December 2010 (i.e. eight years).

The weather normal eight year average has been used as the purchased forecast in this Application for the purposes of determining a billed kWh load forecast which is used to design rates. The eight year average has been used as this is consistent with the period of time over which the regression analysis was conducted

With regard to the forecast of the CDM savings variable, CPUC applied a savings of 242,000 kWh to the 2012 test year forecast. The CDM savings was prorated to the rate classes based on the 2012 weather corrected forecast. The CDM savings is based on the Electricity Conservation and Demand Management Targets Board File Number EB-2010-0216 issued June 22, 2010. CPUC's 2011-2014 net cumulative energy savings target is 1.210 GWh. Based on the CDM schedule from the OPA in 2012 the target conservation is 20% of the cumulative energy savings target. Therefore CPUC applied 20% of the 1.210 GWh as CDM savings in the 2012 test year.

Table F - CDM Savings

Total CDM savings kWh	Residential	General Service < 50	General Service >50	USL	Sentinel Lights	Street Lights
242,000	125,910	43,743	69,130	73	249	2,896

Billed KWh Load Forecast

To determine the total weather normalized energy billed forecast, the total system weather normalized purchases forecast is adjusted by an average historical (2003 to 2010) loss factor of 1.0490.

Billed KWh Load Forecast and Customer/Connection Forecast by Rate Class

Since the total weather normalized billed energy amount is known, this amount needs to be distributed by rate class for rate design purposes taking into consideration the customer/connection forecast and expected usage per customer by rate class.

The next step in the forecasting process is to determine a customer/connection forecast. The customer/connection forecast is based on reviewing historical customer/connection data that is available as shown in the following table.

Table G - Historical Customer/Connection Data

Year	Residential	General Service < 50	General Service >50	USL	Sentinel Lights	Street Lights	Total
2003 Actual	1,189	169	16	6	26	341	1,747
2004 Actual	1,179	169	14	6	25	341	1,734
2005 Actual	1,176	169	14	6	24	341	1,730
2006 Actual	1,136	159	15	6	24	341	1,681
2007 Actual	1,159	159	14	6	26	341	1,705
2008 Actual	1,148	167	14	6	25	341	1,701
2009 Actual	1,144	162	14	6	23	341	1,690
2010 Actual	1,132	160	14	6	23	341	1,676

From the historical customer/connection data the growth rates in customers/ connections can be evaluated. The growth rates are provided in the following table. The geometric mean growth rate in number of customers is also provided. The geometric mean approach provides the average growth rate from 2003 to 2010.

Table H - Growth Rate in Customer/Connections

Year	Residential	General Service < 50	General Service >50	USL	Sentinel Lights	Street Lights
2004	0.9916	1.0000	0.8750	1.0000	0.9615	1.0000
2005	0.9975	1.0000	1.0000	1.0000	0.9600	1.0000
2006	0.9660	0.9408	1.0714	1.0000	1.0000	1.0000
2007	1.0202	1.0000	0.9333	1.0000	1.0833	1.0000
2008	0.9905	1.0503	1.0000	1.0000	0.9615	1.0000
2009	0.9965	0.9701	1.0000	1.0000	0.9200	1.0000
2010	0.9895	0.9877	1.0000	1.0000	1.0000	1.0000
Geometric Mean	0.9930	0.9922	0.9811	1.0000	0.9826	1.0000

The resulting geometric mean was applied to the customer/connection numbers to determine the forecast of customer/connections in 2011 and 2012. Table I below outlines the forecast of customers by rate class for 2011 and 2012.

Table I - Forecast of Customers By Rate Class

Year	Residential	General Service < 50	General Service >50	USL	Sentinel Lights	Street Lights	Total
2011	1,124	159	14	6	23	341	1,666
2012	1,116	158	13	6	22	341	1,656

The next step in the process is to review the historical customer/connection usage and to reflect this usage per customer in the forecast. The following table provides the average annual usage per customer by rate class from 2003 to 2010.

Table J - Historical Annual Usage per Customer

Year	Residential	General Service < 50	General Service >50	USL	Sentinel Lights	Street Lights
2,003	13,906	35,665	604,259	1,208	1,058	865
2,004	13,552	35,150	628,442	1,207	947	870
2,005	12,935	34,470	582,167	1,208	973	867
2,006	12,900	34,855	527,140	1,214	973	864
2,007	12,959	34,207	552,894	1,214	954	864
2,008	13,115	31,552	566,309	1,217	986	868
2,009	13,351	32,104	562,252	1,202	1,081	870
2,010	12,003	30,481	526,750	1,232	1,088	869

From the historical usage per customer/connection data the growth rate in usage per customer/connection can be reviewed. That information is provided in the following table. The geometric mean growth rate has also been shown.

Table K - Geometric Mean Growth Rate in Usage per Customer/Connection

Year	Residential	General Service < 50	General Service >50	USL	Sentinel Lights	Street Lights
Growth Rate in Customer Numbers						
2003						
2004	0.9916	1.0000	0.8750	1.0000	0.9615	1.0000
2005	0.9975	1.0000	1.0000	1.0000	0.9600	1.0000
2006	0.9660	0.9408	1.0714	1.0000	1.0000	1.0000
2007	1.0202	1.0000	0.9333	1.0000	1.0833	1.0000
2008	0.9905	1.0503	1.0000	1.0000	0.9615	1.0000
2009	0.9965	0.9701	1.0000	1.0000	0.9200	1.0000
2010	0.9895	0.9877	1.0000	1.0000	1.0000	1.0000
Geometric Mean	0.9930	0.9922	0.9811	1.0000	0.9826	1.0000

For the forecast of usage per customer/connection the historical geometric mean was applied to the 2011 and 2012 usage and the resulting usage forecast is as follows:

Table L -Forecast Annual kWh Usage per Customer/Connection

Year	Residential	General Service < 50	General Service >50	USL	Sentinel Lights	Street Lights
Forecast Annual kWh Usage per Customer/Connection						
2,011	11,789	29,477	526,653	1,236	1,119	870
2,012	11,578	28,505	526,555	1,241	1,150	872

With the preceding information the non-normalized weather billed energy forecast can be determined by applying the forecast number of customer/connections from Table I by the forecast annual usage per customer/connection Table L. The resulting non-normalized weather billed energy forecast is shown in the following table.

Table M - Non-normalized Weather Billed Energy Forecast

Year	Residential	General Service < 50	General Service >50	USL	Sentinel Lights	Street Lights
Non Normalized Weather Billed Energy Forecast (kWh)						
2011 Not Normalized	13,251,687	4,679,540	7,233,822	7,417	25,284	296,806
2012 Not Normalized	12,924,006	4,490,045	7,095,826	7,444	25,549	297,269

The non-normalized weather billed energy forecast has been determined but this needs to be adjusted in order to be aligned with the total weather normalized billed energy forecast. As previously determined, the total weather normalized billed energy forecast is 2,318,881 kWh for 2011 and 3,024,507 kWh for 2012.

The difference between the non-normalized and normalized forecast adjustment is assumed to be associated with the moving forecast from a non-normalized to weather normal basis and this amount will be assigned to those rate classes that are weather sensitive. Based on the weather normalized work completed by Hydro One it was determined that the weather sensitivity by rate classes is as follows.

Table N - Weather Sensitivity by Rate Class

Residential	General Service < 50	General Service >50	USL	Sentinel Lights	Street Lights
92.65%	92.65%	85.30%	0.00%	0.00%	0.00%

For the General Service > 50 kW class the weather sensitivity amount of 85.30% was provided in the weather normalization work completed by Hydro One. For the Residential and General Service < 50 kW classes, it is has been previously assumed in cost of service applications that these two classes are 100% weather sensitive. Intervenors expressed concern with this assumption and have suggested that 100% weather sensitivity is not appropriate. CPUC agrees with this position but also submits that the weather sensitivity for the Residential and General Service < 50 kW classes should be higher than the General Service > 50 kW class. As a result, CPUC has assumed the weather sensitivity for the Residential and General Service < 50 kW classes to be mid-way between 100% and 85.30% or 92.65%.

The difference between the non-normalized and normalized forecast of 2,318,881 kWh in 2011 and 3,024,507 kWh in 2012 has been assigned on a pro rata basis to each rate class based on the above level of weather sensitivity. The following

table outlines how the weather sensitive rate classes have been adjusted to align the non-normalized forecast with the normalized forecast.

Table O - Alignment of Non-normal to Weather Normal Forecast

Year	Total	Residential	General Service < 50	General Service >50	USL	Sentinel Lights	Street Lights
Non Weather Corrected Forecast							
2011	25,494,556	13,251,687	4,679,540	7,233,822	7,417	25,284	296,806
2012	24,840,138	12,924,006	4,490,045	7,095,826	7,444	25,549	297,269
Weather Corrected Forecast							
2011	27,813,437	14,501,285	5,120,806	7,861,839	7,417	25,284	296,806
2012	27,864,645	14,430,402	5,013,396	7,851,805	7,372	25,300	294,372
% Weather Sensitive		92.65%	92.65%	85.30%			
2011	2,318,881	12,277,688	4,335,593	6,170,450	0	0	0
2012	3,024,507	11,974,091	4,160,026	6,052,739	0	0	0
Allocation of Weather Sensitive Amount							
2011	2,318,881	1,249,598	441,268	628,016	0	0	0
2012	3,024,507	1,632,305	567,094	825,108	0	0	0

Billed KW Load Forecast

There are three rate classes that charge volumetric distribution on per kW basis. These include General Service > 50, Sentinel Lights and Street lighting. As a result, the energy forecast for these classes needs to be converted to a kW basis for rate setting purposes. The forecast of kW for these classes is based on a review of the historical ratio of kW to kWhs and applying the average ratio to the forecasted kWh to produce the required kW.

The following table outlines the annual demand units by applicable rate class.

Table 3 P - Historical Annual kW per Applicable Rate Class

Year	General Service >50	Sentinel Lights	Street Lights	Total
2,003	25,121	76	771	27,971
2,004	24,094	66	789	26,952
2,005	21,944	65	780	24,794
2,006	21,243	64	780	24,093
2,007	19,178	67	780	22,032
2,008	20,115	70	780	22,973
2,009	19,967	66	780	22,821
2,010	18,568	66	780	21,424

The following table illustrates the historical ratio of kW/kWh as well as the average ratio for 2003 to 2010.

Table Q - Historical kW/kWh Ratio per Applicable Rate Class

Year	General Service >50	Sentinel Lights	Street Lights
2003	0.2598%	0.2756%	0.2615%
2004	0.2738%	0.2771%	0.2659%
2005	0.2692%	0.2780%	0.2638%
2006	0.2687%	0.2741%	0.2649%
2007	0.2478%	0.2706%	0.2647%
2008	0.2537%	0.2818%	0.2635%
2009	0.2537%	0.2643%	0.2629%
2010	0.2518%	0.2642%	0.2632%
Average	0.2598%	0.2732%	0.2638%

The average ratio was applied to the weather normalized billed energy forecast in Table O to provide the forecast of kW by rate class as shown below. The following Table R outlines the forecast of kW for the applicable rate classes.

Table R - kW Forecast by Applicable Rate Class

Year	General Service >50	Sentinel Lights	Street Lights	Total
2,011	20,426	69	783	23,289
2,012	20,400	69	777	23,258

Table S provides a summary of the billing determinants by rate class.

Table S - Summary of Forecast

	2003 Actual	2004 Actual	2005 Actual	2006 Actual	2007 Actual	2008 Actual	2009 Actual	2010 Actual	2011 Weather Normal	2012 Weather Normal
Actual kWh Purchases	33,611,224	32,654,946	31,058,652	29,569,274	29,857,234	30,257,407	29,917,187	27,909,701		
Predicted kWh Purchases	33,144,680	32,568,940	31,416,472	28,776,483	29,839,536	30,580,875	30,273,856	28,234,783	29,175,800	29,229,517
% Difference	-1.4%	-0.3%	1.2%	-2.7%	-0.1%	1.1%	1.2%	1.2%		
Billed kWh	32,559,118	31,044,406	29,513,664	28,429,027	28,525,074	28,582,032	28,674,687	26,167,966	27,813,437	27,622,645
By Class										
Residential										
Customers	1,189	1,179	1,176	1,136	1,159	1,148	1,144	1,132	1,124	1,116
kWh	16,533,903	15,978,327	15,211,690	14,654,854	15,018,918	15,056,531	15,273,442	13,587,676	14,501,285	14,430,402
General Service < 50										
Customers	169	169	169	159	159	167	162	160	159	158
kWh	6,027,416	5,940,345	5,825,357	5,541,938	5,438,894	5,269,211	5,200,927	4,877,032	5,120,806	5,013,396
General Service >50										
Customers	16	14	14	15	14	14	14	14	14	13
kWh	9,668,139	8,798,182	8,150,335	7,907,099	7,740,511	7,928,332	7,871,532	7,374,502	7,861,839	7,851,805
kW	25,121	24,094	21,944	21,243	19,178	20,115	19,967	18,568	20,426	20,400
USL										
Customers	6	6	6	6	6	6	6	6	6	6
kWh	7,248	7,239	7,248	7,286	7,286	7,301	7,212	7,391	7,417	7,372
Sentinel Lights										
Connections	26	25	24	24	26	25	23	23	23	22
kWh	27,506	23,670	23,346	23,346	24,801	24,659	24,861	25,021	25,284	25,300
kW	76	66	65	64	67	70	66	66	69	69
Street Lights										
Connections	341	341	341	341	341	341	341	341	341	341
kWh	294,906	296,643	295,688	294,504	294,664	295,998	296,713	296,344	296,806	294,372
kW	771	789	780	780	780	780	780	780	783	777

Conclusion

Due to some abnormalities with the 2012 data generated through the Weather Normalization exercise a comparison of kWh, kW and number of customers is warranted.

The following table compares kWh, kW and number of customers with CPUCs original submission that was adjusted for the 2012 CDM savings.

Table T - Comparison

-	-	Residential	General Service < 50	General Service >50	USL	Sentinel Lights	Street Lights	Total
Weather Normal Data	kWh	14,430,402	5,013,396	7,851,805	7,372	25,300	294,372	27,622,647
	kW	-	-	20,400	-	69	777	21,246
	# of Customers	1,116	158	13	6	22	341	1,656
								0
Original Submission	kWh	14,448,113	5,209,322	7,592,321	7,209	25,718	292,061	27,574,744
	kW	-	-	19,360	-	65	773	20,198
	# of Customers	1,133	161	14	6	23	341	1,678
Change	kWh	(17,711)	(195,926)	259,484	163	(418)	2,311	47,903
	kW	-	-	(1,040)	-	(4)	(4)	-1,048
	# of Customers	- 17.00	- 3.00	- 1.00	-	- 1.00	-	- 22.00

Chapleau Public Utilities Corporation is a Northern Ontario electrical distribution company operating within the Township of Chapleau. Its main industry is forestry and the Canadian Pacific Railway. Several plant closures prior to 2006 in the forestry industry caused a population reduction of 16.9% resulting in 17.1% reduction in CPUC's total customer consumptions.

Although the economy has not improved, economic levels have been maintained from 2006 to 2011. In general, there is little change from year to year in population and CPUC does not expect 2012 to be any different than the 2006 to 2011 statistics for kWh and kW consumptions and for the number of customers.

The weather normalization methodology utilized Geometric Mean averages that include the 2003 to 2010 statistics to arrive at its 2012 consumptions and number of customers. This caused customer counts to drop due to the reductions experienced prior to 2006 (see Tables G, H and I). As for CPUCs consumptions, in some instances, as in GS < 50 kW class, are reduced by 195,926 kWh or 0.0376% and in the GS > 50 kW class, are increased by 259,484 or 0.0342 while the residential class reduced by 17,711 kWh or 0.0012%. The overall kWh difference is an increase of 47,903 kWh or 0.0017% and customer counts is a decrease of 22 or 0.013%.

Based on the above analysis that shows very little change in total consumptions between weather normalized and CPUCs submission, CPUC is more comfortable in using the original numbers submitted (less CDM savings) for kWh, kW and number of customers. However, if the OEB insist on using the data from the weather normalization process, CPUC will comply.

d. Please provide the CDM savings that were proposed in CPUC's last Board approved load forecast.

<u>Response</u>

CPUCs proposed CDM savings for the approved load forecast is 1,210,000 kWh. Annual CDM savings of 20% are 242,000 kWh.

e. Please explain how CPUC has considered the historical CDM in setting the 2012 forecast.

<u>Response</u>

CPUC has not considered the historical CDM in setting the 2012 forecast

f. The Board in its Decision and Order on Licence Amendments and CDM Targets set 2011 – 2014 CDM targets for CPUC of Net Cumulative 2011-2014 energy savings of 1.210 GWh, and a 2014 net annual peak savings of 0.170 MW. Please explain how these targets are incorporated into the 2012 forecast.

<u>Response</u>

CPUC has not incorporated these targets into the 2012 forecast.

g. If CPUC has not done so, please update the proposed load forecast with a CDM reduction included that represents 20% of Chapleau's energy consumption target of 1.210 GWh (0.242 GWh).

<u>Response</u>

CPUC will update the proposed load forecast with a CDM reduction that represents 20% of Chapleau's energy consumption target of 1.210 GWh (0.242 GWh or 242,000 kWh).

6. Other Revenues

Reference: Exhibit 3 pages 115 - 116

In the Other Operating Revenue table on page 115, CPUC shows a decrease in the account balance from 2008 to 2009 for Account 4405 – Interest and Dividend Income. This decrease is from $41,697 to $17,854 or a $23,843 decrease, which is 57.2%. CPUC states on page 116 that this is due to cash purchases of smart meters. It stated that the available cash and investments dropped from $789,500 to $449,000 (43.1%) from December 31, 2008 to December 31, 2009.

a. Please show the determination of the Total Variance stated on page 116 of ($32,719).

<u>Response</u>

Determination of the Total Variance of ($32,719) is as follows:

A/C #	A/C Description	2008	2009	Variance
4235	Misc. Service Revenue	129.55	495.00	365.45
4235.1	NSF Fee	270.00	390.00	120.00
4235.2	Credit Reference	75.00	105.00	30.00
4235.4	Account Set Up Fees	6,930.00	4,950.00	-1,980.00
4235.5	Disc/Reconnect Fees	3,575.00	2,405.00	-1,170.00
4236.6	Misc. Service Revenue	1,307.61	130.00	-1,177.61
	Sub Total	**12,287.16**	**8,475.00**	**-3,812.16**
4225	**Late Payment Charges**	**4,609.00**	**4,780.00**	**171.00**
4082	**Retail services Revenue**	**2,647.00**	**2,846.00**	**199.00**
4405	Investment Income	29,108.71	14,208.55	-14,900.16
4405.1	Interest revenue on RSVAs	12,588.10	3,645.5	-8,942.60
	Sub Total	**41,696.81**	**17,854.05**	**-23,842.76**
5210	**Rent From Electric Property**	**8,264.00**	**7,089.00**	**-1,175.00**
4325	Revenue From Merchandise Jobbing etc.	1,183.02	48.30	-1,134.72
4325.1	Overheads Recovered	767.67	0.05	-767.62
	Sub Total	**1,950.69**	**48.05**	**-1,902.34**
4330	**Cost & Expense of Merchandise**	**2,861.39**	**323.38**	**-2,358.01**
	TOTAL	**74,136.05**	**41,415.78**	**-32,720.27**

b. Please show the Cash and Interest source balances and the calculation of the income recorded in Account 4405 – Interest and Dividend Income for years 2008 – 2012.

Response

The following table, Appendix G, shows CPUCs investment summary and interest income recorded in a/c 4405 for 2008 to 2011 actual and 2012 estimate

		Investment Amount	Interest Earned A/C 4405
Opening Balance - January 1, 2008		**679,103.32**	
Interest Earned 2008		25,872.29	25,872.29
Interest earned on Bank a/c Balance			1,830.70
Interest on Customer Deposit (Refunds)			(718.47)
Interest earned from RSVA accounts			14,712.24
Total Interest Earned 2008			**41,696.76**
Closing Balance - December 31, 2008		**704,975.61**	
Withdrawals:			
	Jan. 20, 2009	(61,791.76)	
	Mar. 3, 2009	(170,000.00)	
	Jun. 17, 2009	(110,000.00)	
	Oct. 30, 2009	(142,635.74)	
Investment			
	Apr. 27, 2009	20,000.00	
	Sep. 30, 2009	467.15	
	Nov. 6, 2009	140,000.00	
Interest Earned 2009		14,627.20	14,627.20
Interest on Customer Deposit (Refunds)			(418.65)
Interest earned from RSVA accounts			3,645.50
Total Interest Earned 2009			**17,854.05**
Closing Balance - December 31, 2009		**395,642.46**	

Continued on next page

Continued from previous page

Closing Balance - December 31, 2009		**395,642.46**	
Interest Earned 2010		8,651.31	8,651.31
Interest from Standard Life			4,830.00
Interest on Customer Deposit (Refunds)			(5.77)
Interest earned from RSVA accounts			3,755.64
Total Interest Earned 2010			**17,231.18**
Closing Balance - December 31, 2010		**404,293.77**	
Withdrawals:			
	Jan. 5, 2011	(100,000.00)	
	Feb. 28, 2011	(61,784.09)	
Interest Earned 2011		5,642.71	5,642.71
Interest from Standard Life			4,826.63
Interest on Customer Deposit (Refunds)			(2.37)
Interest earned from RSVA accounts			7,903.06
Total Interest Earned 2011			**18,370.03**
Closing Balance - December 31, 2011		**248,152.39**	
Investment	Aug. 1, 2012	50,000.00	
	Nov. 1, 2012	78,000.00	
Diff. In 2011 Closing Bal. Proforma/Actual		443.00	
Interest Earned 2011		6,020.00	6,020.00
Interest from Standard Life			4,830.00
Interest on Customer Deposit (Refunds)			-
Interest earned from RSVA accounts			2,350.00
Total Interest Earned 2011			**13,200.00**
Closing Balance - December 31, 2011		**382,615.39**	

c. Please state the number of customers and the 2012 total revenues for MicroFIT. Please state in which account the forecast is recorded.

Response

CPUC does not have customers or revenue under MicroFIT.

7. Capital Expenditures

References: Exhibit 2 pages 90 – 91, and 94 – 97

Exhibit 8 page 189

EB-2007-0755 Excel Model: ChapleauPUC_RATE_APP _20081015, Tab Exhibit 3(a) Op. Rev. (Data 1)

On page 91, CPUC state that capital projects can be categorized as; for improving safety and reliability, caused by inclement weather, and for conservation purposes.

a. Please complete the following table giving the capital expenditures for each *category by year, and the percentage that the category's expenditure is of the* total yearly expenditure.

Table 4

Capital Expenditures ($)

Chapleau Public Utilities Corporation

EB-2011-0322

	2006	2007	2008	2009	2010	2011	2012
1 Safety and Reliability ($)							
2 Safety and Reliability (%)							
3 Inclement Weather ($)							
4 Inclement Weather (%)							
5 Conservation ($)							
6 Conservation (%)							
7 Total ($)							
8 Total (%)							

<u>Response</u>

Table 4

		2006	*2007*	*2008*	*2009*	*2010*	*2011*	*2012*
1	***Safety and Reliability and Conservation ($)***	*12,501*	*-*	*16,078*	*5,756*	*1,790*	*7,211*	*11,004*
2	***Safety and Reliability and Conservation (%)***	*51.5%*		*37.9%*	*69.7%*	*18.8%*	*100.0%*	*56.4%*
3	***Inclement Weather ($)***		*-*	*1,133*	*484*	*-*	*-*	
4	***Inclement Weather (%)***			*2.7%*	*5.9%*			
5	***Conservation ($)***	*10,949*	*-*	*12,681*	*1,182*	*2,228*	*-*	*8,501*
6	***Conservation (%)***	*45.1%*		*29.9%*	*14.3%*	*23.4%*		*43.6%*
7	***Total ($)***	*23,450*	*-*	*29,892*	*7,593*	*4,018*	*7,211*	*19,505*
8	***Total (%)***	*96.5*		*70.5%*	*92.0%*	*42.2%*	*100.0%*	*100.0%*

b. Using the same categories, please provide a table with CPUC's 5 year forecast capital programme, 2013 – 2017.

Response

CPUC's proposal over the next 5 years may change when the asset management plan is put in place.

		2013	*2014*	*2015*	*2016*	*2017*
1	*Safety and Reliability and Conservation ($)*	*44,760*	*10,869*	*37,731*	*19,880*	*22,921*
2	*Safety and Reliability and Conservation (%)*	*86.4%*	*17.9%*	*75.9%*	*53.6 %*	*61.9%*
3	*Inclement Weather ($)*	*-*	*-*	*-*		
4	*Inclement Weather (%)*	*-*	*-*	*-*		
5	*Conservation ($)*	*7,071*	*-*	*11,948*	*17,200*	*14,940*
6	*Conservation (%)*	*13.6%*	*-*	*24.1%*	*46.4%*	*39.5%*
7	*Total ($)*	*51,831*	*10,869*	*49,679*	*37,080*	*37,861*
8	*Total (%)*	*100.0%*	*17.9%*	*100.0%*	*100.0%*	*100.0%*

CPUC is proposing to increase its Total Loss Adjustment Factors from the current 1.0654% to 1.0671%. While this is not a significant increase, it nonetheless is an increase. In CPUC's last cost of service application EB-2007-0755, on the referenced excel model tab, it stated that the increase in loss factors in the 2008 COS application was due the age of CPUC's infrastructure in certain parts of the town. CPUC went on to address this by saying that a study had been undertaken to address losses and that CPUC would invest $23,500 for the replacement of conductors during 2007 in an effort to reduce line losses. However, Board staff notes that on page 90, CPUC indicates that there were no capital expenditures at all in 2007. Board staff also notes that on pages 94 – 96 the capital projects are listed for 2013 – 2015, however the 2012 projects are not listed.

Response

The 2012 capital projects are listed on page 82 of the submission.

c. Did CPUC invest the $23,500 for line replacement in 2007?

Response

CPUC was not able to replace the conductors in 2007 due to the lateness of the year and long lead times for their delivery from the USA.,

d. If not, has it in any of the subsequent years made the proposed investment, or similar investments for line replacements?

Response

The investment was made in 2008 and is included in the "Line Transformer" category.

e. What is CPUC planning in order to reduce line losses in the future?

Response

CPUC will continue to replace old transformers with new ones in order to reduce line losses. A recommendation made in the study performed by Burman Energy to address our losses was to try to balance the load on our 3 feeders. CPUC will continue to investigate this option in order to reduce line losses.

f. With losses increasing, why is CPUIC forecasting only low priority projects?

Response

CPUC forecasts projects at a low priority while the distribution system is still operational. Capital projects planned each year are for the replacement of old poles, conductors and transformers. CPUC will class a project a higher priority for a new development, whether residential or commercial, or where an asset has become a danger to public safety that requires replacement at the earliest opportunity.

8. Smart Meter Costs

Reference: Appendix J 2012 Smart Meter Model

Guideline G-2011-0001 Smart Meter Funding and Cost Recovery – Final Disposition (the "Guideline")

Implementation Status

The Guideline states that a distributor is to provide the implementation status with respect to the smart meters. It appears from the Smart Meter Model that 100% of the residential and GS<50 kW meters have been installed.

a. Please confirm or correct as to whether 100% of the installations have been completed.

Reference - Smart Meter Model - Appendix B

Response

CPUC confirms that 100% of smart meter installations have been completed.

Audited Costs

The Guideline states that a distributor is to have as a minimum, 90% of its total costs audited before it could apply to dispose the balances in the smart meter deferral accounts. Board staff notes that the last audited balances were 2010 when CPUC filed its application, and that the 2010 capital expenditures was not at or above the 90%.

b. Please confirm that the auditors have approved the 2011 balances in Account 1555 and Account 1556.

Response

The auditors have approved the 2011 balances in accounts 1555 and 1556

c. Please provide the audited balance.

Response

Audited Balances are - account 1555 - $378,617.46

- account 1556 - $126,426.34

Carrying charges	***$ 9,408.68***
Total	***$514,272.48***

Fairness Commissioner's Letter

The Guideline states that a copy of the letter from the Fairness Commissioner is to be filed as support that the distributor was authorized for smart metering activities.

d. Please file a copy of the Fairness Commissioner's Letter as to the smart meter acquisition process that CPUC undertook.

Response

A copy of the Fairness Commissioner's Letter as to the smart meter acquisition process is attached as Appendix H.

Smart Meter Model Tab 1: Smart Meter Costs

The annual capital expenditures and operating expenditures are inputs found in the green cells on this tab.

e. CPUC indicate that they installed 47 smart meters in 2010, however there are no installation costs found on line 1.1.2 Installation Costs. Please explain or correct.

Response

CPUC installed meters in 2010 and recorded costs of $1,493.96 in "Meter Expense" account 5065.

f. Were any of the installations performed by CPUC personnel? If so were there any incremental costs? Please explain the incremental costs.

Response

CPUC personnel performed installations and no incremental costs were incurred.

g. CPUC has not included any capital for an Advanced Metering Control Computer. Please explain or correct.

Response

CPUC did not have any capital costs for an Advanced Metering Control Computer. CPUC is sharing an RNI with 7 other utilities in our District. Sensus Metering Systems provide a service as our Application Service Provider for which we pay a monthly fee.

h. CPUC has not included any capital for a Wide Area network. Please explain or correct.

Response

No up-front capital was required. Sensus Metering Systems is the AMI operator and is providing the service through Pagenet as part of the service they provide.

Smart Meter Model Tab 2: Cost of Service Parameters

The financial parameters for cost of capital, PILs, Depreciation, and CCA rates are inputs found in the green cells on this tab.

i. The deemed long-term debt rate for 2006 and 2007 is 6.25% while the Board approved 7.25% in RP-205-0020/EB-2005-0349. Please explain the difference in the debt rate or correct.

Response

The deemed debt rate for 2006 and 2007 has been corrected to 7.25%

j. For 2009 – 2011, please state the source documents for the cost of capital parameters CPUC has used. Alternatively, if these rates are incorrect, please correct.

Response

CPUC used the 2008 Board Approved cost of capital parameters for years 2008 to 2011

k. For 2012, please update the cost of capital parameters for the Board's March 2, 2012 letter Re: Cost of Capital Parameter Updates for 2012 Cost of Service Applications for Rates Effective May 1, 2012.

Response

CPUC has updated the cost of capital parameters for 2012 as per the Board's March 2, 2012 letter as follows:

Particulars	**Capitalization Ratio**		**Cost Rate**	**Return**
DEBT				
Long-Term Debt	56.00%	$1,256,112	4.41%	$55,395
Short-Term Debt	4.00%	$89,722	2.08%	$1,866
Total Debt	60.00%	$1,345,835	4.25%	$57,261
EQUITY				
Common Equity	40.00%	$897,223	9.12%	$81,827
Preferred Shares	0.00%	0.00	0.00%	$0.00
Total Equity	40.00%	$897,223	9.12%	$81,827
TOTAL	100.00%	$2,243,058	6.20%	$139,088

CPUC has also amended the Revenue Requirement work-form to show the above capital parameters.

l. CPUC has used the maximum taxes/PILs rates input on Tab 3 Cost of Service Parameters, for the years 2006 – 2012. Please confirm that these are the tax rates underpinning CPUC's rates for each of the respective years. This should be readily available from taxes/PILs calculations or spreadsheets used in annual cost of service or Incentive Regulation Mechanism ("IRM") rates applications. In the alternative, please correct if needed.

Response

CPUC has made corrections to the taxes/PILs rates input on Tab 3 Cost of Service Parameters, for the years 2006 – 2012.

Customer Repairs

The Board, in the Guideline stated:

> "*The actual costs for materials and parts to repair or replace any customer-owned equipment should be expensed and also tracked separately in a different sub-account of the Smart Meter OM&A Variance Account 1556 until disposition is ordered by the Board following a review for prudence of the smart meter costs. As the meter base remains the property of the customer, the Board determined that it would not be appropriate to have it form part of the distributor's rate base.*"

m. Please state the total costs of any repairs or replacements of customer-owned equipment.

Response

CPUC had 3 meter sockets that required repair. We had the parts (lugs) in stock, no new material was purchased. In 2010, CPUC had to hire a Master Electrician to repair the meter sockets as per ESA rules. The cost to CPUC of $441.80 for the electrician, was recorded in acct # 5605 - Meter maintenance.

n. Are there any meter bases included in these costs? If so, please state the total amount.

Response

There are no meter bases included in these costs.

o. Please confirm that these costs were recorded in a different sub-account of the Smart Meter OM&A Variance Account 1556.

Response

Not applicable, since we did not have any repairs reported in our OM&A Variance Account 1556.

Costs Beyond Minimum Functionality

CPUC has not provided any information regarding its installation of smart meters other than the smart meter model. Board staff is interested if there may have been costs incurred that are considered to be beyond minimum functionality.

The Board states in the Guideline at page 17:

> "Costs for CIS systems, TOU rate implementation, etc. are beyond minimum functionality…"

and

> "Costs for other matters such as CIS changes or TOU bill presentment may be recoverable, but the distributor will have to support these costs and will have to demonstrate how they are required for the smart meter deployment program and that they are incremental to the distributor's normal operating costs."

p. Please state the level of, and describe the costs incurred, beyond minimum functionality making specific reference to MDM/R, web presentment, CIS changes, TOU rates, business process changes, training and customer education costs.

Response

CPUC, in completing the Smart Meter model, identified costs ($5,915) in section 1.6 "Capital Costs Beyond Minimum Functionality" which should have been identified in section 2.5 "Other AMI OM&A Costs Related to Minimum Functionality" and section 1.5 "Other AMI Capital Costs Related to Minimum Functionality". These costs were for Staff Training ($2,557), Customer Communication/Education ($1,858) and software related to the interface of AMI to CIS ($1,500).

CPUC therefore did not incur costs for MDM/R, CIS changes, TOU rates, business process changes and does not have web presentment.

q. Please state how these costs are required for CPUC's smart meter programme, and how they are incremental to CPUC's normal course of business.

Response

See above response.

r. Please restate Tab 1 Smart Meter Costs, separating any costs beyond minimum functionality

Response

CPUC has made the changes to Tab 1 as identified in question p. above, therefore there are no costs beyond minimum functionality.

s. State the total costs for beyond minimum functionality, and then state the costs again as an average unit costs per smart meter.

Response

Not applicable.

t. What is the annual impact on OM&A for beyond minimum functionality?

Response

CPUC has not included any costs beyond minimum functionality in its OM&A costs

Unit Costs

The Guideline requires reporting of capital and operating unit cost per installed smart meter and in total for:

- procurement and installation of the components of the AMI system;
- customer information system;
- incremental operating and maintenance activities;

- changes to ancillary systems; and
- stranded meters;

The Guideline also states that a variance analysis comparing actual costs to previously approved costs is to be provided.

u. Please provide the unit costs information stated in the Guideline.

Response

- ***Cost per installed meter for the procurement and installation of the components of the AMI system is $289.68***
- ***Cost per installed meter for the customer information system is $48.40***
- ***Cost per installed meter for the incremental operating and maintenance activities is $65.00***
- ***Cost per installed meter for changes to ancillary systems is $0.00***
- ***Cost per installed meter for stranded meters is $36.85 for residential and $67.29 for commercial <50 kW. This is an average of $40.64 per meter.***

v. Please provide the cost comparison between the previously approved costs and the actual costs.

Response

Previously approved costs of $506,253 taken from the 2011 Rate Application, "Smart Meter Rate Calculation Model".

Current proposed actual costs are $513,528.

9. Stranded Meters

References: Exhibit 2 page 87

CPUC has stated in the referenced evidence that all smart meters have been fully deployed as of November 2011 and as at December 31, 2011 the pooled residual NBV was calculated to be $52,585 (unaudited actual). It also stated that an adjustment will be made for removals at December 31, 2011.

a. Please provide the audited NBV for the stranded meters as of December 31, 2011.

Response

The audited net book value of stranded meters as of December 31, 2011 is $52,585

b. CPUC stated that an adjustment would be made for removal of the meters at December 31, 2011. Was that adjustment made?

Response

CPUC has made the adjustment for the removal of the meters at December 31, 2011

c. If the audited December 31, 2011 NBV differs from $52,584, please update the Stranded Meter Rate Rider.

Response

Although the NBV of the audited December 31, 2011 stranded meters does not differ from the $52,584, CPUC auditors removed stranded meters at January 1, 2011 without applying full depreciation to all meters at December 31, 2011. Accumulated depreciation of $93,961 for stranded meters is inclusive of the 2011 depreciation.

CPUC Rate Application

	Asset	*Depreciation*	*NBV*
Opening Balance 2011	*174,647*	*105,015*	*69,632*
Depreciation Additions	*-*	*6,963*	*6,963*
Stranded Meters	*(146,546)*	*(93,961)*	*(52,585)*
Closing Balance 2011	*28,101*	*18,017*	*10,084*

Audited Financials

	Asset	*Depreciation*	*NBV*
Opening Balance 2011	*174,647*	*105,015*	*69,632*
Stranded Meters	*(146,546)*	*(93,961)*	*(52,585)*
Balance of Meters	*28,101*	*11,054*	*17,047*
Depreciation Additions	*-*	*1,705*	*1,705*
Closing Balance 2011	*28,101*	*12,759*	*15,342*

The 2011 depreciation difference of $5,258 ($6,963 - $1,705) has been confirmed by the auditors and they will make the adjustment in 2012 for 2011.

10. Outside Services

References: Exhibit 4 page 123

Chapter 2 Appendix 2-L

CPUC has provided detailed tabulated costs by account for its OM&A from 2007 to 2012. On page 123, CPUC gives the annual costs for account 5630, Outside Services for the stated years.

a. Please confirm that the 2008 costs are the actual costs for the year, and not the Board approved costs.

<u>Response</u>

CPUC confirms that the 2008 costs for Outside Services Employed are the actual costs for the year.

b. There have been significant variances in outside services. Please provide a detailed itemized list of each outside service acquired by CPUC, providing the service, reasons for the service and the amount.

<u>Response</u>

The following can be found in Appendix G

		2007	2008	2009	2010	2011	2012
RCS	IRM Rates	14,674.72	4,625.50	10,739.80	14,137.60	1,713.30	15,000
	2008 COS Rates	25,040.65					
	2008 COS Interrogatories		30,260.60				
	2012 COS Rates					18,000.00	10,000
KPMG	3 YR Business Plan	11,450.00					
	Profesional Services	7,950.00	4,182.00				4,500
	Audit	9,436.50	16,918.99	30,613.00	14,732.00	16,989.00	18,000
	Set-up Vision Bus. System		3,009.00				
AESI	ESA Audit	1,702.19	1,733.05	1,780.64	1,792.95	1,802.24	1,850
Sudbury Control	Infra Red Scan	600.00	600.00	600.00	700.00	-	700
Highline Power	Labour & Equipment		3,300.00				
Iron Mountain	Intelectual Prop. Mgnt.					700.00	700
Weaver Simmons	Legal requirements					1,474.31	
Burman Energy	CDM Planning/Strategy				2,640.27		-
	Asset Management Plan						30,000
	Preparation of LRAM						4,000
Hydro One	CPUC Load Data	3,500.00	-				
	Set-up Line Generators	-	954.00				
Peterborough Utility Services	Meter Service Provider	17,739.52	17,776.56	17,814.84	(1,485.92)	-	-
SENSUS	FLEXNET Monitoring Service	-	-	1,307.48	3,792.86	(513.32)	26,000
Harris Computer Systems	ODS - Store Readings						2,000
Screaming Power	EBT Hub Transport						
	Support Service	3,060.00					
Util-Assist	Smart Meter Initiative	-	4,838.83	(2,390.46)			
CESC	Snow removal	912.82	1,336.10	736.12	576.38	1,523.27	1,400
	Janitorial Services	2,421.62	2,469.18	1,920.34	2,404.94	1,967.86	2,250
	Audit	6,184.12	8,382.46	9,995.76	4,315.55	-	
	Legal Fees					928.02	
	Computer Set -up					336.72	
TOTAL		104,672.14	100,386.27	73,117.52	43,606.63	44,921.40	116,400

c. In Appendix 2-L, CPUC states that these costs are allocated at 84% to CPUC. 84% appears to be the same allocator as for all other allocations that are not 100% allocated. Please explain why an allocation is used.

Response

2012 Outside Services being allocated to CPUC are for snow removal, janitorial services, legal fees and computer set up which are considered to be shared costs. Therefore the same allocator is used as calculated that apply to all other allocations that are not 100.0%.

11. Shared Services

Reference: Exhibit 4 page 117

Exhibit 4 pages 136 – 141

CPUC states on page 117 that CPUC and Chapleau Energy Services Corporation (CESC) have an operation and maintenance service agreement between the two companies. CPUC goes on to state that all services are charged to CPUC at direct cost plus applicable overhead (no mark-up). On page 141, CPUC shows that these services are estimated to be $417,913 in total for 2012.

a. Please provide the referenced operation and maintenance service agreement between CPUC and CESC.

Response

The Operation and Maintenance agreement between CPUC and CESC is attached as requested as Appendix I.

b. Please itemize the overhead components and state the manner in which overheads are determined for a cost item charged to CPUC, and provide an example

Response

In the application CPUC erroneously identified that there was an overhead component in charges from CESC.

All overhead component charges such as truck depreciation expenses, holidays and sick time, employee pensions and benefits, etc. are all charged at the allocation percentage (%) as discussed in question 10 c. above.

c. For 2010, the year of the last audited actuals, for each account and sub account number listed on page 138, state whether the costs were determined on an as occurred basis such as time and materials, as invoiced, etc. or was determined on an allocation of costs, before overheads. State the allocator(s) used and reasons for the allocator.

Response

A/C #	Service Offered	Cost for Service $	Allocator
5016	Distribution Station Equipment - Operation Labour	4,388	100 % - As occurred basis -Direct labour charge - No overhead
5017	Distribution Station Equipment - Operation Supplies and Expenses	610	100 % - As occurred basis -Direct labour charge - No overhead
5020	Overhead Distribution Lines and Feeders - Operation Labour	123,772	100 % - As occurred basis -Direct labour charge - No overhead
5020.006	Holidays and Sick Time	16,702	84.1% - Allocation Basis - no overhead
5020.100	Undistributed Expenses - On Call	7,650	As occurred basis - actual cost for on-call allowance - No overhead
5025	Overhead Distribution Lines and Feeders - Oper. Supp. & Exp	4,861	84.1% - Allocation Basis - no overhead
5025.100	Truck Depreciation & Expenses	24,278	Allocation Basis @ 84.1% - no overhead
5065	Meter Expense	1,492	100% - As invoiced - no overhead
5310	Meter Reading Expense	7,955	100 % - As occurred basis -Direct labour charge - No overhead
5315	Customer Billing	36,304	84.1% - Allocation Basis - no overhead
5610	Management Salaries and Expenses	53,986	84.1% - Allocation Basis - no overhead
5610.003	EHT Expense	3,823	84.1% - Allocation Basis - no overhead
5610.005	WSIB	2,776	84.1% - Allocation Basis - no overhead
5615.001	CPP Expense	8,623	84.1% - Allocation Basis - no overhead
5615.002	EI Expense	4,242	84.1% - Allocation Basis - no overhead
5620	Office Supplies and Expenses	18,925	84.1% - Allocation Basis - no overhead
5630	Outside Services Employed	7,297	84.1% - Allocation Basis - no overhead
5635	Property Insurance	909	84.1% - Allocation Basis - no overhead
5645	OMERS - Employee Pensions and Benefits	16,862	84.1% - Allocation Basis - no overhead
5645.100	Group Insurance	38,248	84.1% - Allocation Basis - no overhead
5665	Miscellaneous General Expenses	11,410	84.1% - Allocation Basis - no overhead
6105	Taxes Other than Income Taxes	7,720	84.1% - Allocation Basis - no overhead
	Total	402,833	

CESC employs all personnel who perform duties to both companies and it is reasonable to allocate all common costs on the basis of the work performed to each company.

An allocator is used to apply common expenditures to CESC and CPUC such as office supplies, billing and collecting, management salaries & expenses, pension and benefits, holidays & sick time, truck depreciation & expenses, etc. to each affiliated company on the basis of

direct hours worked for CPUC and determined as a percentage to all hours worked by CESC employees.

As an example, in 2010 the allocator of 84.1% was determined:

Direct hours worked for CPUC	***8,712.1 x100 = 84.1%***
Total direct hours worked	***10,356.0***

Any expenditure directly related to either company is charged directly to that company at 100%.

d. For 2010, for each account and sub account number listed on page 138, state the methodology for allocating overheads, and the rational for the allocators.

Response

As identified above in question 11 b. CPUC erroneously identified that there was an overhead component in charges from CESC. Overhead is not applied to distribution employees direct labour hours.

e. Please confirm that for 2012 the same methodology described above applies.

Response

CPUC confirms that the same methodology as described above applies to 2012.

It appears that capital costs pertaining to vehicles, office equipment, tools and work equipment, etc. are held in CESC. Given the transition to IFRS in January 1, 2013, Board staff is interested in the depreciation rates and other related costs as they affect CPUC.

f. Are the 2012 estimates for depreciation used in the transferred costs to CPUC from CESC based on an assessment of the average age and remaining life of the asset groups?

Response

The componentization approach will not be used in 2012 because CPUC will not be adopting IFRS until 2013.

CPUC used the pooled amortization approach for 2012, which is consistent with prior years.

g. Please state the 2012 depreciation rates for each asset group charged to CPUC.

Response

The depreciation rates per the CESC financial statements are as follows:

Building – 25 years, Equipment – 5 years, Office equipment – 5 years and Vehicles – 5 years.

The assets are amortized on a straight line basis and only 50% amortization is taken in the year of acquisition.

h. Please state the total depreciation that is included in the transferred costs from CESC for 2012.

Response

As CPUCs transition to IFRS will not occur till 2013 the total depreciation included in transferred costs from CESC in 2012 is $12,146. This being the same as was transferred in 2011.

i. If there is a component for return and taxes in the transferred costs, please state the associated percentage rates for return and taxes, and associated costs for 2012.

Response

There is no component for return and taxes in the transferred costs, or associated costs for 2012.

12. Depreciation Rates

References: Exhibit 4 page 143

Board Letter, July 8, 2010 Re: Depreciation Study for Use by Electricity Distributors.

Depreciation Study for Use by Electricity Distributors (EB-2010-0178), the "Kinectrics Report," July 8, 2010

The regulatory paradigm for depreciation is straight line remaining life depreciation, in which the asset, usually of mixed ages, is depreciated over the average remaining life. The Kinectrics Report was commissioned to assist distributors in their transition from CGAAP to IFRS. Kinectrics assessed common groups of assets in Ontario. For each of the assets and their respective components, a useful life range and a typical useful life value within the range are given. The Kinectrics Report will assist CPUC in assessing and ascribing appropriate depreciation rates based on the estimated remaining lives of its assets. Using the Kinectrics Report:

a. Please evaluate CPUC's assets and ascribe depreciation rates based on estimated remaining lives. Please state the asset group, the remaining life and the rationale that led to the remaining life.

Response

Due to the Accounting Standards Board in Canada allowing for an additional one year deferral for the transition to IFRS, CPUC therefore will not be adopting IFRS until the 2013 year-end and at present is not able to evaluate its assets and ascribe depreciation rates based on the remaining life of the assets because the asset assessment, although it has been started, will not be completed till the fall of 2012. This work has to be done and completed by only one individual while performing all of his other regular duties.

To complete the transition to IFRS, CPUC will be paying particular attention to the componentization of assets along with the related useful lives that will be used for the assets. In order to complete this, utilization of the Kinetrics report, that was prepared with the assistance of the OEB to break the various assets into the individually significant components, is being used. During the IFRS conversion, CPUC will be going with the Typical Useful Life per the Kinectrics report.

b. Please update the 2012 depreciation expense using straight line remaining life depreciation and the new rates from the evaluation.

Response

Please see response to a. above.

13. Employee Costs

References: Chapter 2 Appendix 2-K

Board staff would like an explanation for the variances (positive and negative) year over year that is exhibited in Total Salaries and Wages in this appendix. Please explain these variances.

Response

Appendix 2-K shows salaries and wages as charged by CESC to CPUC for each year and will cause variances from one year to the next through the different allocators used and the difference in direct labour being charged each year.

Variances are as follows:

2008 and 2009 difference - ($34,531)

Variance of ($34,531) was caused mainly by:

a) 2 qualified linemen left in the fall of 2008 and 2 new apprentices were hired at a lower rate of pay. Total savings of $16,859

b) Received financial assistance from the Northern Ontario Heritage Fund Corporation for hiring new apprentices. CPUCs allocated portion received from CESC of $22,743.

c) Increases of 3% applied effective January 1, 2009 for $7,320.

d) Reduced allocator from 85.6% to 82.7% - $2,810

Total variances above of $35,092 compares with actual of $34,531.

2009 and 2010 difference - $41,284

Variance of $41,284 was caused mainly by:

a) Add back the financial assistance from the Northern Ontario Heritage Fund Corporation for hiring new apprentices of $22,743.

b) Increases of 2% plus a merit increase for a total of $9,790

c) Progressive Increases to apprentices to 3rd level $7,450

d) Increase allocator from 82.7% to 84.1% - $1,500

Total variances above of $41,483 compares with actual of $41,284

<u>2010 and 2011 difference - ($7,466)</u>

Variance of ($7,466) was caused mainly by:

a) Direct labour hours charged are lower by $11,595

b) Increases of 2% applied Jan. 1, 2011 of $4,865

c) Progressive Increases to apprentices to 4th level $2,580

d) Reduced allocator from 84.1% to 84.0% - $109

Total variances above of $4,259 compares with actual of $7,466

<u>2011 and 2012 difference - $8,385</u>

Variance of $8,385 was caused mainly by:

a) Direct labour hours charged are higher by $2,117

b) Increases of 2% applied Jan. 1, 2012 of $5,034

Total variances above of $7,151 compares with actual of $8,385

14. PILs

References: Chapleau_appl_CoS_2012_Rev_Reqt_Work_Form_Appendix_A _20120127.xls (Tab 6)

Chapleau_appl_CoS_2012_Test_year_Income_Tax_PILs_ Workform_Appendix_B_20120127.xls (Tab T)

The Revenue Requirement Work Form shows the Grossed up amount for PILs proxy to be $15,050, and the PILs work form Tab T shows the PILs proxy as $21,864.

a. The PILs proxy amounts are different in the pre-filed evidence referenced above. Please explain the differences?

Response

There are changes to be made to the Revenue Requirement Work Form that will change CPUCs income before taxes for 2012. CPUC will ensure that the PILs proxy amounts in the Revenue Requirement Work Form and the PILs Work Form will be the same. Appendix C.

b. If the PILs in both instances are to be the same, please state which number should the Board rely on for the purpose of this proceeding and why?

Response

Please see response a. above

15. Cost of Capital

On March 2, 2012, the Board, in a letter set the parameters for the Cost of Capital for rates beginning May 1, 2012. Please update CPUC's Application for the new parameters.

Response

CPUC will update its application for the new parameters - see also response to Question 8 k.

16. Cost Allocation

References: Appendix G Cost Allocation Model and the supporting Excel model ("CA Model")

Exhibit 7 page 178, 180

Exhibit 3 page 102

Chapter 2 of the Filing Requirements for Transmission and Distribution Applications June 33, 2011 ("Filing Guidelines")

Load Profiles

CPUC states on page 102 that several plant closures prior to 2006 in the forestry industry caused a population reduction of 16.9% resulting in 17.1% reduction in CPUC's customer consumption. Board staff notes that the load profiles that underpinned the coast allocation informational filings were based on loads prior to 2006. The Filing Guidelines state that if updated load profiles are not available, the profiles used in the informational filing may be used if they are scaled to match the respective classes.

a. Did CPUC use updated load profiles in its cost allocation?

Response

CPUC has used updated load profiles in its cost allocation.

b. If not, did CPUC scale the load profiles prepared by Hydro One for its informational filing to reflect the 2012 forecast loads?

Response

Not applicable

c. If CPUC did not scale its load profiles, please scale the profiles to match the forecast 2012 loads by class.

Response

CPUC did scale its load profiles to match the forecast 2012 loads by class.

Weighting Factors

The Filing Guidelines requires that a description of the weighting factors.

d. Please explain the relative weightings that CPUC has assigned to Services, and Billing and Collection as found on page 180.

Response

As a small distribution utility, CPUC does not allocate costs to accounts 5320, 5325, 5330 and 5340 to assign weight factors to billing and collection. The only accounts that costs are allocated to are 5310 and 5315.

CPUC does not allocate costs to account 1855 to enable them to develop weight factors to services.

Assigning weight factors to billing and collection and to services CPUC considered the use of default weight factors to all classes however CPUC did not agree with the GS >50 kW, USL and sentinel Lights default weight factors and considered the residential factor of 1 for the residential class to determine weight factors that CPUC believes to be more realistic for these classes. In determining weight factors for the GS >50 kW, USL and Sentinel Lights classes, CPUC used the experience of its staff to determine the "difficulty" level as compared to the residential class, paying particular attention to the manual reading of meters in the > 50 kW class and to the manual recording of these readings into the billing system. In answering this interrogatory CPUC believes that the weight factors used are too low and should be increased to 6 for both billing and collection and to services. As for unmetered scattered load and sentinel lights classes, because they are not metered, utility staff pay periodic visits to these sites to ensure that all is OK.

Please note that the USL and Sentinel Lights classes represent 0.5% of CPUCs distribution revenue and 0.001% of the total kWh consumption.

e. Please explain the meter weighting factors on Tab I7.1 Meter Capital, and Tab I7.2 Meter Reading in the CA Model.

<u>Response</u>

The smart meter weight factors (prices) on Tab I7.1 in the CA model of the rate submission were the prices developed as at September 2011 and

did not include estimates to the end of the year. We have since developed more accurate prices for all meters that include all expenditures to December 31, 2011 and estimates for 2012 that were used in the table as identified in Question 20. CPUC will change the prices on Tab I7.1 in the CA model.

The meter reading weight factors on Tab I7.2 were logical to assume the difficulty in meter reading for the GS >50 kW class are 5.8 times more difficult than either the residential or the GS <50 kW classes.

17. Cost of Power

Reference: RTSR Work Form for Electricity Distributors

On December 20, 2011, the Board issued its EB-2011-0268 Decision with respect to the 2012 Uniform Electricity Transmission Rates which became effective January 1, 2012. CPUC's filing did not incorporate these rates.

a. Please update the RTSR Work Form.

Response

The RTSR Work Form is correct - The amounts used for the cost of power in the working capital allowance requires adjustment.

b. Please update the rate base for the cost of power in the working capital allowance

Response

The Rate Base for the cost of power in the working capital allowance has been adjusted.

18. Rate Design

On December 20, 2011, the Board issued its EB-2011-0405 Decision with respect to the Rural or Remote Electricity Rate Protection ("RRRP") benefit and charge. The charge is now $0.0011 per kWh, down from $0.0013 per kWh. Please update the rate schedules for the new RRRP rate.

<u>Response</u>

The rate schedules, Appendix K, for the new RRRP rate have been updated.

19. Rate Impact Mitigation

Reference: Exhibit 8 pages 209 - 211

CPUC is proposing a rate impact mitigation plan. CPUC states that 128 residential customers, 28 GS<50 customers, 23 Sentinel Lighting, and 341 Street Lighting customers/connections will see a rate impact greater than 10%. CPUC is proposing a rate mitigation plan that will result in lost revenues of $43,628. CPUC intends to book the lost revenues into a variance account for future recovery.

a. Please state whether the impacts calculated by CPUC are based on the distribution component of the bill, or whether it is the total bill. If the impacts are on the distribution portion of the bill, are there any impacts over 10% on a total bill bases. If there are any impacts over 10% on the total bill basis, please provide summaries as found in the table on page 209 and 211.

Response

The impacts calculated by CPUC are based on the total bill as provided in the summaries found in the table on page 209 and 211.

b. Please confirm that CPUC plans to raise all rates to the proposed levels in 2013, except for Sentinel Lighting, and that CPUC intends to raise Sentinel Lighting in both years, 2013 and 2014, to bring Sentinel Lighting to the proposed rate levels.

Response

CPUC confirms that it plans to raise all rates to the proposed levels in 2013, except for Sentinel Lighting and that CPUC intends to raise Sentinel Lighting in both years, 2013 and 2014, to bring them to the proposed rate levels.

CPUC states that it requests the recovery of revenue losses of $38,340.72 and $3,478.20 from the Residential and Street Lighting classes respectively commencing on May 1, 2013 to April 30, 2014. CPUC proposes to collect these lost revenues in a deferral account in 2012.

c. Please confirm that this proposal forgoes the lost revenues from the GS<50, USL, and Sentinel Lighting classes.

<u>Response</u>

CPUC confirms that the lost revenues from the GS <50 kW, USL and Sentinel Lighting classes will be foregone

d. Please state the deferral account in which CPUC intends to record the lost revenues.

<u>Response</u>

CPUC intends to record lost revenue in "Deferred Rate Impact" account 1574

20. Smart Meter Rate Adder

Reference: Tab 9, SMFA SMDR SMIRR; Smart Meter Model

CPUC seems to be relying upon the results found in Tab 9 for its SMDR for CPUC has not provided smart meter calculations for class specific SMDRs. Board staff is interested as to whether a rate rider by class could be calculated. In PowerStream's 2010 smart meter application EB-2010-0209, costs were allocated to each class based on cost allocation principles. The allocation to each class was based on:

- Allocating the return and depreciation based on customer weighted smart meter costs;
- Allocating the OM&A based on the number of meters; and
- Allocating the PILs based on the allocated revenue requirement.

The revenues from the SMFA were also allocated.

In Midland's smart meter application EB-2011-0434, Midland allocated costs in a similar way. However, the Board found that that an appropriate determination of the SMDR should be based on the direct assignment of class SMFA revenues. Please calculate SMDRs by class.

Response

The following table shows the allocation of smart meter costs to determine rate riders by customer class based on cost allocation principles.

Allocation of smart meter costs were determined by a) the price of the meter plus the price of adapters used, plus b) the average cost per meter for the regional collector, installation costs and computer software expenditures.

Allocating the total return and depreciation is based on customer weighted smart meter costs

Allocating OM&A is based on the number of meters.

Allocating PILs is based on the allocated revenue requirement.

The following table, Appendix G, shows the calculation of the monthly rate rider per class to be collected over a 4 year period.

	Smart Meter Cost Recovery Rate Rider SMDR Calculated by rate class							
	Total		Residential		GS <50 kW		GS >50 kW	
	Qty	$	Qty	$	Qty	$	Qty	$
Sensus Icon A2S	1,172	370,662	1,096	316	76	316		
Sensus Icon A12S	19	7,432	15	384	4	418		
Sensus Icon A3S	29	12,603	3	462	26	431		
Elster A3RL 16S &36S	14	8,545			14	610		
Elster A3RL 12S	20	9,020			20	451		
GE KV2C 9S	9	6,825			9	758		
GE KV2C 12S	9	10,935			9	1,215		
GE KV2C 16S	2	1,468			2	734		
3 Phase Demand Meter	14	12,025					14	859
Total smart Meter Cost	1,288	439,515	1,114	353,766	160	73,719	14	12,025
Smart Meter Cost Allocation		100.0%		80.49%		16.77%		2.74%
Number of Meters - Allocation	100.0%		86.49%		12.42%		1.09%	
Total Return on Capital		56,750		45,678.08		9,518.63		1,552.65
Amortization		70,517		56,759.14		11,827.75		1,929.31
OM&A		82,813		71,625.53		10,287.33		900.14
Sub total before PILs		210,080		174,062.75		31,633.71		4,382.09
PILs		- 1,087		- 901		- 164		- 23
Total Revenue Requirement	100.0%	208,993	82.86%	173,162.11	15.06%	31,470.03	2.09%	4,359.42
Smart Meter Adder Revenues		- 79,918		- 69,121.62		- 9,927.70		- 868.67
Carrying Charges		1202		1039.62		149.32		13.07
Net Deferred Revenue Requirement		**130,277**		**105,080**		**21,692**		**3,504**
Metered Customers		**1,308**		**1,133**		**161**		**14**
Rate Rider/month/Meter Over 4 Yrs		**$ 2.08**		**$ 1.93**		**$ 2.81**		**$ 5.21**

21. LRAM

Reference: Burman Energy, LRAM Support Document, Page 162-166

CPUC has requested an LRAM recovery for a total amount of $23,131.15 for lost revenues incurred from 2006 to 2010 from OPA CDM programs implemented between 2006 and 2010.

a. If CPUC did not use the final detailed 2010 program evaluation results from the OPA, please provide supporting reasons for not doing so, and update the LRAM amount with the final detailed 2010 OPA evaluation results. Please ensure that, amongst other variables, both the input assumptions and free ridership rates are up-to-date.

<u>Response</u>

The finalized 2010 details program evaluation results from the OPA were used to calculate LRAM amounts.

b. Please provide a table that shows the LRAM amounts CPUC has collected in the past.

<u>Response</u>

CPUC has not collected any LRAM amounts in the past.

c. If CPUC has any unclaimed lost revenues from its 3rd Tranche CDM programmes, please state the reasons for not claiming for the lost revenues.

<u>Response</u>

CPUC's Third Tranche programs consisted of the following:

- ***Distribution system improvements***
- ***Energy savings information and promotions***
- ***Customer oriented conservation and demand management programs***
- ***Examination and roll out of smart meters***

The programs offered did not result in any energy or demand savings for which LRAM could be claimed.

d. Please confirm that CPUC is not requesting LRAM for any third tranche CDM programs that have already been claimed in previous applications to the Board.

Response

CPUC has not claimed any prior LRAM, including LRAM for any third tranche programs.

e. It appears that CPUC has not applied for interest on its LRAM balances. Please explain not requesting interest and update the LRAM to include interest

Response

Not claiming interest was an oversight. CPUC will update the LRAM to include interest.

f. If CPUC prefers to apply for carrying charges, please provide a table similar to the one below that shows the monthly LRAM balances, the Board-approved carrying charge rate and the total carrying charges by month for the duration of this LRAM request. Use the table below as an example:

Table 5

Year	Month	Monthly Lost Revenue	Closing Balance	Interest Rate	Interest $
Total					

Response

The following is a summary of carrying charges

Year	Month	Annual Lost Revenue	Closing Balance	Interest rate Average %	Interest $
2006	Jan. to Dec	1,386.24	1,386.24	5.40	36.55
2007	Jan. to Dec.	2,504.89	3,891.13	4.59	125.91
2008	Jan. to Dec.	3,303.14	7,194.27	4.07	224.19
2009	Jan. to Dec.	6,537.75	13,732.02	1.14	109.55
2010	Jan. to Dec.	4,891.57	18,623.59	0.80	134.14
2011	Jan. to Dec.	4,507.56	23,131.15	1.47	309.66
					940.00

Calculation of carrying charges (interest) on monthly LRAM balances. Appendix G

YEAR	Month	Lost Revenue	Closing Balance	Interest Rate	Interest $		Average Interest Rate %
2006	January	115.52	115.52	7.25	0.70		
	February	115.52	231.04	7.25	1.40		
	March	115.52	346.56	7.25	2.09		
	April	115.52	462.08	7.25	2.79		
	May	115.52	577.6	4.14	1.99		
	June	115.52	693.12	4.14	2.39		
	July	115.52	808.64	4.59	3.09		
	August	115.52	924.16	4.59	3.53		
	September	115.52	1039.68	4.59	3.98		
	October	115.52	1155.2	4.59	4.42		
	November	115.52	1270.72	4.59	4.86		
	December	115.52	1386.24	4.59	5.30	36.55	5.40
2007	January	208.74	1594.98	4.59	6.10		
	February	208.74	1803.72	4.59	6.90		
	March	208.74	2012.46	4.59	7.70		

	April	208.74	2221.20	4.59	8.50		
	May	208.74	2429.94	4.59	9.29		
	June	208.74	2638.69	4.59	10.09		
	July	208.74	2847.43	4.59	10.89		
	August	208.74	3056.17	4.59	11.69		
	September	208.74	3264.91	4.59	12.49		
	October	208.74	3473.65	4.59	13.29		
	November	208.74	3682.39	4.59	14.09		
	December	208.74	3891.13	4.59	14.88	125.91	4.59
2008	January	275.26	4166.39	5.14	17.85		
	February	275.26	4441.65	5.14	19.03		
	March	275.26	4716.92	5.14	20.20		
	April	275.26	4992.18	5.14	21.38		
	May	275.26	5267.44	4.08	17.91		
	June	275.26	5542.70	4.08	18.85		
	July	275.26	5817.96	3.35	16.24		
	August	275.26	6093.22	3.35	17.01		
	September	275.26	6368.49	3.35	17.78		
	October	275.26	6643.75	3.35	18.55		
	November	275.26	6919.01	3.35	19.32		
	December	275.26	7194.27	3.35	20.08	224.19	4.07
2009	January	544.81	7739.08	2.45	15.80		
	February	544.81	8283.90	2.45	16.91		
	March	544.81	8828.71	2.45	18.03		
	April	544.81	9373.52	1.00	7.81		
	May	544.81	9918.33	1.00	8.27		
	June	544.81	10463.15	1.00	8.72		
	July	544.81	11007.96	0.55	5.05		
	August	544.81	11552.77	0.55	5.30		
	September	544.81	12097.58	0.55	5.54		
	October	544.81	12642.40	0.55	5.79		
	November	544.81	13187.21	0.55	6.04		
	December	544.81	13732.02	0.55	6.29	109.55	1.14
2010	January	407.63	14139.65	0.55	6.48		
	February	407.63	14547.28	0.55	6.67		
	March	407.63	14954.91	0.55	6.85		
	April	407.63	15362.54	0.55	7.04		
	May	407.63	15770.17	0.55	7.23		
	June	407.63	16177.81	0.55	7.41		
	July	407.63	16585.44	0.89	12.30		
	August	407.63	16993.07	0.89	12.60		

	September	407.63	17400.70	0.89	12.91		
	October	407.63	17808.33	1.20	17.81		
	November	407.63	18215.96	1.20	18.22		
	December	407.63	18623.59	1.20	18.62	134.14	0.80
2011	January	375.63	18999.22	1.47	23.27		
	February	375.63	19374.85	1.47	23.73		
	March	375.63	19750.48	1.47	24.19		
	April	375.63	20126.11	1.47	24.65		
	May	375.63	20501.74	1.47	25.11		
	June	375.63	20877.37	1.47	25.57		
	July	375.63	21253.00	1.47	26.03		
	August	375.63	21628.63	1.47	26.50		
	September	375.63	22004.26	1.47	26.96		
	October	375.63	22379.89	1.47	27.42		
	November	375.63	22755.52	1.47	27.88		
	December	375.63	23131.15	1.47	28.34	309.66	1.47
	Total Interest				940.00		

Rate Rider Calculation to include carrying charges of $940.00

Customer Classes	2012 # of Customers	2012 kWh	2012 kW	LRAM 2006 - 2010	Interest 2006 - 2010	Volumetric Rate Rider	Billing Determinants
Residential Customers	1133	14,448,113		22,221.91	903.05	**0.00160**	kWh
Gen Service <50 kW	161	5,209,322		189.02	7.68	**0.00004**	kWh
Gen Service >50 kW	14	7,592,321	19,360	720.22	29.27	**0.03871**	kW
Unmetered Scattered Load	6	7,209					kWh
Sentinel Lighting	23	25,718	65				kW
Street Lighting	341	292,061	773				kW
Total		**27,574,744**	**20,198**	**23,131.15**	**940.00**		

22. Deferral and Variance Accounts

General

a. Has CPUC made any adjustments to deferral and variance account balances that were previously approved by the Board, subsequent to the balance sheet date that was cleared in the most recent rates proceeding? If yes, please provide explanations for the nature and amounts of the adjustments and include supporting documentation.

Response

CPUC has not made any adjustments to deferral and variance account balances.

Account 1588 RSVA Power and Account 1588 RSVA Sub-account Global Adjustment

b. Does CPUC pro-rate IESO Charge Type 146 Global Adjustment into the RPP portion and non-RPP portion? If not, why not. If so, please provide the supporting spreadsheet for the year 2010 which prorates the IESO Charge Type 146 Global Adjustment into RPP portion and non-RPP portion.

Response

Yes, CPUC pro-rate IESO Charge Type 146 Global Adjustment into the RPP portion and non-RPP portion.

Account 1588 RSVA Power and Account 1588 RSVA Sub-account Global Adjustment
2010

	IESO Invoice Global Adjustment Settlement Amount Charge Type 0146	GA Billed RPP Cust.	GA Charged Non-RPP Cust	GA Billed Non-RPP Cust
Jan	$106,338.47	-$73,591.31	$32,747.16	-$30,436.32
Feb	$96,029.52	-$76,186.19	$19,843.33	-$30,952.23
Mar	$83,637.54	-$68,880.48	$14,757.06	-$26,441.84
Apr	$106,869.54	-$75,045.59	$31,823.95	-$30,313.09
May	$74,457.96	-$64,814.69	$9,643.27	-$25,236.23
Jun	$40,359.68	-$43,301.11	-$2,941.43	-$23,489.68
Jul	$38,858.30	-$27,976.15	$10,882.15	-$16,026.68

Aug	$11,679.98	-$18,501.56	-$6,821.58	-$11,747.63
Sep	$19,114.70	-$12,408.25	$6,706.45	-$8,624.56
Oct	$49,063.40	-$21,309.33	$27,754.07	-$5,075.30
Nov	$88,379.33	-$41,881.36	$46,497.97	-$12,451.45
Dec	$90,411.37	-$64,874.40	$25,536.97	-$24,912.08
	$805,199.79	-$588,770.42	$216,429.37	-$245,707.09

Account 1592 Sub-account HST/OVAT ITCs

During the 2010 IRM application process, the Board directed electricity distributors to record the incremental ITCs received on distribution revenue requirement items that were previously subject to PST and became subject to HST in deferral account 1592 PILs and Tax Variances, Sub-account HST/OVAT Input Tax Credits ("ITCs"), beginning July 1, 2010,.

As part of its Frequently Asked Questions on the Accounting Procedures Handbook for electricity distributors, the Board provided accounting guidance on this matter and provided a simplified approach designed to facilitate administrative cost-saving opportunities in December 2010.

c. Please state the balance for Account 1592 Sub-account HST/OVAT ITCs as of December 31, 2010.

Response

The balance for account 1592 Sub-account HST/OVAT as of December 31, 2010 was $14,340.00.

d. Please provide the analysis supporting the balance, along with a detailed description. If the analysis is significantly different from the December 2010 FAQ, FAQ 4 regarding Account 1592 Sub-account HST/OVAT ITCs please state why CPUC chose the method it used.

Response

The analysis is not significantly different from the December 2010 FAQ, FAQ 4 regarding account 1592 Sub-account HST/OVAT ITCs. The analysis is attached as Appendix G.

Please confirm that CPUC has made entries to record variances in the sub-account account of Account 1592 to cover the period from July 1, 2010 to April 30, 2012. If this is not the case, please explain

Response

CPUC confirms that entries have been made to record variances in the sub-account of Account 1592 to cover the period from July 1, 2010 to April 30, 2012.

e. Please confirm that CPUC is requesting only the balance in Account 1592 Sub-account HST/OVAT ITCs for disposition, and not Account 1592 HST/OVAT Contra Account, which is used only for RRR reporting purposes. If this is not the case, please explain.

Response

CPUC confirms that only the balance in Account 1592 Sub-account HST/OVAT ITCs for disposition is requested.

In CPUC's 2010 IRM EB-2009-0219 Decision the Board stated that 50% of the confirmed balances in Account 1592 PILs and Tax Variances, Sub-account HST/OVAT Input Tax Credits is to be returned the ratepayers.

f. Please recalculate the rate riders to include 50% of the amount recorded in Account 1592 Sub-account HST/OVAT ITCs, as per the direction of the Board in EB-2009-0219.

Response

CPUC has recalculated the rate rider to include 50% of the amount recorded in Account 1592 Sub-account HST/OVAT ITCs. Appendix E.

EB-2007-0755 Audit Review

Reference: Board Letter, August 6, 2009 Re: Action Required Per Audit Review Resulting from EB-2007-0755

The results of an OEB Regulatory Audit review from proceeding EB-2007-0755 determined that the amount filed for disposition of a credit amount of $261,348 was incorrectly recorded in CPUC's books of accounts, and the amount disposed should be adjusted to a credit of $215,662, a difference of $45,686. In response to Interrogatory 8 b) in EB-20010-0073, CPUC confirmed that it would request to dispose of the balance in Account 1595 in its next rate proceeding.

g. It appears that CPUC has not included this amount, Please recalculate the rate riders to include, as part of its proposed dispositions. Please state why has CPUC not requested disposition of this amount?

Response

Following the Board letter of August 6, 2009, CPUC has included the difference of $45,686 in the EDDVAR Continuity Schedule account 1595. This appears in 2009, column AV "Adjustments during 2009 - Other" for the principal amount of $38,615 and in column BA "Adjustments during 2009 - Other" for the interest amount of $7,071. It is now evident that the full amount of $45,686 should be in column AV "Adjustments during 2009 - Other".

CPUC has not requested disposition of the variance because the variance at December 31, 2011 had not been audited at the time of the rate submission.

The variance of $18,317 for principal and ($4,652) for interest (net balance of $13,665) in account 1595 has now been audited and CPUC has recalculated the balance to include interest to April 30, 2012.

CPUC has recalculated the rate riders to include disposition of $13,742. Appendix E

h. Please recalculate the rate riders to include a debit amount of $45,686 with interest to April 30, 2012.

Response

CPUC believes that to only include the debit amount of $45,686 for 2012 disposition will cause a further refund in 2013 of the credit balance of $31,944 plus carrying charges to April 30, 2013.

CPUC requests that disposition be of the net balance of $13,742 beginning May 1, 2012, to be calculated on the basis of the 2008 kWh customer class allocations.

Account 1508 Other Regulatory Assets

Reference: Exhibit 9 page 217

CPUC has not requested disposition of Account 1508 Other Regulatory Assets, which has a debit balance of $15,104 as of December 31, 2010.

i. Please state the reasons for not disposing of Account 1508.

Response

This was an oversight and will dispose of account 1508. Appendix E.

j. Please update the rate rider calculations to include the balance in account 1508, Sub-account IFRS Transition Costs as of December 31, 2010, and interest forecasted to April 30, 2012.

Response

The rate rider calculations have been updated to include interest to April 30, 2012 for a total of $15,398.

Disposition Period

Reference: Addendum to 2012 Cost of Service Rate Application filed on March 16, 2012; Exhibit 9, page 217 – Disposition of Deferral and Variance Accounts

Exhibit 9 page 217

In the reference, CPUC has stated:

> The total amount for disposition is 30.8% of CPUC's net revenue requirement of $823,030. This will place CPUC at risk, therefore CPUC requests that disposition of Account 1562, i.e. refund to customers, be spread over a period of 3 years at ($45,535) per year.

On Exhibit 9 page 217 of the pre-filed evidence, CPUC has requested the rate rider term of one year. However, in the updated evidence in the above-referenced Addendum, CPUC has proposed two rate riders. The first rate rider is proposed for all accounts, except account 1562 with a proposed term of one year, and the second rate rider is proposed for account 1562 with the proposed disposition of 3 years. These two rate riders are in addition to the proposed rate rider for global adjustment.

The practice to date for the Board has been to dispose the balances over a consistent time period. While the Board's default position is one year, it is open to a different period.

k. Please recalculate the rate riders for the Deferral and Variance Accounts using a 2 year period for disposition.

<u>Response</u>

CPUC will recalculate rate riders for the Deferral and Variance Accounts using a 2 year period. Appendix G.

23. Updates

The foregoing interrogatories along with changes in certain rate setting parameters by the Board necessitate updates to various models and documents. For clarity, Board staff requests, at a minimum, updates for the following:

- RRWF; - ***Appendix F***
- Cost Allocation Model; - ***Appendix D***
- PILs Model; and ; - ***Appendix C***
- RTSR Model; - ***No changes Required***
- LRAM Model; - ***Appendix G***
- Smart Meter Model; and ; - ***Appendix B***
- Rate Schedules ; - ***Appendix H***

In updating the RRWF, do not input updates into the first column “Initial Application”. Please use the green cells for entering impacts in the second column or the updated values in the third column.