CAMBRIDGE AND NORTH DUMFRIES HYDRO INC.

1500 Bishop Street, P.O. Box 1060, Cambridge, ON N1R 5X6

November 30, 2009

Ms. Kirsten Walli
Board Secretary
Ontario Energy Board
P.O. Box 2319
2300 Yonge Street
27th Floor
Toronto, ON M4P 1E4

Dear Ms. Walli:

Re: Cambridge and North Dumfries Hydro Inc.
Response to OEB Board Staff Interrogatories
2010 Electricity Distribution Rates, Board File EB-2009–0260.

In accordance with Procedural Order No. 1 received from the Ontario Energy Board on October 23, 2009, please find attached Cambridge and North Dumfries Hydro Inc.'s responses to Board Staff Interrogatories in the above proceedings.

Sincerely,

CAMBRIDGE AND NORTH DUMFRIES HYDRO INC.

John W. Grotheer
President and CEO

c.c. All Intervenors

Board staff Interrogatories
2010 Electricity Distribution Rates
Cambridge and North Dumfries Hydro Inc. ("C&ND Hydro")
EB-2009-0260

Rate Base

1. Ref: Exhibit 2/page 6/ll. 1-9 and Exhibit 4/page 75/ll. 1-7 – Capitalization Policy

In these Exhibits, C&ND Hydro states that it does not have a formal capitalization policy, but generally follows GAAP, particularly CICA Handbook Section 3060 – Capital Assets. It further states that it "does not currently capitalize interest on funds used during construction unless such funds relate to specific borrowings for capital purposes, and does not capitalize, through internal cost allocations, any indirect administrative support costs such as Finance, Human Resources, or Corporate Services."

a) Please explain why C&ND Hydro, given its relative size, does not have a formal capitalization policy. Has C&ND Hydro considered adopting or adapting the capitalization policies of other distributors, particularly distributors of similar size and operating environments? Has C&ND Hydro considered partnerships with other, similar distribution utilities for the development of a capitalization policy? Please provide sufficient detail in your response.
b) Please identify any instances where C&ND Hydro has capitalized interest on funds used during construction due borrowing to fund (a) specific capital project(s).

Response

a) The issue of having a formal capitalization policy has not been directly considered by our utility prior to the completion of the rate application filing. We have considered it to be appropriate to rely upon the CICA Handbook and the ongoing updating that is completed by the CICA. We have not, in the past, considered partnership with other organizations to develop a capitalization policy based on our reliance on the CICA handbook requirements.

Currently we are jointly working with a number of utilities on the implementation and transition to IFRS. This joint consultation will directly and indirectly lead to our utility having a formal capitalization policy within the next few years.

b) We have not capitalized interest on funds used during construction due to the fact that no borrowing has been required for any project in the past.

2. Ref: Exhibit 2/page 78 and Exhibit 3/page 32 – Disposals of Land and Buildings

In its application C&ND Hydro notes that, as a result of completion of the voltage conversion project, it will be decommissioning and disposing of three substations.

a) Please confirm that the amounts shown for disposals in 2010 of $67,043 for land and $8,723 for buildings are related to substation decommissioning.

b) C&ND Hydro has estimated $5,000 as the net gain on disposition of utility property for the 2010 year, after reducing by 50%. It states that vehicles generally sell in excess of book value but substation equipment and property sells at a loss due to environmental evaluation and clean-up, and property location and size. In addition to disposals of land and buildings of about $75,000, C&ND Hydro shows disposals of $74,890 for 2010 under Account 1925 – Transportation Equipment. Please provide further information on how C&ND Hydro has estimated the revenues from disposals of $10,000 in 2010 (or $5,000 after reducing by 50%) given that land and buildings, and transportation, disposals are expected to be about $75,000 each.

Response

a) It is confirmed that the amounts shown for disposal in 2010 of $67,013 for land and $8,723 for buildings is related to substation decommission/disposal.

b) The estimated net revenue from disposals of $10,000 in 2010 comes from two sources.

Vehicles that are sold generally have a zero net book value because of the age of the vehicle. In 2010, we plan to replace 3 small vehicles. Generally, because of the age and condition, we sell the vehicles in the range of $500 - $2500. In 2010, this would yield in the range of $1500 - $7500 for the three vehicles.

In the case of the substation, we anticipate the sale of the final two locations in 2010. The buildings/fixtures at one location has no book value and the other has a book value of $1,110. When a location is sold, we complete a Phase 1 and 2 Environmental Assessment and a Record of Site Condition document (if required) as a risk management tool. The cost associated with this process is $30,000 - $40,000 per location. As part of the sale we incur real estate and legal fees. Because of the location, conditions of the building and size of property, the selling price is generally in the $45,000 - $50,000 range. The overall net income is therefore a few thousand dollars.

Given the unknown, we consider the $10,000 to be a reasonable estimate of net income for 2010.

Capital Expenditures

3. Ref: Exhibit 2/page 91/Table 28 – Capital Expenditures

In the referenced table, C&ND Hydro provides the forecasted capital expenditures for 2010, 2011 and 2012. Elsewhere in **Exhibit 2**, in the tables for the fixed asset continuity schedules, the capital additions in each historical year and the bridge and test years are provided.

Please provide an expanded version of Table 28 providing capital expenditures in each year from 2004 to 2008 actuals, 2009 bridge, 2010 test, and the forecasts for 2011 and 2012.

Response

An expanded version of Table 28 providing actual and forecasted capital expenditures from 2006 to 2012 is presented below. Cambridge and North Dumfries Hydro Inc. records do not have information readily available to provide actual for 2004 and 2005 in the format presented below. It would have analyzed all projects for each year in order to derive the required information which would require extensive effort. Given the time constraint, Cambridge and North Dumfries Hydro Inc. is unable to provide 2004 and 2005 actual.

Summary of Capital Additions 2006 - 2012								
	2006 Actual	2007 Actual	2008 Actual	2009 Bridge	2010 Test	2011 Forecast	2012 Forecast	Total
Land & Building	133,410	57,104	109,233	90,000	150,000	475,000	100,000	1,114,747
Transformer Station Equipment	178,743	297,194	5,239	-	-		400,000	881,176
New Line	518,230	921,218	262,889	1,315,000	-	500,000	875,000	4,392,337
Rebuilds	3,828,894	4,425,665	2,935,012	4,795,000	4,750,000	4,750,000	4,750,000	30,234,571
Reliability/Power Factor/Power Quality	140,122	733,121	745,614	162,000	837,000	400,000	400,000	3,417,857
Relocation	392,004	267,954	852,883	610,000	540,000	650,000	500,000	3,812,841
New Service	2,922,263	1,890,611	1,727,758	2,305,000	2,840,000	2,500,000	2,500,000	16,685,632
Revenue Metering & Instrumnet Transformers	230,241	523,512	568,954	179,000	100,000	100,000	100,000	1,801,707
Computer Hardware	179,437	173,198	144,409	189,500	117,000	150,000	150,000	1,103,544
Computer Software		545,683	645,781	1,267,500	1,035,000	900,000	800,000	5,193,964
Fleet	31,091	209,634	436,967	719,000	125,000	465,000	125,000	2,111,692
Office Equipment & Tools	99,895	91,695	89,402	180,000	178,000	280,000	200,000	1,118,992
Gross Capital Additions	**8,654,330**	**10,136,589**	**8,524,141**	**11,812,000**	**10,672,000**	**11,170,000**	**10,900,000**	**71,869,060**

4. Ref: Exhibit 2/page 89 – Computer Software

Please confirm that the ERP Software Replacement, projected at $650,000 and to comply with IFRS, is expected to be in service in 2010.

Response

The ERP Software Replacement will be in service in late 2010 and now has a projected cost of $1,000,000.

5. Ref: Exhibit 2/page 75 and Exhibit 2/page 89 – CIS replacement and upgrade

On **Exhibit 2/page 75**, C&ND Hydro documents the costs in 2009 to replace its CIS system at $1.002 million for software and $70,000 for hardware, and indicates that it is to be cut over on November 2, 2009.

On **Exhibit 2/page 89**, C&ND Hydro projects CIS upgrade costs of $200,000 to deal with issues and possible new regulatory requirements.

a) Please confirm whether the new CIS system has come into service by November 2, 2009 and an overview of any issues associated with the transition to the new system. If the new system has not come into service, please provide updated information on the status of this project and when it is expected to go in service.

b) The projected 2010 budget for upgrading the new system is nearly 20% of the original cost.

i) Please indicate what "issues that are identified later", as documented on **Exhibit 2/page 89**, other than to accommodate regulatory features not currently known, C&ND Hydro is anticipating.

ii) Please indicate what software support is contracted for under the original $1.002 million cost. If software support during the initial period is not factored in the original cost, please explain.

iii) Please provide the basis for C&ND Hydro's estimate for the $200,000 CIS upgrade budget for 2010.

Response

a) The new CIS system did not come into service by November 2, 2009. The conversion to the new software system is based on the development of a template that was being developed by another LDC. That template was delayed in planned implementation and after 5 months still has some operational issues. In addition, our system integrator has recently been served with a Notice of Default by Cambridge and North Dumfries Hydro Inc. The response period for the cure is in December. The new CIS system is now planned for 2010. It should be noted that the new estimated cost is now in excess of $1.8 Million based on unforeseen costs associated with the hiring of a third party Project Manager, additional trainers and staff training costs.

b)

i) CIS upgrades for 2010 could include:

- Integration of IVR software
- Upgrading SAP software version 5.2 to 7.0 for updated features
- Instead of modifying system for LEAP, other changes relating to new Code requirements for customer assistance
- Reworking processes based on operational issues that are identified.

ii) There is no software support contracted under the original cost as this amount was for system integration of the template. After going live, the system integrator provides a five week support period.

iii) We have a sharing agreement with the other two utilities that outlines a projected cost sharing amount of $125,000 in 2010. In addition we included amounts for the IVR integration and projects for changes that apply only to our utility.

6. Ref: Exhibit 2/page 15 – Rebuilds

C&ND Hydro notes that it is completing in 2009 a rebuild of older parts of its distribution system in the City of Cambridge. This is a project that commenced in the 1990s and involves a voltage conversion from 4 kV to 27.6 kV. The utility states that it will begin in 2009 a rebuild of lines in the Township of North Dumfries that are 50-60 years old, and that this project will reduce the risks of PCBs.

a) Please provide further information on C&ND Hydro's prioritization to complete the City of Cambridge rebuild and voltage conversion in contrast to rebuilding assets in North Dumfries.
b) Please provide information on the condition of assets to be rebuilt in North Dumfries, including any consideration of reliability (i.e. Worst Performing Circuits) that justify this project.
c) Has C&ND Hydro commenced the North Dumfries rebuild?
d) C&ND Hydro has indicated that the North Dumfries rebuild will reduce the risk of PCBs.
    i) Please explain whether PCB removal was part of the City of Cambridge rebuild just being completed.
    ii) Please provide an estimate of the percentage of capital costs for these rebuilds that is attributable to PCB removals.
    iii) Please indicate C&ND Hydro's treatment of PCB removal-related costs and whether these costs are proposed for rate recovery in this application. If so, please explain how these are being reflected in rates.
    iv) Beyond PCB removal in these rebuild projects, does C&ND Hydro have specific projects to test PCBs and remove PCBs in accordance with federal regulatory requirements? Please provide a detailed explanation.

Response

a) The rebuild in the City of Cambridge was prioritized based on reliability, statistics conversion based on the systems of the pre 1970 merger predecessor utilities (Galt, Preston, Hespeler) and the feeder associated with each distribution substation. The rebuild progressed each year based on a pre-determined plan that ensured that an effective manner of rebuild would occur and that any changes in reliability would be addressed. It should be noted, that in 2004, the rebuild in the City of Cambridge was deferred to complete pole testing throughout the whole system to ensure we had information to replace poles at risk and also

ensure the decision to delay the Township of North Dumfries rebuild was technically sound.

The rebuild in the Township of North Dumfries will be different than the City based on the fact that it is predominantly rural and there are no substations. The priorities will be established based on a number of variables, including data on pole conditions in the 2004 study, reliability of sections of line, recent incidents of broken conductors and any impact of a renewable generation project.

b) The assets in the Township of North Dumfries are 60 – 70 years old. The assets are generally beyond the useful criteria for assets of this type. We did the testing in 2004 to ensure that poles could be deferred to this time frame. During the last number of years, we have had conductor failure at many locations which impacted a small number of customers. Our engineering group consider it technically prudent to place a high priority on replacement at this time. Based on funds available, we will complete the rebuild of these over-extended assets in the next 4 – 6 years.

c) We have commenced the Township of North Dumfries rebuild with the Clyde Road project (Exhibit 2, Page 73).

d)

i) Transformers manufactured prior to 1981 have the potential to contain PCB materials. The ongoing process of the City of Cambridge rebuild contained many transformers manufactured prior to 1981 because of the age of assets. PCB removal therefore was a by-product of the process.

ii) The rebuilds in the past few years have typically included a majority of the transformers being manufactured prior to 1981. The number of transformers that are deemed to have PCB contents being removed from service in rebuilds is in the 2 – 5% range. The capital cost for transformers in rebuilds varies from 15% to 25% of the overall cost of the project. The removal of the PCBs is a by-product of the rebuild activity and therefore does not impact the overall capital cost.

iii) PCB removal costs are included in the overall capital projects included in the application. We also have PCB testing, storage and disposal costs that are included in the ongoing operations costs.

iv) In accordance with the federal regulatory requirements, we have created a list of transformers that are in sensitive areas. These 50 transformers will be tested and any removals required will be completed. We also have a few hundred transformers that are in unknown status that will be left in service but over the years will be replaced in normal course or based on federal regulation deadlines.

Service Quality and Reliability

7. Ref: Exhibit 2/pg. 9-11 – Service Reliability

On this page, C&ND Hydro documents its service reliability measures for SAIDI (System Average Interruption Duration Index), SAIFI (System Average Interruption Frequency Index) and CAIDI (Customer Average Interruption Duration Index) for 2008, for all service interruptions.

a) Please provide reliability performance for the period 2006 to 2008 actuals for SAIDI, SAIFI and CAIDI, with and without Loss of Supply interruptions, by filling out the following table in addition to what is provided in **Exhibit 2/pp. 10-11**.

	All Service Interruptions			**Service Interruptions excluding Loss of Supply (Cause Code 2)**		
	SAIDI	**SAIFI**	**CAIDI**	**SAIDI**	**SAIFI**	**CAIDI**
2002						
2003						
2004						
2005						
2006	0.93	1.36	0.69	0.93	1.36	0.69
2007	1.51	1.74	0.86	1.51	1.74	0.86
2008	0.70	1.08	0.65	0.68	1.04	0.65

b) The 2006 Electricity Distribution Rate Handbook specifies the standard for reliability performance as being "within the range of the last three year's performance". For any year and reliability indicator where performance did not meet the standard, please describe the reasons for below-standard performance and what actions C&ND Hydro took or is taking to remedy the situation. Please identify, as appropriate, operating or capital projects linked to reliability improvement.

c) On **Exhibit 2/page 9/ll. 9-10**, C&ND Hydro indicates that it annually provides a report on its reliability in detail and on benchmarking its performance relative to other similar distributors. Please provide a copy of the most recent report. Please discuss how C&ND Hydro incorporates the results of this report, and those of its Customer Satisfaction Survey (**Exhibit 1/Appendix B**) in its Asset Management and capital and operating projects.

Response

a) The Service Reliability information requested is provided is in the table below.

	All Service Interruptions			Service Interruptions excluding Loss of Supply (Cause Code 2)		
	SAIDI	**SAIFI**	**CAIDI**	**SAIDI**	**SAIFI**	**CAIDI**
2002	0.82	1.47	0.56	0.82	1.47	0.56
2003	18.44	4.36	4.23	18.44	4.36	4.23
2004	0.75	1.04	0.73	0.75	1.04	0.73
2005	1.12	1.08	1.03	0.75	1.04	0.73
2006	0.93	1.36	0.69	0.93	1.36	0.69
2007	1.51	1.74	0.86	1.51	1.74	0.86
2008	0.70	1.08	0.65	0.68	1.04	0.65

b) For the years that the reliability indicators are provided in the table above, Cambridge and North Dumfries Hydro Inc. have met or exceeded the performance standard with the exception of 2003. Cambridge and North Dumfries Hydro Inc. did not meet the performance indicator for 2003 because of the province wide black out in August of 2003.

c) Attached as Exhibit A is the 2007 Reliability Report prepared in August 2008. This is the most recent report available that can be provided.

Both our reliability statistics and Customer Satisfaction Survey are used as general indicators for trends for our utility and the industry. Based on these high level results, we then drill down in specific areas to ensure that we have addressed outage reasons. Examples of this would be addressing the adequacy of tree trimming programs or the customers' impressions on outages to map the perception to actual data. We also drill down to actual feeder results to evaluate the need for maintenance and/or capital improvements.

8. Ref: Exhibit 2/page 9 – Service Quality

a) Please provide the following information on C&ND Hydro's service quality performance as requested in the following table:

Service Quality Indicators

	Standard	2002	2003	2004	2005	2006	2007	2008
1a Low Voltage Connections Met	90%							
1b High Voltage Connections Met	90%							
2 Underground Cable Locates	90%							
3 Appointments Met	90%							
4 Telephone Accessibility	65%							
5 Written Response to Inquiries	80%							
6a Emergency Response - Urban	80%							
6b Emergency Response - Rural	80%							

b) For any year and reliability indicator where performance did not meet the standard, please describe the reasons for below-standard performance and what actions C&ND Hydro took or is taking to remedy the situation. Please identify, as appropriate, operating or capital projects linked to service quality improvement.

Response

a) The Service Quality Indicators requested are provided in the table below.

Service Quality Indicators

	Standard	2002	2003	2004	2005	2006	2007	2008
1a Low Voltage Connections Met	90%	90	100	98	93	96	96	95
1b High voltage Connections Met	90%	--	--	--	--		--	--
2 Underground Cable Locates	90%	99	100	98	97	99	99	100
3 Appointments Met	90%	100	99	100	99	100	100	100
4 Telephone Accessibility	65%	61	59	74	73	75	73	84
5 Written Response to Inquiries	80%	100	98	97	99	98	100	100
6a Emergency Response – Urban	80%	100	100	100	97	98	91	97
6b Emergency Response – Rural	80%	100	100	100	91	89	97	94

b) For the years that the Service Quality Indicators are provided, Cambridge and North Dumfries Hydro Inc. have met and in most cases exceeded the standard with the exception of Telephone Accessibility which was slightly below the standard for 2002 and 2003. Telephone results were negatively impacted by high call volumes associated with market opening and the arrival of retailers. Starting in 2004 Cambridge and North Dumfries Hydro Inc. continually exceeded the standard.

Customer and Load Forecast

9. Ref: Exhibit 3/pp. 13-16 – System Load Regression Model

C&ND Hydro indicates that it has estimated the system load regression model based on monthly data from 1996 to 2008 inclusive. It states that class-specific modelling was unsuccessful, and that a system consumption model was adopted. The model is summarized on **Exhibit 3/page 15**, and model statistics are provided in the table at **Exhibit 3/page 14/ll. 8-9**. The statistical results indicate that the Spring/Fall Flag and population parameters are statistically insignificant at the 90% confidence level. In addition, the population coefficient has a negative coefficient, which is unintuitive. In response to this, C&ND Hydro documents, at **Exhibit 3/pg. 15/ll. 10-13** that:

> "The Population variable has a negative coefficient as shown [in] the table above. This is affected by the successful Conservation and Demand Management programs undertaken by Cambridge and North Dumfries Hydro Inc. over the pass few years. Customers are embracing the Conservation culture and as result per Capita energy usage is less."

a) Please provide further explanation and support for C&ND Hydro's view that it is the impacts of CDM which account for the negative population coefficient.
b) Given that the population and Spring/Fall Flag variables have insignificant coefficients, please provide C&ND Hydro's explanation for why it has preferred the documented model.
c) Please provide results of stepwise regression to include/exclude the population and Spring/Fall Flag variables.
d) Please provide C&ND Hydro's views about whether the poorer fit when more recent data is used, could be indicative that the model is not properly specified.
e) Please describe what alternative modelling efforts, such as alternative econometric model forms or additional variables, were examined by C&ND Hydro to improve the system load regression model.

Response

a) Actual power purchases for C&ND Hydro have been declining since 2005. It is C&ND Hydro's view that this decline, prior to September 2008, resulted from the impacts of successful CDM programs. All explanatory variables used in the regression analysis generally remain the same or increase in value over the historical actual period from January 1996 to December 2008. The regression analysis needed to account for the decline in purchases resulting from CDM programs. However, it did not have an explanatory variable that was declining in value to assign the decline in purchases. As a

result, the regression analysis choice to assign the decline in power purchases to the population explanatory variable that was increasing in value by giving it a negative coefficient. As stated in the evidence, this suggests to C&ND Hydro that customers are embracing the conversation culture and as result per capita energy use is less. In addition, as shown in the response to b) including the population explanatory variable with a negative coefficient produced a prediction model with a higher R square value and lower variance between predicted and actual amounts

b) Cambridge and North Dumfries Hydro Inc. had an objective to achieve a 95% R square value with the chosen model. Although this objective was not met, including the population and Spring/Fall Flag variables increased the R square from 94.16% to 94.31%. Cambridge and North Dumfries Hydro Inc. understands this is not an significant movement but including these two variables provided a slightly more accurate model that had, in most years, less yearly variance between actual and predicted values as shown in the following table.

	Application - Load Forecast		Application - Load Forecast w/o Population and Spring/Fall Flag	
Year	Variance Predicted to Actual (kWh)	% of Actual	Variance Predicted to Actual (kWh)	% of Actual
1996	12,138,703	1.1%	19,404,989	1.7%
1997	4,117,700	0.3%	10,915,650	0.9%
1998	(9,532,533)	(0.7%)	(8,828,804)	(0.7%)
1999	(4,926,415)	(0.4%)	(10,671,872)	(0.8%)
2000	14,222,959	1.0%	5,498,913	0.4%
2001	24,557,448	1.7%	16,728,302	1.2%
2002	(8,245,729)	(0.5%)	(15,005,671)	(1.0%)
2003	(5,163,897)	(0.3%)	(8,380,746)	(0.6%)
2004	(42,977,899)	(2.7%)	(40,917,494)	(2.6%)
2005	(36,476,677)	(2.2%)	(35,036,110)	(2.1%)
2006	(4,965,647)	(0.3%)	(1,916,582)	(0.1%)
2007	26,390,388	1.6%	29,771,437	1.9%
2008	30,861,600	2.0%	38,437,989	2.5%

c) Results of the stepwise regression that exclude the population and Spring/Fall Flag variables are presented below.

Regression Statistics	Values
Multiple R	97.04%
R Square	94.16%
Adjusted R Square	93.97%
F - Test	484.0
Coefficients by Variable	
Intercept	(70,050,911.23)
Heating Degree Days	18,927.14
Cooling Degree Days	63,416.16
Ontario Real GDP Monthly %	465,352.24
Number of Days in Month	2,437,660.82
Number of Peak Hours	220,941.45
T - Stats by Coefficient	
Intercept	(6.14)
Heating Degree Days	13.03
Cooling Degree Days	3.68
Ontario Real GDP Monthly %	11.89
Number of Days in Month	6.69
Number of Peak Hours	11.79
Purchased Forecast	
2009 (W N) MWh	1,543,585
2010 (W N) MWh	1,541,693

d) It is Cambridge and North Dumfries Hydro Inc.'s view that the poorer fit shown in the evidence, when more recent data is used, is indicative of the issues associated with attempting to conduct the regression analysis on a rate class basis compared to a total system basis. In Cambridge and North Dumfries Hydro Inc.'s views this does not indicate that the model based on the total system is not properly specified.

e) Based on concerns raised by Intervenors and Board staff in the 2009 cost of service rate applications about the methodology that supports the proposed load forecasting, Cambridge and North Dumfries Hydro Inc. attempted to improve the methodology by concentrating its efforts on conducting the regression analysis on a rate class basis. However, as shown in the evidence in Exhibit 3, page 13 and 14 Cambridge and North Dumfries Hydro Inc. was not successful in this endeavor. As a result, Cambridge and North Dumfries Hydro Inc. decided to use the same load forecasting methodology used in a number of the 2009 cost of service rate applications and attempt to achieve a R square as close as possible to 95%. The proposed model provided in the evidence reflects the model with the highest R square or best fit that was achieved at the time the application was prepared.

10. Ref: Exhibit 3/pp. 17-18 – Weather-normalized load forecast

In **Exhibit 3/page 18/Table 7**, C&ND Hydro documents 2010 weather-normalized load forecasts of 1,522,594 kWh (13 year average), 1,523,221 kWh (10 year average) and 1,526,541 kWh (20-year trend). On **Exhibit 3/page 17/ll. 9-11**, the utility states:

> "Cambridge and North Dumfries Hydro Inc. decided to use the load forecast based on the 13 years average of the heating and cooling degree days for rate setting purposes in this application."

Please provide further explanation as to why C&ND Hydro believes that the 13-year average, which is the lowest of the three estimates, is preferred.

Response

Given the economic uncertainty, Cambridge and North Dumfries Hydro Inc. decided to take a conservative approach and used the lower of the three estimates. The forecasts indicated the recovery will be slow and long and it seemed prudent and appropriate to use the 13 year average. In addition, the 13-year weather normal average was used to be consistent with the numbers of years of actual monthly purchases data used in the regression analysis.

11. Ref: Exhibit 3/pp. 21-22/Tables 12, 13 and 14 – Average Usage per Customer - Streetlights

Exhibit 3/page 21/Table 12 indicates that the average annual usage per streetlight connection was around 800 kWh for 2003 to 2005 inclusive, and then dropped to about 765 kWh for 2006 to 2008. C&ND Hydro has used the average annual growth rate of -1.17% to forecast the average annual consumption per streetlight connection of 754 kWh for 2009 and 745 kWh for 2010, as shown in **Exhibit 3/page 22/Table 14**.

Please provide further explanation of:

a) What change in operations or technology accounted for the stepwise reduction in average consumption from 2005 to 2006; and
b) What operations or technology changes are ongoing to imply that 2009 and 2010 consumption will see further decreases relative to the consistent consumption from 2006 to 2008.

Response

a) As part of Cambridge and North Dumfries Hydro Inc. Conservation and Demand Management initiative during the period 2004 to 2006, Cambridge

and North Dumfries Hydro Inc. upgraded some mercury vapour street light fixtures with high pressure sodium fixtures. The high pressure sodium fixtures are more energy efficient than the mercury vapour, thus reducing the average annual energy consumption per street light.

b) Any existing street light fixtures that are being replaced or repaired are replaced with the energy efficient high pressure sodium fixtures. The energy efficient street light fixtures are being used in all new development in Cambridge and North Dumfries Hydro Inc. service territory.

As a result, the annual average consumption per street light will continually reduce until all street light fixtures in Cambridge and North Dumfries Hydro Inc. service territory are replaced with the energy efficient high pressure sodium fixtures.

The City of Cambridge has the largest percentage of street lights and is currently studying the possible replacement of older technology with energy efficient LED technology.

12. Ref: Exhibit 3/pp. 21-22/Tables 12, 13 and 14 – Average Usage per Customer – Unmetered Scattered Load

Exhibit 3/page 21/Table 12 indicates that the average annual usage per Unmetered Scattered Load ("USL") connection was around 5,809 kWh for 2066, 4,827 for 2007 and 4,612 for 2008. C&ND Hydro has used the average annual growth rate of -10.90% to forecast the average annual consumption per USL connection of 4,109 kWh for 2009 and 3.662 kWh for 2010.

a) Given that Unmetered Scattered Load is not metered and that the consumption is estimated, please provide further explanation for the documented reductions in average annual consumption from 2006 to 2008. Please indicate if special studies of a sample of USL connections are used to derive the annual estimates.
b) Please provide further explanation and support that the average annual consumption per USL connection is expected to reduce at 10.90% per annum.

Response

a) The average annual usage per USL is impacted by a variety of issues including the following:
    - Cambridge and North Dumfries Hydro Inc. provided funding to the Region of Waterloo to upgrade all existing traffic light locations with LED technology

- Telecommunication companies are installing wireless technology devised that consumer less than 700 kWh per annum which decreases the average
- Based on energy conservation, many companies are upgrading their lighting at their locations to more energy technology.
- Technical calculation of hours of operation and electrical load are used to estimate the amount to be billed. In the case of some locations such as cable company power supplies, we attach temporary metering to verify that estimates are relevant to actual.

b) The data provided in part (a) supports the trend and the estimated reduction.

Operating Revenues

13. Ref: Exhibit 3/pp. 30-31 – Specific Service Charges

In its explanation of the variances of Specific Service Charge revenues, C&ND Hydro states: "The increase in Collection Notices/Documents fees relates to the increase of rate to $15,000 from $8.80 effective May 1, 2006 and more emphasis on collection of document fees."

Please confirm whether the Collection Notices/Documents fees rate effective May 1, 2006 was $15.00 and not $15,000, as shown.

Response

We can confirm that the document had a typing error and that the correct amount should be $15.00.

14. Ref: Exhibit 3 – Specific Service Charges and Conditions of Service

C&ND Hydro has its Conditions of Services posted on its website at http://www.camhydro.com/pdf/conditions_service2006.pdf .

a) Please confirm that this is C&ND Hydro's current version of its Conditions of Service. If not, please provide a version of the current version.
b) Please confirm that there are no changes to C&ND Hydro's Conditions of Service that would be necessary as a result of C&ND Hydro's proposals in this application. In the alternative, please identify and explain what changes to the Conditions of Service are foreseen.

c) Please confirm that there are no rates and charges documented in C&ND Hydro's Conditions of Service that are not documented on C&ND Hydro's Board-approved Tariff of Rates and Charges. Charges on a time and material basis do not have to be explicitly identified. If there are charges that should be included on the Tariff of Rates and Charges, please identify and explain these. If necessary, please provide an updated proposed Tariff of Rates and Charges as documented in **Exhibit 8/pp. 27-29**.

Response

a) It is confirmed that the current version of our Conditions of Service are on our website.

b) At the time that monthly billing and the OEB better customer service measures are implemented, the Conditions of Service will be updated to reflect those impacts.

c) It is confirmed that there are no rates and charges documented in our Conditions of Service that are not documented on Cambridge and North Dumfries Hydro Inc.'s Board approved Tariff of Rates and Charges.

15. Ref: Exhibit 3/page 34 – Miscellaneous Non-Operating Income

With respect to the Table provided at **Exhibit 3/page 34/line 1** of account 4390 – Miscellaneous Non-operating Income:

a) Please confirm the total shown for the 2009 Bridge year, against the components of $50,000 for Scrap Sales, $12,000 for Discounts Earned, and $33,000 for Miscellaneous.
b) Please provide some examples of typical activities or incomes that would fall under "Miscellaneous".
c) C&ND Hydro has estimated Scrap Sales at $50,000, below 2006 to 2008 actuals. C&ND Hydro states that "[s]crap sales are directly impacted by the volatility in commodity prices. By the nature of this volatility, it was difficult to accurately forecast balances for 2009 and 2010 but commodity prices are currently below historical highs.
    i) Please identify the nature of commodities that compose scrap sales.
    ii) Please provide C&ND Hydro's income from scrap sales for 2009 Year-to-Date.

iii) Please provide further explanation of why C&ND Hydro is projecting that scrap sales for each of 2009 and 2010 should be about 50% of the average annual scrap sales income from 2006 to 2008.

Response

a) The totals shown for 2009 Bridge year, are confirmed as $50,000 for scrap sales, $12,000 for Discounts Earned and $33,000 for Miscellaneous.

b) Examples of typical activities or incomes that fall under "Miscellaneous" are as follows:
- Reversal of stale dated cheques
- Rebate for return of skids by our transformer supplier
- Rebate from suppliers for purchases exceeding yearly threshold
- Management fees earned by Cambridge and North Dumfries Hydro Inc. for services provided to its affiliates.

c) i) The commodities that are sold are: copper, aluminum, and steel.
ii) Scrap sales year to date as at August 31, 2009 are $39,954 as compared to $82,197 as at August 31, 2008.
iii) The scrap sales are a function of price and quantity. The vast majority of the scrap comes from areas of rebuild. In 2009, the rebuild area includes totally urban areas with a mix of overhead and underground. The overhead area has some areas of three phase conductoring. Generally, the amount of scrap has been lower and the valuation of scrap is much less than prior years.

In 2010 projections we face a high level of uncertainty with respect to prices. The rebuild areas for 2010 are predominantly rural areas that typically are single phase conductoring which will yield less quantities of scrap. Given our understanding of the variables and the level of uncertainty on prices the $50,000 amount for 2010 seems reasonable.

Operating Expenses

16. Ref: Exhibit 4/pp. 6-7 – OM&A

C&ND Hydro states that: "Commencing in 2007 and throughout 2008 when copper was an expensive commodity, theft of copper grounds became an issue at Cambridge and North Dumfries Inc. The cost of replacing the stolen material amounted to $118,394 which is reflected in additional maintenance costs."

a) Please confirm whether the $118,394 for the replacement of stolen copper is for one year or two.
b) Please confirm whether any of these losses were covered by insurance, and if so, the amount of the insurance claim received.
c) Is theft of copper, or other distribution assets and material, an issue continuing in 2009 and does C&ND Hydro see this continuing in 2010 and beyond? Please provide a detailed explanation.
d) What steps has C&ND Hydro undertaken to address this issue, to reduce theft of its property and to protect its assets and employee and public safety?

Response

a) The $118,394 for the replacement of stolen copper is for 2007 and 2008 years.

b) The costs associated with the replacement of stolen copper is not covered by insurance and there is therefore no recovery from claims.

c) The theft of copper is a continuing problem in 2009. As an example, on Friday, November 6, 2009, Waterloo Regional Policy arrested two individuals who were removing and stealing copper grounding (40 locations) in the City of Cambridge.

Now that the theft of copper has become an ongoing issue for the last few years, we consider it to be part of the norm going forward, especially in these tough economic times with high unemployment.

We will put in place programs to reduce the risks but the nature of our assets being spread out over a large geographic area makes it difficult to anticipate the events. A prime example occurred in 2008 when our fuel tanks were burglarized and large quantities of fuel were lost. Prior to the event, we had no awareness that the problem was happening elsewhere. We immediately notified neighbouring utilities to make them aware of the risk.

d) Cambridge and North Dumfries Hydro Inc. has put in place a number of programs to mitigate the risk associated with theft and the issues associated with employees and public safety.

We have contacted Waterloo Regional Police to make them aware of the issues relating to the theft of copper grounding and provide them with ongoing data with respect to locations that are uncovered as part of our patrols.

We have installed video surveillance cameras at our main office including storage areas to potentially deter entry and to provide information if a theft occurs.

We have installed motion sensing surveillance cameras with 24/7 monitoring at our Transformer Station. This equipment has lead to one police charge of trespassing for an individual who was in the process of stealing copper.

We have recently had a technical study completed that will provide for the purchase of new grounding materials on the feeders. The new grounding material has no scrap value and over time, as we install these new grounds, the theft of copper grounds will be diminished. This process will continue over many years.

17. Ref: Exhibit 4/page 31/ll. 14-20 and Exhibit 2/page 52 – Sub-Contracting

C&ND Hydro states that sub-contracting costs have increased by $78,000 during the period, starting in 2006 to handle overflow locates in the summer months. C&ND Hydro documents that it updated its GIS system in 2007. Please provide further explanation of the increased sub-contracting costs to handle cable locates beginning in 2007. Further explain how the GIS system upgrade has factored into the actual and proposed costs for such sub-contracted work in 2008 and in the 2009 Bridge and 2010 Test Years.

Response

The change in operating procedures was made to improve efficiencies. Prior to 2006, when our one locator got busy based on volume (normally during the busy construction months) we would reallocate existing staff from operations maintenance or construction crews. The crews would then be short staffed and not have the necessary resources (i.e. Truck Driver) and productivity was reduced. We therefore decided to out-source to an overflow locator as a more efficient and economical alternative. This change continues and is part of our on-going costs.

The GIS Software Replacement was driven mostly by the needs of the Engineering Department staff to assist the designer, field workers, service co-ordinator and control room. It provided them with updated technology so they could do their jobs more efficiently. The GIS system upgrade has a slight impact on the data available to the locator and a very minimal impact on the subcontracted work for locating.

18. Ref: Exhibit 4/pp. 32-33 and Exhibit 6 – Monthly Billing

C&ND Hydro is proposing a revenue requirement of $24,958,934, including a revenue deficiency of $2,461,873 grossed up for PILs.

On **Exhibit 6/page 5**, C&ND Hydro states the following as being key drivers for the increases:

> "In Exhibit 4, a discussion of the various key drivers is included. The major key cost drivers are as follows:
> - Increase staffing cost relating to annual wage increases and new staff ($395,000)
> - Increase in benefit cost ($166,000)
> - Costs associated with a new customer billing system ($111,000)
> - Switching to monthly billing ($255,000)
> - Increased bad debts ($90,000)
> - Inflation and non labour items and all other charges ($164,000)"

This indicates that $376,000 of the increase is due to the new billing system and going to monthly billing, while increased bad debt accounts for a further $90,000 of the increase.

a) Please provide C&ND Hydro's views as to whether a move to monthly billing should not result in a decrease in bad debt, as it would more quickly allow the utility to identify and deal with delinquent customers.

b) Please provide C&ND Hydro's views as to the benefits for customers, including operational productivity gains by the utility, that result from the new billing system and the move to monthly billing. Please identify whether these are reflected in the proposed revenue requirement, and if so, where.

Response

a) With the move to monthly we anticipate a possible decrease in bad debts. We do not anticipate that the number of write offs will decrease but that average amount written off, especially in skip situations (i.e. customer leaves before utility is aware they are gone), should be lower.

b) The identifiable savings arising out of the move to monthly billing are small compared to the increased costs. As noted in the Energy Probe Interrogatory #27 (a) an estimated amount of $19,184 is reflected as savings that has been netted against increases. The decision to move to monthly billing is driven by many factors, including the following customer benefits and operational productivity gains:
   - Customers currently receive monthly billing for most other services (natural gas, telephone, cable).
   - Monthly billing provides a better opportunity for customers to manage their cash flow.

- The OEB and Ministry continue to promote the need for monthly payments.
- Monthly billing provides customers with more timely information of how much power they have used and the potential impact on their conservation efforts.
- The switch to monthly at this time is a lead into the switch to Time of Use. Time of Use impacts and associated education will be much more relevant with monthly billing.
- High bill complaint calls should be easier to handle based on shorter time span.
- Customers have been asking for monthly billing.
- It provides consistency for small business customers. Currently some are monthly and others are bi-monthly.
- The new CIS template is designed for monthly only. Extra costs of modifications were high.

19. Ref: Exhibit 4/page 27/Table 11 and Exhibit 4/page 33 – Inflation on Non-labour Items and All Other Charges

C&ND Hydro estimates that "Inflation on Non-Labour Items and All Other Charges" represents about $457,000 of the estimated $2,535,000 increase in OM&A from 2006 Board approved. Table 11 shows a decrease of $246,000 in 2006 Board approved, which indicates that the increase from 2006 actuals to 2010 test year is $703,000, occurring mostly in 2007, 2009 and 2010.

a) Please provide a clearer definition of what C&ND Hydro means by the term "Inflation on Non-labour Items and All Other Charges".

b) On Exhibit 4/page 33, C&ND Hydro estimates that about $262,000 of the $457,000 is attributable to inflation. Please provide further explanation of and support for C&ND Hydro's statement. Also, identify the inflation factor used to derive this estimate that the inflationary effect is $262,000.

c) On Exhibit 4/page 33/ll. 15-16, C&ND Hydro indicates that the 2010 amount (a cost driver increase of $164,000), includes $40,000 for rebasing regulatory costs (1/4 of $160,000), IFRS one-time costs of $25,000 (1/4 of $100,000), and incremental LEAP costs of $21,000. This would total $86,000. Please provide an explanation for the other $78,000 in 2010 increased OM&A costs due to this driver.

Response

a) The term grouped two different things in one.
The "inflation on Non-Labour Items" included cost drivers for increased prices during the period. This would include: maintenance materials, office supplies, vehicle fuel, equipment and vehicle repairs, safety clothing, building

maintenance, retirees benefit costs, memberships, training costs, professional fees, advertising, etc.

The "All Other Charges" include the increase attributed to new costs that occurred and continue to be part of the ongoing cost structure. These costs were not considered material key drivers but do contribute to the over cost drivers. Examples of these include increased training costs associated with more apprentices, new costs associated with ESA auditing requirements, new standards for personal protective clothing, i.e. Arc Flash, regulatory changes such as stray voltage, regulation changes such as hours of work, etc.

b) As noted in part (a), many items experienced price increases (inflation) during the period. By reviewing our expenses, we concluded that the overall net impact was in the range of 1.8 – 2.4% per year.

c) The cost drivers included both new and ongoing incremental costs and cost increases (inflation). The other $78,000 would predominately be cost increases.

20. Ref: Exhibit 4/pp. 24-25 – LEAP

a) In the above reference, C&ND Hydro states that the amount of $30,000 is included in the 2010 Test Year for Low Income Energy Assistance Program. Please identify whether the amounts relate to existing or new program(s).
b) Please provide further explanation of why C&ND Hydro anticipates that 0.33 FTE is required for LEAP administration.
c) Please provide the estimated costs in the 2010 bridge year associated specifically with LEAP administration for each of the 0.33 FTE and annual CIS software upgrade.

Response

a) The $30,000 assumed that the LEAP program would be put in place and we would discontinue our annual support ($9,000) for the Waterloo Region Heat Bank. Based on the recent developments, we have committed the 2010 funding to the Waterloo Region Heat Bank and are unsure if the Ministry will put in place an additional requirement for assistance funding.

b) The original LEAP program and now the better customer service measures add a new level of incremental administration that will require increased staffing. These include:
- potential requirement to determine when payment is received
- cheque preference for billing errors
- semi annual or quarterly review of equal payment plans

- increased complexity for handling disconnections
- third party involvement in disconnections
- extra handling/follow up re: extended period for disconnects and deposits
- the new arrears management program, etc.

c) The additional 0.33 FTE has an estimated cost of $23,500 and the CIS upgrades are $35,000 - $50,000.

Employee Compensation

21. Ref: Exhibit 4/pp. 57-58 and Exhibit 4/page 60/Table 20 – Performance Plan

C&ND Hydro states that it has an incentive performance plan as part of compensation for management and executive. On **Exhibit 4/page 57/ll. 20-25**, it states:

> "Cambridge and North Dumfries Hydro Inc. considers all of its Performance Plans to accrue benefits to the Ratepayers. The corporate strategic work plan is designed to exceed customers and other stakeholders' expectations through operational excellence. Any performance pay related to efficiencies and the improvement in EBITA will ultimately benefit Cambridge and North Dumfries Hydro Inc.'s customers in the form of savings at the next cost of service application."

Further, in **Table 23**, C&ND Hydro shows the following statistics for the average annual incentive pay for Executive and Management categories:

	Last Rebasing Year 2006	Historical Year 2007	Historical Year 2008	Bridge Year 2009	Test Year 2010
Compensation - Average Yearly Incentive Pay					
Executive	$ 10,684	$ 15,921	$ 16,388	$ 19,143	$ 19,714
Management	$ 3,757	$ 4,453	$ 4,776	$ 5,462	$ 5,769

a) Does C&ND Hydro consider that improvement in EBITA also benefits the shareholder? Please explain your response.

b) The above information provides the average annual incentive pay. Please indicate the range of incentive payments possible under the plan for each year and for each of the Executive and Management categories.

c) Please provide support for savings in this cost of service/rebasing application that will benefit customers that justify the average annual incentive compensation to Executives and Management in recent years, as documented in Table 23 and replicated above.

d) Please provide further explanation of the increases in the average annual incentive compensation. In particular, the expected incentive payments

for both Executive and Management are higher for the 2009 Bridge and 2010 Test years compared to historical actuals.

e) Please provide further explanation on the components of the performance incentive plan, with respect to operational, financial and service quality and reliability/customer satisfaction goals. Please indicate how the targets are established.

Response

a) Improvements in EBITA has the potential to increase net income which could increase the dividend payable to the shareholder and thereby create a benefit for the shareholders. In the context of the performance plans, only the executive plans have variables relating to improvements in EBITA. The potential for payment is limited by a threshold to create a stretch factor and normally not earned each year. The threshold factor translates into the vast majority of the improvements in EBITA accruing to the Ratepayers.

b)

Average Annual Incentive Pay Range

	Management	Executive
2006	$ 0 - $ 7,449	$ 0 - $ 19,176
2007	$ 0 - $ 7,689	$ 0 - $ 19,779
2008	$ 0 - $ 8,024	$ 0 - $ 21,489
2009	$ 0 - $ 8,258	$ 0 - $ 22,312
2010	$ 0 - $ 8,505	$ 0 - $ 22,981

c) The key ingredient of our incentive compensation is that there is a stretch factor required to earn the payment. Projects and tasks are accomplished that improve our level of service, enrich the employee or improve our processes that justify the expenditure. Some of the projects could be delayed or never accomplished. Some expenditures may not be managed as prudently.

Across the province there are varied philosophies with respect to compensation. Many utilities do not have incentive plans. Our utility has chosen to look at overall compensation as base salary plus potential incentive payments. When we review industry salary surveys, we look at how our overall compensation compares to base salaries at other utilities.

d) The incentive payments are a percentage of base salary and the average payments and range of payments possible are directly impacted. Incentive payments are impacted by the individuals in the group. Recently, some employees in the group that historically did not work to earn an incentive payment have left the company and the new replacement employees are stretching to earn the incentive payments.

e) The School Energy Coalition (SEC) Interrogatory #9 requested copies of the plans (See Exhibits B, C, D of SEC response).

Property Taxes

22. Ref: Exhibit 4/page 89

C&ND Hydro provides a table showing its Property Taxes paid in **Table 45**.

a) On **lines 5-6**, C&ND Hydro states "The distribution station reflects a disposal over the period. In addition to the property taxes, incremental amounts payable in PILs have also been paid." Please explain what is meant by "incremental amounts payable in PILs".
b) Do the "incremental amounts payable in PILs" only pertain to the distribution station? If not, please explain.
c) Please provide an estimate of these "incremental amounts payable in PILs" for each of the years shown in **Table 45**.
d) On **lines 8-9**, C&ND Hydro states: "The amounts shown above are not reported separately in our USoA filing based on the fact that a portion is included in internal burden calculations. The net of any amounts not capitalized would be included in OM&A expenses shown in Exhibit 6, Table 1, Page 4." Account 6105 – Taxes Other Than Income Taxes is part of the Uniform System of Accounts documented in Article 220 of the Board's Accounting Procedures Handbook, and states:

> A. This account shall include the amounts of ad valorem, gross revenue or gross receipts taxes, "payments-in-lieu of taxes", capital taxes, payments equivalent to municipal and school taxes, property taxes, property transfer taxes, franchise taxes, commodity taxes, and all other related taxes assessed by federal, provincial, municipal, or other local governmental authorities, except income taxes.

Please explain why C&ND Hydro does not record Property Taxes in Account 6105, but includes the amount in OM&A expenses, either as a part of burdens or as net amounts included in other OM&A expenses.

Response

a) The term "incremental amounts payable in Pils" was used to refer to the payments made by Cambridge and North Dumfries Hydro Inc. to the Ontario Ministry of Revenue for Payment in Lieu of Property Taxes.

b) No. Payment in Lieu of Taxes to the Ontario Ministry of Revenue is mandated by Ontario Regulation 224/00. LDCs are required to make Payment in Lieu of Taxes for all properties owned that are listed in the regulation.

c) The actual Payment in Lieu of Taxes to the Ontario Ministry of Revenue from 2004 to 2008 plus the estimated amount for 2009 and 2010 are outlined in the table below.

Payment in Lieu of Property Taxes

Description	2004 Actual	2006 Actual	2007 Actual	2008 Actual	2009 Bridge	2010 Test
Ontario Electricity Financial Corp	4,753	3,601	3,757	3,478	12,177[(1)]	3,500[(2)]

[(1)] Based on reduced assessment, the payments to the Municipality dropped but the Payment in Lieu of Taxes to the Ontario Ministry of Revenue go up on equivalent assessments.

[(2)] The 2010 amount reflects fewer locations.

d) The recording of Property Taxes in accounts other than Account 6105 is an oversight. The property taxes as reported currently are correct with respect to the revenue requirement.

When the 2009 OEB filings are completed, we will report the amount properly in Account 6105.

Details of property taxes for 2009 are included in Energy Probe Interrogatory #42 (a).

Regulatory Costs

23. Ref: Exhibit 4/page 36 – 2010 Rebasing Application

C&ND Hydro has estimated costs for this rate rebasing application as follows:

- Legal: $60,000
- Consulting: $40,000
- Intervenor costs: $60,000

This totals $160,000, which C&ND Hydro has proposed to recover over four years at $40,000 per year.

Please provide further support for the above cost estimates associated with the 2010 rebasing application. In particular, what is the $60,000 for Legal Costs based on? C&ND Hydro filed the Application itself and has not indicated that it is yet been represented by Legal Counsel.

Response

The cost estimates were established consistent with other amounts included in other rebasing applications for utilities of comparable size.

The intervenor costs are a conservative estimate that could increase with oral hearings. The legal costs are based on a level of uncertainty of how the process will occur. We have established a working relationship with Legal Counsel. In the written phase, we have filed the Application ourselves, but probably will seek their guidance on responding to interrogatories. The base case for legal is estimated to be $10,000. The $60,000 amount has a provision for the possible costs associated with Dispute Resolution/Witness Preparation/Oral Hearings costs. The estimated cost for dispute resolution, Witness Preparation/Oral Hearing Cost is $110,000. Given the uncertainty, we averaged $10,000 and $110,000.

Depreciation

24. Ref: Exhibit 4/page 74/ll. 8-11

In this Exhibit, C&ND Hydro states:

> "Prior to 2008 a full year's amortization was taken on capital additions during the current year. Effective 2009 Cambridge and North Dumfries Hydro Inc. used the half year rule for calculating depreciation expense for additions for the 2009 Bridge Year and 2010 Test Year."

The general rate treatment by the Board for electricity distributors has been to apply a "half year" rule for capital additions in the year they come into service. Since they are not in the opening balances but are in the closing balances, averaging the opening and closing balances means that they only contribute 50% of their value to the rate base in the first year. Similarly, amortization or depreciation expense is calculated on a half-year rule for the year that assets enter service.

a) Please explain why C&ND Hydro had been applying a full year of depreciation expense for the year that assets entered service. How long has C&ND Hydro used this approach?
b) Please explain why C&ND Hydro has changed its policy.

Response

a) The full year depreciation expense for the year that the asset enters service is consistent with Ontario Hydro accounting guidelines and have been in use for many years.

There is no prescriptive guidance in either the CICA Handbook or the OEB APH stating that only one half year's depreciation should be taken in the year of acquisition.

The APH states that "Consistent with the CICA Handbook, this APH Handbook does not provide prescriptive guidance in terms of the amortization methods to be used, the asset categories, the estimated useful lives or amortization rates. Instead it is expected that in the absence of an objective study to support the changes to the current methods, lives or rates, utilities will continue to use methods, lives or rates consistent with past practice."

b) Cambridge and North Dumfries Hydro Inc. has changed its amortization policy in 2009 to calculate amortization expenses based on the half year rule for the years that assets enter service to be consistent with the board rate treatment for electricity distributors.

PILs

25. Ref: Exhibit 4/page 85/Table 42 – Ontario Capital Tax

In the calculation of the Ontario Capital Tax ("OCT") for the 2009 bridge and 2010 test years, no exemption is made. Please explain why C&ND Hydro has not applied the $15 million base exemption for the calculation of the OCT in those years. If appropriate, please provide a corrected calculation of the OCT for the 2009 bridge and 2010 test years.

Response

In calculating the Ontario Capital Tax for 2009 Bridge and 2010 Test years, the exemption amount of $15 million was not included as it was an oversight by Cambridge and North Dumfries Hydro Inc. The corrected OCT calculation for 2009 Bridge and 2010 Test years is outlined below.

Corrected Ontario Capital Tax

Capital Tax Expense Calculation	2009 Bridge Year	2010 Test Year
Total Rate Base	102,937,405	106,120,669
Exemption	15,000,000	15,000,000
Deemed Taxable Capital	**87,937,405**	**91,120,669**
Ontario Capital Tax Rate	0.225%	0.075%
Ontario Capital Tax	**197,859**	**68,341**
Ontario Capital Tax without Exemption	231,609	79,591
Ontario Capital Tax with Exemption	197,859	68,341
Difference	**33,750**	**11,250**

26. Ref: Exhibit 4/page 85/Table 42 and Exhibit 4/page 170 – Apprenticeship Training Tax Credit

C&ND Hydro's 2008 filed tax return shows an Apprenticeship Training Tax Credit ("ATC") claim of $15,560 for that year. C&ND Hydro's detailed tax calculations shown in Table 42 do not appear to show forecasts for the ATTC for the 2009 bridge and 2010 test years.

a) Please confirm whether the forecasted corporate income taxes for 2009 and 2010 include or exclude an amount for ATTC.
b) If there is an allowance for the ATTC in those years, please document explicitly the amounts in the tax calculations.
c) If C&ND Hydro is forecasting no ATTC in the 2009 and 2010 years, please provide an explanation.

Response

a) The forecasted corporate income taxes for 2009 Bridge and 2010 Test years include an amount of $15,560 each year for Apprenticeship Training Tax Credit (ATTC). The amounts are included in the line "Other Additions - $23, 607" for both years.

b) Cambridge and North Dumfries Hydro Inc. used the 2008 ATTC amount of $15,560 for both 2009 and 2010 because it is not expected that the actual ATTC amount to be materially different from the 2008 amount. The revised amount Cambridge & North Dumfries Hydro Inc. is proposing in presented in response to Energy Probe question 40 part a and VECC question 29.

c) N/A

Cost of Capital

27. Ref: Exhibit 5/pg. 1 – Capital Structure

In this Exhibit, C&ND Hydro states that it "… continues to have an actual debt/equity structure that departs from the OEB deemed structure for rate making purposes, but is not proposing any departure from the deemed structure for the purposes of rate making in the application."

a) For each of 2006 actual, 2007 actual and 2008 actual, please provide C&ND Hydro's actual capital structure.
b) Please describe C&ND Hydro's philosophy underlying its actual capital structure.
c) Does C&ND Hydro have any plans to more closely align its actual capital structure with the deemed capital structure?
   i) If yes, please explain.
   ii) If not, please explain C&ND Hydro's reasons for maintaining its existing capital structure, including how the utility, its shareholders, debt holders and ratepayers benefit from its approach.

Response

a) Actual Capital Structure

		2006	2007	2008
Debt	- short	-	-	-
	- long	40.9%	40.1%	39.5%
Equity		59.1%	59.9%	60.5%

b) The actual capital structure was established at the time of incorporation based on the OEB guidelines for utilities of our size (i.e. 50% Debt/50% Equity).

At the time that the majority shareholder monetized the debt, the cash requirements of the organization were analysed and no additional debt was required.

The current capital structure has evolved from the original starting point by applying a dividend guideline that is comparable to companies in our industry,

and prudently financing capital expenditures based on funds generated from operations.

c) Although a formal plan is not in place to align the capital structure, the alignment will occur over the next few years. In recent years, the credit balances in the variance accounts have provided a source of funds and indirectly cash flow.

The repayment of these balances will potentially lead to short-term borrowing to finance operations. In addition, the potential capital requirement for the GEACE activities and the need for a new transformer station in the next 3 – 5 years will be funded by increased long-term borrowing.

28. Ref: Exhibit 5/pp. 1 and 6, Exhibit 1/pg. 70 – Long-term Debt

One of the debt instruments owned by C&ND Hydro is a Promissory Note due to the Corporation of the Township of North Dumfries, the minority shareholder in C&ND Hydro's corporate parent. A copy of the Promissory Note is documented in **Exhibit 5/pg. 6**. Note 12 of the C&ND Hydro's 2008 Audited Financial Statements (**Exhibit 1/page 70**) also documents C&ND Hydro's outstanding debt at that time.

a) Note 12 of the 2008 Audited Financial Statements states that the principal is "due on six months demand notice". However, the copy of the Promissory Note states that "[t]he Township may demand repayment of all or part of the outstanding Principal with interest at the Established Rate [documented as 4.993%] upon two (2) months' written notice of demand". Please explain the difference in the terms as shown in the Promissory Note and as documented in Note 12 of the Audited Financial Statements.

b) If there has been an update to the Promissory Note documented in **Exhibit 5**, please provide a copy of the updated note.

c) The terms of the Promissory Note state that "[i]nterest at the Established Rate shall accrue from July 1, 2006 until the Principal is paid in full, with interest on overdue interest at the Established Rate". However, the terms do not document a term length or maturity date, or terms for repayment except for payment on demand by the Township. Please explain any terms for repayment of principal on this debt. Has the Township ever called for payment on the principal, or is there any indication that the Township intends to call payment?

d) Please confirm that C&ND Hydro does not forecast any new or renewed debt during the 2009 bridge or 2010 test years. In the alternative, please provide C&ND's forecasts of any such new or renewed debt, including updating **Tables 1 and 2** of **Exhibit 5**.

Response

a) Note 12 from the financial statements is incorrect. When the Promissory Note was updated in 2006, the note in the financial statements was not updated to reflect the changes.

b) The copy of the Promissory Note in Exhibit 5 is the note that is in place at this time.

c) There are no terms for repayment of principal and no term length or maturity date. The Township has never called for payment on the principal and there is no indication that the Township intends to call for payment.

d) Cambridge and North Dumfries Hydro Inc. can confirm that it does not forecast any new or renewed debt during the 2009 Bridge or 2010 Test Year.

Cost Allocation

29. Ref: Exhibit 7/page 7/Table 5 – General Service > 5,000 kW (Large Use)

In **Table 5**, the Revenue-to-Cost ("R/C") ratio shown for the General Service > 5,000 kW customer class ranges from 67.20% for the initial Cost Allocation Study, 45.40% when adjusted for the Transformer Allowance, and 56.14% for the updated 2010 Cost Allocation Study.

a) Please provide further detailed discussion of why the R/C ratios for this class are, initially, so low. What assumptions or allocators has C&ND Hydro made that factor into these low R/C ratios?
b) For this class, are the results of the cost allocation study impacted by loss and reclassification of customers from this class? Please explain your response.

Response

a) In order to assist with the issue of understanding R/C ratios, C&ND has attempted to answer this question with a simple approach. Currently the revenue associated with the Large Use class is around 2.2% of Cambridge and North Dumfries Hydro Inc.'s revenue. In the Cambridge and North

Dumfries Hydro Inc. cost allocation model, in simple terms, the costs are categorized as 45% customer related and 55% demand related. In addition, in the Cambridge and North Dumfries Hydro Inc. cost allocation model it is assumed that about 30% of costs are associated with the secondary system and line transformers which are assets not used by the Large Use class.

In the Cambridge and North Dumfries Hydro Inc. cost allocation model, the demand for the Large User class represents about 10.4% of total demand for all rate classes. As a result, the Large User class should be allocated 10.4% of the demand related cost or 5.7% of the total costs (i.e. 10.4% times 55% of total cost which are demand). However, the Large User class does not use the secondary system, and line transformers of Cambridge and North Dumfries Hydro Inc. which means the 5.7% should be reduced by 30% or 1.7%. Consequently, the resulting allocated demand costs to Large User class are around 4.0% (i.e. 5.7% -1.7%) of the total costs.

With regards to customer related cost, the Large User class has 2 customers compare to a total of 57,670 customer/connections assumed in the Cambridge and North Dumfries Hydro Inc. cost allocation model. As a result, very minimal customer related costs are allocated to the Large User class (i.e. less 0.1% of total costs)

In summary, the Large User class is allocated about 4.0% of the total costs of Cambridge and North Dumfries Hydro Inc. resulting from the level of demand for the Large User class but the revenue collected is only 2.2%. Therefore the resulting revenue cost ratio should be around 55% (i.e. 2.2%/4.0%)

b) The results of the cost allocation study reflect the 2010 costs, numbers of customers and loads. As a result, reclassification of customers from this class are reflected in the results.

30. Ref: Exhibit 7/page 7/Table 5 – Streetlighting

In **Table 5**, the Revenue-to-Cost ("R/C") ratio shown for the Streetlighting customer class ranges from 9.82% for the initial Cost Allocation Study, 10.41% when adjusted for the Transformer Allowance, and 13.72% for the updated 2010 Cost Allocation Study.

Please provide further detailed discussion of why the R/C ratios for this class are, initially, so low. What assumptions or allocators has C&ND Hydro made that factor into these low R/C ratios.

Response

It is Cambridge and North Dumfries Hydro Inc.'s understanding that the R/C ratio, shown for the Streetlighting customer class of 13.72% for the updated 2010 Cost Allocation Study, is consistent to R/C ratios for the Streetlighting customer class for many other distributors across the province.

With regards to Streetlighting, it is assumed in the cost allocation study that a street light connection is equivalent to a customer. This appears to be reasonable since in the case of other rate classifications each connection is essentially a customer. This means the customer costs allocated to Streetlighting are based on 6,613 connections, which is the biggest driver that is causing the R/C ratio of 13.72%.

The question is: should streetlights, in particular, be allocated costs based on the number of connections or incremental load? There are arguments for both sides. On one hand, it could be argued that it should be connections because it would be consistent with the other rate classifications. On the other hand, it could be justified that a streetlight is like any other appliance or outside light on a home. It just happens to be outside on the street. In this case, a streetlight would be incremental load much like a stove or refrigerator and it would attract very little customer costs if any at all. The only customer costs it might attract would be the cost of sending a bill to the customer who owns the streetlights.

It is interesting to note that when the Streetlighting class is handled as an incremental load in the cost allocation model the R/C for the Streetlighting class is above 100% and within the Board's acceptable range. It is Cambridge and North Dumfries Hydro Inc.'s view there could be a good reason for this result and that being when Streetlighting rates were developed in the 1980's an incremental load approach was used. Since this application is the first time that Cambridge and North Dumfries Hydro Inc. has proposed changes to the revenue by rate class to address the R/C ratio results from the cost allocation model it might be advisable for the Board to consider an incremental load approach for the Streetlighting class before revenues are adjusted.

Rate Design

31. Ref: Exhibit 8/pg. 1 – Revenue Requirement and Revenue Offsets

In the Rate Design Overview, C&ND Hydro states that its proposed 2010 service revenue requirement is $24,958,934, with revenue offsets of $1,488,010, to produce a base revenue requirement of $23,470,733. However, **Table 1 – Calculation of Base Revenue Requirement – 2010 Test Year** shows revenue offsets of $1,613,010, resulting in a base revenue requirement of $23,345,924. Please reconcile Table 1 with the discussion above in the table on **Exhibit 8/pg. 1**.

Response

Cambridge and North Dumfries Hydro Inc. is proposing service revenue of $24,958,934, with revenue offsets of $1,613,010, to produce base revenue requirements of $23,345,924. The revenue offsets of $1,488,010 on line 6 needs to be replaced with $1,613,010. The calculation provided in Table 1 is correct.

32. Ref: Exhibit 8/pg. 14/Table 13 and Exhibit 8/pg. 16/Tables 15 and 16 – Retail Transmission Rates

C&ND Hydro proposes that there be no adjustment to the Retail Transmission Service ("RTS") Network Services rate despite the variance showing an over-collection from May 1, 2007 to April 30, 2009 of $474,881 on IESO and Hydro One Networks billings of $15,797,650. Board staff observes that this variance is about 3% of actual billings. C&ND Hydro proposes that no adjustment be performed as the variance is not consistent (i.e. tending to over- or under-collect).

a) Please provide further explanation or support for C&ND Hydro's proposal to not adjust the RTS Network Services rate for the RSVA variance. Since May 1, 2009, do the monthly variances exhibit any trend or pattern?
b) Based on Tables 15 and 16 of Exhibit 8, please provide 2010 RTS Network Services rates that would result from adjustments including that for the 2-year over-collection of 3.0%.

Response

a) Cambridge and North Dumfries Hydro Inc. did not propose to adjust the RTS Network Service rates effective May 01, 2010 because the trending of the variance in the last twelve months from May 1, 2008 to April 30, 2009 shows the variance reducing. Also, the variance was not showing a consistent trending. Therefore proposing any adjustment would have been arbitrary by Cambridge and North Dumfries Hydro Inc.

   Since May 1, 2009, the monthly variances have been reducing resulting in a total $294, 313 or 1.52% of actual billings.

b) The 2010 RTS Network Service rate that would result from the 3.0 % over collection is presented below.

Changes In Rates			
	July 1, 2009 Rate Changes	Adjustment Re Variances	Total Rate Change
Network Service Rates	3.5%	- 3.0%	0.5%
Line & Transformation Connection Service Rates	- 2.2%	-12.6%	-14.8%

Transmission Network and Connection Rates					
Customer Class	Metric	2009 RTR Network	2009 RTR Connection	2010 RTR Network	2010 RTR Connection
Residential	kWh	$ 0.0043	$ 0.0038	$ .0043	$ .0032
General Service <50 kW	kWh	0.0039	0.0035	0.0039	0.0030
General Service >50kW	kW	2.4991	2.1726	2.5116	1.8511
General Service >1000-4999 kW	kW	1.8981	1.7051	1.9076	1.4527
Large Users	kW	1.7986	1.7357	1.8076	1.4788
Street lighting	kW	1.2558	1.0918	1.2621	0.9302
Unmetered Scattered Load	kWh	0.0039	0.0035	0.0039	0.0030
Embedded Distribution	kW	1.7986	1.7357	1.8076	1.4788

Embedded Distributors

33. Ref: Exhibit 8/pp. 6-8/Tables 8 and 9

a) Please provide the spreadsheets used to derive the proposed embedded distributor rates for Hydro One Networks Inc. and Waterloo North Hydro Inc. (collectively, the "Embedded Distributors") in working Excel format.

b) Please identify what, if any changes, have been made to the methodology from that submitted by C&ND Hydro on behalf of itself and the Embedded Distributors and accepted by the Board in the application dealt with under Board file number EB-2007-0900.

c) Please identify the cost of capital and the tax/PILs rate used to derive the proposed rates.

d) If the cost of capital or tax/PILs rate differ from that used elsewhere in this application to derive the revenue requirement for other customer classes, please explain.

Response

a) The excel version of the spreadsheet used to derive the proposed embedded distribution rates for Hydro One Network Inc. and Waterloo North Hydro Inc. is attached to this submission. The excel spreadsheet is attached to the submission.

b) No changes have been made to the methodology used to calculate the embedded distribution rates from that submitted by Cambridge and North Dumfries Hydro Inc. on behalf of itself and the Embedded Distributors and accepted by the Board in the application (Board file Number EB- 2007-0900).

c) The cost of capital and the tax/PILs rate used to derive the proposed rates are consistent with the cost of capital and the tax/PILs rate used to calculate the proposed 2010 revenue requirement for other customer classes.

d) Not applicable.

34. Ref: Exhibit 7/page 4 – Cost Allocation and Embedded Distributors

Under details of its Cost Allocation Study, C&ND Hydro notes that the calculations of embedded distributor rates for Hydro One Networks Inc. and Waterloo North Hydro Inc. are dealt with outside of the cost allocation model. C&ND Hydro requests that these calculations take precedence over the cost allocation ranges.

a) Please indicate whether embedded distributor revenues are recorded in account 4080. If recorded elsewhere, please indicate which account is used and why.
b) Please provide further explanation of the difficulties that C&ND Hydro encountered in trying to model the embedded distributor classes in the total distribution system cost allocation model; and
c) Does C&ND Hydro believe that it would be possible, by the time of its next rebasing application, to make appropriate corrections or adjustments so that the embedded distributors can be included like other customer classes in a total distribution system cost allocation model? Please explain your response.

Response

a) Embedded Distributor revenues are recorded in account 4080

b) Cambridge and North Dumfries Hydro Inc. did not encountered any difficulties in trying to model the embedded distributor classes in the total distribution system cost allocation model. Nevertheless, under Board file number EB-2007-0900, Cambridge and North Dumfries Hydro Inc. on behalf of itself and the Embedded Distributors submitted a methodology to calculate low voltage charges for Embedded Distributors. This methodology was approved by the Board on August 15, 2008. At the time of preparing the 2010 rate application, Cambridge and North Dumfries Hydro Inc. considered using the results of the cost allocation model to adjust rates for Embedded Distributors. However, considering the approved methodology was just over a year old, Cambridge and North Dumfries Hydro Inc. believe it was more reasonable to use the relatively recently approved methodology to determine low voltage charges for Embedded Distributors in the 2010 rate application than to use the results of the cost allocation model.

c) Yes. Cambridge and North Dumfries Hydro Inc. believes that by the time of the next rebasing application it would be able make the necessary corrections or adjustments so that the embedded distributors can be included like other customers in a total distribution system cost allocation model. Given that fact, the applicant continues to maintain that this customer class should be outside of the cost allocation modeling for the purposes of this rate application.

Deferral and Variance Accounts

35. Ref: Exhibit 9/page 2/ll. 4-6 – Accounts 1518 and 1548

a) Please confirm that the Continuity Schedule for 2008 shown on **Exhibit 9/page 6** shows the net of revenues and costs for 2008 for accounts 1518 and 1548 under the column Transactions (reductions) during 2008, excluding interest and adjustments.

b) The application, at **Exhibit 9/page 2/ll. 4-6**, indicates that the transactions in 1518 and 1548 include only the revenue from retailers during 2005 to 2007, but incremental operating costs were left in operating expense. Please provide an updated Continuity Schedule including the adjustments related to the costs that were left in operating expense during 2005 to 2007.

c) Please update all relevant schedules and Tables elsewhere in the application (e.g. **Exhibit 9/page 9/Table 5**, and Rate Rider Calculations etc.) that would be impacted due to these adjustments.

Response

a) The amounts shown on continuity schedule for 2008 on Exhibit 9/page 6 for account 1518 and 1548 under the column transaction (reductions) during 2008, excluding interest and adjustments are not net of revenues and expenses. The amount shown under this column for each account 1518 ($77,671) and 1548 ($2,368) is the revenue.

The costs for account 1518 and 1548 are shown under the column transaction (additions) during 2008, excluding interest and adjustments. The amount shown under this column, $2,369 and $78, 557 for account 1518 and 1548 respectively is the costs.

b) The updated continuity schedule requested with the adjustments related to the costs that were left in operating expense during 2005 to 2007 is presented below.

Account Description	Account Number	2005 Opening Principal Amounts as of Jan-1-05	2005 Transactions (additions) during 2005, excluding interest and adjustments	2005 Transactions (reductions) during 2005, excluding interest and adjustments	2005 Adjustments during 2005 - instructed by Board	2005 Adjustments during 2005 - other	2005 Closing Principal Balance as of Dec-31-05	2005 Opening Interest Amounts as of Jan-1-05	2005 Interest Jan-1 to Dec31-05	2005 Closing Interest Amounts as of Dec-31-05	2005 Total
Group 1											
LV Variance Account	1550						$ -			$ -	$ -
RSVA - Wholesale Market Service Charge	1580	$ 1,533,928	$ 1,124,039				$ 2,657,967	$ 331,789	$ 140,714	$ 472,503	$ 3,130,470
RSVA - Retail Transmission Network Charge	1584	$ (65,105)	$ (315,686)				$ (380,791)	$ 39,398	$ (20,163)	$ 19,235	$ (361,556)
RSVA - Retail Transmission Connection Charge	1586	$ (1,266,207)	$ (687,169)				$ (1,953,376)	$ (109,646)	$ (121,357)	$ (231,003)	$ (2,184,379)
RSVA - Power (including Global Adjustment)	1588	$ (135,639)	$ (1,900,657)				$ (2,036,296)	$ (363,855)	$ (67,642)	$ (431,497)	$ (2,467,793)
RSVA - Power - Sub-Account - Global Adjustment [4]	1588		$ (2,653,941)				$ (2,653,941)		$ (65,258)	$ (65,258)	$ (2,719,199)
Recovery of Regulatory Asset Balances	1590	$ (603,804)	$ (368,783)	$ -	$ -	$ -	$ (972,587)	$ (19,034)	$ (55,583)	$ (74,617)	$ (1,047,204)
Sub-Totals		**$ (536,827)**	**$ (4,802,197)**	**$ -**	**$ -**	**$ -**	**$ (5,339,024)**	**$ (121,348)**	**$ (189,289)**	**$ (310,637)**	**$ (5,649,661)**
Group 2											
Other Regulatory Assets - Sub-Account - OEB Cost Assessments	1508	$ 39,254	$ 84,868				$ 124,122			$ -	$ 124,122
Other Regulatory Assets - Sub-Account - Pension Contributions	1508		$ 238,234				$ 238,234			$ -	$ 238,234
Other Regulatory Assets - Sub-Account - Other	1508	$ 1,100,314	$ -				$ 1,100,314	$ 93,078	$ 97,904	$ 190,982	$ 1,291,296
Retail Cost Variance Account - Retail	1518	$ (150,324)	$ 79,400	$ (62,140)			$ (133,064)			$ -	$ (133,064)
Misc. Deferred Debits	1525	$ 43,494	$ 13,252				$ 56,746			$ -	$ 56,746
Retail Cost Variance Account - STR	1548	$ (17,476)	$ 1,620	$ (2,417)			$ (18,273)			$ -	$ (18,273)
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Capital	1555						$ -			$ -	$ -
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Recoveries	1555						$ -			$ -	$ -
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Stranded Meter	1555						$ -			$ -	$ -
Smart Meter OM&A Variance	1556						$ -			$ -	$ -
Conservation and Demand Management Expenditures and Recoveries	1565						$ -			$ -	$ -
CDM Contra	1566						$ -			$ -	$ -
Qualifying Transition Costs	1570	$ 1,363,392	n/a	n/a	$ (136,339)		$ 1,227,053	$ 228,219	$ 81,543	$ 309,762	$ 1,536,815
Pre-Market Opening Energy Variances Total	1571	$ (151,542)	n/a	n/a			$ (151,542)			$ -	$ (151,542)
RSVA - One-time Wholesale Market Service	1582	$ 476,758	$ 86,321				$ 563,079	$ 32,648	$ -	$ 32,648	$ 595,727
2006 PILs & Taxes Variance	1592						$ -			$ -	$ -
Sub-Totals		**$ 2,227,112**	**$ 417,374**	**$ (64,557)**	**$ (136,339)**	**$ -**	**$ 2,443,590**	**$ 321,297**	**$ 179,447**	**$ 500,744**	**$ 2,944,334**

Interest Rates used to Calculate Carrying Charges:

Q1	**7.25%**
Q2	**7.25%**
Q3	**7.25%**
Q4	**7.25%**

Account Description	Account Number	2006 Opening Principal Amounts as of Jan-1-06	2006 Transactions (additions) during 2006, excluding interest and adjustments	2006 Transactions (reductions) during 2006, excluding interest and adjustments	2006 Adjustments during 2006 - instructed by Board	2006 Adjustments during 2006 - other	2006 Transfer of Board-approved amounts to 1590 as per 2006 EDR	2006 Closing Principal Balance as of Dec-31-06	2006 Opening Interest Amounts as of Jan-1-06	2006 Interest Jan-1 to Dec31-06	2006 Transfer of Board-approved amounts to 1590 as per 2006 EDR	2006 Closing Interest Amounts as of Dec-31-06	Total
Group 1													
LV Variance Account	1550	$ -	$ 178,246	$ (36,088)				$ 142,158	$ -	$ 2,178		$ 2,178	$ 144,336
RSVA - Wholesale Market Service Charge	1580	$ 2,657,967	$ (1,991,831)					$ 666,136	$ 472,503	$ 99,802		$ 572,305	$ 1,238,441
RSVA - Retail Transmission Network Charge	1584	$ (380,791)	$ (181,411)					$ (562,202)	$ 19,235	$ (27,405)		$ (8,170)	$ (570,372)
RSVA - Retail Transmission Connection Charge	1586	$ (1,953,376)	$ (563,398)					$ (2,516,774)	$ (231,003)	$ (118,124)		$ (349,127)	$ (2,865,901)
RSVA - Power (including Global Adjustment)	1588	$ (2,036,296)	$ 877,867					$ (1,158,429)	$ (431,497)	$ (67,419)		$ (498,916)	$ (1,657,345)
RSVA - Power - Sub-Account - Global Adjustment [4]	1588	$ (2,653,941)	$ 3,625,274					$ 971,333	$ (65,258)	$ (53,898)		$ (119,156)	$ 852,177
Recovery of Regulatory Asset Balances	1590	$ (972,587)	$ (1,289,198)					$ (2,261,785)	$ (74,617)	$ (98,489)		$ (173,106)	$ (2,434,891)
													$ -
Sub-Totals		**$ (5,339,024)**	**$ 655,549**	**$ (36,088)**	**$ -**	**$ -**	**$ -**	**$ (4,719,563)**	**$ (310,637)**	**$ (263,355)**	**$ -**	**$ (573,992)**	**$ (5,293,555)**
Group 2													
Other Regulatory Assets - Sub-Account - OEB Cost Assessments	1508	$ 124,122	$ 94,721					$ 218,843	$ -	$ 5,311		$ 5,311	$ 224,154
Other Regulatory Assets - Sub-Account - Pension Contributions	1508	$ 238,234	$ 365,155					$ 603,389	$ -	$ 17,286		$ 17,286	$ 620,675
Other Regulatory Assets - Sub-Account - Other	1508	$ 1,100,314						$ 1,100,314	$ 190,982	$ 46,218		$ 237,200	$ 1,337,514
Retail Cost Variance Account - Retail	1518	$ (133,064)	$ 80,057	$ (81,985)				$ (134,992)	$ -			$ -	$ (134,992)
Misc. Deferred Debits	1525	$ 56,746	$ 94,905					$ 151,651	$ -			$ -	$ 151,651
Retail Cost Variance Account - STR	1548	$ (18,273)	$ 1,633	$ (4,651)				$ (21,291)	$ -			$ -	$ (21,291)
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Capital	1555	$ -	$ 95,979					$ 95,979	$ -			$ -	$ 95,979
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Recoveries	1555	$ -		$ (81,587)				$ (81,587)	$ -			$ -	$ (81,587)
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Stranded Meter	1555	$ -						$ -	$ -			$ -	$ -
Smart Meter OM&A Variance	1556	$ -	$ 77,404					$ 77,404	$ -			$ -	$ 77,404
Conservation and Demand Management Expenditures and Recoveries	1565	$ -	$ 754,495	$ (1,355,976)				$ (601,481)	$ -			$ -	$ (601,481)
CDM Contra	1566	$ -	$ (754,495)	$ 1,355,976				$ 601,481	$ -			$ -	$ 601,481
Qualifying Transition Costs	1570	$ 1,227,053	n/a	n/a				$ 1,227,053	$ 309,762	$ 58,484		$ 368,246	$ 1,595,299
Pre-Market Opening Energy Variances Total	1571	$ (151,542)	n/a	n/a				$ (151,542)	$ -			$ -	$ (151,542)
RSVA - One-time Wholesale Market Service	1582	$ 563,079	$ 56,535					$ 619,614	$ 32,648	$ -		$ 32,648	$ 652,262
2006 PILs & Taxes Variance	1592	$ -						$ -	$ -			$ -	$ -
Sub-Totals		**$ 2,443,590**	**$ 809,854**	**$ (168,223)**	**$ -**	**$ -**	**$ -**	**$ 3,085,221**	**$ 500,744**	**$ 127,298**	**$ -**	**$ 628,042**	**$ 4,365,525**

Interest Rates used to Calculate Carrying Charges:

Q1	**7.25%**
Q2	**4.14%**
Q3	**4.59%**
Q4	**4.59%**

Account Description	Account Number	2007 Opening Principal Amounts as of Jan-1-07	Transactions (additions) during 2007, excluding interest and adjustments	Transactions (reductions) during 2007, excluding interest and adjustments	Adjustments during 2007 - instructed by Board	Adjustments during 2007 - other	Transfer of Board-approved amounts to 1590 as per 2006 EDR	Closing Principal Balance as of Dec-31-07	Opening Interest Amounts as of Jan-1-07	Interest Jan-1 to Dec31-07	Transfer of Board-approved amounts to 1590 as per 2006 EDR	Closing Interest Amounts as of Dec-31-07	Total
Group 1													
LV Variance Account	1550	$ 142,158	$ 221,218	$ (53,944)				$ 309,432	$ 2,178	$ 11,082		$ 13,260	$ 322,692
RSVA - Wholesale Market Service Charge	1580	$ 666,136	$ (1,902,807)				$ (1,533,928)	$ (2,770,599)	$ 572,305	$ (56,873)	$ (481,805)	$ 33,627	$ (2,736,972)
RSVA - Retail Transmission Network Charge	1584	$ (562,202)	$ 65,694				$ 65,105	$ (431,403)	$ (8,170)	$ (17,355)	$ (8,018)	$ (33,543)	$ (464,946)
RSVA - Retail Transmission Connection Charge	1586	$ (2,516,774)	$ (298,920)				$ 1,266,207	$ (1,549,487)	$ (349,127)	$ (97,204)	$ (166,349)	$ (612,680)	$ (2,162,167)
RSVA - Power (including Global Adjustment)	1588	$ (1,158,429)	$ (671,165)				$ 135,640	$ (1,693,954)	$ (498,916)	$ (71,186)	$ 362,888	$ (207,214)	$ (1,901,168)
RSVA - Power - Sub-Account - Global Adjustment [4]	1588	$ 971,333	$ (473,524)					$ 497,809	$ (119,156)	$ 31,388		$ (87,768)	$ 410,041
Recovery of Regulatory Asset Balances	1590	$ (2,261,785)	$ (989,630)				$ 2,688,892	$ (562,523)	$ (173,106)	$ (113,690)	$ 982,670	$ 695,874	$ 133,351
Sub-Totals		**$ (4,719,563)**	**$ (4,049,134)**	**$ (53,944)**	**$ -**	**$ -**	**$ 2,621,916**	**$ (6,200,725)**	**$ (573,992)**	**$ (313,838)**	**$ 689,386**	**$ (198,444)**	**$ (6,399,169)**
Group 2													
Other Regulatory Assets - Sub-Account - OEB Cost Assessments	1508	$ 218,843	$ 55,825				$ (39,254)	$ 235,414	$ 5,311	$ 6,947		$ 12,258	$ 247,672
Other Regulatory Assets - Sub-Account - Pension Contributions	1508	$ 603,389						$ 603,389	$ 17,286	$ 22,613		$ 39,899	$ 643,288
Other Regulatory Assets - Sub-Account - Other	1508	$ 1,100,314					$ (1,100,314)	$ -	$ 237,200	$ 15,637	$ (215,188)	$ 37,649	$ 37,649
Retail Cost Variance Account - Retail	1518	$ (134,992)	$ 82,025	$ (90,219)			$ 150,424	$ 7,238	$ -			$ -	$ 7,238
Misc. Deferred Debits	1525	$ 151,651		$ (53,772)			$ (97,879)	$ -	$ -			$ -	$ -
Retail Cost Variance Account - STR	1548	$ (21,291)	$ 1,673	$ (6,149)			$ 17,376	$ (8,391)	$ -		$ -	$ -	$ (8,391)
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Capital	1555	$ 95,979	$ 13,386					$ 109,365	$ -			$ -	$ 109,365
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Recoveries	1555	$ (81,587)		$ (156,997)				$ (238,584)	$ -			$ -	$ (238,584)
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Stranded Meter	1555	$ -						$ -	$ -			$ -	$ -
Smart Meter OM&A Variance	1556	$ 77,404						$ 77,404	$ -			$ -	$ 77,404
Conservation and Demand Management Expenditures and Recoveries	1565	$ (601,481)	$ 1,414,242	$ (806,024)				$ 6,737	$ -			$ -	$ 6,737
CDM Contra	1566	$ 601,481	$ (1,414,242)	$ 806,024				$ (6,737)	$ -			$ -	$ (6,737)
Qualifying Transition Costs	1570	$ 1,227,053	n/a	n/a			$ (1,227,053)	$ (0)	$ 368,246	$ 27,217	$ (395,463)	$ -	$ (0)
Pre-Market Opening Energy Variances Total	1571	$ (151,542)	n/a	n/a			$ 151,542	$ -	$ -			$ -	$ -
RSVA - One-time Wholesale Market Service	1582	$ 619,614	$ 18,162				$ (476,758)	$ 161,018	$ 32,648	$ -	$ (78,735)	$ (46,087)	$ 114,931
2006 PILs & Taxes Variance	1592	$ -						$ -	$ -			$ -	$ -
Sub-Totals		**$ 3,085,221**	**$ 152,909**	**$ (307,137)**	**$ -**	**$ -**	**$ (2,145,158)**	**$ 785,835**	**$ 628,042**	**$ 72,414**	**$ (610,651)**	**$ 89,805**	**$ 990,571**
Interest Rates used to Calculate Carrying Charges:													
Q1										**4.59%**			
Q2										**4.59%**			
Q3										**4.59%**			
Q4										**5.14%**			

Account Description	Account Number	2008 Opening Principal Amounts as of Jan-1-08	Transactions (additions) during 2008, excluding interest and adjustments	Transactions (reductions) during 2008, excluding interest and adjustments	Adjustments during 2008 - instructed by Board	Adjustments during 2008 - other	Transfer of Board-approved amounts to 1590 as per 2006 EDR	Closing Principal Balance as of Dec-31-08	Opening Interest Amounts as of Jan-1-08	Interest Jan-1 to Dec31-08	Transfer of Board-approved amounts to 1590 as per 2006 EDR	Closing Interest Amounts as of Dec-31-08	Total
Group 1													
LV Variance Account	1550	$ 309,432	$ 148,967	$ (52,363)				$ 406,036	$ 13,260	$ 13,716		$ 26,976	$ 433,012
RSVA - Wholesale Market Service Charge	1580	$ (2,770,599)	$ (812,354)					$ (3,582,953)	$ 33,627	$ (379,037)		$ (345,410)	$ (3,928,363)
RSVA - Retail Transmission Network Charge	1584	$ (431,403)	$ (431,843)					$ (863,246)	$ (33,543)	$ (7,078)		$ (40,621)	$ (903,867)
RSVA - Retail Transmission Connection Charge	1586	$ (1,549,487)	$ (860,458)					$ (2,409,945)	$ (612,680)	$ (9,612)		$ (622,292)	$ (3,032,237)
RSVA - Power (including Global Adjustment)	1588	$ (1,693,954)	$ 33,737					$ (1,660,217)	$ (207,214)	$ (112,582)		$ (319,796)	$ (1,980,013)
RSVA - Power - Sub-Account - Global Adjustment [4]	1588	$ 497,809	$ 393,978			$ 1,170,542		$ 2,062,329	$ (87,768)	$ 266,043		$ 178,275	$ 2,240,604
Recovery of Regulatory Asset Balances	1590	$ (562,523)	$ (610,151)					$ (1,172,674)	$ 695,874	$ 55,640		$ 751,515	$ (421,160)
Sub-Totals		**$ (6,200,725)**	**$ (2,138,124)**	**$ (52,363)**	**$ -**	**$ 1,170,542**	**$ -**	**$ (7,220,670)**	**$ (198,444)**	**$ (172,911)**	**$ -**	**$ (371,354)**	**$ (7,592,025)**
Group 2													
Other Regulatory Assets - Sub-Account - OEB Cost Assessments	1508	$ 235,414				$ (128,699)		$ 106,715	$ 12,258	$ 5,849		$ 18,107	$ 124,822
Other Regulatory Assets - Sub-Account - Pension Contributions	1508	$ 603,389				$ (128,267)		$ 475,122	$ 39,899	$ 19,037		$ 58,936	$ 534,058
Other Regulatory Assets - Sub-Account - Other	1508	$ -				$ 4,190		$ 4,190	$ 37,649	$ 18,642		$ 56,290	$ 60,480
Retail Cost Variance Account - Retail	1518	$ 7,238	$ 78,557	$ (77,671)				$ 8,124	$ -	$ 854		$ 854	$ 8,978
Misc. Deferred Debits	1525	$ -	$ 1,145					$ 1,145	$ -			$ -	$ 1,145
Retail Cost Variance Account - STR	1548	$ (8,391)	$ 2,369	$ (2,368)				$ (8,390)	$ -	$ (1,286)		$ (1,286)	$ (9,676)
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Capital	1555	$ 109,365	$ 279,815					$ 389,180	$ -			$ -	$ 389,180
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Recoveries	1555	$ (238,584)		$ (158,116)				$ (396,700)	$ -			$ -	$ (396,700)
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Stranded Meter	1555	$ -						$ -	$ -			$ -	$ -
Smart Meter OM&A Variance	1556	$ 77,404		$ (77,328)				$ 76	$ -			$ -	$ 76
Conservation and Demand Management Expenditures and Recoveries	1565	$ 6,737		$ (6,737)				$ -	$ -			$ -	$ -
CDM Contra	1566	$ (6,737)		$ 6,737				$ -	$ -			$ -	$ -
Qualifying Transition Costs	1570	$ (0)	n/a	n/a				$ (0)	$ -			$ -	$ (0)
Pre-Market Opening Energy Variances Total	1571	$ -	n/a	n/a				$ -	$ -			$ -	$ -
RSVA - One-time Wholesale Market Service	1582	$ 161,018	$ 22,453					$ 183,471	$ (46,087)	$ 48,161		$ 2,074	$ 185,545
2006 PILs & Taxes Variance	1592	$ -						$ -	$ -			$ -	$ -
Sub-Totals		**$ 785,835**	**$ 361,886**	**$ (315,483)**	**$ -**	**$ (252,776)**	**$ -**	**$ 579,462**	**$ 89,805**	**$ 43,096**	**$ -**	**$ 132,901**	**$ 712,363**

Interest Rates used to Calculate Carrying Charges:

Q1	**5.14%**
Q2	**4.08%**
Q3	**3.35%**
Q4	**3.35%**

c) The updated schedules that have been impacted by the adjustments mentioned in part b) above are presented below.

Deferral and Variance Accounts @ December 31, 2008

Account Description	Account Number	Principal Amounts as of Dec-31 2008	Interest to Dec31-08	Interest Jan-1 to Dec31-09	Interest Jan1-10 to Apr30-10	Total Claim
Group 1						
Low Voltage	1550	$ 406,036	$ 26,976	$ 4,619	$ 744	$ 438,375
RSVA - Wholesale Market Service Charge	1580	$ (3,582,953)	$ (345,410)	$ (40,756)	$ (6,569)	$ (3,975,688)
RSVA - Retail Transmission Network Charge	1584	$ (863,246)	$ (40,621)	$ (9,819)	$ (1,583)	$ (915,269)
RSVA - Retail Transmission Connection Charge	1586	$ (2,409,945)	$ (622,292)	$ (27,413)	$ (4,418)	$ (3,064,069)
RSVA - Power	1588	$ (3,722,546)	$ (498,071)	$ (42,344)	$ (6,825)	$ (4,269,786)
RSVA - Power, Gobal Adjustment	1588	$ 2,062,329	$ 178,275	$ 23,459	$ 3,781	$ 2,267,844
Recovery of Regulatory Asset Balances	1590	$ (1,172,674)	$ 751,515	$ (13,339)	$ (2,150)	$ (436,649)
Sub-Totals		$ (9,282,999)	$ (549,630)	$ (105,594)	$ (17,019)	$ (9,955,242)
Group 2						
Other Regulatory Assets	1508	$ 586,027	$ 133,333	$ 6,666	$ 1,074	$ 727,101
Retail Cost Variance Account - Retail	1518	$ 8,124	$ 854	$ 92	$ 15	$ 9,085
Retail Cost Variance Account - STR	1548	$ (8,390)	$ (1,286)	$ (95)	$ (15)	$ (9,787)
Smart Meters Revenue and Capital	1555			$ -	$ -	$ -
Smart Meter Expenses	1556			$ -	$ -	$ -
RSVA - One-time Wholesale Market Service	1582	$ 183,471	$ 2,074	$ 2,087	$ 336	$ 187,968
					$ -	
Sub-Totals		$ 769,232	$ 134,975	$ 8,750	$ 1,410	$ 914,367
Totals per column		$ (8,513,767)	$ (414,655)	$ (96,844)	$ (15,609)	$ (9,040,874)
		$ (2,062,329)				
Annual interest rate:	2009 Average	1.14%				
	2010 Q1	0.55%				

Rate Riders Calculation

Deferral and Variance Accounts:	Amount	ALLOCATOR	Residential	General Service < 50 kW	General Service > 50 to 999 kW	General Service > 1000 to 4999	General Service > 5000 kW	Unmettered Scattered Load	Street Lights	Total
Group 1										
Low Voltage	$ 438,375	kWh	$ 110,717	$ 48,671	$ 138,423	$ 71,427	$ 65,832	$ 604	$ 2,701	$ 438,375
WMSC - Account 1580	$ (3,975,688)	kWh	$ (1,004,108)	$ (441,406)	$ (1,255,375)	$ (647,784)	$ (597,043)	$ (5,476)	$ (24,496)	$ (3,975,688)
Network - Account 1584	$ (915,269)	kWh	$ (231,162)	$ (101,619)	$ (289,008)	$ (149,131)	$ (137,449)	$ (1,261)	$ (5,639)	$ (915,269)
Connection - Account 1586	$ (3,064,069)	kWh	$ (773,867)	$ (340,192)	$ (967,520)	$ (499,248)	$ (460,142)	$ (4,220)	$ (18,879)	$ (3,064,069)
Power - Account 1588	$ (4,269,786)	kWh	$ (1,078,386)	$ (474,058)	$ (1,348,240)	$ (695,703)	$ (641,209)	$ (5,881)	$ (26,308)	$ (4,269,786)
Power, Gobal Adjustment - Account 1588	$ 2,267,844	kWh for Non RPP Customer	$ 134,565	$ 54,628	$ 971,670	$ 582,374	$ 501,185	$ -	$ 23,423	$ 2,267,844
Recovery of Regulatory Asset Balances	$ (436,649)	2006 Reg. Assets %	$ (534,667)	$ (27,246)	$ 56,581	$ 10,711	$ 57,860	$ (1,380)	$ 1,492	$ (436,649)
Subtotal	$ (9,955,242)		$ (3,376,908)	$ (1,281,223)	$ (2,693,470)	$ (1,327,353)	$ (1,210,967)	$ (17,614)	$ (47,707)	$ (9,955,242)
Group 2										
Other Regulatory Assets - Account 1508	$ 727,101	Dx Revenue	$ 360,881	$ 101,549	$ 178,790	$ 56,814	$ 23,818	$ 2,302	$ 2,947	$ 727,101
Retail Cost Variance Account - Acct 1518	$ 9,085	# of Customers	$ 8,093	$ 848	$ 125	$ 5	$ 1	$ 12	$ 1	$ 9,085
Retail Cost Variance Account (STR) Acct 1548	$ (9,787)	# of Customers	$ (8,718)	$ (913)	$ (135)	$ (6)	$ (1)	$ (13)	$ (2)	$ (9,787)
One-Time WMSC - Account 1582	$ 187,968	kWh	$ 47,474	$ 20,869	$ 59,353	$ 30,627	$ 28,228	$ 259	$ 1,158	$ 187,968
Subtotal - Non RSVA, Variable	$ 914,367		$ 407,730	$ 122,353	$ 238,134	$ 87,440	$ 52,045	$ 2,560	$ 4,105	$ 914,367
Smart Meters Revenue and Capital, 1555 (Fixed)	$ -	# of Metered Customers	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Smart Meter Expenses, 1556 (Fixed)	$ -	# of Metered Customers	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Subtotal - Non RSVA Fixed	$ -		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total to be refunded	$ (9,040,874)		$ (2,969,178)	$ (1,158,870)	$ (2,455,336)	$ (1,239,913)	$ (1,158,921)	$ (15,054)	$ (43,602)	$ (9,040,874)

Balance to be collected or refunded, Variable	$ (9,040,874)		$ (2,969,178)	$ (1,158,870)	$ (2,455,336)	$ (1,239,913)	$ (1,158,921)	$ (15,054)	$ (43,602)	$ (9,040,874)
Balance to be collected or refunded, Fixed	$ -		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Number of years for Variable	1									
Number of years for Fixed	1									
Balance to be collected or refunded per year, Variable	$ (9,040,874)		$ (2,969,178)	$ (1,158,870)	$ (2,455,336)	$ (1,239,913)	$ (1,158,921)	$ (15,054)	$ (43,602)	$ (9,040,874)
Balance to be collected or refunded per year, Fixed	$ -		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -

Class	Residential	General Service < 50 kW	General Service > 50 to 999 kW	General Service > 1000 to 4999 kW	General Service > 5000 kW	Unmettered Scattered Load	Street Lights
Deferral and Variance Account Rate Riders, Variable	$ (0.0077)	$ (0.0068)	$ (1.9735)	$ (2.2380)	$ (2.5959)	$ (0.0071)	$ (1.8099)
Billing Determinants	kWh	kWh	kW	kW	kW	kWh	kW

Proposed Rate Rider

Rate Class	Billing Parameter	Proposed Rate Rider, May 01, 2010 - Apr 30, 2011
Residential	kWh	$ (0.0077)
General Service < 50 kW	kWh	$ (0.0068)
General Service > 50 to 999 kW	kW	$ (1.9735)
General Service > 1000 to 4999 kW	kW	$ (2.2380)
General Service > 5000 kW	kW	$ (2.5959)
Unmetered Scattered Loads	kWh	$ (0.0071)
Street Lights	kW	$ (1.8099)

36. Ref: Exhibit 9/pg. 9/Table 5

C&ND Hydro has proposed to dispose of a number of Deferral and Variance ("D/V") Account balances, as listed on **Exhibit 9/page 7**:

Group 1

a. 1550 Low Voltage Account
b. 1580 RSVA Wholesale Market Service Charge Account
c. 1584 RSVA Retail Transmission Network Charges Account
d. 1586 RSVA Retail Transmission connection Charge Account
e. 1588 RSVA Power (Not Including Global Adj. Sub. a/c) Account
f. 1588 RSVA Power Account – Global Adj. Sub. Account
g. 1590 Recovery of Regulatory Accounts Balances Account

Group 2

- 1508 Other Regulatory Assets Account – OEB Cost Assessment
- 1508 Other Regulatory Assets Account – Pension Contributions
- 1518 RCVA Retail Account
- 1548 RCVA Service Transaction Account
- 1582 One Time Wholesale Market Service Account

There are other D/V Accounts for which C&ND Hydro is not proposing disposition of the audited December 31, 2008 balances including interest to April 30, 2010.

a) For those D/V accounts for which C&ND Hydro is not proposing disposition, please provide an explanation of why C&ND Hydro is not proposing to dispose of the balances for those accounts.

b) **Exhibit 9/page 9/Table 5** provides the calculation of the total D/V account balance of ($9,314,681) for which C&ND Hydro is proposing disposition.

i) In **Table 5**, under Group 2, C&ND Hydro lists the Smart Meter D/V accounts 1555 and 1556, but shows no amounts to be disposed. Please

confirm that C&ND Hydro is not seeking disposition of the balances in the Smart Meter D/V accounts 1555 and 1556. If C&ND Hydro is seeking disposition of these account balances, please provide an update to Table 5 and a detailed explanation of why this is being proposed.

ii) Please provide an update to **Table 5** showing, as an additional group, with individual account details, the December 31, 2008 principals, and the associated interest for 2008, 2009 and January 1 to April 30, 2010, for the D/V accounts for which C&ND Hydro is not proposing disposition.

Response

a) In the review of accounts for disposition it was determined that the posting to 1525 would be reversed in 2009 and therefore should not be included. Accounts 1555 and 1556 were considered to be more appropriately dealt with at a later time when the permanent costs for smart meters are placed in the rate base.

b)

i) It is confirmed that disposition of the balances in 1555 and 1556 is not requested in the application.

ii) An updated **Table 5** showing, as an additional group, with individual account details, the December 31, 2008 principals, and the associated interest for 2008, 2009 and January 1 to April 30, 2010, for the D/V accounts for which Cambridge and North Dumfries Hydro Inc. is not proposing disposition is presented below.

Deferral and Variance Accounts @ December 31, 2008

Account Description	Account Number	Principal Amounts as of Dec-31 2008	Interest to Dec31-08	Interest Jan-1 to Dec31-09	Interest Jan1-10 to Apr30-10	Total Claim
Group 1						
Low Voltage	1550	$ 406,036	$ 26,976	$ 4,619	$ 744	$ 438,375
RSVA - Wholesale Market Service Charge	1580	$ (3,582,953)	$ (345,410)	$ (40,756)	$ (6,569)	$ (3,975,688)
RSVA - Retail Transmission Network Charge	1584	$ (863,246)	$ (40,621)	$ (9,819)	$ (1,583)	$ (915,269)
RSVA - Retail Transmission Connection Charge	1586	$ (2,409,945)	$ (622,292)	$ (27,413)	$ (4,418)	$ (3,064,069)
RSVA - Power	1588	$ (3,722,546)	$ (367,394)	$ (42,344)	$ (6,825)	$ (4,139,108)
RSVA - Power, Gobal Adjustment	1588	$ 2,062,329	$ 47,598	$ 23,459	$ 3,781	$ 2,137,167
Recovery of Regulatory Asset Balances	1590	$ (1,172,674)	$ 751,515	$ (13,339)	$ (2,150)	$ (436,649)
Sub-Totals		$ (9,282,999)	$ (549,629)	$ (105,594)	$ (17,019)	$ (9,955,241)
Group 2						
Other Regulatory Assets	1508	$ 586,027	$ 133,333	$ 6,666	$ 1,074	$ 727,101
Retail Cost Variance Account - Retail	1518	$ 8,124	$ 854	$ 92	$ 15	$ 9,085
Retail Cost Variance Account - STR	1548	$ (8,390)	$ (1,286)	$ (95)	$ (15)	$ (9,787)
Smart Meters Revenue and Capital	1555			$ -	$ -	$ -
Smart Meter Expenses	1556			$ -	$ -	$ -
RSVA - One-time Wholesale Market Service	1582	$ 183,471	$ 2,074	$ 2,087	$ 336	$ 187,968
					$ -	
Sub-Totals		$ 769,232	$ 134,975	$ 8,750	$ 1,410	$ 914,367
Accounts not included for Disposition						
Miscellaneous Deferred Debits - Rebate	1525	$ 1,145		$ 13	$ 2	$ 1,160
Smart Meter Capital and Recovery Offset	1555	$ (7,520)		$ (86)	$ (14)	$ (7,619)
Smart Meter Operation, Maintenace and Administration	1556	$ 76		$ 1	$ 0	$ 77
Deferred Payment in Lieu of Taxes	1562	$ (726,729)	$ (342,417)	$ (8,267)	$ (1,332)	$ (1,078,745)
Pils and Tax Variance Account for 2006 & Subsequent year	1592	$ (7,273)	$ (304)	$ (83)	$ (13)	$ (7,673)
Sub-Totals		$ (740,301)	$ (342,721)	$ (8,421)	$ (1,357)	$ (1,092,800)
Totals per column		**$ (9,254,068)**	**$ (757,375)**	**$ (105,265)**	**$ (16,966)**	**$ (10,133,674)**

Annual interest rate:	2009 Average	1.14%
	2010 Q1	0.55%

37. Ref: Exhibit 9 – Account 1588

On October 15, 2009, the Board's Regulatory Audit & Accounting group issued a bulletin related to Regulatory Accounting & Reporting of Account 1588 RSVA Power and Account 1588 RSVA Power Sub-account Global Adjustment. Please confirm whether or not C&ND Hydro plans on making any changes to its filing with respect to Account 1588.

Response

Cambridge and North Dumfries Hydro Inc. does not plan to make any changes to its filing with respect to Account 1588 based on the Bulletin issued by the Board on October 15, 2009.

Smart Meters

38. Ref: Exhibit 1/pages 9 and 15 and Exhibit 8/page 17 – Smart Meters

C&ND Hydro notes that it is authorized to deploy smart meters under O. Reg. 427/06 as it is procuring and deploying smart meters and related infrastructure pursuant to the London Hydro RFP. C&ND Hydro currently has an approved smart meter funding adder of $1.00 per month per metered customer. C&ND Hydro is not proposing to change the funding adder, nor, subject to clarification, does it appear that C&ND Hydro is proposing that amounts in the established deferral/variance accounts 1555 and 1556 be reviewed and disposed of at this time.

Please provide information of smart meter rate adder revenues collected, or forecasted to be collected, and smart meter capital and operating costs booked to sub-accounts of accounts 1555 and 1556, and on smart meters installed and forecasted to be installed, per the table shown in Appendix 2-S of the Board's Filing Requirements.

Response

Appendix 2 – S of the Board's Filing Requirements providing information regarding Smart Meters is presented below

Appendix 2 - S
Smart Meters

Year	Smart Meter Installed			Percentage of applicable customers converted %	Account 1555		Account 1556
	Residential	GS < 50 kW	Other		Funding Adder Collected	Capital Expenditures	Operating Expenses
2006	0	0	0	0	$ (81,587)		
2007	0	0	0	0	(156,998)		
2008	1,127	0	0	2.3%	(158,116)	389,180	76
2009	4,964	272	0	10.5%	(392,686)	2,297,000	239,614
2010	39,127	4,310	0	87.2%	(600,000)	5,239,000	602,315
2011							
Total	**45,218**	**4,582**	**-**	**100.0%**	**(1,389,386)**	**7,925,180**	**842,005**

LRAM/SSM

39. Ref: Exhibit 1/page 30

At lines 4 to 7, C&ND Hydro states:

> "In preparing this Application, Cambridge and North Dumfries Hydro Inc. has considered the impacts on its customers, with a goal of minimizing those impacts and in doing so, Cambridge and North Dumfries Hydro Inc. has elected not to file an application for a CDM-related lost revenue adjustment ("LRAM") or shared saving ("SSM") with this Application."

As proposed in the Application, most customers would see bill decreases, at least for 2010, due to the proposal to refund the significant deferral/variance account balance over a period of one year.

Please confirm that, by electing to not apply for LRAM or SSM recovery in this application, C&ND Hydro is foregoing the opportunity of ever seeking LRAM or SSM recovery for the period up to 2008.

Response

This will confirm that by electing to not apply for LRAM or SSM recovery in the Application, Cambridge and North Dumfries Hydro Inc. is foregoing the opportunity of ever seeking LRAM or SSM recovery for the period up to 2008.

Green Energy and Green Economy Act

40. Ref: Exhibit 4/page 26

C&ND Hydro indicates that it has included a new staffing position for contract administration and customer contact requirements for the FIT and microFIT programs of the OPA.

a) Is this position dedicated to the FIT and microFIT program administration? If not, please indicate what other activities the employee will be engaged in, and the percentage of time that the employee is expected to be involved in Green Energy and Green Economy Act activities.
b) Please estimate the costs in the 2010 test year related to this staffing position.

Response

a) The position is not totally dedicated to the FIT and microFIT programs. The volume of activity associated with these programs' participants and the technical evaluation required is still very speculative. If the volumes are similar to the projections presented by the Ministry of Energy and Infrastructure, the position would be at 60% of time spent on FIT and microFIT programs.

b) The estimated costs in the 2010 test relating to this staffing position is $114,750.

OEB Board Staff Interrogatories
Cambridge and North Dumfries Hydro Inc.
EB-2009-0260

EXHIBIT A

CAMBRIDGE AND NORTH DUMFRIES HYDRO INC.

2007 RELIABILITY REPORT

Energy+
CAMBRIDGE AND NORTH DUMFRIES HYDRO INC.

we deliver

Introduction

Reliability continues to be a very important component of our service to customers. We track reliability for both planned outages (ie. scheduled maintenance work) and unplanned outages (ie. equipment failure, vehicle accidents or a lightning storm). We track our reliability on a monthly basis. This report discusses the reliability of CND Hydro's electrical system and compares our performance to other Ontario utilities.

We compare ourselves against other Local Distribution Companies in Ontario as a guide as to how we are doing. Comparisons are never precise because each utility has a unique system (ie. mix of rural and urban areas, % underground versus % overhead system, operating voltages, age of plant, amount of technology deployed, etc.).

Measurement of reliability requires adherence to some set definitions so that useful comparisons can be made between utilities. The basic definitions are reviewed below:

Definitions:

Customer: A customer is defined as a metered service. Therefore, Toyota counts as one customer in the statistics the same as a residential home. A bulk metered apartment building counts as one customer but an individually metered apartment building could count as 100 customers.

Interruption: An interruption is the loss of service to one or more customers for one minute or longer. Momentary interruptions (ie. autorecloses are tracked separately).

Interruption Duration: This is the period from the initiation of an interruption to a customer until service has been restored to that customer.

Customer Hours of Interruption: This is the product of the customer services interrupted by the period of interruption (ie. if 10 customers are out of service for 3 hours, 10 x 3 = 30 Customer Hours are lost).

Customer Interruptions: This is the sum of the products of the customer services interrupted by the number of interruptions that affect those customer services (ie. if 30 customers are out of power for 1 hour, 10 customers are out of power for 2 hours and 1 customer is out of power for 1 hour, there are 30x1 + 10x1 +1x1 = 41 Customer Interruptions).

System Average Interruption Frequency Index (SAIFI): This index is defined as the average number of interruptions per customer served per year.

SAIFI = Total Customer Interruptions/Total Customers Served

System Average Interruption Duration Index (SAIDI): This index is defined as the system average interruption duration for customers served per year.

SAIDI = Total Customer Hours of Interruption/Total Customers Served

Customer Average Interruption Duration Index (CAIDI): This index is defined as the customer average interruption duration for customers interrupted during a year.

CAIDI = Total Customer Hours of Interruption/Total Customer Interruptions

How are we doing?:

SAIFI (System Average Interruption Frequency Index)

Note: 2003 numbers exclude the August 14th/15th Blackout.

Year	2007	2006	2005	2004	2003
CND Hydro	1.74	1.38	1.11	1.04	3.09
Barrie Hydro	3.23	3.29	3.70	1.33	4.31
Burlington Hydro	0.68	0.88	1.20	0.92	1.92
Enwin Powerlines	2.11	2.20	3.12	2.70	2.29
Guelph Hydro	1.02	1.18	1.04	1.03	0.94
Horizon Utilities (Hamilton only for 2004 data and prior)	1.59	1.44	1.67	1.03	n/a
Hydro One Brampton Networks	1.85	1.48	1.81	1.27	2.43
Kitchener Wilmot Hydro	0.94	0.92	0.80	0.51	1.42
London Hydro	2.46	2.14	1.65	2.09	1.87
Ottawa Hydro	1.21	1.19	n/a	0.66	n/a
Waterloo North Hydro	6.65	7.35	n/a	1.71	4.04

In terms of frequency of outages (SAIFI), our customers had an increase in 2007 over 2006 with the trend continuing to go up. The SAIFI number is still below the average of the ten utilities who we use to compare our performance but it is a cause for concern.

SAIDI (System Average Interruption Duration Index)

Note: 2003 numbers exclude the August 14th/15th Blackout.

Year	2007	2006	2005	2004	2003
CND Hydro	1.51	0.95	1.14	0.75	5.03
Barrie Hydro	2.38	3.61	2.55	1.34	4.63
Burlington Hydro	1.03	1.05	1.27	1.15	1.91
Enwin Powerlines	1.20	1.39	2.62	1.20	1.84
Guelph Hydro	0.59	0.36	0.48	0.37	0.47
Horizon Utilities (Hamilton only for 2004 data and prior)	1.01	0.94	1.09	0.77	n/a
Hydro One Brampton Networks	1.26	0.86	1.10	0.73	1.40
Kitchener Wilmot Hydro	1.10	0.66	1.00	0.54	0.98
London Hydro	1.69	1.25	1.15	1.32	1.10
Ottawa Hydro	1.40	1.51	n/a	0.76	n/a
Waterloo North Hydro	0.91	0.99	n/a	2.19	3.77

CAIDI (Customer Average Interruption Duration Index)

Note: 2003 numbers exclude the August 14th/15th Blackout.

Year	2007	2006	2005	2004	2003
CND Hydro	0.86	0.69	1.03	0.72	1.63
Barrie Hydro	0.74	1.10	0.69	1.01	1.08
Burlington Hydro	1.51	1.19	1.05	1.25	1.00
Enwin Powerlines	0.57	0.63	0.84	0.44	0.80
Guelph Hydro	0.58	0.31	0.46	0.36	0.50
Horizon Utilities (Hamilton only for 2004 data and prior)	0.64	0.65	0.65	0.74	n/a
Hydro One Brampton Networks	0.68	0.58	0.60	0.57	0.58
Kitchener Wilmot Hydro	1.18	0.71	1.25	1.06	0.69
London Hydro	0.69	0.59	0.70	0.63	0.59
Ottawa Hydro	1.15	1.27	n/a	1.15	n/a
Waterloo North Hydro	0.14	0.13	n/a	0.54	0.93

In terms of the total number of hours lost (SAIDI), there was a substantial increase (almost 60%) compared to 2006. 30,805 Customer-Hours lost out of the total of 73,394 Customer-Hours lost in 2007 relate to one event where poles fell down along a stretch of Franklin Boulevard during a spring ice storm. This event had a significant impact on the SAIDI and CAIDI numbers in 2007 since the duration of the outage was long and a large number of customers were affected. In September, 2007, we also lost 11,998 Customer-Hours as a result of a violent windstorm in the Main Street area of Galt. In 2007, the distribution system was available 99.983% of the time to the average customer.

In terms of the time that it took us to restore power when we had an interruption (CAIDI), we performed worse in 2007 than in 2006 due in large part to the ice storm event in March, 2007.

What are the causes of the outages?:

It is important to understand what is causing the outages so that we can try to take steps to prevent them. The following cause codes are used.

Unknown – Customer interruptions with no apparent cause or reason.

Scheduled – Customer interruptions due to the disconnection at a selected time for the purpose of construction or preventive maintenance.

Loss of Supply – Customer interruptions due to problems in the bulk electricity system (ie. supply from Hydro One).

Trees – Customer interruptions caused by faults due to trees or tree limbs contacting energized circuits.

Lightning – Customer interruptions due to lightning striking the distribution system, resulting in an insulation breakdown and/or flashovers.

Defective Equipment – Customer interruptions due to deterioration from age, incorrect maintenance, or imminent failures detected by maintenance.

Adverse Weather – Customer interruptions resulting from rain, ice storms, snow, winds, extreme ambient temperatures, freezing fog, or frost and other extreme conditions.

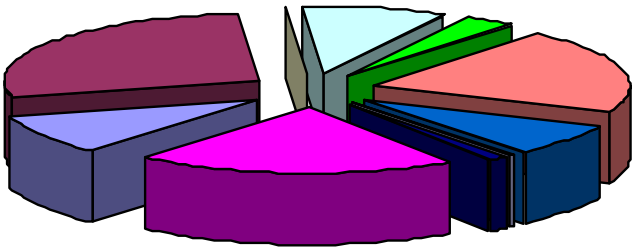
Adverse Environment – Customer interruptions due to equipment being subjected to abnormal environment such as salt spray, industrial contamination, humidity, corrosion, vibration, fire or flooding.

Human Element – Customer interruptions due to the interface of the utility staff with the system such as incorrect records, incorrect use of equipment, incorrect construction or installation, incorrect protection settings, switching errors, commissioning errors, deliberate damage or sabotage.

Foreign Interference – Customer interruptions beyond the control of the utility such as vehicle accidents, birds, animals, dig-ins, vandalism, sabotage and foreign objects.

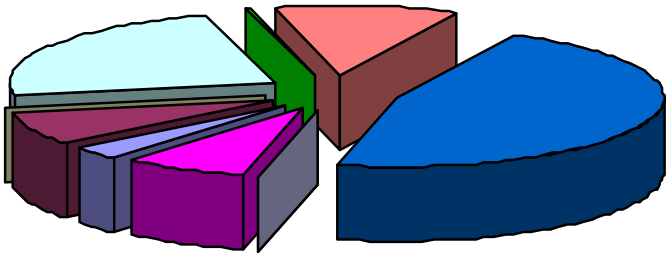
Pie charts showing the number of interruptions by cause, the Customer-Hours lost by cause and the Customer-Interruptions by cause are shown on the following pages. The results are also shown in tabular form.

2007 Reliability - Number of Interruptions by Cause

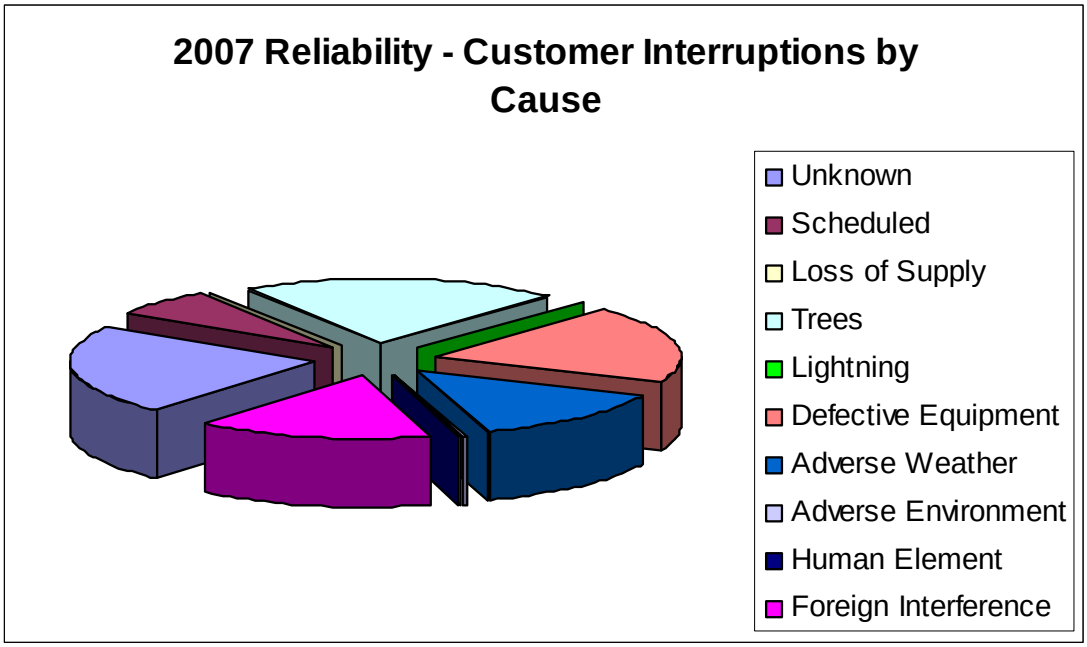


- Unknown
- Scheduled
- Loss of Supply
- Trees
- Lightning
- Defective Equipment
- Adverse Weather
- Adverse Environment
- Human Element
- Foreign Interference

2007 Reliability - Customer Hours Lost by Cause



- Unknown
- Scheduled
- Loss of Supply
- Trees
- Lightning
- Defective Equipment
- Adverse Weather
- Adverse Environment
- Human Element
- Foreign Interference



2007 Reliability by Cause

	Number of Interruptions	Customer-Hours Lost	Customer-Interruptions
Unknown	24	2174.8	19471
Scheduled	68	5771.5	5761
Loss of Supply	0	0	0
Trees	23	17549.2	17846
Lightning	8	243.7	159
Defective Equipment	50	8154.6	16520
Adverse Weather	19	33896.3	11793
Adverse Environment	1	1.9	1
Human Element	3	14.9	11
Foreign Interference	50	5587.2	13309
Total	**246**	**73394.1**	**84871**

The largest number of outages in 2007 fell into the scheduled category. This reflects our ongoing rebuild activities. Outages are required to replace existing equipment but it is better and more cost effective to do the replacements in a planned way rather than wait for failure.

The highest category as far as Customer-Hours lost in 2007 was adverse weather as a result of the ice storm in March, 2007. We can't control the weather but we are designing all new pole lines to meet the more rigorous structural requirements of the latest CSA standard for Overhead Systems.

The highest category as far as Customer-Interruptions in 2007 was unknown. This primarily relates to feeder lockouts lasting just over a minute. Feeder lockouts typically affect a few thousand customers each time.

Major Outages in 2007

Date	Cause	Customer Hours Lost	Details
March 1	Adverse weather	31,625	A severe ice storm in the area caused numerous outages. The triple circuit pole line on Franklin Boulevard between Bishop Street and Sheldon Drive came down in the storm.
Sept. 11	Trees	11,998	High winds and an electrical storm caused severe damage in the Main Street area of Galt.
Sept. 11	Trees	2,507	A tree limb fell into the 27.6kV line at the corner of Queenston and Argyle.
June 8	Foreign	1,916	A bird contact on Galt Avenue caused the Interference caused the 27.6kV 65M20 feeder to lock out.
June 19	Trees	1,822	A storm in the area resulted in a tree contact on the 4.16kV in the bush between Salisbury Avenue and Blenheim Road.
Feb. 21	Foreign interference	1,555	A transport truck hit a pole causing the 27.6kV 21M29 feeder to lock out.
Aug. 5	Defective equipment	1,285	A broken insulator at #64 Spruce Street resulted in a pole fire and the lockout of the 27.6kV 65M16 feeder.
June 19	Trees	973	A large tree limb broke and fell into a transformer pole on Peck Street causing the 27.6kV 65M16 feeder to lock out.
Oct. 26	Defective equipment	845	An underground primary burnoff caused an extended outage in the Hahn Avenue and Scott Road area.
Feb. 28	Defective equipment	808	A broken insulator on Roseville Road at Dickie Settlement Road caused the 27.6kV 21M27 feeder to lock out.
June 2	Defective equipment	772	A pair of 4.16kV insulators on Winter Avenue broke.
June 9	Trees	602	Storms in the area caused a tree to contact the lines on Speedsville Road resulting in the lockout of the 27.6kV 21M23 feeder.

Efforts to Make Improvements

2007 was not a good year for us as far as reliability provided to our customers. In March, 2007, we had a major outage where a section of poles fell down along Franklin Boulevard between Bishop Street and Sheldon Drive during an ice storm. This event resulted in the loss of 30,805 Customer-Hours. There was also a major wind storm in the Main Street area of Galt in September, 2007 which caused 11,998 Customer-Hours of outages. These two events represented over 58% of Customer-Hours lost in 2007.

We have ongoing maintenance programs and a sustained capital investment program to minimize as much as possible outages related to defective equipment. We have an ongoing equipment inspection program. We maintain loadbreak switches. We devote funds each year to pro-actively replace porcelain insulators which are subject to breakage. We install animal guards to reduce animal contacts. We invest in new poles, transformers and overhead/underground lines to replace aged plant. We install SCADA technology to reduce the length of outages.

We continue to have an ongoing tree trimming program. We can't, however, clear cut a swath wide enough to prevent trees from ever falling into overhead lines during storms. Trees are a part of the neighbourhoods where our lines are located.

Major improvements to the statistics outside our long term averages (other than better weather conditions) require increases in capital and/or operating spending (ie. reduce age of the system, have more resources available to respond to outages, increase SCADA level, more underground, etc.). Of course, there would be an impact on rates.

How we are doing so far in 2008?

To give an indication of how we are doing as far as reliability presently, here are the values for SAIFI, SAIDI and CAIDI as of the end of July, 2008. They are rolling 12 month numbers so data from the latter part of 2007 is still included in them.

SAIFI = 1.46
SAIDI = 0.82 Hours
CAIDI = 0.56 Hours

We are performing better so far in 2008.