CAMBRIDGE AND NORTH DUMFRIES HYDRO INC.

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

November 30, 2009

Mr. Michael Buonaguro
Counsel for VECC
Public Interest Advocacy Centre
34 King Street East, Suite 1102
Toronto, Ontario
M5C 2X8

Re: Cambridge and North Dumfries Hydro Inc.
Response to Vulnerable Energy Consumers Coalition (VECC) Interrogatories
2010 Electricity Distribution Rates, Board File EB-2009–0260.

Dear Mr. Buonaguro:

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 Vulnerable Energy Consumers Coalition Interrogatories in the above proceedings.

Sincerely,

CAMBRIDGE AND NORTH DUMFRIES HYDRO INC.

John W. Grotheer
President and CEO

c.c. All Intervenors
Board Secretary, Ontario Energy Board

CAMBRIDGE AND NORTH DUMFRIES HYDRO INC.

2010 RATE APPLICATION

EB-2009-0260

VECC'S INTERROGATORIES (ROUND #1)

GENERAL

Question #1

Reference: Exhibit 1, page 14

a) Please confirm that as well as the four high voltage transformer station delivery points described here, Cambridge and North Dumfries Hydro ("Cambridge") also receives power from a low voltage delivery point off Hydro One Networks distribution system (i.e,, Ayr PME per page 19). Is this one point, the only LV delivery point to Cambridge's system? If not, please describe the other points.

Response:

a) It is confirmed that the Ayr PME Low Voltage point described in Exhibit 1, page 19 is the only LV delivery point to the Cambridge system.

Question #2

Reference: Exhibit 1, page 22

a) Please describe more fully what the "street light maintenance coordination" service provided to Cambridge and North Dumfries Energy Solutions entails.

Response:

a) Street light maintenance coordination includes the following:
   - Taking residents' telephone calls and creating a trouble report
   - Giving the trouble reports to the Energy Solutions contractor
   - Providing contractor with assistance on circuitry issues
   - For safety regulation requirements, provide access to live point of supply locations
   - Coordinate annual wash and re-lamp contractor

- Coordinate underground contractor for major maintenance projects
- Identify and coordinate completion of long term maintenance of streetlight system

Question #3

Reference: Exhibit 1, page 28
Exhibit 2, page 10

a) Please provide the historical values for Cambridge's Service Reliability statistics for the period 2005-2007. Based on these results, what were the "minimum standards" for 2008?

Response:

a) Please refer to response to OEB Board Staff Interrogatory #7 (a) for Service Reliability statistics for the period 2005 to 2007. The minimum standards for 2008 are presented below.

Minimum Service Reliability Standard for 2008

	All Service Interruptions			**Service Interruptions excluding Loss of Supply (Cause Code 2)**		
	SAIDI	SAIFI	CAIDI	SAIDI	SAIFI	CAIDI
2008	0.93	1.08	0.69	0.93	1.08	0.69

Question #4

Reference: Exhibit 1, page 34

a) Please update the OM&A comparison for the 2008 data released by the Board in September 2009.

Response:

a) The updated OM&A comparison with the 2008 data released by the Board in September 2009 is presented below.

LDC Cohort Group	OM&A 2008
Oshawa PUC Networks Inc.	$ 170.01
Oakville Hydro Electricity Distribution Inc.	$ 163.14
Waterloo North Hydro Inc.	$ 177.14
Cambridge and North Dumfries Hydro Inc.	$ 184.20
Brantford Power Inc.	$ 205.32
Guelph Hydro Electric Systems Inc.	$ 206.70
Whitby Hydro Electric Corporation	$ 209.23
Burlington Hydro Inc.	$ 206.47
Average for Cohort Group	**$ 190.28**

Question #5

Reference: Exhibit 1, page 40

a) Please provide a schedule that sets out the 2010 revenues at existing rates by customer class, including the rates and volumes used. The rates used should: i) exclude the Smart Meter rate adder, ii) exclude the LV adder, and iii) allow for the discount due to Transformer ownership where applicable.

b) Please reconcile and differences between the total revenues calculated per part (a) and those reported on page 40.

Response:

a) The schedule requested that set out 2010 revenues at existing rates by customer class, including rates and volumes used is presented below.

Class	Annual kWh	Annual kW For Dx	Annualized Customers	Annualized Connections	Fixed Distribution Revenue	Variable Distribution Revenue	Dist. Rev. Including Transformer	Transformer Allowance	Dist. Rev. Excluding Transformer	Dist Rev At Existing Rates %	Dist Rev At Existing Rates Excl Embedded Distributor %
Residential	410,473,239		542,612		4,737,000	5,816,406	10,553,406		10,553,406	50.53%	50.678%
GS < 50 kW	177,148,264		54,978		674,581	2,315,328	2,989,909		2,989,909	14.32%	14.36%
GS >50	506,952,245	1,345,750	8,694		862,335	4,500,941	5,363,276	43,466	5,319,810	25.47%	25.55%
GS >1000 to 4999 kW	218,544,993	468,058	300		236,139	1,329,201	1,565,340	235,901	1,329,438	6.37%	6.38%
Large Users	159,305,102	301,094	24		105,186	547,110	652,296	180,657	471,639	2.26%	2.26%
Sentinel Lights											0.00%
Street Lighting	9,470,257	24,732		152,598	41,202	42,372	83,574		83,574	0.40%	0.40%
USL	2,997,302			6,082	37,285	39,175	76,460		76,460	0.37%	0.37%
Embedded Distributor		103,266	24		0	59,816	59,816		59,816	0.29%	0.00%
	1,484,891,402	**2,242,900**	**606,632**	**158,681**	**6,693,728**	**14,650,348**	**21,344,075**	**460,024**	**20,884,051**	**100%**	**100%**

b) There is no difference between the total revenues calculated per part (a) and the amount reported in Exhibit 1, page 40.

Question #6

Reference: Exhibit 1, page 60

a) Please outline Cambridge's Dividend Policy (i.e., how is the level of dividends paid annually to its shareholders determined?).

Response:

a) Cambridge and North Dumfries Hydro Inc. does not have a dividend policy but instead has a guideline that states: *"Each year after approval of the prior year's financial results, a dividend would be declared and paid to the holding company equivalent to 50% of audited net income."*

RATE BASE

Question #7

Reference: Exhibit 2, page 14

a) Please provide a schedule that set out the number of installed new services that is associated with the New Servicing expenditures in each year. Please include in the same schedule the Contributions each year that were associated with New Servicing.

Response:

a)

New Services

Year	New Services	Contributions
2006	740	$ 1,019,000
2007	221	$ 258,000
2008	276	$ 334,000
2009	535	$ 725,000
2010	690	$ 943,000

Question #8

Reference: Exhibit 2, pages 54, 65, 72 and 78

a) Do the disposals for Account #1820 reported for 2008 (page 54) represent the decommissioning of the Churchill St. substation (page 61)?

b) Page 72 makes reference to the decommissioning of 3 substations in 2009. However, there are no disposal costs reported on page 65. Please reconcile. Was the decommissioning of these substations included in the 2008 disposal?

c) There does not appear to be any disposal of land reported in 2008-2010.
- What happened to the land associated with the various decommissioned substations?
- If Cambridge still owns the land what are its plans for future use and/or disposition?
- Does the Application include property taxes on these properties for 2010?

Response:

a) The disposals for Account 1820 reported for 2008 represent the write off of the equipment at 5 stations. The equipment at Elgin St. North and Churchill Street were decommissioned in 2008 and were correctly accounted for. Unfortunately the equipment at Grand Avenue, Domms Lane and Wauchope Street that are being decommissioned in 2009 were incorrectly written off in 2008. The net impact is a loss on disposal of $23,938 was reported in 2008 instead of 2009.

b) See part (a).

c) The summary of land and building disposals is shown below:

Table	Year	Land	Buildings
18	2008	$ 72,119	-
21	2009	$ 61,721	$ 14,804
24	2010	$ 67,043	$ 8,723

The land associated with the various decommissioned substations is sold as soon as possible.

One or two of the properties will be sold in the first half of 2010 and property taxes of $4,500 are included in the application.

Question #9

Reference: i) Exhibit 2, pages 67 and 80
II) Exhibit 1, page 36

a) Reference (ii) states that Cambridge prioritizes its capital projects based on defined criteria on a relative basis. Please provide schedule that sets out the prioritized ranking for the capital projects planned for 2009 and 2010 respectively (see Reference (i)). In each case, please indicate the criteria used to establish the relative priority of the projects.

Response:

a) Capital projects are classified in five main categories with two of the categories subject to a relative priority determination.

1. Customer Driven Projects
   These projects are automatically allocated funding.

   Projects included in this category are as follows:

   2009
   Kossuth Road
   Boxwood Industrial Subdivision
   New Servicing – Residential
   - Industrial
   Revenue Metering – Instrumentation Transformers

   2010
   New Servicing – Residential
   - Industrial
   Revenue Metering – Instrumentation Transformers

2. Local Government/MTO Projects
   The projects are automatically allocated funding. They are generally road relocation projects.

   Projects included in this category are as follows:

   2009
   Seven Relocation Projects

   2010
   Five Relocation Projects

3. Government Ministry/Regulatory Requirements
   These projects are automatically allocated funding. They could include new Ministry of Energy programs, environmental matters, health and safety requirements and OEB/OPA/IESO requirements.

   Projects included in this category are as follows:

   2009

   Environmental Assessments
   Townline – North of 401 re: Long Term Load Transfers
   Trussler Road re: Long Term Load Transfers
   SCADA – ICCP Node Addition

   2010

   Environmental Assessments
   ERP Upgrade re: IFRS
   Safety Message Signage

4. Business Process Changes and Equipment Requirements
   These projects are evaluated on their merit and priority and based on multiple variables (age, external factors, security risk, productivity improvements, etc.).

   Projects included in this category are listed in order of highest priority as follows:

   2009

   CIS – Hardware, Conversion, Customization
   Firewall Replacement
   ESX Server Upgrade – Memory
   Upgrade SCADA W/S Software
   Annual Upgrade – Office
   Two Double Bucket Trucks
   New Engines – Tension Machines
   Server Upgrade – Active Directory
   Update Topbase and Licenses
   Hazard Hamlet Safety Unit
   MS Exchange Sewer
   Citrix – Licenses
   Hot Stick Ammeter
   House Jumper Cables
   O/H Fault Indicators
   Streetlight Software
   Grounding Mats
   Hydraulic Press/Dies
   Miller Transformer Lifter and Attachments
   Neutral Buster
   Fibre Optic Switches

Inverter – Truck #1 and 8
Oil Sprayer
HP Plotter Replacement
Replace Dump Body
Various Items Not Yet Identified / Miscellaneous

2010
CIS – Template Updating
IVR Software – collection calling
Microsoft Office Upgrades
Workstations and Renovations – New Staff
Redundancy – Disc Storage
Server Expansion, Memory
UPS Replacement
Load Flow Software
Replace Three Small Trucks
Switches for Storage Area Network
Printer Replacement
Hydraulic Attachment Tools
Paving Replacement
Various Items Not Yet Identified

5. Reliability/Refurbishment Requirements
   These projects are evaluated with respect to reliability and the priorities associated with a multi-year rebuild program. Reliability stats with respect to areas and feeders are compiled to establish priorities and the physical condition of the facilities that need to be replaced are ranked.

   Projects included in this category are listed in order of highest priority as follows:

2009
West Side Rebuild
Clyde Road
Porcelain SMD – 20 Replacements
Porcelain Insulator Replacements
Pole Replacements
Galt Core Upgrades
Miscellaneous Ties and Loadbreak Switches
Improvements – Preston TS Even Bus Feeders

2010
Plant Rebuild Township – Phase 1
Voltage Conversion Rebuilds

Galt Core Upgrades
SCADA Loadbreak Switches
Pole Replacements
Porcelain SMD – 20 Replacements
Porcelain Insulator Replacements
Miscellaneous Ties and Loadbreak Switches
Improvements – Preston TS Even Bus Feeders

Question #10

Reference: Exhibit 2, pages 63, 75 and 89

a) Please indicate the options considered for replacing the existing CIS and the reasons for selecting the approach chosen.

b) With respect to the proposed $200,000 in CIS upgrade spending for 2010 can Cambridge provide any further clarification as to what upgrades will be required and their associated cost. In responding please address the need for upgrades to address LEAP requirements in view of the Board's September 28, 2009 update on this initiative.

Response:

a) In June of 2006, Cambridge and North Dumfries Hydro Inc.'s CIS provider (Advanced Utility Systems) was acquired by Harris Computer System. In January of 2007, Harris announced that it would discontinue the Advanced CIS solution in Ontario effective December 31, 2008 and offer the Harris CIS solution as an alternative. In response to the announcement RFP's were issued to all CIS Vendors operating in the Ontario market. Eleven proposals were received offering the following CIS solutions:
   - COS
   - Daffron
   - Harris
   - SAP (SAP, IBM, Capgemini)
   - SPL (IBM)
   - H.T.E

   Each proposal was reviewed and rated based on functionality, understanding of market requirements, value for money, ability to meet timelines and overall implementation strategy. Based on the review Harris, SAP, SPL and H.T.E were shortlisted. The functionality offered by each of the short list vendor was compare to the 53 core functionalities of Cambridge and North Dumfries

Hydro Inc.'s existing CIS solution. SAP was the only vendor offering all of the core functionalities, plus additional functionalities not included in the Advanced System.

SAP system also offered future Enterprise Resource Planning (ERP) capabilities.

At the time of the evaluation, London Hydro was implementing SAP using Wipro as the system integrator. They offered Cambridge and North Dumfries Hydro Inc. the opportunity to implement SAP using the standard template that Wipro was implementing for London Hydro.

Considering the functionality offered by SAP, future ERP capability, the option to implement the standard template from London Hydro, value for money, the understanding of the market requirement and implementation strategy, SAP was selected. In the original proposal there were other system integrators for the SAP system. Based on price and the existing relationship with London Hydro, WIPRO was selected.

b) Please see response to OEB Board Staff Interrogatory #5 (b) (i).

Question #11

Reference: Exhibit 2, pages 92-93

a) What is the source of the $0.0607 / kWh value used for the Cost of Power?

b) Are any of Cambridge's retail customers registered as Market Participants and billed directly for commodity costs by the IESO?

c) If the response to part (b) is yes, what is their forecast use for 2009 and 2010 and has it been excluded from the calculation of the commodity cost used to determine the working capital allowance?

d) Please confirm that, based on Cambridge's proposed average cost of capital (5.2%), the 2010 return associated with working capital allowance is approximately $990,000, excluding tax implications. Based on the materiality of the figure, why didn't Cambridge undertake a lead lag study?

e) Please confirm that almost 2/3's of Cambridge's sales are to non-RPP customers (per Exhibit 9, page 10). If the $0.0607 value used for the commodity cost is based on the RPP price, please undertake the following:
    - Using the same source, estimate the commodity cost for non-RPP customers

- Estimate an average commodity cost for all sales based on the weighted average of the RPP and non-RPP forecast costs.
- Re-estimate the Total Commodity cost for 2010.

Response:

a) The source of the $0.0607 /kWh value used for the Cost of Power is from the Regulated Price Plan Report published by the OEB on April 15, 2009

b) None of Cambridge and North Dumfries Hydro Inc. retail customers are registered as Market Participant and billed directly for commodity costs by the IESO.

c) Not applicable.

d) Cambridge and North Dumfries Hydro Inc.'s proposed average cost of capital is 6.17%. As a result the 2010 return associated with the working capital allowance is $1,171,651. According to Chapter 2 of the Filing Requirements for Transmission and Distribution Applications issued by the OEB on May 27, 2009, under section 2.3.4 it states that the applicant may take two approaches to calculate its allowance for working capital (1) the 15% allowance approach, or (2) filing a lead-lag study. Cambridge and North Dumfries Hydro Inc. selected option (1).

   In addition, it is Cambridge and North Dumfries Hydro Inc.'s understanding that for those 2009 rebased/cost of service distributors that were a similar size to Cambridge the Board did not require the distributors to complete a lead lag study as a result of the significant cost of the study. As a result, Cambridge and North Dumfries Hydro Inc. did not believe it would be cost effective to conduct such a study for this application.

e) Cambridge and North Dumfries Hydro Inc. agrees that almost 2/3 of its sales are to non RPP customers as shown in Exhibit 9, page 10.

   The commodity costs for the RPP and non-RPP customers based on the price from the OEB Regulated Price Plan Report published on April 15th, 2009.

2010 Forecasted Loss Adjusted kWhs	2010			
	kWhs	Percentage	Price per kWh	Amount
kWhs for RPP Customer	521,709,790	34%	0.0607	31,667,784
kWhs for Non - RPP Customer	1,000,884,053	66%	0.05914	59,192,283
Total	**1,522,593,844**	**100%**		**90,860,067**

LOAD FORECAST & OPERATING REVENUE

Question #12

Reference: Exhibit 3, page 3

a) Please provide a schedule setting out the rates and volumes by customer class supporting the 2010 test year revenues reported here.

b) Please clarify whether the rates used in part (a) included:
   - Smart Meter charges
   - LV charges
   - Discounts for transformer ownership where applicable.

c) Please reconcile the 2010 revenues (both Other Operating Revenue and Distribution Revenue) reported here with the values in Exhibit 6/Tab 1/Schedule and Exhibit 8/Tab 1. Note: The latter two references suggest a 2010 Distribution Revenue of $29,734,912.

Response:

a) The rates and volumes by customer class supporting the 2010 test year revenues are presented below. There is a minimal difference of $9,871 between the schedule presented below and Exhibit 3, page 3 due to rounding.

Class	Annual kWh	Annual kW For Dx	Annualized Customers	Annualized Connections	Distribution Volumetric Rate Excluding LV	Fixed Distribution Rate Excluding Smart Meter Rate Adder	Fixed Distribution Revenue	Variable Distribution Revenue	Dist. Rev. Including Transformer	Transformer Allowance	Dist. Rev. Excluding Transformer
Residential	410,473,239	0	542,612	0	0.0158	9.75	5,290,464	6,485,477	11,775,941	0	11,775,941
GS < 50 kW	177,148,264	0	54,978	0	0.0130	12.22	671,833	2,302,927	2,974,760	0	2,974,760
GS >50	506,952,245	1,345,750	8,694	0	3.7157	110.30	958,923	5,000,402	5,959,326	43,466	5,915,859
GS >1000 to 4999 kW	218,544,993	468,058	300	0	3.1139	879.51	263,853	1,457,486	1,721,339	235,901	1,485,438
Large Users	159,305,102	301,094	24	0	1.7276	6,221.27	149,310	520,171	669,481	0	669,481
Sentinel Lights	0	0	0	0	0.0000	0.00	0	0	0	0	0
Street Lighting	9,470,257	24,732	0	152,598	7.2024	1.14	173,214	178,130	351,345	0	351,345
USL	1,855,931	0	0	6,082	0.0146	6.85	41,660	27,097	68,757	0	68,757
Embedded Distributor:									0		0
Waterloo North Hydro		76,261	12		0.9303	0.00	0	70,946	70,946		70,946
Hydro One Network		27,005	12		0.8712	0.00	0	23,527	23,527		23,527
	1,483,750,031	**2,242,900**	**606,632**	**158,681**			**7,549,258**	**16,066,163**	**23,615,421**	**279,368**	**23,336,053**

b) The rates used in part (a) does not include Smart Meter and Low Voltage charges but does include discounts for transformer ownership where applicable.

c) The total revenues net of transformer allowance of $24,958,934 presented in Exhibit 3, Table 1, page 3 equals the total revenue presented in Exhibit 6, Table 1, page 4 and the total service revenue presented in Exhibit 8, Table 1, page 1.

Cambridge and North Dumfries Hydro Inc. could not find any information in the latter two references to suggest 2010 Distribution Revenue of $29,734,912.

<u>Question #13</u>

Reference: Exhibit 3, pages 8-14

a) In its EB-2007-0680 Report (page 33) the Board directed Toronto Hydro to work with other parties to understand differences in load forecast methodologies employed. Has Cambridge had any discussions with Toronto Hydro regarding changes it may be implementing in its load forecast methodology? If yes, what was the outcome and how are they reflected in Cambridge's current approach?

b) Please provide an expanded version of Table 3 that includes historic and forecast annual values for population and GDP along with the associated year over year growth rates.

c) Is Cambridge aware of the fact that for its 2010 Rate Application (EB-2009-0139), Toronto Hydro has changed its load forecasting methodology to one that uses class specific models to forecast sales on a class specific basis? If yes, please comment as to why the Toronto data supports such analysis while (as discussed on page 9) Cambridge's data does not.

d) Please provide the various "models" tested for the Residential, GS<50 and GS > 1000-4999 classes and the associated statistical results in a format similar to that used on page 14 (line 8) and page 15 (line 1) for the proposed model.

e) If the models tested for Residential and GS<50 did not include the ones currently proposed by Toronto Hydro, please provide the statistical results of such models.

<u>Response:</u>

a) Cambridge and North Dumfries Hydro Inc. has not had any discussion with Toronto Hydro regarding changes it may be implementing in its load forecast methodology.

b) The expanded version of Table 3 requested is presented below.

Year	Billed (MWh)	Growth (MWh)	Percentage Change	Customer/ Connection Count	Growth	Percentage Change %	Annual Population	Percentage Change %	Real Ontario GDP	Percentage Change %
2003	1,486,260			56,533			124,284		127.3	
2004	1,528,292	42,032	2.83%	57,705	1,172	2.07%	127,428	2.53%	130.5	2.51%
2005	1,599,364	71,072	4.65%	58,591	886	1.54%	129,372	1.53%	134.0	2.68%
2006	1,561,103	-38,261	-2.39%	60,172	1,581	2.70%	131,460	1.61%	137.3	2.46%
2007	1,566,590	5,487	0.35%	61,209	1,038	1.72%	133,428	1.50%	140.3	2.18%
2008	1,518,626	-47,964	-3.06%	61,617	408	0.67%	134,532	0.83%	139.8	-0.36%
2009 (B)	1,488,745	-29,881	-1.97%	62,724	1,107	1.80%	135,576	0.78%	136.3	-2.50%
2010 (T)	1,483,750	-4,995	-0.34%	63,774	1,050	1.67%	136,572	0.73%	139.4	2.27%

c) Yes, Cambridge and North Dumfries Hydro Inc. is aware of the fact that for its 2010 Rate Application (EB-2009- 0139), Toronto Hydro has changed its load forecasting methodology to one that uses class specific models to forecast sales on a class specific basis. Cambridge and North Dumfries Hydro Inc. notes that it appears the Toronto Hydro model uses Purchased kWh Energy per day by customer class by month as the actual data which the regression analysis attempts to predict. In the case of Cambridge and North Dumfries Hydro Inc. Purchased kWh Energy per day by customer class by month is not available. As noted in response to OEB Staff IR 9 e) Cambridge and North Dumfries Hydro Inc. attempted to improve the load forecasting 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.

d) Excel models are attached to the submission.

e) Please see response to c).

Question #14

Reference: Exhibit 3, pages 14-19

a) What other regression models (using alternative explanatory variables) were tested? Please provide a description of each and a summary of the results similar to that shown on page 14.

b) Page 15 suggests that the negative coefficient for the Population variable is because this variable is also capturing the increasing effect of CDM. Has Cambridge tried any model specifications aimed a separating out the effect of CDM from what one would expect to be the positive correlation between power purchases and population? If yes, what models were tested and why were they rejected?

c) If the response to part (b) is no. please provide the results of a model formulation which includes the same explanatory variables as currently proposed by Cambridge and also includes a trend variable to capture CDM. Please provide the resulting statistics and a forecast for 2009 and 2010 based on the model.

d) With respect to page 16, if the data source for “population” does not provide monthly values, what is the frequency of the historical data and how were the monthly values established?

e) What was the source for the Population forecast used?

f) Please provide any other recent projections of Ontario GDP growth for 2009 and 2010 that Cambridge is aware of and compare the year over year growth rates with those prepared by the Ontario Ministry of Finance (per page 16).

g) With respect to the table on page 17 (Table 6), please calculate the predicted “weather normal” sales for 1996-2008 by using the “weather normal variables” as opposed to actual weather HDD and CDD values in the model.

h) Why has the 13-year weather normal average been used when the results are lower than either the 10 year or 20 year value?

i) Please comment on the appropriateness of using a 10 year value given that it is in the “middle” of the three results shown in Table 7.

j) How many years did the utilities Cambridge has cited (i.e., Toronto, Innisfil, Lakeland Power, Niagara-on-the-Lake and Thunder Bay) use for their definition of weather normal?

k) Why has Cambridge chosen the period 2004 – 2008 to determine average losses (page 19) when the analysis covered the period 1996-2008? What was the value for average losses over this longer period? If data is not available for this period, what were the average losses over the 2001-2008 period?

Response:

a) Please see response to OEB Board Staff Interrogatory # 9 (b), (c) and (e).

b) Cambridge and North Dumfries Hydro Inc. and North Dumfries Hydro Inc. has not tried any model specifications aimed a separating out the effect of CDM from what one would expect to be the positive correlation between power purchases and population.

c) Cambridge and North Dumfries Hydro Inc. has rerun the regression analysis and included a trend variable to capture CDM. The trend variable starts a 1 on January 2006 and grows to 60 by December 2010. The following table provides the resulting statistics and a forecast for 2009 and 2010.

Regression Statistics	Value
Multiple R	97.8%
R Square	95.7%
Adjusted R Square	95.4%
F- Test	407.4
T-Stats by Coefficient	
Intercept	(6.90)
Heating Degree Days	12.91
Cooling Degree Days	5.74
Ontario Real GDP Monthly %	4.07
Number of Days in Month	7.47
Spring Fall Flag	0.13
Population	2.01
Number of Peak Hours	8.78
CDM Flag	(6.83)
Purchased Forecast	
2009 (W N) - kWh	1,468,651,648
2010 (W N) - kWh	1,429,225,393

d) The historical population data was provided on an annual basis. The monthly values were established by assuming that the growth occurred evenly over the year, thus adding 1/12th of annual growth monthly.

e) The population data was provided by the City of Cambridge and the Region of Waterloo.

f) With regards to GDP, on October 22, 2009 the Ontario Minister of Finance provided a fall update to the 2009 Ontario Economic Outlook and Fiscal Review. In this review the 2009 GDP was updated from -2.5% to -3.5% and the 2010 GDP was updated from 2.3% to 2.0%.

Cambridge and North Dumfries Hydro Inc. is not aware of any other recent Ontario GDP growth for 2009 and 2010 other than the rates prepared by the Ontario Ministry of Finance.

g) The requested information is provided in the following table

Year	Actual Purchases (MWh)	Predicted (MWh)	Predicted Weather Normal (MWh)
1996	1,126,779	1,138,917	1,136,172
1997	1,202,822	1,206,940	1,207,768
1998	1,272,551	1,263,019	1,271,209
1999	1,350,815	1,345,889	1,343,656
2000	1,392,174	1,406,397	1,408,143
2001	1,420,978	1,445,535	1,448,034
2002	1,519,145	1,510,899	1,503,797
2003	1,523,718	1,518,554	1,515,248
2004	1,570,406	1,527,428	1,537,552
2005	1,640,989	1,604,512	1,594,295
2006	1,599,360	1,594,394	1,599,542
2007	1,609,194	1,635,584	1,633,125
2008	1,557,523	1,588,385	1,587,913
2009			1,527,719
2010			1,522,594

h) See response to OEB Board Staff Interrogatory #10.

i) It is Cambridge and North Dumfries Hydro Inc.'s understanding that the accuracy of the regression analysis improves when as much historical data is used in the regression analysis as possible. Cambridge and North Dumfries Hydro Inc. was able to include 13 years of data in the regression analysis and it is Cambridge and North Dumfries Hydro Inc. view it is appropriate to conduct the weather normalization analysis over the same period. As a result, Cambridge and North Dumfries Hydro Inc. does not believe it would be appropriate to use 13 years of data in the regression analysis and 10 years of data for weather normalization purposes.

j) Innisfil – 6 years
Lakeland Power – 7 years
Niagara-on-the-Lake – 12.25 years
Toronto - 10 years
Thunder Bay – 12 years

k) Cambridge has used an average loss factor calculated from 2004 to 2008 to be consistent with the number of years used in the calculation of the average loss factor shown in Exhibit 8, page 20. The data is not available to calculate the average loss factor from 1996-2008. The average loss factor over the period 2001-2008 was 1.034.

Question #15

Reference: Exhibit 3, pages 19-23

a) Please confirm that the forecasts of customer/connection count shown in Table 11 are mid-year values.

b) What is the most recent actual customer count for each class and on what month of 2009 are they based?

c) Please confirm that the calculation of the geometric mean annual growth rate in Table 13 really only considers the average use values for 2001 and 2008. If this is not the case, please explain more fully how the value is calculated.

d) Residential and GS<50 classes annual usage per customer values set out in Table 12 will be influenced weather in the year concerned.
   - Given this fact, please confirm that the calculated growth rates for these two classes will be affected by historical variations in weather.
   - Why is it appropriate to use the growth rate in usage per customer/connection (non weather-normalized) to forecast usage for 2008 and 2009?

e) Please provide the Hydro One information relied on in order to determine the weather sensitivity by rate class (page 22).

f) Given that residential uses include lighting, cooking and refrigeration, why is it reasonable to assume that the Residential class is 100% weather sensitive (per page 23)?

g) Please provide a schedule setting the average weather normalized use per customer for each class based on the data provided by Hydro One Networks for Cambridge's 2007 Cost Allocation filing and indicate the year the data is based on.

h) Please apply the same methodology as used by Cambridge to weather normalize 2010 usage and determine the weather normalized use by customer class for 2008 using the predicted total weather normalized purchases as determined in Question 14, part (g) and the actual non-weather normalized used by class for 2008. Please provide a schedule that sets out the results in terms of total weather normalized use by customer class and per customer weather normalized use by customer class for 2008.

l) Please re-do Tables 17 and 18 assuming that the Residential and GS<50 classes are 50% weather sensitive. Note: The purpose of this question is to test the sensitivity of the results to the assumptions regarding class weather sensitivity.

Response:

a) The customer count for 2009 shown in Exhibit 3, Table 11, page 20 are actual customer counts as at April 30, 2009, except for streetlight connections which are forecast at mid year. The 2010 customer counts shown are forecasted based as mid year values.

b) Please refer to response to Energy Probe Research Foundation (Energy Probe) Interrogatory 20 (d).

c) Cambridge and North Dumfries Hydro Inc. confirms that the calculation of the geometric mean annual growth rate in Table 13 really only considers the average use values for 2001 and 2008.

d) Cambridge and North Dumfries Hydro Inc. confirms that for the Residential and GS<50 classes the historical average use per customer will be influence by the weather conditions in the year concerned. Cambridge and North Dumfries Hydro Inc. also confirms the calculated growth rates for these two classes will be affected by historical variations in weather.

The growth rate in usage per customer/connection is used to forecast the usage per customer/connection for 2009 and 2010 which is used to determined the non weather-normalized forecast for 2009 and 2010. It is appropriate to use this growth rate since the non weather normalized forecast should reflect an expectation of usage per customer in the forecast period.

e) The Hydro One information relied on in order to determine the weather sensitivity by rate class is provided below:

General service >50kW to < 1000kW	**2004 kWh (Weather Corrected)**	**% Weather Sensitive**
Weather sensitive load	225,983,620	48%
Non-weather sensitive load	245,253,728	
TOTAL	471,237,348	
General service 1000kW to <5000kW	**2004 kWh (Weather Corrected)**	
Weather sensitive load	67,894,984	23%
Non-weather sensitive load	229,242,272	
TOTAL	297,137,255	

f) Cambridge and North Dumfries Hydro Inc. has assumed that 100% of Residential is weather sensitive based on Cambridge and North Dumfries Hydro Inc.'s understanding of the weather normalization process used by Hydro One to provide weather normalized load data for the cost allocation study.

The Hydro One data shows that for General Service >50kW to < 1000kW and General service 1000kW to <5000kW classes they have a certain percentage of load that is weather sensitive and non-weather sensitive as provided in response to i). The data also shows that for Large User, Street Lighting and USL the total actual weather amounts and the total normalized amounts are the same which suggest they are not weather sensitive. The data shows the classes that are partially weather sensitive and those that are 100% non-weather sensitive but the Residential and GS<50 loads did not fall into these two categories. As a result, Cambridge and North Dumfries Hydro Inc. concluded that Residential and GS<50 loads are 100% weather sensitive. If these classes were partially weather sensitive then Hydro One would have provided similar information as was provided for the General Service >50kW to < 1000kW and General service 1000kW to <5000kW classes.

g) The following table sets out the 2004 average weather normalized use per customer for each class based on the data provided by Hydro One Networks for Cambridge and North Dumfries Hydro Inc.'s 2007 Cost Allocation filing.

Residential class	9,104
General service <50kW	45,170
General service >50kW to < 1000kW	739,408
General service 1000kW to <5000kW	10,083,773
Large User >5000 kW	81,724,293
Streetlights	805
USL	7,102

h) The requested information is provided in the following table.

2008	Residential	General Service < 50 kW	General Service > 50 to 999 kW	General Service > 1000 to 4999 kW	General Service > 5000 kW	Street Lights	Unmetered Loads	Total
KWhs -weather normalized	400,587,691	176,098,392	477,031,368	251,826,433	230,297,755	9,448,890	2,112,232	1,547,402,761
Customer	43,558	4,500	677	28	3	12,393	458	61,617
KWhs -weather normalized/Customer	9,197	39,133	704,625	8,993,801	76,765,918	762	4,612	

i) The requested revised Tables 17 and 18 assuming that the Residential and GS<50 classes are 50% weather sensitive are provided below.

Table 17 - Alingment of Non- Normal to Weather Normal Forecast for 2009

Year	Residential	General Service < 50 kW	General Service > 50 to 999 kW	General Service > 1000 to 4999 kW	General Service > 5000 kW	Street Lights	Unmetered Loads	Total
Non - Normalized Weather Billed Forecast (MWh)								
2009	391,712	172,389	489,933	219,980	156,392	9,460	2,211	1,442,076
Adjustment for Weather								
2009	16,113	7,091	19,329	4,135	0	0	0	46,669
Weather Normalized Billed Forecast (MWh)								
2009	407,825	179,480	509,262	224,115	156,392	9,460	2,211	1,488,745

Table 18 - Alingment of Non- Normal to Weather Normal Forecast for 2010

Year	Residential	General Service < 50 kW	General Service > 50 to 999 kW	General Service > 1000 to 4999 kW	General Service > 5000 kW	Street Lights	Unmetered Loads	Total
Non - Normalized Weather Billed Forecast (MWh)								
2010	397,324	171,473	499,032	216,905	159,305	9,470	1,856	1,455,365
Adjustment for Weather								
2010	9,836	4,245	11,849	2,454	0	0	0	28,385
Weather Normalized Billed Forecast (MWh)								
2009	407,160	175,718	510,881	219,359	159,305	9,470	1,856	1,483,750

OPERATING COSTS

Question #16

Reference: Exhibit 4, page 9

a) Please provide a schedule that sets out the number of authorized positions as of year-end for 2006 – 2010 inclusive and identify the new positions added each year.

Response:

a) Authorized positions as at year end:

2006	85
2007	87
2008	89
2009	89
2010	94

New Positions added:

2007	Operations Contractor Supervisor Apprentice Lineman
2008	Manager, Regulatory Affairs Apprentice Lineman
2010	Engineering Technician Customer Care Clerk (2 positions) Billing/Collections Clerk Apprentice Lineman

Question #17

Reference: Exhibit 4, pages 10 and 37

a) With respect to Table 13, please confirm that the 5th row reports Customers per FTEEs (as opposed to FTEEs per customer).

b) The 2009 and 2010 values in Table 13 match those in Table 11 (Exhibit 3, page 20), when Street Lights and Unmetered Loads are excluded. However, the values in Table 13 for 2006-2008 don't similarly reconcile with the historic data shown in Table 9 (Exhibit 3, page 19). Please explain and revise Table 13 as necessary.

c) The current Table 13 shows that the number of Customers per FTEE is declining. Please reconcile this decline with the claim on page 10 that Cambridge has “contained its staff additions”.

d) What year were the base salary adjustments made for some management positions (per page 10, lines 19-21)?

Response:

a) Yes, Table 13, 5th row should say “Customers/FTEEs”.

b) Table 13 – OM&A Cost Per Customer and FTEE

OM&A Cost per Customer and FTEE					
Regulatory Cost Category	2006 Actual	2007 Actual	2008 Actual	2009 Bridge	2010 Test
Number of Customers	47,517	48,415	48,766	49,632	50,551
Total OM&A	$7,203,612	$8,426,112	$9,080,481	$9,546,042	$10,658,608
OM&A Cost per Customer	$ 149	$ 173	$ 185	$ 192	$ 211
Number of FTEEs	83.4	85.8	87.2	88.2	90.7
Customer/FTEEs	569	564	559	563	557
OM&A Cost per FTEE	$ 87,618	$ 99,454	$ 104,134	$ 108,231	$ 117,149

c) The updated Table 13 now shows that Cambridge and North Dumfries Hydro Inc. has contained its staff additions.

d) The base salary adjustments were made in 2008.

Question #18

Reference: Exhibit 4, pages 11 and 26

a) Please provide a schedule that sets out both the Capital and OM&A spending for 2009 and 2010 that is attributable to the GEGEA and the OPA's FIT and microFIT programs and included the Application's rate base and revenue requirement .

b) With respect to this increased spending, please identify the Capital (gross and net of contributions) as well as the OM&A spending specifically associated with the renewable generation (both connection and related system improvements). Is any of this spending eligible for "external funding" under Ontario Regulation 330/09?

Response:

a) Amounts attributed to the GEGEA and the OPA's FIT and microFIT Programs included in Application.

2009 OM&A - Nil

2009 Capital

A portion of Clyde Road rebuild relates to a biogas generation project. (Gross Cost $220,000)

2010 OM&A $ 114,750 - Staffing

Capital Nil

b) None

Question #19

Reference: Exhibit 4, page 20

a) A number of Ontario electricity distributors have recently purchased insurance to cover bad debts associated with commercial/industrial customers. Has Cambridge considered such insurance and, if so, why has it not opted for such a program?

Response:

a) We have reviewed the insurance products being offered with respect to bad debts. Our assessment indicated that the cost/benefit relationship did not warrant the expenditure, especially with the underlying restriction in the products.

Question #20

Reference: Exhibit 4, pages 24-25

a) Why is Cambridge proposing to amortize its forecast IFRS transition costs over four years as opposed to recording them in a deferral account per the Board's EB-2008-0408 Report (page 27) issued July 2009?

b) Please provide details regarding the forecast $100,000 in IFRS transition costs.

c) Given the Board's September 28, 2009 update regarding the Low Income Energy Assistance Program initiative:
   - Is the budgeted LEAP amount required for 2010? If yes, why?
   - Is the proposed 0.33 FTE addition required for 2010? If yes, why?
   - Are the software changes required for 2010 and, if so, why?

Response:

a) Based on the timing of the filing of the application and the OEB report, it was determined to continue with inclusion in the rate application. The process outline in Question 2 in the October OEB Frequently Asked Questions would apply.

b) The IFRS transition has four phases. Phase One – Scoping, Phase Two – Detailed Assessment, Phase Three – Design and Phase Four – Implementation.

We have completed the first two phases and have spent $44,000. It is estimated that the final two phases will be an additional $150,000 - $250,000.

We therefore plan to record the amounts beyond the $100,000 in the variance account 1508.

c) See response to OEB Board Staff Interrogatory #20 (a) (b) and (c).

Question #21

Reference: Exhibit 4, page 27

a) Table 11 shows an increase in OM&A costs over 2007 and 2008 of $119,000 related to theft of copper. Have these higher costs continued for the subsequent years? If so, what has Cambridge done to reduce such thefts? If not, why isn't there an offsetting reduction in subsequent years?

b) With respect to the "Inflation on Non-Labour Items & All Other Changes" driver, please identify the portion of the annual changes shown for 2007 through 2010 that is due to inflation versus other factors. Please provide a schedule which describes the other factors impacting on each of these years and note those that are one-time as opposed to ongoing factors.

Response:

a) Please see the response to OEB Staff Interrogatory 16 (c) and (d).

b) Please see the response to OEB Staff Interrogatory 19 (a), (b) and (c).

Question #22

Reference: Exhibit 4, page 45

a) Please explain further the $94,000 increase in 2010 attributed to "hosting fees" (lines 11-12).

b) Please indicate the FTE associated with the $57,000 increase in staffing costs associated with LEAP and monthly billing.

Response:

a) Our current CIS software runs on in-house computer resources. With the transfer to the new CIS software platform, we will be moving to a third party service that owns and operates the hardware as a host service for a fee.

b) The FTE is .8 for the new requirements.

Question #23

Reference: Exhibit 4, pages 48-49

a) Please indicate the total recruitment costs included in 2008, 2009 and 2010. Please also indicate the number of new staff recruited in each year.

Response:

a)

	2008	2009	2010
Recruitment Costs	$ 26,622	$ 10,000	$ 25,000
# of Positions Filled (including replacements)	7	3	6

Question #24

Reference: Exhibit 4, pages 68-69

a) Please explain what the "Board of Directors costs" are that CNDHI is paying CNDES and CNDEP for in 2009 and 2010 (e.g., which "Board" is cost for?). Why is CNDHI paying any costs associated with the Boards of its affiliates?

Response:

Please see response to Energy Probe Interrogatory #36 (c).

Question #25

Reference: Exhibit 4, pages 73 & 77

a) Page 73 states that prior to 2008 a full year's depreciation was taken on assets the first year they came into service. However, the schedule on page 77 suggests the ½ year rule was used for 2006. Please reconcile.

Response:

a) We have reviewed the data presented on page 77 and it reflects full year's depreciation.

Question #26

Reference: Exhibit 4, pages 80-83

a) Please explain why the total Depreciation for 2009 is different in Table 38 ($6,664,433) and Table 39 ($6,672,545). Similarly, please explain why the 2009 additions in the two tables differ for many of the individual accounts.

b) Please also address the issues raised in part (a) as they apply to 2010 (i.e., Tables 40 and 41)

Response:

a) The total depreciation for 2009 as outlined in Table 38 ($6,664,433) and Table 39 ($6,672,545) is different by $8,112. Depreciation on Table 39 is calculated in accordance with the OEB filing requirements (Appendix 2 – N), which assumes that all asset in a class is amortize over the same period. Also, Appendix 2-N does not include disposals in calculating depreciation.

The depreciation expense presented in Table 38 is calculated based on Cambridge and North Dumfries Hydro Inc. records which date back to over 25 years and includes assets that are amortized at different rates. The difference would include different building types, vehicle size and the historical records also include adjustments in depreciation amounts implemented by the Ontario Hydro accounting rules in the 1980's. Cambridge and North Dumfries Hydro Inc. also amortizes assets according to major category such as Distribution System Underground, Distribution System Overhead, Transformer etc.

In order to complete Table 38 these major categories had to be allocated to the different accounts. These issues contribute to the difference between Tables 38 and 39.

b) Please refer to the explanation provided in part a) for the difference between Tables 40 and 41.

Question #27

Reference: Exhibit 4, page 85

a) Do the tax rates used for 2010 reflect the May 2009 budget changes that, effective July 1, 2010, will reduce the small business tax to 4.5% and eliminate the small business deduction surtax? If not, please provide an updated tax calculation.

Response:

a) Please see response to Energy Probe Interrogatory #39 (a) and (b).

COST OF CAPITAL

Question #28

Reference: Exhibit 5, page 2

a) If Cambridge wanted to pay off the promissory note with Corporation of the Township of North Dumfries, is it able to do so without the agreement of the note holder? If no, what agreements are required and why?

b) If the note holder (i.e., the Corporation of the Township of North Dumfries) were to demand re-payment of the promissory note (or, Cambridge elected to pay-off the note), are there any impediments to Cambridge borrowing from a third party such as a commercial bank? For example, would it require the "guarantee" or "permission" of its shareholders to undertake such borrowing?

c) If the response to part (b) is yes, is there any reason to expect these impediments would prevent it from undertaking 3rd party borrowing? For example, if a "guarantee" was required from the shareholders, is there any reason to expect such a guarantee could not/would not be provided?

Response:

a) The note with the Corporation of the Township of North Dumfries can be repaid without the agreement of the note holder.

b) Based on the amount of the note, there are no impediments for replacement of the borrowing from a third party.

c) See (b) above.

REVENUE DEFICIENCY

Question #29

Reference: i) Exhibit 6, page 4

a) Please indicate where property taxes are captured in the Application.

b) Based on the responses to the first round of interrogatories from all parties please prepare a schedule that sets out all the adjustments/revisions that Cambridge has acknowledged as being required to the currently requested 2010 revenue requirement and the impact of each.

Response:

a) Property taxes are not broken down in Exhibit 6, page 4 based on the fact that some of the property taxes are included in burdens.

The property taxes for the transformer station are included in 5015.

The property taxes for the distribution stations are included in 5017.

The property taxes for the administrative and operations centre are embedded in variances burden accounts. These burden accounts are allocated to various cost centers and to capital projects.

b) The schedule below reflects all the adjustments Cambridge & North Dumfries Hydro Inc. acknowledges and is proposing to the currently requested 2010 revenue requirement and the impact of each.

Service Revenue Requirement Proposed in Rate Application				**24,958,934**
Changes from Interrogatory Process CNDHI are accepting:				
OEB, Q 20 a)	Reduce amount included for LEAP funding	(21,242)		
OEB Q 25	Reduction in capital tax expense as per calculation shown	(11,250)		
Ene. Probe, Q 40 a)	Change resulting from amount included for Apprenticeship Training Tax Credit	(4,968)		
Ene. Probe Q 41	Change resulting from adjustment to 2010 CCA Schedule	(128,660)	(166,120)	
Changes from Interrogatory Process CNDHI are Proposing:				
OEB Q 4	Change in amortization expense based on higher cost for ERP Software replacement (Increase from $650,000 to $1,000,000). Amortization increase from $65,000 to $100,000)	49,380		
VECC Q 14 c) & f)	Reduction in revenue requirement based on the updated Load Forecast CNDHI is proposing	(89,157)	(39,777)	(205,897)
Revised Service Revenue requirement CNDHI is proposing				**24,753,037**
Revenue Offset Proposed in Rate Application			**1,613,010**	
Changes from Interrogatory Process CNDHI are accepting:				
Ene. Probe, Q 24 a)	Forecasted Revenue from Retail Services and Transactions increase from $15,000 to $76,400. Thus increasing revenue offset	61,400		
Changes from Interrogatory Process CNDHI are Proposing:				
Ene. Probe Q 24 f)	Based on discontinuation of water and sewer billing in 2010 reduce revenue offset	(110,290)	(48,890)	1,564,120.00
Revised Base Revenue Requirement CNDHI is Proposing				**23,188,917.00**

Cambridge and North Dumfries Hydro Inc. is proposing an updated load forecast to reflect the new information highlighted in response to VECC question 14 part c and f. Based on the updated load forecast and the other adjustments presented in the table above, Cambridge and North Dumfries Hydro Inc. is presenting the following updates to the rate application.

- Cost of Power Amount
- Rate Base and Working Capital Allowance
- Revenue Deficiency
- Allocation of Proposed Revenue
- Rates Schedule
- Bill Impact
- Sheet O1 from the updated 2010 Cost Allocation Model.

Electricity - Commodity Class per Load Forecast	2010 Forecasted Metered kWhs	2010 Loss Factor	2010		
Residential	364,407,615	1.0262	373,947,619	$0.0607	$22,706,099
GS<50kW	157,267,686	1.0262	161,384,873	$0.0607	$9,799,289
GS>50kW	479,206,383	1.0262	491,751,759	$0.0607	$29,859,167
TOU	212,798,776	1.0262	218,369,738	$0.0607	$13,259,411
LU	159,305,102	1.0262	163,475,627	$0.0607	$9,926,240
ST.Light	9,470,257	1.0262	9,718,183	$0.0607	$590,088
Unmetered Scattered Load	1,855,931	1.0262	1,904,518	$0.0607	$115,642
TOTAL	**1,384,311,749**		**1,420,552,319**		**$86,255,937**

Transmission - Network Class per Load Forecast		Volume Metric	2010		
Residential		kWh	373,947,619	$0.0045	$1,664,254
GS<50kW		kWh	161,384,873	$0.0040	$651,430
GS>50kW		kW	1,272,096	$2.5866	$3,290,363
TOU		kW	455,751	$1.9645	$895,339
LU		kW	301,094	$1.8616	$560,503
ST.Light		kW	24,732	$1.2998	$32,146
Unmetered Scattered Load		kWh	1,904,518	$0.0040	$7,688
Embedded Distributor		kW	103,266	$1.8616	$192,235
TOTAL					**$7,293,957**

Transmission - Connection Class per Load Forecast		Volume Metric	2010		
Residential		kWh	373,947,619	$0.0032	$1,210,693
GS<50kW		kWh	161,384,873	$0.0030	$481,250
GS>50kW		kW	1,272,096	$1.8511	$2,354,720
TOU		kW	455,751	$1.4527	$662,091
LU		kW	301,094	$1.4788	$445,263
ST.Light		kW	24,732	$0.9302	$23,006
Unmetered Scattered Load		kWh	1,904,518	$0.0030	$5,679
Embedded Distributor		kW	103,266	$1.4788	$152,711
TOTAL					**$5,335,413**

Wholesale Market Service Class per Load Forecast			2010		
Residential			373,947,619	$0.0052	$1,944,528
GS<50kW			161,384,873	$0.0052	$839,201
GS>50kW			491,751,759	$0.0052	$2,557,109
TOU			218,369,738	$0.0052	$1,135,523
LU			163,475,627	$0.0052	$850,073
ST.Light			9,718,183	$0.0052	$50,535
Unmetered Scattered Load			1,904,518	$0.0052	$9,903
TOTAL					**$7,386,872**

Rural Rate Assistance Class per Load Forecast			2010		
Residential			373,947,619	$0.0013	$486,132
GS<50kW			161,384,873	$0.0013	$209,800
GS>50kW			491,751,759	$0.0013	$639,277
TOU			218,369,738	$0.0013	$283,881
LU			163,475,627	$0.0013	$212,518
ST.Light			9,718,183	$0.0013	$12,634
Unmetered Scattered Load			1,904,518	$0.0013	$2,476
TOTAL					**$1,846,718**

	2010	OEB Acct
4705-Power Purchased	$86,255,937	4705
4708-Charges-WMS	$7,386,872	4708
4714-Charges-NW	$7,293,957	4714
4716-Charges-CN	$5,335,413	4716
4730-Rural Rate Assistance	$1,846,718	4730
4750-Low Voltage	$84,252	4750
TOTAL	**108,203,149**	

WORKING CAPITAL ALLOWANCE FOR 2010

Distribution Expenses	
Distribution Expenses - Operation	2,872,659
Distribution Expenses - Maintenance	1,166,239
Billing and Collecting	1,447,594
Community Relations	46,969
Administrative and General Expenses	5,104,147
Taxes Other than Income Taxes	-
Less: Capital Taxes within 6105	
Total Eligible Distribution Expenses	**10,637,608**
Power Supply Expenses	108,203,149
Total Working Capital Expenses	118,840,757
Working Capital Allowance rate of 15%	17,826,114

RATE BASE CALCULATION FOR 2010

Fixed Assets Opening Balance 2010	85,829,334
Fixed Assets Closing Balance 2010	88,398,052
Average Fixed Asset Balance for 2010	87,113,693
Working Capital Allowance	17,826,114
Rate Base	104,939,807
Regulated Rate of Return	6.17%
Regulated Return on Capital	6,474,915
Deemed Interest Expense	3,112,644
Deemed Return on Equity	3,362,271

Cambridge and North Dumfries Hydro Inc.
Revenue Deficiency Determination

Description	2009 Bridge Actual	2010 Test Existing Rates	2010 Test - Required Revenue
Revenue			
Revenue Deficiency			**3,505,080**
Distribution Revenue	21,088,569	19,683,837	19,683,837
Other Operating Revenue (Net)	1,838,445	1,564,120	1,564,120
Smart Meter Deferral Account Adjustment			
Total Revenue	**22,927,014**	**21,247,957**	**24,753,037**
Costs and Expenses			
Administrative & General, Billing & Collecting	5,728,013	6,598,710	6,598,710
Operation & Maintenance	3,818,029	4,038,898	4,038,898
Depreciation & Amortization	6,409,679	6,525,738	6,525,738
Property Taxes	0	0	0
Capital Taxes	197,859	67,455	67,455
Deemed Interest	2,641,926	3,112,644	3,112,644
Total Costs and Expenses	**18,795,507**	**20,343,445**	**20,343,445**
Less OCT Included Above			
Total Costs and Expenses Net of OCT	**18,795,507**	**20,343,445**	**20,343,445**
Utility Income Before Income Taxes	**4,131,507**	**904,513**	**4,409,592**
Income Taxes:			
Corporate Income Taxes	1,124,571	(39,254)	1,047,321
Total Income Taxes	**1,124,571**	**(39,254)**	**1,047,321**
Utility Net Income	**3,006,936**	**943,767**	**3,362,271**
Capital Tax Expense Calculation:			
Total Rate Base	102,937,405	104,939,807	104,939,807
Exemption	15,000,000	15,000,000	15,000,000
Deemed Taxable Capital	**87,937,405**	**89,939,807**	**89,939,807**
Ontario Capital Tax	197,859	67,455	67,455
Income Tax Expense Calculation:			
Accounting Income	4,131,507	904,513	4,409,592
Tax Adjustments to Accounting Income	(723,717)	(1,031,138)	(1,031,138)
Taxable Income	**3,407,790**	**(126,626)**	**3,378,454**
Income Tax Expense	1,124,571	(39,254)	1,047,321
	33.00%	31.00%	31.00%
Actual Return on Rate Base:			
Rate Base	102,937,405	104,939,807	104,939,807
Interest Expense	2,641,926	3,112,644	3,112,644
Net Income	3,006,936	943,767	3,362,271
Total Actual Return on Rate Base	**5,648,863**	**4,056,411**	**6,474,915**
Actual Return on Rate Base	5.49%	3.87%	6.17%
Required Return on Rate Base:			
Rate Base	102,937,405	104,939,807	104,939,807
Return Rates:			
Return on Debt (Weighted)	4.99%	4.94%	4.94%
Return on Equity	9.00%	8.01%	8.01%
Deemed Interest Expense	2,739,441	3,112,644	3,112,644
Return On Equity	4,326,459	3,362,271	3,362,271
Total Return	**7,065,900**	**6,474,915**	**6,474,915**
Expected Return on Rate Base	6.86%	6.17%	6.17%
Revenue Deficiency After Tax	**1,417,038**	**2,418,505**	**(0)**
Revenue Deficiency Before Tax	**2,114,982**	**3,505,080**	**(0)**

Tax Exhibit	**2010**
Deemed Utility Income	3,362,271
Tax Adjustments to Accounting Income	(1,031,138)
Taxable Income prior to adjusting revenue to PILs	**2,331,133**
Tax Rate	31.00%
Total PILs before gross up	**722,651**
Grossed up PILs	**1,047,321**

Cost Allocation Based Calculations

Class	Distribution Revenue @ Existing Rate %	2010 Base Rev. Requirement Allocated as per Distrubtion @ Existing Rates	2010 EDR Miscellaneous Rev Allocation - Cost Allocation	Total Revenue Before Adjsutment for Rev/Cost Ratio	Revenue Requirment from Cost Allocation Study	Revenue Cost Ratios	Revenue Cost Ratios from Cost Allocation Model	Proposed Revenue Cost Ratios	Proposed Revenue	2010 EDR Miscellaneous Rev Allocation - Cost Allocation	2010 Revenue Assuming Proposed Revenue to Cost Ratios	Board Target Low	Board Target High
Residential	50.25%	11,651,543	983,846	$12,635,389	$12,420,029	101.73%	101.73%	101.73%	$12,635,389	$983,846	$11,651,543	85%	115%
GS < 50 kW	13.86%	3,212,871	201,719	$3,414,590	$2,683,464	127.25%	127.25%	113.80%	$3,053,715	$201,719	$2,851,996	80%	120%
GS >50	25.76%	5,973,491	226,379	$6,199,869	$5,402,095	114.77%	114.77%	113.80%	$6,147,447	$226,379	$5,921,069	80%	180%
GS >1000 to 4999 kW	6.60%	1,530,714	77,028	$1,607,742	$1,700,193	94.56%	94.56%	94.56%	$1,607,742	$77,028	$1,530,714	85%	115%
Large Users	2.39%	555,046	26,824	$581,870	$1,056,605	55.07%	55.07%	70.03%	$739,992	$26,824	$713,168	85%	115%
Street Lighting	0.42%	98,354	27,496	$125,850	$908,856	13.85%	13.85%	41.92%	$381,025	$27,496	$353,529	70%	120%
USL	0.31%	72,425	7,235	$79,660	$83,613	95.27%	95.27%	95.27%	$79,660	$7,235	$72,425	80%	120%
Embedded Distributor	0.41%	94,473	13,593	$108,067	$498,181	21.69%	21.69%	21.69%	$108,067	$13,593	$94,473	80%	120%
TOTAL	**100.00%**	**23,188,917**	**1,564,120**	**24,753,037**	**24,753,037**	100.00%			**$24,753,037**	$1,564,120	$23,188,917		

2010 TEST YEAR - BASE REVENUE DISTRIBUTION RATES

Customer Class	Connection	Customer	kW	kWh
Residential	0.00	10.27	0.0000	0.0167
GS < 50 kW	0.00	12.82	0.0000	0.0137
GS >50	0.00	115.71	3.8961	0.0000
GS >1000 to 4999 kW	0.00	926.33	3.2529	0.0000
Large Users	0.00	6,627.17	1.8403	0.0000
Sentinel Lights				
Street Lighting	1.14	0.00	7.2473	0.0000
USL	7.21	0.00	0.0000	0.0154
Embedded Distributor				

2010 TEST YEAR - Low Voltage Distribution Rates

Customer Class	Connection	Customer	kW	kWh
Residential				0.0001
GS < 50 kW				0.0000
GS >50			0.0303	
GS >1000 to 4999 kW			0.0238	
Large Users			0.0242	
Sentinel Lights				
Street Lighting			0.0152	
USL				0.0000
Embedded Distributor				0.0000

2010 TEST YEAR - Distribution Rates

Customer Class	Connection	Customer	kW	kWh
Residential	0.00	10.27	0.0000	0.0168
GS < 50 kW	0.00	12.82	0.0000	0.0137
GS >50	0.00	115.71	3.9264	0.0000
GS >1000 to 4999 kW	0.00	926.33	3.2767	0.0000
Large Users	0.00	6,627.17	1.8645	0.0000
Sentinel Lights				
Street Lighting	1.14	0.00	7.2625	0.0000
USL	7.21	0.00	0.0000	0.0154
Embedded Distributor	0.00	0.00	0.0000	0.0000

Transformer Ownership Credit (0.6000)

RESIDENTIAL

Consumption: 500 kWh	2009 BILL Volume	2009 BILL RATE $	2009 BILL CHARGE $	2010 BILL Volume	2010 BILL RATE $	2010 BILL CHARGE $	IMPACT $	IMPACT %	IMPACT % of Total Bill
Monthly Service Charge			8.73			10.27	1.54	17.64%	17.54%
Distribution (kWh)	500	0.0142	7.10	500	0.0168	8.40	1.30	18.31%	14.35%
Smart Meter Rider (per month)			1.00			1.00	0.00	0.00%	1.71%
LRAM & SSM Rider (kWh)	500			500	0.0000	0.00	0.00	0.00%	0.00%
Regulatory Assets (kWh)	500	0.0000	0.00	500	(0.0082)	(4.12)	(4.12)	100.00%	(7.03%)
Sub-Total			**16.83**			**15.55**	**(1.28)**	**(7.58%)**	**26.56%**
Other Charges (kWh)	521	0.0216	11.25	514	0.0212	10.90	(0.36)	(3.16%)	18.61%
Cost of Power Commodity (kWh)	521	0.0570	29.69	514	0.0570	29.31	(0.38)	(1.28%)	50.06%
Total Bill Before Taxes			**57.78**			**55.77**	**(2.01)**	**(3.48%)**	**95.24%**
GST		5.00%	2.89		5.00%	2.79	(0.10)	(3.48%)	4.76%
Total Bill			**60.67**			**58.55**	**(2.11)**	**(3.48%)**	**100.00%**

RESIDENTIAL

Consumption: 800 kWh	2009 BILL Volume	2009 BILL RATE $	2009 BILL CHARGE $	2010 BILL Volume	2010 BILL RATE $	2010 BILL CHARGE $	IMPACT $	IMPACT %	IMPACT % of Total Bill
Monthly Service Charge			8.73			10.27	1.54	17.64%	11.58%
Distribution (kWh)	800	0.0142	11.36	800	0.0168	13.44	2.08	18.31%	15.15%
Smart Meter Rider (per month)			1.00			1.00	0.00	0.00%	1.13%
LRAM & SSM Rider (kWh)	800			800	0.0000	0.00	0.00	0.00%	0.00%
Regulatory Assets (kWh)	800	0.0000	0.00	800	(0.0082)	(6.58)	(6.58)	100.00%	(7.42%)
Sub-Total			**21.09**			**18.13**	**(2.96)**	**(14.06%)**	**20.43%**
Other Charges (kWh)	834	0.0216	18.00	823	0.0212	17.43	(0.57)	(3.16%)	19.66%
Cost of Power Commodity (kWh)	834	0.0570	49.64	823	0.0570	48.92	(0.73)	(1.46%)	55.15%
Total Bill Before Taxes			**88.74**			**84.48**	**(4.26)**	**(4.80%)**	**95.24%**
GST		5.00%	4.44		5.00%	4.22	(0.21)	(4.80%)	4.76%
Total Bill			**93.17**			**88.70**	**(4.47)**	**(4.80%)**	**100.00%**

RESIDENTIAL

Consumption 1,500 kWh	2009 BILL Volume	2009 BILL RATE $	2009 BILL CHARGE $	2010 BILL Volume	2010 BILL RATE $	2010 BILL CHARGE $	IMPACT $	IMPACT %	IMPACT % of Total Bill
Monthly Service Charge			8.73			10.27	1.54	17.64%	6.38%
Distribution (kWh)	1,500	0.0142	21.30	1,500	0.0168	25.20	3.90	18.31%	15.66%
Smart Meter Rider (per month)			1.00			1.00	0.00	0.00%	0.62%
LRAM & SSM Rider (kWh)	1,500			1,500	0.0000	0.00	0.00	0.00%	0.00%
Regulatory Assets (kWh)	1,500	0.0000	0.00	1,500	(0.0082)	(12.35)	(12.35)	100.00%	(7.67%)
Sub-Total			**31.03**			**24.12**	**(6.91)**	**(22.26%)**	**14.99%**
Other Charges (kWh)	1,563	0.0216	33.76	1,543	0.0212	32.69	(1.07)	(3.16%)	20.32%
Cost of Power Commodity (kWh)	600	0.0570	34.20	600	0.0570	34.20	0.00	0.00%	21.25%
Cost of Power Commodity (kWh)	963	0.0660	63.55	943	0.0660	62.23	(1.32)	(2.08%)	38.67%
Total Bill Before Taxes			**162.54**			**153.24**	**(9.29)**	**(5.72%)**	**95.24%**
GST		5.00%	8.13		5.00%	7.66	(0.46)	(5.72%)	4.76%
Total Bill			**170.66**			**160.90**	**(9.76)**	**(5.72%)**	**100.00%**

GENERAL SERVICE < 50 kW

Consumption 2,000 kWh	2009 BILL Volume	2009 BILL RATE $	2009 BILL CHARGE $	2010 BILL Volume	2010 BILL RATE $	2010 BILL CHARGE $	IMPACT Change $	IMPACT Change %	IMPACT % of Total Bill
Monthly Service Charge			12.27			12.82	0.55	4.48%	6.15%
Distribution (kWh)	2,000	0.0131	26.20	2,000	0.0137	27.40	1.20	4.58%	13.13%
Smart Meter Rider (per month)			1.00			1.00	0.00	0.00%	0.48%
Regulatory Assets (kWh)	2,000	0.0000	0.00	2,000	(0.0069)	(13.78)	(13.78)	100.00%	(6.61%)
Sub-Total			**39.47**			**27.44**	**(12.03)**	**(30.48%)**	**13.15%**
Other Charges (kWh)	2,084	0.0209	43.55	2,057	0.0205	42.21	(1.34)	(3.08%)	20.23%
Cost of Power Commodity (kWh)	750	0.0570	42.75	750	0.0570	42.75	0.00	0.00%	20.49%
Cost of Power Commodity (kWh)	1,334	0.0660	88.03	1,307	0.0660	86.27	(1.76)	(2.00%)	41.36%
Total Bill Before Taxes			**213.80**			**198.67**	**(15.13)**	**(7.08%)**	**95.24%**
GST		5.00%	10.69		5.00%	9.93	(0.76)	(7.08%)	4.76%
Total Bill			**224.49**			**208.60**	**(15.89)**	**(7.08%)**	**100.00%**

General Services >50 to 999kW

Consumption
100,000 kWh
199 kW

	2009 BILL			2010 BILL			IMPACT		
	Volume	RATE $	CHARGE $	Volume	RATE $	CHARGE $	$	%	% of Total Bill
Monthly Service Charge			99.19			115.71	16.52	16.65%	1.22%
Distribution (kWh)	100,000	0.0000	0.00	100,000	0.0000	0.00	0.00	0.00%	0.00%
Distribution (kW)	199	3.3600	668.64	199	3.9264	781.35	112.71	16.86%	8.23%
Smart Meter Rider (per month)			1.00			1.00	0.00	0.00%	0.01%
Regulatory Assets (kW)	199	0.0000	0.00	199	(1.9883)	(395.68)	(395.68)	100.00%	(4.17%)
Sub-Total			**768.83**			**502.39**	**(266.44)**	**(34.66%)**	**5.29%**
Other Charges (kWh)	104,190	0.0135	1,406.57	102,857	0.0135	1,388.57	(18.00)	(1.28%)	14.62%
Other Charges (kW)	207	4.6717	968.62	205	4.4376	908.31	(60.31)	(6.23%)	9.56%
Cost of Power Commodity (kWh)	104,190	0.0607	6,326.42	102,857	0.0607	6,245.46	(80.96)	(1.28%)	65.76%
Total Bill Before Taxes			**9,470.43**			**9,044.73**	**(425.71)**	**(4.50%)**	**95.24%**
GST		5.00%	473.52		5.00%	452.24	(21.29)	(4.50%)	4.76%
Total Bill			**9,943.95**			**9,496.96**	**(446.99)**	**(4.50%)**	**100.00%**

General Services > 1,000 to 4,999kW

Consumption
500,000 kWh
1,500 kW

	2009 BILL			2010 BILL			IMPACT		
	Volume	RATE $	CHARGE $	Volume	RATE $	CHARGE $	$	%	% of Total Bill
Monthly Service Charge			787.13			926.33	139.20	17.68%	1.92%
Distribution (kWh)	500,000	0.0000	0.00	500,000	0.0000	0.00	0.00	0.00%	0.00%
Distribution (kW)	1,500	2.8507	4,276.05	1,500	3.2767	4,915.05	639.00	14.94%	10.20%
Smart Meter Rider (per month)			1.00			1.00	0.00	0.00%	0.00%
Regulatory Assets (kW)	1,500	0.0000	0.00	1,500	(2.2604)	(3,390.59)	(3,390.59)	100.00%	(7.04%)
Sub-Total			**5,064.18**			**2,451.79**	**(2,612.39)**	**(51.59%)**	**5.09%**
Other Charges (kWh)	520,950	0.0135	7,032.83	514,284	0.0135	6,942.83	(90.00)	(1.28%)	14.41%
Other Charges (kW)	1,563	3.6032	5,631.26	1,543	3.4173	5,272.35	(358.91)	(6.37%)	10.94%
Cost of Power Commodity (kWh)	520,950	0.0607	31,632.08	514,284	0.0607	31,227.30	(404.78)	(1.28%)	64.80%
Total Bill Before Taxes			**49,360.35**			**45,894.28**	**(3,466.07)**	**(7.02%)**	**95.24%**
GST		5.00%	2,468.02		5.00%	2,294.71	(173.30)	(7.02%)	4.76%
Total Bill			**51,828.37**			**48,188.99**	**(3,639.38)**	**(7.02%)**	**100.00%**

LARGE USER (> 5000 kW)

Consumption		2009 BILL			2010 BILL			IMPACT		
2,850,000 kWh 5,500 kW		Volume	RATE $	CHARGE $	Volume	RATE $	CHARGE $	$	%	% of Total Bill
	Monthly Service Charge			4,382.74			6,627.17	2,244.43	51.21%	2.72%
	Distribution (kWh)	2,850,000	0.0000	0.00	2,850,000	0.0000	0.00	0.00	0.00%	0.00%
	Distribution (kW)	5,500	1.8333	10,083.15	5,500	1.8645	10,254.75	171.60	1.70%	4.20%
	Smart Meter Rider (per month)			1.00			1.00	0.00	0.00%	0.00%
	Transformer Credit	5,500	(0.6000)	(3,300.00)	5,500		0.00	3,300.00	(100.00%)	0.00%
	Regulatory Assets (kW)	5,500	0.0000	0.00	5,500	(2.6166)	(14,391.51)	(14,391.51)	100.00%	(5.90%)
	Sub-Total			**11,166.89**			**2,491.41**	**(8,675.48)**	**(77.69%)**	**1.02%**
	Other Charges (kWh)	2,857,695	0.0135	38,578.88	2,850,741	0.0135	38,485.00	(93.88)	(0.24%)	15.77%
	Other Charges (kW)	5,515	3.5343	19,491.13	5,501	3.3404	18,376.80	(1,114.34)	(5.72%)	7.53%
	Cost of Power Commodity (kWh)	2,857,695	0.0607	173,519.24	2,850,741	0.0607	173,096.99	(422.25)	(0.24%)	70.92%
	Total Bill Before Taxes			**242,756.15**			**232,450.20**	**(10,305.94)**	**(4.25%)**	**95.24%**
	GST		5.00%	12,137.81		5.00%	11,622.51	(515.30)	(4.25%)	4.76%
	Total Bill			**254,893.95**			**244,072.71**	**(10,821.24)**	**(4.25%)**	**100.00%**

Sheet O1 Revenue to Cost Summary Worksheet - Second Run

Revenue, Cost Analysis, and Return on Rate Base

		1	2	3	4	6	7	9	10
	Total	Residential	GS <50 kW	GS >50 to 999kW	GS > 1,000 to 4,999kW	Large Use	Street Light	Unmetered Scattered Load	Embedded Distributor
Distribution Revenue (sale)	$23,188,917	$11,651,543	$3,212,871	$5,973,491	$1,530,714	$555,046	$98,354	$72,425	$94,473
Miscellaneous Revenue (mi)	$1,564,120	$983,846	$201,719	$226,379	$77,028	$26,824	$27,496	$7,235	$13,593
Total Revenue	$24,753,037	**$12,635,389**	**$3,414,590**	**$6,199,869**	**$1,607,742**	**$581,870**	**$125,850**	**$79,660**	**$108,067**
Expenses									
Distribution Costs (di)	$3,528,917	$1,640,635	$322,772	$798,200	$308,397	$215,064	$143,512	$12,410	$87,928
Customer Related Costs (cu)	$1,957,575	$1,239,753	$332,419	$319,481	$48,890	$2,019	$10,389	$4,597	$26
General and Administration (ad)	$5,151,116	$2,702,609	$614,094	$1,050,375	$335,686	$204,047	$145,382	$16,000	$82,924
Depreciation and Amortization (dep)	$6,525,738	$3,088,495	$659,693	$1,550,271	$479,953	$301,990	$266,410	$22,312	$156,615
PILs (INPUT)	$1,114,776	$550,586	$110,819	$247,312	$77,445	$48,982	$50,404	$4,156	$25,071
Interest	$3,112,644	$1,537,330	$309,427	$690,538	$216,240	$136,767	$140,736	$11,604	$70,002
Total Expenses	$21,390,766	**$10,759,408**	**$2,349,222**	**$4,656,177**	**$1,466,611**	**$908,869**	**$756,834**	**$71,079**	**$422,566**
Direct Allocation	$0	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**
Allocated Net Income (NI)	$3,362,271	$1,660,621	$334,242	$745,918	$233,582	$147,736	$152,023	$12,535	$75,616
Revenue Requirement (includes NI)	$24,753,037	$12,420,029	$2,683,464	$5,402,095	$1,700,193	$1,056,605	$908,856	$83,613	$498,181
	Revenue Requirement Input equals Output								
Rate Base Calculation									
Net Assets									
Distribution Plant - Gross	$177,691,116	$85,982,180	$17,887,850	$40,943,221	$12,609,099	$7,887,960	$7,620,730	$632,649	$4,127,427
General Plant - Gross	$11,169,311	$5,501,879	$1,112,175	$2,490,422	$778,124	$491,432	$501,614	$41,395	$252,271
Accumulated Depreciation	($88,326,009)	($41,961,919)	($8,989,395)	($21,017,478)	($6,383,371)	($3,956,036)	($3,607,341)	($301,453)	($2,109,016)
Capital Contribution	($13,420,725)	($6,501,004)	($1,350,172)	($3,086,464)	($951,317)	($595,453)	($577,187)	($47,899)	($311,228)
Total Net Plant	$87,113,693	**$43,021,136**	**$8,660,458**	**$19,329,700**	**$6,052,534**	**$3,827,904**	**$3,937,816**	**$324,691**	**$1,959,455**
Directly Allocated Net Fixed Assets	$0	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**
Cost of Power (COP)	$108,203,149	$28,357,272	$12,238,171	$37,290,620	$16,559,459	$12,396,717	$736,951	$144,424	$479,535
OM&A Expenses	$10,637,608	$5,582,997	$1,269,284	$2,168,055	$692,973	$421,129	$299,284	$33,007	$170,878
Directly Allocated Expenses	$0	$0	$0	$0	$0	$0	$0	$0	$0
Subtotal	*$118,840,757*	***$33,940,269***	***$13,507,455***	***$39,458,675***	***$17,252,432***	***$12,817,847***	***$1,036,235***	***$177,431***	***$650,413***
Working Capital	$17,826,114	**$5,091,040**	**$2,026,118**	**$5,918,801**	**$2,587,865**	**$1,922,677**	**$155,435**	**$26,615**	**$97,562**
Total Rate Base	$104,939,807	**$48,112,176**	**$10,686,576**	**$25,248,501**	**$8,640,399**	**$5,750,581**	**$4,093,251**	**$351,306**	**$2,057,017**
	Rate Base Input equals Output								
Equity Component of Rate Base	$41,975,923	**$19,244,871**	**$4,274,630**	**$10,099,400**	**$3,456,159**	**$2,300,232**	**$1,637,301**	**$140,522**	**$822,807**
Net Income on Allocated Assets	$3,362,271	**$1,875,981**	**$1,065,367**	**$1,543,693**	**$141,130**	**($326,999)**	**($630,984)**	**$8,581**	**($314,499)**
Net Income on Direct Allocation Assets	$0	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**
Net Income	$3,362,271	**$1,875,981**	**$1,065,367**	**$1,543,693**	**$141,130**	**($326,999)**	**($630,984)**	**$8,581**	**($314,499)**
RATIOS ANALYSIS									
REVENUE TO EXPENSES %	**100.00%**	101.73%	127.25%	114.77%	94.56%	55.07%	13.85%	95.27%	21.69%
EXISTING REVENUE MINUS ALLOCATED COSTS	**$0**	$215,361	$731,125	$797,775	($92,451)	($474,734)	($783,007)	($3,954)	($390,115)
RETURN ON EQUITY COMPONENT OF RATE BASE	8.01%	9.75%	24.92%	15.28%	4.08%	-14.22%	-38.54%	6.11%	-38.22%

COST ALLOCATION

Question #30

Reference: i) Exhibit 7, pages 2-3
ii) Cambridge's 2010 Cost Allocation Model Filing

a) With respect to Sheet O1 of Reference (ii), please explain the basis for the Distribution Revenues by customer class included at Row #18.

b) With respect to Reference (i), Table 2 please explain how the revenue by customer class for each of the following columns was derived and provide a schedule setting out the derivation:
- "2010 Serv Rev Requirement Allocated per Distribution @ Current Rates"
- "Total Revenue Before Adjustment for Rev/Cost Ratio"
- "2010 Revenue Assuming Proposed Revenue to Cost Ratio"

c) Also, with respect to Table 2, please explain why the values reported here for Revenue at Existing Rates are not the values used for Row #18 of the 2010 Cost Allocation Model filing.

d) What do the Revenue to Cost Ratios shown in the last column of Table 2 represent? They do not match either the current ratios per the Cost Allocation Model filing or the proposed ratios per Table 5.

Response:

a) The two O1 sheets shown in Exhibit 7 on page 9 and 10 are in accordance with the OEB filing requirements 2.8.3. Sheet O1 on page 9 is from the initial cost allocation model and Sheet O1 on page 10 is from the initial cost allocation model adjusted for transformer allowance. Sheet O1 from the updated 2010 cost allocation model is presented below.

Sheet O1 Revenue to Cost Summary Worksheet - Second Run

Revenue, Cost Analysis, and Return on Rate Base

		1	2	3	4	6	7	9	10
	Total	**Residential**	**GS <50 kW**	**GS >50 to 999kW**	**GS > 1,000 to 4,999kW**	**Large Use**	**Street Light**	**Unmetered Scattered Load**	**Embedded Distributor**
Distribution Revenue (sale)	**$23,345,924**	$11,783,482	$3,338,405	$5,939,872	$1,484,394	$526,612	$93,315	$85,371	$94,473
Miscellaneous Revenue (mi)	**$1,613,010**	$999,552	$205,096	$242,164	$82,232	$29,396	$32,458	$7,304	$14,808
Total Revenue	**$24,958,934**	**$12,783,034**	**$3,543,501**	**$6,182,036**	**$1,566,625**	**$556,008**	**$125,773**	**$92,675**	**$109,281**
Expenses									
Distribution Costs (di)	**$3,528,917**	$1,683,317	$333,421	$781,792	$293,626	$199,693	$143,356	$12,380	$81,330
Customer Related Costs (cu)	**$1,957,575**	$1,239,753	$332,419	$319,481	$48,890	$2,019	$10,389	$4,597	$26
General and Administration (ad)	**$5,172,116**	$2,754,015	$626,671	$1,039,084	$323,104	$190,370	$145,825	$16,037	$77,010
Depreciation and Amortization (dep)	**$6,490,738**	$3,140,351	$673,623	$1,510,315	$456,590	$279,621	$264,389	$22,098	$143,752
PILs (INPUT)	**$1,261,812**	$636,481	$128,602	$273,758	$83,631	$51,478	$57,023	$4,697	$26,143
Interest	**$3,147,670**	$1,587,741	$320,806	$682,907	$208,622	$128,414	$142,248	$11,716	$65,217
Total Expenses	**$21,558,828**	**$11,041,658**	**$2,415,542**	**$4,607,336**	**$1,414,463**	**$851,595**	**$763,230**	**$71,525**	**$393,479**
Direct Allocation	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**
Allocated Net Income (NI)	**$3,400,106**	$1,715,074	$346,534	$737,674	$225,353	$138,713	$153,656	$12,656	$70,447
Revenue Requirement (includes NI)	**$24,958,934**	$12,756,732	$2,762,076	$5,345,011	$1,639,816	$990,307	$916,886	$84,181	$463,926
	Revenue Requirement Input equals Output								
Rate Base Calculation									
Net Assets									
Distribution Plant - Gross	**$177,691,116**	$87,852,968	$18,346,784	$40,063,840	$12,046,329	$7,333,408	$7,612,334	$630,949	$3,804,503
General Plant - Gross	**$11,169,311**	$5,619,387	$1,140,306	$2,435,687	$742,496	$456,362	$501,323	$41,324	$232,427
Accumulated Depreciation	**($88,308,509)**	($42,883,726)	($9,221,468)	($20,572,217)	($6,104,496)	($3,681,366)	($3,600,484)	($300,254)	($1,944,499)
Capital Contribution	**($13,420,725)**	($6,642,295)	($1,384,784)	($3,020,084)	($908,794)	($553,554)	($576,569)	($47,773)	($286,871)
Total Net Plant	**$87,131,193**	**$43,946,334**	**$8,880,839**	**$18,907,225**	**$5,775,535**	**$3,554,851**	**$3,936,603**	**$324,246**	**$1,805,561**
Directly Allocated Net Fixed Assets	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**
Cost of Power (COP)	**$115,937,897**	$31,941,046	$13,784,823	$39,448,576	$17,006,116	$12,396,354	$736,930	$144,420	$479,634
OM&A Expenses	**$10,658,608**	$5,677,086	$1,292,511	$2,140,357	$665,620	$392,082	$299,571	$33,014	$158,367
Directly Allocated Expenses	**$0**	$0	$0	$0	$0	$0	$0	$0	$0
Subtotal	***$126,596,505***	***$37,618,131***	***$15,077,334***	***$41,588,933***	***$17,671,737***	***$12,788,436***	***$1,036,500***	***$177,434***	***$638,000***
Working Capital	**$18,989,476**	**$5,642,720**	**$2,261,600**	**$6,238,340**	**$2,650,760**	**$1,918,265**	**$155,475**	**$26,615**	**$95,700**
Total Rate Base	**$106,120,669**	**$49,589,053**	**$11,142,439**	**$25,145,565**	**$8,426,295**	**$5,473,116**	**$4,092,078**	**$350,861**	**$1,901,261**
	Rate Base Input equals Output								
Equity Component of Rate Base	**$42,448,268**	**$19,835,621**	**$4,456,976**	**$10,058,226**	**$3,370,518**	**$2,189,247**	**$1,636,831**	**$140,345**	**$760,504**
Net Income on Allocated Assets	**$3,400,106**	**$1,741,376**	**$1,127,959**	**$1,574,699**	**$152,163**	**($295,587)**	**($637,457)**	**$21,150**	**($284,198)**
Net Income on Direct Allocation Assets	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**
Net Income	**$3,400,106**	**$1,741,376**	**$1,127,959**	**$1,574,699**	**$152,163**	**($295,587)**	**($637,457)**	**$21,150**	**($284,198)**
RATIOS ANALYSIS									
REVENUE TO EXPENSES %	**100.00%**	100.21%	128.29%	115.66%	95.54%	56.14%	13.72%	110.09%	23.56%
EXISTING REVENUE MINUS ALLOCATED COSTS	**($0)**	$26,302	$781,425	$837,025	($73,190)	($434,299)	($791,113)	$8,494	($354,644)
RETURN ON EQUITY COMPONENT OF RATE BASE	8.01%	8.78%	25.31%	15.66%	4.51%	-13.50%	-38.94%	15.07%	-37.37%

b) “2010 Service Revenue Requirement Allocated per Distribution @ Current Rates” was derived by taking the base revenue requirement of $23,345,924 and allocating it to the different customer classes based on the percentage of distribution revenue at existing rates.

“Total Revenue before Adjustment for Rev/Cost Ratio” was derived by adding the “Service Revenue Requirement Allocated per Distribution @ Current Rates” and the 2010 EDR Miscellaneous Rev Allocation- Cost Allocation, which is from the cost allocation model.

“2010 Revenue Assuming Proposed Revenue to Cost Ratio” was derived by taking the revenue requirements for each customer class from the cost allocation model (O1 Revenue to cost/RR Row 35) multiplied by the revenue to cost ratio for each class. The ratio for each class is either from the cost allocation model (O1 Revenue to cost/RR Row 70) or has been adjusted by Cambridge and North Dumfries Hydro Inc. to ensure that the proposed revenue for each class is within the OEB target range.

The miscellaneous revenue for each class is subtracted from the amount derived from above to arrive at the “2010 Revenue Assuming Proposed Revenue to Cost Ratio” amount for each class. A table outlining the calculation for each of the categories discussed above is presented below.

Class	Distribution Revenue @ Existing Rate %	2010 Base Rev. Requirement Allocated as per Distrubtion @ Existing Rates	2010 EDR Miscellaneous Rev Allocation - Cost Allocation	Total Revenue Before Adjsutment for Rev/Cost Ratio	Revenue Requirment from Cost Allocation Study	Revenue Cost Ratios	Revenue Cost Ratios from Cost Allocation Model	Proposed Revenue Cost Ratios	Proposed Revenue	2010 EDR Miscellaneous Rev Allocation - Cost Allocation	2010 Revenue Assuming Proposed Revenue to Cost Ratios
Residential	50.51%	11,791,929	999,552	$12,791,481	$12,756,732	100.27%	100.21%	100.21%	$12,783,034	$999,552	$11,783,482
GS < 50 kW	14.31%	3,340,798	205,096	$3,545,894	$2,762,076	128.38%	128.29%	115.21%	$3,182,189	$205,096	$2,977,093
GS >50	25.46%	5,944,130	242,164	$6,186,294	$5,345,011	115.74%	115.66%	115.21%	$6,157,990	$242,164	$5,915,827
GS >1000 to 4999 kW	6.36%	1,485,458	82,232	$1,567,690	$1,639,816	95.60%	95.54%	95.60%	$1,567,690	$82,232	$1,485,458
Large Users	2.26%	526,989	29,396	$556,386	$990,307	56.18%	56.14%	70.57%	$698,885	$29,396	$669,488
Sentinel Lights	0.00%	0							$0	$0	$0
Street Lighting	0.40%	93,382	32,458	$125,840	$916,886	13.72%	13.72%	41.86%	$383,797	$32,458	$351,339
USL	0.29%	68,764	7,304	$76,068	$84,181	90.36%	110.09%	90.36%	$76,068	$7,304	$68,764
Embedded Distributor	0.40%	94,473	14,808	$109,281	$463,926	23.56%	23.56%	23.56%	$109,281	$14,808	$94,473
TOTAL	**100.00%**	**23,345,924**	**1,613,010**	**24,958,934**	**24,958,934**	100.00%			**$24,958,934**	$1,613,010	$23,345,924

c) The amount shown in table 2 for Revenue at Existing Rates is the Total Base Revenue Requirement allocated to the various rate class using the 2010 revenue at existing rate percentage. The value reported on table 2 per class is slightly different than the amount on row 18 of the 2010 cost allocation model. The percentage used in the allocation does not include an amount for embedded distributor.

d) The Revenue to Cost Ratios shown in the last column is the ratio for “Total Revenue before Adjustments for Rev/Cost to Revenue Requirement from Cost Allocation Study”. The ratios calculations are below.

Class	Total Revenue Before Adjsutment for Rev/Cost Ratio	Revenue Requirment from Cost Allocation Study	Revenue Cost Ratios
Residential	$12,791,481	$12,756,732	100.27%
GS < 50 kW	$3,545,894	$2,762,076	128.38%
GS >50	$6,186,294	$5,345,011	115.74%
GS >1000 to 4999 kW	$1,567,690	$1,639,816	95.60%
Large Users	$556,386	$990,307	56.18%
Sentinel Lights			
Street Lighting	$125,840	$916,886	13.72%
USL	$76,068	$84,181	90.36%
Embedded Distributor	$109,281	$463,926	23.56%
TOTAL	**$24,958,934**	**$24,958,934**	**100.00%**

The ratios that should have been shown in the last column of table 2 should have been the Proposed Revenue to Cost Ratios as shown in table 5.

Question #31

Reference: i) Exhibit 7, pages 4-6

a) With respect to Tables 3 and 4, neither Table contains all of the data used in the derivation. For example the following values appear to be missing:
- The values AK and S used to determine “Return on Assets”
- The value N used to determine PILS

Please provide a full version of the work sheets used to determine the costs for Waterloo North and Hydro One Networks.

b) How was the $2,798,058 OM&A costs associated with LV lines determined?

c) How were the asset values (original cost, accumulated depreciation and annual amortization) associated with the LV lines determined?

d) Please confirm that the proposed charges for embedded distributors do not include any recovery of:
- Billing and Collecting costs
- A&G costs
- General Plant related costs.

e) Please provide a schedule setting out an allocation of each of the cost elements referred to in part (d) to the embedded distributor class based on the allocation factors used in the Cost Allocation Model for each of these costs.

Response:

a) Please see response to OEB Board Staff Interrogatory #33 (a).

b) This amount is total annual OM&A costs of asset class providing LV services plus a administrative burden of 12%. The USoA account numbers that contain OM&A costs of asset class providing LV services are - 5020, 5025, 5030, 5095, 5005, 5010, 5120, 5125, 5135, 5035, 5160, 5105, 5040, 5045, 5050, 5090, 5145, 5150 and 5055.

c) In the model used to calculate the proposed LV charges an utilization factor is calculated. The utilization factor is (A) times (B) where:
(A) = Line length providing LV services (KM)/ Total line length (KM)
(B) = Annual billed Embedded Distributor demand on line providing LV services (kW or kVA)/ Annual billed total demand on line providing LV services (kW or kVA)

   In the case of Waterloo North Hydro the resulting utilization factor is 0.73%. The original cost associated with the LV lines is the utilization factor times the 2010 gross assets values included in accounts 1830, 1835, 1850, 1980, 1840 and, 1845. The accumulated depreciation associated with the LV lines is the utilization factor times the 2010 accumulated depreciation values for accounts 1830, 1835, 1850, 1980, 1840 and, 1845. The annual depreciation associated with the LV lines is the utilization factor times the 2010 depreciation values for accounts 1830, 1835, 1850, 1980, 1840 and, 1845.

d) The model used to calculate the proposed LV charges has be designed to account for billing and collecting costs, A&G costs and general plant costs associated with providing the LV service.

e) The follow sets for each of the cost elements referred to in part (d) the costs allocated to the embedded distributor class based on the allocation factors used in the Cost Allocation Model for each of these costs.

Billing and Collecting costs	$23
A&G costs	$77,010
General Plant related costs – NBV	$60,957

RATE DESIGN

Question #32

Reference: Exhibit 8, page 2

a) Please explain why the values reported in Table 2 for "2010 Base Revenue Allocation from Cost Allocation" don't match the values reported Sheet O1 of the 2010 Cost Allocation Model filing.

Response:

a) The heading "2010 Base Revenue from Cost Allocation" should have been "2010 Base Rev. Requirement Allocated as per Distribution Rev. @ Existing Rate". The amounts per customer class in this column would not match the values from Sheet O1 of the 2010 Cost Allocation Model as they are different. Please refer to Interrogatory 30 (b) for more detail.

Question #33

Reference: Exhibit 8, pages 3-4

a) Please provide a schedule that sets out the derivation of the revenue splits reported in Table 4.

b) Please confirm that the Board's EB-2007-0667 Guideline (page 12) sets the upper limit for the MSC at 120% of avoided costs plus the allocated customer costs (i.e., Minimum System plus PLCC Adjustment).

c) On page 4 Cambridge states that "an MSC ceiling has not been established". However, on page 3 Cambridge states that "the OEB indicated that for the time being, it does not expect distributors to make changes to the MSC that result in a charge that is greater than the ceiling as defined in the Methodology for the MSC". Please explain why the later direction from the OEB doesn't effectively establish a ceiling for those distributors whose MSC values are below the Board's upper limit.

Response:

a) Cambridge and North Dumfries Hydro Inc. derived the variable revenue split for each customer class by taking the 2010 variable revenue at existing rate less transformer allowance where applicable divided by the total revenue for the class. The remaining percentage revenue for each class is the fixed split.

Please refer to the schedule presented in question 5 (a) for the calculation of variable and fixed revenue split.

b) In the Report of the Board's EB-2007-0667 Application of Cost Allocation for Electricity Distributors it states the following under section 4.2.2. of the report

4.2.2 Upper Bound for the Monthly Service Charge
The Methodology set a ceiling for the MSC based on the avoided costs plus the allocated customer costs. The Discussion Paper proposed that the ceiling for the MSC be 120% of this level. Some participants believed that the results of the sensitivity analysis were not an appropriate basis for setting an upper bound.

The Board considers it to be inappropriate to make significant changes to the ceiling for the MSC at this time, given the number of issues that remain to be examined. The appropriateness of the methodologies cited above, used to set the MSC is an issue that will be examined within the scope of the Rate Review. The Rate Review will also examine the role of rate design in achieving various objectives, including conservation of energy. Both of these undertakings will have determinative impacts on the fixed/variable ratio policy. In the interim, the Board does not expect distributors to make changes to the MSC that result in a charge that is greater than the ceiling as defined in the Methodology for the MSC. Distributors that are currently above this value are not required to make changes to their current MSC to bring it to or below this level at this time.

Based on the above and specifically the statement in the second paragraph in italic suggests to Cambridge and North Dumfries Hydro Inc. that the Board has not yet established a ceiling for the MSC. It would appear to Cambridge and North Dumfries Hydro Inc. that the issue of the appropriate ceiling and related issue of the proper fixed/variable split is still under review. In addition, consider the Board has approved MSC in recent rate application that are above the MSC reference above also suggest to Cambridge and North Dumfries Hydro Inc. that a ceiling for the MSC has not yet been established.

c) Please see response to (b).

<u>Question #34</u>

Reference: Exhibit 8, page 9

a) What is the basis for the Hydro One Networks' rates used on page 9?

<u>Response:</u>

The Hydro One Network rates used on Exhibit 8, page 9 are from Hydro One invoices from May 2008 to April 2009. The rates used to estimate the 2010 costs are from the 2009 Hydro One invoices.

<u>DEFERRAL/VARIANCE ACCOUNTS</u>

<u>Question #35</u> (Corrected to #35)

Reference: Exhibit 9,

a) With respect to page 6, why is the 2008 interest on the Account 1590 positive ($55,640) when the opening balance and the transactions for the year are negative?

<u>Response:</u>

a) The interest for Account 1590 for 2008 is positive because an adjustment to correct the life to date carrying costs for the account was included in 2008 which results in a positive amount.