3240 Mavis Road
Mississauga, ON
L5C 3K1
Tel: (905) 273-9050
Fax:(905) 566-2737

September 22, 2009

Ms. Kirsten Walli
Board Secretary
Ontario Energy Board
2300 Yonge St., Suite 2700
Toronto, ON, M4P 1E4

Dear Ms. Walli:

Re: Enersource Hydro Mississauga Inc. 2010 Electricity Distribution Rate Application – EB-2009-0193 –Responses to Interrogatories

Please find enclosed responses to interrogatories of the Board Staff and the intervenors in the above-captioned proceeding.

A confidential version of Enersource's responses to Vulnerable Energy Consumers Coalition (VECC) interrogatory #3, sub-parts (c) and (d), is being filed under separate cover, as the responses contain information that is commercially sensitive.

Sincerely,

Original signed by

Gia M. DeJulio
Director, Regulatory Affairs
gdejulio@enersource.com
905-283-4098

c.c.: George Vegh, McCarthy Tétrault
Intervenors in EB-2009-0193

Attach.

Response to Interrogatory from
Board Staff

Reference: Tab B Page 4 Paragraph 11

Question:

Enersource Hydro Mississauga ("Enersource") proposes that the price escalator, the Canada Gross Domestic Product Implicit Price Index (the GDP-IPI) be updated with data for the period October 2008 to September 2009 (3rd quarter) for rates to be effective January 1, 2010. Enersource believes that this update should be available in a reasonable amount of time to issue a rate order.

Historically the Board has updated the annual GDP-IPI after February month end for rates effective May 1, two months prior to the effective date.

a) Board staff expects that the availability of data for October 2008 to September 2009 will be at the beginning of December 2009. On what basis does Enersource believe this is a reasonable amount of time?

b) Does Enersource have any contingency plan should a decision and order not be available prior to January 1, 2010?

c) Has Enersource considered any other alternative periods (i.e. July 2008 to June 2009, 2nd Quarter 2009) for the calculation of the price escalator, and any financial impacts?

Response:

a) Enersource believes that its proposed timeline is reasonable and will allow the calculation of the final rates for implementation on January 1, 2010. This belief is based on Enersource's understanding from Statistics Canada that the data is available by the middle of November and the assumption that the Board would be able to process the data by early December. However, if it is found that time is insufficient, Enersource is amenable to using twelve months of data ending June 30, 2009.

b) Should a decision and order not be available prior to January 1, 2010, Enersource will request the Board to follow its standard practice when a decision is released after the effective date of a rate order, namely, to seek an interim order of the Board to maintain the current rates pending such decision and order of the Board. If the application is approved, Enersource will draft a rate order that captures the change in rates between the implementation date January 1, 2010 and the actual date that Enersource is able to commence a rate change.

c) Please see the response in part a) above for the alternative period considered and Tab I, Exhibit 6.2, part e) for the financial impacts.
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Response to Interrogatory from
Board Staff

Reference: Tab B Page 4 Paragraph 11

Question:

Enersource has not included in its Manager's summary any proposal for the potential change in their stretch factor as included in the calculation of the Price Cap Index. Currently the Board includes in IRM applications a proxy stretch factor of Group II or 0.4%. The 2010 benchmarking exercise and assignment of stretch factors has not been completed as of the date of these interrogatories and may not be available before January 1, 2010.

a) How does Enersource propose the Board consider handling changes to stretch factors for decisions and orders issued post January 1, 2010 should such an event occur?

Response:

If changes to stretch factors occur post January 1, 2010, Enersource recommends using a formulaic application at the time of any such changes that will result in a revised determination of Enersource's price escalator, with an effective start date of January 1, 2010.

Response to Interrogatory from
Board Staff

Reference: Tab B Page 4 Paragraphs 12 thru 16

Question:

By Enersource requesting the updated 2009 3rd quarter resultant price cap index (PCI) being applied as 8/12's (eight twelve's), the applicant in essence proposes that the 2009 PCI of 1.18% essentially continue for the "overlap" period of January 1, 2010 to April 30, 2010. For the subsequent year 2011, Board staff understands that Enersource proposes to apply the full increment of the 2010 3rd quarter resultant PCI. This proposal could constructively result in the overlap period of the 2009 3rd quarter PCI being eliminated. The consequences of such elimination could be financially harmful either to the customer or to the shareholder.

a) *Would Enersource please confirm or clarify Board staff's understanding?*

b) *If correct, would Enersource agree that the potential for financial harm resulting from overlap elimination exists in their proposed methodology? Please explain why or why not.*

c) *Has Enersource considered as an alternative reversing 4/12's (four twelve's) of the 2009 PCI of 1.18% and applying the full value of the 2009 3rd quarter PCI? What would be the effect of such an alternative?*

d) *Has Enersource considered as an alternative applying the sum of the last three quarters (March, June and September 2009) PCI's divided by three and then applying 8/12's? What would be the effect of such an alternative?*

e) *Would Enersource's shareholders consider compensating their customers for any negative impacts of an overlap inequity should that event occur? Should a materiality level be set?*

f) *Should Enersource's shareholders be compensated if the impact of any overlap inequity favours the customer? Should a materiality level be set?*

Response:

a) In Tab B, Attachment 1 Enersource has calculated the impact of its proposal and determined the change to be financially neutral to the customer and to the shareholder. Only if there are significant changes to the PCI between October and December 2009, would the rate change requested be financially harmful to the customer or shareholder.

b) Enersource believes that any financial harm resulting from the overlap period will be immaterial because there are no significant changes to the PCI anticipated between October and December 2009.

c) Enersource did not consider reversing the 2009 PCI of 1.18%, since the 2009 PCI was for the 2009 rate year. The $4/12^{ths}$ of the 2010 PCI was proposed to be reversed since Enersource is applying for 2010 rates. Enersource believes that the $4/12^{ths}$ of the 2009 PCI should not be reversed since any over collection relates to the 2010 PCI and not the 2009 PCI. Enersource's proposal, as presented in Tab B, Attachment 1, is financially neutral to the customer and to the shareholder because the rate change will occur on January 1, 2010 and the amount returned to customers relates to the 2010 PCI change.

d) Enersource did not consider this alternative. The effect of applying the sum of the last three quarters' (March, June and September 2009) PCIs divided by three and then applying 8/12's to the 2010 rates will be equivalent to Enersource's proposal, i.e., the change will be financially neutral to the customer and the shareholder.

e) and f) Enersource is willing to compensate either the customer or the shareholder for any negative impact of an overlap inequity that might occur. Enersource believes that any overlap inequity will be immaterial because there are no significant changes to the PCI anticipated between October and December 2009. Enersource is open to setting a materiality level.

Response to Interrogatory from
Board Staff

Reference: IRM3 Rate Generator Sheet" C3.1 Curr Low Voltage Vol Rt"

Question:

For the 2010 IRM process, as outlined in Chapter 3 of the Board's "Filing Requirements for Transmission and Distribution Applications" (the "Filing Requirements") issued July 22nd, 2009, applicants are required to identify their Low Voltage rate adder included in their re-based cost of service application. Further these rates are to be identified separately on their 2010 Tariff of Rates and Charges.

a) Enersource has not entered any Low Voltage rate adders in the above noted input sheet. Please provide the rate adders as applied in the applicant's re-based cost of service application (EB-2007-0706).

b) If Enersource does not have any Low Voltage rate adders, please explain why not? Please include any documented evidence to support non-existence of rate adders.

c) If Enersource does not in fact have Low Voltage rate adders as evidenced by question 2 above, does Enersource wish to apply for Low Voltage rates?

Response:

a) Please see Tab I, Exhibit 1.4, Attachment A (EB-2007-0706 Exhibit H, Schedule 2, Tab 3, Page 1 UPDATED) for the approved rate adders in Enersource's 2008 cost of service proceeding which includes the amount of $252,886 for low voltage charges.

b) As indicated in part a) above, Enersource included in the 2008 COS application (EB-2007-0706) the low voltage charges as a rate adder. The adder was effective from May 1, 2008 to April 30, 2009. In the 2009 3rd GIRM proceeding (EB-2008-0171), Enersource did not include recovery of any low voltage charges through a rate adder given the limitations of the 3rd GIRM model. Please see Tab I, Exhibit 1.4, Attachment B (Appendix A of the EB-2008-0171 Decision and Order dated March 16, 2009) and Tab I, Exhibit 1.4, Attachment C (EB-2008-0171 Summary of Model) Changes) which show that Board-approved Tariff of Rates and Charges for Enersource effective May 1, 2009 did not include any low voltage rate adder.

c) Yes, Enersource wishes to apply for the full 2009 low voltage rate adder and 8/12^{ths} of the 2010 low voltage rate adder which will be added to the final rates and charges. The calculation of these rate adders are shown in Tab I, Exhibit 1.4, Attachment D.

DERIVATION OF PROPOSED RATE RIDERS FOR 2008 TEST YEAR (000's)

		Note 1								Note 1	Note 1					Note 2	Note 2		Note 3	Note 3	
	Allocation to Customer Classes %	Allocation to Customer Classes by Customer numbers	Allocation to Customer Classes %	Allocation to Customer Classes % for LRAM	Allocation to Customer Classes % for SSM	Ontario Price Credit Admin Costs	Large Corporation Tax Over Recovery	Deferred OEB Costs (Jan. 1, 2005 to Apr. 30, 2006)	OMERS Pension Deferral (Jan. 1, 2005 to Apr. 30, 2006)	Interest on Regulatory Assets (based on kWhs)	Interest on Regulatory Assets (based on no. of customers)	RSVA Balances returned to customers (as at Dec.31, 2006)	Sub-Total before Low Voltage	LV Charges for 2008 Test Year	Sub-Total Including Low Voltage	LRAM to April 30, 2007	SSM to April 30, 2007	Total to be recovered over 1 year	kWh Forecast 2008	kW Forecast 2008	Proposed Rate Riders
	Total for customer class as % of Total for all classes	Total for customer count as % of Total for all classes	Basis for Allocation: Retail transmission connection rate multiplied by volume	Total kWh savings per class / Total kWh savings	Total kWh savings per class / Total kWh savings	$ 23.1	$ (30.5)	$ 1,121.7	$ 1,613.1	$ 877.7	$ 659.7	$ (11,286.0)	$ (7,021.1)	$ 252.9	$ (6,768.2)	$ 331.9	$ 823.9	$ (5,612.5)			
RESIDENTIAL	35.82%	87.50%	22.32%	97.96%	56.57%	$ 8.3	$ (10.9)	$ 401.8	$ 577.8	$ 314.4	$ 577.3	$ (4,042.6)	$ (2,174.0)	$ 56.4	$ (2,117.6)	$ 325.2	$ 466.9	$ (1,325.5)	1,594,768,347		$ (0.0008)
General Service < 50 kW	13.82%	8.43%	8.41%	1.76%	0.12%	$ 3.2	$ (4.2)	$ 155.1	$ 223.0	$ 121.3	$ 55.6	$ (1,560.1)	$ (1,006.1)	$ 21.3	$ (984.8)	$ 5.9	$ 1.0	$ (978.0)	657,014,642		$ (0.0015)
Small Commercial	0.78%	1.72%	0.15%	0.00%	0.00%	$ 0.2	$ (0.2)	$ 8.8	$ 12.6	$ 6.9	$ 11.4	$ (88.5)	$ (48.8)	$ 0.4	$ (48.4)	$ -	$ -	$ (48.4)	11,905,567		$ (0.0041)
General Service 50 kW - 499 kW	28.85%	2.09%	32.86%	0.19%	1.87%	$ 6.7	$ (8.8)	$ 323.7	$ 465.4	$ 253.2	$ 13.8	$ (3,256.4)	$ (2,202.4)	$ 83.1	$ (2,119.3)	$ 0.6	$ 15.4	$ (2,103.3)		6,418,332	$ (0.3277)
General Service 500 kW - 4999 k	14.55%	0.25%	26.61%	0.09%	26.75%	$ 3.4	$ (4.4)	$ 163.3	$ 234.8	$ 127.7	$ 1.6	$ (1,642.7)	$ (1,116.3)	$ 67.3	$ (1,049.0)	$ 0.3	$ 220.4	$ (828.3)		5,310,121	$ (0.1560)
Large Use (> 5000 kW)	5.69%	0.00%	9.21%	0.00%	14.59%	$ 1.3	$ (1.7)	$ 63.8	$ 91.7	$ 49.9	$ 0.0	$ (641.8)	$ (436.7)	$ 23.3	$ (413.4)	$ -	$ 120.2	$ (293.3)		1,720,956	$ (0.1704)
Street Lighting	0.48%	0.00%	0.43%	0.00%	0.00%	$ 0.1	$ (0.1)	$ 5.4	$ 7.7	$ 4.2	$ 0.0	$ (54.0)	$ (36.7)	$ 1.1	$ (35.7)	$ -	$ -	$ (35.7)		115,190	$ (0.3096)
TOTALS	100.00%	100.00%	100.00%	100.00%	100.00%	$ 23.1	$ (30.5)	$ 1,121.7	$ 1,613.1	$ 877.7	$ 659.7	$ (11,286.0)	$ (7,021.1)	$ 252.9	$ (6,768.2)	$ 331.9	$ 823.9	$ (5,612.5)			

Notes to track from 2008 Rates Application filed August 23, 2007 to final proposed Settlement Agreement filed March 28, 2008:

Note 1: See interrogatory question and responses from: i) SEC #45 Clarification Interrogatory (second round) and ii) JTA #22 Technical Conference Interrogatories (third round).

Note 2: See interrogatory question and responses from: i) CCC #18 Interrogatories (first round) and ii) Board Staff #20 Clarification Interrogatory (second round) which includes calculations of LRAM (net of free riders) and SSM (excluding PILs gross-up).

Note 3: See interrogatory questions and responses from: i) Board Staff #20 Interrogatory (first round) which references Exhibit B/Schedule 2/Tab 2.1 and ii) JTA #22 Technical Conference Interrogatories (third round) as per settlement agreement projected CDM savings were eliminated from 2008 units calculation.

EB-2009-0193
Tab I
Exhibit 1.4
Attachment A

Appendix A

To Decision and Order

EB-2008-0171

March 16, 2009

Enersource Hydro Mississauga Inc.
TARIFF OF RATES AND CHARGES
Effective May 1, 2009

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

EB-2008-0171

APPLICATION

- The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Codes, Guidelines or Orders of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule.
- No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code, Guideline or Order of the Board, and amendments thereto as approved by the Board, or as specified herein.
- This schedule does not contain any rates and charges relating to the electricity commodity (e.g. the Regulated Price Plan).

EFFECTIVE DATES

DISTRIBUTION RATES – May 1, 2009 for all consumption or deemed consumption services used on or after that date.
SPECIFIC SERVICE CHARGES – May 1, 2009 for all charges incurred by customers on or after that date.
RETAIL SERVICE CHARGES – May 1, 2009 for all charges incurred by retailers or customers on or after that date.
LOSS FACTOR ADJUSTMENT – May 1, 2009 unless the distributor is not capable of prorating changed loss factors jointly with distribution rates. In that case, the revised loss factors will be implemented upon the first subsequent billing for each billing cycle.

SERVICE CLASSIFICATIONS

Residential
This classification refers to all residential services including, without limitation, single family or single unit dwellings, multi-family dwellings, row-type dwellings and subdivision developments. Energy is supplied in single phase, 3-wire, or three phase, 4-wire, having a nominal voltage of 120/240 Volts. There shall be only one delivery point to a dwelling.

General Service Less Than 50 kW
This classification refers to a non-residential account whose monthly average peak demand is less than, or is forecast to be less than, 50 kW.

Small Commercial and Unmetered Scattered Load
This classification applies to an account taking electricity at 750 volts or less whose average monthly maximum demand is less than, or is forecast to be less than, 50 kW and the consumption is either metered or unmetered. While this customer class includes existing metered customers, metered customers are no longer added to this customer class. The amount of electricity consumed by unmetered connections will be based on detailed information/documentation provided by the device's manufacturer and will be agreed to by Enersource Hydro Mississauga Inc. and the customer and may be subject to periodic monitoring of actual consumption. Eligible unmetered loads include cable TV power packs, bus shelters, telephone booths, traffic lights, railway crossings.

General Service 50 to 499 kW
This classification refers to a non-residential account whose monthly average peak demand is equal to or greater than, or is forecast to be equal to or greater than, 50 kW but less than 500 kW.

General Service 500 to 4,999 kW
This classification refers to a non-residential account whose monthly average peak demand is equal to or greater than, or is forecast to be equal to or greater than, 500 kW but less than 5,000 kW.

Large Use
This classification refers to an account whose monthly average peak demand is equal to or greater than, or is forecast to be equal to or greater than, 5,000 kW.

Standby Distribution Service
This classification refers to an account that requires Enersource Hydro Mississauga to provide distribution service on a standby basis as a back-up supply to an on-site generator.

Enersource Hydro Mississauga Inc.
TARIFF OF RATES AND CHARGES
Effective May 1, 2009

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

EB-2008-0171

Street Lighting
This classification refers to an account for roadway lighting. Street Lighting is unmetered where energy consumption is estimated based on the connected wattage and calculated hours of use using methods established by the Ontario Energy Board.

MONTHLY RATES AND CHARGES

Residential

Service Charge	$	13.14
Distribution Volumetric Rate	$/kWh	0.0118
Retail Transmission Rate – Network Service Rate	$/kWh	0.0060
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	0.0054
Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0013
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

General Service Less Than 50 kW

Service Charge	$	40.85
Distribution Volumetric Rate	$/kWh	0.0115
Retail Transmission Rate – Network Service Rate	$/kWh	0.0055
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	0.0050
Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0013
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

Small Commercial and Unmetered Scattered Load

Service Charge for metered account	$	11.97
Service Charge for Unmetered Scattered Load account (per connection)	$	10.56
Distribution Volumetric Rate	$/kWh	0.0193
Retail Transmission Rate – Network Service Rate	$/kWh	0.0055
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	0.0050
Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0013
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

General Service 50 to 499 kW

Service Charge	$	70.42
Distribution Volumetric Rate	$/kW	4.1527
Distribution Volumetric Tax Change Rate Rider – effective until April 30, 2010	$/kW	(0.0029)
Retail Transmission Rate – Network Service Rate	$/kW	2.1454
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	1.9392
Retail Transmission Rate – Network Service Rate – Interval Metered	$/kW	2.1454
Retail Transmission Rate – Line and Transformation Connection Service Rate – Interval Metered	$/kW	1.9392
Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0013
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

Enersource Hydro Mississauga Inc.
TARIFF OF RATES AND CHARGES
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EB-2008-0171

General Service 500 to 4,999 kW

Service Charge	$	1,520.79
Distribution Volumetric Rate	$/kW	2.0724
Distribution Volumetric Tax Change Rate Rider – effective until April 30, 2010	$/kW	(0.0023)
Retail Transmission Rate – Network Service Rate – Interval Metered	$/kW	2.0756
Retail Transmission Rate – Line and Transformation Connection Service Rate – Interval Metered	$/kW	1.8975
Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0013
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

Large Use

Service Charge	$	13,688.11
Distribution Volumetric Rate	$/kW	2.8866
Distribution Volumetric Tax Change Rate Rider – effective until April 30, 2010	$/kW	(0.0023)
Retail Transmission Rate – Network Service Rate – Interval Metered	$/kW	2.2149
Retail Transmission Rate – Line and Transformation Connection Service Rate – Interval Metered	$/kW	2.0266
Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0013
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

Standby Distribution Service

A Standby Service Charge will be applied for a month where standby power is not provided. The applicable rate is the approved Distribution Volumetric Rate of the applicable service class and is applied to gross metered demand or contracted amount, whichever is greater. A monthly administration charge of $200, for simple metering arrangements, or $500, for complex metering arrangements, will also be applied. Further servicing details are available in Enersource Hydro's Conditions of Service.

Street Lighting

Service Charge (per connection)	$	1.33
Distribution Volumetric Rate	$/kW	10.1327
Distribution Volumetric Tax Change Rate Rider – effective until April 30, 2010	$/kW	(0.0105)
Retail Transmission Rate – Network Service Rate	$/kW	1.4857
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	1.4022
Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0013
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

Specific Service Charges

Customer Administration		
Arrears Certificate	$	15.00
Request for other billing information	$	15.00
Credit reference/credit check (plus credit agency costs)	$	15.00
Credit reference/credit check (plus credit agency costs – General Service)	$	25.00
Income tax letter	$	15.00
Returned cheque (plus bank charges)	$	12.50
Account set up charge/change of occupancy charge (plus credit agency costs if applicable)	$	30.00
Account set up charge/change of occupancy charge (plus credit agency costs if applicable – Residential)	$	20.00
Meter dispute charge plus Measurement Canada fees (if meter found correct)	$	10.00
Special meter reads	$	30.00
Interval meter request change	$	40.00

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EB-2008-0171

Non-Payment of Account		
Late Payment - per month	%	1.50
Late Payment - per annum	%	19.56
Collection of account charge – no disconnection	$	9.00
Disconnect/Reconnect at meter - during regular hours	$	20.00
Disconnect/Reconnect at pole - during regular hours	$	185.00
Disconnect/Reconnect at pole - after regular hours	$	415.00
Temporary service install and remove – overhead – no transformer	$	400.00
Specific Charge for Access to the Power Poles – per pole/year	$	22.35
Allowances		
Transformer Allowance for Ownership - per kW of billing demand/month	$/kW	(0.40)
Primary Metering Allowance for transformer losses – applied to measured demand and energy	%	(1.00)

Retail Service Charges (if applicable)

Retail Service Charges refer to services provided by a distributor to retailers or customers related to the supply of competitive electricity

One-time charge, per retailer, to establish the service agreement between the distributor and the retailer	$	100.00
Monthly Fixed Charge, per retailer	$	20.00
Monthly Variable Charge, per customer, per retailer	$/cust.	0.50
Distributor-consolidated billing charge, per customer, per retailer	$/cust.	0.30
Retailer-consolidated billing credit, per customer, per retailer	$/cust.	(0.30)
Service Transaction Requests (STR)		
Request fee, per request, applied to the requesting party	$	0.25
Processing fee, per request, applied to the requesting party	$	0.50
Request for customer information as outlined in Section 10.6.3 and Chapter 11 of the Retail Settlement Code directly to retailers and customers, if not delivered electronically through the Electronic Business Transaction (EBT) system, applied to the requesting party		
Up to twice a year		no charge
More than twice a year, per request (plus incremental delivery costs)	$	2.00

LOSS FACTORS

Total Loss Factor – Secondary Metered Customer < 5,000 kW	1.0360
Total Loss Factor – Secondary Metered Customer > 5,000 kW	1.0145
Total Loss Factor – Primary Metered Customer < 5,000 kW	1.0256
Total Loss Factor – Primary Metered Customer > 5,000 kW	1.0045

Summary of Model Changes
Enersource Hydro Mississauga Inc. (“Enersource”)
EB-2008-0171

In addition to the changes made to the rate models to reflect the elements of the Decision, the following changes were made to correct what appeared to be errors and omissions following a review of Enersource’s 2008 Board-approved Tariff of Rates and Charges.

Rate Generator

Ref.: Sheet J2.5, Cells G31-37

- The proposed tax sharing rate riders were corrected to reflect the new figures provided by Enersource in response to Board staff interrogatory #2. The new figures are as follows:

Residential	$(0.000017)
General Service < 50 kW	$(0.000014)
Small Commercial	$(0.000034)
General Service 50 kW – 499 kW	$(0.002923)
General Service 500 kW – 4999 kW	$(0.002308)
Large Use (> 5000 kW)	$(0.002346)
Street Lighting	$(0.010518)

These figures were then rounded to the fourth decimal place before being incorporated in the 2009 Tariff of Rates and Charges.

Ref.: Sheet N3.1, Cell D25

- Entry (total loss factor for primary metered customers with demand greater than 5,000 kW) was changed to 1.0045 from 1.0444, consistent with Enersource’s reply to Board staff interrogatory #3.

Enersource Hydro Mississauga

DERIVATION OF PROPOSED LOW VOLTAGE RATE ADDERS FOR 2009 & 2010 (000's)

	Allocation to Customer Classes % (Based on 2008 COS)	LV Charges for 2009 3rd GIRM	LV Charges for 2010 3rd GIRM	Load Forecast 2009 3rd GIRM (kWh)	Load Forecast 2009 3rd GIRM (kW)	Load Forecast 2010 3rd GIRM (kWh)	Load Forecast 2010 3rd GIRM (kW)	LV Rate Adder 2009	LV Rate Adder 2010 (8/12 ths) May 1 - Dec. 31, 2010 (see note below)	Proposed 2010 LV Rate Adder
	Basis for Allocation: Retail transmission connection rate multiplied by volume	**$ 252.9**	**$ 252.9**							
RESIDENTIAL	22.32%	$ 56.4	$ 56.4	1,594,788,347		1,579,606,433		$ 0.000035	$ 0.000024	$ 0.000059
General Service < 50 kW	8.41%	$ 21.3	$ 21.3	657,014,642		666,537,466		$ 0.000032	$ 0.000021	$ 0.000054
Small Commercial	0.15%	$ 0.4	$ 0.4	11,905,587		11,701,517		$ 0.000033	$ 0.000022	$ 0.000055
General Service 50 kW - 499 kW	32.86%	$ 83.1	$ 83.1		6,418,332		6,347,165	$ 0.012947	$ 0.008728	$ 0.021676
General Service 500 kW - 4999 kW	26.61%	$ 67.3	$ 67.3		5,310,121		5,107,408	$ 0.012674	$ 0.008784	$ 0.021458
Large Use (> 5000 kW)	9.21%	$ 23.3	$ 23.3		1,720,956		1,847,558	$ 0.013535	$ 0.008405	$ 0.021941
Street Lighting	0.43%	$ 1.1	$ 1.1		115,190		115,695	$ 0.009365	$ 0.006216	$ 0.015582
TOTALS	**100.00%**	**$ 252.9**	**$ 252.9**							

Note - Enersource proposes to give back 4/12 ths of the 2010 LV Rate Adder for period January 1 - April 30, 2010

Response to Interrogatory from
Board Staff

Reference: *Tab B Page 4 Paragraphs 12 thru 16*

Question:

Enersource submits that, pursuant to the Settlement Agreement from its 2008 Cost of Service Rate Application, EB-2007-0706, negotiated among the intervenors of record and Enersource, and which was approved by the Board on January 4, 2008, all parties agreed on the current customer class cost allocation ratios.

a) Has Enersource examined the revenue cost ratio adjustments proposed in the 2010 IRM Supplemental Filing module in respect to the adjustment to Transformer Ownership Allowance ("TOA") and the impact to affected customers?

b) If the application of the TOA adjustment is found to be significant, would Enersource entertain an opportunity to adjust current customer class cost allocation?

Response:

a) and b) Since the 2008 cost of service proceeding (EB-2007-0706), Enersource has not examined the revenue to cost ratios with respect to the Transformer Ownership Allowance. Please also refer to the response in Tab I, Exhibit 2.3.

Response to Interrogatory from
Board Staff

Reference: Deferral and Variance Account Recovery Deferral and Variance Account

Question:

On July 31, 2009 the Board issued its Report of the Board; Electricity Distributors' Deferral and Variance Account Review Initiative (EDDVAR). The report requires applicants whose Group 1 (as defined in the report) variance accounts exceed a disposition threshold of $0.001/kWh to apply for a rate rider to dispose of Group 1 variance accounts.

a) *Has Enersource examined the Deferral and Variance Account Work Form and the impact to affected customers?*

b) *If the application of the Deferral and Variance Account recovery is found to be in excess of the value threshold of $0.001/kWh, would Enersource consider the amendment of its application to introduce a deferral account rate rider to enact disposition of Group 1 accounts?*

Response:

a) Yes. The Deferral and Variance Account Work Form is presented in Tab I, Exhibit 1.6, Attachment A.

b) The results of the calculations in the Deferral and Variance Account Work Form as at December 31, 2008 shows a refund rate that is in excess of the preset disposition threshold of $0.001/ KWh. Enersource does not propose an amendment to its application to introduce any deferral account disposition rate rider at this time. Enersource believes that the disposition of Group 1 account balances should not be considered because as at August 31, 2009, the sum of the Group 1 account balances has changed from an amount refundable to customers to an amount that is recoverable from customers as shown in Tab I Exhibit 1.6, Attachment B. The amount is expected to remain as an amount recoverable from customers as at December 31, 2009.

Ontario

Name of LDC: Enersource Hydro Mississauga Inc.
File Number: EB-2009-0193
Effective Date: Friday, January 01, 2010

LDC Information

Applicant Name	Enersource Hydro Mississauga Inc.
OEB Application Number	EB-2009-0193
LDC Licence Number	ED-2003-0017
Applied for Effective Date	January 1, 2010

Ontario

Name of LDC: **Enersource Hydro Mississauga Inc.**
File Number: **EB-2009-0193**
Effective Date: **Friday, January 01, 2010**

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Ontario

Name of LDC: Enersource Hydro Mississauga Inc.
File Number: EB-2009-0193
Effective Date: Friday, January 01, 2010

2006 Regulatory Asset Recovery

Account Description	Account Number	Principal Amounts as of Dec-31 2004 A	Hydro One charges (if applicable) to Dec31-03 B	Hydro One charges (if applicable) Jan 1-04 to Apr 30-06 C	Transition Cost Adjustment D	Principal Amounts E = A + B + C + D	Interest to Dec31-04 F	Interest per 2006 Reg Assets G = H - F - E	Total Claim and Recoveries per 2006 Reg Assets H	Transfer of Board-approved amounts to 1590 as per 2006 EDR I = - E	Transfer of Board-approved Interest to 1590 as per 2006 EDR J = - (F + G)
		1. Dec. 31, 2004 Reg. Assets									
		Column G	Column K	Column M			Column H		Column N		
RSVA - Wholesale Market Service Charge	1580	(267,757)				(267,757)	(23,595)	0	(291,351)	267,757	23,595
RSVA - One-time Wholesale Market Service	1582	460,984				460,984	21,275	0	482,259	(460,984)	(21,275)
RSVA - Retail Transmission Network Charge	1584	(1,713,447)				(1,713,447)	(57,140)	0	0	0	0
RSVA - Retail Transmission Connection Charge	1586	(2,517,648)	0			(2,517,648)	(89,386)	0	0	0	0
RSVA - Power	1588	(2,850,219)				(2,850,219)	(115,492)	(0)	(2,965,711)	2,850,219	115,492
Sub-Totals		**(6,888,086)**	**0**	**0**		**(6,888,086)**	**(264,337)**	**0**	**(2,774,803)**	**2,656,992**	**117,811**
Other Regulatory Assets	1508	1,298,936				1,298,936	10,223	0		0	0
Retail Cost Variance Account - Retail	1518	8,224				8,224	262	0	8,485	(8,224)	(262)
Retail Cost Variance Account - STR	1548	51,395				51,395	1,005	(0)	52,400	(51,395)	(1,005)
Misc. Deferred Debits - incl. Rebate Cheques	1525	0				0	0	0	0	0	0
Pre-Market Opening Energy Variances Total	1571	0				0	0	0	0	0	0
Extra-Ordinary Event Losses	1572					0		0		0	0
Deferred Rate Impact Amounts	1574					0		0		0	0
Other Deferred Credits	2425					0		0		0	0
Sub-Totals		**1,358,554**	**0**			**1,358,554**	**11,489**	**0**	**60,886**	**(59,619)**	**(1,267)**
Qualifying Transition Costs	1590	(5,254,873)				(5,254,873)	(115,426)	0	0	0	0
Transition Cost Adjustment	1595	0			0	0		0	0	0	0
Sub-Totals		**(5,254,873)**	**0**			**(5,254,873)**	**(115,426)**	**0**	**0**	**0**	**0**
Total Regulatory Assets		**(10,784,405)**	**0**	**0**	**0**	**(10,784,405)**	**(368,273)**	**0**	**(2,713,917)**	**2,597,373**	**116,544**
Total Recoveries to April 30-06	2. Rate Riders Calculation	Cell C48								**0**	
Balance to be collected or refunded	2. Rate Riders Calculation	Cell N51							**(2,713,917)**	**2,597,373**	

Name of LDC: **Enersource Hydro Mississauga Inc.**
File Number: **EB-2009-0193**
Effective Date: **Friday, January 01, 2010**

2006 Regulatory Asset Recovery Proportionate Share

Rate Class	Total Claim	% Total Claim
Residential	(493,090)	18.2%
GS < 50 KW	(238,512)	8.8%
GS > 50 Non TOU	(841,053)	31.0%
GS > 50 TOU	(780,038)	28.7%
Intermediate		0.0%
Large Users	(356,775)	13.1%
Small Scattered Load	(3,524)	0.1%
Sentinel Lighting		0.0%
Street Lighting	(926)	0.0%
Total	**(2,713,917)**	**100.0%**

2. Rate Riders Calculation
Row 29

Name of LDC: Enersource Hydro Mississauga Inc.
File Number: EB-2009-0193
Effective Date: Friday, January 01, 2010

Rate Class and 2008 Billing Determinants

Rate Group	Rate Class	Fixed Metric	Vol Metric	2008 Billed Customers or Connections A	2008 Billed kWh B	2008 Billed kW C	Billed kWh for Non-RPP customers D	1590 Recovery Share Proportion 1 E
RES	Residential	Customer	kWh	165,882	###########		237,111,876	18.2%
GSLT50	General Service Less Than 50 kW	Customer	kWh	16,318	698,622,376		126,289,699	8.8%
GSLT50	Small Commercial and USL - per meter	Customer	kWh	375	11,864,055		6,171,769	0.1%
GSGT50	General Service 50 to 499 kW	Customer	kW	3,867	###########	6,355,155	1,824,063,787	31.0%
GSGT50	General Service 500 to 4,999 kW	Customer	kW	477	###########	5,277,864	2,126,247,000	28.7%
LU	Large Use > 5000 kW	Customer	kW	10	###########	5,770,995	1,056,723,993	13.2%
SL	Street Lighting	Connection	kW	48,471	40,809,305	1,392,504	40,909,305	0.0%
NA	Rate Class 8	NA	NA					
NA	Rate Class 9	NA	NA					
NA	Rate Class 10	NA	NA					
NA	Rate Class 11	NA	NA					
NA	Rate Class 12	NA	NA					
NA	Rate Class 13	NA	NA					
NA	Rate Class 14	NA	NA					
NA	Rate Class 15	NA	NA					
NA	Rate Class 16	NA	NA					
NA	Rate Class 17	NA	NA					
NA	Rate Class 18	NA	NA					
NA	Rate Class 19	NA	NA					
NA	Rate Class 20	NA	NA					
NA	Rate Class 21	NA	NA					
NA	Rate Class 22	NA	NA					
NA	Rate Class 23	NA	NA					
NA	Rate Class 24	NA	NA					
NA	Rate Class 25	NA	NA					
								100.0%

Name of LDC: Enersource Hydro Mississauga Inc.
File Number: EB-2009-0193
Effective Date: Friday, January 01, 2010

Ontario

Regulatory Assets - Continuity Schedule 2005

Account Description	Account Number	Opening Principal Amounts as of Jan-1-05 [1]	Transactions (additions) during 2005, excluding interest and adjustments [2]	Transactions (reductions) during 2005, excluding interest and adjustments [2]	Adjustments during 2005 - instructed by Board [3]	Adjustments during 2005 - other [4]	Closing Principal Balance as of Dec-31-05	Opening Interest Amounts as of Jan-1-05	Interest Jan-1 to Dec31-05	Closing Interest Amounts as of Dec-31-05
LV Variance Account	1550						0			0
RSVA - Wholesale Market Service Charge	1580	(267,757)	5,587,753				5,319,996	(23,595)	106,957	83,363
RSVA - Retail Transmission Network Charge	1584	(1,713,447)	1,765,581				52,134	(57,140)	35,084	(22,056)
RSVA - Retail Transmission Connection Charge	1586	(2,517,648)	(562,736)				(3,080,384)	(89,386)	(129,494)	(218,880)
RSVA - Power (Excluding Global Adjustment)	1588	(2,850,219)	(1,937,015)				(4,787,234)	(115,492)	(259,323)	(374,815)
RSVA - Power (Global Adjustment Sub-account)	1588	0	(6,402,236)				(6,402,236)	0	(334,123)	(334,123)
Recovery of Regulatory Asset Balances	1590	(5,254,873)		(7,705,630)	29,845,816		16,885,313	(115,426)	892,285	776,859
Disposition and recovery of Regulatory Balances Account	1595						0			0
Total		(12,603,943)	(1,548,653)	(7,705,630)	29,845,816	0	7,987,590	(401,038)	311,387	(89,651)

[1] As per general ledger, if does not agree to Dec-31-04 balance filed in 2006 EDR then provide supplementary analysis
[2] For RSVA accounts only, report the net additions to the account during the year. For all other accounts, record the additions and reductions separately.
[3] Provide supporting statement indicating whether due to denial of costs in 2006 EDR by the Board
[4] Provide supporting statement indicating nature of this adjustments and periods they relate to

Name of LDC: Enersource Hydro Mississauga Inc.
File Number: EB-2009-0193
Effective Date: Friday, January 01, 2010

Regulatory Assets - Continuity Schedule 2006

Account Description	Account Number	Opening Principal Amounts as of Jan-1-06	Transactions (additions) during 2006, excluding interest and adjustments 2	Transactions (reductions) during 2006, excluding interest and adjustments 2	Adjustments during 2006 - instructed by Board 3	Adjustments during 2006 - other 4	Low Voltage and Recoveries per 2006 Reg Asset	Transfer of Board-approved amounts to 1590 as per 2006 EDR	Closing Principal Balance as of Dec-31-06	Opening Interest Amounts as of Jan-1-06	Interest Jan-1 to Dec31-06	Interest per 2006 Reg Asset	Transfer of Board-approved amounts to 1590 as per 2006 EDR	Closing Interest Amounts as of Dec-31-06
LV Variance Account	1550	0	(218,851)						(218,851)	0	(2,847)			(2,847)
RSVA - Wholesale Market Service Charge	1580	5,319,996	(10,216,418)		0		0	267,757	(4,628,665)	83,363	76,724	0	23,595	183,681
RSVA - Retail Transmission Network Charge	1584	52,134	1,358,422				0	0	1,410,556	(22,056)	(6,962)	0	0	(29,018)
RSVA - Retail Transmission Connection Charge	1586	(3,080,384)	676,484				0	0	(2,403,900)	(218,880)	(179,336)	0	0	(398,216)
RSVA - Power (Excluding Global Adjustment)	1588	(4,787,234)	(3,645,198)		0			2,850,219	(5,582,213)	(374,815)	(408,142)	(0)	115,492	(667,465)
RSVA - Power (Global Adjustment Sub-account)	1588	(6,402,236)	13,115,415						6,713,179	(334,123)	148,350			(185,773)
Recovery of Regulatory Asset Balances	1590	16,885,313	388,262	(7,372,745)	0		0	(2,597,373)	7,303,458	776,859	680,746		(116,544)	1,341,061
Disposition and recovery of Regulatory Balances Account	1595	0							0	0				0
Total		7,987,590	1,458,116	(7,372,745)	0	0	0	520,603	2,593,564	(89,651)	308,533	0	22,542	241,424

[2] For RSVA accounts only, report the net additions to the account during the year. For all other accounts, record the additions and reductions separately.
[3] Provide supporting evidence i.e. Board Decision, CRO Order, etc.
[4] Provide supporting statement indicating nature of this adjustments and periods they relate to

Name of LDC: **Enersource Hydro Mississauga Inc.**
File Number: **EB-2009-0193**
Effective Date: **Friday, January 01, 2010**

Regulatory Assets - Continuity Schedule 2007

Account Description	Account Number	Opening Principal Amounts as of Jan-1-07	Transactions (additions) during 2007, excluding interest and adjustments [2]	Transactions (reductions) during 2007, excluding interest and adjustments [2]	Adjustments during 2007 - instructed by Board [3]	Adjustments during 2007 - other [4]	Closing Principal Balance as of Dec-31-07	Opening Interest Amounts as of Jan-1-07	Interest Jan-1 to Dec31-07	Closing Interest Amounts as of Dec-31-07
LV Variance Account	1550	(218,851)	(493,299)				(712,149)	(2,847)	(20,200)	(23,047)
RSVA - Wholesale Market Service Charge	1580	(4,628,665)	(10,383,004)				(15,011,669)	183,681	(435,761)	(252,080)
RSVA - Retail Transmission Network Charge	1584	1,410,556	1,171,952				2,582,508	(29,018)	104,611	75,593
RSVA - Retail Transmission Connection Charge	1586	(2,403,900)	1,253,835				(1,150,065)	(398,216)	(83,054)	(481,269)
RSVA - Power (Excluding Global Adjustment)	1588	(5,582,213)	(5,694,876)				(11,277,089)	(667,465)	(278,062)	(945,527)
RSVA - Power (Global Adjustment Sub-account)		6,713,179	(3,447,785)				3,265,394	(185,773)	113,159	(72,614)
Recovery of Regulatory Asset Balances	1590	7,303,458	1,809,749	(7,073,302)			2,039,905	1,341,061	270,762	1,611,823
Disposition and recovery of Regulatory Balances Account	1595	0					0	0		0
Total		2,593,564	(15,783,428)	(7,073,302)	0	0	(20,263,166)	241,424	(328,545)	(87,122)

[2] For RSVA accounts only, report the net additions to the account during the year. For all other accounts, record the additions and reductions separately.
[3] Provide supporting evidence i.e. Board Decision, CRO Order, etc.
[4] Provide supporting statement indicating nature of this adjustments and periods they relate to

Name of LDC: Enersource Hydro Mississauga Inc.
File Number: EB-2009-0193
Effective Date: Friday, January 01, 2010

Regulatory Assets - Continuity Schedule 2008

Account Description	Account Number	Opening Principal Amounts as of Jan-1-08	Transactions (additions) during 2008, excluding interest and adjustments 2	Transactions (reductions) during 2008, excluding interest and adjustments 2	Adjustments during 2008 - instructed by Board 3	Adjustments during 2008 - other 4	Transfer of Board-approved 2006 amounts to 1595 (2008 COS)5	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 2006 interest amounts to 1595 (2008 COS)	Closing Interest Amounts as of Dec-31-08
LV Variance Account	1550	(712,149)	73,421					(638,728)	(23,047)	(29,760)		(52,807)
RSVA - Wholesale Market Service Charge	1580	(15,011,669)	(4,422,511)		4,628,663			(14,805,516)	(252,080)	(594,983)	(183,772)	(1,030,835)
RSVA - Retail Transmission Network Charge	1584	2,582,508	(3,578,960)		(1,410,556)			(2,407,008)	75,593	(4,774)	29,018	99,837
RSVA - Retail Transmission Connection Charge	1586	(1,150,065)	(2,141,653)		2,403,900			(887,818)	(481,269)	(33,306)	398,216	(116,360)
RSVA - Power (Excluding Global Adjustment)	1588	(11,277,089)	3,482,497		5,582,213			(2,212,379)	(945,527)	(290,070)	667,465	(568,132)
RSVA - Power (Global Adjustment Sub-account)		3,265,394	4,061,908					7,327,302	(72,614)	143,943		71,329
Recovery of Regulatory Asset Balances	1590	2,039,905	4,967,783				(7,074,696)	(67,008)	1,611,823	48,351	(1,618,861)	41,313
Disposition and recovery of Regulatory Balances Account	1595											
Total		(20,263,166)	2,442,487	0	11,204,220	0	(7,074,696)	(13,691,155)	(87,122)	(760,599)	(707,935)	(1,555,656)

2 For RSVA accounts only, report the net additions to the account during the year. For all other accounts, record the additions and reductions separately.
3 Provide supporting evidence i.e. Board Decision, CRO Order, etc.
4 Provide supporting statement indicating nature of this adjustments and periods they relate to
5 This records the values of amounts removed from Group One accounts in previous proceedings; but does not enter offsets for disposition of 1590, as recovery has not been completed.

Name of LDC: Enersource Hydro Mississauga Inc.
File Number: EB-2009-0193
Effective Date: Friday, January 01, 2010

Regulatory Assets - Continuity Schedule Final

Account Description	Account Number	Opening Principal Amounts as of Jan-1-09	Transfer of Board-approved 2007 amounts to 1595 (2009 COS)	Opening Principal Amounts as of Jan-1-09 After Transfer to 1595	Opening Interest Amounts as of Jan-1-09	Transfer of Board-approved 2007 interest amounts to 1595 (2009 COS)	Projected Interest on Dec 31 -08 balance from Jan 1, 2009 to Dec 31, 2009 [5]	Projected Interest on Dec 31 -08 balance from Jan 1, 2010 to April 30, 2010 [5]	Total Claim
		A	B	C = A + B	D	E	F	G	H = C + D+ E + F + G
LV Variance Account	1550	(638,728)		(638,728)	(52,807)		(7,858)	(1,266)	(700,659)
RSVA - Wholesale Market Service Charge	1580	(14,805,516)		(14,805,516)	(1,030,835)		(179,951)	(28,981)	(16,045,283)
RSVA - Retail Transmission Network Charge	1584	(2,407,008)		(2,407,008)	99,837		(26,217)	(4,222)	(2,337,610)
RSVA - Retail Transmission Connection Charge	1586	(887,818)		(887,818)	(116,360)		(11,411)	(1,838)	(1,017,426)
RSVA - Power (Excluding Global Adjustment)	1588	(2,212,379)		(2,212,379)	(568,132)		(31,595)	(5,088)	(2,817,195)
RSVA - Power (Global Adjustment Sub-account)		7,327,302		7,327,302	71,329		84,072	13,540	7,496,242
Recovery of Regulatory Asset Balances	1590	(67,008)		(67,008)	41,313		(292)	(47)	(26,035)
Disposition and recovery of Regulatory Balances Account	1595	0		0	0		0	0	0
Total		(13,691,155)	0	(13,691,155)	(1,555,656)	0	(173,252)	(27,902)	(15,447,965)

[5] Interest projected on December 31, 2008 closing principal balance.

Month	Prescribed Rate
Saturday, January 31, 2009	2.45
Saturday, February 28, 2009	2.45
Tuesday, March 31, 2009	2.45
Thursday, April 30, 2009	1.00
Sunday, May 31, 2009	1.00
Tuesday, June 30, 2009	1.00
Friday, July 31, 2009	0.55
Monday, August 31, 2009	0.55
Wednesday, September 30, 2009	0.55
Saturday, October 31, 2009	0.55
Monday, November 30, 2009	0.55
Thursday, December 31, 2009	0.55
Effective Rate	0.0114

Month	Prescribed Rate
Jan-10	0.55
Feb-10	0.55
Mar-10	0.55
Apr-10	0.55
Effective Rate	0.0018

Name of LDC: **Enersource Hydro Mississa**
File Number: **EB-2009-0193**
Effective Date: **Friday, January 01, 2010**

Threshold Test

Rate Class	Billed kWh B
Residential	1,590,715,870
General Service Less Than 50 kW	698,622,376
Small Commercial and USL - per meter	11,864,055
General Service 50 to 499 kW	2,298,548,818
General Service 500 to 4,999 kW	2,384,183,297
Large Use > 5000 kW	1,071,190,308
Street Lighting	40,809,305
	8,095,934,029
Total Claim	(15,447,965)
Total Claim per kWh	- 0.001908

Name of LDC: **Enersource Hydro Mississauga Inc.**
File Number: **EB-2009-0193**
Effective Date: **Friday, January 01, 2010**

Cost Allocation - kWh

Rate Class	Billed kWh	% kWh	1550	1580	1584	1586	1588 [1]	Total
Residential	1,590,715,870	19.6%	(137,668)	(3,152,630)	(459,301)	(199,907)	(553,532)	(4,503,038)
General Service Less Than 50 kW	698,622,376	8.6%	(60,462)	(1,384,595)	(201,719)	(87,797)	(243,104)	(1,977,678)
Small Commercial and USL - per meter	11,864,055	0.1%	(1,027)	(23,513)	(3,426)	(1,491)	(4,128)	(33,585)
General Service 50 to 499 kW	2,298,548,818	28.4%	(198,927)	(4,555,480)	(663,680)	(288,861)	(799,841)	(6,506,789)
General Service 500 to 4,999 kW	2,384,183,297	29.4%	(206,338)	(4,725,199)	(688,406)	(299,623)	(829,640)	(6,749,206)
Large Use > 5000 kW	1,071,190,308	13.2%	(92,706)	(2,122,986)	(309,294)	(134,618)	(372,749)	(3,032,352)
Street Lighting	40,809,305	0.5%	(3,532)	(80,880)	(11,783)	(5,129)	(14,201)	(115,524)
	8,095,934,029	100.0%	(700,659)	(16,045,283)	(2,337,610)	(1,017,426)	(2,817,195)	(22,918,172)
			-	-	-	-	-	-

[1] RSVA - Power (Excluding Global Adjustment)

Ontario

Name of LDC: Enersource Hydro Mississauga Inc.
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Cost Allocation - Non-RPP kWh

Rate Class	Non-RPP kWh	% kWh	1588 [1]
Residential	237,111,876	4.4%	328,093
General Service Less Than 50 kW	126,289,699	2.3%	174,748
Small Commercial and USL - per meter	6,171,769	0.1%	8,540
General Service 50 to 499 kW	1,824,063,787	33.7%	2,523,965
General Service 500 to 4,999 kW	2,126,247,000	39.2%	2,942,097
Large Use > 5000 kW	1,056,723,993	19.5%	1,462,193
Street Lighting	40,909,305	0.8%	56,606
	5,417,517,429	100.0%	7,496,242
			-

[1] RSVA - Power (Global Adjustment Sub-account)

Name of LDC: Enersource Hydro Mississauga Inc.
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Cost Allocation - 1590

Rate Class	1590 Recovery Share Proportion	1590
Residential	18.2%	(4,730)
General Service Less Than 50 kW	8.8%	(2,288)
Small Commercial and USL - per meter	0.1%	(34)
General Service 50 to 499 kW	31.0%	(8,068)
General Service 500 to 4,999 kW	28.7%	(7,482)
Large Use > 5000 kW	13.2%	(3,424)
Street Lighting	0.0%	(8)
	100.0%	(26,035)
		-

Name of LDC: Enersource Hydro Mississauga Inc.
File Number: EB-2009-0193
Effective Date: Friday, January 01, 2010

Cost Allocation - 1595

Rate Class	1595 Recovery Share Proportion	1595
Residential	0.0%	0
General Service Less Than 50 kW	0.0%	0
Small Commercial and USL - per meter	0.0%	0
General Service 50 to 499 kW	0.0%	0
General Service 500 to 4,999 kW	0.0%	0
Large Use > 5000 kW	0.0%	0
Street Lighting	0.0%	0
	0.0%	0
		-

Ontario

Name of LDC: Enersource Hydro Mississauga Inc.
File Number: EB-2009-0193
Effective Date: Friday, January 01, 2010

Calculation of Regulatory Asset Recovery Rate Rider

Rate Rider Recovery Period - Years Four

Rate Rider Effective To Date

Tuesday, December 31, 2013

Rate Class	Vol Metric	Billed kWh A	Billed kW B	kWh C	Non-RPP D	1590 E	1595 F	Total G = C + D + E + F	Rate Rider kWh H = G / A (kWh) or H = G / B (kW)
Residential	kWh	1,590,715,870	0	(4,503,038)	328,093	(4,730)	0	(4,179,676)	(0.00066)
General Service Less Than 50 kW	kWh	698,622,376	0	(1,977,678)	174,748	(2,288)	0	(1,805,218)	(0.00065)
Small Commercial and USL - per meter	kWh	11,864,055	0	(33,585)	8,540	(34)	0	(25,079)	(0.00053)
General Service 50 to 499 kW	kW	2,298,548,818	6,355,155	(6,506,789)	2,523,965	(8,068)	0	(3,990,893)	(0.15699)
General Service 500 to 4,999 kW	kW	2,384,183,297	5,277,864	(6,749,206)	2,942,097	(7,482)	0	(3,814,591)	(0.18069)
Large Use > 5000 kW	kW	1,071,190,308	5,770,995	(3,032,352)	1,462,193	(3,424)	0	(1,573,582)	(0.06817)
Street Lighting	kW	40,809,305	1,392,504	(115,524)	56,606	(8)	0	(58,925)	(0.01058)
		8,095,934,029	18,796,518	(22,918,172)	7,496,242	(26,035)	0	(15,447,965)	
				-	-	-	-	-	

Enter the above value onto Sheet
"J2.1 DeferralAccount Rate Rider"
of the 2010 OEB IRM2 Rate Generator
"J2.5 DeferralAccount Rate Rider2"
of the 2010 OEB IRM3 Rate Generator

Enersource Hydro Mississauga
Regulatory Assets Continuity Schedule (Note 1)
As at August 31, 2009

Account Description	Account Number	Opening Principal Amounts as at December 31, 2008 A	Opening Interest Amounts as at December 31, 2008 B	Balance as at December 31, 2008 C (A+B)	YTD August 2009 Activity (Principal) D	Balance as at August 31, 2009 E (C+D)	Projected Interest on Dec 31 -08 balance from Jan 1, 2009 to Dec 31, 2009 F	Projected Interest on Dec 31 -08 balance from Jan 1, 2010 to April 30, 2010 G	Total amount for Recovery H = (E + F + G)
LV Variance Account	1550	$ (638,728)	$ (52,807)	$ (691,535)	$ (3,948)	$ (695,483)	$ (7,903)	$ (1,273)	$ (704,659)
RSVA - Wholesale Market Service Charge	1580	$ (14,805,516)	$ (1,030,835)	$ (15,836,351)	$ (136,499)	$ (15,972,850)	$ (181,502)	$ (29,230)	$ (16,183,582)
RSVA - Retail Transmission Network Charge	1584	$ (2,407,008)	$ 99,837	$ (2,307,171)	$ (750,558)	$ (3,057,729)	$ (34,745)	$ (5,596)	$ (3,098,070)
RSVA - Retail Transmission Connection Charge	1586	$ (887,818)	$ (116,360)	$ (1,004,177)	$ (670,729)	$ (1,674,906)	$ (19,032)	$ (3,065)	$ (1,697,004)
RSVA - Power (Excluding Global Adjustment)	1588	$ (2,212,379)	$ (568,132)	$ (2,780,511)	$ (4,040,398)	$ (6,820,909)	$ (77,507)	$ (12,482)	$ (6,910,899)
RSVA - Power (Global Adjustment Sub-account)		$ 7,327,302	$ 71,329	$ 7,398,630	$ 33,082,416	$ 40,481,046	$ 459,993	$ 74,081	$ 41,015,120
Recovery of Regulatory Asset Balances	1590	$ (67,008)	$ 41,313	$ (25,696)	$ -	$ (25,696)	$ (292)	$ (47)	$ (26,035)
Disposition and recovery of Regulatory Balances Account	1595	$ -	$ -						$ -
Total		$ (13,691,155)	$ (1,555,656)	$ (15,246,811)	$ 27,480,284	$ 12,233,473	$ 139,011	$ 22,387	$ 12,394,871

Month	Prescribed Rate	Month	Prescribed Rate
Saturday, January 31, 2009	2.45	Jan-10	0.55
Saturday, February 28, 2009	2.45	Feb-10	0.55
Tuesday, March 31, 2009	2.45	Mar-10	0.55
Thursday, April 30, 2009	1.00	Apr-10	0.55
Sunday, May 31, 2009	1.00	Effective Rate	**0.0018**
Tuesday, June 30, 2009	1.00		
Friday, July 31, 2009	0.55		
Monday, August 31, 2009	0.55		
Wednesday, September 30, 2009	0.55		
Saturday, October 31, 2009	0.55		
Monday, November 30, 2009	0.55		
Thursday, December 31, 2009	0.55		
Effective Rate	**0.0114**		

Threshold Test - to August 31, 2009

Rate Class	Billed kWh B
Residential	1,590,715,870
General Service Less Than 50 kW	698,622,376
Small Commercial and USL - per meter	11,864,055
General Service 50 to 499 kW	2,298,548,818
General Service 500 to 4,999 kW	2,384,183,297
Large Use > 5000 kW	1,071,190,308
Street Lighting	40,809,305
	8,095,934,029
Total Claim	12,394,871
Total Claim per kWh	0.001531

Note 1 - Regulatory Assets Continuity Schedule - In accordance with the Board's methodology, Enersource has prepared a continuity schedule to August 31, 2009, to reflect the impact of transactions from January 1 to August 31, 2009. Enersource has also computed interest to April 30, 2010 in accordance with the Board's methodology used in the 2010 IRM Deferral and Variance Account Work Form analysis.

EB-2009-0193
Tab 1
Exhibit 1.6
Attachment B

Response to Interrogatory from
Association of Major Power Consumers in Ontario

Reference: *Tab B, Page 3, Paragraphs 8 & 9*

Preamble: *Enersource states that as a result of the misalignment between its fiscal year end (commencing January 1) and the effective date of rate orders (May 1), the actual rate of return does not match the approved rate of return.*

Question:

Please provide specific details and figures for Enersource's actual rate of return vs the approved rate of return for the 2009 and 2010 calendar years and rate years to further explain this point.

Response:

Enersource's budgeted return on equity for the 2009 calendar year is 7.67% whereas the current rate of return is 8.57%. Enersource is in the process of preparing its 2010 budget and cannot provide the budgeted return on equity at this time.

Response to Interrogatory from
Association of Major Power Consumers in Ontario

Reference: *Tab B, Pages 8 & 9*

Preamble: *Table 1 on Page 8 shows the 2009 3GIRM load forecast for the Large Use class as 1,720,956 kW. Table 2 on Page 9 shows the 2010 load forecast for the Large User as 1,847,558 kW, an increase of 126,602 kW.*

Table 1 on Page 8 shows the 2009 3GIRM load forecast for the General Service 500kW – 4999 kW as 5,310,121 kW. Table 2 on Page 9 shows the 2010 load forecast for the large user as 5,107,408 kW, a decrease of 202,713 kW.

Question:

Please explain the change in load forecast in 2010 and the derivation of this figure for the General Service 500kW – 4999kW and Large Use classes.

Response:

Enersource's 2009 load forecast was created before the effects of the economic downturn, which have had a significant impact on the load forecast. Enersource also had a customer move from the GS 500kW-4999kW to the Large User class. Enersource accordingly reflected the changes required by these two events in its 2010 load forecast.

Response to Interrogatory from
Association of Major Power Consumers in Ontario

Reference: *Tab B, Page 11, Paragraph 33, Cost Allocation*

Preamble: *Enersource submits that pursuant to the Settlement Agreement from its 2008 Cost of Service Rate Application, EB-2007-0706, all parties agreed on the current customer cost allocation ratios. All customer classes with revenue-to-cost ratios below 100% were increased to 91.5%. All customer classes with revenue-to-cost ratios above 100% were reduced to 111%. Four customer classes are overcontributing (GS<50kW, small commercial, GS>50kW , large user). Three customer classes are undercontributing (residential, GS>500kW, street lighting). As part of the EB-2007-0706 Settlement Agreement, AMPCO accepted the proposed 2008 revenue-to-cost ratios on the understanding that it may address in Enersource's 2009 IRM application the appropriateness of continuing those revenue to cost ratios after the 2008 test year.*

Question:

Please provide an update on the steps Enersource has taken to improve the quality of the data and knowledge of the costs to serve each customer class, and what plans are underway to move revenue-to-cost ratios closer to one.

Response:

In EB-2007-0706 (Enersource's 2008 COS proceeding), Enersource and the intervenors reached a complete settlement on the issue of cost allocation. Enersource remains in compliance with the requirements of the *Board Report on Application of Cost Allocation for Electricity Distributors* (EB-2007-0667).

From the Ontario Energy Board website introduction to EB-2007-0031, found at the link:

http://www.oeb.gov.on.ca/OEB/Industry+Relations/OEB+Key+Initiatives/Rate+Design+for+Electricity+Distributors/Rate+Design the Board stated that:

"One of the rate-setting initiatives set out in the Ontario Energy Board's business plan is a comprehensive electricity distribution rate design review. This review is intended to consider the need for, and approaches to, changes to distribution rate design in light of industry changes and emerging issues. These include the commercialization of electricity distributors, developments in metering and increased distributed generation and conservation and demand management activities, among others. The Board has decided to defer completion of the rate design project while staff conducts more research and expands the ability to model rate impacts."

Pending additional guidance from the Board, Enersource continues to apply and comply with the Board's current policy.

Response to Interrogatory from
Consumers Council of Canada

Question:

The evidence states that Enersource is proposing a transition plan aimed at ensuring that the proposed change, in the timing of this 3rd Generation Incentive Rate Mechanism Application and implementation of rates, would not result in any financial gain or loss to Enersource and/or its customers, relative to the alternative of a May 1, 2010 distribution rate change (Tab B, p. 3). Please provide detailed evidence to demonstrate that ratepayers will not suffer a financial loss relative to the current rate change timing.

Response:

Please refer to the response in Tab I, Exhibit 1.3 a) and b).

Response to Interrogatory from
Consumers Council of Canada

Question:

Please provide a schedule setting out actual load, by rate class, by month for the past 5 years.

Response:

Please refer to Tab I, Exhibit 3.2, Attachment A.

Enersource Hydro Mississauga
Actual Load Data (2004 - 2008)
Based on Billed kWh

SUMMARY kWh 2008

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
Residential	153,710,323	141,124,516	134,451,935	121,192,258	108,980,161	119,686,452	143,917,742	163,124,677	159,478,871	118,345,645	109,431,935	117,271,354	1,590,715,870
GS<50 kW (Small Comercial)	763,387	1,134,516	1,049,677	727,742	1,275,161	1,132,258	655,323	1,103,710	1,034,516	725,484	1,172,581	1,089,677	11,864,032
GS < 50 kW	61,674,516	57,944,194	60,931,774	61,412,742	51,392,419	58,368,387	60,589,355	59,123,871	55,424,839	51,657,581	56,857,258	63,245,463	698,622,399
GS 50-499 kW	204,647,903	190,843,387	207,117,258	189,374,516	181,158,226	201,112,581	189,228,548	189,462,419	185,394,839	178,663,226	184,002,581	197,543,387	2,298,548,871
GS 500-4999 kW	200,370,323	196,207,742	201,523,387	186,575,323	204,794,516	218,576,613	199,847,742	202,403,871	189,950,000	196,905,968	206,068,871	180,958,890	2,384,183,244
Large User	91,182,903	75,469,677	77,131,935	80,262,097	94,791,935	101,223,548	102,337,581	80,921,935	98,478,387	93,100,484	95,515,806	80,774,017	1,071,190,308
Streetlight	4,658,387	3,673,226	3,384,677	2,911,452	2,727,581	2,853,548	2,180,323	2,404,516	3,198,387	3,676,452	4,500,806	4,639,950	40,809,305
Total	717,007,742	666,397,258	685,590,645	642,456,129	645,120,000	702,953,387	698,756,613	698,545,000	692,959,839	643,074,839	657,549,839	645,522,739	8,095,934,029

SUMMARY kWh 2007

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
Residential	148,762,903	123,642,903	146,769,032	131,639,516	111,740,161	124,146,935	143,240,968	196,836,935	147,056,290	144,839,839	103,754,032	110,386,613	1,632,816,129
GS<50 kW (Small Comercial)	1,157,581	709,032	1,198,387	1,070,806	774,194	1,223,065	955,968	777,097	1,502,742	652,419	750,323	1,158,548	11,930,161
GS < 50 kW	57,231,129	56,362,903	61,868,065	58,520,161	54,756,129	58,733,387	56,992,742	64,191,935	52,749,677	56,209,839	54,307,742	59,086,129	691,009,839
GS 50-499 kW	189,333,710	178,010,968	226,113,387	189,245,806	194,660,161	202,606,129	189,352,581	222,119,516	173,493,548	198,467,258	197,238,065	202,578,226	2,363,219,355
GS 500-4999 kW	211,214,032	182,793,548	216,640,161	200,592,419	208,643,548	241,731,613	208,171,774	232,716,935	184,308,065	224,436,935	206,114,839	190,145,323	2,507,509,194
Large User	88,617,419	70,874,677	82,417,742	72,999,839	94,757,742	94,936,452	73,836,129	119,010,806	55,139,355	90,366,129	100,280,484	88,382,903	1,031,619,677
Streetlight	4,617,903	3,137,097	3,427,097	3,056,129	2,759,839	2,788,226	2,013,226	2,827,419	2,763,710	3,901,129	4,511,935	4,472,742	40,276,452
Total	700,934,677	615,531,129	738,433,871	657,124,677	668,091,774	726,165,806	674,563,387	838,480,645	617,013,387	718,873,548	666,957,419	656,210,484	8,278,380,806

SUMMARY kWh 2006

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
Residential	138,860,323	130,076,290	153,909,677	92,998,710	129,162,097	104,580,161	170,465,484	189,290,161	154,512,742	134,819,355	81,107,581	123,549,516	1,603,332,097
GS<50 kW (Small Comercial)	1,058,065	651,129	1,294,355	937,097	1,285,000	681,935	1,353,548	634,677	1,163,871	1,253,387	722,258	1,300,323	12,335,645
GS < 50 kW	58,240,645	55,629,355	66,965,323	50,523,548	56,489,839	52,489,677	64,049,839	59,008,871	51,778,065	56,370,645	51,731,290	60,939,194	684,216,290
GS 50-499 kW	204,436,774	177,821,613	266,271,129	157,034,355	214,064,355	161,464,032	219,781,935	175,367,742	181,056,290	216,327,419	180,806,774	194,048,387	2,348,480,806
GS 500-4999 kW	182,566,935	173,373,065	234,366,129	153,349,677	229,547,742	224,841,129	249,515,000	193,399,355	200,875,806	235,995,000	187,593,871	199,594,516	2,465,018,226
Large User	74,527,742	62,272,742	92,223,387	70,422,903	93,316,613	90,222,097	97,253,065	80,866,613	62,824,516	97,715,161	74,911,129	83,509,839	980,065,806
Streetlight	4,140,806	3,459,032	3,997,419	2,488,226	4,040,806	1,259,032	2,526,935	2,135,000	2,925,323	3,481,774	4,808,387	4,692,632	39,955,374
Total	663,831,290	603,283,226	819,027,419	527,754,516	727,906,452	635,538,065	804,945,806	700,702,419	655,136,613	745,962,742	581,681,290	667,634,516	8,133,404,244

SUMMARY kWh 2005

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
Residential	152,180,806	143,546,741	139,465,909	115,529,844	108,225,649	128,753,381	166,700,631	234,324,651	171,494,978	112,435,012	108,493,667	121,569,878	1,702,721,148
GS<50 kW (Small Comercial)	1,884,516	(10,806)	1,213,992	1,045,161	1,100,323	823,871	1,098,871	1,062,581	693,548	1,236,774	977,130	1,521,161	12,647,122
GS < 50 kW	59,522,580	59,570,147	61,730,556	55,096,293	54,275,325	63,076,287	61,395,640	65,727,573	55,140,638	53,247,425	52,411,692	60,680,238	701,874,396
GS 50-499 kW	218,495,483	200,102,372	224,909,558	190,214,848	197,986,298	226,937,732	209,895,466	221,675,136	196,836,749	183,483,729	225,327,755	203,903,611	2,499,768,739
GS 500-4999 kW	193,892,418	174,266,249	195,987,604	178,543,880	195,989,524	233,802,731	199,598,209	197,481,429	186,943,041	189,707,440	221,741,937	211,485,020	2,379,439,481
Large User	83,725,161	72,450,467	81,161,854	76,988,230	78,947,261	107,710,156	78,290,800	82,734,345	75,949,023	74,303,395	101,310,746	67,087,155	980,658,593
Streetlight	4,098,710	3,381,451	3,341,987	2,840,807	2,697,581	2,444,193	2,559,838	3,188,387	2,890,806	4,010,162	3,754,262	4,008,794	39,216,977
Total	713,799,674	653,306,621	707,811,460	620,259,063	639,221,960	763,548,352	719,539,456	806,194,102	689,948,784	618,423,937	714,017,189	670,255,857	8,316,326,455

SUMMARY kWh 2004

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
Residential	154,900,016	139,354,320	134,018,301	112,629,862	111,316,350	109,290,438	126,104,076	150,329,007	142,723,358	129,452,854	153,127,339	79,559,628	1,542,805,550
GS<50 kW (Small Comercial)	752,312	630,058	1,416,897	781,579	1,391,365	760,694	1,237,708	827,641	1,271,970	1,369,212	975,001	1,422,251	12,836,689
GS < 50 kW	61,324,855	59,773,246	58,552,048	58,975,573	55,639,962	54,439,345	54,900,356	58,068,155	55,759,525	55,710,260	54,105,793	60,255,525	687,504,645
GS 50-499 kW	255,172,380	197,098,621	201,988,402	188,388,595	186,297,465	201,179,290	195,818,936	203,077,479	211,435,947	184,264,877	203,444,711	209,209,458	2,437,376,162
GS 500-4999 kW	146,867,110	195,952,757	182,595,184	176,761,981	188,907,943	212,062,235	207,098,193	185,577,042	188,129,253	181,445,485	168,894,970	201,614,862	2,235,907,015
Large User	109,362,526	64,395,605	80,611,377	74,913,147	91,376,824	85,735,996	83,654,065	82,682,523	81,111,108	79,281,962	84,944,731	86,687,860	1,004,757,724
Streetlight	4,259,658	3,642,582	3,475,559	2,948,947	2,797,869	2,539,785	2,656,569	2,993,088	3,410,065	3,125,418	3,971,113	3,514,022	39,334,676
Total	732,638,857	660,847,189	662,657,769	615,399,684	637,727,778	666,007,784	671,469,904	683,554,935	683,841,227	634,650,069	669,463,659	642,263,606	7,960,522,460

Response to Interrogatory from
Consumers Council of Canada

Question:

Please provide all materials provided to Enersource's Board of Directors when the proposal to move to a January 1, 2010, rate implementation date was put before the Board for approval.

Response:

Management's proposal to move to a January 1, 2010 rate implementation date was not put to the Enersource Board of Directors for approval. Further, as a matter of principle, Enersource does not believe that any material provided by management to its Board of Directors is relevant to the issue of determining just and reasonable rates. It therefore considers the question to be out of scope for these proceedings.

Response to Interrogatory from
Energy Probe Research Foundation

Reference: *Exhibit: Tab B*
Alignment of Rate Year with Calendar Year

Preamble:

The evidence of the Applicant, beginning at Paragraph 6 of Tab B, outlines points that the Board should weigh when considering its request to make its rates effective January 1, 2010. At Paragraph 8, the Applicant submits that:

… there is currently a misalignment between its fiscal year (commencing January 1) and the effective date of its rate orders (May 1). The result of this misalignment is that Enersource's actual rate of return does not match the approved rate of return. Enersource, as a reporting issuer, is required to explain this complicated outcome to the investment community, including our bondholders. Enersource seeks to rectify this situation as soon as possible.

Questions:

a) *Is the Applicant aware of any regulated electricity distribution company within the Ontario Energy Board's jurisdiction, out of some 80 utilities, that currently has its fiscal year and the effective date of its rate orders aligned?*

b) *Please provide examples exhibiting difficulty experienced by bondholders in understanding the non-alignment of fiscal year and the effective date of rate orders when Enersource explains it to them.*

c) *How has Enersource dealt with the examples outlined in question (b) above?*

d) *Has Enersource been refused a bond due to the non-alignment of fiscal year and the effective date of rate orders?*

Response:

a) Enersource is not aware of the fiscal year and rate order details of the 80 or so regulated electricity distribution companies within the Board's jurisdiction. Enersource is aware that Hydro One Networks' 2010 and 2011 distribution revenue requirement and rate application (EB-2009-0096) seeks approval for changes to rates to be effective January 1, 2010 and January 1, 2011. Hydro One's fiscal year begins January 1.

b) and c) Please refer to the response in Tab I, Exhibit 6.1, part c)

d) No.

Response to Interrogatory from
Energy Probe Research Foundation

Reference: *Exhibit: Tab B*
Alignment of Rate Year with Calendar Year

Preamble:

The evidence of the Applicant, beginning at Paragraph 9 of Tab B, states that the "Board has approved the alignment of rate years with fiscal years in the past." The Decisions in regard to specific Applications in respect of gas distribution companies under the Ontario Energy Board's jurisdiction are referenced.

Questions:

a) *Were any of the Decisions of the Board referenced above rendered during an incentive regulation regime for gas distribution companies?*

b) *Do you agree that the 3rd GIRM, which was used to set Enersource's current rates, is a formulaic rate adjustment method, a price (rate) cap form of incentive regulation that does not require the calculation of a traditional revenue requirement?*

Response:

a) No.

b) Enersource agrees that the 3rd GIRM is a formulaic rate adjustment method that does not require the calculation of an annual cost of service revenue requirement. Incentive rate making has been in place in several jurisdictions for several decades, so it is no less traditional than cost of service rate making.

Response to Interrogatory from
Energy Probe Research Foundation

Reference: *Exhibit: Tab B*
Alignment of Rate Year with Calendar Year

Preamble:

The evidence of the Applicant, beginning at Paragraph 10 of Tab B, states that the proposed approach of the Applicant results in no financial gain or loss to either Enersource or its customers:

In accordance with this approach, Enersource proposes a transition plan aimed at ensuring that the proposed change in the timing of this 3rd GIRM Application and implementation of rates would not result in any financial gain or loss to Enersource and/or its customers, relative to the alternative of a May 1, 2010 distribution rate change.

Questions:

a) Has the Applicant considered the additional cost to the Board of providing regulatory oversight to some 80 local electricity distribution companies having the effective date of their respective rate orders misaligned with one another?

b) Is it the considered opinion of the Applicant that incentive regulation of some 80 local electricity distribution companies, which relies to some extent on the ability of the regulator to measure and compare financial outcomes of utilities, will not be impaired by the misalignment of the effective dates of their respective rate orders?

Response:

a) The Board has not raised this as an issue with Enersource. However, it would seem reasonable that the Board's resources may be less taxed if all of the province's local electricity distribution companies did not file their rate applications at the same time for the same effective date. That is, this could possibly trim the peak workload of the Board Staff.

b) All electricity distribution reporting to the Board is provided on a calendar-year basis; therefore, it is reasonable to assume that the Board may find improved comparability for a distribution company whose rates are applied also on a calendar-year basis.

Response to Interrogatory from
Energy Probe Research Foundation

Reference: *Reference Exhibit: Tab B Smart Meters*

Preamble:

The evidence of the Applicant, beginning at Paragraph 19 of Tab B, states that Enersource was one of the thirteen licensed distributors deemed to be applicants in the EB-2007-0063 Combined Proceeding. Further, the evidence states that the Board issued its Decision in this Combined Proceeding on August 8, 2007, approving the costs claimed by Enersource with respect to smart metering activities.

***Questions**:*

a) On December 13, 2007, the Board issued its Decision and Order on Cost Awards. Is Enersource in compliance in respect of that Board Order?

b) If the answer to a) above is yes, please advise the date that your cheque for $1,802. 78 was issued in payment and forwarded to Energy Probe Research Foundation.

c) If the answer to a) above is no, please advise the steps the Applicant will now take to achieve compliance.

Response:

a), b) and c) This question is not relevant to this proceeding.

For the Board's information, the relevant invoice has been paid by Enersource.

Response to Interrogatory from
Energy Probe Research Foundation

Reference: *Exhibit: Tab E*
Smart Meter Funding Adder

Preamble:

The evidence of the Applicant, beginning at Paragraph 5 of Tab E, states that the Applicant proposes to increase the Smart Meter Funding Adder (SMFA) from $1.41 per customer per month to $2.17 per customer per month which is an increase of about 54%. The primary reason for this increase is "due to the fact that Enersource will be in its final year of its SMIP."

Question:

What factors unique to the final year of Enersource's SMIP would cause the SMFA to increase by such a significant amount?

Response:

Enersource began its SMIP in 2006 and continued to deploy smart meters throughout 2007, 2008, and 2009, and we will continue into 2010, the final year of the SMIP. As Enersource continues with its SMIP deployment, the revenue requirement and all of its components, as shown on Tab E, Schedule 2, continue to grow. The evidence captures all over-collections and under-collections from the past four years of the SMIP in addition to expected 2010 revenue requirements as part of this final SMFA.

Response to Interrogatory from
Energy Probe Research Foundation

Reference: Exhibit: Tab E Smart Meter Funding Adder

Preamble:

The evidence of the Applicant, beginning at Paragraph 5 of Tab E, states that the increase in the SMFA is also attributed to "an increase in operating costs associated with the replacements of hazardous meter bases".

Questions:

Please explain:

a) What distinguishes a "hazardous meter base" from a non hazardous meter base?

b) What are the operating costs that will increase because of hazardous meter bases?

c) Of the 25,400 residential smart meters to be installed in 2010 (referenced in paragraph 3 page 1), how many will involve "hazardous meter bases"?

d) Similarly, of the 9,440 small commercial smart meters to be installed in 2010, how many will involve "hazardous meter bases"?

e) How do these numbers of hazardous bases compare with the number of hazardous bases already dealt with in the smart meter program in the applicant's territory?

f) How much of the SMFA increase is attributable to increased operating costs associated with hazardous meter bases?

Response:

a) Enersource has meter bases in service that present a potential hazard when the meter is pulled. These meter bases must be repaired or replaced. Enersource prepared a Safe Work Practice policy upon first encountering this hazard before the introduction of Smart Meters and has respected that policy during the Smart Meter implementation. It is important to understand that under normal operating circumstances these bases are safe. The hazard exists when the meter is removed or pulled from the hazardous base.

The determination of a hazardous meter base is first made by examining the physical characteristics of the meter base itself. Dimensions, outward markings and certain known manufacturers are immediate indicators. To date, these meter bases have not been replaced as part of the smart metering deployment process. However, Enersource has been identifying these hazardous meters from 2006 to the present, and these remain as conventional meters until the company replaces them in 2010.

Additionally, the true level of potential danger is only known when the meter is removed and the internal components can be inspected.

b) The replacement of hazardous meter bases are outsourced and included as contract labour. In Tab E, Schedule 7, the 2010 operating cost related to the replacement of hazardous meter bases is $1,350,000.

c) Enersource has not yet started a program to replace hazardous meter bases. The company has allocated time and financial resources to address the issue of hazardous meter bases in 2010, the last year of its smart meter program. Enersource anticipates encountering additional hazardous meter bases in the 2010 deployment with similar proportions as were found from the start of the smart meter program to date (2006-2009).

d) None will involve hazardous meter bases.

e) Please refer to the response in part c) above.

f) Hazardous meter bases account for approximately $0.59 cents of the $2.17 SMFA. This increase is due to the undertaking of the replacement of hazardous meter bases in 2010.

Response to Interrogatory from
Energy Probe Research Foundation

Reference: *Exhibit: Tab E, Schedule 1 – Assumptions and Data*
Smart Meter Funding Adder

This Smart Meter Revenue Requirement Calculation shows Incremental Operating Costs for 2010 at $1,627,695.

Question:

Please provide a breakdown of these operating costs and an explanation of why they are expected to increase over 2009 costs by approximately $1M.

Response:

Please see Tab E, Schedule 7 which provides a breakdown of the operating costs. In this schedule, it is evident that the majority of the increase is related to labour and benefits which is a direct result of the replacement of hazardous meter bases.

Response to Interrogatory from
Energy Probe Research Foundation

Reference: *Exhibit: Tab E, Schedule 1 – Assumptions and Data*
Smart Meter Funding Adder

According to the Schedule the SMFA calculation results in an estimated cost of $2.62 per customer per month but the proposed SMFA is only $2.17 per customer per month.

Question:

Please explain why the proposed SMFA is lower than the calculated SMFA.

Response:

When calculating the SMFA, Enersource considers the cumulative revenue requirement based on actuals and/or the latest estimate of revenue requirement, where any over-recovery or under-recovery of smart meter revenue requirement is factored into the latest SMFA. As shown in Tab E, Schedule 2, Enersource has calculated total smart meter revenue requirement each rate year based on the SMFA that had been charged in that year, and has compared it against the actual/estimated smart meter revenue requirement over each of those same periods. Any over-collection or under-collection in a prior rate year is rolled forward or "trued-up" into the determination of the next year's Smart Meter Funding Adder. In that way, the balances in deferral accounts 1555 and 1556 have been minimized over the entire four year period, and as a result, ratepayers have been charged on a timely and relatively accurate basis for the actual smart meters installed.

Response to Interrogatory from
School Energy Coalition

Reference: Tab B/ Attach.1/ p.2

Question:

Please show the calculation of your monthly bills for each class for each year, as they do not appear to reconcile to your current and proposed tariff sheets. Please confirm that the spreadsheet attached as Schedule 1 to these interrogatories correctly continues your Bill Impacts chart through to April 30, 2014, on the following assumptions:

a) The Applicant files for 2012 rates based on cost of service with a rate increase of 6% for all classes.

b) The Applicant files for IRM-based rates for 2013 and 2014 with a formula rate increase of 1%.

If the information in the attached Schedule 1 is not correct, please insert corrected figures in the spreadsheet and show their derivation. Subject to any such corrections, please confirm that over the five year period May 1, 2009 to April 30, 2014, at current volumes and customer numbers, and using the cost of service rate increase assumption above, the proposal of the Applicant results in more than $3 million additional revenue to the distributor relative to methodology normally employed by the Board.

Response:

Enersource cannot confirm if the spreadsheet is correct and is unable to correct the figures based on the above assumptions.

First, with respect to the spreadsheet, it only includes distribution charges – not total bill impacts – and as footnoted in Tab B, Attachment 1, page 1, “The Base Monthly Rates do not include SMFAs or shared tax savings rate riders”.

Second, with respect to future cost of service applications and rate orders, Enersource has proposed that the rate year and fiscal year alignment will not have a material impact on any customer class for 2010 and 2011, as shown in Tab B. Assuming that Enersource files a cost of service application in 2012, it will propose, and the Board will approve, just and reasonable distribution rates for the period starting the effective date of the rate order. SEC has made the assumption that it is appropriate to apply a 6% rate increase to the previous year's rate. In a cost of service application, Enersource would be required to recalculate the revenue requirement, number and types of customers, consumption and any revenue sufficiency/deficiency in order to determine new distribution rates. The Board's determination of costs in support of rates for the period will have an effective date that is the same as the date that the costs are assumed to start being incurred. Rates collected in previous rate periods are not relevant for that determination.

Schedule 1 to the Interrogatories of School Energy Coalition

Impact of Change in Effective Date for Rates

Customer Class	Monthly	May 1, 2009 to December 31, 2009		January 1,2010 to April 30,2010		12 Month Bill	May 1, 2010 to December 31, 2010		January 1,2011 to April 30,2011		12 Month Bill	May 1, 2011 to December 31, 2011	
	Consumption	Monthly Bill	Total Period	Monthly Bill	Total Period		Monthly Bill	Total Period	Monthly Bill	Total Period		Monthly Bill	Total Period
Residential - current	800	21.17	$169.36	21.17	$84.68	$254.04	21.38	$171.04	21.38	$85.52	$256.56	21.59	$172.75
- proposed		21.17	$169.36	21.31	$85.24	$254.60	21.31	$170.48	21.52	$86.08	$256.56	21.52	$172.16
- difference						$0.56					$0.00		
						0.22%					0.00%		
General Service <50 - current	10000	154.44	$1,235.52	154.44	$617.76	$1,853.28	155.98	$1,247.84	155.98	$623.92	$1,871.76	157.54	$1,260.32
- proposed		154.44	$1,235.52	155.47	$621.88	$1,857.40	155.47	$1,243.76	157.02	$628.08	$1,871.84	157.02	$1,256.16
- difference						$4.12					$0.08		
						0.22%					0.00%		
Small Commercial	10000	203.56	$1,628.48	203.56	$814.24	$2,442.72	205.60	$1,644.80	205.60	$822.40	$2,467.20	207.66	$1,661.25
- proposed		203.56	$1,628.48	204.92	$819.68	$2,448.16	204.92	$1,639.36	206.97	$827.88	$2,467.24	206.97	$1,655.76
- difference						$5.44					$0.04		
						0.22%					0.00%		
General Service 50-499	230	1024.13	$8,193.04	1024.13	$4,096.52	$12,289.56	1034.37	$8,274.96	1034.37	$4,137.48	$12,412.44	1044.71	$8,357.71
- proposed		1024.13	$8,193.04	1030.96	$4,123.84	$12,316.88	1030.96	$8,247.68	1041.27	$4,165.08	$12,412.76	1041.27	$8,330.16
- difference						$27.32					$0.32		
						0.22%					0.00%		
General Service 500-4999	2250	6182.28	$49,458.24	6182.28	$24,729.12	$74,187.36	6244.10	$49,952.80	6244.10	$24,976.40	$74,929.20	6306.54	$50,452.33
- proposed		6182.28	$49,458.24	6223.50	$24,894.00	$74,352.24	6223.50	$49,788.00	6285.73	$25,142.92	$74,930.92	6285.73	$50,285.84
- difference						$164.88					$1.72		
						0.22%					0.00%		
Large Use >5000	50000	158016.70	$1,264,133.60	158016.70	$632,066.80	$1,896,200.40	159596.98	$1,276,775.84	159596.87	$638,387.48	$1,915,163.32	161192.84	$1,289,542.71
- proposed		158016.70	$1,264,133.60	159070.14	$636,280.56	$1,900,414.16	159070.14	$1,272,561.12	160660.85	$642,643.40	$1,915,204.52	160660.85	$1,285,286.80
- difference						$4,213.76					$41.20		
						0.22%					0.00%		
Street Lighting	0.5	6.40	$51.20	6.40	$25.60	$76.80	6.46	$51.68	6.46	$25.84	$77.52	6.52	$52.20
- proposed		6.40	$51.20	6.44	$25.76	$76.96	6.44	$51.52	6.50	$26.00	$77.52	6.50	$52.00
- difference						$0.16					$0.00		
						0.21%					0.00%		

Continuation of columns

Customer Class	January 1,2012 to April 30,2012		12 Month Bill	May 1, 2012 to December 31, 2012		January 1,2013 to April 30,2013		12 Month Bill	May 1, 2013 to December 31, 2013		January 1,2014 to April 30,2014		12 Month Bill	Total Bills
	Monthly Bill	Total Period		Monthly Bill	Total Period	Monthly Bill	Total Period		Monthly Bill	Total Period	Monthly Bill	Total Period		for Period
Residential - current	21.59	$86.38	$259.13	22.81	$182.49	22.81	$91.24	$273.73	23.04	$184.31	23.04	$92.16	$276.47	$1,319.93
- proposed	22.81	$91.24	$263.40	22.81	$182.49	23.04	$92.16	$274.65	23.04	$184.31	23.27	$93.08	$277.39	$1,326.60
- difference			$4.28					$0.91					$0.92	$6.67
			1.65%					0.33%					0.33%	0.51%
General Service <50 - current	157.54	$630.16	$1,890.48	166.44	$1,331.53	166.44	$665.76	$1,997.29	168.11	$1,344.84	168.11	$672.42	$2,017.27	$9,630.08
- proposed	166.44	$665.76	$1,921.92	166.44	$1,331.53	168.11	$672.42	$2,003.95	168.11	$1,344.84	169.79	$679.15	$2,023.99	$9,679.11
- difference			$31.45					$6.66					$6.72	$49.03
			1.66%					0.33%					0.33%	0.51%
Small Commercial	207.66	$830.62	$2,491.87	219.39	$1,755.11	219.39	$877.55	$2,632.66	221.58	$1,772.66	221.58	$886.33	$2,658.98	$12,693.44
- proposed	219.39	$877.55	$2,533.31	219.39	$1,755.11	221.58	$886.33	$2,641.43	221.58	$1,772.66	223.80	$895.19	$2,667.85	$12,757.99
- difference			$41.44					$8.78					$8.86	$64.56
			1.66%					0.33%					0.33%	0.51%
General Service 50-499	1044.71	$4,178.85	$12,536.56	1103.75	$8,829.97	1103.75	$4,414.98	$13,244.95	1114.78	$8,918.27	1114.78	$4,459.13	$13,377.40	$63,860.92
- proposed	1103.75	$4,414.98	$12,745.14	1103.75	$8,829.97	1114.78	$4,459.13	$13,289.10	1114.78	$8,918.27	1125.93	$4,503.73	$13,422.00	$64,185.88
- difference			$208.58					$44.15					$44.59	$324.96
			1.66%					0.33%					0.33%	0.51%
General Service 500-4999	6306.54	$25,226.16	$75,678.49	6662.87	$53,302.99	6662.87	$26,651.50	$79,954.49	6729.50	$53,836.02	6729.50	$26,918.01	$80,754.03	$385,503.57
- proposed	6662.87	$26,651.50	$76,937.34	6662.87	$53,302.99	6729.50	$26,918.01	$80,221.00	6729.50	$53,836.02	6796.80	$27,187.19	$81,023.21	$387,464.71
- difference			$1,258.84					$266.51					$269.18	$1,961.14
			1.66%					0.33%					0.33%	0.51%
Large Use >5000	161192.84	$644,771.35	$1,934,314.06	170300.50	$1,362,404.01	170300.50	$681,202.00	$2,043,606.01	172003.51	$1,376,028.05	172003.51	$688,014.02	$2,064,042.07	$9,853,325.87
- proposed	170300.50	$681,202.00	$1,966,488.80	170300.50	$1,362,404.01	172003.51	$688,014.02	$2,050,418.03	172003.51	$1,376,028.05	173723.54	$694,894.16	$2,070,922.21	$9,903,447.73
- difference			$32,174.74					$6,812.02					$6,880.14	$50,121.86
			1.66%					0.33%					0.33%	0.51%
Street Lighting	6.52	$26.10	$78.30	6.89	$55.12	6.89	$27.56	$82.68	6.96	$55.67	6.96	$27.84	$83.51	$398.80
- proposed	6.89	$27.56	$79.56	6.89	$55.12	6.96	$27.84	$82.96	6.96	$55.67	7.03	$28.11	$83.79	$400.78
- difference			$1.26					$0.28					$0.28	$1.98
			1.62%					0.33%					0.33%	0.50%

Response to Interrogatory from
School Energy Coalition

Reference: Tab B/Attach.1/ p.2

Question:

Please illustrate the effect of growing load on the proposed adjustment factor over time by preparing a table that:

a) Forecasts load and customer numbers over the period 2010 to 2013. If no such forecasts are available, please use an annual increase in load and customers numbers for each class in each year equal to the average increase for that class for the period 2006 to 2008.

b) Calculates the overall forecast revenues for the Applicant for each of the periods set out in the Bill Impacts chart (extended to December 31, 2013, as we have illustrated), on the assumptions set out in question #1 above.

c) Compares the forecast revenues using the May 1st starting date for new rates each year, as opposed to the proposed January 1st starting date.

Response:

a) Enersource filed its 2008 load and customer forecast in EB-2007-0706, its 2008 cost of service rates proceeding. Enersource notes that load and customer forecasts will be part of future cost of service applications.

Tab I, Exhibit 5.2, Attachment A shows the calculations of the annual load and customer numbers for each class from 2010 to 2013 assuming the annual increase is equal to the average increase for that class for the period 2006 to 2008.

b) Please refer to the response in Tab I, Exhibit 5.1.

c) Please refer to the response in Tab I, Exhibit 5.1.

	2008	2007	2006	2007 over 2006	2008 over 2007	Avg (2006 over 2008)	2009	2010	2011	2012	2013
TOTAL											
Number of Customers	**235,400**	**232,078**	**230,405**	**0.7%**	**1.4%**	**1.1%**	**237,967**	**240,578**	**243,234**	**245,937**	**248,689**
Billed kW	**13,585,043**	**13,744,945**	**13,457,340**	**2.1%**	**-1.2%**	**0.5%**	**13,654,817**	**13,726,331**	**13,799,640**	**13,874,798**	**13,951,859**
Billed kWh	**8,095,934,029**	**8,278,380,806**	**8,133,404,244**	**1.8%**	**-2.2%**	**-0.2%**	**8,083,973,854**	**8,075,200,572**	**8,069,703,229**	**8,067,575,649**	**8,068,916,640**
Residential											
Number of Customers	165,882	162,800	161,749	0.6%	1.9%	1.3%	167,991	170,127	172,290	174,481	176,699
Billed kWh	1,590,715,870	1,632,816,129	1,603,332,097	1.8%	-2.6%	-0.4%	1,584,834,509	1,578,974,893	1,573,136,941	1,567,320,574	1,561,525,712
GS Small Commercial											
Number of Customers	375	387	428	-9.6%	-3.1%	-6.3%	351	329	308	289	270
Billed kW											
Billed kWh	11,864,055	11,930,161	12,335,645	-3.3%	-0.6%	-1.9%	11,636,194	11,412,709	11,193,516	10,978,534	10,767,680
GS<50kW											
Number of Customers	16,318	16,018	16,024	0.0%	1.9%	0.9%	16,468	16,619	16,771	16,925	17,081
Billed kW											
Billed kWh	698,622,376	691,009,839	684,216,290	1.0%	1.1%	1.0%	705,938,869	713,331,986	720,802,530	728,351,310	735,979,147
GS 50 - 499 kW											
Number of Customers	3,867	4,042	4,019	0.6%	-4.3%	-1.9%	3,794	3,723	3,653	3,585	3,517
Billed kW	6,355,155	6,487,946	6,337,992	2.4%	-2.0%	0.2%	6,365,299	6,375,458	6,385,634	6,395,826	6,406,035
Billed kWh	2,298,548,818	2,363,219,355	2,348,480,806	0.6%	-2.7%	-1.1%	2,274,311,011	2,250,328,789	2,226,599,454	2,203,120,342	2,179,888,812
GS500 - 4999 kW											
Number of Customers	477	460	367	25.3%	3.7%	14.5%	546	626	716	820	939
Billed kW	5,277,864	5,400,270	5,275,299	2.4%	-2.3%	0.1%	5,280,564	5,283,266	5,285,969	5,288,673	5,291,379
Billed kWh	2,384,183,297	2,507,509,194	2,465,018,226	1.7%	-4.9%	-1.6%	2,346,101,879	2,308,628,717	2,271,754,096	2,235,468,455	2,199,762,388
GS>5000kW Large User											
Number of Customers	10	9	9	0.0%	11.1%	5.6%	11	11	12	12	13
Billed kW	1,842,419	1,747,676	1,735,695	0.7%	5.4%	3.1%	1,898,717	1,956,736	2,016,528	2,078,146	2,141,648
Billed kWh	1,071,190,308	1,031,619,677	980,065,806	5.3%	3.8%	4.5%	1,119,908,166	1,170,841,717	1,224,091,733	1,279,763,565	1,337,967,358
Streetlights											
Number of Customers	48,471	48,362	47,809	1.2%	0.2%	0.7%	48,806	49,143	49,483	49,825	50,169
Billed kW	109,605	109,052	108,354	0.6%	0.5%	0.6%	110,236	110,871	111,509	112,151	112,797
Billed kWh	40,809,305	40,276,452	39,955,374	0.8%	1.3%	1.1%	41,243,226	41,681,761	42,124,959	42,572,869	43,025,542

Response to Interrogatory from
School Energy Coalition

Reference: Tab B, p. 3

Question:

Please confirm that the Applicant is not proposing to change its fiscal year end or financial reporting period. Assuming that is confirmed, please confirm that, under the Board's normal rules for electricity distributors, rates to recover costs in the calendar year are collected over a twelve month period that starts four months later, such that cost of service for the period January 1, 2010 to December 31, 2010 is collected over the period May 1, 2010 to April 30, 2011. Please confirm that the Applicant is seeking to change the period over which the revenue requirement is collected, accelerating it from May 1-April 30 to January 1-December 31.

Response:

Enersource confirms that it is not proposing to change its fiscal year-end or financial reporting period.

As approved by the Board in EB-2007-0706, Enersource's costs for calendar year 2008 were recovered over the twelve-month period that started on May 1, 2008. Subsequent to that rate year, Enersource's rates have not been rebased in an annual cost of service proceeding. Accordingly, Enersource's annual forecasted costs have not been recovered per se but its rates have been formulaically adjusted based on the 3rd GIRM price escalator.

Enersource confirms that it is seeking a rate order for 3rd GIRM adjusted rates to be effective January 1, 2010.

Response to Interrogatory from
School Energy Coalition

Reference: Tab B, p. 3

Question:

Please set out the GDP-IPI for each month commencing September 2008 and ending with the latest month that is currently available.

Response:

GDP-IPI data is not available on a monthly basis. It is, however, available on a quarterly basis as presented by Statistics Canada in CANSIM Table 380-0003. Please refer to the response in Tab I, Exhibit 6.2.

Response to Interrogatory from
School Energy Coalition

Reference: Tab B, p. 3

Question:

Please confirm that the Applicant's proposal results in each component of the annual rate increase being reduced by one-third, including the productivity factor, the stretch factor, and the inflation factor. Please explain why the productivity factor and the stretch factor should be reduced for this Applicant.

Response:

Yes, the PCI is reduced by one-third. In Tab B, Attachment 1 Enersource has calculated the impact of this implementation and determined that the change will be financially neutral to the customer and to the shareholder only if the PCI is reduced by one-third.

Response to Interrogatory from
School Energy Coalition

Reference: Tab B, p. 8

Question:

Please confirm that the Applicant proposes to pay the amount of $24,235 applicable to the period January 1, 2010 to April 30, 2010 over twelve months instead of four. Please describe the impact, if any, of rounding in the Applicant's billing program on the proposed rate riders. Please explain why, given the small amount, the Applicant did not consider it more appropriate to propose a one time refund on January 2010 bills.

Response:

Yes, Enersource has included 4/12ths of the 2009 shared tax savings rate rider to be returned to customers over a 12-month period. Enersource has included the remaining 2009 shared tax savings rate rider along with the full 2010 shared tax savings rate rider to compute the final shared tax savings rate rider. The effects of rounding related to the 2009 shared tax savings rate riders are as follows:

Effects of Rounding on 2009 Shared Tax Savings Rider	Total for customer class as % of Total for all classes	Shared Tax Savings	Total to be refunded over 1 year	kWh Forecast 2008	kW Forecast 2008	Rate Riders May 1. 2009 - April 30. 2010	Rounded Rates	Shared Tax Saving - Impact due to rounding of rates
		$ (24,235)	**$ (24,235)**					
RESIDENTIAL	36.48%	$ (8,841)	$ (8,841)	1,594,788,347		$ (0.000006)	$ -	(8,841)
General Service < 50 kW	13.08%	$ (3,171)	$ (3,171)	657,014,642		$ (0.000005)	$ -	(3,171)
Small Commercial	0.56%	$ (135)	$ (135)	11,905,587		$ (0.000011)	$ -	(135)
General Service 50 kW - 499 k	25.80%	$ (6,253)	$ (6,253)		6,418,332	$ (0.000974)	$ (0.001000)	-
General Service 500 kW - 4999	16.86%	$ (4,086)	$ (4,086)		5,310,121	$ (0.000769)	$ (0.000800)	-
Large Use (> 5000 kW)	5.55%	$ (1,346)	$ (1,346)		1,720,956	$ (0.000782)	$ (0.000800)	-
Street Lighting	1.67%	$ (404)	$ (404)		115,190	$ (0.003506)	$ (0.003500)	404
TOTALS	**100.00%**	**$ (24,235)**	**$ (24,235)**					(11,743)

Enersource did not consider a different method of refund as it is following the Board's models with regards to including the shared tax savings rate rider as a volumetric rate rider.

Response to Interrogatory from
School Energy Coalition

Reference: Tab B, p. 8

Question:

Please provide the reference in the rate generator that shows the inclusion of this rate rider in bills commencing January 1, 2010. Please confirm that the reference (on page N1.1 of the rate generator filed as a .pdf with the Application) to the tax rider ending December 31, 2009 is incorrect, and the correct date of December 31, 2010, is included in the live version of the rate generator filed with the Board.

Response:

Tab N.1.1 includes the 2009 and 2010 tax sharing rate riders as presented in Tab B, page 8. Enersource confirms that the originally-filed application was based on the 2009 3rd GIRM model which hard-coded the date of December 31, 2009, and that the revised 2010 Rate Generator model filed with the Board on August 18, 2009 through the Board's RESS, includes the correct date of December 31, 2010.

Response to Interrogatory from
School Energy Coalition

Reference: Tab B, p. 13

Question:

Please provide the calculations supporting each of the figures in Table 4. If those calculations are already in the evidence, please direct us to the appropriate reference.

Response:

Please see the table below which presents information that is consistent with Worksheet: O2.1 (Calculation of Bill Impact) of the revised rate generator (Enersource APPL_OEB 2010 IRMS Rate Generator_20090818) that was filed through the Board's RESS on August 18, 2009.

Proposed 2010 Total Monthly Bill Impact

Customer Type	Monthly Consumption	Change $	Change %
Residential	800 kWh	$ 0.97	1.0%
General Service < 50 kW	10,000 kWh	$ 2.15	0.2%
Small Commercial (per meter)	10,000 kWh	-$ 0.14	0.0%
Small Commercial (per connection)	10,000 kWh	-$ 0.94	-0.1%
General Service 50 kW - 499 kW	230 KW	$ 10.01	0.1%
General Service 500 kW - 4999 kW	2,250 KW	$ 74.50	0.1%
Large Use (> 5000 kW)	50,000 KW	$ 1,976.10	0.1%
Street Lighting	0.5 KW	$ 0.03	0.3%

Source: Enersource_APPL_OEB 2010 IRMS Rate Generator_20090818
Worksheet: O2.1 Calculation of Bill Impact

Response to Interrogatory from
School Energy Coalition

Reference: Tab B, p. 13

Question:

Please confirm that the spreadsheet attached as Schedule 2 correctly sets out the proposed distribution bill impacts for the various sample customers as indicated. If it does not, please provide corrected figures.

Response:

Confirmed.

Schedule 2 to the Interrogatories of School Energy Coalition

Distribution Rate Impacts

Customer Class	*Monthly*	*2009 Rates*			*2010 Rates*			*Increase*	
	Consumption	*Fixed*	*Variable*	*Total Annual*	*Fixed*	*Variable*	*Total Annual*	*Amt.*	*Percent*
Residential	800	13.14	0.0118	$270.96	13.98	0.0119	$282.00	$11.04	4.07%
General Service <50	10000	40.85	0.0115	$1,870.20	41.87	0.0116	$1,894.44	$24.24	1.30%
Small Commercial	10000	11.97	0.0193	$2,459.64	12.8	0.0194	$2,481.60	$21.96	0.89%
General Service 50-499	230	70.42	4.1527	$12,306.49	71.64	4.1804	$12,397.58	$91.09	0.74%
General Service 500-4999	2250	1520.79	2.0724	$74,204.28	1531.68	2.0862	$74,707.56	$503.28	0.68%
Large Use >5000	50000	13688.11	2.8866	$1,896,217.32	13780.11	2.9058	$1,908,841.32	$12,624.00	0.67%
Street Lighting	0.5	1.33	10.1327	$76.76	1.34	10.2003	$77.28	$0.53	0.68%

Response to Interrogatory from
Vulnerable Energy Consumers Coalition

Reference: *Application, Tab B, pages 2-3, paragraphs #6-#9*

Preamble: *Enersource states that the misalignment between the commencement of its fiscal year and its effective date for Rate Orders leads to a difference between its actual rate of return and its approved rate of return and that, as a reporting issuer, it is required to explain this complicated outcome to the investment community, including its bondholders.*

Question:

a) *Please indicate who Enersource's bondholders are.*

b) *Which of Enersource's bondholders, if any, also hold debt issued by other electricity distributors or transmitters in Ontario?*

c) *Please provide copies of all requests or other communications received from either bondholders or the investment community over the last twelve months that resulted in Enersource providing explanations as to the difference between Enersource's actual vs. approved rate of return.*

d) *Please provide copies of all materials prepared by Enersource for use in explaining to either bondholders or the investment community the difference between its approved and actual rate of return. Please also include all internal materials prepared to assist with oral explanations.*

e) *Please confirm that the difference between start of the fiscal year and the effective date for rates is only one of the reasons why Enersource's actual rate of return could vary from the approved rate.*

f) *Based on Enersource's experience over the past 3 years what have been the other factors contributing to a difference between the approved and actual rate of return.*

g) *With respect to paragraph #9, please confirm that the quoted reference deals with the implementation of a change in fiscal year end – not a change in effective date.*

Response:

a) and b)
Enersource does not have access to a listing of the bondholders and, as such, cannot provide this information.

c) Enersource has not received any direct communications from bondholders, who are a subset of Enersource's stakeholders in the investment community. Enersource management has, over the years, found itself having to explain to its shareholders and to credit agencies the disconnect between its rate year and fiscal year. One of the unwelcome effects of this disconnect is that the company's actual rate of return, which is calculated and reported on a fiscal year basis (January 1 to December 31), cannot be compared to the Board's allowed rate of return without having to also explain the regulated rate-making process. This is a complexity in the Company's communications with its stakeholders that is avoidable and unnecessary.

Other parties have observed the timing misalignment between rate year and calendar (fiscal) year. For example, Sun Life Financial stated:

> "Although the Board's process with respect to the timing of determination of the Cost of Capital has been set for a period of time, a change to a January 1 – December 31 rate year, and a related advancing of the Cost of Capital determination to November would align the Board's timelines with those in other jurisdictions and ease comparison of regulatory decisions across jurisdictions."
> *Sun Life Financial's submission dated April 17, 2009 in the Board's proceeding EB-2009-0084, Cost of Capital in Current Economic and Financial Market Conditions. (Note that Sun Life Financial is a bondholder with a significant investment interest in Ontario and other Canadian utilities.)*

The process is not clear for stakeholders, and for the sake of transparency requires repeated explanations due to the unnecessarily but inherently complex process of setting rates effective May 1.

Complexity stems from the two different cycles at play in the process: the calendar year from which inputs are captured and the delayed start of the rate year during which the resulting rates are implemented. It is difficult to justify to stakeholders why such a process utilizes input data (e.g., costs, expenses, inflation factors) all on a prior calendar year basis, while rates are set on some other (delayed) timing basis.

As a result of this disconnect, stakeholders must undertake additional analyses in order to conduct comparisons. Typically, this is categorized as "regulatory uncertainty" because the gaps from the disconnect are not completely understood or accurately measured.

A change to a January 1 rate year will improve the matching of the input data with the resulting application of the rate change, and will result in no harm to the ratepayers.

d) Enersource provides a distribution revenue variance analysis in its quarterly Management Discussion and Analysis (MD&A) provided to the Ontario Securities Commission to inform bondholders and potential investors. Please refer specifically to pages 3 and 4 of the Management's Discussion and Analysis of Financial Condition and Results of Operations For the Second Quarter Ended June 30, 2009, which is attached as Tab I, Exhibit 6.1, Attachment A.

There are several references in the MD&A to the May 1 rate year, distinguishing it from the conventional fiscal reporting period, that is, in this case, the three-months and the six-months ending June 30. This is an example of a public document that reflects the type of complicated communication which Enersource must make to stakeholders due to the misalignment between the rate year and the calendar fiscal year. A financial comparison between the three-months or the six-months ending June 30 and the rate year commencing May 1 is very difficult for the reader to make.

e) Confirmed. Furthermore, this difference between the start of the fiscal year and the effective date for rates is a fundamental variance which occurs every year and significantly complicates the explanation of other anticipated variances.

f) The other factors are:

- variances between the actual electricity consumption in the City of Mississauga and the consumption figures underpinning Enersource's rates; and
- variances between planned and actual expenditures.

g) The result of the Decision cited in Tab B paragraph 9, which is the alignment of the rate year and the fiscal year, is the same result that is being sought by Enersource in this proceeding.

Management's Discussion and Analysis of Financial Condition and Results of Operations For the Second Quarter Ended June 30, 2009

($000 CAD)

This document has been prepared for the purpose of providing management's discussion and analysis ("MD&A") of our financial position and results of operations as at and for the three and six months ended June 30, 2009 compared to the six months ended June 30, 2008. The MD&A should be read in conjunction with our unaudited consolidated financial statements and accompanying notes for the six month period ended June 30, 2009, Enersource Corporation's ("Enersource") audited consolidated financial statements for fiscal year ended December 31, 2008 and other securities filings available on www.sedar.com. Enersource reports its consolidated financial statements in accordance with Canadian generally accepted accounting principles ("GAAP") considering regulatory requirements where applicable.

Throughout this MD&A, "our", "us", "we", "Company", "Corporation" and Enersource, refer to Enersource Corporation and its subsidiaries. The abbreviation "Qtr" refers to the relevant quarter within the fiscal year.

GENERAL

The financial statements as presented include results for both the regulated and non-regulated business activities. The Enersource Corporation group of companies includes Enersource, Enersource Hydro Mississauga Inc. ("Enersource Hydro"), Enersource Services Inc., Enersource Telecom Inc. ("Telecom"), Enersource Hydro Mississauga Services Inc. ("EHM Services"), Enersource Technologies Inc. and First Source Energy Corporation ("First Source").

Enersource is a holding company established in response to the restructuring and deregulation of Ontario's electricity industry. Enersource's principal operating subsidiary, Enersource Hydro, is the regulated electricity distributor for the City of Mississauga. The *Energy Competition Act*, *1998*, and its enabling regulations, require the separation of regulated distribution business activities from non-regulated business activities. Enersource has organized other affiliated companies and related entities for the purpose of operating its non-distribution related businesses.

EHM Services is a non-regulated subsidiary of Enersource with a primary business focus on providing electrical infrastructure design, procurement, construction, commissioning, and operating and maintenance services to businesses and other utilities. EHM Services also provides a range of utility and industry services including street light asset design, construction and maintenance.

Telecom and First Source remain dormant corporations as all major assets have been divested.

FORWARD LOOKING INFORMATION

Certain statements made in the MD&A, including, without limitation, statements relating to Enersource's expectations concerning future revenues and earnings, market conditions and the sufficiency of capital and liquidity, constitute forward-looking statements. Enersource believes these statements to be true based on its knowledge as at August 14 2009. These forward-looking statements are subject to risks, uncertainties, and other factors including, but not limited to, regulatory risk and electricity supply risk, many of which are beyond Enersource's control, which may cause future results to differ materially from those expected. Enersource does not undertake or accept any obligation to release publicly any updates or revisions to any forward-looking statements to reflect any change in Enersource's expectations, except as prescribed by applicable securities laws.

RATE REGULATION

Enersource Hydro is regulated by the Ontario Energy Board ("OEB") under authority of the Ontario Energy Board Act, 1998. The OEB is charged with the responsibility of approving or setting rates for the transmission and distribution of electricity and the responsibility for ensuring that distribution companies fulfill obligations to connect and service customers. The OEB has the power to establish electricity prices under a regulated price plan ("RPP"), as summarized in the following chart, for low volume consumers and designated consumers who do not choose an electricity retailer. The OEB may adjust the electricity commodity prices and consumption thresholds charged to these RPP consumers every six months as required.

Regulated Price Plan:

	Jan 2008 -Apr 2008	May 2008 -Oct 2008	Nov 2008 –Apr 2009	May 2009 – June 2009
Residential Consumption Threshold	1,000 kWh	600 kWh	1,000 kWh	600 kWh
Non-Residential Consumption Threshold	750 kWh	750 kWh	750 kWh	750 kWh
Price below threshold	$.050/kWh	$.050/kWh	$.056/kWh	$0.57/kWh
Price above threshold	$.059/kWh	$.059/kWh	$.065/kWh	$.066/kWh

Distribution Rates:

Enersource Hydro submitted an electricity distribution rate re-basing application to the OEB on August 23, 2007 for the rate period May 1, 2008 through April 30, 2009. A settlement was negotiated with intervenors and was accepted by the OEB on January 4, 2008. The final distribution rates and charges for 2008 based upon the settlement were approved on April 18, 2008. The impact of this decision on the total bill of an average residential customer consuming 1,000 kWh of electricity per month was a decrease of 2.9%, which consists of an increase in base distribution rates of 0.4% and a decrease of 3.3% due to a refund of regulatory liabilities. The net impact of the new distribution rates combined with an increase in electricity pricing and price thresholds effective May 1, 2008, reduced the total bill of an average residential customer consuming 1,000 kWh of electricity per month by 0.6%.

In November 2008, Enersource Hydro submitted a formula based rate application to the OEB for the rate period May 1, 2009 through April 30, 2010. On March 16, 2009, the OEB released its decision and order on this rate application. The net impact of the new distribution rates combined with an increase in electricity pricing and price thresholds effective May 1, 2009 increased the total bill of an average residential customer consuming 1,000 kWh of electricity per month by 7.3%.

RESULTS OF OPERATIONS

Summary:

Consolidated net income for the three months ended June 30, 2009 was $3,278 as compared to net income of $3,857 for the second quarter of 2008. The decrease of $579 was primarily due to the effect of higher operations, maintenance and administration costs combined with reduced interest income and lower margins in non-regulated operations. This impact was partially offset by the effect of Enersource Hydro's distribution rate increase on May 1, 2009, lower payments due in lieu of corporate income taxes and reduced interest expense in the 2009 period as compared to 2008.

Consolidated net income for the six-months ended June 30, 2009 was $7,830 as compared to net income of $8,125 for the same period of 2008. The decrease of $295 was primarily due to the effect of higher operations, maintenance and administration costs combined with reduced interest income and higher amortization of capital assets in the 2009 period as compared to 2008. This impact was partially offset by the effect of Enersource Hydro's distribution rate increases on May 1, 2008 and May 1, 2009, lower payments due in lieu of corporate income taxes and reduced interest expense in the 2009 period as compared to 2008.

The consolidated cash position of Enersource at June 30, 2009 was $56,456 representing a decrease of $19,649 over the 2008 year end position.

Revenues:

	2nd Qtr 2009	2nd Qtr 2008	Change $
Electricity Pass Through	96,582	134,153	(37,571)
Distribution Revenue	27,525	27,050	475
Recovery (refund) of regulatory assets (liabilities)	(511)	(639)	128
Services Revenue	1,458	1,829	(371)
Other Revenue	1,401	1,071	330
Total Revenue	126,455	163,464	(37,009)

	YTD June 2009	YTD June 2008	Change $
Electricity Pass Through	229,353	270,130	(40,777)
Distribution Revenue	56,439	54,309	2,130
Recovery (refund) of regulatory assets (liabilities)	(2,278)	967	(3,245)
Services Revenue	3,786	3,290	496
Other Revenue	2,454	1,984	470
Total Revenue	289,754	330,680	(40,926)

Energy revenues consist mainly of electricity passed through at cost to standard service supply customers and retailer customers. All energy revenues were generated from regulated operations. For the second quarter ended June 30, 2009, electricity pass through revenue was $96,582 as compared to $134,153 for the second quarter of 2008, representing a decrease of $37,571 or 28.0%. This decline was primarily due to a decline of 5.5% or $5,592 in energy consumption in the 2009 period combined with a 23.8% $31,979 decrease in electricity prices in 2009 as compared to the second quarter of 2008.

For the six-months ended June 30, 2009, electricity pass through revenue was $229,353 as compared to $270,130 for 2008, representing a decrease of $40,777 or 15.1%. This decline was primarily due to a reduction of 4.2% or $10,146 in energy consumption in the 2009 period combined with an 11.3% or $30,631 decrease in electricity prices in 2009 as compared to 2008.

Distribution revenue in the regulated operations was $27,525 for the second quarter of 2009 compared to $27,050 in the 2008 period, representing an increase of $475 or 1.8%. The increase was primarily due to rate adjustments implemented May 1, 2008 and May 1, 2009 contributing $1,295 of additional revenue and quarter over quarter customer growth of $172. These increases were partially offset by a net decline of $992 due to reduced electricity consumption by residential and small commercial customers and lower energy demand by larger customers in the 2009 period as compared to 2008.

For the year to date period, distribution revenue was $56,439 compared to $54,309 in the 2008 period, representing an increase of $2,130 or 3.9%. Enersource Hydro's rate adjustments implemented May 1, 2008 and May 1, 2009 provided $2,784 of additional revenue and year over year customer growth of $504. This increase was partially offset by a net revenue decline of $1,158 relating to lower electricity consumption by residential and small commercial customers and reduced energy demand by larger customers in the 2009 period as compared to 2008.

The net refund of regulatory liabilities to customers was $511 for the second quarter of 2009 and $2,278 for the six-months ended June 30, 2009 as compared to a regulatory liability refund of $639 and a regulatory asset recovery of $967 for the 2008 corresponding periods.

Services revenue from non-regulated operations was generated from street lighting services and engineering design and construction contracts. The decrease in services revenue of $371 for the second quarter of 2009 as compared to 2008 was the result of lower engineering design and construction activity and related revenue for the second quarter of 2009.

The increase in services revenue of $496 for the six-months ended June 30, 2009 as compared to 2008 was the result of higher street light maintenance activity and related contract revenue for the 2009 period as compared to 2008.

Other revenues are mainly attributable to distribution operations and include late payment charges, set-up charges, pole rental fees and funding by the Ontario Power Authority ("OPA") for conservation programs. Other revenues increased by $330 over the second quarter of 2008 primarily due to higher conservation and demand management program funding provided by the OPA combined with an increased gain on disposal of capital assets in the 2009 quarter as compared with 2008.

Other revenues increased by $470 for the six-months ended June 30, 2009 over 2008 primarily due to higher conservation and demand management program funding provided by the OPA and the Ontario Ministry of Energy and Infrastructure ("MEI") combined with an increased gain on disposal of capital assets in the 2009 period as compared with 2008.

Operating Expenses:

	2nd Qtr 2009	2nd Qtr 2008	Change $
Energy Purchases	96,582	134,153	37,571
Cost of Services	1,399	1,487	88
Operations, Maintenance and Administration	11,020	9,891	(1,129)
Amortization of Capital Assets	8,069	7,879	(190)
Amortization of Intangible Assets	132	268	136
Amortization of Regulatory (Liabilities) Assets	(511)	(639)	(128)
Expenses	116,691	153,039	36,348

	YTD June 2009	YTD June 2008	Change $
Energy Purchases	229,353	270,130	40,777
Cost of Services	3,413	2,642	(771)
Operations, Maintenance and Administration	21,957	19,659	(2,298)
Amortization of Capital Assets	16,028	15,684	(344)
Amortization of Intangible Assets	260	508	248
Amortization of Regulatory (Liabilities) Assets	(2,278)	967	3,245
Expenses	268,733	309,590	40,857

Energy purchase expense, which is entirely attributed to regulated operations and is passed through to customers at cost, declined by $37,571 or 28.0% for the second quarter ended June 30, 2009 as compared to the corresponding quarter of 2008 due to a decline in consumption as well as lower electricity market pricing in the 2009 period.

Energy purchase expense declined by $40,777 or 15.1% for the six-months ended June 30, 2009 as compared to the corresponding period of 2008 due to the aforementioned reasons.

The cost of services in non-regulated operations of $1,399 was $88 lower for the quarter ended June 30, 2009 than for the corresponding quarter of 2008 as a result of lower engineering design and construction activity and related costs during the second quarter of 2009.

The cost of services in non-regulated operations of $3,413 was $771 higher for the six-months ended June 30, 2009 than for the corresponding period of 2008 as a result of increased street light activity and related costs during the 2009 period as compared to 2008.

Consolidated operations, maintenance and administration costs, or the overhead costs incurred to manage the operations of the regulated and non-regulated companies, increased by $1,129 or 11.4% for the quarter ended June 30, 2009 from the corresponding quarter of 2008. Enersource Hydro costs increased by $1,277 primarily due to one-time restructuring costs incurred in the quarter, combined with an increase of $235 in conservation and demand management program expenditures as well as general inflationary increases in manpower and overhead expenses. These increases were partially offset by an operational tax credit of $782 recognized in the 2009 quarter.

Consolidated operations, maintenance and administration costs increased by $2,298 or 11.7% for the six-months ended June 30, 2009 from the corresponding period of 2008. Enersource Hydro costs increased by $2,543 primarily due to one-time restructuring costs, combined with an additional provision of $461 for bad debts, an increase of $448 in conservation and demand management program expenditures and an increase of $147 in environmental rehabilitation costs, as well as general economic increases in manpower and overhead expenses. These increases were partially offset by an operational tax credit of $782 recognized in the 2009 period. A one-time restructuring cost was also incurred in non-regulated operations in the 2009 period.

Amortization of capital assets increased by $190 for the quarter ended June 30, 2009 over the related 2008 period and by $344 for the six-months ended June 30, 2009 over 2008 primarily due to the ongoing investment in electricity distribution infrastructure assets.

Amortization of Enersource Hydro's intangible assets decreased by $136 for the quarter ended June 30, 2009 from the corresponding period of 2008 and by $248 for the six-months ended June 30, 2009 as compared to 2008 primarily due to the revision of the amortization rate for major computer systems from two years to ten years effective October 1, 2008.

Amortization of Enersource Hydro's regulatory balances that were previously deferred on the balance sheet was unfavourable by $128 for the quarter ended June 30, 2009 and favourable by $3,245 for the six-months ended June 30, 2009 over the corresponding periods of 2008. The amortization of regulatory balances is recorded based on the related recovery or refund amount included in revenue.

Operating Income:

	2nd Qtr 2009	**2nd Qtr 2008**	**Change $**
Revenue	126,455	163,464	(37,009)
Operating Expenses	116,691	153,039	36,348
Operating Income	9,764	10,425	(661)

	YTD June 2009	**YTD June 2008**	**Change $**
Revenue	289,754	330,680	(40,926)
Operating Expenses	268,733	309,590	40,857
Operating Income	21,021	21,090	(69)

Consolidated operating income declined by $661 in the second quarter of 2009 over the corresponding 2008 quarter, due to an increase of $1,129 in operations, maintenance and administration expenses combined with a reduction of $283 in EHM Services margins. This decline was partially offset by an increase in Enersource Hydro's distribution revenue of $475 and an increase of $330 in other revenue.

Consolidated operating income declined by $69 for the six-months ended June 30, 2009 over 2008 due to an increase of $2,298 in operations, maintenance and administration expenses combined with an increase of $344 in amortization of capital assets. These decreases were partially offset by the net effect of an increase in Enersource Hydro's distribution revenue of $2,130 and an increase of $470 in other revenue.

Non-Operating Revenue (Expense):

	2nd Qtr 2009	2nd Qtr 2008	Change $
Interest Income	92	850	(758)
Interest Expense	(4,381)	(4,891)	510
Foreign Exchange Gain (Loss)	(274)	(28)	(246)
Non-operating income (expense)	(4,563)	(4,069)	(494)

	YTD June 2009	YTD June 2008	Change $
Interest Income	372	1,812	(1,440)
Interest Expense	(8,907)	(9,837)	930
Foreign Exchange Gain (Loss)	(143)	168	(311)
Non-operating income (expense)	(8,678)	(7,857)	(821)

Interest income for the quarter and year to date periods ended June 30, 2009 declined by $758 and $1,440 due to lower average interest rates and lower average cash and cash equivalent position as compared to the corresponding period in 2008.

Enersource Hydro's interest expense for the three months and six months ended June 30, 2009 was primarily attributable to the Borealis – Enersource series bonds, interest on customer deposits and regulatory balances. Interest expense for the quarter and year to date periods ended June 30, 2009 declined by $510 and $930 due to lower average interest rates and regulatory liabilities as compared to the corresponding period in 2008. The amount of interest expense relating to the Borealis – Enersource series bonds was $4,548 for each three-month period and $9,046 for each six-month period.

For the quarter ended June 30, 2009, Enersource Hydro had a foreign exchange loss of $274 on U.S. dollar cash and cash equivalents as compared to a foreign exchange loss of $28 in 2008. In 2007, Enersource Hydro purchased U.S. dollars to mitigate foreign exchange risk relating to the implementation of a new Customer Care and Billing System where a substantial portion of the cost is to be paid in U.S. currency.

For the six-months ended June 30, 2009, Enersource Hydro had a foreign exchange loss of $143 on U.S. dollar cash and cash equivalents as compared to a foreign exchange gain of $168 in the corresponding period in 2008.

Payments in Lieu of Corporate Income Taxes:

2nd Qtr 2009	2nd Qtr 2008	Change $	YTD June 2009	YTD June 2008	Change $
1,870	2,496	626	4,458	5,108	650

For the quarter ended June 30, 2009, Enersource recorded payments in lieu of corporate income taxes ("PILs") of $1,870. The decline in PILs during the second quarter of 2009 as compared to the same quarter in 2008 was primarily due to lower income before payments in lieu of corporate income taxes in the 2009 quarter as well as a corporate tax rate reduction to 33.0% in 2009 from 33.5% in 2008. The adoption of CICA Handbook Section 3465, "Income Taxes" reduced PILs by $38 in the second quarter of 2009.

For the six-months ended June 30, 2009, Enersource recorded PILs of $4,458. The decline in PILs as compared to the first six months of 2008 was primarily due to lower income before payments in lieu of corporate income taxes in the 2009 period as well as a reduced corporate tax rate of 33.0%. The adoption of CICA Handbook Section 3465, "Income Taxes" reduced PILs by $410 in the first six-months of 2009.

Consolidated Cash Flows

	2nd Qtr 2009	**2nd Qtr 2008**	**YTD June 2009**	**YTD June 2008**
Increase (decrease) in cash and cash equivalents	(21,675)	11,463	(19,649)	24,575

During the quarter ended June 30, 2009, net cash outflow was $21,675 as compared to net inflow of $11,463 for the corresponding period of 2008. The net cash outflow in the second quarter of 2009 was comprised of a decline of $14,185 in retail settlement variances, combined with outflows of $10,423 and $1,406 to finance capital and intangible asset additions. The net cash inflow in the 2008 period was driven primarily by an increase in operating activities of $17,311 and outflows of $10,318 and $1,375 to finance capital and intangible asset additions.

During the six-months ended June 30, 2009, net cash outflow was $19,649 as compared to net inflow of $24,575 for the corresponding period of 2008. The net cash outflow in 2009 was comprised of a decline of $17,224 in retail settlement variances, combined with outflows of $21,978 and $2,704 to finance capital and intangible asset additions. These outflows were partially offset by a decline of $11,908 in unbilled revenue. The net cash inflow in the 2008 period was driven primarily by an increase in operating activities of $38,620 and outflows of $18,223 and $2,214 to finance capital and intangible asset additions.

Capital Expenditures

Enersource's capital expenditures were primarily attributable to investments in distribution system infrastructure assets in response to electricity demand and reliability requirements within Mississauga. Capital asset investment strategies are developed and reviewed continuously to maintain pace with the demand for electricity and to ensure that the operating performance of Enersource's distribution system, the condition of its assets and its customer service levels are all maintained to the highest industry standards.

Consolidated capital asset and intangible asset additions for the six-months ended June 30, 2009 were $22,622 as compared to $18,391 for the corresponding period in 2008. During the six months of 2009, distribution system capacity-related investments were $5,400 with system upgrades of $5,138 and system expansion-related investment of $4,519. Non-distribution system investments were $7,565 and included capital initiatives relating to information technology, fleet vehicles, smart meters and conservation and demand management programs. During the six-months of 2008, distribution system capacity-related investment was $2,693 with system upgrades of $5,506 and system expansion-related investment of $3,857. Non-distribution system investment was $6,335 and was inclusive of information technology, fleet vehicles, smart meters and conservation and demand management capital initiatives.

Liquidity and Capital Resources

Enersource's primary sources of liquidity and capital resources are funds from operating activities as well as an established banking line of credit, if required. These resources are primarily used for capital investments to maintain the integrity of the electricity distribution system and for servicing interest expense on debt.

Enersource's bank line of credit in the amount of $50,000 was not utilized during 2008.

In their report dated October 31, 2008, DBRS confirmed Borealis – Enersource series bonds debt rating at 'A', supported by stable financial metrics attributable to generally consistent earnings, cash flows and debt levels. Standard & Poor's confirmed Borealis – Enersource series bonds debt rating at 'A' in their June 12, 2009 report, citing Enersource's excellent business risk, regulated cash flows and growing customer base as factors for the confirmation.

Future Capital Expenditures

Enersource's capital and intangible asset expenditures in 2009 are projected to be $54,700 ($49,400 in 2010 and $42,700 in 2011). The overall planned capital and intangible asset expenditure levels reflect infrastructure investments required to construct and maintain electricity distribution assets. Additional capital and intangible asset investments include the deployment of smart meters and the replacement of Enersource Hydro's Customer Care and Billing System. Current cash balances and future cash flows from operations are expected to be sufficient to fund all capital requirements.

Contractual Obligations

The following table presents a summary of debt and other major contractual obligations as at June 30, 2009:

June 30, 2009 ($000's)	**Total**	**2009**	**2010/2011**	**2012/2013**	**After 2013**
Due By Year:					
Long-term debt*	290,000	-	290,000	-	-
Interest on long-term debt	36,482	9,121	27,361		
Capital purchase obligations	8,231	7,706	525	-	-
Operating leases	50	50	-	-	-
Total contractual obligations	334,763	16,877	317,886	-	-

- The Borealis – Enersource series bonds mature in May, 2011. The long term debt is expected to be refinanced at that time.
- The Long-term debt of $290,000 excludes debt issuance costs of $4,336.

Related Party Transactions

Enersource's operations included the provision of electricity and services to its principal shareholder, the City of Mississauga (the "City") in the normal course of business. Electricity was billed to the City at the prices and terms established between the City and its electricity retailer. Street lighting maintenance and construction services were provided at a fixed price or on a time and materials basis at an exchange amount, being that amount agreed to by the parties. A summary of amounts charged by Enersource to the City for the six-months ended June 30, 2009 is as follows:

	2009	2008
Electrical Energy	$4,387	$4,145
Street lighting Maintenance and Construction	2,642	2,588
Street lighting Energy	2,793	2,229
Total	9,822	8,962

At June 30, 2009, accounts payable and accrued liabilities due to the City were $1 (2008 - $nil). Accounts receivable due from the City was $1,416 (2008 - $2,016).

Enersource was charged $391 in the six-months ended June 30, 2009 (2008 - $386) by the City for property taxes.

Enersource charged Borealis $5 (2008 - $5) for an access agreement in 2009. These transactions were recorded at the exchange amount, being the amount agreed to by the parties. At June 30, 2009, accounts receivable included $nil (2008 – $1) due from Borealis.

Enersource was charged $2,742 in 2009 (2008 - $4,020) by Enerpower Corporation, an organization for which Enersource has a 10% minority ownership interest, for the construction of distribution system infrastructure. Enersource received a dividend from Enerpower Corporation of $nil in 2009 (2008 - $10).

Quarterly Results of Operations

The following table sets forth unaudited quarterly information for each of the eight quarters beginning July 1, 2007 and ending June 30, 2009. This information has been derived from Enersource's unaudited interim Consolidated Financial Statements. These financial results are not necessarily indicative of results for any future period and should not be relied upon to predict future performance. The consumption of electricity generally follows the number of cooling degree days during the summer months and heating degree days during the winter months, and therefore energy related revenue, all other things being equal, tends to be higher during the first and third quarters.

	2009/2008				2008/2007			
	30-Jun	31-Mar	31-Dec	30-Sep	30-Jun	31-Mar	31-Dec	30-Sep
Total Revenue	$126,455	$163,299	$162,088	$177,979	$163,464	$167,216	$172,676	$181,975
Total Expense	123,177	158,747	157,027	171,943	159,607	162,948	170,412	177,309
Net Income	$3,278	$4,552	$5,061	$6,036	$3,857	$4,268	$2,264	$4,666
Dividends	-	-	$8,980	-	-	-	$10,336	-

CRITICAL ACCOUNTING ESTIMATES

The preparation of financial statements requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the year. Estimates and assumptions are based on historical experience, current conditions and various other factors that are believed to be reasonable under the circumstances, the results of which form the basis for making estimates about the carrying values of assets and liabilities as well as identifying and assessing our accounting treatment with respect to commitments and contingencies. Actual results may differ from these estimates and assumptions.

Management believes the following critical accounting estimates involve the more significant estimates and assumptions used in the preparation of the financial statements:

Unbilled Distribution Revenue

Distribution revenue attributable to the delivery of electricity is based upon OEB approved distribution tariff rates and is recognized as electricity is delivered to customers, which includes an estimate of unbilled revenue, representing electricity consumed by customers since the date of each customer's last meter reading. Actual electricity usage could differ from estimates.

Employee Future Benefits

The total change in the employee accrued benefit obligation for the second quarter ended June 30, 2009 was $99 as compared to $136 for the second quarter ended June 30, 2008. The total net employee future benefit cost for the year to date period ended June 30, 2009 was $232 as compared to $283 for the corresponding 2008 period.

Future Income Tax Assets and Liabilities

The adoption by Enersource Hydro of CICA Handbook Section 3465, "Income Taxes" required Enersource Hydro to estimate and recognize future income tax liabilities and assets as well as a regulatory asset or liability for future income taxes expected to be recovered from or refunded to customers through future distribution rates. The estimates and assumptions used by Management are based on substantially enacted tax rates, historical experience and current regulatory conditions. Actual results may differ from these estimates and assumptions.

NEW AND EMERGING ACCOUNTING PRONOUNCEMENTS

Credit risk and the fair value of financial assets and financial liabilities

In January 2009, the CICA issued Emerging Issues Committee ("EIC") 173, Credit Risk and the Fair Value of Financial Assets and Financial Liabilities, which clarifies that the credit risk of counterparties should be taken into account in determining the fair value of derivative instruments. EIC 173 is to be applied retrospectively without the restatement of prior periods to all financial assets and liabilities measured at fair value in interim and annual statements for periods ending on or after the date of issuance of this Abstract. This change has not had a material impact on Enersource's results of operations.

Rate Regulated Future Tax Assets and Liabilities

Effective January 1, 2009, Enersource adopted CICA Handbook Section 3465, "Income Taxes" which required Enersource Hydro to record future income taxes using the asset and liability method. Under this method, future income tax assets and liabilities are recorded to recognize future income tax inflows and outflows arising from settlement or recovery of assets and liabilities at their carrying values. The adoption of this section required Enersource Hydro to recognize future income tax liabilities and assets and a corresponding regulatory asset or liability for future income taxes expected to be recovered from or refunded to customers through future distribution rates. The adoption of this section resulted in an increase in future income tax assets of $49,733, an increase in regulatory tax liability of $48,677, a decrease in PILs of $410 and an increase in retained earnings of $646 as at and for the year to date period ended June 30, 2009.

Capital Disclosure

Enersource's objectives with respect to its capital structure are to maintain effective access to capital on a long-term basis, at reasonable rates, and to deliver the appropriate financial returns to its shareholders.

Enersource Hydro was deemed by the OEB to have a capital structure that was funded by 60% long term debt and 40% equity. Effective May 1, 2008 the deemed capital structure for Enersource Hydro changed to 56% long-term debt, 4% short-term debt and 40% equity. The OEB applies this deemed structure as a basis of determining how capital is funded for rate setting purposes only. The actual capital structure for Enersource Hydro may differ from the OEB deemed structure.

Enersource has covenants typically associated with long-term debt. Enersource is in compliance with all credit agreement covenants and limitations associated with its long-term debt.

The Corporation has the following material covenants associated with its long-term debt.

(i) The consolidated financial statements must be audited, comply with GAAP and be filed directly on The System for Electronic Document Analysis and Retrieval ("SEDAR").

(ii) The Corporation shall make all payments of principal, interest and, as applicable, premiums in favour of Borealis Infrastructure Trust.

(iii) The Corporation shall not incur, issue or become liable for obligations that exceed 75% of the total consolidated capitalization or provide another security interest upon the same assets as the debt.

(iv) The Corporation shall not directly or indirectly invest in energy retailing unless at the time and after giving effect to the proposed investment:

  (a) No default or event of default shall have occurred and be continuing, or shall occur;

  (b) The aggregate amount of all such investments made shall not exceed the greater of (i) $20,000 and (ii) 5% of consolidated net worth.

Future Accounting Changes

Transition to International Financial Reporting Standards ("IFRS")

The Accounting Standards Board ("AcSB") has adopted a new strategic plan that will have Canadian GAAP converge with IFRS, effective January 1, 2011. The adoption date of January 1, 2011 will require the restatement, for comparative purposes, of the amounts reported by Enersource in its interim and year ended December 31, 2010 financial statements, and the opening balance sheet as at January 1, 2010. In May 2008, the Canadian Securities Administrators issued Staff Notice 52-320, which provides guidance on the disclosure of changes in expected accounting policies related to the change over to IFRS. According to the notice, Enersource is required to provide an update of the Corporation's IFRS conversion plan in each financial reporting period prior to conversion on January 1, 2011.

Enersource's IFRS conversion project consists of four phases: awareness, assessment, design and implementation. The awareness and assessment phases have been completed and included training for key stakeholders, identification of major impacts on systems, process and internal controls and completion of a detailed systematic gap analysis of the accounting and reporting differences between Canadian GAAP and IFRS.

Enersource is currently in the design phase of the IFRS conversion project which will assess the impacts of adopting IFRS on its financial statements after consideration of the options available under IFRS 1, First-time Adoption of IFRS. Enersource has determined that the adoption of IFRS will have an impact on information system requirements and is currently assessing the system upgrades or modifications required to ensure a seamless conversion to IFRS. Enersource will also design and develop new accounting policies under IFRS and assess whether there are any internal controls that may be impacted from the conversion. The differences currently identified as having the highest impact include the accounting for fixed assets, regulatory accounting, employee benefits and the initial adoption of IFRS under the provision of IFRS 1.

In July 2009, the International Accounting Standards Board ("IASB") issued an IFRS Exposure Draft relating to rate regulated activities. The proposed standard defines what criteria must be met in order to record a regulatory asset or liability and how to recognize and disclose the financial effects of the regulated asset or liability recorded. The IASB is expected to conclude on this matter in June 2010.

Enersource currently estimates that the total cost of the IFRS conversion project will be between $1,500 and $2,500. The OEB has indicated that a deferral account will be established that will allow utilities to defer incremental one-time administrative costs related to the transition to IFRS for potential recovery in future distribution rates.

SELECTED ANNUAL INFORMATION

The following table sets forth annual information for each of the three years ended December 31, 2006, 2007, and 2008. This information has been derived from the audited annual Consolidated Financial Statements.

Consolidated Statements of Income	2008	2007	2006
Total revenues[1]	$670,747	$696,491	$680,318
Net income	19,222	13,970	17,226

Consolidated Balance Sheets	2008	2007	2006
Total assets[2]	$653,906	$628,092	$613,789
Total long-term debt	288,735	288,556	288,122
Cash dividends declared	8,980	10,336	8,900

[1]Total revenue consists mainly of electricity passed through at cost to customers. Fluctuations in energy revenue are caused by variances in consumption and/or price.
[2]Total assets & long-term debt for 2006 reflects the reclassification of deferred debt issuance costs in 2007, applied retroactively.

RISK MANAGEMENT

Enersource utilizes a risk management program to mitigate business risk while optimizing shareholder value. A corporate risk assessment is undertaken annually under the guidance of Enersource's Audit Committee. This annual assessment identifies all operating risks for the organization and categorizes these risks according to significance and probability of occurrence. Risks that are deemed significant with a moderate to high probability of occurrence are analyzed for the purpose of developing mitigating strategies and implementing or validating operational controls. The annual risk assessment is a comprehensive review of all risks and mitigating controls to derive "residual risk".

Regulatory Risk

Enersource Hydro's operations are regulated by the OEB. The OEB exercises statutory authority over matters such as operational performance, rate setting, and financial returns.

The Ontario Government has provided a revenue adjustment mechanism to compensate utilities for lost revenues as a result of conservation programs. Until the rate application for recovery of lost revenues is submitted and appropriate recovery rates are permitted by the OEB, distribution revenues lost as a result of conservation programs remain at risk.

On April 22, 2004, the Supreme Court of Canada ruled on the case of Gordon Garland v. Enbridge Gas Distribution Inc. ("EGD"). The court concluded that the late penalties, which the natural gas utility had charged customers from 1994 to 2002, exceeded legal limits and amounted to criminal misconduct. A settlement was reached between the parties on July 20, 2006 which proposed that EGD would pay approximately $21,200 including a $9,000 donation to the Winter Warmth Fund prior to the end of January 2007, approximately $10,200 for the plaintiff's legal fees and expenses, and a payment of approximately $2,000 to the Class Proceedings Fund, operated by the Law Foundation of Ontario. The Supreme Court, on review of the proposal, directed that certain changes be made to the agreement. The Ontario Superior Court approved a settlement in December 2007 and the OEB ruled in February, 2008 that EGD can now recover $22,000 from ratepayers because the costs resulted from having to defend late-payment penalties established by OEB orders. The Electricity Distributors Association is reviewing the potential implications of the decision on the electricity distribution sector. It is too soon to assess if or to what extent the EGD decision will impact the electricity distribution utilities and, as such, any potential exposure for Enersource Hydro is indeterminable at this time.

On July 16, 2004, the Ontario Government announced that all electricity consumers in Ontario will have a smart meter no later than December 31, 2010. The OEB's smart meter implementation plan identifies local distribution companies as the source of funding for the supply and installation of the smart meters. Enersource Hydro is committed to executing the MEI's smart meter initiative to the full extent of OEB approvals. Notwithstanding the April 12, 2006 OEB announcement regarding the smart meter program, the recovery and recognition of all smart meter revenue and associated costs will dictate the timing and amount of future expenditures.

Electricity Supply Risk

At peak consumption periods the Independent Electricity System Operator ("IESO") may issue public appeals for reduced energy consumption with warnings of brownouts or blackouts if consumption is not reduced. In the event of a brownout or blackout in Mississauga due to electricity consumption levels exceeding available supply from the IESO, Enersource Hydro's distribution revenue would be adversely affected and as such, represents financial risk to the company.

Environmental Risk

Enersource is subject to numerous environmental regulations. As part of the Corporation's risk mitigation strategy, various environmental assessments are currently underway. At December 31, 2008, the Corporation had identified four sites and provided $180 for testing and future soil remediation. During the second quarter of 2009, the Corporation completed the soil remediation at three sites, identified one additional site and provided an additional $20 for testing and future soil remediation.

Environment Canada has issued new regulations governing the management of PCBs. Enersource is in the process of determining the impact of the new regulations. On December 1, 2008, the OEB approved Enersource Hydro's request to defer any expenses that may be incurred to comply with the new regulations. As at June 30, 2009 the Corporation deferred $514 regarding compliance with the new regulations.

Financial Instrument Risk

Exposure to market risk, credit risk and liquidity risk arises in the normal course of Enersource's business.

(a) Market Risk

Market risk refers primarily to risk of losses that result from changes in commodity prices, foreign exchange rates and interest rates. Enersource does not have commodity risk and its foreign exchange risk is limited to US Dollar cash and cash equivalent holdings of $2,568 as at June 30, 2009.

Distribution rates and charges are currently based on a revenue requirement less other income, which includes interest income. The difference between the interest revenue reduction from rates and the actual interest income earned by Enersource is expected to be insignificant.

(b) Credit Risk

Financial assets have an element of credit risk in that a counter party may fail to discharge its obligation, causing a financial loss. Enersource's distribution revenue is earned on a broad base of customers. As a result, Enersource did not earn a significant amount of revenue from any individual customer.

As at June 30, 2009, there were no significant balances of accounts receivable due from any single customer.

Enersource manages counterparty credit risk through various techniques including the limiting of total exposure levels with individual counterparties consistent with Enersource's policies and the monitoring of the financial condition of counterparties. Short-term investments held as at June 30, 2009 met the credit exposure limits specified under Enersource's Investment Policy.

Management believes that the credit risk of accounts receivable is limited due to the following reasons:

1. There is a broad base of customers with no one customer that accounts for revenue or an accounts receivable balance in excess of 10% of the respective balance;
2. Enersource Hydro as permitted by the OEB's Retail Settlement and Distribution System Code may obtain a security deposit or letter of credit from customers to mitigate the risk of payment default; and,
3. Enersource Hydro included an amount for accounts receivable write-offs within operations, maintenance and administration expense for rate setting purposes.

(c) Liquidity Risk

Liquidity risk is the risk that Enersource will not be able to meet its financial obligations as they come due. Short-term liquidity is provided through cash and cash equivalents on hand, funds from operations, as well as an established $50,000 banking line of credit, if required. Short-term liquidity is currently sufficient to fund normal operating requirements.

Economic Risk

The current economic uncertainty and financial market volatility may have an impact on Enersource. The primary financial impact Enersource may experience is higher customer payment defaults, resulting in larger accounts receivable write-offs. Management believes that its current credit risk policy and customer credit monitoring procedures mitigate to the fullest extent possible, the potential of a significant financial loss. If a significant loss is incurred, Enersource would apply to the OEB to recover the loss through future distribution rates.

The Borealis – Enersource bonds mature in May, 2011 and are expected to be refinanced at that time. Enersource believes that the risk in any change in interest rates on refinanced debt is insignificant as the impact is expected to be reflected in future distribution rates.

OUTLOOK

On May 14 2009, Ontario's Green Energy Act ("GEA") received Royal Assent. The GEA requires that electricity distributors provide priority access to the electricity distribution system to renewable electricity generation facilities. The GEA also allows the MEI to issue directives to the OEB to assign energy conservation and demand management targets to distributors, which may become a condition of the distributor's license. The Corporation may, in the future, be required to make additional investments in order to facilitate renewable generation projects and to increase the functionality and reliability of its distribution infrastructure in order to comply with the GEA. Any additional investments made by the Corporation will depend, to a large extent, on how it will receive funding. The Corporation will review the GEA along with any associated Ministerial Directives or Regulations and evaluate the potential to enhance its role in Ontario's electricity grid development, distributed (green) energy and conservation. At this time, due to the lack of policy details that need to be finalized, the impact of the GEA on the operations of Enersource Hydro can not be determinable at this time.

On June 23, 2009 Enersource Hydro submitted an application to the OEB to recognize the 2008 portion of revenue and expenses relating to its smart meter program, that are currently deferred on the balance sheet.

On July 6, 2009 Enersource Hydro submitted a formula based rate application to the OEB in order to align the distribution rate year to its fiscal year. Enersource Hydro proposed the new tariff of rates to be effective January 1, 2010.

The shareholders of the Corporation were parties to a Put Agreement by which the City held an option to sell its shares to BPC Energy Corporation ("BPC") in accordance with the Agreement. The effective period for this option commenced July 1, 2008 and expired on December 31, 2008. On January 28, 2009, the City decided to pursue the re-negotiation of certain terms of the shareholders agreement with BPC. The negotiations are ongoing at this time.

Enersource will continue to focus on operational excellence, customer care and shareholder value in its regulated and non-regulated businesses with a continued emphasis on growth and financial stability.

ONTARIO SECURITIES COMMISSION REQUIRED DISCLOSURES

Certification of Disclosure in Issuers' Annual and Interim Filings

The Corporation is a reporting issuer and, as such, must comply with Multilateral Instrument 52-109 – *Certification of Disclosure in Issuers' Annual and Interim Filings* (the "Instrument"). Enersource is further sub-classified as a venture issuer and our certifying officers have reviewed and certified the interim filings for the six months ended June 30, 2009.

Response to Interrogatory from
Vulnerable Energy Consumers Coalition

Reference: *Application, Tab B, pages 3-4, paragraphs #10-#15 and Attachment 1*

July 14th, 2008 Report of the Board on 3rd Generation Incentive Regulation for Ontario's Electricity Distributors, pages 10-12

Question:

a) *Please confirm that the GDP IPI FDD index (Series V3940594) used by the OEB is an index of annual values that is produced once a year.*

b) *Please indicate the source of the October 2008 to September 2009 price change that Enersource proposes to use.*

c) *Please provide a schedule that set out the for the period 2003 to that most currently available:*
   - *The (annual) values for the index used by the OEB in its 3GIRM*
   - *The values for the index Enersource proposes to use to determine the October 2008 to September 2009 price change.*

d) *Assuming this proposal had been implemented for January 1st 2009, please (using actual values from part (c)), show how the rate adjustment would be calculated under Enersource's proposal.*

e) *Please confirm that for purposes of the calculations in Attachment 1 Enersource has assumed that the year over year change in the index from October 2008 to September 2009 is equal to the annual change (2009 over 2008) in the index that the OEB will calculate and apply for 2010 rates effective May 1st, 2010. Please also confirm that the results will not be equivalent if this is not the case.*

f) *Please confirm that for purposes of the calculations in Attachment 1 Enersource has assumed that the amount of electricity consumed in each month is the same.*

g) *With respect to part (f), please indicate what the results would be if the consumption was doubled for the months December through March relative to the other months of the year.*

h) *Please provide a schedule of Enersource's monthly purchases from the IESO for the most recent 12 months available.*

Response:

a) Confirmed. The GDP IPI FDD used by the OEB from Statistics Canada CANSIM table 380-0056 is based on annual values. This data is also available on a quarterly basis in CANSIM table 380-0003.

b) The source is the quarterly inflation data presented by Statistics Canada in CANSIM Table 380-0003.

c) The annual values used by the OEB in its 3rd GIRM are represented in Tab I, Exhibit 6.2, Attachment A (CANSIM table 380-0056).

   As discussed in part b) above, Enersource proposes to use the quarterly data in Statistics Canada CANSIM Table 380-0003 which is expected to be available mid-November 2009. Tab I, Exhibit 6.2, Attachment B presents the latest quarterly data available from Q3 2006 to Q2 2009.

d) If the Company's proposal was implemented for January 1, 2009, Enersource would, consistent with Statistics Canada's methodology, calculate the annual percent change in the Implicit Price Index for National Gross Domestic Product (GDP-IPI) for Final Domestic Demand based on October 2007 to September 2008 over the similar prior period of October 2006 to September 2007. This calculation results in a 2.2% GDP-IPI-FDD percentage change for this period as shown in Tab I, Exhibit 6.2, Attachment B. Enersource would then continue to calculate the PCI and the resulting rate adjustment as shown in Attachment 1.

e) In Tab B, Attachment 1, Enersource assumed, for the purposes of illustration, a 2.12% inflation factor as the year-over-year change from October 2008 – September 2009 versus October 2007 – September 2008. Enersource notes that, regardless of the actual inflation factor, the end result, that is keeping customers and shareholders whole, would be equivalent. Please see Tab I, Exhibit 6.2, Attachment C for the recalculations of information in Tab B, Attachment 1 assuming an inflation factor of 2.3%. The calculations show that there will be no harm, neither to the customers nor to the shareholders.

f) Confirmed.

g) Enersource is a summer peaking utility with the majority of consumption occurring in the summer months. It is not realistic to consider that consumption would double for the winter period, December to March.

h) Please see the table below.

2008 Actual Load Purchases from the IESO

	kWhs
Month	**Actuals (including Embedded Generation)**
Jan	709,462,676
Feb	665,257,622
Mar	680,252,763
Apr	622,896,467
May	628,310,107
Jun	690,516,119
Jul	749,568,631
Aug	706,433,400
Sep	660,617,140
Oct	644,487,270
Nov	647,499,520
Dec	691,147,250
TOTAL	8,096,448,965

Source: Enersource Hydro Mississauga

Table 380-0056 - Gross domestic product (GDP) indexes, annual (2002=100)

Survey or program details:

National Income and Expenditure Accounts - 1901

Geography	Indexes	Estimates	2002	2003	2004	2005	2006	2007	2008
Canada	Fixed-weighted price index 2002=100	Gross domestic product (GDP) at market prices(2)	100	103.4	106.6	110.3	112.9	116.6	120.7
Canada	Fixed-weighted price index 2002=100	Personal expenditure on consumer goods and services	100	101.7	103.3	105.1	106.7	108.5	110.6
Canada	Fixed-weighted price index 2002=100	Personal expenditure on durable goods	100	99.3	98.2	97.9	97.1	95.7	91.2
Canada	Fixed-weighted price index 2002=100	Personal expenditure on semi-durable goods	100	99.3	99	98.8	97.6	96.9	95
Canada	Fixed-weighted price index 2002=100	Personal expenditure on non-durable goods	100	104.2	107.7	112.4	115.5	117.8	123.4
Canada	Fixed-weighted price index 2002=100	Personal expenditure on services	100	101.5	103.3	104.8	106.8	109.6	112.4
Canada	Fixed-weighted price index 2002=100	Government current expenditure on goods and services	100	103	104.8	108.5	112.5	115.8	118.8
Canada	Fixed-weighted price index 2002=100	Government gross fixed capital formation	100	100.2	102.1	105.1	109.8	114.7	123
Canada	Fixed-weighted price index 2002=100	Business gross fixed capital formation	100	99.6	102.1	104.4	108.7	112.8	116.4
Canada	Fixed-weighted price index 2002=100	Residential structures	100	105.1	111.7	117	126	135.3	138.7
Canada	Fixed-weighted price index 2002=100	Non-residential structures and equipment	100	96.9	97.3	98.2	100	101.5	105.2
Canada	Fixed-weighted price index 2002=100	Non-residential structures	100	102	108.5	115.2	123.6	130.9	139
Canada	Fixed-weighted price index 2002=100	Machinery and equipment	100	93.6	90.2	87.4	85.1	83	83.9
Canada	Fixed-weighted price index 2002=100	Exports of goods and services	100	99	101.2	104.7	105.3	107.4	116.4
Canada	Fixed-weighted price index 2002=100	Exports of goods	100	98.7	101	104.7	105.1	107.2	117
Canada	Fixed-weighted price index 2002=100	Exports of services	100	100.9	102.9	105.3	107	108.8	113.1
Canada	Fixed-weighted price index 2002=100	Imports of goods and services	100	93.7	92.3	92.3	92.7	91.8	97.6
Canada	Fixed-weighted price index 2002=100	Imports of goods	100	93.4	92.2	92.2	92.7	91.6	97.7
Canada	Fixed-weighted price index 2002=100	Imports of services	100	95.1	93.1	92.3	92.9	92.8	97.4
Canada	Fixed-weighted price index 2002=100	Final domestic demand	100	101.6	103.4	105.7	108.3	111	113.6

Footnotes

2 The fixed-weighted price index excludes the value of the physical change in inventories.

Source:

Statistics Canada. Table 380-0056 - Gross domestic product (GDP) indexes, annual (2002=100) (table), CANSIM (database), .
http://cansim2.statcan.gc.ca/cgi-win/cnsmcgi.exe?Lang=E&CNSM-Fi=CII/CII_1-eng.htm
(accessed: September 10, 2009)

Table 380-0056 - Gross domestic product (GDP) indexes, annual (percent change (year-to-year))

Survey or program details:

National Income and Expenditure Accounts - 1901

Geography	Indexes	Estimates	2003	2004	2005	2006	2007	2008
Canada	Fixed-weighted price index 2002=100	Gross domestic product (GDP) at market prices(2)	3.4	3.1	3.5	2.4	3.3	3.5
Canada	Fixed-weighted price index 2002=100	Personal expenditure on consumer goods and services	1.7	1.6	1.7	1.5	1.7	1.9
Canada	Fixed-weighted price index 2002=100	Personal expenditure on durable goods	-0.7	-1.1	-0.3	-0.8	-1.4	-4.7
Canada	Fixed-weighted price index 2002=100	Personal expenditure on semi-durable goods	-0.7	-0.3	-0.2	-1.2	-0.7	-2
Canada	Fixed-weighted price index 2002=100	Personal expenditure on non-durable goods	4.2	3.4	4.4	2.8	2	4.8
Canada	Fixed-weighted price index 2002=100	Personal expenditure on services	1.5	1.8	1.5	1.9	2.6	2.6
Canada	Fixed-weighted price index 2002=100	Government current expenditure on goods and services	3	1.7	3.5	3.7	2.9	2.6
Canada	Fixed-weighted price index 2002=100	Government gross fixed capital formation	0.2	1.9	2.9	4.5	4.5	7.2
Canada	Fixed-weighted price index 2002=100	Business gross fixed capital formation	-0.4	2.5	2.3	4.1	3.8	3.2
Canada	Fixed-weighted price index 2002=100	Residential structures	5.1	6.3	4.7	7.7	7.4	2.5
Canada	Fixed-weighted price index 2002=100	Non-residential structures and equipment	-3.1	0.4	0.9	1.8	1.5	3.6
Canada	Fixed-weighted price index 2002=100	Non-residential structures	2	6.4	6.2	7.3	5.9	6.2
Canada	Fixed-weighted price index 2002=100	Machinery and equipment	-6.4	-3.6	-3.1	-2.6	-2.5	1.1
Canada	Fixed-weighted price index 2002=100	Exports of goods and services	-1	2.2	3.5	0.6	2	8.4
Canada	Fixed-weighted price index 2002=100	Exports of goods	-1.3	2.3	3.7	0.4	2	9.1
Canada	Fixed-weighted price index 2002=100	Exports of services	0.9	2	2.3	1.6	1.7	4
Canada	Fixed-weighted price index 2002=100	Imports of goods and services	-6.3	-1.5	0	0.4	-1	6.3
Canada	Fixed-weighted price index 2002=100	Imports of goods	-6.6	-1.3	0	0.5	-1.2	6.7
Canada	Fixed-weighted price index 2002=100	Imports of services	-4.9	-2.1	-0.9	0.7	-0.1	5
Canada	Fixed-weighted price index 2002=100	Final domestic demand	1.6	1.8	2.2	2.5	2.5	2.3

Legend

.. Not available

Footnotes

2 The fixed-weighted price index excludes the value of the physical change in inventories.

Source:

Statistics Canada. Table 380-0056 - Gross domestic product (GDP) indexes, annual (2002=100) (table), CANSIM (database), .
http://cansim2.statcan.gc.ca/cgi-win/cnsmcgi.exe?Lang=E&CNSM-Fi=CII/CII_1-eng.htm

Table 380-0003 - Gross domestic product (GDP) indexes, quarterly (2002=100)
Survey or program details:
National Income and Expenditure Accounts - 1901

Geography	Indexes	Estimates	2006/09	2006/12	2007/03	2007/06	2007/09	2007/12	2008/03	2008/06	2008/09	2008/12	2009/03	2009/06
Canada	Fixed-weighted price indexes 2002=100	Gross domestic product (GDP) at market prices(2)	113	113.5	115.5	116.8	116.3	117.6	119.7	121.8	122.1	119.2	117.6	117.3
Canada	Fixed-weighted price indexes 2002=100	Personal expenditure on consumer goods and services	106.9	106.8	107.8	108.6	108.7	109	109.5	110.5	111.5	110.7	110.7	110.9
Canada	Fixed-weighted price indexes 2002=100	Personal expenditure on durable goods	96.7	96.3	96.5	96.3	95.9	94.2	92.5	91.6	90.9	89.7	88.8	89
Canada	Fixed-weighted price indexes 2002=100	Personal expenditure on semi-durable goods	97.4	96.9	97	97.3	96.8	96.6	95.2	95	95.2	94.7	95.4	95.7
Canada	Fixed-weighted price indexes 2002=100	Personal expenditure on non-durable goods	116	114.6	116.5	118.2	117.6	119	121	123.7	126.6	122.3	121.1	120.5
Canada	Fixed-weighted price indexes 2002=100	Personal expenditure on services	107.1	107.7	108.7	109.3	110	110.5	111.1	112	112.8	113.6	114.2	114.8
Canada	Fixed-weighted price indexes 2002=100	Government current expenditure on goods and services	112.2	113.2	115.2	116.7	114.8	116.4	117.3	118.4	119.3	120.4	121.1	122
Canada	Fixed-weighted price indexes 2002=100	Government gross fixed capital formation	110.9	111.4	113.5	114.8	114.6	115.8	118.4	121.5	125.4	126.6	126.1	123.9
Canada	Fixed-weighted price indexes 2002=100	Business gross fixed capital formation	109.5	110.9	112.4	112.9	113	112.8	113.8	115.3	116.7	119.9	119.9	118.8
Canada	Fixed-weighted price indexes 2002=100	Residential structures	127.7	129.9	131.8	134.7	136.5	138	138.6	139	138.9	138.4	136.7	137
Canada	Fixed-weighted price indexes 2002=100	Non-residential structures and equipment	100.3	101.3	102.7	102	101.2	100.2	101.4	103.4	105.5	110.6	111.5	109.6
Canada	Fixed-weighted price indexes 2002=100	Non-residential structures	124.8	126.4	128.4	130.5	131.5	133	135.1	138.6	140.6	141.6	142	141.4
Canada	Fixed-weighted price indexes 2002=100	Machinery and equipment	84.8	85.4	86.5	84	82.1	79.5	80.1	81.2	83.3	91	92.3	89.6
Canada	Fixed-weighted price indexes 2002=100	Exports of goods and services	105.7	106.3	109.4	108.4	105.7	106.1	111.2	117.5	120.7	116.3	110.1	106.2
Canada	Fixed-weighted price indexes 2002=100	Exports of goods	105.4	106.1	109.5	108.3	105.2	105.6	111.2	118.2	121.7	116.7	109.5	105.1
Canada	Fixed-weighted price indexes 2002=100	Exports of services	107.7	107.7	108.6	109	108.5	109.1	111.1	113.3	114.1	113.7	113.7	113.2
Canada	Fixed-weighted price indexes 2002=100	Imports of goods and services	93.2	93.8	95.2	92.9	90.5	88.5	90.6	95	100.5	104.3	102	98.6
Canada	Fixed-weighted price indexes 2002=100	Imports of goods	93.2	93.7	95.1	92.8	90.1	88.3	90.3	95.1	101	104.2	101.2	97.7
Canada	Fixed-weighted price indexes 2002=100	Imports of services	93.5	94.5	95.5	93.6	92.4	89.7	91.8	94.6	98	105	106.2	103.1
Canada	Fixed-weighted price indexes 2002=100	Final domestic demand	108.5	109	110.3	111.2	110.9	111.4	112.1	113.2	114.4	114.7	114.8	114.9

Footnotes
2 The fixed-weighted price index excludes the value of the physical change in inventories.

Source:
Statistics Canada. Table 380-0003 - Gross domestic product (GDP) indexes, quarterly (2002=100) (table), CANSIM (database), .
http://cansim2.statcan.gc.ca/cgi-win/cnsmcgi.exe?Lang=E&CNSM-Fi=CII/CII_1-eng.htm
(accessed: September 10, 2009)

Based on Statistics Canada calculation of the annual percent change in the Implicit Price Index for National Gross Domestic Product (GDP-IPI) for Final Domestic Demand,

Enersource's proposal, consistent to Statistic Canada annual calculation, is to use October - September Final Domestic Demand to calculate GDP-IPI as follows:

	2006/7 Oct-Sept	2007/8 Oct-Sept	
Sum of October to September quarters	**441.4**	**451.1**	
Average of quarters (rounded to 1 decimal)	**110.4**	**112.8**	
Annualized GDP-IPI			**2.2%**

EB-2009-0193
Tab I
Exhibit 6.2
Attachment B

Illustration Comparing Current and Proposed Scenarios using 3rd GIRM Application Methodology

Note: This table shows recalculaltions of information in Tab B, Attachment 1 assuming an inflation factor of 2.3%.

Price Escalator (GDP-IPI)	Average annual expected Productivity Gain (X)	(GDP-IPI) - X	8/12th (GDP-IPI) - X
2.30%	1.12%	1.18%	0.79%

CURRENT 3rd GIRM SCENARIO

	Approved May 1, 2009 (EB-2008-0171)					May 1 2010 (full incr.)					May 1 2011 (full incr.)				
	Approved Rate	Less: SMFA and Rate Riders	"Base" Monthly*1 Service Charge	Volume	$ / Month	Proposed Base Rate	Rate Increase	Monthly Service Charge	Volume	$ / Month	Proposed Base Rate	Rate Increase	Monthly Service Charge	Volume	$ / Month
Residential Fixed	13.14	1.41	11.73	1	11.73	11.73	0.14	11.87	1	11.87	11.87	0.14	12.01	1	12.01
Residential Volumetric	0.0118	0.0000	0.0118	800	9.44	0.0118	0.0001	0.0119	800	9.55	0.0119	0.0001	0.0121	800	9.66
Total Residential					$ 21.17					$ 21.42					$ 21.67
GS < 50 kW Fixed	40.85	1.41	39.44	1	39.44	39.44	0.47	39.91	1	39.91	39.91	0.47	40.38	1	40.38
GS < 50 kW Volumetric	0.0115	0.0000	0.0115	10000	115.00	0.0115	0.0001	0.0116	10000	116.36	0.0116	0.0001	0.0118	10000	117.73
Total GS < 50 kW					$ 154.44					$ 156.26					$ 158.11
Small Commercial Fixed	11.97	1.41	10.56	1	10.56	10.56	0.12	10.68	1	10.68	10.68	0.13	10.81	1	10.81
Small Commercial Volumetric	0.0193	0.0000	0.0193	10000	193.00	0.0193	0.0002	0.0195	10000	195.28	0.0195	0.0002	0.0198	10000	197.58
Total Small Commerical					$ 203.56					$ 205.96					$ 208.39
GS 50 - 499 kW Fixed	70.42	1.41	69.01	1	69.01	69.01	0.81	69.82	1	69.82	69.82	0.82	70.65	1	70.65
GS 50 - 499 kW Volumetric	4.1498	(0.0029)	4.1527	230	955.12	4.1527	0.0490	4.2017	230	966.39	4.2017	0.0496	4.2513	230	977.79
Total GS 50 - 499 kW					$ 1,024.13					$ 1,036.22					$ 1,048.44
GS 500 - 4999 kW Fixed	1520.79	1.41	1519.38	1	1,519.38	1,519.38	17.93	1,537.31	1	1,537.31	1,537.31	18.14	1,555.45	1	1,555.45
GS 500 - 4999 kW Volumetric	2.0701	(0.0023)	2.0724	2250	4,662.90	2.0724	0.0245	2.0969	2250	4,717.92	2.0969	0.0247	2.1216	2250	4,773.59
Total GS 500 - 4999 kW					$ 6,182.28					$ 6,255.23					$ 6,329.04
GS > 5000 kW Fixed	13688.11	1.41	13686.7	1	13,686.70	13,686.70	161.50	13,848.20	1	13,848.20	13,848.20	163.41	14,011.61	1	14,011.61
GS > 5000 kW Volumetric	2.8843	(0.0023)	2.8866	50000	144,330.00	2.8866	0.0341	2.9207	50000	146,033.09	2.9207	0.0345	2.9551	50000	147,756.28
Total GS > 5000 kW					$ 158,016.70					$ 159,881.30					$ 161,767.90
Streetlights kW Fixed	1.33	0	1.33	1	1.33	1.33	0.02	1.35	1	1.35	1.35	0.02	1.36	1	1.36
Streetlights kW Volumetric	10.1222	(0.0105)	10.1327	0.5	5.07	10.1327	0.1196	10.2523	0.5	5.13	10.2523	0.1210	10.3732	0.5	5.19
Total Streetlights kW					$ 6.40					$ 6.47					$ 6.55

PROPOSED 3rd GIRM SCENARIO

	Approved May 1, 2009 (EB-2008-0171)					Jan 1 2010 (8/12ths incr.)					Jan 1 2011 (full incr.)				
	Approved Rate	Less: SMFA and Rate Riders	"Base" Monthly*1 Service Charge	Volume	$ / Month	Proposed Base Rate	Rate Increase	Monthly Service Charge	Volume	$ / Month	Proposed Base Rate	Rate Increase	Monthly Service Charge	Volume	$ / Month
Residential Fixed	13.14	1.41	11.73	1	11.73	11.73	0.09	11.82	1	11.82	11.82	0.14	11.96	1	11.96
Residential Volumetric	0.0118	0.0000	0.0118	800	9.44	0.0118	0.0001	0.0119	800	9.51	0.0119	0.0001	0.0120	800	9.63
Total Residential					$ 21.17					$ 21.34					$ 21.59
GS < 50 kW Fixed	40.85	1.41	39.44	1	39.44	39.44	0.31	39.75	1	39.75	39.75	0.47	40.22	1	40.22
GS < 50 kW Volumetric	0.0115	0.0000	0.0115	10000	115.00	0.0115	0.0001	0.0116	10000	115.90	0.0116	0.0001	0.0117	10000	117.27
Total GS < 50 kW					$ 154.44					$ 155.65					$ 157.49
Small Commercial Fixed	11.97	1.41	10.56	1	10.56	10.56	0.08	10.64	1	10.64	10.64	0.13	10.77	1	10.77
Small Commercial Volumetric	0.0193	0.0000	0.0193	10000	193.00	0.0193	0.0002	0.0195	10000	194.52	0.0195	0.0002	0.0197	10000	196.81
Total Small Commerical					$ 203.56					$ 205.16					$ 207.58
GS 50 - 499 kW Fixed	70.42	1.41	69.01	1	69.01	69.01	0.54	69.55	1	69.55	69.55	0.82	70.37	1	70.37
GS 50 - 499 kW Volumetric	4.1498	(0.0029)	4.1527	230	955.12	4.1527	0.0327	4.1854	230	962.63	4.1854	0.0494	4.2348	230	973.99
Total GS 50 - 499 kW					$ 1,024.13					$ 1,032.19					$ 1,044.37
GS 500 - 4999 kW Fixed	1520.79	1.41	1519.38	1	1,519.38	1,519.38	11.95	1,531.33	1	1,531.33	1,531.33	18.07	1,549.40	1	1,549.40
GS 500 - 4999 kW Volumetric	2.0701	(0.0023)	2.0724	2250	4,662.90	2.0724	0.0163	2.0887	2250	4,699.58	2.0887	0.0246	2.1133	2250	4,755.04
Total GS 500 - 4999 kW					$ 6,182.28					$ 6,230.91					$ 6,304.44
GS > 5000 kW Fixed	13688.11	1.41	13686.7	1	13,686.70	13,686.70	107.67	13,794.37	1	13,794.37	13,794.37	162.77	13,957.14	1	13,957.14
GS > 5000 kW Volumetric	2.8843	(0.0023)	2.8866	50000	144,330.00	2.8866	0.0227	2.9093	50000	145,465.40	2.9093	0.0343	2.9436	50000	147,181.89
Total GS > 5000 kW					$ 158,016.70					$ 159,259.76					$ 161,139.03
Streetlights kW Fixed	1.33	0	1.33	1	1.33	1.33	0.01	1.34	1	1.34	1.34	0.02	1.36	1	1.36
Streetlights kW Volumetric	10.1222	(0.0105)	10.1327	0.5	5.07	10.1327	0.0797	10.2124	0.5	5.11	10.2124	0.1205	10.3329	0.5	5.17
Total Streetlights kW					$ 6.40					$ 6.45					$ 6.52

*1 In this illustration, the Base Monthly rates do not include smart meter funding adders or shared tax savings rate riders. These are distribution rates only.

Illustration of Bill Impacts on Customers

Total Distribution Per Rate Rebasing Period

	May 1 to Dec. 31, 2009		Jan 1 to Apr 30, 2010		May 1 to Dec 31, 2010		Jan 1 to Apr 30, 2011		May 1 to Dec 31, 2011		Total from May 1, 2009 to Dec. 31, 2011	Total from May 1, 2009 to Dec. 31, 2011	
	Monthly Amt	Total Period	Monthly Amt	Total Period	Monthly Amt	Total Period	Monthly Amt	Total Period	Monthly Amt	Total Period		Change $	Change %
Residential Current 3rd GIRM	$ 21.17	$ 169.36	$ 21.17	$ 84.68	$ 21.42	$ 171.36	$ 21.42	$ 85.68	$ 21.67	$ 173.38	$ 684.46		
Residential Proposed 3rd GIRM	$ 21.17	$ 169.36	$ 21.34	$ 85.35	$ 21.34	$ 170.69	$ 21.59	$ 86.35	$ 21.59	$ 172.71	$ 684.46	$ -	0.00%
GS < 50kW Current 3rd GIRM	$ 154.44	$ 1,235.52	$ 154.44	$ 617.76	$ 156.26	$ 1,250.10	$ 156.26	$ 625.05	$ 158.11	$ 1,264.85	$ 4,993.28		
GS < 50kW Proposed 3rd GIRM	$ 154.44	$ 1,235.52	$ 155.65	$ 622.62	$ 155.65	$ 1,245.24	$ 157.49	$ 629.97	$ 157.49	$ 1,259.93	$ 4,993.28	$ -	0.00%
Small Commercial Current 3rd GIRM	$ 203.56	$ 1,628.48	$ 203.56	$ 814.24	$ 205.96	$ 1,647.70	$ 205.96	$ 823.85	$ 208.39	$ 1,667.14	$ 6,581.40		
Small Commercial Proposed 3rd GIRM	$ 203.56	$ 1,628.48	$ 205.16	$ 820.65	$ 205.16	$ 1,641.29	$ 207.58	$ 830.33	$ 207.58	$ 1,660.66	$ 6,581.40	$ -	0.00%
GS 50-499kW Current 3rd GIRM	$ 1,024.13	$ 8,193.05	$ 1,024.13	$ 4,096.52	$ 1,036.22	$ 8,289.73	$ 1,036.22	$ 4,144.86	$ 1,048.44	$ 8,387.54	$ 33,111.71		
GS 50-499kW Proposed 3rd GIRM	$ 1,024.13	$ 8,193.05	$ 1,032.19	$ 4,128.75	$ 1,032.19	$ 8,257.50	$ 1,044.37	$ 4,177.47	$ 1,044.37	$ 8,354.94	$ 33,111.71	$ -	0.00%
GS 500-4999kW Current 3rd GIRM	$ 6,182.28	$ 49,458.24	$ 6,182.28	$ 24,729.12	$ 6,255.23	$ 50,041.85	$ 6,255.23	$ 25,020.92	$ 6,329.04	$ 50,632.34	$ 199,882.47		
GS 500-4999kW Proposed 3rd GIRM	$ 6,182.28	$ 49,458.24	$ 6,230.91	$ 24,923.66	$ 6,230.91	$ 49,847.31	$ 6,304.44	$ 25,217.75	$ 6,304.44	$ 50,435.51	$ 199,882.47	$ -	0.00%
GS > 5000kW Current 3rd GIRM	$ 158,016.70	$1,264,133.60	$ 158,016.70	$ 632,066.80	$ 159,881.30	$ 1,279,050.38	$ 159,881.30	$ 639,525.19	$161,767.90	$ 1,294,143.17	$ 5,108,919.14		
GS > 5000kW Proposed 3rd GIRM	$ 158,016.70	$1,264,133.60	$ 159,259.76	$ 637,039.06	$ 159,259.76	$ 1,274,078.12	$ 161,139.03	$ 644,556.12	$161,139.03	$ 1,289,112.24	$ 5,108,919.14	$ -	0.00%
Streetlights Current 3rd GIRM	$ 6.40	$ 51.17	$ 6.40	$ 25.59	$ 6.47	$ 51.77	$ 6.47	$ 25.89	$ 6.55	$ 52.39	$ 206.80		
Streetlights Proposed 3rd GIRM	$ 6.40	$ 51.17	$ 6.45	$ 25.79	$ 6.45	$ 51.57	$ 6.52	$ 26.09	$ 6.52	$ 52.18	$ 206.80	$ -	0.00%

Response to Interrogatory from
Vulnerable Energy Consumers Coalition

Reference: Application, Tab B, pages 5-7
Application, Tab E

Question:

a) *With respect to Tab E, Schedule 2 (Smart Meter Revenue Requirement Calculation for 2006, 2007, 2008, 2009 & 2010 & SMFA), please provide a schedule that compares the 2008 values as forecast in Enersource's EB-2008-0171 Application versus the 2008 actual values in the Current Application for the following:*
- *Capital Spending on Smart Meters*
- *Increase in Year End Net Fixed Asset over 2007 year end*
- *2008 Operating Expenses*
- *2008 Depreciation Expenses*
- *Number of Smart Meters Installed in 2008.*

Please provide a variance explanation for any differences of more than 5%.

b) *With respect to Tab E, Schedule 2 (Smart Meter Revenue Requirement Calculation for 2006, 2007, 2008, 2009 & 2010 & SMFA), please provide a schedule that compares the 2009 values as forecast in Enersource's EB-2008-0171 Application versus the 2009 forecast in the Current Application for the following:*
- *Capital Spending on Smart Meters*
- *Increase in Year End Net Fixed Asset over 2008 year end*
- *2009 Operating Expenses*
- *2009 Depreciation Expenses*
- *Number of Smart Meters Installed in 2009*

Please provide a variance explanation for any differences of more than 5%.

c) *Please provide a schedule that sets out the average operating cost per installed smart meter for 2006, 2007, 2008, 2009 (estimate) and 2010 (forecast). Note: For purposes of calculating the average please use the average number of smart meters in-service in the respective year. Please explain any year over year variances.*

d) *Please provide a schedule that sets out the average capital cost per installed smart meter incurred annually from 2006 to 2010 (forecast). Please explain any year over year variances.*

e) *With respect to Tab E, paragraph 5, please explain more fully:*
   i.. What gives rise to hazardous meter bases
   ii. Why the replacement of hazardous meter bases results in higher operating costs
   iii. Why these should be considered Smart Meter costs as oppose to normal operating costs.

Response:

a) Please see Attachment A.

b) Please see Attachment B.

c) and d) Please see Tab I, Exhibit 6.3, Attachment C which will be provided in confidence.

e) i. Please refer to the response in Tab I, Exhibit 4.6, part a).

ii. and iii. Please refer to the EB-2007-0063 Decision with Reasons dated August 8, 2007, page 17 which states that:

"The Board considers that the costs of repairing or replacing the meter base extend the useful life of the service asset. Therefore all labour and associated costs incurred, with the exception of material and parts costs for customer owned equipment, shall be capitalized and tracked in a sub-account of the Smart Meter Capital and Recovery Offset Variance Account 1555. The actual material costs to repair or replace any customer owned equipment shall be expensed and also tracked separately in a different sub-account of the Smart Meter OM&A Variance Account 1556 until disposition is ordered by the Board. As the meter base will remain the property of the customer, it would not be appropriate to have it form part of the utility's rate base."

2008					
	2009 3GIRM EB-2008-0171	2010 3GIRM EB-2009-0193	Variance	%	Explanation
Capital	7,031,649	6,058,740	(972,909)	-13.8%	The long Measurement Canada approval process caused late delivery of small commercial (SC) meters by supplier, delaying deployment.
Increase in Average Net Fixed Assets	6,822,086	6,325,899	(496,187)	-7.3%	Reduction due to capital decrease as per above
Operating Costs	207,850	94,140	(113,710)	-54.7%	Higher materials handling overhead than planned as we installed more residential meters than budgetted
Depreciation	405,488	538,004	132,516	32.7%	See details in EB-2009-0193, Tab E, Schedule 5
No. of Residential meters	47,500	48,020	520	1.1%	N/A (less than 5%)
No. of SC meters	3,100	1,731	(1,369)	-44.2%	The long Measurement Canada approval process caused late delivery of SC meters by supplier, delaying deployment.

2009					
	2009 3GIRM EB-2008-0171	**2010 3GIRM EB-2009-0193**	**Variance**	**%**	**Explanation**
Capital	8,072,556	7,949,658	(122,898)	-1.5%	N/A (less than 5%)
Increase in Average Net Fixed Assets	6,047,146	5,905,900	(141,246)	-2.3%	N/A (less than 5%)
Operating Costs	1,655,614	669,759	(985,855)	-59.5%	The schedule for hazardous meter base replacements originally planned to begin in 2009 has been moved to 2010.
Depreciation	425,111	123,637	(301,474)	-70.9%	See details in EB-2009-0193, Tab E, Schedule 5
No. of Residential meters	29,000	30,000	1,000	3.4%	N/A (less than 5%)
No. of SC meters	6,500	5,802	(698)	-10.7%	Parts shortages caused late delivery of meters by supplier, delaying deployment.

Response to Interrogatory from
Vulnerable Energy Consumers Coalition

Reference: *Application, Tab B, paragraphs #28-29 and Tabs C and D*

September 17, 2008 Supplemental Report of the Board on 3rd Generation Incentive Regulation for Ontario's Electricity Distributors, page 22

Board Decision, EB-2008-0160 (Barrie), page 7

Question:

a) *The Board's Supplemental Report states that the Stretch Factors used in the 3GIRM will be updated annually and could change. Please indicate Enersource's understanding of when the 2010 values will be available (and the basis for this understanding). Based on this timing, please explain how the application will be updated for the 2010 stretch factor.*

b) *With respect to Tab B, Footnote #3, please provide a schedule that highlights the differences between proposed rates per Table #5 and those resulting from the filing model results provided in Tabs C and D. For each difference, please explain how the proposed rate was determined.*

c) *On August 25th, 2009 the OEB issued the 2010 3GIRM rate application models (http://www.oeb.gov.on.ca/OEB/Industry+Relations/OEB+Key+Initiatives/2010+Electricity+Distribution+Rate+Applications#updates). Please provide revised versions of Tabs C and D using these models.*

Response:

a) Please refer to the response in Tab I, Exhibit 1.2, part a).

b) Enersource's original submission of the 2010 3rd GIRM application, dated July 6, 2009, relied on 2009 3rd GIRM models. The limitations of using the 2009 3rd GIRM application of which modifications were required are listed in Enersource's application Tab C and Tab D. On August 18, 2009, Enersource submitted revised OEB-issued models for its 2010 3rd GIRM application through the Board's Regulatory Electronic Submission System (RESS). The revised models have corrected the limitations identified in the application and are available on the Board's website. Tab I, Exhibit 6.4, Attachment A shows the changes in the proposed rates between the original submission and the revised one.

c) As indicated in part b) above, Enersource submitted revised OEB-issued models for the 2010 3rd GIRM application on August 18, 2009 through the Board's RESS.

Enersource Hydro Mississauga Inc.

Schedule of Distribution Rates and Charges Including Rate Riders (2010 Proposed Rates dated August 18, 2009 vs. 2010 Proposed Rates dated July 6, 2009)

			Proposed 2010 (August 18, 2009)	**Proposed 2010 (July 6, 2009)**	**Change**	**Change %**
			(a)	**(b)**	**(c) = (a) - (b)**	**c / b**
			2010	2010		
			January 1	**January 1**		
Customer Class	Item Description	Unit	Rate $	Rate $	Rate Change $	
RESIDENTIAL Regular						
	Monthly Service Charge	per month	13.98	13.98	0.00	0.00%
	Distribution Volumetric Rate	per kWh	0.0119	0.0119	0.0000	0.00%
	Rate Rider	per kWh	(0.0001)	(0.0001)	0.0000	0.00%
	Retail Trans. - Network (Note 1)	per kWh	0.0062	0.0060	0.0002	3.33%
	Retail Trans. - Connection (Note 1)	per kWh	0.0053	0.0054	-0.0001	-1.85%
	Wholesale Market Service	per kWh	0.0052	0.0052	0.0000	0.00%
	Rural Rate Protection	per kWh	0.0013	0.0013	0.0000	0.00%
	RPP - Admin Charge	per month	0.25	0.25	0.0000	0.00%
GENERAL SERVICE Less than 50 kW						
	Monthly Service Charge	per month	41.87	41.87	0.00	0.00%
	Distribution Volumetric Rate	per kWh	0.0116	0.0116	0.0000	0.00%
	Rate Rider	per kWh	(0.0001)	(0.0001)	0.0000	0.00%
	Retail Trans. - Network (Note 1)	per kWh	0.0057	0.0055	0.0002	3.64%
	Retail Trans. - Connection (Note 1)	per kWh	0.0049	0.0050	-0.0001	-2.00%
	Wholesale Market Service	per kWh	0.0052	0.0052	0.0000	0.00%
	Rural Rate Protection	per kWh	0.0013	0.0013	0.0000	0.00%
	RPP - Admin Charge	per month	0.25	0.25	0.0000	0.00%
GENERAL SERVICE Other < 50 kW (specify) .Small Commercial						
	Monthly Service Charge - Metered Cust.	per month	12.80	12.80	0.00	0.00%
Service Charge for Unmetered Scattered Load account (per connection)	Monthly Service Charge - Unmetered Cust.	per month	10.63	10.63	0.00	0.00%
	Distribution Volumetric Rate	per kWh	0.0194	0.0194	0.0000	0.00%
	Rate Rider	per kWh	(0.0003)	(0.0003)	0.0000	0.00%
	Retail Trans. - Network (Note 1)	per kWh	0.0057	0.0055	0.0002	3.64%
	Retail Trans. - Connection (Note 1)	per kWh	0.0049	0.0050	-0.0001	-2.00%
	Wholesale Market Service	per kWh	0.0052	0.0052	0.0000	0.00%
	Rural Rate Protection	per kWh	0.0013	0.0013	0.0000	0.00%
	RPP - Admin Charge	per month	0.25	0.25	0.0000	0.00%
GENERAL SERVICE Other > 50 kW (specify) .50 kW - 499 kW						
	Monthly Service Charge	per month	71.64	71.64	0.00	0.00%
	Distribution Volumetric Rate	per kW	4.1804	4.1804	0.0000	0.00%
	Rate Rider	per kW	(0.0269)	(0.0269)	0.0000	0.00%
	Retail Trans. - Network (Note 1)	per kW	2.2205	2.1454	0.0751	3.50%
*Identical rates for Interval metered Customers	Retail Trans. - Connection (Note 1)	per kW	1.8965	1.9392	-0.0427	-2.20%
	Wholesale Market Service	per kWh	0.0052	0.0052	0.0000	0.00%
	Rural Rate Protection	per kWh	0.0013	0.0013	0.0000	0.00%
	RPP - Admin Charge	per month	0.25	0.25	0.0000	0.00%
GENERAL SERVICE Other > 50 kW (specify) .500 kW - 4999 kW						
	Monthly Service Charge	per month	1,531.68	1,531.68	0.00	0.00%
	Distribution Volumetric Rate	per kW	2.0862	2.0862	0.0000	0.00%
	Rate Rider	per kW	(0.0203)	(0.0203)	0.0000	0.00%
	Retail Trans. - Network (Note 1)	per kW	2.1482	2.0756	0.0726	3.50%
	Retail Trans. - Connection (Note 1)	per kW	1.8558	1.8975	-0.0417	-2.20%
	Wholesale Market Service	per kWh	0.0052	0.0052	0.0000	0.00%
	Rural Rate Protection	per kWh	0.0013	0.0013	0.0000	0.00%
	RPP - Admin Charge	per month	0.25	0.25	0.0000	0.00%
GENERAL SERVICE Large Use (> 5000 kW)						
	Monthly Service Charge	per month	13,780.11	13,780.11	0.00	0.00%
	Distribution Volumetric Rate	per kW	2.9058	2.9058	0.0000	0.00%
	Rate Rider	per kW	(0.0186)	(0.0186)	0.0000	0.00%
	Retail Trans. - Network (Note 1)	per kW	2.2924	2.2149	0.0775	3.50%
	Retail Trans. - Connection (Note 1)	per kW	1.9820	2.0266	-0.0446	-2.20%
	Wholesale Market Service	per kWh	0.0052	0.0052	0.0000	0.00%
	Rural Rate Protection	per kWh	0.0013	0.0013	0.0000	0.00%
	RPP - Admin Charge	per month	0.25	0.25	0.0000	0.00%
STREET LIGHTING						
	Monthly Service Charge	per month	1.34	1.34	0.00	0.00%
	Distribution Volumetric Rate	per kW	10.2003	10.2003	0.0000	0.00%
	Rate Rider (Note 2)	per kW	(0.0889)	(0.0888)	-0.0000	0.06%
	Retail Trans. - Network (Note 1)	per kW	1.5377	1.4857	0.0520	3.50%
	Retail Trans. - Connection (Note 1)	per kW	1.3714	1.4022	-0.0308	-2.20%
	Wholesale Market Service	per kWh	0.0052	0.0052	0.0000	0.00%
	Rural Rate Protection	per kWh	0.0013	0.0013	0.0000	0.00%
	RPP - Admin Charge	per month	0.25	0.25	0.0000	0.00%

Note 1) The 2010 Proposed Rates from the original model submission dated July 6, 2009 did not reflect the OEB's Guideline on Retail Transmission Service Rates (RTSR) which was issued on July 22, 2009. The August 18, 2009 re-submission incorporated the adjusted RTSR rates per this Guideline.

Note 2) Model Rounding

Response to Interrogatory from
Vulnerable Energy Consumers Coalition

Reference: Application, Tab B, pages 8-10

Question:

a) *Please provide the basis of the Total Customer Class %'s used in Table 1. Please also explain how they were determined.*

b) *Please provide the basis for the Total Customer Class %'s used in Table 2 and explain why they are different from Table 1, particularly since there are no cost allocation adjustments for 2010 that would shift revenue responsibility between customer classes.*

c) *Please confirm that the 2009 Load Forecast used in Table #1 is really the OEB-approved load forecast for 2008. If not, please explain its source.*

d) *What is the basis for the 2010 load forecast used to determine the Rate Riders as calculated in Table #2?*

Response:

a) The information on total customer class percentages in Table 1 was provided in Enersource's 2009 3rd GIRM application at EB-2008-0171, Tab 4 (Supplementary Filing Module), Schedule C 2.1, and is consistent with the EB-2007-0706 Settlement Agreement Exhibit A, Schedule 4, Appendix C.

b) Enersource has revised Table 2 to reflect the total customer class percentages used in Table 1 described in part a) above. The impact of the revision on the Tax Sharing Rate Rider is shown below and will be reflected in the final rates.

Revised 2010 Shared Tax Savings Rate Rider

	Proposed Rate Rider related to 2009 3rd GIRM	Proposed Rate Rider Jan - Dec 2010 Fiscal Year	Revised 2010 Shared Tax Savings Rate Rider (Tab 3 page 10)	Proposed 2010 Shared Tax Savings Rate Rider (Tab 3 page 10)	Variance	Load Forecast 2010 (kWh)	Load Forecast 2010 (kW)	Variance $
RESIDENTIAL	$ (0.000006)	$ (0.000139)	$ (0.000145)	$ (0.000142)	$ (0.000003)	1,579,606,433		(4,433)
General Service < 50 kW	$ (0.000005)	$ (0.000118)	$ (0.000123)	$ (0.000121)	$ (0.000002)	666,537,466		(1,606)
Small Commercial	$ (0.000011)	$ (0.000287)	$ (0.000298)	$ (0.000293)	$ (0.000006)	11,701,517		(66)
General Service 50 kW - 499 kW	$ (0.000974)	$ (0.024515)	$ (0.025489)	$ (0.026881)	$ 0.0013918		6,347,165	8,834
General Service 500 kW - 4999 kW	$ (0.000769)	$ (0.019908)	$ (0.020677)	$ (0.020301)	$ (0.000376)		5,107,408	(1,920)
Large Use (> 5000 kW)	$ (0.000782)	$ (0.018123)	$ (0.018904)	$ (0.018562)	$ (0.000342)		1,847,558	(632)
Street Lighting	$ (0.003506)	$ (0.086864)	$ (0.090370)	$ (0.088845)	$ (0.001525)		115,695	(176)
						Net Variance		0

c) Confirmed.

d) As discussed in the response in Tab I, Exhibit 2.2, Enersource has revised its load forecast for 2010. The revised forecast will be used to accurately allocate the tax-sharing rate adder.