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ISSUE 1: GENERAL

Oral Argument References include 1-10

1. Hearing Exhibit 1 2013 from : Enersource_Excel_IRR3_Issues General_Board Staff_Attachment2_2013 Rev-Req_Work_Form_20120723 / 2014 from: Enersource_Excel_IRR3_Issues General_Board Staff_Attachment2_2014 Rev-Req_Work_Form_20120723
2. Technical Conference Transcript, Volume 1, July 30, 2012, pages 43-44
3. Exhibit I, Issue: 1.1, Board Staff, I.R. #8, Page 2 of 2
4. Exhibit 1, Tab 3, Schedule 5, Appendix 1,Page 1 of 7
5. Technical Conference July 30 & 31, 2012,Undertaking No. JT1.15,Page 1 of 1
6. 2008 & 2009: Exhibit 1, Tab 3, Schedule 1, Appendix 1, pages 3-4 /2010 & 2011: Exhibit 1, Tab 3, Schedule 1, Appendix 3, pages 3-4
7. Argument-in-Chief , page 6
8. Exhibit I, Issue: 1.2, Board Staff, I.R. #11, Page 1 of 1
9. Enersource Argument-in-Chief, page 4
10. Issue: 1.4, Energy Probe, IR # 2, Page 3 of 3

Additional References

TC V1

(2)

time rate increases for rebasing years under the current model and more accurately provides compensation for the cost of capital, and he asks, does Enersource agree that the 2014 increases as proposed by Enersource will be higher than they would be under third-generation IRM?

MR. MACUMBER: I think what you are asking is our approach is to have the PILs return on amortization through rates rather than using an IRM. I am not sure what inflation would be used or the stretch factor or other factors, so I cannot compare whether or not there would be more or less rate impact from our proposal.

MR. FAYE: So I think what I heard you say is you don't agree, because you don't know what the effect of an IRM would have been on the rates; is that right?

MR. MACUMBER: I think what we are suggesting is our way of setting rates, of adding in the capital for the following year, we believe is just and reasonable. I cannot comment on whether or not it's the ICR or our method is better or worse or...

MS. GIRVAN: Peter, can I just follow up? So just to be clear, you didn't do that analysis, I mean, in assessing your options? You didn't look at what 2014 would look like under IRM or IRM with an incremental capital module? You didn't do that analysis?

MS. DeJULIO: Ms. Girvan, you are right. We did not do that analysis. There were -- with respect to IRM there are unknowns, and we believed that the ICR proposal was, you know, the best proposal for ratepayers and

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shareholders, and that's why we went -- that's why we made this proposal for the 2014.

With respect to your question on ICM, that's correct, we did not run that model either. A big factor in that decision to not run that model was the -- one of the criterion, which is -- one of the criteria, which is a criterion to have the capital expenditures being non-discretionary, and our capital expenditures for 2014, most of them, if not all of them, do not fall into that category.

MS. GIRVAN: Okay. Thanks.

MR. FAYE: So then without an analysis of the IRM process -- and I apologize if it seems to be overlapping backwards here on something I just sort of closed off -- what is the basis for your consideration of just and reasonable? For most people, I think, just and reasonable rates, from the customer's perspective, is lowest reasonable rates you can get while still getting reasonable reliability, and if you have not made that analysis from a customer's point of view, how would you be able to convince them that the rates are just and reasonable?

MR. VEGH: That's somewhat of a rhetorical question, Mr. Faye, and I think it relates to the discussion we had just a few minutes ago. Enersource has put in its evidence in support of its proposal, and that's described in the pre-filed evidence and the rationale for including the 2014 ICR year, but we are not in a position to carry out a calculation which provides what the comparison would be if

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Response:

a) Enersource is not proposing an approach that makes use of the ICM. Instead, it seeks to recover the cost of capital expenditures for two years: the 2013 Test Year and the 2014 Incremental Capital and Return Year. Enersource is of the view that its proposed approach is just and reasonable because it smoothes the amount of one-time rate increases for rebasing years under the current model, and more accurately provides compensation for the cost of capital.

No, Enersource did not prepare an analysis comparing the approach proposed in this Application, i.e., the ICR, with the existing IRM-ICM.

b) Enersource is of the view that its proposed approach is just and reasonable, serving two primary purposes: it smoothes what are otherwise expected to be step rate increases to customers every rebasing year under the current cost of service rate setting model; and it more accurately provides compensation for the cost of capital.

c) It is not possible to speculate on all of the permutations of what decisions may be made in the Renewed Regulatory Framework for Electricity ("RRFE") and how they may impact Enersource's 2015 rate application. As indicated in the evidence, if approved, Enersource's proposed approach can provide experience and information that may be helpful for the Board in finalizing the RRFE. In addition, the proposed approach does not address a multi-year solution that may interfere with the Board's timing horizon for implementing a new approach.

d) At page 6, lines 19-22 of Exhibit 1 Tab 2 Schedule 1, Enersource states "However, unlike the Straw Man Model, if Enersource's proposed treatment of capital is approved, Enersource will hold flat OM&A levels in rates over the two years, with greater incentive for increased productivity and performance outcomes." Enersource is noting that OM&A is flat or unchanging over the two years 2013 (once adjusted) and 2014.

	SAIDI				
Distributors	2010	2009	2008	2007	2006
Enersource Hydro Mississauga Inc.	0.58	0.61	0.33	0.64	0.45
Horizon Utilities Corporation	1.24	1.18	1.49	1.01	0.94
Hydro One Brampton Networks Inc.	0.66	0.79	0.77	1.26	0.86
Hydro Ottawa Limited	1.36	1.50	0.98	1.40	1.51
London Hydro Inc.	0.88	0.89	2.29	1.69	1.25
PowerStream Inc.	0.81	1.97	0.88	2.17	5.49
Toronto Hydro-Electric System Limited	1.66	2.90	1.24	1.95	1.62
Veridian Connections Inc.	0.92	3.69	2.36	1.94	0.85
	SAIFI				
Distributors	2010	2009	2008	2007	2006
Enersource Hydro Mississauga Inc.	1.32	1.18	0.73	0.78	0.73
Horizon Utilities Corporation	1.80	1.81	1.80	1.59	1.44
Hydro One Brampton Networks Inc.	1.47	1.27	1.12	1.85	1.48
Hydro Ottawa Limited	1.39	1.15	1.02	1.21	1.19
London Hydro Inc.	1.12	1.59	2.39	2.46	2.14
PowerStream Inc.	0.92	1.23	0.92	1.54	2.64
Toronto Hydro-Electric System Limited	1.95	1.86	1.76	2.27	2.03
Veridian Connections Inc.	1.58	2.45	2.41	1.81	1.25
	CAIDI				
Distributors	2010	2009	2008	2007	2006
Enersource Hydro Mississauga Inc.	0.44	0.53	0.45	0.83	0.62
Horizon Utilities Corporation	0.69	0.65	0.83	0.64	0.65
Hydro One Brampton Networks Inc.	0.45	0.62	0.69	0.68	0.58
Hydro Ottawa Limited	0.97	1.30	0.97	1.15	1.27
London Hydro Inc.	0.79	0.56	0.96	0.69	0.59
PowerStream Inc.	0.88	1.60	0.95	1.40	2.08
Toronto Hydro-Electric System Limited	0.85	1.56	0.70	0.86	0.80
Veridian Connections Inc.	0.58	1.51	0.98	1.07	0.68

c) The OEB publishes its Annual Yearbook which provides the reliability statistics, and other data, for all utilities in the Province. Enersource is unable to comment and compare on its reliability results to other LDCs on an "apples-to-apples" basis as the data capture and monitoring techniques may differ amongst each company.

Arg. Chief

(6)

is, in effect, a remedial power that the Board exercises where it is not satisfied with the way in which the utility has been managed. In other words, a good test for prudence is results based: a utility that produces high quality service at low cost should be presumed to have made prudential decisions.[4] A utility that produces low quality service at relatively high cost is not necessarily entitled to that presumption. In other words, the presumption of prudence is not an entitlement of all utilities – it is earned.

10. It is submitted that Enersource has earned the applicability of the presumption of prudence to its decisions.

11. Second, and related, any comparison of utility performance demonstrates that Enersource has consistently providing high quality low cost electricity distribution.

Comparing Enersource's Performance to other Distributors

12. The quality of Enersource's service to its customers is second to none. As counsel for Energy Probe noted, Enersource's reliability performance has been "stellar."[5] Reliability is, of course, measured by the delivery of KWh and peak KW. The success of reliable delivery is by reference to the consistent delivery of KWh and peak KW.

13. In response to parties' questions in the technical conference, Enersource collected information recorded in the OEB's Yearbook of Distributors. This

[4] Regulatory disallowance has been recognized as a de facto exercise of utility management by a number of commentators. Thus, according to Alfred Kahn, "Effective regulation of operating expenses and capital outlays would require a detailed, day-by-day transaction-by-transaction, and decision-by-decision review of every aspect of the company's operation. Commissions could do so only if they were prepared completely to duplicate the role of management itself. This society has never been willing to have commissions fill the role of management, each with an equally pervasive role in its operations." (*The Economics of Regulation*, vol 1, pp. 27-28(MIT, 1998). See also, Stephen Breyer, *Regulation and its Reform*, p. 49 (Harvard University Press, 1982). Both of these authorities, writing from an American perspective, emphasize the judicial oversight of disallowance decisions, which incorporate a clear presumption of prudence. While the Ontario *legal* restrictions on the presumption of prudence are less restrictive, the considerations respecting the practical limitations of simply disallowing costs without a strong factual or regulatory reason to do so are equally relevant here. In other words, when a Board disallows costs it is stepping into management's shoes. Although it may not be unlawful to do this, it should be done only when there is some reason to suppose that management is acting imprudently. Otherwise, the disallowance of cost has the risk of appearing to be impressionistic and even arbitrary second-guessing.

[5] See Transcript, vol. 1, p. 83.

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DBRS
Insight beyond the rating.

Rating Report

Report Date:
April 14, 2011
Previous Report:
April 15, 2010

Enersource Corporation

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The Company
Enersource Corporation is a holding company that owns Enersource Hydro Mississauga (EHM), a regulated electricity distribution company, and Enersource Services Inc., a non-regulated holding company. Enersource Corporation is 90% owned by the City of Mississauga, and 10% owned by BPC Energy Corporation, a subsidiary of Ontario Municipal Employees Retirement System.

Recent Actions
April 15, 2010
Confirmed

Rating

Debt	Rating	Rating Action	Trend
Issuer Rating	A	Confirmed	Stable
Senior Unsecured Debentures	A	New Rating – Provisional	Stable

Rating Rationale

DBRS has confirmed the Issuer Rating of Enersource Corporation (Enersource or the Company) at "A" with a Stable trend, and has assigned a provisional rating of "A" with a Stable trend to Enersource's expected $320 million private placement senior unsecured debentures offering. The proceeds from the new issuance will be used to refinance the maturing $290 million debt with Borealis Infrastructure Trust and for general corporate purposes.

Enersource continues to benefit from a low level of business risk stemming from its regulated electricity distribution operations, its solid financial profile and a strong franchise area with a favourable customer mix. The confirmation is also supported by the relatively stable regulatory environment in Ontario. On March 17, 2011, the Ontario Energy Board (OEB) announced electricity distribution rates for Enersource Hydro Mississauga Inc (EHM). The net impact of the new distribution rates, which were set using incentive regulation, will be an increase of 0.18% for residential customers using 800 kWh per month.

In December 2009, the OEB changed its methodology for calculating return on equity (ROE), which resulted in an increase in ROE to the mid- to high 9.00% range. However, Enersource will continue to utilize 8.57% for rate-setting until it rebases rates in 2013, at that time it will adopt the then-current allowed ROE (currently 9.58%).

Enersource's financial metrics have remained stable over time, attributable to generally consistent earnings, cash flows and debt levels. For the year ending December 31, 2010, the Company witnessed an improvement in both financial and operating performance, with cash flow-to-debt of 22.4%, debt-to-capital of 55% and EBIT interest of 2.24 times.

DBRS believes that the Company will be able to fund capital expenditures and dividends with internally generated funds and cash balances on hand, and that Enersource's financial profile will continue to support the current rating.

Rating Considerations

Strengths
(1) Low business risk owing to Enersource's predominantly regulated electricity distribution operations
(2) Solid balance sheet and reasonable credit metrics
(3) Strong franchise area and favourable customer mix

Challenges
(1) Approved ROE sensitive to long-term interest rates
(2) Earnings sensitive to volume of electricity sold
(3) Inability to access equity capital markets

Financial Information

	For the 12 months ending				
	Dec. 31/10	Dec. 31/09	Dec. 31/08	Dec. 31/07	Dec. 31/06
EBIT interest coverage (times)	2.24	2.29	2.35	2.05	2.04
Total debt-to-capital	55.0%	55.7%	56.3%	57.5%	58.0%
Cash flow/total debt (times)	22.4%	18.5%	17.6%	18.0%	17.6%
Cash flow/capital expenditures (times)	1.54	0.95	1.08	1.11	1.42
Reported net income ($ millions)	17.7	17.6	19.1	13.9	17.2
Cash flow from operations ($ millions)	65.0	53.4	51.0	51.8	50.9
Return on average equity	7.6%	7.7%	8.8%	6.6%	8.4%
Electricity throughputs (millions kWh)	7,709	7,499	7,820	7,963	7,833

Undertaking No. JT1.15

To provide the rate of return for the shareholder from 2009 to 2012, as well as the regulated rate, both the actual rate on the actual equity and the deemed rate on the deemed equity. P. 180

Response:

The actual and deemed regulated shareholder rate of return for 2009 to 2011 are shown in the table below. The actual rate of return for 2012 will not be known until year end.

Actual Shareholder Rate of Return

	CGAAP 2009	CGAAP 2010	MIFRS 2011
Actual Net Income[1]	15,507	14,353	17,250
Actual Equity[1,2]	200,091	204,342	209,759
Actual RoR Shareholder	7.75%	7.02%	8.22%

1. Net income and equity have been adjusted to exclude conservation and demand management revenue and expense, smart meter net income and other non-utility expenses
2. Equity has been calculated using an average of opening and closing values

Deemed Shareholder Rate of Return

	CGAAP 2009	CGAAP 2010	MIFRS 2011
Deemed Net Income	16,405	21,464	21,513
Deemed Equity	204,800	217,909	224,557
Deemed RoR Shareholder	8.01%	9.85%	9.58%

(9)

Enersource Hydro Mississauga Inc.
Response to Interrogatories by Issue

Interrogatory #11

Board Staff

1. General

Issue 1.2: What is the appropriate approach to set rates for 2015 and 2016?

Assuming the current four year rate cycle remains in place, please confirm that Enersource will apply for rates under IRM for the rate years 2015 and 2016?

Response:

Enersource anticipates that the Board's current initiative, the Renewed Regulatory Framework for Electricity ("RRFE"), will have been concluded by that time, but it is not possible to speculate on all of the permutations of what decisions may result from the RRFE and how they may impact Enersource's 2015 and 2016 rate applications. Enersource will review its options for 2015 and 2016 rate applications upon receiving the Board's decision in this Application. These options include an IRM filing for rate adjustments for those rate years.

(10)

ISSUE 2: RATE BASE

Issue 2: Rate Base notes 11
11. Energy Probe IR #3 Issue 2.1. /SEC IR # 13 Issue 2.1 /VECC IR # 6 Issue 2.1.

Additional References

Table 1: Net Capital Expenditures, CGAAP 2011 - 2014 ($000s)

Description	2011 CGAAP	2012 CGAAP	2013 CGAAP	2014 CGAAP
Land and Buildings	$ 2,694	$ 22,170	$ 9,300	$ 4,515
TS Primary Above 50	$ -	$ -	$ -	$ -
Distribution Station	$ 8,364	$ 6,666	$ 3,242	$ 3,473
Poles, Wires	$ 25,501	$ 23,922	$ 24,329	$ 26,555
Line Transformers	$ 3,282	$ 3,196	$ 3,291	$ 3,551
Services and Meters	$ 2,749	$ 4,191	$ 2,273	$ 2,875
General Plant	$ -	$ -	$ -	$ -
Equipment	$ 2,284	$ 2,839	$ 3,175	$ 3,660
IT Assets	$ 5,615	$ 5,464	$ 4,351	$ 4,388
Other Distribution Assets	$ 1,358	$ 1,523	$ 1,919	$ 2,320
CIP including CIAC	$ (3,560)	$ (101)	$ -	$ -
Customer Contributions	$ (3,603)	$ (2,907)	$ (2,933)	$ (2,960)
Net Capital Expenditures	**$ 44,684**	**$ 66,964**	**$ 48,947**	**$ 48,377**
Plus Borrowing cost	$ 400	$ 563	$ 285	$ 288
Net Capital Additions	**$ 45,084**	**$ 67,527**	**$ 49,231**	**$ 48,664**

b) Figures presented in the Exhibit 2 Tab 2 Schedule 1 Table 1 are actual capital expenditures for 2011in IFRS.

Figures presented in the above table for 2011 are actual capital expenditures in CGAAP.

All figures presented for 2012, 2013, and 2014 are forecasts.

c) Enersource will provide year-to-date figures to June 2012 once the period is closed.

Enersource Hydro Mississauga Inc.
Response to Interrogatories by Issue

Interrogatory #13

School Energy Coalition (SEC)

2. Rate Base

Issue 2.1 – Is the proposed rate base for 2013 and 2014, including capital expenditures for 2013 and 2014, appropriate?

Reference: Ex. 1/2/1, p. 5

Please provide a table showing actual capital contributions from developers or other third parties in each year from 2000 through 2011, both in dollars and as a percentage of total capital spending by the Applicant in the year, and forecasts of capital contributions (also dollars and percentage) for each of 2012 through 2016.

Response:

Please see the table below.

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Year	Gross Capital Expenditures	Customer Contributions	Net Capital expenditures	Customer Contributions as % of Gross CapEx	
2000	$ 28,577	$ (4,223)	$ 24,353	15%	Average 2000-2005
2001	$ 33,839	$ (11,078)	$ 22,760	33%	$ (9,963)
2002	$ 31,398	$ (17,680)	$ 13,718	56%	32%
2003	$ 26,058	$ (9,418)	$ 16,641	36%	
2004	$ 30,218	$ (7,415)	$ 22,803	25%	
2005	$ 32,658	$ (8,808)	$ 23,850	27%	
2006	$ 36,729	$ (2,934)	$ 33,796	8%	Average 2006-2011
2007	$ 47,628	$ (9,947)	$ 37,681	21%	$ (4,417)
2008	$ 57,653	$ (6,916)	$ 50,737	12%	9%
2009	$ 52,033	$ 6,277	$ 58,310	-12%	
2010	$ 61,198	$ (8,484)	$ 52,714	14%	
2011	$ 46,657	$ (4,498)	$ 42,159	10%	
2012	$ 66,849	$ (2,907)	$ 63,942	4%	Average 2012-2016
2012*	$ 46,897	$ (2,907)	$ 43,990	6%	$ (2,939)
2013	$ 49,106	$ (2,933)	$ 46,173	6%	6%
2014	$ 48,311	$ (2,960)	$ 45,351	6%	
2015	$ 47,752	$ (2,987)	$ 44,766	6%	
2016	$ 49,223	$ (3,013)	$ 46,209	6%	

2012* Represents Capital expenditures excluding new administration building expenditures

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Table 6: System Expansion and Upgrades – Customer Driven Investment, 2007 - 2014 ($000s)

Major Capital Program	2007 CGAAP	2008 Board Approved	2008 CGAAP	2009 CGAAP	2010 CGAAP	2011 IFRS	2012 IFRS	2013 IFRS	2014 IFRS
Industrial and Commercial Services	$ 5,897	$4,450	$ 4,729	$ 5,634	$ 3,372	$ 3,452	$ 2,926	$ 2,560	$ 2,560
New Subdivisions	$ 9,029	$5,575	$ 3,761	$ (4,461)	$ 12,083	$ 3,331	$ 2,443	$ 2,247	$ 2,247
Road Projects	$ 1,446	$1,250	$ 3,171	$ 1,589	$ 3,601	$ 2,457	$ 1,776	$ 1,687	$ 1,599
Metering Equipment	$ (274)	$889	$ 462	$ 408	$ 356	$ 658	$ 952	$ 695	$ 760
Smart Metering in New Condos	$ -	$975	$ 1,680	$ 608	$ 970	$ 681	$ 977	$ 952	$ 1,383
Gross Total	$ 16,098	$13,139	$ 13,804	$ 3,778	$20,382	$ 10,579	$ 9,074	$ 8,142	$ 8,549
Industrial and Commercial Services	$ (751)	-$250	$ (2,548)	$ (3,162)	$ (3,112)	$ (1,911)	$ (1,600)	$ (1,600)	$ (1,600)
New Subdivisions	$ (8,826)	-$3,000	$ (1,980)	$ 5,279	$ (4,082)	$ (933)	$ (600)	$ (600)	$ (600)
Road Projects	$ (370)	-$500	$ (2,388)	$ (533)	$ (1,289)	$ (1,466)	$ (600)	$ (600)	$ (600)
Customer Contributions To	$ (9,947)	-$3,750	$ (6,916)	$ 1,584	$ (8,484)	$ (4,310)	$ (2,800)	$ (2,800)	$ (2,800)
Net Total	$ 6,151	$9,389	$ 6,888	$ 5,363	$11,899	$ 6,269	$ 6,274	$ 5,342	$ 5,749

Table 7: Non-System Requirements - Regulatory Driven Investments, 2007 - 2014 ($000s)

Major Capital Program	2007 CGAAP	2008 Board Approved	2008 CGAAP	2009 CGAAP	2010 CGAAP	2011 IFRS	2012 IFRS	2013 IFRS	2014 IFRS
Conservation & Demand Response	$ 396	$0	$ (22)	$ 43	$ -	$ -	$ -	$ -	$ -
Wholesale Metering	$ 509	$145	$ 75	$ 974	$ 518	$ 700	$ 2,779	$ -	$ -
Smart Metering	$ 7,760	$0	$ 6,104	$ 8,392	$ 8,184	$ 2,850	$ 1,488	$ -	$ -
Green Energy – FIT/MicroFIT	$ -	$0	$ -	$ -	$ 61	$ 197	$ 240	$ 316	$ 379
Gross Total	$ 8,665	$145	$ 6,157	$ 9,410	$ 8,763	$ 3,747	$ 4,507	$ 316	$ 379
Green Energy – FIT/MicroFIT	$ -	$0	$ -	$ -	$ -	$ -	$ (107)	$ (133)	$ (160)
Customer Contributions Tot	$ -	$0	$ -	$ -	$ -	$ -	$ (107)	$ (133)	$ (160)
Net Total	$ 8,665	$145	$ 6,157	$ 9,410	$ 8,763	$ 3,747	$ 4,401	$ 183	$ 219

Enersource Hydro Mississauga Inc.
Response to Interrogatories by Issue

Interrogatory #14

School Energy Coalition (SEC)

2. Rate Base

Issue 2.1 – Is the proposed rate base for 2013 and 2014, including capital expenditures for 2013 and 2014, appropriate?

Reference: Ex. 1/2/1, p. 10

Please provide a table comparing the actual and forecast increase in rate base each year from 2008 to 2014 to the actual and forecast inflation and customer growth for each of those years. Please explain any material growth in rate base that exceeds the combination of inflation and customer growth.

Response:

Please see the table below.

	2008 Board Approved	2009 Actual	2010 Actual	2011 Actual	2012 Forecast	2013 Forecast	2014 Forecast
Net Fixed Assets in Rate Base	$ 410,637	$ 429,395	$ 448,899	$ 463,784	$ 492,663	$ 519,647	$ 536,143
Increase % (A)		4.57%	4.54%	3.32%	6.23%	5.48%	3.17%
PCI = Inflation - Productivity - Strech factor		1.18%	0.18%	0.18%	0.88%	0.88%	0.88%
Customer Growth (based on E3-T1-S2 pg31, attachment6)		1.60%	1.60%	1.50%	1.30%	1.20%	1.40%
Combination of PCI & Customer Growth (B)		2.78%	1.78%	1.68%	2.18%	2.08%	2.28%
Difference (A) - (B)		1.79%	2.76%	1.64%	4.05%	3.40%	0.89%

Please refer to Exhibit 2 Tab 1 Schedule 1, p. 3 for overall major drivers of net capital asset increases and Exhibit 2 Tab 1 Schedule 1 pages 7-10 for the details of these increases each year.

ISSUE 3: OPERATING REVENUES

Issue 3: Operating Revenues notes 12-28

[1] Exhibit 3, Tab 1, Schedule 1, page 2
[1] Exhibit 3, Tab 1, Schedule 2, page 16
[1] Response to Issue 3.1, Board Staff #29 c)
[1] Technical Conference Undertaking JT2.24
[1] Exhibit 3 Tab 1, Schedule 2, page 6
[1] Technical Conference Undertaking JT2.39 d)
[1] Technical Conference, July 31, 2012, page 135
[1] Response to Issue 3.1, VECC IR #20, Attachment #2
[1] Technical Conference Undertaking JT2.36
[1] EB-2008-0037, page 18
[1] Exhibit 3, Tab 1, Schedule 2, page 6
[1] Technical Conference, July 31, 2012, pages 147-148
[1] Exhibit 3, Tab 1, Schedule 2, page 16
[1] Exhibit 3, Tab 1, Schedule 1, page 7
[1] Exhibit 3, Tab 1, Schedule 1, page 7 and Exhibit 3, Tab 1, Schedule 2, page 6
[1] Exhibit 3, Tab 3, Schedule 1, page 2
[1] Response to Issue 3.2, Energy Probe #3 (Updated)

Additional References

short term energy consumption are also utilized for long term system planning requirements.

Historical Data (1996-2011)

Sixteen years of Enersource's actual energy purchases from the Ontario electricity wholesale market from 1996 to 2011 are used to establish relationships between analytic and econometric drivers to energy and peak demand. The annual energy purchases from the Independent Electricity System Operator ("IESO") have increased over the sixteen-year period at an average annual rate of 1.45%. When corrected for normal weather, the average annual consumption growth rate for that period was found to be 1.36%.

Table 1 below provides the annual energy purchases from 1997 to 2011, actual and weather-corrected, and identifies the annual growth rates. Figure 1 follows and provides the same annual energy purchase information in illustrative format.

1 # Attachment A – Short Term System Load Energy Model Statistics

Regression Statistics	
Iterations	18
Adjusted Observations	191
Deg. of Freedom for Error	173
R-Squared	0.988
Adjusted R-Squared	0.987
AIC	17.914
BIC	18.221
Log-Likelihood	-1,963.83
Model Sum of Squares	790,516,390,955.78
Sum of Squared Errors	9,533,001,678.53
Mean Squared Error	55,104,055.95
Std. Error of Regression	7,423.21
Mean Abs. Dev. (MAD)	5,413.50
Mean Abs. % Err. (MAPE)	0.86%
Durbin-Watson Statistic	2.092
Ljung-Box Statistic	35.95
Prob (Ljung-Box)	0.0556
Skewness	-0.168
Kurtosis	3.291
Jarque-Bera	1.577
Prob (Jarque-Bera)	0.4546

2

Variable	Coefficient	StdErr	T-Stat	P-Value
Monthly.MonthlyTimeTrend	-18692.675	1373.18	-13.613	0.00%
Population.Population	-0.271	0.063	-4.323	0.00%
Employment.EmpLand	0.573	0.156	3.673	0.03%
Employment.MajOff	6.305	0.507	12.441	0.00%
Monthly.MonthlyGDP	2.849	0.77	3.698	0.03%
MonthlyWeather.MonthlyDBCubed	-0.239	0.081	-2.958	0.35%
MonthlyWeather.MonthlyBuildUp	137.917	39.549	3.487	0.06%
MonthlyWeather.MonthlyCDD	1042.732	93.13	11.196	0.00%
MonthlyWeather.MonthlyHDD	323.34	36.225	8.926	0.00%
Monthly.WorkingDays	2889.973	464.444	6.222	0.00%
MonthlyWeather.MonthlyDwPtCubed	0.15	0.04	3.759	0.02%
MonthlyCalTrans.Month_Feb	-37044.965	2849.082	-13.002	0.00%
MonthlyCalTrans.Month_Aug2003	-4312.616	635.232	-6.789	0.00%
MonthlyCalTrans.Month_Apr	-18234.514	2706.349	-6.738	0.00%
MonthlyCalTrans.Month_Nov1996	-24857.429	6776.573	-3.668	0.03%
MonthlyCalTrans.Month_Dec1999	24056.334	6797.63	3.539	0.05%
AR(1)	0.292	0.076	3.831	0.02%
SMA(1)	0.352	0.078	4.522	0.00%

3

4

Enersource Hydro Mississauga Inc.
Response to Interrogatories by Issue

Interrogatory #29

Board Staff

3. Operating Revenue

Issue 3.1: Is the proposed load forecast for 2013 and 2014, including billing determinants, appropriate?

Reference: E3-T1-S1 p. 2 & 11

At p. 2 Enersource states that sixteen years of Enersource's actual energy purchases from the Ontario electricity wholesale market from 1996 to 2011 are used to establish relationships between analytic and econometric drivers to energy and peak demand. At p. 11 Enersource also states that it developed multivariate regression models to determine energy consumption for each rate class and that the models capture the relationship between rate class sales and a number of explanatory variables including weather, calendar, econometric and other explanatory variables. The models were developed based on energy sales from 2004 to 2011 and include the same input variables such as weather, calendar, and econometric data as the system energy and peak demand models.

The models appear to utilize different historical periods, i.e. 15 years vs. 7 years.

a) Which model underpins the forecasted load (consumption purchases), for 2012 and 2013.

b) In the underpinning model, has Enersource made any adjustment to weight more recent years more heavily than earlier years? If so, please elaborate the details of the adjustment.

c) For the residential and large uses classes, please provide a description the actual steps, including the trail numbers, that was used to generate the load forecast (billed/charge determinant volumes) for 2012 and 2013.

Response:

a) Enersource created two independent forecasting models.

   The first model is the load forecast model that captures purchases from the Ontario electricity wholesale market from 1996 to 2011 (i.e., sixteen years) based on weather, calendar, and econometric variables.

   The second model was developed solely to determine a weather-correction normalization for rate classes and relied on seven years of actual energy sales data by customer class.

   The load forecast model, which is the first model described above, underpins the energy purchase forecast, as addressed in Exhibit 3 Tab 1 Schedule 1 page 2.

b) No. Enersource has not made any adjustments to weight more recent years more heavily.

c) The following are the actual steps used to generate the load forecast, billed determinant volumes, for 2012 and 2013. The table below highlights these steps and the trail numbers used to generate the billed determinants for residential and large user classes.

   1. Enersource developed a multivariate regression load forecast model to obtain total energy purchases for 2012 and 2013;

   2. Enersource developed multivariate regression models for weather sensitive rate classes to derive weather corrected energy sales by rate class;

   3. Enersource adjusted total purchases to incorporate projected incremental CDM activity in 2012 and 2013;

   4. Enersource adjusted total purchases to account for line losses to derive total billed consumption;

   5. Enersource converted billed consumption to billed demand for demand related classes (i.e., GS > 50 kW) by utilizing five year actual average load factors by class by average days per month and hours per day.

	Reference	2012		2013	
Step 1 – Load Forecast	E3-T1-S2, p. 2 of 31	7,749,732,964		7,817,740,567	
Step 2 – Weather normalization models	E3-T1-S2, p. 11 of 31	**Residential**	**Large User**	**Residential**	**Large User**
Residential		1,498,238,071		1,510,959,264	
Large User			1,011,627,005		1,020,566,402
Step 3 - Remove CDM Impact					
Residential	E3-T1-S2, p. 6 of 31	(22,709,000)		(35,842,920)	
Large User	E3-T1-S2, p. 6 of 31		(14,714,815)		(8,983,655)
	E3-T1-S2, p.29 of 31, Attach. 2&3	1,475,529,071	996,912,190	1,475,116,344	1,011,582,747
Step 4 - Remove Line Losses to obtain metered billed kWh					
Residential	E3-T2-S1, p.24-25 of 27, Attach. 10&11	1,424,255,860		1,423,857,475	
Large User (Note)			982,663,568		997,124,443
Step 5 – Convert consumption classes to demand					
Load Factor			79%		79%
Average Days per month			30.4		30.4
Hours per Day			24		24
Billed/Charge Determinant Volumes	E3-T2-S1, p.24-25 of 27, Attach. 10&11	1,424,255,860	1,712,059	1,423,857,475	1,737,267

Undertaking No. JT2.24

To provide weather-corrected numbers and shares and average for each rate class for 2012 and 2013. P. 116

Response:

Enersource relied on the following methodology to develop the energy forecast by rate class before incremental CDM adjustments:

1. Enersource developed a multivariate regression load forecast model to obtain total forecasted energy purchases for 2012 and 2013 (7,749.7 GWh and 7,817.7 GWh, respectively).

2. Enersource developed multivariate regression models for weather-sensitive rate classes to derive weather-corrected energy sales (inclusive of losses) by rate class. The results can be found at Table 1 below. The explanatory variables used for the rate class models were provided in Undertaking JT2.29.

3. Enersource relied on the weather-corrected energy sales developed above in Step 2 to calculate an historical average weather-corrected energy sales percentage allocation for each rate class. The results can be found at Table 2 attached.

(23)

Table 1

Actuals — All Data in GWh

Year	Total Energy Sales	Residential	Sm Com	GS<50	GS 50-499	GS 500-4999	Large User	Street Lights
2005	8,316	1,703	13	702	2,500	2,379	981	39
2006	8,133	1,603	12	684	2,348	2,465	980	40
2007	8,278	1,633	12	691	2,363	2,508	1,032	40
2008	8,096	1,591	12	699	2,299	2,384	1,071	41
2009	7,747	1,555	11	677	2,188	2,252	1,024	41
2010	7,963	1,643	12	685	2,207	2,287	1,088	41
2011	7,878	1,641	12	674	2,209	2,247	1,053	41

Weather Corrected (30 year normal) — All Data in GWh

Year	Total Energy Sales	Residential	Sm Com	GS<50	GS 50-499	GS 500-4999	Large User	Street Lights
2005	7,956	1,434	13	679	2,427	2,364	1,000	39
2006	8,002	1,483	12	686	2,353	2,443	986	40
2007	8,097	1,480	12	680	2,332	2,505	1,048	40
2008	8,036	1,543	12	690	2,303	2,381	1,066	41
2009	7,801	1,548	11	674	2,222	2,267	1,039	41
2010	7,787	1,527	12	681	2,171	2,275	1,080	41
2011	7,738	1,535	12	667	2,187	2,240	1,055	41

TABLE 1

SUMMARY of 2007 - 2011 ACTUALS & FORECAST 2012 and 2013 BASED ON ACTUAL ALLOCATION

SUMMARY kWh 2013 — Weather Normal on 5 Year Actual Average

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
Enersource's 2013 Forecast	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]

By %

SUMMARY kWh 2012 — Weather Normal on 5 Year Actual Average

By %

5 YEAR AVERAGE (2007-2011) ENERGY SALES (INCLUDING LOSSES)

By %

SUMMARY kWh 2011

By %

SUMMARY of 2007 - 2011 WEATHER NORMALIZED ACTUALS & FORECAST 2012 and 2013 BASED ON WEATHER NORMALIZED ALLOCATION

SUMMARY kWh 2013 — Weather Normal on 5 Year Normal Average

By %

SUMMARY kWh 2012 — Weather Normal on 5 Year Normal Average

By %

5 YEAR AVERAGE WEATHER NORMAL (2007-2011) of ENERGY SALES LOSSES INCLUDED

By %

SUMMARY kWh 2011

By %

Enersource Hydro Mississauga Inc.
EB-2012-0033
Filed: August 7, 2012
Undertakings from
Technical Conference
July 30 31, 2012
Undertaking No. JT2.24
Attachment

SUMMARY kWh 2010

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
Res	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
Small Commercial	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
Unmetered Scattered Load	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
0-50	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
50-499	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
500-4999	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
LU	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
SL	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
Total kWh	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
By %													
Residential	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
Small Commercial	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
Unmetered Scattered Load	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
0-50	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
50-499	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
500-4999	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
LU	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
St Light	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
Total	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]

SUMMARY kWh 2010 (Weather corrected)

	Weather corrected	Total allocation	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]

SUMMARY kWh 2009

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
Res	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
Small Commercial	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
Unmetered Scattered Load	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
0-50	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
50-499	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
500-4999	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
LU	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
SL	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
Total kWh	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
By %													
Residential	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
Small Commercial	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
Unmetered Scattered Load	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
0-50	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
50-499	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
500-4999	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
LU	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
St Light	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
Total	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]

SUMMARY kWh 2009 (Weather corrected)

	Weather corrected	Total allocation	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]

SUMMARY kWh 2008

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
Residential	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
Small Commercial	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
Unmetered Scattered Load	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
0-50	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
50-499	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
500-4999	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
LU	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
St Light	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
Total Consumption	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
By %													
Residential	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
Small Commercial	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
Unmetered Scattered Load	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
0-50	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
50-499	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
500-4999	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
LU	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
St Light	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
Total	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]

SUMMARY kWh 2008 (Weather corrected)

	Weather corrected	Total allocation	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]

SUMMARY kWh 2007

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
Residential	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
Small Commercial	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
Unmetered Scattered Load	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
0-50	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
50-499	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
500-4999	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
LU	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
Street lighting	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
Total Consumption	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
By %													
Residential	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
Small Commercial	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
Unmetered Scattered Load	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
0-50	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
50-499	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
500-4999	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
LU	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
Street lighting	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
Total	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]

SUMMARY kWh 2007 (Weather corrected)

	Weather corrected	Total allocation	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]

* Effective July 1, 2012 the LU and GS 500-4999kW class were adjusted to reflect the movement of 2 large users to the GS 500-4999kW class

The impact of historical CDM programs on the load in future years is incorporated in the load forecast presented in Table 1 above as a CDM trending variable is utilized in the load forecast model. The load forecast model however does not incorporate projections of incremental energy savings from the aggressive CDM targets that Enersource will need to deliver in 2012 to 2013. Hence, Enersource has adjusted the forecast shown in Table 1 with the cumulative increases in CDM over and above those included in the load forecast model over the 2012 to 2013 period. The incremental CDM energy consumption savings are identified in Table 3 below.

Table 3: CDM Adjustments by Customer Class, 2012 to 2013 (kWh)

Rate Class	2012 CDM Adjustment	2013 CDM Adjustment
Residential	(22,709,000)	(35,842,920)
Small Commercial	-	-
Unmetered Scattered Load	-	-
GS < 50	(32,620,613)	(39,519,293)
GS 50-499	(4,349,853)	(6,718,613)
GS 500-4999	(4,648,053)	(7,166,687)
Large User	(14,714,815)	(8,983,655)
Street Lighting	(5,228,799)	(20,915,195)
Total	(84,271,133)	(119,146,362)

Table 3 highlights the adjustment made to the sales forecasts by customer class to reflect the load reductions in 2012 and 2013 as a result of the incremental CDM activities. A detailed monthly breakdown of the CDM adjustment shown on Table 3 is provided as Attachment 1 to this exhibit.

The net result of the CDM adjustments yields an overall consumption forecast as shown in Table 4 below. The forecast data on Table 4 is also shown at Attachment 2, which provides the actual and forecast sales by rate class, net of CDM impacts, from 2008 to 2013.

Undertaking No. JT2.39

VECC Question No. 3 as provided in hard copy to Enersource.

Reference Issue 3.1: **VECC - #20 e),**

Energy Probe # 5a)

Issue: Clarifications that the CDM Adjustments represent the full impact of their CDM programs for 2012 – 2013.

Question

a) Confirm that CDM Target is 417.22 GWh (per Ex 3/Tab 1/Sch 2, page 5)
b) Confirm that 2011 CDM savings were 26.48 GWh from VECC # 20 Attachment 2 and that this is assumed to contribute 105.57 GWh towards their overall 2011-2014 cumulative energy target
c) Refer to Energy Probe #5 – confirm that the 84.271 GWh represents the GWh savings in 2012 from 2012 programs.
d) Also confirm that the 119.146 GWh savings for 2013 represent the savings in 2013 from both programs implemented in 2012 (where savings continue in 2013) as well as the savings in 2013 from 2013 programs.
e) Confirm that the 155.317 GWh savings for 2014 represent the impact in 2014 of programs implemented in 2012 and 2013 as well the impact of 2014 programs.
f) Confirm that overall all the cumulative 2011 -2014 energy savings from their planned CDM Programs are 105.57 + 84.271 + 119.146 + 155.317 = 464.304 which is well in excess of the actual target.
g) Why is Enersource targeting for savings well in excess of the actual target.

Response

a) Confirmed.

b) Yes, the 2011 CDM unverified savings were 26.48 GWh based on the OPA's 2011 Q4 report released in March 2012 and this is assumed to contribute 105.57 GWh towards the overall 2011-2014 CDM cumulative energy target.

c) The 84.271 GWh savings in 2012 represents the incremental savings from 2011 and 2012 programs.

d) The 119.146 GWh savings in 2013 represents the incremental savings from 2011, 2012, and 2013 programs.

e) The 155.317 GWh savings in 2014 represents the incremental savings from 2011, 2012, 2013s and 2014 programs.

f) The 2011 – 2014 cumulative energy savings from the planned CDM programs are: 58.486 + 84.271 + 119.146 + 155.317 = 417.22 GWh.

g) Enersource intends to meet its conservation targets for the 2011-2014 period, as shown in f).

TC V2

MR. HARPER: Right. That was the 26.48. And if you accumulate that over four years you come up with about 105.57 gigawatt-hours, as that being the contribution from that to your overall target. Would that be a fair characterization?

MR. SULTANA: Yes.

MR. HARPER: Okay. And then if I look at Energy Probe No. 5 -- and I believe it's attachment A. Oh, no, no, actually, it's Table 3. It's response to Part A of Energy Probe No. 5, under issue 3.1, and Table 3, which is in the response to part (a), has your CDM adjustments for 2012, 2013, and also has one for 2014.

MR. RAMTAHAL: Yes.

MR. HARPER: And I just want to make sure I understand what these numbers represent. The 2012 adjustment of roughly 84.3 gigawatt-hours is the impact of 2012 programs in 2012.

MR. RAMTAHAL: So this also includes the incremental savings from the 2011 programs.

MR. HARPER: So -- okay. So the 84,271 includes the incremental savings from -- includes the 26 -- excuse me, the -- yes, the 2,648 from 2011?

MR. RAMTAHAL: No, it wouldn't be the actual savings, it would be the plan -- original plan, which was 53 gigawatt-hours.

MR. HARPER: So what you are telling me is the 84 is made up of 53 gigawatt hours from 2011 programs, and the balance of that, which is about 30-something gigawatt-hours

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Ontario Power Authority Q4 2011 Conservation & Demand Management Status Report

January 1, 2011 to December 31, 2011

Enersource Hydro Mississauga Inc.

The following tables show progress to OEB targets first: following the OPA reporting practice of 1 year persistence for demand response and second: assuming demand response remains in your territory until 2014.

Unverified 2014 Peak Demand Savings Target Achieved (%):	**6.1%**
Unverified 2011-2014 Cumulative Energy Target Achieved (%):	**25.3%**

Assuming Demand Response resources remain in your territory until 2014:		**Standing:**
Unverified 2014 Peak Demand Savings Target Achieved (%):	**12.8%**	20 of 77
Unverified 2011-2014 Cumulative Energy Target Achieved (%):	**25.4%**	9 of 77

Message from the Vice President

The OPA Conservation team is pleased to provide the Q4 2011 CDM Status Report. Province-Wide programs are showing success and we are well positioned to meet our 2011-14 targets, thanks to the efforts of the OPA and you, the LDCs. A "Standing" column has been included in this report (in the table above) which reflects your position based on the percent of target achieved. This is based on preliminary results and is intended to provide you with a snapshot of how your LDC is performing relative to the others in the province.

We have achieved 80% of our 2011 Province-Wide programs peak demand savings forecast - more data will be available as projects progress through the final stages of approval. We will continue to update preliminary 2011 data (which will be reflected in the "Program-to-Date" columns) until the results are verified later this year.

We invite you to continue to look for opportunities to improve this report to meet your needs and welcome your suggestions. Additionally, if you are having any concerns with roll-out or have a particular success to share, please contact the OPA Conservation Business Development team at ldc.support@powerauthority.on.ca.

- Andrew Pride
Vice President, Conservation
Ontario Power Authority

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About this Report

This report contains:

- Peak demand and energy savings for OPA-Contracted Province-Wide programs (does not incl. Ontario Energy Board (OEB) approved CDM programs or other conservation efforts undertaken by an LDC).
- Unverified quarterly results discounted using forecasted net-to-gross ratios. Once full Evaluation, Measurement & Verification (EM&V) occurs in the following year, results will be identified as final (verified).
- Data presented in this report represents program activity (i.e. projects completed, appliances picked up) completed on or before December 31, 2011 and received and entered into the OPA processing systems as per the dates specified in table 5.
- Updates to the previous quarter's participation due to more data availability.

Future reports will contain:

- More data for the Home Assistance Program
- ***peaksaver*** PLUS preliminary results representing all participants that are enrolled in ***peaksaver*** PLUS.
- Full, bar-code specific 2011 Coupon and Bi-Annual Retailer Event data (Retailers have until March 31, 2012 to submit coupons redeemed in 2011 to the OPA).Results are currently provincially allocated; once bar-code specific data is gathered, results can be attributed to a particular LDC. Data will be available to LDCs once retailers have submitted the coupons and QA/QC by the OPA is undertaken.

New this quarter based on LDC feedback:

- Demand response is now reported only in the "YTD Incremental" column. This value represents the total demand response under contract in your LDC territory as of the end of the current reporting period.
- The allocation methodology used to attribute non-bar code specific coupon redemptions from the Instant Coupon Booklet and Bi-Annual Retailer Event to each LDC was updated to reflect each LDC's proportion of the average 2008 and 2009 residential throughput as per the OEB yearbook.
- Table 5 on the final page of this report is intended to assist the LDC in reconciling internal data sources with the data contained in this report by communicating: **1.** The date in which the OPA considers savings to 'start'; **2.** At what point the data becomes available to the OPA; **3.** The date in which the data was collected for reporting purposes; **4.** The expectated probability and magnitude of updates to the data as more information becomes available.

Reporting Methodology (Quarterly Unverified results)

The OPA's policy on reporting preliminary results for prescriptive measures (i.e. standard technologies and items) is to determine the activity (i.e. appliances collected, projects completed, coupons redeemed, etc.) in the most detail possible and multiply these values by Prescriptive Input Assumptions (PIAs) and net-to-gross (NTG) ratios that were used to forecast the programs if available.

*Preliminary Net Savings = Activity * Gross per unit PIA * Net-to-gross ratio*

For engineered or custom projects, the calculated savings from each participant worksheet are summed and then multiplied by the forecasted net-to-gross ratio used for program planning purposes.

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2011-2014 Summary

2011 Quarter 4 *January 1, 2011 to December 31, 2011*

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

Table 1 presents preliminary net peak demand savings results from 2011 to date by implementation period. This table also presents the net annual peak demand savings that are expected to persist through to 2014 from program activity completed to date. Please note that demand response 1 and 3 have a persistence of 1 year.

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

#	Implementation Period	Annual			
		2011	2012	2013	2014
1	2011 - Reported - Quarter 1	5.78	1.23	1.23	1.23
2	2011 - Reported - Quarter 2	7.48	1.57	1.57	1.57
3	2011 - Reported - Quarter 3	8.65	1.92	1.92	1.92
4	2011 - Reported - Quarter 4	7.15	0.93	0.93	0.93
5	2012				
6	2013				
7	2014				
Annual Reported (Unverified)		11.86			
Annual Final (Verified)		n/a			
Unverified Net Annual Peak Demand Savings in 2014					5.65
2014 Annual CDM Capacity Target					92.98
Unverified 2014 Peak Demand Savings Target Achieved (%)					6.1%

Table 2 presents preliminary net annual energy savings results from 2011 to date by implementation period. This table also presents 2011-2014 net cumulative energy savings expected in 2014 from program activity completed to date.

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

#	Implementation Period	Annual				Cumulative
		2011	2012	2013	2014	2011-2014
1	2011 - Reported - Quarter 1	5.18	5.09	5.09	5.09	20.36
2	2011 - Reported - Quarter 2	6.74	6.64	6.64	6.64	26.54
3	2011 - Reported - Quarter 3	9.98	9.86	9.86	9.86	39.42
4	2011 - Reported - Quarter 4	4.90	4.78	4.78	4.78	19.24
5	2012					
6	2013					
7	2014					
Annual Reported (Unverified)		26.48				
Annual Final (Verified)		n/a				
Unverified Net Cumulative Energy Savings 2011-2014						105.57
2011-2014 Cumulative CDM Energy Target						417.22
Unverified 2011-2014 Cumulative Energy Target Achieved (%)						25.3%

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2011-2014 Summary

2011 Quarter 4 *January 1, 2011 to December 31, 2011*

Figure 1 presents unverified net annual peak demand savings achieved and expected persistence through to 2014 for program activity completed to date. The 2014 annual peak demand savings target as per OEB is also presented.

Figure 1: Net Peak Demand Savings (MW)

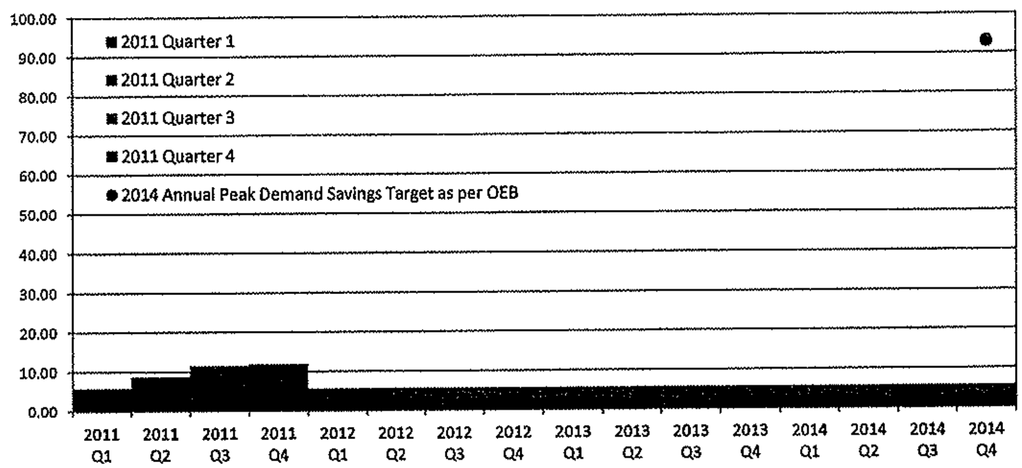

Figure 2 presents unverified net cumulative energy savings achieved including expected persistence to 2014 from program activity completed to date. The 2011-2014 cumulative energy savings target as per OEB is also presented.

Figure 2: Net Cumulative Energy Savings (GWh)

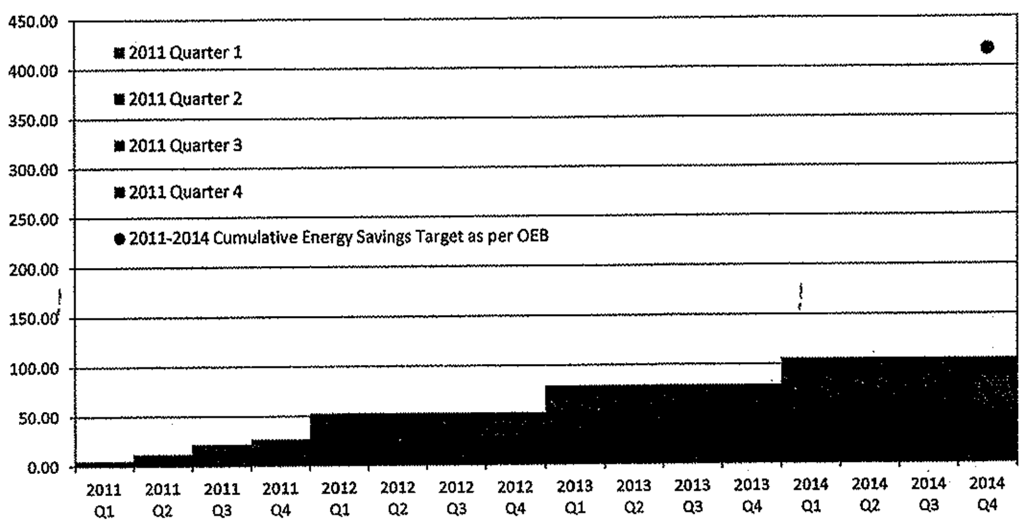

Table 3: Enersource Hydro Mississauga Inc. Initiative and Program Level Savings
Shaded areas indicate data is not yet available

All results are NET and presented at the end-user level

#	Initiative	Unit	Activity: Incremental (Current Quarter)	Activity: Program-to-Date (2011 to Date)	Net Peak Demand Savings (kW): Incremental (Current Quarter)	Net Peak Demand Savings (kW): YTD Incremental (2011 to Date)	Net Peak Demand Savings (kW): Program-to-Date: unverified annual savings in 2014	Net Energy Savings (kWh): Incremental (Current Quarter)	Net Energy Savings (kWh): YTD Incremental (2011 to Date)	Net Energy Savings (kWh): Program-to-Date (unverified) cumulative savings in 2014
1	Appliance Retirement	Appliances	540	1,799	41	134	134	283,498	938,787	3,755,150
2	Appliance Exchange	Appliances	0	253	0	25	25	0	30,695	122,782
3	HVAC Incentives	Equipment	529	3,689	121	786	786	38,926	1,039,502	4,158,007
4	Conservation Instant Coupon Booklet	Coupons	3,538	4,383	11	14	14	279,348	345,310	1,381,240
5	Bi-Annual Retailer Event	Coupons	7,677	9,882	15	21	21	473,058	622,850	2,491,399
6	Retailer Co-op	Items	0	5	0	0	0	0	1	5
7	*peaksaver* extension	Devices	0	431	0	336	336	0	6,711	26,843
8	Midstream Electronics	Items				not in market				
9	Midstream Pool Equipment	Items				not in market				
10	Residential New Construction	Houses	0	0	0.00	0.00	0.00	0	0	0
	Consumer Program Total				1,187	1,315	1,315	1,074,830	2,983,857	11,935,425
11	Equipment Replacement Incentive	Projects	27	48	372	743	743	1,372,284	3,459,653	13,838,613
12	Direct Installed Lighting	Projects	388	2,918	215	1,463	1,463	1,589,773	10,848,211	43,392,846
13	Direct Service Space Cooling	Equipment				not in market				
14	Building Commissioning	Buildings	0	0	0	0	0	0	0	0
15	New Construction	Buildings	0	0	0	0	0	0	0	0
16	*peaksaver* extension	Devices	0	0	0	0	0	0	0	0
17	Demand Response 1	Facilities		0		0	0		0	0
18	Demand Response 3	Facilities		10		2,373	0		74,038	74,038
	Business Program Total				587	4,580	2,207	2,962,057	14,381,902	57,305,496
19	Process & System Upgrades	Projects	0	0	0	0	0	0	0	0
20	Monitoring & Targeting	Projects	0	0	0	0	0	0	0	0
21	Energy Manager	Managers	0	0	0	0	0	0	0	0
22	Equipment Replacement Incentive	Projects	3	12	24	130	130	101,608	525,081	2,100,322
23	Demand Response 1	Facilities		0		0	0		0	0
24	Demand Response 3	Facilities		8		3,840	0		39,936	39,936
	Industrial Program Total				24	3,970	130	101,608	565,017	2,140,258
25	Home Assistance Program	Units	0	0	0	0	0	0	0	0
	Home Assistance Program Total				0	0	0	0	0	0
25	Electricity Retrofit Incentive Program	Projects	12	87	84	1,549	1,549	307,137	5,737,444	22,949,776
26	High Performance New Construction	Projects	2	17	51	369	369	336,404	2,598,650	10,394,599
27	Toronto Comprehensive	Projects	0	0	0	0	0	0	0	0
28	Multifamily Energy Efficiency Rebates	Projects	0	2	0	82	82	0	211,520	846,082
	Pre-2011 Programs completed in 2011 Total				135	1,999	1,999	643,541	8,547,614	34,190,457
	OPA-Contracted Province-Wide Portfolio Total				933	11,863	5,650	4,782,036	26,478,389	105,571,637

Table 4: Province-Wide Initiative and Program Level Savings

Shaded areas indicate data is not yet available

All results are NET and presented at the end-user level

#	Initiative	Unit	Activity: Incremental (Current Quarter)	Activity: Program-to-Date (2011 to Date)	Net Peak Demand Savings (kW): Incremental (Current Quarter)	Net Peak Demand Savings (kW): YTD Incremental (2011-to-Date)	Net Peak Demand Savings (kW): Program-to-Date (unverified annual savings in 2014)	Net Energy Savings (kWh): Incremental (Current Quarter)	Net Energy Savings (kWh): YTD Incremental (2011-to-Date)	Net Energy Savings (kWh): Program-to-Date unverified cumulative savings in 2014
[illegible]										
1	Appliance Retirement	Appliances	15,019	56,035	1,194	4,333	4,333	7,716,329	28,872,984	115,491,936
2	Appliance Exchange	Appliances	0	4,715	0	479	479	0	604,709	2,418,836
3	HVAC Incentives	Equipment	7,397	56,127	1,717	12,512	12,512	1,134,038	17,784,401	71,137,602
4	Conservation Instant Coupon Booklet	Coupons	90,106	144,467	269	468	468	7,114,454	11,358,484	45,433,938
5	Bi-Annual Retailer Event	Coupons	195,529	337,358	374	791	791	12,047,863	21,685,594	86,742,376
6	Retailer Co-op	Items	0	152	0	0	0	0	41	162
7	*peaksaver* extension	Devices	10	18,435	8	14,352	14,352	156	287,033	1,148,132
8	Midstream Electronics	Items			not in market					
9	Midstream Pool Equipment	Items			not in market					
10	Residential New Construction	Houses	5	5	0.04	0.04	0.04	557	557	2,227
Consumer Program Total					3,561	32,934	32,934	28,013,397	80,593,802	322,375,209
[illegible]										
11	Equipment Replacement Incentive	Projects	243	944	1,845	8,223	8,223	7,170,097	37,650,286	150,601,145
12	Direct Installed Lighting	Projects	2,422	18,667	1,546	10,407	10,407	11,414,663	77,311,193	309,244,770
13	Direct Service Space Cooling	Equipment			not in market					
14	Building Commissioning	Buildings	0	0	0	0	0	0	0	0
15	New Construction	Buildings	0	0	0	0	0	0	0	0
16	*peaksaver* extension	Devices	0	121	0	201	201	0	4,029	16,117
17	Demand Response 1	Facilities		0		0	0		0	0
18	Demand Response 3	Facilities		145		21,390	0		667,368	667,368
Business Program Total					3,391	40,222	18,832	18,584,760	115,632,876	460,529,401
[illegible]										
19	Process & System Upgrades	Projects	0	0	0	0	0	0	0	0
20	Monitoring & Targeting	Projects	0	0	0	0	0	0	0	0
21	Energy Manager	Managers	0	0	0	0	0	0	0	0
22	Equipment Replacement Incentive	Projects	35	179	439	1,636	1,636	2,056,245	7,800,798	31,203,192
23	Demand Response 1	Facilities		0		0	0		0	0
24	Demand Response 3	Facilities		125		67,276	0		699,670	699,670
Industrial Program Total					439	68,912	1,636	2,056,245	8,500,468	31,902,862
[illegible]										
25	Home Assistance Program	Units	494	494	1	1	1	18,047	18,047	72,188
Home Assistance Program Total					1	1	1	18,047	18,047	72,188
[illegible]										
25	Electricity Retrofit Incentive Program	Projects	29	483	397	5,079	5,079	1,441,254	19,451,459	77,805,835
26	High Performance New Construction	Projects	28	220	650	4,723	4,723	4,306,415	33,266,180	133,064,719
27	Toronto Comprehensive	Projects	27	576	1,559	13,774	13,774	13,405,628	83,570,866	334,283,463
28	Multifamily Energy Efficiency Rebates	Projects	0	110	0	1,886	1,886	0	7,218,883	28,875,534
Pre-2011 Programs completed in 2011 Total					2,606	25,461	25,461	19,153,297	143,507,388	574,029,551
OPA-Contracted Province-Wide Portfolio Total					9,998	167,529	78,863	67,825,747	348,252,582	1,388,909,212

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Glossary

Annual: the peak demand or energy savings that occur in a given year (includes resource savings from new program activity in a given year and resource savings persisting from previous years).

Cumulative Energy Savings: represents the sum of the annual energy savings that accrue over a defined period (in the context of this report the defined period is 2011 - 2014). This concept does not apply to peak demand savings.

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

End-User Level: resource savings in this report are measured at the customer level as opposed to the generator level (the difference being line losses).

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

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

Incremental: the new resource savings attributable to activity procured in a particular reporting period based on when the savings are considered to 'start' (please see table 5).

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

Net Energy Savings (MWh): energy savings attributable to conservation and demand management activities net of free-riders, etc.

Net Peak Demand Savings (MW): peak demand savings attributable to conservation and demand management activities net of free-riders, etc.

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

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

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

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

Table 5: Data Qualifiers for Initiatives currently in market

For Example: Preliminary results for Retrofit are reported in this quarter if a project is completed on or before Dec. 31, 2011 and had the iCON status "Approved for payment by LDC" or "Released for Payment" as of Jan. 20, 2012. There is a high probability that there are more results coming in for this initiative.

Initiative	Savings 'start' Date	Data Available	As of:	Updates:
Consumer Program				
Conservation Instant Coupon Booklet	Invoice date from coupon clearinghouse	Once data is submitted to the OPA by retailers	Dec. 21, 2011	
Bi-Annual Retailer Event				
Appliance exchange initiative	Event date		Dec. 16, 2011	
Retailer co-op activities	Will vary by specific project	Varies by specific project	Dec. 31, 2011	
Appliance Retirement	Pick-up date	When database is queried	Jan. 11, 2012	
HVAC Incentives	Installation date	Customers submit rebate and invoices are processed	Oct. 31, 2011	
peaksaver extension	Device installation date	Upon payment to LDC	Jan. 26, 2012	
New construction	Project completion	Preliminary Billing Report issued to LDC	Jan. 2, 2012	
Home Assistance Program				
Home Assistance Program	Project Completion Date	TBD	Jan. 23, 2012	
Business (Commercial & Institutional) Program				
Direct Installed Lighting	Project Completion Date	Work-order: invoiced, approved and paid to LDC	Dec. 1, 2011	
Equipment Replacement Incentive		"Approved for Payment by LDC" or "Released for Payment" status on iCON	Jan. 20, 2012	
Process & Systems Upgrades			Jan. 20, 2012	
Building Commissioning		Upon payment to LDC	Jan. 20, 2012	
New Construction		Upon payment to LDC	Jan. 20, 2012	
peaksaver extension	Device installation Date	Upon payment to LDC	Jan. 26, 2012	
Demand Response (DR1, DR3)	Facility is available under contract	Facility under contract with aggregator	Dec. 31, 2011	
Pre-2011 Projects Completed in 2011				
High Performance New Construction	Project Completion Date	Upon payment to LDC	Jan. 16, 2012	
Electricity Retrofit Incentive Program			Jan. 13, 2012	
Multifamily Energy Efficiency Rebates			Nov. 2011	
Toronto Comprehensive			Jan. 11, 2012	
Industrial Program				
Equipment Replacement Incentive	Project Completion Date	"Approved for Payment by LDC" or "Released for Payment" status on iCON	Jan. 20, 2012	
Process & System Upgrades	In Service Date		Jan. 20, 2012	
Monitoring & Targeting	2nd year Report	Report submitted	Jan. 20, 2012	
Demand Response (DR1, DR3)	Facility is available under contract	Facility available under contract	Dec. 31, 2011	
Energy Manager	Quarterly Report Date	Report submitted quarterly	Jan. 20, 2012	

Undertaking No. JT2.36

To provide an estimate of when each of the OPA programs gained traction with customers during the year. P. 138

Response:

Reference Issue 3.1: VECC - #20 e),

Energy Probe # 5a)

Issue: 2011 CDM Adjustment as captured in Load Forecast

Please see the table below which indicates when the OPA programs gained traction with customers, and provides a calculation of estimated 2011 savings. Due to delays in program implementation, i.e., gaining traction, the total estimated OPA CDM savings of 26,478,388 in 2011 is reduced for the purpose of determining Enersource's load forecast, resulting in only 27% or 7,175,686 kWh savings actually related to 2011.

It is important to note that this amount (7,175,686 kWh), which represents the CDM savings from OPA-related programs in 2011, must be incorporated in the context of the entire 16 years of actuals from which the load forecast was developed.

This amounts to a determination of a 2011 CDM savings effect of 448,480 kWh (7,175,686/16) which is reflected in the 2013 load forecast.

Enersource response to JT2.36 - Estimate of when each of the OPA Programs Gained Traction with Customer during the year

CDM Program Initiative name	OPA 2011 CDM Savings (Vers. 2011.q4) kWh (12 months)	Load Forecast - 2011 Savings kWh (Pro-rated)	Estimated Date Programs Gained Traction with Customers
1.01 Conservation Instant Coupon Booklet Initiative	345,310	115,103	Jun-11
1.02 HVAC Incentives Initiative (Heating and Cooling)	1,039,502	59,926	May-11
1.03 Bi-Annual Retailer Event Initiative	622,850	311,425	Apr-11
1.04 Appliance Retirement Initiative - Fridge / Freezer	938,787	459,426	May-11
1.05 Appliance Exchange Initiative	30,695	20,463	Apr-11
1.06 Home Energy Assessment Tool Initiative	-	-	N/A
1.07 Residential and Commercial DR - Peaksaver	-	-	Aug-12
1.08 Midstream Electronics Initiative	-	-	N/A
1.09 Midstream Pool Equipment Initiative	-	-	N/A
1.10 Residential New Construction	-	-	N/A
1.11 Peaksaver 2011	6,711	3,356	Jun-11
1.12 Home Assistance Program	-	-	Jun-11
2.01 Efficiency: Equipment Replacement Incentive Initi	3,459,653	311,369	Aug-11
2.02 Direct Install Lighting and Water Heating Initiative	10,848,211	3,062,014	Jun-11
2.03 Direct Service Space Cooling Initiative	-	-	N/A
2.04 Building Commissioning Initiative	-	-	Aug-11
2.05 New Construction Initiative	-	-	Aug-11
2.06 Residential and Small Commercial Demand Respo	-	-	Aug-12
2.07 Demand Response 1 Initiative	-	-	N/A
2.08 Demand Response 3 Initiative	74,038	21,594	Jun-11
2.09 Efficiency: Energy Audit Initiative	-	-	Aug-11
2.10 ERIP + HPNC + MEER, 2010	8,547,614	2,752,105	Apr-11
3.01 PSUI: Preliminary Engineering Study Initiative	-	-	Aug-11
3.02 PSUI: Detailed Engineering Study Initiative	-	-	Aug-11
3.03 PSUI: Project Incentive Initiative	-	-	Aug-11
3.04 PSUI: Monitoring & Targeting Initiative	-	-	Aug-11
3.05 PSUI: Metering & Instrumentation Library	-	-	Aug-11
3.06 PSUI: Energy Manager Initiative	-	-	Aug-11
3.07 PSUI: Key Account Manager Initiative	-	-	Dec-11
3.08 Efficiency: Equipment Replacement Incentive Initi	525,081	47,257	Aug-11
3.09 Building Commissioning Initiative	-	-	Aug-11
3.10 Efficience Energy Audit	-	-	Aug-11
3.11 Demand Response 1 Initiative	-	-	N/A
3.12 Demand Response 3 Initiative	39,936	11,648	Jun-11
Total	26,478,388	7,175,686	
		27%	

Ontario Energy Board

Commission de l'énergie de l'Ontario

Ontario

GUIDELINES FOR

ELECTRICITY DISTRIBUTOR

CONSERVATION AND DEMAND MANAGEMENT

EB-2008-0037

Date: March 28, 2008

5.0 LOST REVENUE ADJUSTMENT MECHANISM (LRAM)

Unforecasted CDM results can have the effect of eroding distributor revenues due to lower than forecast throughput. Distributors recover fixed distribution costs through both a fixed and a variable rate, which is set based on a forecast of consumption, including natural changes in energy efficiency. If actual consumption is less than the forecasted amount used for rate-setting purposes, the distributor earns less revenue than it otherwise would have, all other things being equal. Since the intention and effect of CDM activities is to reduce capacity and energy use, it also has the effect of reducing throughput and associated distributor revenues, which can result in a disincentive for distributors to deliver CDM programs.

A mechanism to compensate for distributor-induced lost revenues is intended to remove the disincentive. LRAM is a retrospective adjustment, which is designed to recover revenues lost from distributor supported CDM activities in a prior year. It is designed to compensate a distributor only for unforecasted lost revenues associated with CDM activities undertaken by the distributor within its licensed service area.

5.1 Eligible programs

LRAM is available regardless of whether the programs are funded by the OPA or through distribution rates. The LRAM applies to programs implemented by the distributor, within its licensed service area, including programs delivered by the distributor itself and/or programs delivered for the distributor by a third party (under contract with the distributor, either in relation to rate-funded programs, or where the distributor has contracted with the OPA but has outsourced CDM program delivery to a third party).

Distributors may undertake some programs in partnership with other entities, such as natural gas utilities or community agencies. In assessing the distributor's involvement in program delivery, and the resulting potential impacts on revenue, distributors should be guided by section 3.4.2, regarding the attribution of benefits. Distributors may only recover LRAM for revenue losses that can be attributed to the distributor's involvement in the program.

5.2 Calculation of LRAM

The LRAM is determined by calculating the energy savings by customer class and valuing those energy savings using the distributor's Board-approved variable distribution charge appropriate to the class. The calculation does not include any Regulatory Asset Recovery rate riders, as these funds are subject to their own independent true-up process. Lost revenues are only accruable until new rates (based on a new revenue requirement and load forecast) are set by the Board, as the savings would be assumed to be incorporated in the load forecast at that time.

The impact of historical CDM programs on the load in future years is incorporated in the load forecast presented in Table 1 above as a CDM trending variable is utilized in the load forecast model. The load forecast model however does not incorporate projections of incremental energy savings from the aggressive CDM targets that Enersource will need to deliver in 2012 to 2013. Hence, Enersource has adjusted the forecast shown in Table 1 with the cumulative increases in CDM over and above those included in the load forecast model over the 2012 to 2013 period. The incremental CDM energy consumption savings are identified in Table 3 below.

Table 3: CDM Adjustments by Customer Class, 2012 to 2013 (kWh)

Rate Class	2012 CDM Adjustment	2013 CDM Adjustment
Residential	(22,709,000)	(35,842,920)
Small Commercial	-	-
Unmetered Scattered Load	-	-
GS < 50	(32,620,613)	(39,519,293)
GS 50-499	(4,349,853)	(6,718,613)
GS 500-4999	(4,648,053)	(7,166,687)
Large User	(14,714,815)	(8,983,655)
Street Lighting	(5,228,799)	(20,915,195)
Total	(84,271,133)	(119,146,362)

Table 3 highlights the adjustment made to the sales forecasts by customer class to reflect the load reductions in 2012 and 2013 as a result of the incremental CDM activities. A detailed monthly breakdown of the CDM adjustment shown on Table 3 is provided as Attachment 1 to this exhibit.

The net result of the CDM adjustments yields an overall consumption forecast as shown in Table 4 below. The forecast data on Table 4 is also shown at Attachment 2, which provides the actual and forecast sales by rate class, net of CDM impacts, from 2008 to 2013.

staying constant, but we've got to be also mindful of the fact that there is other trends that will continue and to grow into the future.

So in response to your question, it wouldn't be appropriate to keep that trend variable constant over the forecasting period.

MR. HARPER: But on the other hand, one of the reasons -- is it fair to say that -- and I think in your evidence you characterize it at page 7, you know, of Exhibit 3, tab 1, schedule 1, I believe. You -- when you are discussing this trending variable you specifically made reference to CDM, if I am not mistaken.

And so -- and is it fair to say that over that historical period the savings you have been getting from CDM have been increasing each year?

MR. BONADIE: I don't agree that that's true. I don't believe so.

MR. HARPER: You don't agree that the amount of savings that you were getting from the CDM programs in 2011 in total from all the programs you implemented, starting with the third-tranche programs, is greater -- the cumulative effect is greater in 2011 than it was in 2005 and 2006, and 2008?

MR. BONADIE: I can't comment.

MR. HARPER: Okay. We will leave it at that, then. I think Mr. Aiken covered one of my questions I was dealing with on the Board Staff No. 29 and how you come up with your individual customer class forecasts, so I don't think we have to deal with that.

The next question that I have actually deals with change of the cost allocation, so it's issue 6.1. And I would like to look at Board Staff No. 27.

And here, you talk about the customer growth in the residential class due to new condos and retrofits of condos, and I guess when you say "retrofit" you mean from bulk meter to individual suite meter; is that fair?

MR. BONADIE: Sorry, I was going to ask for the reference again.

MR. HARPER: Okay. I am sorry. It's issue 6.1, Board Staff No. 27. It's page -- actually, I was looking specifically at the table on the third page.

MR. BONADIE: Is this in issue 6.1 or 3.1?

MR. HARPER: Sorry, issue 3.1. I apologize.

Right. Okay. Now, first of all, when you say "retrofits" I assume that means retrofits from bulk-metered condominiums or apartments to individual suite-metered condominiums and apartments?

MR. BONADIE: That is correct.

MR. HARPER: So you are showing an increase of 2,430 customers in 2012 and 1,982 in 2013; right?

Can you tell me, do you have any estimate as to how many of your residential customers, say, on average in 2013 would be suite-metered customers in either apartments or condos? Out of your total residential customer count forecast for 2013?

MR. BONADIE: I believe the answer to your question is

Attachment A – Short Term System Load Energy Model Statistics

Regression Statistics	
Iterations	18
Adjusted Observations	191
Deg. of Freedom for Error	173
R-Squared	0.988
Adjusted R-Squared	0.987
AIC	17.914
BIC	18.221
Log-Likelihood	-1,963.83
Model Sum of Squares	790,516,390,955.78
Sum of Squared Errors	9,533,001,678.53
Mean Squared Error	55,104,055.95
Std. Error of Regression	7,423.21
Mean Abs. Dev. (MAD)	5,413.50
Mean Abs. % Err. (MAPE)	0.86%
Durbin-Watson Statistic	2.092
Ljung-Box Statistic	35.95
Prob (Ljung-Box)	0.0556
Skewness	-0.168
Kurtosis	3.291
Jarque-Bera	1.577
Prob (Jarque-Bera)	0.4546

Variable	Coefficient	StdErr	T-Stat	P-Value
Monthly.MonthlyTimeTrend	-18692.675	1373.18	-13.613	0.00%
Population.Population	-0.271	0.063	-4.323	0.00%
Employment.EmpLand	0.573	0.156	3.673	0.03%
Employment.MajOff	6.305	0.507	12.441	0.00%
Monthly.MonthlyGDP	2.849	0.77	3.698	0.03%
MonthlyWeather.MonthlyDBCubed	-0.239	0.081	-2.958	0.35%
MonthlyWeather.MonthlyBuildUp	137.917	39.549	3.487	0.06%
MonthlyWeather.MonthlyCDD	1042.732	93.13	11.196	0.00%
MonthlyWeather.MonthlyHDD	323.34	36.225	8.926	0.00%
Monthly.WorkingDays	2889.973	464.444	6.222	0.00%
MonthlyWeather.MonthlyDwPtCubed	0.15	0.04	3.759	0.02%
MonthlyCalTrans.Month_Feb	-37044.965	2849.082	-13.002	0.00%
MonthlyCalTrans.Month_Aug2003	-4312.616	635.232	-6.789	0.00%
MonthlyCalTrans.Month_Apr	-18234.514	2706.349	-6.738	0.00%
MonthlyCalTrans.Month_Nov1996	-24857.429	6776.573	-3.668	0.03%
MonthlyCalTrans.Month_Dec1999	24056.334	6797.63	3.539	0.05%
AR(1)	0.292	0.076	3.831	0.02%
SMA(1)	0.352	0.078	4.522	0.00%

- Hourly weather data from 1980 to 2011 (temperature, dew point) obtained from Environment Canada for Lester B. Pearson International Airport;
- City of Mississauga demographic variables, including population and employment from the City of Mississauga's Building and Planning Department; and
- Econometric variables including GDP and CPI from the Conference Board of Canada, dated November, 2011.

Actual historical energy consumption and peak demands are modelled to weather and calendar variables, and to econometric, binary, and trending variables in order to capture relationships. Binary variables are used to incorporate seasonal effects into the model. A trending variable is utilized in the models to capture impacts of time-related initiatives such as energy efficiency, including conservation and demand management savings implemented. It is important to note that trending variables only capture implemented initiatives with persistence and do not incorporate incremental projections of energy efficiency savings. Hence, future conservation and demand management energy savings are incorporated by adjustments to energy and peak demand forecasts. (The CDM adjustments are discussed in detail at Exhibit 3 Tab 1 Schedule 2).

Weather

Hot and cold weather are prominent factors in driving energy consumption in Mississauga. Figure 4 illustrates the impact of weather on the system load including the impact of workday (blue dots) from weekend and holidays (green dots). The scatter plot was utilized to derive appropriate heating, cooling, and extreme cooling degree splines at 10° C, 18° C, and 22° C, respectively. The system model is developed using actual system load data with actual weather

Table 1: Other Revenue Summary, 2008 to 2013 ($000s)

Other Revenue Category	2008 Approved	2008 Actual	2009 Actual	2010 Actual	2011 Actual	2012 Bridge	2013 Test
Specific Service Charges	1,282	1,330	1,311	1,283	1,347	1,330	1,335
Late Payment Charges	420	408	413	1,379	2,068	1,800	1,800
Retailer Service Charges	329	311	303	292	244	207	193
Other Regulated Revenues	1,260	1,189	1,124	1,608	1,212	1,464	1,452
Interest Revenue	2,049	1,957	284	187	735	377	50
TOTAL	5,340	5,195	3,434	4,751	5,605	5,178	4,830

Revenue offsets are deducted from the revenue requirement to derive the base revenue requirement. Each of the categories in Table 1 is described below.

Exhibit 3 Tab 3 Schedule 1 Appendices 1 and 2 provide detail supporting other revenues. Appendix 1 provides the number of transactions per year, from 2008 to 2013, for various types of other revenues including specific service charges, retailer charges and the SSS administration charge. Appendix 2 provides a detailed breakdown of the five other revenue categories shown in Table 1 from the 2008 Board-approved amount to the 2013 Test Year.

Specific Service Charges

Enersource charges user fees for certain services. Some of these services are provided at a customer's request, such as an account setup. Others result from Enersource's business operations, such as collection fees resulting from the non-payment of a customer bill. Enersource does not propose any changes to these specific service charges.

Enersource Hydro Mississauga Inc.
Response to Interrogatories by Issue

Interrogatory # 3

Energy Probe Research Foundation
(Energy Probe)

3. Operating Revenue

3.2 Is the proposed forecast of other regulated rates and charges for 2013 and 2014 appropriate?

Ref: Exhibit 3, Tab 3, Schedule 1, Appendix 2-C

Please provide the most recent actual year-to-date figures for 2012 in the same level of detail as shown in the top table in Appendix 2-C. Please also provide the year-to-date figures for the corresponding year-to-date period in 2011.

Response:

Please see the table below.

USoA #	USoA Description	Approved 2008	Actual 2008	Actual 2009	Actual 2010	2011 YTD June	Actual 2011	2012 YTD June	Bridge 2012	Test Year 2013	Test Year 2014
4080	SSS Administration Charge	$477,000	$463,673	$476,511	$501,830	$260,607	$523,058	$268,564	$532,630	$535,964	$544,134
4082	Retail Services Revenues	$315,000	$297,697	$293,110	$279,105	$125,825	$236,687	$100,953	$200,554	$186,631	$186,631
4084	Service Transaction Requests	$14,000	$13,218	$9,781	$13,121	$3,766	$7,120	$3,569	$6,600	$6,100	$6,100
4210	Pole Rental	$463,003	$519,647	$523,868	$536,835	$264,609	$540,953	$284,236	$530,000	$532,000	$533,000
4225	Late Payment Charges	$420,000	$407,623	$412,941	$1,379,315	$1,051,814	$2,067,728	$826,982	$1,800,000	$1,800,000	$1,800,000
4235	Specific Service Charges	$670,795	$637,210	$644,300	$660,174	$295,042	$657,994	$298,325	$631,900	$635,150	$629,400
4235	Miscellaneous Service Revenues	$358,000	$246,630	$274,207	$492,053	$141,425	$272,046	$155,320	$449,161	$433,633	$434,657
4355	Gain on Disposition of Utility	$425,000	$144,509	$178,952	$167,312	$92,988	$156,927	$57,323	$161,000	$161,000	$161,000
4380	Misc Non-Operating Income	$0	$334,052	$194,378	$447,171	$91,180	$259,727	$145,934	$321,000	$321,000	$321,000
4405	Investment Interest Income	$2,049,000	$1,957,086	$283,629	$187,273	266,509	$735,310	$477,968	$377,164	$50,207	$95,119
5330	Collection Charges	$148,500	$173,587	$142,779	$86,461	$78,920	$147,847	$65,617	$168,000	$168,000	$168,000
[redacted]											
	Specific Service Charges	$1,177,295	$1,057,427	$1,061,286	$1,238,688	$515,388	$1,077,887	$518,794	$1,249,061	$1,236,783	$1,232,057
	Late Payment Charges	$420,000	$407,623	$412,941	$1,379,315	$1,051,814	$2,067,728	$826,982	$1,800,000	$1,800,000	$1,800,000
Other Distribution Revenue		$1,269,003	$1,294,235	$1,303,270	$1,330,891	$654,807	$1,307,819	$657,323	$1,269,784	$1,260,695	$1,269,865
	Other Income and Expenses	$2,474,000	$2,435,647	$656,959	$801,756	$450,677	$1,151,963	$681,225	$859,164	$532,207	$577,119
	Total	$5,340,298	$5,194,933	$3,434,456	$4,750,650	$2,672,687	$5,605,397	$2,784,792	$5,178,009	$4,829,685	$4,879,041

ISSUE 4: OPERATING COSTS

Issue 4: Operating Costs notes 29-46

[1] Exhibit 4, Tab 1, Appendix 2-E, pages 2-3
[1] Exhibit I, Issue: 2.1, SEC,IR # 14,Page 1 of 1
[1] Exhibit K2.6
[1] Exhibit I, Issue: 4.1, VECC, IR # 36
[1]Technical Conference VOl.1, page 163-164).
[1]Exhibit K1.1
[1] Exhibit I, General, Board Staff, IR#5, Appendix 2-L, page 1
[1] Issue: 4.1, Energy Probe, IR # 15, page 2 of 2
[1] Exhibit 4, Tab 1, Schedule 3, page 14
[1] Issue 4.1, Board Staff, I.R. #32, page 1 of 2
[1] Hearing Transcript (SEC) Vol. 3 – Volume is missing page number – page 95 of Word Document
[1] Exhibit 4, Tab 1, Table 2-H, page 1
[1] Exhibit JT1.13
[1] Exhibit 4, Tab 1, Schedule 10, page 4 of 4
[1] Board Staff Issue 4.4 IR #42 /EP IR # 2 Issues 4.1
[1] Hearing Transcript, Volume 2, page 158-159 / see also Technical Conference Transcript Volume, page 11-12
[1]Exhibit I, Issue 4.4, Energy Probe; IR 3b – Attachment; Page 1 of 1 /see also Exhibit 4, Tab 3, Schedule 1, Appendix 2-K
[1] Technical Conference Volume 2, page 13

Additional References

Enersource Hydro Mississauga Inc.
Response to Interrogatories by Issue

Interrogatory #37

Board Staff

4. Operating Costs

Issue 4.1: Is the proposed 2013 and 2014 OM&A forecast appropriate?

Reference: E 4-T1 Appendix 2-1

The table below sets out headcount numbers presented in the evidence.

Headcount	2008 Brd Appr.	2008 Actuals	2009 Actuals	2010 Actuals	2011 Actuals	2012 Actuals	2013 Forecast
Appendix 2-I Number of FTEEs (EHM & Corp)	368	360	378	383	377	383	391
Appendix 2-K Number of Employees (FTEs including PT.)	318	310.74	325.92	327.66	325.25	331	339

a) Please explain why Enersource appears to include Corporate Headcount in the OM&A/FTEE calculation while other schedules with headcount numbers do not appear to include the corporate portion i.e. E4-T3-S1 Appendix 2-K.

b) Please explain why Enersource did not complete E4-T3-S1 Appendix 2-K using the headcount shown in E4-T1 Appendix 2-I.

c) Please select the consistent headcount numbers that should be reflected in the evidence and update the affected appendix(ices) accordingly.

Response:

a) Enersource's total OM&A costs include shared services costs from Enersource Corporation. In order to more accurately depict OM&A costs per FTEE, Enersource believed that it was important to include the

K 2.6

2010 Yearbook of Electricity Distributors

Ontario Energy Board

Published on August 29, 2011

Utility	2010 OM&A per customer	2012 OM&A per customer
Enersource Hydro Mississauga Inc.	242.63	
Horizon Utilities Corporation	165.24	
Hydro Ottawa Limited	265.75	
London Hydro Inc.	203.97	
PowerStream Inc.	172.00	

Appendix 2-L
Recoverable OM&A Cost per Customer and per FTEE

	Last Rebasing Year (2008 Board-Approved)	Last Rebasing Year (2008 Actuals)	2009 Actuals	2010 Actuals	2011 Actuals	2012 Bridge Year	2013 Test Year
Reporting Basis	CGAAP	CGAAP	CGAAP	CGAAP	MIFRS	MIFRS	MIFRS
Number of Customers	187,763	185,314	188,335	191,350	194,172	196,727	199,187
Total Recoverable OM&A from Appendix 2-I	$ 41,653,058	$ 36,234,120	$ 41,523,563	$ 45,598,558	$ 50,783,218	$ 57,008,685	$ 61,099,236
OM&A cost per customer	$ 221.84	$ 195.53	$ 220.48	$ 238.30	$ 261.54	$ 289.79	$ 306.74
Number of FTEEs (EHM & Corp)	368	360	378	383	377	383	391
Customers/FTEEs	510	515	498	500	515	514	509
OM&A Cost per FTEE	$ 113,188	$ 100,650	$ 109,851	$ 119,056	$ 134,703	$ 148,848	$ 156,264

Notes:

1. If it has been more than three years since the applicant last filed a cost of service application, additional years of historical actuals should be incorporated into the table, as necessary, to go back to the last cost of service application. If the applicant last filed a cost of service application less than three years ago, a minimum of three years of actual information is required.
2. The method of calculating the number of customers must be identified.
3. The method of calculating the number of FTEEs must be identified. See also Appendix 2-K
4. The number of customers and the number of FTEEs should correspond to mid-year or average of January 1 and December 31 figures.

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Enersource Hydro Mississauga Inc.
Response to Interrogatories by Issue

Interrogatory #36

Vulnerable Energy Consumers Coalition (VECC)

4. Operating Costs
Issue 4.1 Is the proposed 2013 and 2014 OM&A forecast appropriate?

Reference: Exhibit 4, Tab 1, Appendix 2-1, page 1

a) Please provide the OM&A cost per customer and per FTEE for Enersource's cohort of utilities as identified by the OEB.

Response:

Enersource does not maintain information on other distributors and therefore does not have the information requested.

Table 1

OM&A Cost per Customer and per FTEE (EHM FTEE and Corp FTEE allocated to EHM)

	LRY - 2008 Board Approved	LRY - 2008 Actual	2009 Actual	2010 Actual	2011 Actual	2012 Bridge Year	2013 Test Year
Number of Customers	187,763	185,314	188,335	191,350	194,172	196,727	199,187
Total OM&A from Appendix 2-G	$ 41,653	$36,234	$41,524	$45,599	$50,783	$ 57,009	$ 61,099
OM&A cost per customer	$ 221.84	$ 195.53	$ 220.48	$ 238.30	$ 261.54	$ 289.79	$ 306.74
Number of FTEEs (EHM & Corp)	360	352	373	380	374	380	388
Customers/FTEEs	522	526	505	503	518	518	514
OM&A Cost per FTEE	$ 116	$ 103	$ 111	$ 120	$ 136	$ 150	$ 158

Table 2
Appendix 2-I revised per question

	2008 COS	2008 Actual	2009 Actual	2010 Actual	2011 Actual	2012 Bridge Year	2013 Test Year
Number FTEE's for Enersource Corporation							
Executive	5.00	4.00	4.00	3.00	4.00	5.00	5.00
Management	12.00	13.00	13.00	14.00	12.00	12.00	12.00
Non Union	18.00	17.08	18.33	22.42	20.50	20.00	20.00
Union	15.00	15.50	16.41	15.83	15.33	15.00	15.00
Total FTEE's for Enersource Corporation	50.00	49.58	51.74	55.25	51.83	52.00	52.00
Percentage Allocated to EHM	83.80%	83.80%	91.30%	95.00%	95.00%	93.40%	93.40%
Corp's FTEE's allocated to EHM	41.90	41.55	47.24	52.49	49.24	48.57	48.57
FTEE's for EHM (Exhibit 4 Tab 3, Schedule 1 Appendix 2-K)	318.00	310.74	325.92	327.66	325.25	331.00	339.00

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MR. JANIGAN: I want to, finally, deal with issue 5 on shared services, and note that your evidence indicates that you've changed the allocation of costs from your affiliate from 83.8 to 93.4 percent. And as I understand it, it's coincident with a change in the business planning of the LDC, and in particular getting you out of businesses, other businesses.

Can you explain the reason for the change in the allocation of costs?

MR. MACUMBER: In 2006 we sold our water heater business and sold our Enersource telecom.

From 2006 to 2008, the intention was to grow our non-regulated business, which was agreed to in our shared services model about how much each of the non-regulated and regulated companies would pay.

During 2008, I believe, or at the end of 2007, it was determined that we were not going to be growing the business, and a more accurate reflection of who should pay for the services should be revenue or head count. And we changed that, changed our service agreements between the two companies and changed the percentage of allocation of costs.

MR. JANIGAN: But I take it there was no change in the business activity of either company?

MR. MACUMBER: There was no fundamental change in the activity.

If anything, I was requested in the technical conference: Do I believe that one overpaid or did not pay it? I would, again, say that they agreed to pay it.

But since the non-regulated services company did not grow, in theory they overpaid.

MR. JANIGAN: I wonder if you could turn up appendix 2N, in the shared services corporate allocation. It's Exhibit I, and it's actually from a Board Staff interrogatory, IR 5, appendix 2N, page 6 of 6. Sorry. Can that be located? It's not up on the screen. Sorry.

I wonder if you could share with us how that 93.4 percent is calculated. When you look on this Appendix 2-N, it shows for 2008 a set of various percentages for services that are offered that range from 92 percent to 43 percent. In 2013 the range is 94 percent to 93.3 percent.

Can you tell me what the relationship between the allocation figure of 83.8 percent for 2008 and 93.4 percent for 2013 and what is shown on these tables?

MR. MACUMBER: When we filed our 2008 cost of service in 2007, the way we allocated shared services was either based on historical knowledge or amount they contributed or head count.

As I said before, due to the fact that we weren't growing our non-regulated company, we sat down and said, What's probably the appropriate method to allocate costs? And it was determined that a majority of the expenses for Enersource Corporation would be allocated based on budgeted revenue or head count, which, assuming that it's HR, was head count.

MR. JANIGAN: And how does that drive the percentages?

Table 3: Bad Debt Expense and Late Payment Revenue, 2008 to 2013 ($000s)

Description	2008 Rates	2008 Actual	2009 Actual	2010 Actual	2011 Actual	2012 Bridge	2013 Test
Late-Payment Revenue	(420)	(408)	(413)	(1,379)	(2,068)	(1,800)	(1,800)
Bad Debt Expense	1,575	1,270	1,253	2,802	3,706	3,600	3,550
Net Impact	$1,155	$ 862	$ 840	$1,423	$1,638	$1,800	$ 1,750

In summary, the increase in Customer Care costs is attributable to:

- increased average compensation levels;
- increased employee benefits costs (mainly due to pension-related costs);
- increased call volume and bill delivery activities;
- increased activities levels due to added metering complexity and a significant increase in doubtful accounts;
- staff transferred from the smart meter project;
- increase in printing, postage, and courier service costs to deliver bills;
- increased telecommunications expenses, including the costs related to toll free telephone numbers; and
- increase in third-party contract costs for centralized payment processing.

Enersource Hydro Mississauga Inc.
Response to Interrogatories by Issue

Interrogatory #32

Board Staff

4. Operating Costs

Issue 4.1: Is the proposed 2013 and 2014 OM&A forecast appropriate?

Reference: E 4-T1-S3 p13 and p. 14 Table 3

Enersource indicates that it has hired an Accounts Receivable Manager and selected two new third party collection agencies to mitigate the growing trend in uncollectable accounts receivable. Table 3 presents the history and forecast of bad debt expense and late payment revenue.

Table 3: Bad Debt Expense and Late Payment Revenue, 2008 to 2013 ($000s)

Description	2008 Rates	2008 Actual	2009 Actual	2010 Actual	2011 Actual	2012 Bridge	2013 Test
Late-Payment Revenue	(420)	(408)	(413)	(1,379)	(2,068)	(1,800)	(1,800)
Bad Debt Expense	1,575	1,270	1,253	2,802	3,706	3,600	3,550
Net Impact	$1,155	$ 862	$ 840	$1,423	$1,638	$1,800	$ 1,750

Please explain why 2013 shows no material improvement in bad debt expense and late payment revenue.

Response:

Enersource believes that hiring an Accounts Receivable Manager and selecting two new third party collection agencies will allow it to stop the significant increases in bad debt expense. The forecast anticipates a reduction to the number of accounts overdue, and a corresponding decrease in the amount of late payment revenue in 2013, than what would otherwise occur.

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that correct?

MR. MACUMBER: That is correct.

MR. JANIGAN: I was wondering why there is such a small decrease in the amount of the bad-debt expense after you initiated these measures?

MR. MACUMBER: I provided that in one of the IR responses. Enersource believed at the time in 2011 when we hired the temporary manager, which was subsequently converted to a permanent, that our bad-debt expense would continue to climb to 4.3 million. And we have forecasted it with this additional manager and the collection agencies, that our forecast for 2013 is 3.5, rather than 4.3.

MR. JANIGAN: So the increase that you anticipated did not eventuate. Is that what you're saying?

MR. MACUMBER: No, what I'm saying is we anticipate by having these resources that it won't go to 4.3 million.

MR. JANIGAN: Why did you think it was going to go to 4.3 million?

MR. MACUMBER: Just based on the trending that was occurring in 2011, or 2010/2011, we had a significant amount of accounts that were deemed uncollectible. I made a pitch to hire a temporary manager to see if we could put some more rigour around collecting the accounts, and then with -- through 2011 we saw improvements, and I reduced the forecast for 2013.

MR. JANIGAN: I mean, this is a rather steep increase from 2008 to 2012. Is there some reason for the relative steepness of this?

MR. MACUMBER: We have stated that in our evidence as well. We believe some of it's due to the economy. We also believe that, due to the ever increasing electricity prices, that people are unable to pay.

MR. JANIGAN: You don't look at -- and I remember from the evidence you don't look at other utilities in relation to their O&M, but are you aware, even anecdotally, if this is occurring elsewhere?

MR. MACUMBER: All I can say is, from reading the paper of what has happened to the economy since 2008.

MR. JANIGAN: And you haven't done any empirical --

MR. MACUMBER: I have not looked at other utilities. I'm just assuming in our service territory that there is probably similar experiences with increases and bad debt.

MR. JANIGAN: Is this -- are these increases and bad debt leading to increased disconnections from the network?

MR. MACUMBER: We have increased our disconnection process. A lot of people that we disconnect have set up for payment plans. Sometimes, though, a majority is when people can't pay they simply move out of the service territory, and we aren't able to locate them.

MR. PASTORIC: In addition, I think one of the measures that the OEB has put to us as a performance measure is to ensure that we have the customer back reconnected once they have a payment plan, so it's been acknowledged within the industry and the OEB that there has been a change in this industry, because we have to meet

ENERSOURCE CORPORATION	2008 COS	2008 Actual	2009 Actual	2010 Actual	2011 Actual	2012 Bridge Year	2013 Test Year
Number of Employees (FTE's Including Part time							
Executive	5.00	4.00	4.00	3.00	4.00	5.00	5.00
Management	12.00	13.00	13.00	14.00	12.00	12.00	12.00
Non Union	18.00	17.08	18.33	22.42	20.50	20.00	20.00
Union	15.00	15.50	16.41	15.83	15.33	15.00	15.00
Total	50.00	49.58	51.74	55.25	51.83	52.00	52.00
Number of Part Time Employees							
Executive	-	-	-	-	-	-	-
Management	-	-	-	-	-	-	-
Non Union							
Union		-	-	-	-	-	-
Total	-	-	-	-	-	-	-
Total Salary and Wages							
Executive	719,711	635,547	675,007	598,687	727,405	797,890	939,219
Management	1,107,160	1,065,583	1,304,406	1,411,106	1,245,496	975,942	1,199,765
Non Union	831,337	800,118	1,004,076	1,225,896	1,284,012	1,747,156	1,999,608
Union	759,166	715,434	704,864	786,406	790,026	840,856	838,517
Total	3,417,374	3,216,681	3,688,352	4,022,095	4,046,939	4,361,844	4,977,109
Current Benefits							
Executive	283,948	279,616	254,085	307,957	347,766	414,664	445,312
Management	473,457	464,381	449,475	721,869	589,870	522,495	550,783
Non Union	349,020	342,695	409,767	620,278	603,325	932,930	997,509
Union	306,296	286,477	259,014	392,265	366,444	443,033	500,498
Total	1,412,721	1,373,168	1,372,341	2,042,369	1,907,405	2,313,121	2,494,101
Accrued Post-Retirement Benefits							
Executive	2,369	2,190	1,675	2,972	2,813	2,894	3,082
Management	8,766	8,105	6,199	10,995	10,408	10,708	11,405
Non Union	13,069	12,082	9,241	16,391	15,516	15,963	17,002
Union	10,499	9,706	7,424	13,168	12,465	12,824	13,659
Retirees	18,457	17,064	13,052	23,150	21,914	22,546	24,013
Total	53,160	49,148	37,592	66,676	63,116	64,936	69,163
Total Benefits (Current + Accrued)							
Executive	286,317	281,806	255,760	310,929	350,579	417,558	448,394
Management	482,224	472,486	455,674	732,864	600,278	533,203	562,188
Non Union	362,088	354,777	419,008	636,669	618,841	948,893	1,014,511
Union	316,795	296,183	266,439	405,433	378,909	455,857	514,157
Total	1,447,424	1,405,252	1,396,881	2,085,895	1,948,607	2,355,511	2,539,250
Total Compensation (Salary, Wages & Benefits)							
Executive	1,006,028	917,353	930,767	909,616	1,077,984	1,215,448	1,387,613
Management	1,589,384	1,538,069	1,760,080	2,143,970	1,845,774	1,509,145	1,761,953
Non Union	1,193,425	1,154,895	1,423,084	1,862,565	1,902,853	2,696,049	3,014,119
Union	1,075,961	1,011,617	971,302	1,191,838	1,168,935	1,296,713	1,352,674
Total	4,864,798	4,621,933	5,085,232	6,107,989	5,995,546	6,717,355	7,516,359
Compensation - Average Yearly Base Wages							
Executive	143,942	158,887	168,752	199,562	181,851	159,578	187,844
Management	92,263	81,968	100,339	100,793	103,791	81,328	99,980
Non Union	46,185	46,845	54,778	54,679	62,635	87,358	99,980
Union	50,611	46,157	42,953	49,678	51,535	56,057	55,901
Total	333,002	333,857	366,822	404,712	399,812	384,321	443,706
Compensation - Average Yearly Overtime							
Executive		-	-	-	-	-	-
Management		-	-	59	-	-	-
Non Union		87	191	305	431	-	-
Union	333	-	8	57	276	854	854
Total	333	87	199	420	708	854	854
Compensation - Average Yearly Incentive Pay							
Executive	36,364	38,472	48,397	87,276	63,565	63,159	65,212
Management	11,693	9,136	9,214	9,595	10,162	11,297	11,664
Non Union	4,367	3,895	4,428	2,708	3,451	3,761	3,883
Union	4,817	3,945	3,161	2,143	3,153	3,230	3,335
Total	57,241	55,448	65,200	101,721	80,331	81,447	84,094
Compensation - Average Yearly Benefits							
Executive	57,263	70,452	63,940	103,643	87,645	83,512	89,679
Management	40,185	36,345	35,052	52,347	50,023	44,434	46,849
Non Union	20,116	20,771	22,859	28,397	30,187	47,445	50,726
Union	21,120	19,109	16,236	25,612	24,717	30,390	34,277
Total	138,684	146,677	138,087	209,999	192,572	205,780	221,531
Total Compensation	4,864,798	4,621,933	5,085,232	6,107,989	5,995,546	6,717,355	7,516,359
Total Compensation charged to OM & A	4,864,798	4,621,933	5,085,232	6,107,989	5,995,546	6,717,355	7,516,359
Total Compensation Capitalized							
Total Compensation charged to Enersource Hydro Mississauga[1]	4,076,701	3,873,180	4,642,817	5,802,590	5,695,768	6,274,010	7,020,280
Percentages taken from Exhibit 4, Tab 4, Schedule 1, Appendix 2-L pages 1-8	83.8%	83.8%	91.3%	95.0%	95.0%	93.4%	93.4%

1. Percentages used to allocate the portion of compensation charged by Enersource Corporation to Enersource Hydro Mississauga is based on the total percentage allocation from Exhibit 4, Tab 4, Schedule 1, Appendix 2-L pages 1-8

Appendix 2-H
Regulatory Cost Schedule

	Regulatory Cost Category	USoA Account	2008 Rates	2008 Actuals	2009 Actuals	2010 Actuals	2011 Actuals	2012 Bridge Year	2013 Test Year
	(A)								
1	OEB Annual Assessment	5655	$ 840,000	$ 788,332	$ 804,172	$ 760,066	$ 768,055	$ 820,000	$ 854,000
2	OEB Hearing Assessments (applicant-originated)								
3	OEB Section 30 Costs (OEB-initiated)								
4	Expert Witness costs for regulatory matters								
5	Legal costs for regulatory matters								
6	Consultants' costs for regulatory matters								
7	Operating expenses associated with staff resources allocated to regulatory matters	5615	$ -	$ -	$ -	$ 293,226	$ 376,479	$ 426,072	$ 445,642
8	Operating expenses associated with other resources allocated to regulatory matters [1]	5615	$ -	$ -	$ -	$ 10,866	$ 21,374	$ 54,030	$ 45,531
9	Other regulatory agency fees or assessments	5680	$ 88,000	$ 92,689	$ 94,156	$ 92,868	$ 95,899	$ 97,850	$ 97,850
10	Any other costs for regulatory matters (please define)								
11	Intervenor and legal costs	5655	$ 146,000	$ 17,194	$ 154,700	$ 58,399	$ 78,371	$ 75,000	$ 75,000
11	**Intervenor and legal costs (One time costs)**	5655	$ -	$ -	$ -	$ -	$ -	$ -	$ 162,500
12	Sub-total - Ongoing Costs [3]		$ 1,074,000	$ 898,215	$ 1,053,028	$ 1,215,424	$ 1,340,179	$ 1,472,952	$ 1,518,023
13	Sub-total - One-time Costs [4]		$ -	$ -	$ -	$ -	$ -	$ -	$ 162,500
14	Total		$ 1,074,000	$ 898,215	$ 1,053,028	$ 1,215,424	$ 1,340,179	$ 1,472,952	$ 1,680,523

Notes:

1 Please identify the resources involved (conferences and publication of notices)
2 Where a category's costs include both one-time and ongoing costs, the applicant should prove a separate breakdown between one-time and ongoing costs.
3 Sum of all ongoing costs identified in rows 1 to 11 inclusive.
4 Sum of all one-time costs identified in rows 1 to 11 inclusive.

1 **Table 3: 2013 Cost of Service Application Expenses by Year ($000s)**

	2012 Bridge	2013 Test	Total
Intervenor	$ 50	$ 120	$ 170
Legal	125	75	200
OEB Hearing	150	75	225
Consulting Fees	50	5	55
Total 2013 Cost of Service Application Expenses (To Be Recovered Over Four Years)	$ 375	$ 275	**$650**

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Undertaking No. JT1.13

To provide a breakdown of the $200,000 in legal expenses. P. 54

Response

Estimated Breakdown of Legal Expenses	$000s
Regulatory Strategy and Legal Advice	16
Drafting of Evidence, Review, and Editing	30
Assistance in Responding to IRs and Undertakings	14
Preparation for the Technical Conference	20
Preparation for the Settlement Negotiations	5
Drafting of the Settlement Agreement	20
Preparation for the Oral Hearing	5
Appearances at all OEB Proceeding Events	60
Drafting Argument	20
Final Submissions	10
Total	**$200**

In addition, with respect to regulatory costs, at p. 39 of the transcript from the Technical Conference on July 31, 2012, the following exchange was recorded:

MR. SHEPHERD: Sorry, my question -- and again, I have obviously been inelegant -- my question is: What is the difference between the cost of this proceeding if there is an oral hearing and if there is not an oral hearing?

And I thought you said 225.

MR. MACUMBER: We have estimated the whole process to be 650,000, and the 225 of it is to go to a hearing.

By way of correction, Enersource advises that the estimated amount of $225 captures costs for all proceeding days at the OEB, which are the Technical Conference, Settlement Conference, Presentation of Settlement Agreement, and Oral Hearing. See also the response to IR # 18, CCC, Issue 4.1.

ENERSOURCE HYDRO MISSISSAUGA	2008 COS	2008 Actual	2009 Actual	2010 Actual	2011 Actual	2012 Bridge Year	2013 Test Year
Number of Employees (FTE's including Part time							
Executive	4.00	4.00	3.00	3.00	3.00	2.00	2.00
Management	38.00	41.00	42.00	46.25	48.00	50.00	51.00
Non Union	49.00	44.83	52.92	52.00	54.67	54.00	59.00
Union	227.00	220.91	228.00	226.41	219.58	225.00	227.00
Total	318.00	310.74	325.92	327.66	325.25	331.00	339.00
Number of Part Time Employees							
Executive	-	-	-	-	-	-	-
Management	-	-	-	-	-	-	-
Non Union	-	0.50	1.00	2.00	2.00	2.00	2.00
Union							
Total	-	0.50	1.00	2.00	2.00	2.00	2.00
Total Salary and Wages							
Executive	531,374	537,196	476,209	496,724	516,024	376,074	389,610
Management	2,998,076	3,381,349	4,114,967	3,734,280	4,798,318	4,754,997	4,927,070
Non Union	2,999,570	3,047,023	3,634,927	4,444,288	4,375,879	4,501,656	4,651,064
Union	13,487,693	14,409,187	15,530,928	14,950,646	15,439,214	13,882,574	14,659,450
Total	20,016,713	21,374,755	23,757,031	23,625,937	25,129,434	23,515,302	24,627,194
Current Benefits							
Executive	234,347	241,570	199,204	221,024	212,383	151,715	224,482
Management	1,405,315	1,494,519	1,707,106	1,736,315	1,961,873	1,866,033	2,072,155
Non Union	1,296,928	1,340,177	1,502,347	1,869,918	1,784,416	1,736,841	1,903,318
Union	4,669,585	4,960,723	5,211,861	5,611,853	6,707,141	7,058,536	7,464,473
Total	7,606,175	8,036,989	8,620,519	9,439,111	10,665,814	10,813,125	11,664,428
Accrued Post-Retirement Benefits							
Executive	3,159	3,111	2,365	2,434	2,424	2,663	2,836
Management	46,327	45,611	34,672	35,696	35,539	39,050	41,592
Non Union	48,423	47,674	36,241	37,311	37,146	40,817	43,473
Union	222,204	218,768	166,301	171,211	170,458	187,300	199,491
Retirees	170,256	167,624	127,422	131,185	130,608	143,512	152,854
Total	490,369	482,788	367,000	377,837	376,174	413,342	440,246
Total Benefits (Current + Accrued)							
Executive	237,506	244,681	201,569	223,458	214,807	154,379	227,318
Management	1,451,642	1,540,130	1,741,778	1,772,011	1,997,412	1,905,083	2,113,747
Non Union	1,345,351	1,387,851	1,538,588	1,907,229	1,821,562	1,777,658	1,946,792
Union	4,891,788	5,179,492	5,378,162	5,783,064	6,877,599	7,245,836	7,663,964
Retirees	170,256	167,624	127,422	131,185	130,608	143,512	152,854
Total	8,096,544	8,519,778	8,987,519	9,816,947	11,041,988	11,226,468	12,104,674
Total Compensation (Salary, Wages & Benefits)							
Executive	768,880	781,877	677,778	720,182	730,831	530,452	616,928
Management	4,449,718	4,921,479	5,856,745	5,506,291	6,795,730	6,660,080	7,040,817
Non Union	4,344,921	4,434,874	5,173,515	6,351,517	6,197,441	6,279,314	6,597,855
Union	18,379,481	19,588,678	20,909,090	20,733,710	22,316,813	21,128,410	22,323,413
Total	27,943,001	29,726,909	32,617,127	33,311,700	36,040,814	34,598,257	36,579,014
Compensation - Average Yearly Base Wages							
Executive	132,844	134,299	158,736	165,575	172,008	188,037	194,805
Management	78,897	82,472	97,975	80,741	99,965	95,100	96,609
Non Union	61,216	67,968	68,687	85,467	80,042	83,364	78,832
Union	59,417	65,227	68,118	66,034	70,312	61,700	64,579
Total	332,373	349,966	393,517	397,817	422,327	428,201	434,825
Compensation - Average Yearly Overtime							
Executive	-	-	-	-	-	-	-
Management	1,814	3,509	6,434	4,489	5,766	4,508	4,761
Non Union	1,441	1,082	4,036	3,225	2,821	2,326	2,293
Union	3,401	10,013	11,354	9,710	11,682	4,823	5,378
Total	6,656	14,604	21,824	17,424	20,269	11,657	12,431
Compensation - Average Yearly Incentive Pay							
Executive	18,852	25,177	24,055	40,235	45,870	73,402	75,787
Management	6,931	8,579	8,563	6,120	7,633	7,529	7,681
Non Union	3,585	5,233	4,144	4,153	4,308	3,897	3,766
Union	3,372	4,628	4,165	3,063	3,687	3,236	3,417
Total	32,741	43,618	40,927	53,571	61,498	88,065	90,652
Compensation - Average Yearly Benefits							
Executive	59,377	61,170	67,190	74,486	71,602	77,189	113,659
Management	38,201	37,564	41,471	38,314	41,613	38,102	41,446
Non Union	27,456	30,958	29,074	36,677	33,319	32,920	32,996
Union	21,550	23,446	23,588	25,542	31,322	32,204	33,762
Total	146,584	153,139	161,323	175,020	177,856	180,414	221,864
Total Compensation	27,943,001	29,726,909	32,617,127	33,311,700	36,040,814	34,598,257	36,579,014
Total Compensation charged to OM & A	20,756,025	20,993,072	23,116,503	23,064,959	26,650,212	27,147,228	29,017,894
Total Compensation Capitalized	7,186,976	8,733,837	9,500,625	10,246,740	9,390,602	7,451,028	7,561,120
		-	-	-	-		
***AVERAGE YEARLY BENEFITS INCLUDES BOTH RETIREE AND CURRENT BENEFITS per JK							

ENERSOURCE CORPORATION	2008 COS	2008 Actual	2009 Actual	2010 Actual	2011 Actual	2012 Bridge Year	2013 Test Year
Number of Employees (FTE's including Part time							
Executive	5.00	4.00	4.00	3.00	4.00	5.00	5.00
Management	12.00	13.00	13.00	14.00	12.00	12.00	12.00
Non Union	18.00	17.08	18.33	22.42	20.50	20.00	20.00
Union	15.00	15.50	16.41	15.83	15.33	15.00	15.00
Total	50.00	49.58	51.74	55.25	51.83	52.00	52.00
Number of Part Time Employees							
Executive	-	-	-	-	-	-	-
Management	-	-	-	-	-	-	-
Non Union							
Union		-	-	-	-	-	-
Total	-	-	-	-	-	-	-
Total Salary and Wages							
Executive	719,711	635,547	675,007	598,687	727,405	797,890	939,219
Management	1,107,160	1,065,583	1,304,406	1,411,106	1,245,496	975,942	1,199,765
Non Union	831,337	800,118	1,004,076	1,225,896	1,284,012	1,747,156	1,999,608
Union	759,166	715,434	704,864	786,406	790,026	840,856	838,517
Total	3,417,374	3,216,681	3,688,352	4,022,095	4,046,939	4,361,844	4,977,109
Current Benefits							
Executive	283,948	279,616	254,085	307,957	347,766	414,664	445,312
Management	473,457	464,381	449,475	721,869	589,870	522,495	550,783
Non Union	349,020	342,695	409,767	620,278	603,325	932,930	997,509
Union	306,296	286,477	259,014	392,265	366,444	443,033	500,498
Total	1,412,721	1,373,168	1,372,341	2,042,369	1,907,405	2,313,121	2,494,101
Accrued Post-Retirement Benefits							
Executive	2,369	2,190	1,675	2,972	2,813	2,894	3,082
Management	8,766	8,105	6,199	10,995	10,408	10,708	11,405
Non Union	13,069	12,082	9,241	16,391	15,516	15,963	17,002
Union	10,499	9,706	7,424	13,168	12,465	12,824	13,659
Retirees	18,457	17,064	13,052	23,150	21,914	22,546	24,013
Total	53,160	49,148	37,592	66,676	63,116	64,936	69,163
Total Benefits (Current + Accrued)							
Executive	286,317	281,806	255,760	310,929	350,579	417,558	448,394
Management	482,224	472,486	455,674	732,864	600,278	533,203	562,188
Non Union	362,088	354,777	419,008	636,669	618,841	948,893	1,014,511
Union	316,795	296,183	266,439	405,433	378,909	455,857	514,157
Total	1,447,424	1,405,252	1,396,881	2,085,895	1,948,607	2,355,511	2,539,250
Total Compensation (Salary, Wages & Benefits)							
Executive	1,006,028	917,353	930,767	909,616	1,077,984	1,215,448	1,387,613
Management	1,589,384	1,538,069	1,760,080	2,143,970	1,845,774	1,509,145	1,761,953
Non Union	1,193,425	1,154,895	1,423,084	1,862,565	1,902,853	2,696,049	3,014,119
Union	1,075,961	1,011,617	971,302	1,191,838	1,168,935	1,296,713	1,352,674
Total	4,864,798	4,621,933	5,085,232	6,107,989	5,995,546	6,717,355	7,516,359
Compensation - Average Yearly Base Wages							
Executive	143,942	158,887	168,752	199,562	181,851	159,578	187,844
Management	92,263	81,968	100,339	100,793	103,791	81,328	99,980
Non Union	46,185	46,845	54,778	54,679	62,635	87,358	99,980
Union	50,611	46,157	42,953	49,678	51,535	56,057	55,901
Total	333,002	333,857	366,822	404,712	399,812	384,321	443,706
Compensation - Average Yearly Overtime							
Executive		-	-	-	-	-	-
Management		-	-	59	-	-	-
Non Union		87	191	305	431	-	-
Union	333	-	8	57	276	854	854
Total	333	87	199	420	708	854	854
Compensation - Average Yearly Incentive Pay							
Executive	36,364	38,472	48,397	87,276	63,565	63,159	65,212
Management	11,693	9,136	9,214	9,595	10,162	11,297	11,664
Non Union	4,367	3,895	4,428	2,708	3,451	3,761	3,883
Union	4,817	3,945	3,161	2,143	3,153	3,230	3,335
Total	57,241	55,448	65,200	101,721	80,331	81,447	84,094
Compensation - Average Yearly Benefits							
Executive	57,263	70,452	63,940	103,643	87,645	83,512	89,679
Management	40,185	36,345	35,052	52,347	50,023	44,434	46,849
Non Union	20,116	20,771	22,859	28,397	30,187	47,445	50,726
Union	21,120	19,109	16,236	25,612	24,717	30,390	34,277
Total	138,684	146,677	138,087	209,999	192,572	205,780	221,531
Total Compensation	4,864,798	4,621,933	5,085,232	6,107,989	5,995,546	6,717,355	7,516,359
Total Compensation charged to OM & A	4,864,798	4,621,933	5,085,232	6,107,989	5,995,546	6,717,355	7,516,359
Total Compensation Capitalized							

***AVERAGE YEARLY BENEFITS INCLUDES BOTH RETIREE AND CURRENT BENEFITS per JX

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MR. AIKEN: Of the three packages that we were given yesterday, it's in the package that starts with AMPCO Interrogatory No. 16.

That looks like it.

If you can go right to the bottom, the yellow line and the following line, I just want to confirm that in the 2008 actual, which is the second column of numbers, the total compensation charged to Enersource Hydro Mississauga is the 3.678 million, and that's 83.8 percent of the Enersource corporation cost; is that right?

MR. MACUMBER: We allocate all the costs out to the regulated, non-regulated companies. The question asked how much of the salaries was allocated out.

We used the same percentage of what the total compensation was, to show how much salaries would have been allocated.

We allocate total costs.

MR. AIKEN: Okay. So that was -- the 83.8 is actually what you are referring to as the 85 percent, as a rough estimate?

MR. MACUMBER: Rough estimate, yes.

MR. AIKEN: Then that number, the percentage changes, and you come up to 2013 it's now 95.4 percent, which we heard yesterday.

And that's the 7 million that's being allocated?

MR. MACUMBER: We allocate the corporation's cost to the regulated and non-regulated companies, and we have stated in the evidence that our current method is by

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ENERSOURCE CORPORATION	2008 COS	2008 Actual	2009 Actual	2010 Actual	2011 Actual	2012 Bridge Year	2013 Test Year
Number of Employees (FTE's Including Part time							
Executive	5.00	4.00	4.00	3.00	4.00	5.00	5.00
Management	12.00	13.00	13.00	14.00	12.00	12.00	12.00
Non Union	18.00	17.08	18.33	22.42	20.50	20.00	20.00
Union	15.00	15.50	16.41	15.83	15.33	15.00	15.00
Total	50.00	49.58	51.74	55.25	51.83	52.00	52.00
Number of Part Time Employees							
Executive	-	-	-	-	-	-	-
Management	-	-	-	-	-	-	-
Non Union							
Union		-	-	-	-	-	-
Total	-	-	-	-	-	-	-
Total Salary and Wages							
Executive	719,711	635,547	675,007	598,687	727,405	797,890	939,219
Management	1,107,160	1,065,583	1,304,406	1,411,106	1,245,496	975,942	1,199,765
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Current Benefits							
Executive	283,948	279,616	254,085	307,957	347,766	414,664	445,312
Management	473,457	464,381	449,475	721,869	589,870	522,495	550,783
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Total	1,412,721	1,373,168	1,372,341	2,042,369	1,907,405	2,313,121	2,494,101
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Management	8,766	8,105	6,199	10,995	10,408	10,708	11,405
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Total	53,160	49,148	37,592	66,676	63,116	64,936	69,163
Total Benefits (Current + Accrued)							
Executive	286,317	281,806	255,760	310,929	350,579	417,558	448,394
Management	482,224	472,486	455,674	732,864	600,278	533,203	562,188
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Total Compensation (Salary, Wages & Benefits)							
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Management	92,263	81,968	100,339	100,793	103,791	81,328	99,980
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Union	50,611	46,157	42,953	49,678	51,535	56,057	55,901
Total	333,002	333,857	366,822	404,712	399,812	384,321	443,706
Compensation - Average Yearly Overtime							
Executive		-	-	-	-	-	-
Management		-	-	59	-	-	-
Non Union		87	191	305	431	-	-
Union	333	-	8	57	276	854	854
Total	333	87	199	420	708	854	854
Compensation - Average Yearly Incentive Pay							
Executive	36,364	38,472	48,397	87,276	63,565	63,159	65,212
Management	11,693	9,136	9,214	9,595	10,162	11,297	11,664
Non Union	4,367	3,895	4,428	2,708	3,451	3,761	3,883
Union	4,817	3,945	3,161	2,143	3,153	3,230	3,335
Total	57,241	55,448	65,200	101,721	80,331	81,447	84,094
Compensation - Average Yearly Benefits							
Executive	57,263	70,452	63,940	103,643	87,645	83,512	89,679
Management	40,185	36,345	35,052	52,347	50,023	44,434	46,849
Non Union	20,116	20,771	22,859	28,397	30,187	47,445	50,726
Union	21,120	19,109	16,236	25,612	24,717	30,390	34,277
Total	138,684	146,677	138,087	209,999	192,572	205,780	221,531
Total Compensation	4,864,798	4,621,933	5,085,232	6,107,989	5,995,546	6,717,355	7,516,359
Total Compensation charged to OM & A	4,864,798	4,621,933	5,085,232	6,107,989	5,995,546	6,717,355	7,516,359
Total Compensation Capitalized							
Total Compensation charged to Enersource Hydro Mississauga[1]	4,076,701	3,873,180	4,642,817	5,802,590	5,695,768	6,274,010	7,020,280
Percentages taken from Exhibit 4, Tab 4, Schedule 1, Appendix 2-L pages 1-8	83.8%	83.8%	91.3%	95.0%	95.0%	93.4%	93.4%

1. Percentages used to allocate the portion of compensation charged by Enersource Corporation to Enersource Hydro Mississauga is based on the total percentage allocation from Exhibit 4, Tab 4, Schedule 1, Appendix 2-L pages 1-8

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MR. JANIGAN: I want to, finally, deal with issue 5 on shared services, and note that your evidence indicates that you've changed the allocation of costs from your affiliate from 83.8 to 93.4 percent. And as I understand it, it's coincident with a change in the business planning of the LDC, and in particular getting you out of businesses, other businesses.

Can you explain the reason for the change in the allocation of costs?

MR. MACUMBER: In 2006 we sold our water heater business and sold our Enersource telecom.

From 2006 to 2008, the intention was to grow our non-regulated business, which was agreed to in our shared services model about how much each of the non-regulated and regulated companies would pay.

During 2008, I believe, or at the end of 2007, it was determined that we were not going to be growing the business, and a more accurate reflection of who should pay for the services should be revenue or head count. And we changed that, changed our service agreements between the two companies and changed the percentage of allocation of costs.

MR. JANIGAN: But I take it there was no change in the business activity of either company?

MR. MACUMBER: There was no fundamental change in the activity.

If anything, I was requested in the technical conference: Do I believe that one overpaid or did not pay it? I would, again, say that they agreed to pay it.

But since the non-regulated services company did not grow, in theory they overpaid.

MR. JANIGAN: I wonder if you could turn up appendix 2N, in the shared services corporate allocation. It's Exhibit I, and it's actually from a Board Staff interrogatory, IR 5, appendix 2N, page 6 of 6. Sorry. Can that be located? It's not up on the screen. Sorry.

I wonder if you could share with us how that 93.4 percent is calculated. When you look on this Appendix 2-N, it shows for 2008 a set of various percentages for services that are offered that range from 92 percent to 43 percent. In 2013 the range is 94 percent to 93.3 percent.

Can you tell me what the relationship between the allocation figure of 83.8 percent for 2008 and 93.4 percent for 2013 and what is shown on these tables?

MR. MACUMBER: When we filed our 2008 cost of service in 2007, the way we allocated shared services was either based on historical knowledge or amount they contributed or head count.

As I said before, due to the fact that we weren't growing our non-regulated company, we sat down and said, What's probably the appropriate method to allocate costs? And it was determined that a majority of the expenses for Enersource Corporation would be allocated based on budgeted revenue or head count, which, assuming that it's HR, was head count.

MR. JANIGAN: And how does that drive the percentages?

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MR. MACUMBER: It's around that number, yes.
MR. SHEPHERD: And in 2013 forecast you are allocating 93.4; is that right?
MR. MACUMBER: Yes.
MR. SHEPHERD: So if you had 50 employees in Enersource Corporation in 2008, 85 percent of the cost of those people was allocated to Enersource Hydro Mississauga; right?
MR. MACUMBER: Yes, the costs would have been allocated that way.
MR. SHEPHERD: So from 2008 to 2013 you only added two people there; right? Because you are at 52 now; right?
MR. MACUMBER: Correct.
MR. SHEPHERD: But because the percentages increased, your actual number of employees effectively allocated to Enersource Hydro Mississauga has gone up more; right? Because it has gone up twice. It's gone up because there are more people and it's gone up because a higher percentage goes to the utility; true?
MR. MACUMBER: The higher cost has been allocated to the hydro company. The time spent by the people didn't -- or the work that they performed did not change. It's the amount of cost that gets allocated.
MR. SHEPHERD: Well, why would the utility bear more [redacted]

performed by the staff did not change. It's just the cost that was allocated to the hydro company did.

MR. SHEPHERD: So the hydro company is paying more for the same work now than it was before?

MR. MACUMBER: I would say that they were -- the non-regulated side of the company paid more than the work that they were receiving before.

MR. SHEPHERD: All right. So --

MR. AIKEN: Sorry, Jay, can I just jump in there for a minute?

MR. SHEPHERD: Sure.

MR. AIKEN: Can you go to attachment -- or the attachment to Energy Probe Interrogatory No. 3, under issue 4.4? I think this deals with the numbers that we are talking about.

In Part B of that question we had asked -- yeah, 4.4, Energy Probe No. 3 -- we had asked to show the total compensation charts to OM&A from Enersource Corp., added to the bottom of the Enersource Hydro Mississauga schedule that shows the number of employees and all the wages.

So I see at the bottom --

MR. VEGH: Sorry, Randy, could you give the reference again?

MR. AIKEN: Yes, issue 4.4, Energy Probe IR 3(b) attachment. It was in one of these packages that you gave us yesterday. Number 3 under issue 4.4. It's a big table.

MR. SHEPHERD: Okay. But the table that's shown there on the screen I don't have in 4.4.

ISSUE 5: CAPITAL STRUCTURE AND COST OF CAPITAL

Issue 5: Capital Structure and Cost Capital notes 47
[1] Energy Probe Argument page 34

Additional References

EB-2012-0033

Ontario Energy Board

IN THE MATTER OF the *Ontario Energy Board Act, 1998*, S.O. 1998, c. 15, (Schedule B);

AND IN THE MATTER OF an application by Enersource Hydro Mississauga Inc. for an order approving just and reasonable rates and other charges for electricity distribution to be effective January 1, 2013 and January 1, 2014.

ENERGY PROBE RESEARCH FOUNDATION
("ENERGY PROBE")

ARGUMENT

September 21, 2012

Any changes in the level of taxable income as a result of the Board's decision in this proceeding should be reflected in the calculation of PILs.

4.4 Is the proposed allocation of shared services and corporate costs appropriate?

Energy Probe has made submissions with respect to the proposed level and allocation of shared services from Enersource Corporation as part of its submissions on Issue 4.1 relating to the specific adjustments to OM&A.

5. Capital Structure and Cost of Capital

5.1 Is the proposed capital structure, rate of return on equity and short term debt cost for 2013 and 2014 appropriate?

Energy Probe accepts the proposed capital structure as it follows the Board's policy in this area. Similarly, the rate of return on equity and short term debt rates will be set in compliance with the Board's policy.

5.2 Is the proposed long term debt cost for 2013 and 2014 appropriate?

Enersource has calculated the weighted average cost of its long term debt using the Internal Rate of Return ("IRR") function, as shown in Attachment 1 to Exhibit 5, Tab 1, Schedule 1. This calculation results in a long-term debt rate of 5.09%. Energy Probe submits that this is not appropriate and that the weighted average cost of the long term debt should be based on the interest costs for the 2013 test year.

As shown in Attachment 1, the interest costs in each year of the bond repayment schedules is $11,123,700 (or a coupon rate of 5.297%) for the $210 million issue and $4,973,100 (or a coupon rate of 4.521%) for the $110 million issue. The total interest payment is $16,096,800 on a total principle of $320 million, resulting in a long term debt rate of 5.03%. This is the figure that Energy Probe submits should be used in the calculation of the cost associated with the deemed long term debt.

While the differential is small at only 6 basis points, application of this differential to the deemed long term debt of $351 million (Exhibit I, Issue General RRWF, Board Staff IR#3, Appendix 2-C(i)) results in a reduction in the revenue deficiency of more than $210,000.

ISSUE 6: COST ALLOCATION

Issue 6: Cost Allocation notes 48-60

[1] Exhibit 7, Tab 1, Schedule 1, page 4
[1] Response to Issue 6.1, AMPCO IR #17
[1] Appendix 2-O, Updated May 17, 2012
[1] Exhibit 7, Tab 1, pages 9-10 (Updated May 17, 2012)
[1] EB-2010-0219, pages 34 and 36
[1] EB-2010-0125, page 5
[1] Exhibit 7, Tab 1, pages 3 - 4
[1] Board Report EB-2010-0219, page 26
[1] Response to Issue 6.1, VECC IR 47 a)
[1] EB-2010-0142, page 40
[1] EB-2010-0131, page 43
[1] EB-2010-0131, Response to Comments on DRO, July 28, 2011, page 13
[1] EB-2010-0131, Board Decision and Order on Draft Rate Order, August 3, 2011

Additional References

application for 2012 distribution rates. The Board also released the staff report[2] that documents the changes resulting from the Cost Allocation Review as well as instructions for the Revised Cost Allocation Model.

Enersource has relied on the Cost Allocation Review and Revised Cost Allocation Model to complete this 2013 cost allocation submission. For the purposes of this Application, Enersource has updated the Cost Study (now "2013 Cost Study") to reflect 2013 Test Year costs, annual loads, customer numbers, and hourly load profile demand values. The 2013 demand values were updated by Hydro One Networks Inc. ("Hydro One") for all customer classes.

During the course of the EB-2007-0706 proceeding, the cost allocation model was modified by removing the transformer ownership allowance, a change that has now been incorporated into the *Ontario Energy Board Chapter 2 of the Filing Requirements for Transmission and Distribution Applications* ("Filing Requirements")[3].

Enersource's 2013 Cost Study

This section of the evidence will describe the weighting factors, model runs, load and customer information, and cost information used in Enersource's 2013 Cost Study.

---

[2] EB 2010-0219 *Staff Report to the Board – Implementation of Revisions to the Board's Electricity Distribution Cost Allocation Policy*, August 4, 2011.

[3] *Ontario Energy Board Chapter 2 of the Filing Requirements for Transmission and Distribution Applications*, June 22, 2011, p.38.

Enersource Hydro Mississauga Inc.
Response to Interrogatories by Issue

Interrogatory # 17

Association of Major Power Consumers in Ontario (AMPCO)

6. Cost Allocation

6.1: Is the proposed cost allocation methodology for 2013 and 2014 appropriate?

Reference 1: OEB Filing Requirements for Electricity Transmission and Distribution Applications, 2.10 Exhibit 7, Cost Allocation, Page 42

Preamble: The Board's Filing Requirements states:

2.10 Exhibit 7. Cost Allocation

"Distributors should refer to section 2.6.4 of the March 31, 2011 report concerning weighting factors for allocation of certain costs. A description of the weighting factors is required, including an explanation of why the distributor has chosen to use the default placeholders if applicable."

Reference 2: EB-2010-0219 Report of the Board, Review of Electricity Distribution Cost Allocation Policy, 2.6.4

Preamble: The Board's Guideline EB-2010-0219 states:

"The Board is of the view that default weighting factors should be utilized only in exceptional circumstances. In general, distributors have had sufficient time since preparing their 2006 Cost Allocation Information Filings to have gained the experience necessary to enable them to propose appropriate distributor-specific weighting factors."

Reference 3: Exhibit 7, Tab 1, Schedule 1

Preamble: The evidence states:

"Enersource has made no changes to the weighting factors used in prior cost studies and notes that these weighting factors are consistent with the default weighting factors for services and billings established in the "Staff Report to the Board – Implementation of the Revisions to the Board's Electricity Distributor Cost Allocation Policy, Aug 4, 2011"4. Enersource has no information that would lead it to depart from the previously-used weighting factors.

a) Please explain further why Enersource does not have information to determine appropriate distributor-specific values.

Response:

a) To determine appropriate, accurate and defensible distributor-specific weighting values for Enersource would require considerable data mining and analysis that was not feasible at this time. Enersource intends to do a more in- depth review of the weighting factors for services, billing and collections, and meter reading before filing its next cost allocation model.

Appendix 2-O
Cost Allocation

Enersource Mississauga Hydro's previous Cost Allocation was the 2008 Cost of Service Application.

a) Allocated Costs

Small Commercial and Unmetered Scatter Load (UMSL) were combined into one rate class in the previous Cost Allocation Study. For purposes of comparison the combined total from previous study is split based on the number of customer accounts.

Classes	Costs Allocated from Previous Study	%	Costs Allocated in Test Year Study (Column 7A)	%
Residential	$ 46,484,474	41.3%	$ 59,831,172	44.6%
Small commercial*	$ 225,746	0.2%		0.0%
GS < 50 kW	$ 14,982,784	13.3%	$ 16,549,924	12.3%
GS > 50 kW	$ 27,222,124	24.2%	$ 30,328,404	22.6%
GS > 500 kW	$ 16,965,654	15.1%	$ 19,851,007	14.8%
Large User, if applicable	$ 4,202,131	3.7%	$ 5,475,286	4.1%
Street Lighting	$ 2,123,429	1.9%	$ 1,615,703	1.2%
UMSL	$ 448,123	0.4%	$ 465,398	0.3%
Total	$ 112,654,465	100.0%	$ 134,116,893	100.0%

Table a) Allocated Costs is restated below to reflect the changes in the rate classes - Small Commercial rate class is to be retired, current small commercial customers will migrate to GS < 50 kW, Unmetered Scattered Load will be split out from the formerly combined Small Commercial UMSL.

Classes	Costs Allocated from Previous Study	%	Costs Allocated in Test Year Study (Column 7A)	%
Residential	$ 46,484,474	41.3%	$ 59,831,172	44.6%
GS < 50 kW	$ 15,208,530	13.5%	$ 16,549,924	12.3%
GS > 50 kW	$ 27,222,124	24.2%	$ 30,328,404	22.6%
GS > 500 kW	$ 16,965,654	15.1%	$ 19,851,007	14.8%
Large User, if applicable	$ 4,202,131	3.7%	$ 5,475,286	4.1%
Street Lighting	$ 2,123,429	1.9%	$ 1,615,703	1.2%
UMSL	$ 448,123	0.4%	$ 465,398	0.3%
Total	$ 112,654,465	100.0%	$ 134,116,893	100.0%

c) CA model sheet I8 rows labels DCP1, DCP4, DCP12, DNCP1, DNCP4 and DNCP12 were populated directly from the load data as provided by Hydro One Networks.

The TCP1, TCP4 and TCP12 rows were based on the respective DCP1, DCP4 and DCP12 row multiplied by SFLF factor since TCP is the load of the TS before the meter.

The Bulk Delivery CP (BCP1, BCP4, and BCP12) rows were made equal to the Total System CP (DCP1, DCP4, and DCP12).

The Primary NCP (PNCP1, PNCP4, and PNCP12) rows were based on the respective DNCP1, DNCP4 and DNCP12 divided by the SFLF factor.

The Line Transformer NCP (LTNCP1, LTNCP4 and LTNCP12) were based on the respective Primary NCP less the estimated primary loads (for each customer class and NCP level) divided by the DLF for non large users.

The Secondary NCP was made equal to the Line Transformer NCP.

d) Row 50 from Sheet I6.1 of the Cost Allocation model represents the 2013 weather normalized load forecast, including the impact of the incremental CDM, which was provided to Hydro One to complete their analysis.

Ontario Energy Board

Commission de l'énergie de l'Ontario

Ontario

EB-2010-0142

IN THE MATTER OF the *Ontario Energy Board Act, 1998*, S.O. 1998, c. 15, (Schedule B);

AND IN THE MATTER OF an application by Toronto Hydro-Electric System Limited for an order approving just and reasonable rates and other charges for electricity distribution to be effective May 1, 2011.

BEFORE: Ken Quesnelle
Presiding Member

Marika Hare
Member

Karen Taylor
Member

PARTIAL DECISION & ORDER

The Application and the Proceeding

Toronto Hydro-Electric System Limited ("THESL" or the "Applicant") filed an application dated August 23, 2010 with the Ontario Energy Board (the "Board") under section 78 of the *Ontario Energy Board Act, 1998*, S.O. c.15, Schedule B) (the "Act"), for an order or orders approving just and reasonable rates and charges for the rate year commencing May 1, 2011.

The application included increases in operating expenses, increases in capital expenses, changes to the cost of debt and equity, as well as a smart grid plan. The or whether improved cost allocation information is required to justify the movement of the revenue-to-cost ratio closer to one, within a range.

Finally as set out herein, the Board does not find it to be determinative in the context of this application that the methodology put forth by THESL was accepted by the Board and intervenors as part of the Settlement Agreement related to THESL's 2010 revenue requirement application (EB-2010-0139). Settlement Agreements accepted by the Board do not necessarily create a precedent for the Board. Moreover, Settlement Agreements usually reflect a number of trade-offs negotiated between the parties, and the Board believes it would be inappropriate to take one particular item in isolation, out of the context of the remainder of the Settlement Agreement.

Issue 7.4 – Revenue-to-Cost Ratios

The Board finds that the proposed revenue-to-cost ratios are not appropriate and are not consistent with the Board's revenue-to-cost policy report (EB-2007-0667). In that report, the Board set out that an incremental approach is appropriate and that a range approach is preferable to implementation of a specific revenue-to-cost ratio. The Board also stated that distributors should endeavour to move their revenue-to-cost ratios closer to one if this is supported by improved cost allocations. THESL did not file updated or improved cost allocation information and continues to rely on 2006 information to define the load profiles for certain customer classes.

Based on these findings and those set out above, the Board directs THESL to recalculate the starting revenue-to-cost ratios by customer class. For those customer classes with starting revenue-to-cost ratios greater than or less than the upper or lower end of the range provided by the Board in EB-2007-0667, THESL is directed to move the customer class ratio to the upper or lower boundary, as appropriate, and to adjust other class ratios only as required to reconcile with the overall approved revenue requirement.

Implementation Issues

On March 25, 2011, THESL filed a letter with the Board formally requesting an order of the Board making its existing distribution rates interim, effective May 1, 2011.

The Board granted this request during the first day of the oral hearing.

Ontario Energy Board

Commission de l'énergie de l'Ontario

Ontario

EB-2010-0131

IN THE MATTER OF the *Ontario Energy Board Act, 1998*, S.O. 1998, c. 15, (Schedule B);

AND IN THE MATTER OF an application by Horizon Utilities Corporation for an order approving just and reasonable rates and other charges for electricity distribution to be effective January 1, 2011.

BEFORE: Marika Hare
Presiding Member

Cathy Spoel
Member

Karen Taylor
Member

DECISION AND ORDER

BACKGROUND

Horizon Utilities Corporation ("Horizon") filed an application (the "Application") with the Ontario Energy Board (the "Board") on August 27, 2010 under section 78 of the *Ontario Energy Board Act, 1998*, S.O. 1998, c. 15, (Schedule B), seeking approval for changes to the rates that Horizon charges for electricity distribution, to be effective January 1, 2011. The Board assigned the Application File Number EB-2010-0131.

principle, SEC believes that this should be as a result of a generic and principled Board policy and not just at the discretion of an individual utility. As such, SEC opposed Horizon's proposed adjusted R/C ratios.[94]

In reply, Horizon submitted that the cost allocation methodology and the data used has improved since the 2006 Informational filing used in Horizon's 2008 Cost of Service application. Horizon clarified that it had set the R/C ratio for the Residential class closer to unity, and then adjusted other classes.[95] It requested approval of the R/C ratios as proposed in its updated evidence of March 14, 2011.

Board Findings

The Board accepts the results of Horizon's 2011 Cost Allocation Study and agrees that the results, as updated in the response to VECC IR # 44, represent an appropriate starting point for any consideration of adjustment to customer class revenue-to-cost ratios.

The Board finds, however, that the proposed revenue-to-cost ratios are not appropriate and not consistent with the Board's revenue to cost policy, which establishes ranges of tolerance around revenue-to-cost ratios of one and adopts an incremental approach, whereby changes to revenue-to-cost ratios within the range are to be supported by improvements to the cost allocation model.

The Board is of the view that updating the pre-existing cost allocation model with test year data is an insufficient "improvement" for the purpose of supporting the movement within class ranges, as the Board recognizes that the results will vary somewhat due to data limitations and volatility.

For those customer classes with starting revenue-to-cost ratios greater or less than the upper or lower end of the range provided by the Board in EB-2007-0667, Horizon is directed to move the customer class ratio to the upper or lower boundary, as appropriate, and to adjust the other class ratios only as required to reconcile with the overall approved revenue requirement

[94] *Ibid.*, pp. 44-45
[95] Horizon reply submission [EB-2010-0131], May 20, 2011, pp. 121-123

horizon
UTILITIES *Looking beyond*

July 28, 2011

By RESS and Courier

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

Dear Ms. Walli;

Re: EB-2010-0131 - Horizon Utilities Corporation Application to the Ontario Energy Board for Electricity Distribution Rates and Charges as of January 1, 2011

On July 7, 2011, the Ontario Energy Board (the "Board") issued its Decision and Order in the above-captioned proceeding. On July 18, 2011, Horizon Utilities filed its draft Rate Order and Appendices thereto, which included Horizon Utilities' proposed rates and charges reflecting the Board's findings in the Decision. Horizon Utilities has received submissions on the draft Rate Order from Board Staff, Energy Probe, VECC, the School Energy Coalition and AMPCO.

Please find accompanying this letter Horizon Utilities' response to the submissions of the parties on its draft Rate Order. Two hard copies will be delivered to the Board. A text-searchable electronic version of the response and live Excel versions of the Revised Revenue Requirement Work Form (Revised Appendix C); the Revised Green Energy Act Rate Rider calculations (Revised Appendix E); and Deferral and Variance Account Rate Rider calculations are being filed using the Board's RESS system.

Should you have any questions or require further information, please do not hesitate to contact me.

Yours Truly,

Original signed by Indy Butany-DeSouza

Indy J. Butany-DeSouza
Vice-President, Regulatory and Government Affairs
Horizon Utilities Corporation

Encl.
cc. Keith Ritchie, Ontario Energy Board (electronic version only)
Intervenors of Record (electronic version only)

...Given that the Residential class shows the highest R/C ratio next to Unmetered Scattered Load which is moved down to the class threshold of 120%, Board staff submits that Horizon's proposal to reduce the Residential class R/C ratio to reduce subsidization within that class is reasonable.

Horizon may wish to further address its proposal or to consider whether a more equitable allocation to all classes is appropriate under the circumstances."

Horizon Utilities' Response:

While Board staff have confirmed that the approach proposed by Horizon Utilities in its draft Rate Order is reasonable, Horizon Utilities has considered this matter further and has determined that it will adopt the approach suggested by Energy Probe and VECC. Accordingly, Horizon Utilities has prepared a revised version of Table 9 (Rate Design), below, which illustrates Horizon Utilities' adjustment of both the Residential and USL revenue-to-cost ratios to 108.4%. The revised Table 9 reflects the movement of the USL class from 120% down to the Residential starting ratio of 111.2%, followed by the reduction of the ratios for both of those classes in tandem until the revenue excess is eliminated at 108.4%. The revised Table 9 also illustrates the rates resulting from the adjustments to the revenue-to-cost ratios and other adjustments proposed by Horizon Utilities in this response. Horizon Utilities has provided a revised Schedule of Rates and Charges at Appendix A (Revised) to this response, and revised impact tables at Appendix B (Revised).

Revised Table 9 – Rate Design

Class	Revenue Requirement - 2011 Cost Allocation Model	2010 Base Revenue Allocated based on Porpotion of Revenue at Existing Rates	Miscellaneous Revenue Allocated from 2011 Cost Allocation Model	Total Revenue	Starting Point Revenue to Cost Ratio	Revenue to Cost Ratio per Decision	Revenue per Decision	Miscellaneous Revenue	Base Revenue per Decision
Residential	$ 58,034,239	$ 60,811,098	$ 3,726,717	$ 64,537,815	111.2%	108.4%	$ 62,881,094	($3,726,717)	$ 59,154,377
GS < 50 kW	$ 11,949,011	$ 11,456,614	$ 905,555	$ 12,362,169	103.5%	103.5%	$ 12,362,169	($905,555)	$ 11,456,614
GS >50	$ 20,101,816	$ 16,036,353	$ 850,867	$ 16,887,220	84.0%	84.0%	$ 16,887,220	($850,867)	$ 16,036,353
Large Use	$ 8,066,771	$ 4,845,995	$ 256,630	$ 5,102,624	63.3%	85.0%	$ 6,856,755	($256,630)	$ 6,600,125
Sentinel Lights	$ 57,144	$ 33,555	$ 1,865	$ 35,420	62.0%	80.0%	$ 45,715	($1,865)	$ 43,850
Street Lighting	$ 2,963,843	$ 2,136,477	$ 86,671	$ 2,223,148	75.0%	75.0%	$ 2,223,148	($86,671)	$ 2,136,477
USL	$ 534,372	$ 652,582	$ 49,766	$ 702,348	131.4%	108.4%	$ 579,001	($49,766)	$ 529,235
Standby Power	$ 639,542	$ 478,063	$ 17,929	$ 495,992	77.6%	80.0%	$ 511,634	($17,929)	$ 493,704
TOTAL	$ 102,346,736	$ 96,450,735	$ 5,896,000	$102,346,735	100.0%		$102,346,735	($5,896,000)	$ 96,450,735

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Ontario Energy Board

Commission de l'énergie de l'Ontario

Ontario

EB-2010-0131

IN THE MATTER OF the *Ontario Energy Board Act, 1998*, S.O. 1998, c. 15, (Schedule B);

AND IN THE MATTER OF an application by Horizon Utilities Corporation for an order approving just and reasonable rates and other charges for electricity distribution to be effective January 1, 2011.

BEFORE: Marika Hare
Presiding Member

Cathy Spoel
Member

Karen Taylor
Member

DECISION AND ORDER ON DRAFT RATE ORDER

Horizon Utilities Corporation ("Horizon") filed an application, dated August 27, 2010, with the Ontario Energy Board (the "Board") under section 78 of the *Ontario Energy Board Act, S.O. 1998*, c.15, Schedule B, for an order or orders approving just and reasonable rates and charges for the rate year commencing January 1, 2011.

The Board issued its Decision on the application on July 7, 2011. In the Decision, the Board ordered Horizon to file a draft Rate Order ("DRO") reflecting the Board's findings in the Decision. The Board approved an implementation date of August 1, 2011 and an effective date of May 1, 2011.

Horizon filed its DRO and supporting material on July 18, 2011. Intervenor and Board staff comments on the DRO were due by July 25, 2011.

The Vulnerable Energy Consumers Coalition ("VECC"), Energy Probe Research Foundation ("Energy Probe"), the Association of Major Power Consumers in Ontario ("AMPCO"), the School Energy Coalition ("SEC") and Board staff filed submissions on the DRO. On July 28, 2011, Horizon filed a response to the parties' submissions as well as a revised DRO.

The Board notes that in Horizon's reply, Horizon did not agree with parties' submissions on the calculation of the forgone revenue rate rider. The Board has reviewed the submissions of all of the parties and Horizon's reply and is not persuaded by Horizon's argument that actual data for the May to July period should be used. VECC and Energy Probe noted that Horizon calculates the foregone revenue for the period May 1, 2011 to July 31, 2011 based on actual power purchases for this period. The recovery rate riders are then calculated using the approved 2011 load forecast and the percentage of the total 2010 load accounted for in the months of August to December.

The Board agrees with the intervenors and Board Staff that a consistent approach should be used to calculate both the foregone revenue and the rate riders. The most efficient way to accomplish this is to assume that the revenue requirement and the number of customers and demand is constant through the test year, as noted in Board staff's submission. The Board notes that it has been the Board's practice to employ the $1/12^{th}$ approach in determining the level of forgone revenue rate riders in past applications. In other words, one month's revenue requirement is simply 1/12 of the estimated revenue requirement for the test year. Accordingly, the Board directs Horizon to revise the forgone revenue rate riders to reflect this approach.

The Board has reviewed the remaining information provided in support of the revised DRO and is satisfied that the remaining components of the revised DRO accurately reflect the Board's Decision.

Horizon shall file an updated DRO including an updated Tariff of Rates and Charges and all necessary supporting calculations and explanations reflecting the above finding. Once the calculations are confirmed by the Board, the Board will issue a final Rate Order.

THE BOARD ORDERS THAT:

1. Horizon shall file an updated draft Rate Order attaching an updated Tariff of Rates and Charges reflecting the Board's findings in this Decision on Draft Rate Order by Friday August 5, 2011.

All filings to the Board must quote file number EB-2010-0131, and be made through the Board's web portal at www.errr.ontarioenergyboard.ca, and consist of two paper copies and one electronic copy in searchable / unrestricted PDF format. Filings must clearly state the sender's name, postal address and telephone number, fax number and e-mail address. Parties must use the document naming conventions and document submission standards outlined in the RESS Document Guideline found at www.ontarioenergyboard.ca. If the web portal is not available, parties may email their documents to the address below. Those who do not have internet access are required to submit all filings on a CD in PDF format, along with two paper copies. Those who do not have computer access are required to file 7 paper copies.

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

Attention: Board Secretary

Filings: www.errr.ontarioenergyboard.ca
E-mail: boardsec@ontarioenergyboard.ca

Tel : 1-888-632-6273
Fax : 416-440-7656

DATED at Toronto, August 3, 2011

ONTARIO ENERGY BOARD

Original signed by

Kirsten Walli
Board Secretary

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ISSUE 7: RATE DESIGN

Issue 7: Rate Design notes 61-66
[1] Exhibit 8, Tab 1, pages 4
[1] Response to Issue 7.1, VECC #51 d)
[1] Response to Issue 6.1, CCC IR #1
[1] Enersource Argument-in-Chief, page 29
[1] Enersource Argument-in-Chief, page 30
[1] Exhibit 8, Tab 2, Schedule 1, page 3

Additional References

Enersource is not proposing to adjust the fixed/variable split for each class. Table 4 provides the fixed/variable split for each class after the adjustments for cost allocation.

Table 4: Proposed 2013 Fixed/Variable Split

	A		B	C		D	E	
	Fixed $000s		%	Variable $000s		%	Total $000	
Residential	$	31,194	60.4%	$	20,489	39.6%	$	51,683
General Service < 50 kW [1]	$	9,492	53.9%	$	8,128	46.1%	$	17,620
Unmetered Scattered Load	$	323	64.1%	$	181	35.9%	$	504
General Service 50 kW - 499 kW	$	3,720	11.3%	$	29,195	88.7%	$	32,915
General Service 500 kW - 4999 kW	$	9,127	43.5%	$	11,838	56.5%	$	20,965
Large Use (> 5000 kW)	$	1,364	22.4%	$	4,719	77.6%	$	6,083
Street Lighting	$	911	60.2%	$	603	39.8%	$	1,514
TOTAL	$	56,132	42.8%	$	75,153	57.2%	$	131,285

[1] Columns C to E include small commercial as part of GS < 50 kW

Enersource is proposing to maintain the same monthly fixed rates for standby charges and for microFIT.

Standby charges consist of a monthly fixed charge of $200 for simple metering arrangements, or $500 for complex metering arrangements where Enersource provides distribution service on a standby basis as a back-up supply to an on-site generator.

Enersource currently uses the province-wide microFIT rate of $5.25 per month per customer and proposes to continue charging this rate as reflected in the Proposed Tariff of Rates and Charges found at Appendix 1 of this exhibit.

As required in the OEB's Report of the Board on the Review of Electricity Distribution Cost Allocation Policy (EB-2010-0219), Table 5 below provides

Enersource Hydro Mississauga Inc.
Response to Interrogatories by Issue

Interrogatory #51

Vulnerable Energy Consumers Coalition (VECC)

7. Rate Design

Issue 7.1 Are the fixed to variable splits for each class for 2013 and 2014 appropriate?

Reference: Exhibit 8, Tab 1, Schedule 1, pages 1-3

a) With respect to Table 1, please confirm that:

- The 2012 smart meter adder was included in the fixed charge for each class for purposes of establishing revenue at current rates.
- The revenues for the GS 5-499, GS 500-499 and Large Use classes have not been reduced to reflect the transformer ownership allowance.

b) Please re-do Table 1 such that:

- In column A, the revenue for each customer class reconciles with that reported in Sheet O1 for revenue at current rates (Row 18),
- In column B, the revenue for each customer class reconciles with that reported in Sheet O1 based on the status quo (Row 24)
- Column E sets out Enersource's proposed allocation of the 2013 base revenue requirement, and
- For purposes of including the cost of the transformer ownership allowance, add another two columns where the first allocates the 2013 transformer allowance specifically to the classes receiving it (i.e., based on Cost Allocation Model, Sheet I6, row 40) and the second sets out the total revenues by class (before any transformer ownership discount is applied).

c) Please provide a table that sets out Enersource's calculation of the existing fixed-variable split for each customer class based on revenues at current rates.

d) Confirm whether or not Enersource's calculation of the existing fixed-variable split:

- Included the smart meter funding adder in the calculation of the fixed portion of the split for each class
- Used revenues and rates for each class prior to any reductions for the transformer ownership allowance.

e) If the response to either bullet in part (d) is affirmative, please re-calculate the existing fixed variable split for each class where the fixed rates exclude the smart meter funding adder and the total revenues for each class are reduced by the applicable transformer ownership allowance discount.

f) Based on the results of part (e) please re-calculate Table 2.

g) Based on the results of part (e), please provide a schedule that calculates the variable rate before and after Cost Allocation (similar to Table 3) and then add a column that sets out the after Cost Allocation variable rate inclusive of recovering the cost of providing the transformer allowance to each respective class.

Response:

a) Table 1 in Exhibit 8 Tab 1 Schedule 1 of the updated evidence filed May 17, 2012 excludes the 2012 smart meter funding adder as it was not approved for Enersource's 2012 distribution rates in the Board's decision on April 19, 2012. (EB-2011-0100)

Enersource confirms that the revenues received by the applicable customers in the GS 50 < 499, GS 500 < 4999, and Large Use classes have not been reduced to reflect the transformer ownership allowance discount.

b) Table 1 is provided below, revised as per the interrogatory as follows:

- In column A, the revenue for each customer class reconciles with that reported in Sheet O1 for revenue at current rates (Row 18) (i.e. excludes the transformer ownership allowance revenue requirement);
- In column C (not B), the revenue for each customer class reconciles with that reported in Sheet O1 based on the status quo (Row 23 not Row 24) (i.e. excludes the transformer ownership allowance revenue requirement);
- Column E has been recomputed to exclude the revenue required for the transformer ownership allowance;

(102)

- Column G is equal to the Cost Allocation Model, Sheet I6, row 40; and
- Column H is the sum of Column E and F, which is the required total revenues by class before any transformer ownership discount is applied.

c) Please refer to CCC Issue 6.1 IR #1 for Enersource's calculation of the fixed-variable split for each customer class.

d) The fixed variable split calculated by Enersource excludes the smart meter funding adder. Please refer to part a) of this interrogatory.

The fixed variable split calculated by Enersource used revenues and rates for each class prior to any reductions for the transformer ownership allowance.

e) The following Table 2 presents the fixed variable split after the revenue requirement is reduced by the transformer ownership allowance discount. (Column L is reduced to $nil.)

f) Please refer to part e) of this interrogatory.

g) Please refer to part e) of this interrogatory.

Enersource has followed the Board's guidelines with respect to the exclusion of the transformer ownership allowance from the cost allocation model for the 2013 Test Year. For more information, please refer to Exhibit 7 Tab 1 Schedule 1 Page 4 Line 10.

Table 1

	A	B	C	D	E	F	G	H	I
	Distribution Revenue with Current Rates $000s	%	2013 Distribution Revenue with Initial Rates before Cost Allocation $000s	%	2013 Distribution Revenue after Cost Allocation $000s	%	Per Cost Allocation Model (Sheet I6 row 40) $000s	H = E + F $000s	%
Residential	42,137	37.4%	48,336	37.4%	51,090	39.5%		51,090	38.9%
General Service < 50 kW	15,584	13.8%	17,877	13.8%	17,187	13.3%		17,187	13.1%
Unmetered Scattered Load	580	0.5%	665	0.5%	490	0.4%		490	0.4%
General Service 50 kW - 499 kW	28,965	25.7%	33,226	25.7%	32,134	24.9%	170	32,303	24.6%
General Service 500 kW - 4999 kW	18,246	16.2%	20,930	16.2%	20,940	16.2%	1,133	22,073	16.8%
Large Use (> 5000 kW)	5,879	5.2%	6,744	5.2%	5,946	4.6%	695	6,641	5.1%
Street Lighting	1,316	1.2%	1,509	1.2%	1,501	1.2%		1,501	1.1%
Total Revenue to Recover in Rates	112,706	100.0%	129,287	100.0%	129,287	100.0%	1,998	131,285	100.0%

(103)

Table 2

	A	B	C	D	E = A*C*12	F = B*D	E/(E+F)	H = F/(E+F)	I	J = G * I	K = H * I	L	M = J	N = K + L	M/(M+N)	N/(M+N)
	2012 Board-Approved		2013 Billing Determinants				Proportion		2013 Revenue Requirement after Cost Allocation			Allocation of Transformer Allowance Revenue			Proportion	
	Fixed	Variable	Fixed	Variable	Fixed	Variable	Fixed	Variable		Fixed	Variable		Fixed	Variable	Fixed	Variable
	$/month	$/kWh or $/kW	# of customers	kWh / kW	$ 000s	$ 000s	%	%	$ 000s	$ 000s	$ 000s	$ 000s	$ 000s	$ 000s	%	%
Residential	11.87	0.0119	176,865	1,423,857,475	25,193	16,944	59.8%	40.2%	51,090	30,546	20,544	-	30,546	20,544	59.8%	40.2%
GS<50	39.93	0.0116	17,703	612,188,101	8,483	7,101	54.2%	45.8%	17,187	9,321	7,866	-	9,321	7,866	54.2%	45.8%
USL	10.69	0.0195	2,942	10,383,027	377	202	65.1%	34.9%	490	319	171	-	319	171	65.1%	34.9%
GS 50 < 499	69.86	4.2044	3,950	6,142,022	3,311	25,824	11.4%	88.6%	32,134	3,652	28,481	-	3,652	28,481	11.4%	88.6%
GS 500 < 4999	1,538.27	2.0981	464	5,154,338	8,565	10,814	44.2%	55.8%	20,940	9,255	11,685	-	9,255	11,685	44.2%	55.8%
Large Use	13,856.90	2.9225	9	1,737,267	1,497	5,077	22.8%	77.2%	5,946	1,354	4,592	-	1,354	4,592	22.8%	77.2%
Street Lighting	1.34	10.2587	49,986	49,889	804	512	61.1%	38.9%	1,501	917	584	-	917	584	61.1%	38.9%
					48,229	66,475			129,287	55,363	73,924	-	55,363	73,924		
						114,704					129,287			129,287		

	Q = C	R = D	S = M	T = N	U = S/Q/12	V = T/R
	2013 Billing Determinants				2013 Proposed Rates	
	Fixed	Variable	Fixed	Variable	Fixed	Variable
	# of customers	kWh / kW	$ 000s	$ 000s	$/month	$/kWh or $/kW
Residential	176,865	1,423,857,475	30,546	20,544	14.39	0.0144
GS<50	17,703	612,188,101	9,321	7,866	43.88	0.0128
USL	2,942	10,383,027	319	171	9.03	0.0165
GS 50 < 499	3,950	6,142,022	3,652	28,481	77.05	4.6371
GS 500 < 4999	464	5,154,338	9,255	11,685	1,662.15	2.2671
Large Use	9	1,737,267	1,354	4,592	12,533.37	2.6434
Street Lighting	49,986	49,889	917	584	1.53	11.7044
			55,363	73,924		
				129,287		

(1047)

Enersource Hydro Mississauga Inc.
Response to Interrogatories by Issue

Interrogatory # 1

The Consumers Council of Canada
(CCC)

6 Cost Allocation

6.1: Is the proposed cost allocation methodology for 2013 and 2014 appropriate?

Reference: (7/T1/S1/p.11)

How did Enersource arrive at the proposed monthly charges set out in Table 4 for each rate class?

Response:

The proposed monthly and variable charges were computed as follows:

	A	B	C	D	E = A*C*12	F = B*D	G = E/(E+F)	H = F/(E+F)	I	J = G * I	K = H * I	L	M = J	N = K + L	O = M/(M+N)	P = N/(M+N)
	2012 Board-Approved		2013 Billing Determinants				Proportion		2013 Revenue Requirement after Cost Allocation			Allocation of Transformer Allowance Revenue			Proportion	
	Fixed	Variable	Fixed # of customers	Variable	Fixed	Variable	Fixed	Variable		Fixed	Variable		Fixed	Variable	Fixed	Variable
	$/month	$/kWh or $/kW		kWh / kW	$ 000s	$ 000s	%	%	$ 000s	$ 000s	$ 000s	$ 000s	$ 000s	$ 000s	%	%
Residential	11.87	0.0119	176,865	1,423,857,475	25,193	16,944	59.8%	40.2%	51,090	30,546	20,544	790	30,546	21,334	58.9%	41.1%
GS<50	39.93	0.0116	17,703	612,188,101	8,483	7,101	54.2%	45.8%	17,187	9,321	7,866	266	9,321	8,132	53.4%	46.6%
USL	10.69	0.0195	2,942	10,383,027	377	202	65.1%	34.9%	490	319	171	8	319	179	64.1%	35.9%
GS 50 < 499	69.86	4.2044	3,950	6,142,022	3,311	25,824	11.4%	88.6%	32,134	3,652	28,481	497	3,652	28,978	11.2%	88.8%
GS 500 < 4999	1,538.27	2.0981	464	5,154,338	8,565	10,814	44.2%	55.8%	20,940	9,255	11,685	324	9,255	12,009	43.5%	56.5%
Large Use	13,856.90	2.9225	9	1,737,267	1,497	5,077	22.8%	77.2%	5,946	1,354	4,592	92	1,354	4,684	22.4%	77.6%
Street Lighting	1.34	10.2587	49,986	49,889	804	512	61.1%	38.9%	1,501	917	584	23	917	607	60.2%	39.8%
					48,229	66,475			129,287	55,363	73,924	1,998	55,363	75,922		
						114,704					129,287			131,285		

	Q = C	R = D	S = M	T = N	U = S/Q/12	V = T/R
	2013 Billing Determinants				2013 Proposed Rates	
	Fixed	Variable	Fixed	Variable	Fixed	Variable
	# of customers	kWh / kW	$ 000s	$ 000s	$/month	$/kWh or $/kW
Residential	176,865	1,423,857,475	30,546	21,334	14.39	0.0150
GS<50	17,703	612,188,101	9,321	8,132	43.88	0.0133
USL	2,942	10,383,027	319	179	9.03	0.0172
GS 50 < 499	3,950	6,142,022	3,652	28,978	77.05	4.7180
GS 500 < 4999	464	5,154,338	9,255	12,009	1,662.15	2.3298
Large Use	9	1,737,267	1,354	4,684	12,533.37	2.6963
Street Lighting	49,986	49,889	917	607	1.53	12.1694
			55,363	75,922		
				131,285		

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(107)

EB-2012-0033

Ontario Energy Board

IN THE MATTER OF the *Ontario Energy Board Act,* 1998, S.O. 1998, c.15, Sched. B, as amended;

AND IN THE MATTER OF an Application by Enersource Hydro Mississauga Inc. for an Order or Orders approving just and reasonable rates and other service charges for the distribution of electricity, effective January 1, 2013, and for the distribution of electricity, effective January 1, 2014.

Enersource Hydro Mississauga Inc.

Argument-In-Chief

September 17, 2012

116. The revenue-to-cost ratios are shown in Table 3 below, from Exhibit 7 Tab 1 Schedule 1, updated May 17, 2012. As shown in the table, all of the proposed ratios are within the Board approved range:

Table 3: Proposed 2013 Revenue-to-Cost Ratios

Customer Class	Revenue-to-Cost Ratio 2013 Test Year at existing rates	Revenue-to-Cost Ratio 2013 Test Year at proposed rates
Residential	85%	90%
General Service Less Than 50 kW	113%	109%
General Service 50 kW - 499 kW	112%	109%
General Service 500 kW - 4999 kW	108%	108%
General Service Large Use (> 5000 kW)	124%	109%
Street Lighting	96%	96%
Unmetered Scattered Load	147%	109%

Rate Design

7.1 Are the fixed to variable splits for each class for 2013 and 2014 appropriate?

117. Enersource is not proposing to adjust the fixed/variable split for each class from its current split. As per JT2.45, Enersource will allocate the transformer ownership allowance specifically to the customer class that is receiving the discount.

7.2 Is the proposed implementation of a Low Voltage Service Rate, the introduction of the Unmetered Scattered Load class, and the merger of the Small Commercial < 50kw class into the General Service < 50kw class appropriate?

Low Voltage Service Rate

118. Enersource currently records all costs related to LV to account 1550 and is proposing to create an LV rate to recover Hydro One's LV charges to Enersource from customers for the 2013 Test Year. The revenue generated from this new LV rate will be recorded to account 1550 to offset the Hydro One LV charges that are currently recorded in the same account.

119. Exhibit 8 Tab 6 Schedule 1 describes the forecasted LV charges for 2012 and 2013. Enersource requests approval to create a new rate equal to the 2012 and 2013 forecasted LV charge.

Unmetered Scattered Load

120. Enersource currently does not have a separate Unmetered Scattered Load ("USL") rate class. USL customers are currently included within the Small Commercial rate class. A new USL rate class has been included in the Revised Cost Allocation Model and proposed Tariff of Rates and Charges for the 2013 Test Year.

Merging of Classes

121. The removal of the USL customers from the Small Commercial rate class left few remaining customers within the Small Commercial class. Enersource proposes merging the Small Commercial rate class (excluding USL customers) with the General Service less than 50 kW ("GS<50 kW") rate class as these remaining Small Commercial customers are similar to GS<50 kW customers and have the same quantity threshold. Further, they are not sufficiently different from GS<50 kW customers in service setup, billing, collections, or meter reading profiles to require a separate rate class.

7.3 Are the proposed Total Loss Adjustment Factors appropriate?

122. Total distribution system losses are calculated by taking the total energy purchased over a year and dividing it by the total energy that was billed to customers during the same year.

123. Enersource's total loss factor ("TLF") for the past five years has averaged 1.0379. This TLF is higher than Enersource's current, and proposed, TLF of 1.0360. Enersource proposes excluding 2007 from the analysis as that year experienced an unusually high TLF. The more recent four years of historical actuals more accurately align with the current and proposed TLF.

124. As a result of this analysis, Enersource is proposing to continue with the current OEB-approved TLF of 1.0360 for Secondary Metered Customers <5000 kW for the 2013 Test Year. The TLF for Primary Metered Customers <5000 kW is calculated by multiplying the TLF for Secondary Metered Customers <5000 kW by 0.99.

125. Enersource proposes to continue to use a 1.0045 TLF for Primary Metered Customers >5000 kW and 1.0145 for Secondary Metered Customers >5000 kW.

7.4 Are the proposed retail transmission service rates appropriate?

126. Enersource's current RTSR rates, effective May 1, 2012, are reflected in Table 2 below, from Exhibit 8 Tab 2 Schedule 1.

(11c)

2013 RTSR

Enersource is not seeking to adjust its RTSR at this time. Enersource proposes to update its request for 2013 RTSR when the Board issues the updated Guideline and filing module to reflect the January 1, 2013 Uniform Transmission Rates.

(111)

ISSUE 8: DEFERRAL AND VARIANCE ACCOUNTS

(112)

ISSUE 9: MIFRS

Issue 9: notes 75
[1] Undertaking No. JT1.2

Additional References

(113)

ISSUE 10: SMART METERS

Issue 10: notes

Additional References

Undertaking J1.2
Exhibit I, Issue 4.1 Energy Probe IR #8
Exhibit I, Issue 4.1 VECC IR #36 (unmarked)
Exhibit I, Issue 4.1 Board Staff IR #36
Exhibit I, Issue 4.1, CCC IR #15
Exhibit I, Issue 10.1 Board Staff IR #67

(114)

Undertaking No. JT1.2

To determine, if the response to the previous undertaking is that there is data in previous cost allocation studies that go to demonstrate the difference between the meter classes costs, would Enersource use that data in order to recalculate the rider, the stranded meter rider, and if not then provide a reason why that would not be a good methodology to use. P. 23

Response:

Enersource's proposal to allocate the stranded meter disposition rate rider to the applicable customer classes based on the number of smart meters installed is consistent with the allocation methodology approved by the Board in Guelph Hydro Electric System Inc.'s 2012 cost of service application (EB-2011-0123).

Based on the information provided in JT 1.1 and assuming Run 2 is used as the basis of the allocation, the stranded meter rate rider would be as follows:

Table 1: Stranded Meter Disposition Rate Rider Based on Cost Allocation Model Run 2

	Residential	GS < 50 kW	GS > 50 kW	Total
Smart Meters Forecasted Installed at May 1, 2012	167,525	17,627	1,410	186,562
Tab I7.1 Meter Weighting (2006 CA Model Tab I7.1 Run 2)	1	9.16	35.96	
Calculation	167,525	161,463	50,704	379,692
Weighting	44.1%	42.5%	13.4%	100.0%
Stranded Meters Balance to be Recovered ($000s)	$ 3,369	$ 3,247	$ 1,024	$ 7,640
Number of Customers - 2013 Forecast	176,865	17,703	3,950	198,518
Rate Rider ($ per Customer/month)	**$ 1.59**	**$ 15.28**	**$ 21.60**	

(1/5)

Enersource Hydro Mississauga Inc.
Response to Interrogatories by Issue

Interrogatory # 8

Energy Probe Research Foundation
(Energy Probe)

4. Operating Costs

4.1 Is the proposed 2013 and 2014 OM&A forecast appropriate?

Ref: Exhibit 4, Tab 1, Schedule 6

a) Please provide a table for 2008 through 2013 showing the actual/forecast number of bulk meters replaced by individual meter suites as a result of the suite metering retrofit project. Please also show the number of additional individual meter suites as a result of this program for each year.

b) Please update the status of the installations of smart meters. Did Enersource complete installations for all eligible customers by the end of June 2012?

c) Please provide the most recent year-to-date costs available in the same level of detail as shown in Table 4 for 2012, along with the corresponding costs for the same period in 2011.

Response:

a) Please see table below which identifies the total cumulative number of actual / forecast individual suite meters and bulk meters removed.

Individual Meter Suite
Retrofits

Class	2008 Actual	2009 Actual	2010 Actual	2011 Actual	2012 Bridge	2013 Test
Residential Retrofits Added	0	0	796	127	250	250
Cumulative Residential Retrofits	192	192	988	1,115	1,365	1,615
Bulk Meters Replaced	0	0	3	0	1	1

b) As of the end of June, 2012, Enersource stood at 99.9% installed and 94.8% converted to TOU. Also at that point, Enersource had 683 mechanical residential meters and 653 GS<50 kW meters remaining to be installed. These remaining meters are the result of refusals, and access issues that are continually being

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Enersource Hydro Mississauga Inc.
Response to Interrogatories by Issue

Interrogatory #41

Vulnerable Energy Consumers Coalition (VECC)

4. Operating Costs
Issue 4.1 Is the proposed 2013 and 2014 OM&A forecast appropriate?

Reference: Exhibit 4, Tab 1, Schedule 6

a) Please identify all for 2008 through 2013 the OM&A costs that are related to suite metering.

b) Does Enersource account for suite metering costs separately?

Response:

(a) Enersource does not individually track OM&A costs relating to suite metering so it is not possible to provide the requested information. The only costs that are tracked separately related to suite metering are capital expenditures, which are provided in the table below.

Capital Program ($000s)	2008	2009	2010	2011	2012	2013
Smart Metering in New Condos	$ 1,680	$ 608	$ 970	$ 681	$ 977	$ 952

(b) See answer a) above.

(117)

Enersource Hydro Mississauga Inc.
Response to Interrogatories by Issue

Interrogatory #36

Board Staff

4. Operating Costs

Issue 4.1: Is the proposed 2013 and 2014 OM&A forecast appropriate?

Reference: E 4-T1-S6 p.6

Regarding the costs of inspecting (certifying) installed suite meters, Enersource notes that $141k will be incurred in 2012 and $211k in 2013. Enersource indicates that that in the calculation of its 2013 revenue requirement, it excluded $211k, from the 2013 Test Year OM&A costs, but included $88k, representing one quarter of $352k, the total one-time certification costs.

a) Are the meter inspections or certification costs for newly installed meters normally charged to OM&A or to capital?

b) Did Enersource request the establishment of a variance (or deferral) account to record the $141k in costs which will be incurred in 2012 for future recovery in 2013 and 2014?

c) Please explain why it is appropriate to charge ratepayers in 2013 and 2014 for meter inspection OM&A costs that were incurred in 2012?

Response:

a) Meter inspections or certification costs for newly installed meters are normally charged to capital. However, Enersource has 26 existing IMS buildings that were not previously inspected, and the meter inspections have to be completed to achieve Measurement Canada's SE-04 certification. Since those meter inspection (certification) costs are "one-time" in nature, they are charged to OM&A.

b) Enersource did not request the establishment of a variance account to record the one-time costs of $141 that will be incurred in 2012. Enersource believes that the costs would be expensed under IFRS and that it would simply seek recovery of the costs in 2013. Since the recognition of the expense and recovery of the costs would be occurring very close together there would be no need to charge interest on the account.

However, Enersource is still negotiating the contract for the certification work and has not incurred any expenses year-to-date June 2012. Enersource has also received an extension from Measurement Canada to perform the work over a three-year period. Enersource will remove the request for recovery and will be seeking approval of a deferral account to track the expenses and will seek recovery during its next cost of service rate application.

c) Prior to 2012, there were no clear rules or regulations explained to distributors regarding the need to inspect/certify installed suite meters. In 2012 Enersource was made aware by Measurement Canada that it was required to complete meter inspections to achieve SE-04 certification for existing IMS buildings.

As stated in response b) above, Enersource will be requesting a deferral account to track the expenses instead of seeking recovery at this time.

Enersource Hydro Mississauga Inc.
Response to Interrogatories by Issue

Interrogatory # 15

The Consumers Council of Canada
(CCC)

4 Operating Costs

4.1: Is the proposed 2013 and 2014 OM&A forecast appropriate?

Reference: (4/T1/S4/p. 4)

Has the most recent Toronto Hydro-Electric System Limited Decision regarding suite meters impacted the way in which Enersource intends to deal with suite metering? If so, how? If not, why not?

Response:

Enersource is aware of the Board's recent decision relating to the creation of a new suite metering residential class for Toronto Hydro, however has not had enough time to fully undertake an in-depth analysis of this decision.

Enersource Hydro Mississauga Inc.
Response to Interrogatories by Issue

Interrogatory #67

Board Staff

10. Smart Meters

Issue: 10.1 - Is the proposed treatment of stranded meter costs appropriate?

Reference: E9/T2/S2 – Stranded Meters

A copy of Table 3 from Exhibit 9/Tab 2/Schedule 2 is shown below:

	Residential	GS < 50 kW	GS > 50 kW	Total
Smart Meters Forecasted/Installed at May 1, 2012	167,525	17,627	1,410	186,562
Smart Meters Installed as a Percentage of Total	89.80%	9.40%	0.80%	100.00%
Stranded Meters Balance to be Recovered ($000s)	6860	722	58	7640
Number of Customers - 2013 Forecast	176,865	17703	3950	198,518
Rate Rider ($ per Customer/month)	$3.23	$3.40	$1.22	

Enersource is proposing to recover the remaining net book value of stranded meters through class-specific stranded meter rate riders. For an allocator of the stranded meter costs, Enersource is using the number of smart meters installed in each class, as a percentage of total smart meters installed.

Table 4 of Exhibit 9/Tab 2/Schedule 1 shows that Residential Smart Meters capital costs are about $160/meter, while those for GS < 50 kW customers and for GS > 50 kW customers average about $500/meter and $540/meter, respectively. Board staff acknowledges that these include installation costs as well as the costs of the meters.

a) For the stranded conventional meters, please explain whether the cost per meter differs between Residential, GS < 50 kW and GS > 50 kW customer classes. This may be due, in part to the specifications and manufacture of meters (e.g., single-phase versus polyphase meters, maximum demand rating, etc.).
b) What is Enersource's rationale for using the number of smart meters installed as the allocator for stranded meter costs?
c) Please confirm whether the value of stranded meters by customer class is available, or a suitable proxy from, for example, Enersource's prior cost allocation studies.