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BY EMAIL

June 28, 2012

Ms. Kirsten Walli
Board Secretary
Ontario Energy Board
P.O. Box 2319
2300 Yonge Street, Suite 2700
Toronto ON M4P 1E4

Dear Ms. Walli:

Re: Enersource Hydro Mississauga Inc.
Application for Rates
Board File Number EB-2012-0033

In accordance with Procedural Order No. 1 issued on June 14, 2012, please find attached the Board Staff Interrogatories on the cost of service rate application filed by Enersource Hydro Mississauga Inc.

Yours truly,

Original signed by

Richard Battista
Project Advisor, Applications & Regulatory Audit

June 28, 2012

Board Staff Interrogatories
Enersource Hydro Mississauga Inc.
2013-2014 Electricity Distribution Rates
EB-2012-0033

GENERAL

Letters of Comment

1. Ref: Notice of Application
   Following publication of the Notice of Application, did Enersource receive any letters of comment? If so, please confirm whether a reply was sent from the applicant to the author of the letter. If confirmed, please file that reply with the Board. Please ensure that the author's contact information except for the name is redacted. If not confirmed, please explain why a response was not sent and confirm if the applicant intends to respond.

Conditions of Service

2. Ref: E1-T1-S11
   Please identify any rates and charges that are included in the applicant's conditions of service, but do not appear on the Board-approved tariff sheet, and provide an explanation for the nature of the costs being recovered.

Updated RRWF

3. Upon completing all interrogatories from Board staff and intervenors, please provide an updated RRWF with any corrections or adjustments that the applicant wishes to make to the amounts in the previous version of the RRWF included in the middle column. Please include documentation of the corrections and adjustments, such as a reference to an interrogatory response or an explanatory note.

Updated Revenue Requirement

4. Upon completion of responses to all interrogatories, please identify any adjustments to the proposed service revenue requirement that the applicant wishes to make relative to the original application.

Filing Requirements

5. Ref: E1-T1-S1
   The Board in a letter dated January 26, 2012 identified those electricity distributors, which included Enersource, which it expected to file a cost of service application for 2013 rates. In this regard the Board indicated that applicants that wished to request cost of service rates effective January 1,

2013 should file their applications sooner, and no later than April 27, 2012. The Board also expected that distributors filing applications in advance of any revisions to the Filing Requirements for Transmission and Distribution Applications would update their applications in due course to address any material changes that may be reflected in the revised Filing Requirements.

The Board on June 28, 2012 issued the filing requirements for 2013.

Please complete and file the following appendices, in addition to any others specifically identified in the interrogatories that follow:
2-A, 2-CA, 2-CB, 2-CC, 2-CD, 2-D, 2-EA, 2-F, 2-L, 2-M and 2-N.

6. Ref: E1-T1-S1
The Board's Conservation and Demand Management ("CDM") Guidelines for Electricity Distributors (EB-2012-0003) at page 3 notes that: "At a minimum, distributors must apply for disposition of the balance in the LRAMVA at the time of their Cost of Service rate applications. Distributors may apply for the disposition of the balance in the LRAMVA on an annual basis, as part of their Incentive Regulation Mechanism rate application, if the balance is deemed significant by the applicant." Board staff acknowledges that the final, verified results for Enersource's 2011 OPA-Contracted Province-Wide CDM programs are not currently available.

   a) Does Enersource plan to update its evidence to indentify and/or seek disposition of variances between the final results of its 2011 CDM programs and the CDM savings included in Enersource's 2011 load forecast in this proceeding after it has received the final results from the OPA?
   b) What is Enersource's plan for disposing of its LRAMVA in future applications?

7. Ref: E1-T2-S2 Appendix 2-C(i) p. 8
Please confirm whether or not the forecasted 2013 Distribution Revenue of $114,703,938 (forecasted load at current rates) in the RRWF includes any receipts from the Smart Meter rate adder. If so, what is the amount and please re-run the RRWF for 2013 excluding the Smart Meter rate adder from the calculation.

Issue 1.1 - Is the proposed approach to set rates for two years appropriate?

8. Ref. E1-T2-S1 p3-6
   a) When finalizing its plans for 2014 rate setting, did Enersource consider the IRM-Incremental Capital Module (ICM) approach? If not, why not?
   b) Did Enersource prepare an analysis that compared the approach proposed in this application with the IRM-ICM one? If so, please provide it.

c) Please indicate the primary purpose of the alternative approach proposed by Enersource (as compared to IRM-ICM). For example is it rate smoothing or the generation of adequate returns on capital investments?
d) What adjustments to Enersource's 2015 IRM-ICM application would be required in the event that: (i) the final model that results from the Renewed Regulatory Framework for Electricity is not materially different from the IRM-ICM and (ii) the Board approves Enersource's 2014 rates based on its proposed alternative approach?
e) Enersource at p.6 states that if its 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.

   In that Enersource's 2013 OM&A shows an increase as compared to 2012, what are the two years where OM&A will be held flat?

9. <u>Ref. E1-T2-S1</u>
   Enersource refers to the 2014 as the "Incremental Capital and Return ("ICR") year and to 2013 as the Test Year.

   Please confirm that the 2014 ICR rates as proposed in this application replace any future application Enersource would have filed for 2014 rates under either the Incentive Regulation Mechanism ("IRM") or the IRM Incremental Capital Module ("ICM") frameworks.

10. <u>Ref: E1- T1- S1 p3</u>
   The evidence states that "The Board's current rate setting model has resulted in nominal rate increases via incentive regulation mechanism ("IRM") since Enersource's last COS rate application for the 2008 rate year. During this period, Enersource has continued to invest in essential capital infrastructure in order to deliver on the Company's mission to consistently fulfill and exceed customer needs and stakeholder requirements".

   Please provide the nominal increase (expressed as a %) for each of 2009, 2010, 2011 and 2012.

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

11. 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?

RATE BASE

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

12. Ref: E 2- T2-S5 p.12 Table 1
    Please provide the report and/or working papers that support the results presented in the Summary of Proposed Alternatives for the Enersource Administration Office Accommodation Study.

13. Ref. E1-T2-S1 p.4 Table1
    In Table 1 Enersource shows the annual investments in capital and the resulting changes in revenue requirements for each of the IRM years, 2009-2012.

    Does the indicated revenue requirement change calculation shown in Table 1 reflect the impact of customer growth during the period and any operating efficiencies and other benefits associated with the capital invested during the period? If not, please re-do the revenue requirement calculation to include these elements.

Issue 2.2 - Is the proposed Working Capital Allowance for 2013 and 2014 appropriate?

14. Ref: E2-T1-S4 Appendix 1
    In the introduction of the Lead-Lag Study, it is stated that “This report is based on 2007 historical data and adjusted for anticipated changes to determine the appropriate working capital requirement for the 2010 Test Year.”

    a) Please confirm that 2010 Test Year was an IRM year, and that matters related to working capital did not affect the rates approved in that proceeding.
    b) Why haven’t any adjustments been made to the study to reflect “anticipated changes” associated with the 2013 Test Year?

15. Ref: E2-T1-S4 Appendix 1 p. 2-4
    In determining the Revenue Service lag, the study states that residential and selected small commercial meters are read bi-monthly and that related changes to Time of Use billing (TOU) have not be factored into the calculation.

    Please update the Revenue Lag analysis reflecting current billing, service, collections and payment processing practices, including the impact of Smart Metering.

16. Ref: E2-T1-S4 Appendix 1 p.19
At the bottom of Table 19, "Cash Working Capital" as a % of OM&A is shown as 13.5%. Please confirm that this should read "Cash Working Capital and Cost of Power".

Issue 2.3 - Is the proposed Green Energy Act Plan appropriate?

17. Ref: (a) Filing Requirements[1], Part V, Section 1, bullet 3;
(b) E2-T2-S3 Appendix1 p.11-13/ 4.2 Infrastructure Projects and Activities;
(c) E2 -T2-S3 Appendix1 p.7-8/ 3.4 Expenditures Related to Renewable Generation Connections

With regards to the current assessment of the distributor's system, Reference (a) points to the need for:

> The identification of any expenditures (capital or OM&A) related to renewable generation connection that are already included in the distributor's approved capital plans, funded through current rates (including any approved rate riders or adders) or tracked in deferral accounts;

At reference (b) Enersource discusses system expansion and points to various REI projects that it is carrying out or planning to undertake, including works related to substation equipment and protection, underground system rebuilds, and overhead system expansions. Reference (b) also discusses offers-to-connect, highlighting the possible capital contribution that Enersource may incur in connection to expansion works. In particular, Table 4 shows what Enersource would have had to pay if two offers were exercised. Reference (c) seems to suggest that the implementation of the GEA plan has given rise to very specific actions and it appears that the implementation of the GEA plan is driving, among other things, process changes at Enersource. Reference (c) also highlights the additional human resources that have supplemented Enersource's current workforce to implement the GEA plan, namely 2 co-op interns, an independent engineer field inspector, and a contracted services engineering firm.

a) As per reference (a), are any of the expenditures related to renewable generation connection already included in Enersource's asset management plan, funded through current rates, or tracked in deferral accounts?
b) Where applicable, if costs related to renewable generation connection are reflected in other schedules in the application, please cross-reference them.

[1] This plan was filed using the 25 March, 2010 version.

c) With respect to references (b) and (c), under which plan, namely asset management or GEA, does Enersource foresee the cited REI, expansion (offer-to-connect) and process activities?
d) Please indicate the driver behind these activities namely renewable generation connection or normal distribution work.
e) Where applicable delineate activities appropriately along asset management plan or GEA plan lines and provide an estimate of OM&A and capital expenditures related to the implementation of the GEA plan for the 5-year period.

18. <u>Ref: (a) E2-T2-S3 Appendix1 p.11/ 4.2.1 Renewable Enabling Improvements;
(b) Distribution System Code, Section 3.2.5B;
(c) E2-T2- /S3 Appendix 1 p.13/ 4.2 Infrastructure Projects and Activities/ Table 5;
(d) E2-T2-S3 Appendix1 p.14/ 4.2.3 Continuing Capital Expenditures;
(e) Filing Requirements: Distribution System Plans – Filing under Deemed Condition of Licence, issued March 25, 2010 [EB-2009-0397].</u>

There are no smart grid activities associated with Enersource's filed GEA plan.

At reference (a) Enersource discusses overhead system expansions, stating that:

> Overhead system expansion; additional circuits will be installed that will provide more opportunity for renewable generation connections by providing increased access to Hydro One transformer stations and Enersource substations that have capacity available for generation connections as required.

At reference (b), the Distribution System Code clarifies that for expansions: if the expansion is identified in a Board-approved plan or is otherwise approved or mandated by the Board, the distributor is responsible for 100% of the costs; and in all other cases, the distributor is responsible for the costs up to the "renewable expansion cost cap" ($90,000 per MW of capacity of the connecting generator) and any amount above that cap is the responsibility of the generator.

Reference (c) states:

> The Enersource contribution for each Offer-To-Connect project is required as per the DSC under Section 3.2.5B, "a distributor shall not charge any of the requesting generators to construct the expansion" up to $90,000 per MW of generation. The capital cost of the project over and above the $90,000 per MW of generation is funded by the customer. Although no Offer-To-Connects have been accepted to date, Enersource does anticipate that there will likely be 1-2 projects per year that will require a capital contribution by Enersource.

Furthermore, when an Offer-To-Connect is accepted by a customer, there will likely be a requirement for contribution from the customer for the system expansion. The forecasted customer contributions for the next 5 years are shown in the table below.

Cost Type	2011 (Actual)	2012	2013	2014	2015	2016
Capital Costs Funded By Others (Customers)	$0	$107,000	$133,000	$160,000	$187,000	$213,000

Table 5 – Forecasted Capital Contribution by Others (Customers)[7]

Reference (d):

Cost Type	2011 (Actual)	2012	2013	2014	2015	2016
Capital Costs Funded By Enersource	$197,413	$133,000	$183,000	$219,000	$256,000	$293,000

Table 6 – Forecasted Capital Expenditures by Enersource[8]

a) Please confirm that Enersource does not foresee undertaking any smart grid eligible activities over the 5-year plan period. Briefly explain.
b) Please clarify whether “overhead system expansion” at reference (a) is classified as REI or Expansion or perhaps a mix of both categories as per the *Filing Requirements* nomenclature.
c) Please confirm that all expansions identified fall in the category where costs are jointly shared by Enersource and renewable generators.

   If not, would any of the capital contributions identified in Table 5 relate to project that might not fall in section 3.2.5B (b) of the Distribution System Code? Namely, would some of the identified future expansions arise from the connection of more than one renewable generation facility? Would some of the expansions foreseen be almost a certainty because of the size of the FIT project or the project’s synergy with another activity such as an agricultural expansion or to accommodate a new subdivision?
d) If the level of certainty of a percentage of expansion work materializing is high, please explain why Enersource is choosing not to have those approved in its current GEA plan.
e) If applicable please revise capital expenditures at reference (d) accordingly, and file that revision, indicating whether or not Enersource intends to apply for cost recovery of the Green Energy related qualifying costs, as set out in pages 20-22, “Section VI. GEA Plan Approval”, of reference (e), in this cost of service application, or alternatively in the next cost of service application.

19. <u>Ref: Exhibit 2/Tab2/Sch3/Appendix1/p.14/ 4.3 Direct Benefits to Customers; (b) Report of the Board, Framework for Determining the Direct Benefits Accruing to Customers of a Distributor under Ontario Regulation 330/09, Paragraph 1.1, Regulation 330/09; (c)Exhibit 2/Tab2/Sch3/Appendix1/p.8/ 3.4 Expenditures Related to Renewable Generation Connections; (d) Exhibit 2/Tab2/Sch3/Appendix1/p.11/ 4.2.3 Continuing Capital Expenditures; (e) Filing Requirements, Part VII, Capital and OM&A Deferral Accounts for Renewable Generation Connection or Smart Grid Development; (f) Report of the Board, Framework for Determining the Direct Benefits Accruing to Customers of a Distributor under Ontario Regulation 330/09, Paragraph 3.2.2.3, Basic Benefit Assessments For Basic GEA Plans; (g) Filing Requirements: Distribution System Plans – Filing under Deemed Condition of Licence, issued March 25, 2010 [EB-2009-0397].</u>

In spite of the implementation of the GEA plan and evidence regarding REI and expansion work, reference (a) states that:

> Enersource has not undertaken any projects where costs may be recovered from provincial ratepayers, and does not forecast any projects in this category during the next 5 years.

With respect to reference (b), on OM&A costs, the *Framework for Determining Direct Benefits* clarifies that:

> There is therefore a relationship between the eligible investments costs and the associated direct benefits. […]
>
> “Eligible investment” costs, as set out in O. Reg. 330/09 and section 79.1 (5) of the Act, are not limited to only the initial capital investment costs but also include the *up-front* OM&A costs necessary for the purpose of “enabling the connection of a qualifying generation facility”. However, given that section 79.1 focuses solely on the initial investment, ***ongoing OM&A costs that are incurred by the distributor after the investment has been made will <u>not</u> be eligible for provincial recovery.[emphasis added]***

Reference (c) suggests that initial OM&A costs in relation to the implementation of the GEA plan have been incurred, highlighting that :

In addition to increasing the workload of the pre-existing Customer Engineering team, Enersource has also added the following resources:

- 2 co-op intern Engineering students […]
- A contracted independent Professional Engineer Field Inspector […]
- A contracted Services Engineering firm […]

Enersource is currently supporting the FIT Program with its existing staff compliment and the additional resources as outlined above. It has incorporated the associated costs during the course of annual budgeting.

OM&A costs associated with the implementation of the GEA plan are generally not reflected in Enersource's current plan. At reference (d):

> Enersource will continue to connect generation projects as is required under the DSC. In order to achieve this, Enersource will require continued expenditures in the areas previously identified in section 3.4. This includes the Customer Engineering team as well as the additional resources such the two co-op students, Field Construction Inspector and Service Engineering company. The forecasted costs associated with this are shown in the table below.

Reference (e) points to the various accounting instruments twinned with the GEA Plan.

Reference (f) outlines the methodology for deriving direct benefits.

a) Please explain why costs referred to at reference (d) are not taken into account to derive direct benefits accruing to Enersource's ratepayers.
b) Please indicate whether capital expenses at table 6 of reference (d) would normally generate associated OM&A.
c) Based on the above, please reconcile the statement at reference (a) with the evidence at references (c) and (d).
d) Keeping in perspective reference (e) please explain why Enersource is choosing not to utilize the various accounting instruments at its disposal.
e) Enersource's GEA plan does not indicate how the distributor will recover costs strictly associated with the implementation of the plan. Please explain why Enersource is choosing not to follow the methodology outlined in the *Framework* at reference (f) given that it is a non-discretionary step where it is applicable.
f) If the noted requirement in Question e above is applicable, please include a direct benefits calculation arising from REI and expansion work that are primarily generated by the connection of renewable generation.
g) If the answer to Question f above is affirmative, please confirm that Enersource would be recording the costs as described on pages 22 and 23 of reference (g).

20. <u>Ref:(a) E2-T2-S3 Appendix 1 p.7/ 3.3 Constraints on Ability to Connect Renewable Generation;</u>
<u>(b) E2-T2-S3 Appendix1 p.14 -15/ 4.5 Consultation with Transmitter;</u>
<u>(c) E-2/T2/S3 Appendix 2 p.4/ OPA Letter _Upstream Transmission Constraints</u>

Various segments of the GEA plan seem to indicate that there are upstream system constraints as illustrated in references (a) and (b). Reference (a) states in part that:

> Although a significant number of projects have already been connected to the Enersource system, there are, however, a number of constraints that exist that will limit the amount of renewable generation facility connections. The upstream

> transmitter, Hydro One, has placed a number of restrictions to their transformer station feeders based on the thermal ratings and the short circuit capacity of the relevant equipment in accordance with limits set forth in the Transmission System Code (TSC). To determine if capacity is available on a given Hydro One transformer station feeder, the Hydro One "Station & Feeder Capacity Calculator"[2] is used.

Reference (b) states in part that:

> Enersource has a strong working relationship with its upstream transmitter, Hydro One, and has consulted with them on a series of issues raised by the FIT Program. One discussion initiated by Enersource was with respect to the capital upgrades that would be required to enable renewable generation at capacity constrained transformer stations. This included estimates in order to upgrade equipment to a higher rating or to install transformers with a higher impedance to reduce short circuit levels present at the station. […]
>
> Another area that Enersource has requested further clarification by Hydro One is a secondary review of the restrictions placed on capacity constrained transformer stations. This information was also shared with Enersource's renewable generation customers to help them understand the challenges that exist in the system. This demonstrates Enersource's commitment to servicing its customers and enabling renewable generation.

The OPA letter at reference (c) seems to run contrary to Enersource's assessment with respect to system constraints, stating that :

> There are no currently known upstream transmission constraints applicable to Enersource's service territory.

Please reconcile the statement of the OPA at reference (c) with the Enersource's account regarding system constraints.

OPERATING REVENUE

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

21. Ref: E3-T1-S1 and E3-T1-S2
The Load Forecasting evidence in E3/ T1 /S1 and S2 contains the terms "energy consumption", "system energy consumption" and "energy purchases" and the term Sales by Rate appears in the attachments 2-6 in E3-T1-S1 (a footnote in the attachment reads " Sales figures above includes losses").

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[2] "Station & Feeder Capacity Calculator", retrieved from http://www.hydroone.com/Generators/Pages/StationCapacityCalculator.aspx on April 03, 2012

a) Are the terms “consumption” and “purchases” interchangeable? If they are not, how do they differ for purposes of calculating the load forecast?
b) Please confirm/clarify that the footnote in attachments 2-6 “Sales figures above includes losses” means that the numbers presented in the tables are not intended to reflect the impact of distribution losses and so are not equivalent to what is usually described as “billed” volumes…. i.e. the numbers in the Distribution Revenue starting at E3-T-1 p. 6 are taken to be billed volumes.

22. <u>Ref: E3-T1-S2 / Attachment 1(p. 24-27) and E3-T1-S2 p.2 Table 1</u>
Please show annual sub-totals of actual and weather-corrected energy, to enable comparisons with other tables that show annual amounts.

Are the amounts in Attachment 1 gross of CDM results during the years of data, or inclusive of CDM?

If gross of CDM, what were the annual CDM results that were used to go from actual data to the data used in the analysis?

23. <u>Ref: E3-T1-S2 Tables 1 and 2</u>
It appears that Enersource’s peak demand has been growing more quickly than its energy consumption.

a) Please show the annual load factor in recent years -- i.e. kWh / 8760/ annual peak demand.

   If there is a trend, does Enersource expect it to continue into the future?

b) Does Enersource consider that its CDM programs have been more successful with energy consumption than with curtailing peak demand? Please explain.

24. <u>Ref: E3-T1-S2 p.2 Table 1</u>
Please demonstrate the adjustment from actual to weather -corrected MWh for one of the years in the table, in other words, actual CDD and HDD, normal CDD and HDD, and coefficients.

a) CPI is presented as an economic driver, eg E3-T1-S 2 Attachment B on p.17. Please confirm that CPI is consumer price index, and explain why it would be considered an economic driver of energy consumption.
b) Please provide a definition of Employment Lands.

25. <u>Ref: E3-T1-S2</u>
a) Please provide a definition of the regression statistics AIC and BIC.

b) Please provide a brief explanation of why most of the regression models have a number of iterations, rather than a simple regression of energy on the independent variables.
c) Please provide a definition of the independent variables AR(1), AR(2), and SMA(1).
d) Please explain why the negative coefficients of population is a credible result for the total system (Attachment 1) while positive for the residential class (Attachment 3) and not included for other classes. Alternatively please provide a regression for the system in which population is omitted.
e) Please explain why the negative coefficients of HDD and CDD are a credible result for the Large User class, or alternatively please provide a regression in which those variables are omitted (similar to the GS 500-4999 model).

26. Ref: E3-T1-S2 Attachment 3
a) Please provide a version of the table in which consumption is shown on a per-customer basis.
b) If there is a trend in consumption per customer for any of the classes, please explain if or how the regression results in the corresponding Attachment reflect such a trend, and how (or if) the load forecast reflects any such trend in per-customer consumption.

27. Ref: E8-T8-S1 Appendix 2-U
Please provide the underlying methodology and specific calculation used to generate the forecasted number of customers at year end for each customer/connection class for 2012 and 2013 shown in the table below. For purposes of this interrogatory, it is assumed that "the "start of test year" equates to "end of year "for 2012.

Rate Class	Customers/ Connections	Number of Customers/Connections		
		Start of Test Year	End of Test Year	Average
Residential	Customers	175,874	177,856	176,865
GS < 50 kW	Customers	17,580	17,825	17,703
Unmetered Scattered Load	Connections	2,943	2,940	2,942
GS 50 to 499 kW	Customers	3,948	3,951	3,950
GS 500 to 4,999 kW	Customers	464	464	464
Large Use	Customers	9	9	9
Streetlighting	Connections	49,736	50,235	49,986
				-
				-
				-
				-
				-
Total		250,554	253,280	251,919

28. Ref: E3-T2-S1 & E3 /T1/ S2
E3-T2-S1 p.26 attachment 11 and E3-T1-S2 attachment 6 both provide data on historical and forecast average number of customer/connections. In some cases the numbers differ. For example the 2013 forecast for average number of customers shows 176,865 in attachment 6 while the number shown in attachment 11 is 177,070. Please provide the rationale for using different numbers?

29. Ref: 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.

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

30. Ref. E1-T2-S1 p.16
Enersource updated its evidence on May 17, 2012 to reflect the 2012 IRM Decision (EB-2011-0100). In the updated evidence Enersource indicates that it is seeking approval to charge applicable customers for actual incremental costs incurred by Enersource in non-standard installation and reading of smart meters, and related non-standard communication infrastructure.

Please provide the reference in the EB-2011-0100 that supports this request.

OPERATING COSTS

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

31. Ref: E1-T2 -2
Did the budget preparation guidelines and instructions used to prepare the OM&A expense forecast prescribe the rate of inflation that should be assumed for 2013 and 2014? If so, please indicate the rate and the source. If not, please explain why not.

32. Ref: 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.

33. Ref: E 4-T1-S9 p10
Enersource indicates that the Information Solutions and Technology Services ("ISTS") Division it will be adding three new positions in 2013 that relate to Enersource's customer self service initiative (via Enersource's internet site) and low income account management initiative.

Did Enersource reduce the customer care/customer service budget for 2013 to reflect the reduction in call volumes due to the customer self serve initiative? If so, please indicate the amount of the reduction.

34. Ref: E 4-T1-S1 p2 12 Table 1
The 2008 OM&A for 2008 rates is shown as $41,635,000. Enersource notes that this is $1,177,000 higher than the amount agreed to in the 2008 Settlement agreement.

What is the level of OM&A underpinning the 2008 Board approved rates. If this differs from $41,635,000 please explain the purpose of this adjustment. Was a similar adjustment made to the other years presented in the table?

35. Ref: E 4-T3-S1 Appendix 2-K p.1
For 2013, forecasted salaries and wages costs for 2013 total $24,627,194 and forecasted benefits costs total $ $12,104,674. This compares to $21,374,755 and $8,519,788 respectively in 2008 actual.

a) Please confirm that the percentage ratio of benefits to salaries and wages has increased from about 40% in 2008 to 49% in 2013.
b) Please elaborate on the actions taken by Enersource since 2008 to contain or moderate the marked increase in benefits to salaries and wages cost ratio.

36. Ref: 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?

37. Ref: E 4-T1 Appendix 2-1
The table below sets out headcount numbers presented in the evidence.

Headcount	2008	2008	2009	2010	2011	2012	2013
	Brd Appr.	**Actuals**	**Actuals**	**Actuals**	**Actuals**	**Actuals**	**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.

38. Ref: E1-T2-S2 p.4

Enersource states that Compensation estimates are based on the four-year collective agreement ("Collective Agreement") between Enersource and the International Brotherhood of Electrical Workers ("IBEW"), and include annual increases in OMERS contributory earnings, benefits, and statutory employment contributions. The Collective Agreement became effective April 1, 2010 and is set to expire on March 31, 2014. It provides for increases of 3.00% in the first and second years of the Collective Agreement and 3.25% in the third and fourth years.

Please clarify whether the aforementioned was used to also forecast compensation for non IBEW employees, including Enersource Corporation employees whose costs are allocated to or shared with Enersource. If the aforementioned was not used, please provide the compensation basis that was utilized.

Issue 4.2 - Is the proposed level of depreciation/amortization expense for 2013 and 2014 appropriate?

39. Ref: E1-T2-S2 p.8 and E1-T3-S1 p.5-6

At E1-T2-S2 p.8 Enersource states that the Finance department, in collaboration with business unit managers, evaluates each capital expenditure against the expected useful lives of each asset type to determine the annual depreciation expense to include in the budget.

Please clarify whether this evaluation adds an element of discretion as to the amount of depreciation that will be recorded in any given year. And if this is the case, where do the useful lives adopted by Enersource, which are described as consistent the Asset Depreciation Study for the Ontario Energy Board (prepared by Kinectrics) and cognizant of Enersource Corporation, Burlington Hydro, Oakville Hydro, Halton Hills, Hydro & Milton Hydro Useful Life of Assets, dated December 10, 2009, fit in this evaluation

Issue 4.3 - Is the proposed PILs and property taxes forecast for 2013 and 2014 appropriate?

40. Ref: E4-T7-S1 Appendix 1; E2-T1-S1, Appendix 2-B; E4-T6-S1, p.4
On the Continuity of Reserves Schedule in the PILS model (p.7, 15, 22), total reserves include a reserve for accrued employee future benefits. Please clarify and explain the nature of this reserve.

Board staff noted the following differences between the PILS model and various information filed in the application:

On page 9 of the PILS model, 2011 amortization of tangible assets is $36,772,000. On the 2011 Depreciation Expense schedule, depreciation expense is $27,833,000.

a) Please explain what the difference between the two amortization amounts is due to. Please adjust the PILS model as necessary.
b) On page 13 of the PILS model, 2012 additions are $58,942.000. On the 2012 Fixed Asset Continuity Schedule, 2012 additions excluding land is $59,486,000 ($64,486,000-$5,000,000). Please explain and reconcile the difference between the two “addition” amounts, and make adjustments to the evidence as necessary.
c) On page 20 of the PILS model, 2013 additions are $44,120,000. On the 2013 Fixed Asset Continuity Schedule, 2013 additions excluding land rights/easements is $44,446,000 ($46,466-$2,000,000). Please explain and reconcile the difference between the two “addition” amounts, and make adjustments to the evidence as necessary.

41. Ref: E4-T7-S1, Appendix 2 and E2-T1-S1, Appendix 2-B, p.8
Board staff noted the following in the PILS model and various information filed in the application:

a) On page 4 of the PILS model, 2014 additions are $45,351,000. On the 2014 Fixed Asset Continuity Schedule, 2014 additions are$45,624,000. Please explain and reconcile the difference between the two “addition” amounts, and make adjustments to the evidence as necessary.
b) On page 6 of the PILS model, a cumulative eligible capital (CEC) deduction of $1,063,000 is included as a deduction. Please provide the rationale for such an inclusion when the prior year’s deduction has been used in 2013 and there are no new CEC additions in 2014 per the 2014 Fixed Asset Continuity Schedule. Please make adjustments to the evidence as necessary.

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

42. Ref: E4-T4-S1, p.16 Table 3 and Appendix 2-L
Enersource indicates that Enersource Corporation (EC) provides corporate governance, and administrative and operational services including Finance,

HR, Corporate Relations, Internal Audit, and Purchasing on a cost recovery basis. Of the forecasted $11,664k in test year costs, about 93.4% or $10.874k is allocated to Enersource. This compares to the about 84% that was allocated to Enersource in 2008 board approved. Enersource notes that beginning in 2009 the method of allocating costs was revised to better align with the services being provided to each affiliate based on budgeted headcount or as a percentage of revenue.

a) What was the method used to allocate costs prior to 2009?
b) Please provide any reports or studies which were used to assess and/or support the appropriateness of the change introduced in 2009.

43. <u>Ref: E4-T4-S1 Appendices 1-5 and Appendix 2-L</u>
The Appendices at E4/T4/S1 contain the following 5 Services Agreements:

(i) Enersource Technologies Inc. (Provider) and Enersource (Customer)
(ii) Enersource Corporation (Provider)and Enersource (Customer)
(iii) Enersource (Provider) and Enersource Hydro Mississauga Services Inc. (Customer)
(iv) Enersource Hydro Mississauga Services Inc. (Provider) and Enersource (Customer)
(v) Enersource (Provider) and Enersource Corporation (Customer)

Do the Tables set out in Appendix 2-L capture all of the financial costs and revenues, if applicable, of transactions and/or services covered by the aforementioned 5 Services Agreements?

If not, please update the Tables to capture all the transactions between Enersource and its affiliates.

COST ALLOCATION

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

44. <u>Ref: E7-T1-S1 p.9</u>
The initial application of the 2013 Cost Study results in 2 Revenue to Cost ratios that fall outside the Board’s required ranges. Enersource indicates that it was necessary to reallocate revenues among all rate classes and proposed to re-balance all classes to within 10% of unity.

Please explain the basis for choosing 10%. Were any other percentages considered?

Issue 6.2 - Are the revenue-to-cost ratios for 2013 and 2014 appropriate?

45. Ref: E7T1/S1 p8 Table 1 and p. 10 Table 3
The Table below sets out the Revenue to Cost ratios per the 2008 Settlement and as proposed for 2013.

REVENUE TO COST RATIOS

in %	2008 Settlement	2013 Proposed	Board Target
Residential	91.50	90.00	85-115
Small Commercial < 50kW	111.00	na	na
GS < 50kW	111.00	109.00	80-120
GS 50kW- 499kW	111.00	109.00	80-120
GS 500kW - 4999 kW	91.50	108.00	80-120
GS Large Use (> 5000kW)	111.00	109.00	85-115
Street lighting	91.50	96.00	70-120
Unmetered Scattered Load	na	109.00	80-120

There does not seen to be a material change (move toward unity) for a number of classes, and for the Residential class there is a move away from unity.

a) Please explain why Enersource is proposing to reduce its 2013 Residential Class Revenue to Cost ratio from 91.5% to 90.0%
b) Are there any other reasons, other than the proposed Revenue to Cost ratios are within the Board's ranges, that support Enersource decision to not re-balance Revenue to Cost ratios for 2013 which would result in a more material move toward unity?
c) Please prepare a Residential class @ 800 kWh bill impact (using Appendix 2-template) that reflects a change in the 2013 Revenue to Cost ratio from 90% to 95%.

DEFERRAL AND VARIANCE ACCOUNTS

Issue 8.1 - Are the deferral and variance account balances, allocation methodology and disposition period(s) appropriate?

46. Ref: E9-T1-S1 p.12-17 and E1-T3-S1, Appendix 1, p.4
Enersource has used the 2009 PST Eligible Operating Expenses of $4,527,000 as the proxy of July 2010 to December 2012 PST savings. This is approximately 10% of the $47,267,000 operating, maintenance and administrative (OM&A) expenses reported on the 2009 financial statements.

a) Please provide clarification and details on how the 2009 PST Eligible Operating Expenses correlate to the 2009 OM&A per the financial statements.

   Please update the evidence as necessary.

b) Enersource has estimated $154,000 and $257,000 of estimated savings on capital costs for 2011 and 2012. Please elaborate further on how these amounts were calculated.

47. Ref: E9-T1-S1, p.5-6
Enersource is seeking disposal of DVA balances as at December 31, 2011 and the forecasted interest through to December 31, 2012. Enersource is requesting the disposal of $1,589,000 for Account 1508- Other Regulatory Assets – Sub-account Deferred IFRS Transition Costs for one-time administrative incremental IFRS transition costs not already included for recovery in its rates.

    Please explain why forecasted costs in 2012 are included in the requested disposition amount.

48. Ref: E9-T1-S1
Group 1 Accounts proposed for disposition includes a credit of $7,959,846 for account 1580 Wholesale Market Service Charge. Are any of Enersource's customers wholesale market participants? If so, would it be appropriate to calculate a separate rate rider for the subset of customers who are market participants that would exclude the disposition of account 1580 and perhaps 1588? If so, please provide updated rate rider calculations for the disposition of all deferral and variance accounts included in this application.

49. Ref: E9-T1-S1 p.8
Please provide a copy of the letter from the Board referenced by Enersource concerning the recording of PCB related costs.

50. Ref: E9-T1-S1 p.10
Will Enersource be removing and disposing the remaining PILC cables, which contain PCBs, in 2012 and what is the expected cost? If not, is the activity forecasted to occur in 2013?

MODIFIED INTERNATIONAL FINANCIAL REPORTING STANDARDS

Issue 9.1 - Is the treatment and disposition of the Property Plant & Equipment adjustments due to the transition to MIFRS appropriate?

51. Ref: E1-T3-S3, Appendix 1 p.1-2
In the reconciliation of the CGAAP 2011 financial statements to RRR, there is an addition to distribution revenues and amortization expense in the financial statements of $10,734,000 in relation to IFRS Change in Useful Lives under notes 2 and 3. Please explain what these adjustments are for given that Enersource adopted MIFRS effective January 1, 2012.

52. Ref: E1-3-S2, Appendix 1, p.3; E2, T1, S2, p. 3-6, Tables 4-7; E2-T1-S3, p.3-5 Tables 4-7

Board staff notes the following discrepancies in the 2011 to 2014 customer contribution stated on the Pro Forma Statement of Income and the net customer contributions as calculated using the Gross Asset and Accumulated Depreciation Tables 4 to 7.

(Figures in '000s)		2011	2012	2013	2014
Gross Asset Tables	(A)	4,353	7,260	10,193	13,153
Accumulated Depreciation Tables	(B)	-51	-201	-433	-750
Net Customer Contributions	(C = A-B)	4,302	7,059	9,760	12,403
Pro-forma Statements	(D)	4,447	7,204	9,905	12,528
Difference	(E - C-D)	-145	-145	-145	-125

For the purpose of integrity of the record, please explain what the difference between the Pro-Forma Statements and the net customer contributions as calculated using the Gross Asset and Accumulated Depreciation Tables is due to, and state what the appropriate balances for customer contributions are.

53. Ref: E2-T-S1, Appendix 2-B, p. 5

The 2011 IFRS Fixed Asset Continuity Schedule includes a column titled "Transformation write off". Please explain what this column pertains to and how it differentiates from the "Retirements" column.

54. Ref: E4-T6-S1, p.4-9

Enersource has included "Early De-recognition" in the calculation of depreciation expense, where "Early De-recognition" represents the net book value of assets that have been removed prematurely from the system (before reaching their useful lives).

a) Please further clarify why these assets have been removed prematurely from the system.
b) Please confirm if the assets related to the 2011 and 2012 Early De-recognition were in or not in service in 2011 and 2012.
c) Please explain why Early De-recognition is not a one time IFRS transition issue but is an ongoing issue and applies to the years after the transition to IFRS (i.e. 2012-2014).

Issue 9.2 - Are the proposed new MIFRS deferral and variance accounts appropriate?

55. Ref: E2-T1-S1, p.16 and E9-T1-S1, p.18-19

Per the Addendum to Report of the Board: Implementing International Financial Reporting Standards in an Incentive Rate Mechanism (EB-2008-

0408) dated June 13, 2011, the Board approved a generic deferral account to capture PP&E differences arising only as a result of the accounting policy changes caused by the transition from CGAAP to MIFRS. The operation of the deferral account is set out in Appendix A of the report.

In relation to the transition to IFRS regarding PP&E, Enersource is proposing to refund customers over a one year period commencing January 1, 2013 through a separate rate rider. This treatment is different than the Board approved treatment, where page 32 of the Addendum to the Report of the Board states:

> Amortization of the adjusting amount, up or down, shall be reflected in any applicable rate application as an adjustment to depreciation expense (the refund or recovery of the amount of the adjustment over time) and the return on rate base calculation on the unamortized balance shall be included in applicable revenue requirement calculations in the same way as for any other component of rate base.

Please explain the rationale of why Enersource is requesting to deviate from Board guidance:

- requesting for a new variance account instead of using Account 1575 IFRS-CGAAP Transitional PP&E Amounts as per the APH, and
- refunding customers over a one year period over a separate rate rider rather than clearing the PP&E deferral account through a one time adjustment to rate base

Board staff noted that Enersource has included CWIP in the calculation of PP&E differences arising from the transition to MIFRS, even though CWIP is not included in the rate base.

Please revise and recalculate the PP&E differences excluding CWIP, arising from the result of the IFRS transition using Board approved methodology by completing the schedules noted in Board staff interrogatory number 5 under Filing Requirements.

56. <u>Ref: E9-T1-S1, p. 19 and E1-T4-S1, p.1</u>
Enersource is requesting a deferral account to capture the impact of the post-employment adjustment resulting from MIFRS. The net impact at the date of transition was a reduction of the post-employment accrued liability of $150,000.

Per the Addendum to Report of the Board: Implementing International Financial Reporting Standards in an Incentive Rate Mechanism (EB-2008-0408) dated June 13, 2011, page 15:

The Board will not approve the creation of a generic account for IFRS related impacts on P&OPEB accounts occurring at the date of transition. The option remains for these utilities to seek an individual account if they can demonstrate the likelihood of a large cost impact upon transition to IFRS.

a) Enersource's materiality threshold is $645,000. The net impact at the date of transition is a reduction of the post-employment accrued liability of $150,000. Please demonstrate how there is a large cost impact to Enersource from the $150,000.
b) Please provide supporting documentation (e.g. actuarial valuation report) to support the $150,000 reduction in post-employment accrued liability.

SMART METERS

Issue 10.1 - Are the proposed quanta and nature of smart meter costs, including the allocation and recovery methodologies appropriate?

57. <u>Ref: E 9-T2-S1</u>

Enersource was a utility authorized to undertake discretionary metering activities (i.e. deployment and operation of smart meters) beginning in 2006 as a distributor specifically named in O.Reg. 425/06. Enersource began smart meter deployment in that year.

In 2007, the Board reviewed and approved smart meter costs incurred by Enersource and other distributors then authorized for discretionary metering activities in a combined smart meter proceeding under File Number EB-2007-0063. The Board's Decision with Reasons in that proceeding was issued on August 8, 2007, and Enersource's smart meter costs from May 1, 2006 to April 30, 2007 were approved.

Enersource had smart meter costs reviewed in its 2008 cost of service application under EB-2007-0706. Board staff understands, from the evidence in that application and the resulting Settlement Agreement accepted by the Board in its oral decision at the Settlement Conference on January 4, 2008, that Enersource continued to track all costs, deferred revenue requirement, including return on capital, and funding adder revenues in the established deferral and variance accounts 1555 and 1556, and that the rate base and revenue requirement underpinning 2008 base distribution rates did not reflect any capital or operating costs related to Enersource's smart meter program.

On July 16, 2008, Enersource filed an application with the Board seeking approval of smart meter costs incurred from May 1, 2007 to December 31, 2007, and for an accounting order authorizing disposition. In its decision, the Board stated:

> … The Board therefore approves those costs. The Board also approves the accounting changes as proposed by Enersource in the Application to recognize these approved smart meter costs and those approved in the Combined Smart Meter Proceeding in rate base, and to dispose of the related amounts in the established variance accounts.
>
> The Board notes that Enersource has not applied for any change to its approved distribution rates in relation to the recovery of the smart meter costs that are the subject of the Application, and therefore no change to Enersource's current Tariff of Rates and Charges is required as a result of this Decision and Order.
>
> **THE BOARD THEREFORE ORDERS THAT:**
>
> 1. Enersource Hydro Mississauga Inc. shall clear the balances in its smart meter variance accounts to December 31, 2007 by making the accounting entries documented in Schedule 5 of the its application dated July 16, 2008.[3]

Enersource also filed an application in 2009 seeking a Board order to draw down the balances of its smart meter variance accounts as of December 31, 2008, and the application was dealt with under EB-2009-0191. In the Decision issued on October 1, 2009, Member Vlahos stated:

> I note that Enersource requests that the 1555 and 1556 variance accounts are only to be drawn down; the applicant does not request disposition of the account balances and establishment of the associated smart meter disposition rider. I consider the relief requested solely a matter of financial accounting treatment – and therefore a matter for Enersource to determine in accordance with proper accounting practices. I do not consider the relief requested to be a matter for determination by the regulator as Enersource is not seeking disposition of the account balances, and rates will not be affected by the proposed accounting treatment. I therefore find it unnecessary for the Board to provide the order requested by Enersource. When Enersource files for the disposition of its smart meter variance accounts, the Board will give consideration to that request consistent with its policies and practices including, but not limited to, the Guideline on Smart Meter Funding and Cost Recovery.
>
> I also find that Enersource did not need to file an application for a Board order to affect the accounting treatment it proposes.

[3] DECISION AND ORDER [EB-2008-0265], December 8, 2008, pp. 4-5

> While I am not making any determination that may affect the subsequent disposition of the balances in Enersource's smart meter variance accounts, I find that the current application is on its face consistent with the principles and requirements outlined in the current guideline on Smart Meter Funding and Cost Recovery.

Board staff observes that Enersource has included costs for Enersource's smart meter program for all years from 2006 to 2012 inclusive in the costs for which its is seeking recovery of the deferred revenue requirement, and for inclusion of approved smart meter capital costs net of accumulated depreciation to December 31, 2012 in the 2013 test year rate base.

a) Please confirm or correct the summary of the Board's regulatory decisions with respect to Enersource's smart meter deployment and cost approval.
b) Please confirm that, based on this history, that Enersource has not recovered any smart meter costs other than through the smart meter funding adder to date (i.e. Enersource has not included any approved amounts in rate base and revenue requirement and thus had adjusted distribution rates to reflect such recovery.
c) If the response to b) is in the negative, please explain where smart meter recovery has been approved.
d) Also, since the costs in the Smart Meter Model Version 2.21 include costs back to and including 2006, please explain whether the costs in the smart meter model include any such approved and recovered costs. Further, explain the rationale for including such costs for recovery through the SMDR if the costs have already been recovered elsewhere.

58. <u>Ref: E9-T2-S – Smart Meter Disposition Rider</u>
In its Application, Enersource is proposing a uniform Smart Meter Disposition Rider ("SMDR") of $0.13 per month to be collected from all Residential, GS < 50 kW and GS 50 to 499 kW customers for a 12-month period from January 1 to December 31, 2013.

Guideline G-2011-0001: Smart Meter Funding and Cost Recovery – Final Disposition ("Guideline G-2011-0001") issued December 15, 2011, documents the following in Section 3.5 with respect to information to be filed in support of application for review and disposition of costs incurred for smart meter deployment and recovery through an SMDR:

> At a minimum, the following information should be provided:
> …
> - a calculation of the SMDR, including the proposed cost allocation methodology.[4]

[4] Guideline G-2011-0001, pages 18-19

Also, in the Board's decision with respect to PowerStream's 2011 Smart Meter Disposition Application (EB-2011-0128), the Board approved an allocation methodology based on a class-specific revenue requirement, offset by class specific revenues. The Board noted that this approach may not be appropriate or feasible for all distributors as the necessary data may not be readily available [footnote omitted].

> The Board views that, where practical and where the data is available, class specific SMDRs should be calculated based on full cost causality. The methodology approved by the Board in EB-2011-0128 should serve as a suitable guide. A uniform SMDR would be suitable only where adequate data is not available.
>
> Recognizing that SMFA revenues have been collected from all metered customers since May 1, 2006, the Board's decision in EB-2011-0128 also addressed the treatment of smart meter adder amounts collected from customer classes for which smart meter costs were not incurred, as it related to PowerStream's smart meter deployment program. The Board directed PowerStream to allocate the smart meter adder amounts collected from the GS > 50 kW and Large Use customer classes evenly to the Residential and GS < 50 kW classes when calculating the true-up for the SMDR. The Board concluded that this approach was appropriate because the amounts involved were not significant enough to warrant a more precise allocation.[footnote omitted] However, for all customer classes for which smart meter costs have been directly incurred, the SMFA revenues plus carrying costs should be directly used as an offset to the incremental revenue requirement to determine the SMDR for that class.[5]

Table 4 of Exhibit 9/Tab 2/Schedule 1 shows the following costs in aggregate and on a per customer basis:

	Residential	GS<50 kW	GS>50 kW	Total
Number of Installed Meters:				
Installed Meters 2006/07	60,536	0	0	60,536
Installed Meters from 2008 (Actual) to 2012 (Forecasted)	106,989	17,627	1,410	126,026
Forecasted Installed at May 31, 2012	167,525	17,627	1,410	186,562
Capital Costs ($000s):				
Capital Costs 2006/07	$7,972	$-	$-	$7,972
Capital Costs 2008 (Actual) to 2012 (Forecasted)	$17,698	$8,838	$766	$27,302
Forecasted Capital Costs 2012	$25,670	$8,838	$766	$35,274
Capital Costs Per Meter ($ per meter):				
Capital Cost Per Meter 2006/07	$131.69	$-	$-	$131.69
Capital Cost Per Meter 2008 to 2012	$165.42	$501.39	$543.26	$216.64
Capital Cost Per Meter Forecasted 2012	$153.23	$501.39	$543.26	$189.07

[5] *Ibid.*, page 12

a) Table 4 of Exhibit 9/Tab 2/Schedule 1 shows a significant difference in the average per meter cost for Residential customers compared to customers in either the GS < 50 kW or GS > 50 kW customer classes.

   Please explain why Enersource has not proposed a cost allocation and class-specific SMDRs, as required by Guideline G-2011-0001 given the availability of differential costs.

b) The common approach for cost allocation is to do the following:

   - OM&A expenses have been allocated on the basis of the number of meters installed for each class.
   - The Return and Amortization have been allocated on the basis of the capital costs of the meters installed for each class.
   - PILs have been allocated based on the revenue requirement derived for each class before PILs.
   - SMFA revenues and interest on the principal first calculated directly for the Residential and GS < 50 kW classes, with then the residual SMFA revenues and interest collected from other metered customer classes (i.e., GS 50-4999 kW and Large Use) allocated 50:50 to the Residential and GS < 50 kW classes. This approach has been used and approved in some recent cost of service applications, including that for Guelph Hydro's 2012 rates application [EB-2011-0123].

   Using the attached spreadsheet taken from Guelph Hydro's draft Rate Order filing, please provide calculations for class-specific SMDRs using a more direct allocation of SMFA revenues. Enersource should use a variation of this spreadsheet to account for the fact the smart meter costs and hence an SMDR apply to the GS > 50 kW class in addition to the Residential and GS < 50 kW customer classes. It will also mean that residential SMFA revenues and associated interest are allocated evenly to the three classes. Enersource's response should also reflect any and all revisions to Smart Meter Model, Version 2.21 made as a result of Enersource's responses to interrogatories.

59. <u>Ref: E9-T2-S1 – Cost Savings Related to Smart Meter Deployment</u>
On page 4 of Exhibit 9/Tab 2/Schedule 1, Enersource states:

> In communal meter rooms of certain buildings (such as retail plazas), where the large majority of customers are GS<50 kW not requiring demand readings, but include a small minority of GS meters requiring demand readings (GS>50 kW), Enersource took advantage of the smart meter communication network to reduce future meter reading costs by installing smart meters for those

demand customers. This equates to 1,410 meters installed for GS demand customers, i.e., GS>50 kW, as of December 31, 2011.

a) Please provide an estimate of the expected savings from the deployment of smart meters to these GS > 50 kW demand metered customers.
b) Please explain how Enersource has factored these savings into its 2013 revenue requirement.
c) Please elaborate on Enersource's plans to expand on deployment of "smart meters" to other GS > 50 kW customers (e.g. customers that may be outside of multi-tenant buildings like shopping malls)?
d) If Enersource has no plans to explain, please explain what prevents it from expanding and realizing savings.

60. Ref: E9-T2-S1 – Cost Savings Related to Smart Meter Deployment
a) Please explain what, if any, savings Enersource is realizing or expects to realize from meter reading of smart meters for Residential and GS < 50 kW customers.
b) Please indicate how these savings have been reflected in Enersource's 2013 test year revenue requirement.

61. Ref: E 9-T2-S1-Table 3 – Smart Meter Costs
Enersource provides the following table (Table 3) summarizing its smart meter capital and operating costs from 2006 to 2012:

Capital and Operating Costs to December 31, 2012 ($000s)				
Customer Class or Category of Cost	**2006-2007 Capital**	**2006-2007 Operating**	**2008-2012 Capital**	**2008-2012 Operating**
Residential	7,833	322	14,441	500
GS<50 kW	0	0	8,754	75
GS>50 kW	0	0	759	6
Condominiums (Retrofit)	0	0	-153	13
Software	139	0	646	0
MDM/R Integration	0	0	1,808	0
Hazardous Meter Bases	0	0	1,046	1,471
Total	7,972	322	27,302	2,065

a) Please explain the entry of ($153,000) related to Condominiums (Retrofit) under 2008-2012 Capital.
b) Please provide further details for the 2008-2012 capital and operating costs of $1,046,000 and 1,471,000, respectively related to Hazardous Meter Bases.

62. Ref: Smart Meter Model, Version 2.21 – Smart Meter Costs
Please provide further explanation of the entry of $613,078 under 1.3.2 Computer Software for the Advanced Metering Control Computer (capital costs) for 2012 (cell S66 on sheet 2).

63. Ref: Smart Meter Model, Version 2.21 – Smart Meter Costs
   a) Please provide further explanation of the entry of $768,078 under 1.5.3 Professional Fees for Other AMI Capital Costs Related to Minimum Functionality for 2009 (cell M86 on Sheet 2).
   b) Please explain why Enersource has categorized these costs as “Applications Software” for the purposes of calculating depreciation and CCA.
   c) Given that Enersource commenced smart meter deployment in 2006, why were these costs only incurred in 2009?

64. Ref: Smart Meter Model, Version 2.21 – Smart Meter Costs
   a) Enersource shows a total of $1,555,146 for 1.5.5 Project Management under Other AMI Capital Costs Related to Minimum Functionality for the period 2008 to 2011 (row 90 on sheet 2). Please provide further description of the activities related to these costs and how these relate to Enersource’s smart meter deployment.
   b) Enersource shows no costs for Project Management of its smart meter deployment in 2006 and 2007 despite undertaking smart meter deployment as a distributor specifically named in O.Reg. 425/06. Please explain why these costs only begin in 2008.

65. Ref: Smart Meter Model, Version 2.21 – Smart Meter Operating Costs
   a) Enersource documents the following for 2.5.2 Customer Communications under Other AMI OM&A Costs Related to Minimum Functionality (row 150, sheet 2):

Year	2006	2007	2008	2009	2010	2011	2012	2013	Total
Cost ($)		107032	133125	2569		137250			379976

   Please explain the expenditures in 2007, 2008 and 2011.

   b) Please explain the entry of ($6032) for 2011 under 2.5.4 Change Management (cell Q154 on sheet 2).
   c) Please explain the entry of ($55,053) for 2011 under 2.5.4 Administration Costs (cell Q156 on sheet 2).

66. Ref: Smart Meter Model, Version 2.21 – Smart Meter Operating Costs
In row 158 of sheet 2, under 2.5.6 Other AMI Expenses, Enersource documents the following:

Year	2006	2007	2008	2009	2010	2011	2012	2013	Total
Cost ($)		5591	(322253)	(457014)	617935	454362	51217	180228	379976

   a) Please explain what services are covered under “Other AMI Expenses”.
   b) Please explain the negative (credit) entries for 2008 and 2009.

c) Please explain the amounts of $617,935 for 2010 and $454,362 for 2011.
d) Please explain the entry of $180,228 forecasted for 2013. As Enersource is only seeking an SMDR, the 2013 amount is not factored into the SMDR. Has Enersource reflected this 2013 amount elsewhere in its application?

Issue 10.2 - Is the proposed treatment of stranded meter costs appropriate?

67. Ref: 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.
d) If there is a suitable direct or proxy allocator of the value of stranded meters by customer class, please provide an updated Table 3 in working Microsoft Excel format.