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

Introduction and Summary

1. Enersource is applying for new rates for the period commencing January 1, 2013 and ending December 31, 2014.

2. For the period January 1, 2013 to December 31, 2013, Enersource is proposing rates based on the cost of providing distribution services. For the period January 1, 2014, to December 31, 2014, Enersource is proposing rates based on the Board approved 2013 rates plus an Incremental Capital and Return (“ICR”).

2013 Rates

3. Enersource submits that the proposed 2013 rates are just and reasonable because, based on the extensive evidentiary record in this proceeding, it has demonstrated that the costs it will incur to provide distribution services have been prudently incurred. The evidence includes:

- April 27, 2012 – original evidence of 1700 pages; accompanying this evidence were 27 live Excel spreadsheets;

- May 17, 2012 - updated evidence to reflect the Decision in EB-2011-0100, Enersource’s 2012 rate proceeding; this was another 294 pages of material; accompanying this update, seven live Excel spreadsheets were filed on May 17 and 22, 2012;

- July 23 - responses to over 760 individual interrogatories were originally filed on July 23; approximately 30 responses were updated shortly thereafter with June YTD information. Following further updates and corrections, a complete compilation of IRRs were provided on August 22, 2012 consisting of almost 1800 pages of material; seventeen live Excel spreadsheets accompanied the IRRs.

- July 30 and 31 – Two days of Technical Conference.

- August 7 – Undertakings were originally filed on August 7, 2012. Following some procedural issues related to confidential material, a comprehensive package of sixteen Technical Conference Undertakings were filed on August 21, 2012, adding approximately 400 pages to the proceeding.

- September 4, 6, 10 and 13 - Three days of Oral Hearing on September 4, 6 and 10 with an additional partial session on September 13; a total of sixteen undertakings from those four days of oral hearings were answered, with the final two responses filed on today's date, September 17, 2012.

4. Through all of this, Enersource provided complete and responsive evidence permitting a thorough testing of the prudence of its costs. Enersource did not object to providing any request for substantive information. All disagreements with respect to providing responses related to characterizations of evidence and argument, etc.

2014 Rates

5. Enersource submits that the proposed 2014 rates are just and reasonable because the capital costs it will incur to provide distribution services in that year are prudently incurred and because of the following:

- Approval of 2014 rates would provide Enersource shareholders with compensation for capital costs actually incurred in that year (both capital expenditures and the cost of capital). Delaying recovery of the cost of capital until a future rebasing would effectively deny recovery of prudently incurred costs.

- Further, this denial of recovery cannot be justified by reference to an unproven assumption that Enersource can somehow recover that lost compensation through other cost reductions. Indeed, cost pressures on OM&A expenditures continue to grow. One important driver is OM&A costs incurred to maintain (not improve) reliability performance of aging assets. The pressures on OM&A costs are growing, not receding.

- Recovery in 2014, as opposed to a future rebasing, would match the beneficiaries with the payers. It would thus be consistent with principles of inter-generational equity.

- Delaying recovery of 2014 costs (as well as subsequent years' costs) to a future proceeding would lead to a larger one-time rate adjustment at a future rebasing than if those costs were recovered in 2014.

6. From a policy perspective, the Board is expecting utilities to engage in longer term capital planning. Approving a two-year capital budget will

facilitate that expectation and will provide useful information that can inform the Board's policies respecting multi-year planning.[1]

The Role of Comparators in Prudence Review

7. Enersource submits that the Board can rely entirely on the evidentiary record with respect to the prudence of Enersource's costs. Specifically, the Board has stated that comparisons to other utilities can be informative and "is some instances where a record is lacking in detail it becomes a very important element to consider. However, when, like here, utility specific information is available and on the record, the Board can "base its determinations primarily on the record before it."[2] Enersource submits that there is sufficient utility specific information available in this case to permit a prudence review of specific expenditures in accordance with OEB practice and law respecting the presumption of prudence.

8. In this regard, two points should be made.

9. First, Enersource is entirely prepared for the Board to consider its performance in determining prudence and indeed urges the Board to do so. Performance is related to prudence in that, where the Board has determined that a utility does not provide adequate performance, the Board can take that into account by disallowing costs.[3] This disallowance

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[1] Using this case to provide information on innovative approaches is consistent with the statement from the Board's chair that the Board will be looking at "process changes and pilot initiatives that could be implemented for 2013 rate applications". See letter from OEB Chair to All Interested Parties, June 26, 2012, re: "Review of Rate Applications and Hearing Process."

[2] See, for example, Decision and Order setting rates for Hydro Ottawa, December 30, 2011 (EB-2011-0054), p. 13).

[3] This has been articulated in OPG's rates case where the Board expressed concerns over nuclear operating costs in "in light of the overall performance of the nuclear business." but recognized that hydro performance did not raise those concerns:

> "The Board is allocating this adjustment solely to the nuclear business for the purposes of setting the payment amounts. The Board is not ordering any reductions for the hydroelectric business because the benchmarking evidence for that business supports the conclusion that it is operated reasonably efficiently from an overall perspective, and therefore the Board is less concerned with the specific compensation levels for that part of the company. **For the nuclear business the evidence is clear that overall performance is poor in comparison to its peers** and the staffing levels and compensation exceed the comparators." (Decision with Reasons, March 10, 2011 EB-2010-0008 ONTARIO POWER GENERATION INC., pp. 84 and 87).

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.

evidence demonstrated that, during the period 2008-2010, Enersource's average reliability performance compared to cohorts as follows:[6]

Enersource's Performance in Comparison to:	3rd GIRM Cohort[7]	CLD Cohort[8]	Shareholder Agreement Cohort[9]
System Average Interruption Duration Index (SAIDI)	88% less	69% less	61% less
System Average Interruption Frequency Index (SAIFI)	51% less	33% less	25% less
Customer Average Interruption Duration Index (CAIDI)	74% less	53% less	49% less

14. Further, this stellar reliability performance has been provided in a cost effective manner. Delivering that level of reliability requires investment in both capital and OM&A: capital to replace assets and OM&A to repair them. When both of those costs are combined, Enersource delivers more reliable supply at a lower cost than any comparable utility.

15. The evidence demonstrated that, during the period 2008-2010, Enersource's cost per KWh and peak KW compared to cohorts as follows:[10]

Enersource's Performance in Comparison to:	3rd GIRM Cohort	CLD Cohort	Shareholder Agreement Cohort
Cost per KWh	35% less	24% less	20% less
Cost per peak KW	36% less	26% less	19% less

[6] Exhibit K1.1.

[7] 3rd GIRM Cohort includes all 55 distributors listed in EB-2011-0387.
[8] Enersource, Horizon, Hydro Ottawa, PowerStream, Toronto Hydro, and Veridian.
[9] Described in Enersource's Shareholder Agreement as including Enersource, London Hydro, Horizon, Hydro Ottawa, and PowerStream.
[10] Exhibit K1.1.

16. Enersource recognizes that the metric of reliability, costs and energy and capacity is not the only and ultimate measure of utility performance. However, by any measure, it is an extremely important one. Both the numerator (total cost) and the denominator (kWh and kW) are much more relevant measures than any other measures than have been proposed.

17. As for the numerator, total cost is self-evidently relevant. That is what customers are exposed to. It is also what a performance oriented regulator (as opposed to an input oriented regulator) is most concerned with. Some intervenors have recognized this fact as well. As counsel for SEC has noted in another Board forum, "there is little doubt that a measure of current efficiency that includes both OM&A and capital components would be much better"[11] than a measure which looks at OM&A costs alone.

18. There is also a consensus among regulatory experts across the divide that total costs are a much more useful indicator of performance than partial costs – whether capital or OM&A. This was addressed at the stakeholder consultations on the RRFE.

19. Similarly, according to Mr. Cronin (155-156):

> "And, as we had noted a number of years ago, based on the historical data at that time, which was first generation data from '88 to '97, there was no relationship between O&M ranking and total cost ranking.
>
> And that continues to be true if you look at data as recently as 2010. If you look at a utility's total cost performance, it is unrelated to its O&M rankings."

20. Even the expert from Pacific Economics Group who developed the initial 3rd GIRM stretch factors that used OM&A costs in isolation from capital costs recognized the "limitations of a partial benchmarking and the benefits of the total cost benchmarking and TFP."[12]

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[11] Submissions by SEC to RRFE, April 20, 2012, p. 31.

[12] Renewed Regulatory Framework for Electricity Stakeholder Conference, Transcript, March 29, 2012, (EB 2010-0378, EB 2010-0379, EB 2011-0004EB, 2011-0043), p. 186. It was data quality, not relevance, that made that expert reluctant to use capital costs: "The reason we didn't do that is that you need a consistent data series for capital."

Dr. Yatchew made a similar point as follows:

> "I agree with the idea that partial cost benchmarking does have the potential of creating suboptimal incentives. This is an argument that's been raised for a number of years, and

21. As for the denominator, energy and capacity are the products that distributors provide to customers. Also, given that the Board is seeking to incentivize managerial decision-making, it is crucial to use metrics that lead to the types of decisions it wants managers to make. In other words, in evaluating utility performance, the Board should give careful thought to what it seeks distribution managers to manage towards.

22. Mr. Pastoric's evidence provided a very practical demonstration of how the measure of energy and demand are the most important measures for management decision making:[13]

> MR. PASTORIC: Let me just go down through your metrics as I look at this. Cost per population served, frankly, I don't look at population when I'm designing an electrical system. I look at load. And essentially, load is my characteristic.
>
> Population of Brampton or whichever utility you wish to relate to has more children per family. Doesn't relate to the electrical system, so unfortunately I don't see that metric as being applicable.
>
> The per kilowatt -- or per kilometre of line, that could be loosely used as a measure of effectiveness of the asset. However, when you do have one customer that has four feeders, rather than having 1,900 customers on one feeder, it does change that economics.
>
> So again, I can't manage on a per kilometre of line. I bill to what the load is for the customer. So when

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ultimately the problem is: How do you measure total costs properly? How do you incorporate capital costs for very disparate utilities with very different historical data and very different -- in some cases, very different cost patterns going forward?

That is the fundamental problem. So I still would prefer to see incentive structures that don't focus or put relatively less weight on partial cost benchmarking than those that focus on total cost benchmarking." (at p. 166).

[13] Transcript, vol. 2, pp. 7-8.

we look at connections of customers, first thing we ask is, How much are you going to use? It's not, How many people do you have in your house, or how many feet of kilometre of line, so those metrics to run a business doesn't make too much sense to me.

We've already talked about the per-customer basis. That's skewed to residential utilities.

…

If we have two apartment buildings in two different utilities, one utility will call that 500 customers because they have individual metering. Another utility with bulk metering policies says that's two customers. To say one is more efficient than the other, I'm not sure how I can run a business that way. That would say that I would have to potentially do an uneconomic investment of capital to convert the building that has only two customers to convert it to 500 customers to ensure that my ratio -- by what you're alleging here -- is the best way to look at the business.

I have to run the business by dollars which is both OM&A and capital, and I have to run it by kilowatt-hours, which is the throughput, or kilowatts. I buy equipment on throughput. I don't buy it on a per-customer basis.

… We can talk about 10 other metrics too, but essentially it's throughput and it's dollars. **That's what our business is.**

23. It appears from some questions in interrogatories and cross-examination that some Intervenors may be proposing alternative measures. However, they have not specifically done so and, except in the context of measures of OM&A costs per customer, which Enersource will address in that

portion of its submissions, Enersource will respond to any proposed alternative metrics in its reply argument.

24. Enersource's submissions on specific categories of costs are addressed below, following the categories of costs addressed in the issues list. Direct citations to the evidence are provided in the footnotes. Appendix A provides a summary of all evidence in relation to each issue.

General

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

25. Enersource proposed 2014 revenue requirements and resultant rates are based on:

- Board-approved OM&A expenses for 2013, held unchanged for 2014;

- Board-approved rate of return on rate base, held unchanged from 2013, including capital expenditure budgets for 2014;

- depreciation expense for 2014; and

- PILs for 2014 relating to incremental capital and return.

26. Enersource submits that that this Application provides a practical and reasonable interim solution to the industry's underlying challenges of rate regulation in a time of growing capital requirements.

27. Enersource did not receive a return on capital invested during the period 2009-2011. True, the amount of unfunded capital was not particularly large: the cumulative annual costs in excess of revenue requirement from 2009-2012 are 3.47%.[14] A relatively modest amount is at stake in 2014 as well. (In fact, the impact on the 2014 total electricity bill for a typical residential customer using 800 kWh per month is a decrease from 2013 of 0.3% or $0.40 per month).[15] Enersource is currently on a steady state in terms of capital investment and the total rate increase caused by this proposal is approximately $3.196 million.[16]

[14] Exhibit 1,Tab 2,Schedule 1, p. 4

[15] Exhibit 1,Tab 2,Schedule 1, p. 6, updated May 17, 2012.

[16] Exhibit 1,Tab 2,Schedule 1, p. 20.

28. Enersource has taken steps to avoid the risk of this capital amount. It is prepared to open a variance account to record the difference between its projected and actual capital expenditures for 2014 and to refund any under-spend to ratepayers. Enersource is prepared to take an asymmetrical risk on this proposal and not seek ratepayers to pay for any over-spend of this amount.[17]

29. In Enersource's submission, the fact that the bill impacts of this approach for 2014 are low is a reason in favour of approving this proposal. This low risk approach will provide all participants with helpful information on the practical implications of moving from single to multi-year capital plans. The learning from this experience can help inform future approaches to capital planning, particularly those that may result from the Board's Renewed Regulatory Framework for Electricity.

30. Further, implementing this approach is timely. Enersource's Asset Management Plan has indicated that many of its capital facilities that were built up in the 1970s will have to be replaced in the post-2016 period. Enersource believes that it is not alone in this regard and that considerable infrastructure investment will be required province wide.

31. Innovating with new approaches prior to having to address major new capital investment is more prudent than waiting until the requirement is more urgent.

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

32. Enersource anticipates that the Board's current initiative, the Renewed Regulatory Framework for Electricity, will have been concluded and that any resulting changes to rate setting will have been implemented by the time that Enersource applies for rates in 2015 and 2016. 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.

1.3 Has Enersource responded appropriately to all Board directions from previous proceedings?

[17] Transcript, vol. 1, p. 17.

33. There are no outstanding directives arising from orders issued previously by the Ontario Energy Board to Enersource.

1.4 Is service quality acceptable?

34. With respect to the quality of service to distribute electricity, Enersource has a SAIDI that is 61% to 88% below the average of (i.e., favourable to) any cohort group. Frequency of outages, SAIFI, is 25% to 51% below the average of (i.e., favourable to) any cohort group, and restoration time, CAIDI, is 49% to 74% below the average of (i.e., favourable to) any cohort group.[18]

35. With respect to customer service indicators, Enersource has met and/or exceeded the minimum Board standards for all but one of the customer service quality indicators over the historical period. The sole exception is the rescheduling of missed appointments indicator in 2011.

1.5 Is the proposal to align the rate year with Enersource's fiscal year, and for rates effective January 1, 2013 and January 1, 2014 appropriate?

36. Enersource is seeking Board approval for rates effective January 1, 2013 in this Application. This would align Enersource's distribution rate year with its fiscal year, which is also the calendar year. There was no opposition to Enersource's proposal to align it fiscal and rate years, commencing January 1, 2013.

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

37. The 2013 Test Year adjusted rate base forecast of $626,876 is $130,314 higher than the 2008 Board-approved rate base due to an:

- Increase in average net capital assets of $109,010; and
- Increase in the working capital allowance of $21,305.

The rate base forecast of $626,876 is exclusive of the IFRS-CGAAP Transitional Rate Base Adjustment of $13,041.

38. The major drivers of the increase in net capital assets are:

[18] Cohorts for comparison purposes are discussed at footnotes 7-9 above.

- Inclusion of smart meter expenditures in rate base;
- Purchase of a head office on Derry Road and the retrofit of the operations centre on Mavis Road;
- An increase of distribution and substations net assets;
- Continuous investments in information systems and other general plant assets;
- Transition to IFRS (change of useful lives, non-capitalization of overhead costs, early de-recognition of assets); and
- A decrease resulting from the transfer of stranded meters to regulatory asset 1555 account.

The Derry Road Head Office

39. The single largest rate base addition for 2013 – and the only expenditure that gained any significant attention in the hearing process – related to Enersource's purchase and renovation of a 16-year-old head office on Derry Road in Mississauga. Accompanying this purchase is the restoration of its Mavis Road facility to an operations centre.

40. The evidence respecting the determination that the Mavis Road facility was no longer adequate is as follows:

    - It was constructed almost fifty years ago, in 1963, as a warehouse and maintenance facility, with a minor office component.
    - In 1980, all of Enersource's staff was consolidated to work in the Mavis Road facility.
    - Since 1986, the number of inside workers requiring office space at the Mavis Road facility has steadily grown to meet the growth and incremental needs of Enersource customers and to comply with legislative and regulatory requirements.

41. The Mavis Road facility has undergone several rounds of renovations, including:

    - A three-story office tower was added in 1979 on the north side of the original building structure. It was designed as a connected but independent structure. The floor levels of the 1963 and 1979 structures are not contiguous, and must be accessed via internal fire exit stairs; and

- A further addition to the Mavis Road facility was built in 1991 at the south façade of the original structure. This addition was also designed as independent of the original structure, with access exclusively via stairs.

42. Despite these renovations, it was clear over time that the Mavis Road building was inadequate to meet Enersource's needs for an administrative office. Without repeating the extensive evidence filed by Enersource in this regard, it should suffice to note that the Mavis Road facility continued to be plagued by issues relating to congestion,[19] workplace environment[20] and workplace efficiency.[21]

43. Enersource considered further renovations to address the continuing challenges of the Mavis Road building, but found that the cost of doing so would be double that of building a new facility on a green-field site and the market value of the renovated facility would not reflect the costs of the renovation due to the customized nature of the building and its zoning. Accordingly, that option was rejected and Enersource had to evaluate other options.

44. To evaluate these options, Enersource's retained the expertise of Avison Young Commercial Real Estate (Ontario) ("Avison Young"). Avison Young undertook an extensive review of function, forecast, and anticipated business activities. The review included a needs analysis and a review of the business structure. Avison Young's study analyzed the options for a new administration building, which would allow for a reversal of industrial facilities at Mavis Road back to their intended operational use.

45. Various options for the new Administration Office were considered. All of these options are addressed in detail in Enersource's evidence.[22] With respect to a new building option, Avison Young performed a comprehensive search of existing facilities in the marketplace that met Enersource's requirements.

46. To be sure, a purchased facility, unlike a new-build cannot be precisely tailored to meet all of a tenant's specific requirements – it was bought on an "as is" basis. Mr. Pastoric put it as follows: [23]

> "The first issue we had to deal with with the building

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[19] These are detailed at pre-filed evidence, Exhibit 2, Tab 2, Schedule 5, pp. 4-5.
[20] These are detailed at pre-filed evidence, Exhibit 2, Tab 2, Schedule 5, p. 5
[21] These are detailed at pre-filed evidence, Exhibit 2, Tab 2, Schedule 51, pp. 5-6
[22] See: Exhibit 2, Tab 2, Schedule 5, pp. 10-12.
[23] Transcript, vol. 1, p. 22.

was it was on nine acres of land. We only needed six acres of land for the footprint of the building and the necessary parking for the building to be meeting all the bylaws of the city. We negotiated with the seller to sever three acres of land and reduce the asking price. There is no excess land at this site.

We bought 2185 Derry road, as is, where is. Like buying an existing house, when you buy an existing building, you make trade-offs."

47. Nevertheless, after a detailed review of several candidate facilities, one facility, 2185 Derry Road, was identified as meeting all of the requirements in the targeted geographic area. [24]

48. The table below provides a summary of the estimated capital costs and annual rate impacts of the various opportunities that were available for the new Administration Office: procuring land/constructing a new building; purchasing an existing building; and leasing office space:[25]

Alternatives	Initial Capital Investment	2013-2017 Outflows	2013-2017 Inflows Rate Impact	Annual Revenue Requirement Impact
Option 1. Construct New Building	(22,473)	(8,271)	16,688	3,338
Option 2. Purchase 2185 Derry Rd	(20,069)	(7,653)	15,260	3,052
Option 3. Lease Office Space	(1,310)	(16,587)	17,071	3,414

49. The above table identifies that purchasing an existing building had the lowest annual rate impact, at $3,052. In short, the Derry Road purchase was a necessary initiative that met all of Enersource's criteria, at the lowest annual rate impact to customers.

50. Enersource therefore chose that option and purchased the Derry Road facility.

[24] Ex 2 T2 S5 page 11; Board Staff Issue 2.1 IR# 12, Appendix 1 (the "Office Facilities Project Plan"), pp. 7-8.

[25] Ex. 2, Tab 2, Schedule 5, Table 1, p. 12.

51. No party appeared to question that Enersource either required a new administrative centre, that it identified the reasonable options, or that it made the prudent choice among those options. Instead, the focus seemed to be on the square footage of the Derry Road building.

52. It was suggested by counsel for SEC that the office space in Enersource's facilities "is something in the order of 60 percent too high. For a similar number of employees, PowerStream has 92,000 square feet in a brand new building."[26]

53. Although it is extremely unusual for an economic regulator to delve into detailed office space planning, Enersource has provided evidence in this regard to assist the Board.

54. In response to SEC's assertions about the comparison between PowerStream and Enersource's head office space, Enersource prepared a comparison of its Derry Road head office with the PowerStream office. In doing so, it relied upon the evidence of the PowerStream head office relied upon by SEC. The evidence of this comparison[27] is that, although Enersource's gross square foot per employee is slightly higher than PowerStream's, it falls well under the average square footage for utilities that is reported by surveys of the International Facility Management Association. More importantly, it is lower cost than the PowerStream head office when measured by all of absolute cost, cost per square foot and cost per head office employee.[28]

55. Enersource does not know what further comparisons or positions that parties may take on this issue, and will respond to any further positions in Reply.

Impact of the transition to IFRS

56. The IFRS-CGAAP Transitional Rate Base Adjustment of $13,041 for the 2013 Test Year represents the difference in rate base arising by the transition from CGAAP to MIFRS. This amount, plus the return on capital and PILs impact, is proposed to be refunded to customers over a one-year period commencing January 1, 2013 through a rate rider. This will serve

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[26] Transcript vol. 3, p. 2.

[27] Exhibit K.4.6. For comparison purposes, only head offices were compared. There was no evidence on the square footage, the number of employees, or the costs of PowerStream's operations centres. As a result, there was no comparison with respect to operations centres.

[28] Exhibit K.4.6 and Transcript, volume 4, pp. 13-14.

to align MIFRS capital assets to Enersource's capital assets presented in the IFRS external financial statements.

57. The 2014 ICR Year rate base forecast of $643,372 is $16,496 higher than 2013 Test Year forecast. This is due to the increase in net capital assets.

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

58. Enersource proposes a Working Capital Allowance of $107,229 for the 2013 Test Year, which relies on a working capital allowance percentage of 13.5%. The working capital allowance for the 2013 Test Year increased by $21,305 over the five-year period from 2008 mainly due to the inclusion of Global Adjustment in the cost of power forecast.

59. The working capital allowance requested for the 2014 ICR Year is the same as the 2013 Test Year due to the fact that none of the factors influencing this calculation are considered for the 2014 ICR Year.

2.3 Is the proposed Green Energy Act Plan appropriate?

60. Enersource's evidence[29] proposes the capital costs shown in the first data row of Table 1 below, all of which are Renewable Enabling Improvement (REI) investments, for renewable generation connection. Enersource's Application did not seek the recovery of any portion of the costs from provincial ratepayers.

61. Informed by Board staff's cross-examination on this issue,[30] Enersource is hereby proposing to request the recovery of indirect costs of REI investments from provincial ratepayers. Pursuant to subsection (e) of *Filing Requirements, Part VII, Capital and OM&A Deferral Accounts for Renewable Generation Connection or Smart Grid Development*, revised May 17, 2012 (subsequent to Enersource's filing of its Application), distributors are permitted to use a standardized approach such that direct costs attributable to a distributor's ratepayers are 6% and the balance, 94%, are attributable to provincial ratepayers. Table 1 indicates the amounts each year to attribute to provincial ratepayers and to Enersource ratepayers.

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[29] Exhibit 2 Tab 2 Schedule 3 Table 2 page 3; or see also the GEA Plan at Exhibit 2 Tab 2 Schedule 3 Appendix 1 Table 6 at page 14.

[30] See Transcript, Vol. 2, pp. 101-104.

Table 1: Capital Costs for Renewable Generation Connection

Cost Type	2011 (Actual)	2012	2013	2014	2015	2016
Capital Costs Funded By Enersource	197	133	183	219	256	293
94% attributable to provincial ratepayers	n/a	n/a	172	206	241	275
6% attributable to Enersource ratepayers	n/a	n/a	11	13	15	18

62. Enersource is not proposing to seek recovery of any additional OM&A costs to fulfill its commitments pursuant to its basic GEA Plan.

2.4 Is the capitalization policy and allocation procedure for 2013 and 2014 appropriate?

63. IFRS prescribes which costs can be included as part of the cost of an asset and indicates that only costs that are directly attributable to a specific asset can be capitalized. Indirect overhead costs, such as general and administration costs that are not directly attributable to an asset, that were being capitalized under CGAAP, are not allowed under IFRS.

64. Enersource, in conjunction with its IFRS advisor and auditor, performed a thorough analysis of all costs that were being capitalized under CGAAP in order to determine if they were eligible for capitalization under IFRS. Effective January 1, 2011, Enersource discontinued the capitalization of general overhead costs including labour burdens, general administration, material handling, and fleet burdens.

65. This change resulted in a decrease of capital expenditures of $2,525 compared to CGAAP and the offsetting increase in OM&A for the same amount for 2011. The estimates for 2012 to 2014 are shown below in Table 13 from Exhibit 2 Tab 1 Schedule 1.

Table 13: IFRS Overhead Capitalization 2011 to 2014 ($000s)

	2011 Actual	2012 Forecast	2013 Forecast	2014 Forecast
Overhead Capitalization	$ (2,525)	$ (3,022)	$ (2,774)	$ (3,026)

Operating Revenue

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

66. Enersource's load forecasting process utilizes multivariate regression load forecast models based on weather, calendar, and econometric variables to estimate the relationship between energy consumption or peak demand to analytical factors and drivers. The analytical factors include sixteen years of actual historical energy consumption data, actual weather data, and calendar data. Model drivers include econometric data such as gross domestic product, consumer price index, population, and employment, which are obtained from Conference Board of Canada as well as the Building and Planning Department with the City of Mississauga. Enersource has been utilizing this load forecast process since 2004 and has found it to be robust and effective. Since 2004, the forecasts have produced energy consumption forecasts within 0.3% of actual energy purchases and 1.7% to weather-corrected energy purchases, when incremental conservation and demand side management savings are considered.

67. The performance of the load forecast model continues to be very effective in 2012. Actual energy consumption is within 0.07% of the forecast for the first six months of 2012, and is within 0.32% on a weather-corrected basis[31].

68. Although weather is a significant contributor to both energy consumption and peak demand in Mississauga, Enersource's load forecasting process does not predict weather. Instead, Enersource utilizes weather scenarios to derive system load energy consumption forecasts and system load peak demand forecasts. Two scenarios are derived using 31 years of actual weather data to establish normal and extreme weather scenarios.

69. Enersource utilizes the same actual data and inputs, and similar modeling processes for establishing short term energy consumption and peak demand forecasts as it does for long term system load forecasts that

[31] Exhibit 3 Tab 1 Schedule 2 Table 7 updated August 23, 2012.

underpin the system capacity and asset management plans. Hence, weather scenarios derived for short-term energy consumption are also utilized for long term system planning requirements.

70. In Table 1 below, from Exhibit 3 Tab 1 Schedule 2, are the short-term actuals and forecasts for energy consumption from 2006 to 2013.

Table 1: Actual/Forecast and Weather-Corrected Energy Consumption, 2006 to 2013

Year	Actual/Forecast Energy Consumption (MWh)	*Actual Growth* (%)	Weather-Corrected Energy Consumption (MWh)	*Weather-Corrected Growth* (%)
2006	8,038,676	-2.93	8,035,586	0.14
2007	8,249,692	2.63	8,052,075	0.21
2008	8,096,552	-1.86	7,995,947	-0.70
2009	7,742,344	-4.37	7,788,628	-2.59
2010	7,949,146	2.67	7,739,098	-0.64
2011	7,880,490	-0.86	7,744,998	0.08
2012*	7,749,733	-1.66	7,749,733	0.06
2013*	7,817,741	0.88	7,817,741	0.88

*Incremental CDM activities not included

71. The incremental CDM energy consumption savings are identified in Table 3 below from Exhibit 3 Tab 1 Schedule 2.

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	(7,464,815)	(8,983,655)
Street Lighting	(12,478,799)	(20,915,195)
Total	**(84,271,133)**	**(119,146,362)**

72. 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.

73. The energy consumption forecast model performs very well with an adjusted R^2 of 0.987, indicating that 98.7% of the variations in energy consumption from 1996 to 2011 are explained by the variables in the model. Furthermore, the model statistics indicate a Mean Absolute

Percentage Error of 0.86% with a monthly mean absolute deviation of 5,413 MWh.

74. Energy demand forecasts were determined by applying weather-normalized energy sales to a five-year average load factor by customer rate class to determine weather-normalized billing determinants in kW by customer rate class.

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

75. Other revenue relates to all utility revenues other than distribution and cost of power revenues. Other revenues are also known as revenue offsets as they are used to offset the distribution revenue requirement.

76. A summary of Other Revenues is found at Table 1 below, from Exhibit 3 Tab 3 Schedule 1:

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

Operating Costs

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

77. Enersource's total operating costs will rise from $41,653, as approved by the Board for 2008, to $61,011 in the 2013 Test Year. This is an increase of $19,358, or 46%. Enersource acknowledges that this cost increase is material. This represents the costs of investing in a system that provides high quality service at a relatively low total cost.

The Role of OM&A Costs in the Full Cost Equation

78. Before addressing the detailed evidence with respect to those costs, it is helpful to address the relevance of OM&A costs in isolation of capital costs generally and comparisons among distributor OM&A costs in particular.

79. At the outset, while it is an understandable part of the process to segregate costs between capital costs and OM&A for the purposes of regulatory examination, it is important to consider the relationship between these costs.

80. Specifically, the management decision between investing in capital or OM&A should be driven by reference to which investment results in the biggest "bang for the buck" or the lowest long-term ownership cost for customers in terms of reliability. It is artificial and distortionary to punish management for investing in one category of costs over another.

81. Indeed, the OEB does not have a specific policy with respect to the allocation of costs between capital and OM&A. Nor should it. Its goal should be to encourage lower overall costs – not select one category over another.

82. Other participants have also recognized this. For example, in the RRFE review, counsel for SEC prepared a table demonstrating that there is a wide range of capitalization policies of utilities. That analysis showed capital to OM&A ratios ranging from 66:34 (Brampton Hydro) to 36:64 (Kenora). According to counsel for SEC:[32]

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[32] Submissions by SEC to RRFE, April 20, 2012, p. 31 and Appendix A. The lack of a standardized Board policy respecting capitalization also plagues comparisons in this regard. As Mr. Cronin stated at the RRFE consultation:

> "And so I did some back-of-the-envelope calculations and looked at a subset of utilities, and some of the ones that had what I would refer to as pre-eminent social performances -- that is social meaning -- looking at cost inclusively, capital, O&M and customer interruptions -- had been labelled as inefficient.
>
> Now, if I were on a utility and I were labelled inefficient, I guess I would have to think about whether I wanted to change my performance so that I would not be labelled inefficient and not necessarily be penalized.
>
> So I think, you know, these questions lead to complex behaviours, and they don't often -- they don't sometimes lead to the results that one would hope.

"On the other hand, we agree with LDCs that benchmarking their existing level of productivity based on OM&A alone, while perhaps necessary in 2007, is inherently unfair to some LDCs. Having now seen the wide variations in OM&A vs. capital in revenue requirement (as discussed earlier and seen in Appendix A), the unfairness is even clearer. While the current stretch factor system tries to adjust for some aspects of capital intensity (topography and undergrounding, for example), there is little doubt that a measure of current efficiency that includes both OM&A and capital components would be much better."

83. This inconsistency in capitalization policy also limits the value of comparing specific components of costs. This is one reason why Enersource does not use such comparisons. As Mr. Macumber stated at the technical conference: "I am not sure of how other utilities account for things or capitalize things, their accounting policies, what they get approved by their auditors or in a cost of service, so I am not sure if it's the relevance. I just, I can't comment on what they do in their accounting. So we don't use that information."[33]

84. Indeed, comparing utilities by reference to OM&A costs without considering how OM&A and capital costs work together could create perverse outcomes. Again, Mr. Cronin referred to this in the RRFE consultation process. He stated that, "In fact, one could argue that some

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We had talked about, three to four years ago, the fact that if you go to partial cost benchmarking, you can get a response from a utility which is based on an accounting response. So they can improve their O&M performance by basically moving costs from one bucket to another.

And we said: Well, you know, we're concerned about that. You know, the proof will be in the pudding, and let's see, you know, ex-post what happens.

Well, ex-post, what I can say based on the data I have looked at is that in 2001 the average capitalization -- that is the percentage of labour capitalized across the LDCs -- was 10 percent. In 2010, it was above 34 percent. So the labour capitalization rate increased 250 percent over the course of that decade.

Now, that is pretty much what you would expect would happen.

As well, the amount of overhead going into capital increased, so that if you look at what is being put into the ground, what is actually being put into the ground as capital now has 12 percent of what is being put into the ground as overhead, which is 50 percent higher than what it was in the earlier part of the decade."

[33] Technical Conference, Transcript, vol 1, pp. 162-163.

utilities have been incented to move from socially preferred positions due to the use of partial cost benchmarking and rewards associated with that behaviour." Mr. Cronin listed the problems with focusing on OM&A costs as a measure of performance as follows:[34]

- "Produces phantom O&M "improvements"
- Worsens allocative inefficiency
- Augmented Capital inflates equity and earnings
- Higher earnings drive higher customer rates
- Contaminates 'Capital Additions' data, assessment and response
- Increased capitalization results in higher total cost and future rates in the long run."

85. Enersource submits that this context is important as the Board considers the prudence of Enersource's OM&A costs and, in particular, how they compare to other distributors.

OM&A Cost Drivers

86. The drivers for Enersource's OM&A costs fall into two broad categories: normal business unit activities represent 60% of the operating cost increase since 2008 (an annual average 4.4% compounded growth rate); and other key drivers (IFRS overhead burdens, bad debts, asset management plan ("AMP") initiative, one-time costs and the new administration office) represent 40% of the operating cost increase. Each of these categories will be addressed in turn.

Normal Business Unit Activities ($11.6 Million)

87. Of the $11.6 million of cost increases attributable to normal business activities, $3.9 million is due to overall benefit increases. This is largely due to higher pension-related contributions.

88. A further $2.1 million is due to increases in overtime and contract costs required to meeting the growing challenge to maintain and replace aging

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[34] Renewed Regulatory Framework for Electricity Stakeholder Conference, Transcript, March 29, 2012, pp. 155-156 and Presentation of Frank Cronin to OEB on RRFE, March 28, 2012

infrastructure of Enersource's distribution system. These funds cover 24/7 coverage and other contract labour costs that are used to respond to outages and performing necessary maintenance to maintain reliability.

89. Dealing with aging infrastructure is, and will continue to be, an important driver of OM&A costs in the future. In 2011, for the first time, Enersource fell outside of the three-year ban required by the OEB in its targets for reliability. And in 2012 it is forecasting to be outside of the three-year band again.

90. The number of outages per year has risen from 384 to over 1,000, which is an increase of 167 percent from the year 2008 to 2011. The number of customer minutes has risen from 3.6 million to 10.3 million, which is an increase of 186 percent from 2008 to 2011. Defective equipment has caused essentially half of the incremental outages.

91. The balance of $5.6 million in normal business activities is due to two key factors: full-time equivalents, and salaries.

92. With respect to full-time equivalents, Enersource has added 21 full-time equivalents to manage the complexities of its business.[35]

93. Since 2008, Enersource's control room has seen the introduction and evolution of the integrated operating model. Enersource has seen the smart-meter integration with the Meter Data Management Repository. Enersource is now managing time-of-use rates and the collection of that data. Enersource has also introduced a new customer care and billing system, which has the capabilities to handle the changes needed by the business and also those business requests from the government.

94. Further, Enersource has gone through the implementation of IFRS. IFRS accounting systems are much more complicated and complex and additional resources are required to service and support them.

95. With respect to salary, Enersource negotiated a four-year deal with its unions. The contract provides the union in the final two years of the contract with 3.25 percent, all in. That's salary plus benefits. The non-union staff received 2.25 percent in 2012, a full one percent below union.

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[35] See: Exhibit 4 Tab 3 Schedule 1, Appendix 2-K; a detailed rationale can be found in each of the schedules in Exhibit 4 Tab 1.

Other Key Drivers ($7.7 Million)

96. Other key drivers make up $7.7 million. Of this, $2.8 million is overhead burdens, which moves from capital to OM&A due to Enersource's change from CGAAP to IFRS.

97. An additional $2 million is due to bad debt expense. Since 2008 Enersource has experienced a significant increase in the amount and number of accounts deemed to be uncollectible. In the 2008 cost-of-service application, Enersource forecasted approximately $1.6 million as uncollectible and approximately $400,000 in late-payment revenues, with a net effect or impact on revenue requirements of $1.155 million. In 2011 Enersource had $3.7 million deemed as uncollectible and approximately $2.1 million in late-payment revenues, with a net impact of $1.638 million.

98. Enersource has attempted to mitigate this impact by hiring an accounts receivable manager and selecting two new third-party collection agencies. The net impact on revenue deficiency is approximately $595,000 when the bad-debt expense and the compensating late-payment revenues are taken into account.[36]

99. Another $1.153 million is due to asset management plan initiatives. The asset management plan is to address the approaching increase in the number of assets that are expected to reach the end of their useful lives over the next four to five years. Enersource is closely monitoring, analyzing, evaluating asset-management activities in order to refinance approach to meet the expected increase in replacement rates.

100. These costs attributable to asset management will cover resources needed to carry out detailed inspections and analyze asset conditions; as well, cover some additional software costs to assist with the analysis to enhance our predictive capabilities with respect to asset failure. Essentially, Enersource’s plan is to do more testing, more monitoring, and more analysis. This will enable Enersource to make better decisions, which will be crucial due to its aging distribution system infrastructure.[37] Enersource is proactively planning so that it can get the lowest long-term owning costs for its assets.

101. Enersource forecasted one-time costs of $141 and $211, for 2012 and 2013, respectively, for a total of $352, to certify existing individual metered

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[36] Exhibit 4, tab 1, schedule 3, and pages 13 and 14.

[37] Details of the asset management initiative costs are found in Exhibit 4 Tab 1 Schedule 5.

suites “IMS” installations that were not previously inspected. Enersource originally proposed to recover these costs through its 2013 revenue requirement. However, based on updated information presented in the response to Issue 4.1 Board Staff IR # 36, Enersource was still negotiating the contract for the certification work and therefore had not incurred any of these expenses. Furthermore, Enersource also received an extension from Measurement Canada to perform the work over a three-year period. As a result, Enersource removed all costs related to this issue from its 2013 revenue requirement, and requested the approval of a deferral account to track the expenses. If the cumulative balance in this new account at the time of Enersource’s next rebasing is material, Enersource will seek to dispose of the balance at that time. Please see Exhibit 9 Tab 1 Schedule 3, entitled “Meter Inspection and Certification Costs Request for New Deferral Account Draft Accounting Order” filed on September 17, 2012.

102. The final component is $1.66 million operating costs related to the Derry Road. These represent increases in utility costs, property costs, facility maintenance, and three new positions. The new positions consist of a network technician to address all of the network issues at the new site, a facilities analyst that will deal with HVAC for both buildings, and a caretaker.

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

103. As of January 1, 2011, Enersource revised the useful lives of its depreciable assets. The revised estimates were adopted prospectively and extended the lives of many depreciable assets.

104. Enersource uses the half year rule for calculating depreciation of capital additions during the year of addition for all assets. Depreciation is calculated on a straight-line basis over the estimated service lives of assets. Included in the depreciation expense for 2013 and 2014 is the early derecognition of assets which represents the net book value of assets that have been removed from the system before reaching their end of useful lives. Details of depreciation expense can be found in Exhibit 4 Tab 6 Schedule 1 Table 5.

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

105. Enersource has included a PILs amount of $3,461 for 2013 to be included in the revenue requirement. The model used to calculate the forecasted 2013 PILs amount is based on the Board’s Income Tax/PILs Workform (“Tax Model”) for 2013 rate rebasing applications.

106. Enersource created a separate 2014 PILs Tax Model based on the same assumptions and methodologies as the Board's Tax Model. The only items updated in Enersource's 2014 Tax Model relate to the increase in fixed assets in 2014, including depreciation expense, capital cost allowance, and deemed net income before taxes. The PILs amount calculated in the 2014 Tax Model is $4,149 and is included in the 2014 revenue requirement. Note that 2013 and 2014 PILs amounts were updated in the responses to Issue General Board Staff IR#3.

107. Property tax is included as part of OM&A costs discussed in Exhibit 4 Tab 1 Schedules 4 and 11, Engineering & Operations and Facilities Management Services, respectively.

108. In Table 2 below, from Exhibit 4 Tab 1 Schedule 4, Substation Property Taxes are provided for each year from 2008 to 2013.

Table 2: E&O Operating Costs by Type and by Year ($000s)

	2008 Rates	2008 Actual	2009 Actual	2010 Actual	2011 Actual	2012 Bridge	2013 Test
Substation Property Taxes	597	595	593	600	597	630	650

109. In Table 2 below, from Exhibit 4 Tab 1 Schedule 11, Property Taxes are provided for each year from 2008 to 2013.

Table 2: Facilities Management Services Operating Costs by Type and by Year ($000s)

	2008 Rates	2008 Actual	2009 Actual	2010 Actual	2011 Actual	2012 Bridge	2013 Test
Property Taxes	300	271	271	268	268	280	300

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?

110. Enersource has relied on the OEB's deemed capital structure of 56% long-term debt, 4% short-term debt and 40% common equity for ratemaking purposes in this Application.

111. Enersource is proposing a total debt cost rate of 4.89%, which is comprised of 56% long-term debt at 5.0914% and 4% short-term debt at 2.08%. Enersource is also proposing a 6.58% weighted cost of capital for the 2013 Test Year, based on a cost of debt of 4.89% and a return on equity of 9.12%.

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

112. On April 29, 2011, Enersource Corporation successfully completed its private placement debt offering of $320 million. The placement is comprised of $110 million of Series A 10-year debentures with a fixed coupon rate of 4.521%, and $210 million of Series B 30-year debentures with a fixed coupon rate of 5.297%.

113. The net proceeds of the debentures were used to repay the amount owed by EC to Borealis Infrastructure Trust and the balance will be used for general corporate purposes. The costs to issue these debentures amounted to $2.192 million, which are being amortized using the effective interest rate over the life of the bonds. The total cost of long-term debt is 5.0914%.

Cost Allocation

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

114. Enersource relied on the Report of the Board on the Review of Electricity Distribution Cost Allocation Policy (EB-2010-0219), issued March 31, 2011, ("Cost Allocation Review") and the Board's revised cost allocation model ("Revised Cost Allocation Model") issued August 5, 2011 to complete the 2013 Test Year cost allocation. For the purposes of this Application, Enersource 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.

115. Consistent with the Filing Guidelines, the prospective 2013 Test Year cost information, including all capital and operating costs, are relied upon in the 2013 Cost Study. The breakout of assets, capital contributions, depreciation, accumulated depreciation, customer data, and load data by primary, line transformer, and secondary categories were developed from the best data available to Enersource, from its engineering records, and its customer and financial systems.

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

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.

Table 2: Current Retail Transmission Service Rates

Customer Class	Unit	Network Service Rate	Line and Transformation Connection Service Rate
Residential	kWh	$0.0073	$0.0057
GS < 50 kW	kWh	$0.0068	$0.0052
Unmetered Scattered Load	kWh	$0.0068	$0.0052
GS 50-499 kW	kW	$2.6160	$2.0283
GS 500-4999 kW	kW	$2.5309	$1.9847
Large Use	kW	$2.7007	$2.1197
Street lighting	kW	$1.8116	$1.4666

127. 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.

7.5 Is the proposed Tariff of Rates and Charges for 2013 and 2014 appropriate?

128. Enersource proposes to use rates detailed in Exhibit 8 Tab 1 Schedule 1, Appendix 1 for 2013 Test Year and Appendix 2 for 2014 ICR Year, both as updated on May 17, 2012. Final tariffs of rates and charges will be determined after receipt of the Board's Decision in this Application.

2013 Test Year

129. Based on May 17, 2012 updated evidence, a typical RPP residential customer consuming 800 kWh per month would see the delivery portion of their bill increase by 21.4% or $6.54, with an overall bill increase of 6.1% or $6.65. A non-RPP residential customer using 800 kWh per month would see the delivery portion of their bill increase by 24.1% or $6.94, with an overall bill increase of 6.6% or $7.05.

130. Based on May 17, 2012 updated evidence, a typical RPP GS<50 kW customer consuming 2,000 kWh per month would see the delivery portion of their bill increase by 6.9% or $5.78, with an overall bill increase of 2.0% or $5.87. A non-RPP GS<50 kW customer using 2,000 kWh per month would see the delivery portion of their bill increase by 8.5% or $6.78, with an overall bill increase of 2.4% or $6.90.

2014 ICR Year

131. Based on May 17, 2012 updated evidence, a typical RPP residential customer consuming 800 kWh per month would see the delivery portion of their bill decrease by 1.1% or $0.39, with an overall bill decrease of 0.3% or $0.40. A non-RPP residential customer using 800 kWh per month

would see the delivery portion of their bill decrease by 2.2% or $0.79, with an overall bill decrease of 0.7% or $0.80.

132. Based on May 17, 2012 updated evidence, a typical RPP GS<50 kW customer consuming 2,000 kWh per month would see the delivery portion of their bill increase by 5.2% or $4.64, with an overall bill increase of 1.6% or $4.72. A non-RPP GS<50 kW customer using 2,000 kWh per month would see the delivery portion of their bill increase by 4.2% or $3.64, with an overall bill increase of 1.3% or $3.70.

133. Enersource has provided an updated Revenue Requirement Workform in the responses to Issue General Board Staff IR # 3, filed on July 23, 2012. The bill impacts from these and other identified changes during the proceeding have not been updated.

Deferral and Variance Accounts

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

134. Enersource provided an update to its original evidence on May 17, 2012. This update was necessary to reflect the Decision in EB-2011-0100, Enersource's 2012 Rate Proceeding. This update affected Exhibit 9 Tab 1 Schedule 1 - Disposition of Deferral and Variance Accounts.

135. Included in the responses to Issue General Board Staff IR # 3, Enersource updated the account balances in Account 1508 – Other Regulatory Assets – Sub-account Deferred IFRS Transition Costs, and Account 1572 – Extra-ordinary Costs (PCBs) for actual amounts incurred in 2012.

136. Enersource has included in this Application a request for disposition of Group 1 and Group 2 deferral and variance account balances at December 31, 2011 and the forecasted interest through to December 31, 2012.

137. Enersource is requesting disposition of these deferral and variance account balances, including interest, and totaling $894 over a one-year refund period commencing January 1, 2013. This amount excludes the disposition of smart meter balances, which is addressed at Exhibit 9 Tab 2 Schedule 1. Actual interest is based on the Board's prescribed interest rates. The prescribed interest rate for the first quarter of 2012 was used to calculate forecasted interest for the April to December 2012 period. This rate is 1.47%.

138. Tables 1 and 2 below, from Exhibit 9 Tab 1 Schedule 1, identify the principal and interest for each deferral and variance account that Enersource is proposing for disposition in this Application, except for

deferral accounts 1555 and 1556 relating to smart meters, which are treated separately in Exhibit 9 Tab 2 Schedule 1.

Table 1: Total Group 1 Account Balances to be Disposed ($000s)

Account Number	Account Description	Principal as of December 31, 2011	Interest to December 31, 2011	Less: Amount Approved for Disposition Effective February 1, 2012	Interest from January 2012 to December 2012	Total to be Disposed
Group 1 Accounts:						
1550	Low Voltage Variance Account	$3,493	$50	$(2,044)	$ 22	$1,521
1580	RSVA – Wholesale Market Service Charges	$(18,204)	$ (274)	$10,633	$ (115)	$ (7,960)
1582	RSVA – One Time Wholesale Market Service	$ -	$29	$ -	$ -	$29
1584	RSVA – Retail Transmission Network	$(5,712)	$(138)	$6,353	$7	$510
1586	RSVA – Retail Transmission Connection	$(4,840)	$(119)	$5414	$7	$461
1588	Power	$4,169	$80	$(3,832)	$6	$423
1588	Power Sub-Account Global Adjustment	$(20,779)	$(445)	$23,298	$30	$2,105
1595	Recovery of Regulatory Asset (2008)	$(203)	$(80)	$284	$ -	$1
	Total Group 1 Accounts to be Disposed:	$(42,076)	$(897)	$40,106	$(43)	$(2,909)
1595	Recovery of Regulatory Asset (2009)	$(2,421)	$106	N/A		
	Total Group 1 Accounts:	**$(44,497)**	**$(791)**	**$40,106**		

RSVA Accounts

139. The total amount of all RSVA accounts is a $2,909 refund to customers. Enersource has followed the Accounting Procedures Handbook and other OEB-issued guidance to record the variances in these accounts.

140. Enersource proposes to refund Group 1 balances of $2,909 as detailed above in Table 1, and recover Group 2 balances of $2,015, as detailed below in Table 2.

141. The net Group 1 and Group 2 refund amount of $894, excluding smart meters, is sought to be disposed in this Application. This amount is comprised of a refund of $2,999 to be allocated to all customer classes and a recovery of $2,105, which relates to the global adjustment variance and therefore only applies to customers that are not on the regulated price plan.

Table 2: Total Group 2 Account Balances to be Cleared ($000s)

Account Number	Account Description	Principal as of December 31, 2011	Interest to December 31, 2011	Interest from January 2012 to December 2012	Adjustments	Total to be Disposed
Group 2 Accounts:						
1508	Other Regulatory Assets – Sub-Account Deferred IFRS Transition Costs	$1490	$27	$22	$26	$1565
1508	Other Regulatory Assets – Sub-Account Deferred Incremental Capital Charges	$44	$1	$1	$ -	$46
1518	Retail Cost Variance Account – Retail	$296	$11	$4	$ -	$312
1548	Retail Cost Variance Account – STR	$316	$25	$5	$ -	$346
1572	Extra-Ordinary Costs (PCBs)	$1211	$26	$18	$ 37	$1291
1592	PILs and Tax Variances	$75	$(28)	$(14)	$(1032)	$(998)
1592	PILs and Tax Variances – Sub-Account PST Savings	$(749)	$ -	$	$749	$ -
1592	PILs and Tax Variances – Sub-Account PST Savings (Contra)	$749	$ -	$ -	$(749)	$ -
1592	PILs and Tax Variances – Sub-Account PST Savings (50% portion owing to customers, up to Dec 2012)	$ -	$ -	$ -	$(547)	$(547)
Total Group 2 Accounts		**$3,433**	**$62**	**$36**	**$(1516)**	**$2015**

Account 1508 Other Regulatory Assets Sub-Account Transition to IFRS

142. Enersource confirms that these costs of $1589 are not already approved and included for recovery in distribution rates.

Account 1508 Other Regulatory Assets Sub-Account Incremental Capital Charges

143. The amount proposed for clearance in this account is a $46 recovery from customers. As provided in the APH-FAQ October 2009, this account was used by Enersource to record the charges arising from the new Hydro One capital rate relief rider (Rider 5A) charge. Enersource is including the balance in this sub-account for disposition as part of this Application.

Accounts 1518 and 1548 Retail Cost Variance Accounts ("RCVAs")

144. The amount requested for disposition relating to the RCVAs is a $658 recovery from customers. Accounts 1518 and 1548 capture the difference between the revenue collected from retailers for retail settlement activities and the costs incurred to provide these services.

Account 1555 and 1556 Smart Meter Accounts

145. Enersource is proposing to dispose of its smart meter balances relating to the revenue requirement impact of its Smart Metering Integration Plan ("SMIP") from 2008 to 2011, along with the additional forecasted amounts in 2012 to complete the SMIP. This is addressed in Issue 10 below. The amounts requested for clearance were not included in rates for those years.

146. The balance in Account 1555 includes a sub-account for the net book value of stranded conventional meters that were previously included in Enersource's rate base. This amount is net of all proceeds received from the sale of scrap materials from the stranded conventional meters.

Account 1572 Extraordinary Event Costs

147. Enersource is requesting approval for the disposition of Account 1572, with respect to incremental costs incurred relating to new laws pertaining to the use of polychlorinated biphenyls ("PCBs"). The amount requested to be recovered from customers is $1,291. Details on this program are found at pages 8 to 11 of Exhibit 9 Tab 1 Schedule 1.

Account 1592 PILs and Tax Variances

148. Enersource is requesting approval to dispose of the balance in Account 1592. The amount to be disposed of is a refund to customers of $998.

Account 1592 PILs and Tax Variances Sub-account

HST/OVAT Input Tax Credits ("ITCs")

149. Enersource is proposing to refund to customers $547, inclusive of the amount of PST savings pertaining to 2012 and interest. Enersource has calculated the amount to be refunded to customers in accordance with the Board's guidance; however, Enersource disagrees with including estimated PST savings on capital expenditures in the calculation for the reasons described in Exhibit 9 Tab 1 Schedule 1.

Other Amounts to be Disposed

150. In addition to the clearance of the deferral and variance accounts, Enersource is seeking to refund/recover the following items:

Deferred IFRS Adjustment

151. Enersource adopted IFRS on January 1, 2012. Table 12 on page 18 of E9-T1-S1 summarizes the financial impact of the IFRS transition on fixed assets of $13,041, which Enersource is requesting to refund to customers.

152. As shown in the responses to Issue General Board Staff IR #3, Enersource is also seeking approval to dispose of the corresponding decrease in revenue requirement of $1,029 as a result of the decrease in rate base in 2013. Table 13 on page 19 of E9-T1-S1 details the impact on 2013 revenue requirement. In total, Enersource is proposing to refund $14,071 to customers over a one-year period commencing January 1, 2013 through a separate rate rider and is requesting it to be tracked in a new variance account.

Other Comprehensive Income MIFRS Post-Employment Adjustment

153. This is addressed under Issue 9.2

Two Accounts Not Proposed for Clearance

154. Account 1595 (2009) as the rate riders pertaining to disposition of this account are effective until January 31, 2012; and

155. Account 1595 (2010) as the rate riders pertaining to disposition of this account are effective until January 31, 2014.

8.2 Are the proposed rate riders appropriate?

156. Table 15, from Exhibit 9 Tab 1 Schedule 1, shows the proposed rate riders to clear the balances requested for disposition. The proposed rate riders consist of:

- Rate Rider # 1 – includes disposition of Groups 1 and 2 deferral and variance accounts, refund of MIFRS deferred adjustment, and recovery of OCI MIFRS post-employment adjustment which are applicable to all customers;
- Rate Rider # 2 – Disposition of Global Adjustment Sub-Account applicable to non-regulated price plan customers;
- Rate Rider # 3 – Disposition of stranded meter balance; and

- Rate Rider # 4 – Smart Meter Disposition Rate Rider.

157. The worksheet for determining the rate riders is included in Exhibit 9 Tab 1 Schedule 1 Appendix 3. This worksheet allocates the variance and deferral accounts to each customer class. Enersource proposes the same allocators be used for the accounts as specified in the EDDVAR report.

Implementation

158. Enersource requests that the rate order from the Board set out rate riders to be effective for a period of one year from January 1, 2013 to December 31, 2013.

8.3 Are the deferral and variance accounts, including both existing and proposed new accounts, appropriate?

159. See Enersource's submissions on Issues 8.1 and 8.2, which address Enersource's deferral and variance account proposals in this proceeding.

160. As described above, Enersource has requested the approval of a deferral account to track expenses to certify existing meters installed in individual metered suites. Enersource originally proposed to recover these costs through its 2013 revenue requirement. However, based on updated information presented in the response to Issue 4.1 Board Staff IR #36, Enersource removed all costs related to this issue from its 2013 revenue requirement, and requested the approval of a deferral account to track the expenses. Enersource will seek to dispose of the balance in this deferral account, if material, in its next rebasing application.

Modified International Financial Reporting Standards

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

161. The major differences between MIFRS and CGAAP with respect to the accounting for PP&E and intangible assets are:
    - New componentization structure of PP&E associated with the change of useful lives for the majority of the assets resulting in lower depreciation expense in MIFRS;
    - Change of capitalization policy to comply with MIFRS capitalization rules resulting in less overhead cost being included as part of the cost of the asset; and
    - Early derecognition of assets resulting in removal from rate base and higher write-off for the period for assets that are removed from the distribution system before they reach their end of useful lives.

162. In order to clear this balance in rates, Enersource has requested a rate rider to refund this amount over a one-year period and will not apply any carrying charges to this balance.

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

163. Enersource is seeking approval for two new deferral and variance accounts as part of the transition to MIFRS. Enersource is proposing that an account be created to track variances between the amount approved to be refunded to customers for the impact of MIFRS on fixed assets, which was recorded in Account 1575 IFRS-CGAAP Transitional PP&E Amounts, and the amount billed. A second deferral account is requested which is to be used for future re-measurements of the defined benefit obligation which will be recorded in other comprehensive income instead of being amortized in OM&A.

164. Enersource is requesting a deferral account to capture the impact of the post - employment adjustment resulting from the transition to MIFRS. Upon adoption, Enersource was required to record all re-measurements at the date of transition to MIFRS as opening adjustments to retained earnings. Under CGAAP, a portion of this amount would have been recorded as an expense each year and would have been recovered in distribution rates through OM&A. The net impact to Enersource at the date of transition was a reduction of the post-employment accrued liability of $150.

165. Enersource is also requesting that the new deferral account be used for future re - measurements of the defined benefit obligation, which will be recorded in Other Comprehensive Income (“OCI”) instead of being amortized in OM&A using the corridor approach under CGAAP. For 2011, the actuary loss relating to the post-employment obligation was $769.

166. In total, Enersource is seeking to recover from customers $619 over a one-year term.

167. Actuary gains and losses that are recognized in OCI between the end of 2012 and the next cost of service rate application will be tracked in the deferral account and will be refunded or recovered in future rates.

168. See Exhibit 9 Tab 1 Schedule 2 entitled “Other Comprehensive Income MIFRS Post-Employment Adjustment Request for New Deferral Account Draft Accounting Order”, filed September 17, 2012.

9.3 Have all impacts of the transition to MIFRS been properly identified, and is the treatment of each of those impacts appropriate?

169. Pages 9 to 10 of Exhibit 1 Tab 2 Schedule 3 Changes in Methodology briefly describe the adoption of IFRS by Enersource and the changes in which Enersource performs its accounting, the reporting of financial results, and the impacts on regulated rates and charges.

170. Enersource has taken an active role in the Board's series of consultations to develop policy and provide guidance regarding the transition to IFRS.

171. Enersource has utilized the Board Report for policy guidance on the transition to IFRS, and specifically its requirements for regulatory accounting, regulatory reporting, and the filing requirements for this Application.

Smart Meters

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

172. The evidence at Exhibit 9 Tab 2 Schedule 1 Smart Meters provided the status of Enersource's smart meter plan, the reasons for the few required remaining installations, and its intention to complete the installations in a timely fashion.

173. A summary of the installed meters, capital costs, and cost per meter is shown at Table 4 of Exhibit 9 Tab 2 Schedule 1 Smart Meters. Enersource's average capital cost per meter of $189.074 is reasonable compared to the sector average capital cost of $186.76 derived from the OEB's "Sector Smart Meter Audit Review Report".

174. Pursuant to G-2011-0001 Guideline Smart Meter Funding and Cost Recovery – Final Disposition, Enersource is seeking approval of the smart meter costs, and authorization to transfer the approved amounts from the smart meter deferral accounts to the appropriate fixed asset, revenue, and expense accounts. Enersource has used the 2013 Smart Meter Model provided by the Board on July 3, 2012 (found at the response to Issue 10.1 Board Staff IR #58) to calculate the Smart Meter Disposition Rider.

175. As a result of the updated Smart Meter Model, Enersource proposes a Smart Meter Disposition Rate Rider of a refund $0.71 per month to the residential class and a recovery of $14.16 per month from the GS < 50 kW class. Further details can be found at the response to Issue 10.1 Board Staff IR # 58.

176. In order to improve Enersource's likelihood of reaching 100% compliance, it is also seeking Board approval to charge applicable customers for actual incremental costs incurred by Enersource in the non-standard installation and reading of smart meters, and related non-standard communication infrastructure. Such incremental costs are driven by customer requests

for non-standard installation and metering equipment relative to Enersource's standard smart meter installation.

10.2 Is the proposed treatment of stranded meter costs appropriate?

177. In accordance with the Board's Guideline G-2011-0001, whereby distributors are to be "held whole with respect to the cost recovery of stranded meters (i.e., conventional meters replaced as part of the smart meter initiative)", Enersource seeks disposition of its stranded meter costs as at December 31, 2012, a residual net book value of $7,640.

178. Enersource requests to remove the total forecasted stranded meter net book value as of December 31, 2012, totalling $7,640, from rate base and to recover this amount through separate rate riders for the applicable customer classes.

179. Enersource proposes the recovery period to be twelve months, effective January 1, 2013. Table 3 of Exhibit 9 Tab 2 Schedule 2 Stranded Meters shows the proposed stranded meter rate rider by customer class.

Summary and Conclusion

180. In summary, Enersource submits that the proposed 2013 rates are just and reasonable because, based on the extensive evidentiary record in this proceeding, it has demonstrated that the costs it will incur to provide distribution services have been prudently incurred.

181. Enersource further submits that the proposed 2014 rates are just and reasonable because the capital costs it will incur to provide distribution services in that year are prudently incurred and because of the reasons identified in paragraph 5 of this submission.

All of which is Respectfully Submitted:

George Vegh, McCarthy Tétrault

Gia M. DeJulio, Enersource Hydro Mississauga Inc.

William Killeen, Enersource Hydro Mississauga Inc.

SCHEDULE A

Evidence

EB-2012-0033

General

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

Evidence: The evidence in relation to this issue includes the following:

E1-T2-S1 Manager's Summary of the Application, as updated May 17, 2012.

IRRs - Issue 1.1

Board Staff 8, 9, 10
AMPCO 1
CCC 1 to 5
Energy Probe 1 to 4
SEC 7, 8, 9
VECC 1, 2

Undertakings

JT1.15
J1.2, J1.3, J2.1

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

Evidence: The evidence in relation to this issue includes the following:

IRRs - Issue 1.2

Board Staff 11
AMPCO 2
CCC 1
Energy Probe 1, 2, 3

Undertakings

None

1.3 Has Enersource responded appropriately to all Board directions from previous proceedings?

Evidence: The evidence in relation to this issue includes the following:

E1-T1-S10 Identification of Board Directives from any previous Board Decisions and/or Orders

IRRs - Issue 1.3

None

Undertakings

None

1.4 Is service quality acceptable?

Evidence: The evidence in relation to this issue includes the following:

E2-T3-S1 Service Quality and Reliability Performance
Exhibit K1.1 Performance Presentation

IRRs - Issue 1.4

AMPCO	3, 4, 5
CCC	1
Energy Probe	1 to 5
SEC	10
VECC	2 to 5

Undertakings

JT1.9

1.5 Is the proposal to align the rate year with Enersource's fiscal year, and for rates effective January 1, 2013 and January 1, 2014 appropriate?

Evidence: The evidence in relation to this issue includes the following:

E1-T2-S3 Changes in Methodology

IRRs - Issue 1.5

CCC 1

Undertakings

None

Rate Base

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

Evidence: The evidence in relation to this issue includes the following:

E2-T1-S1 Rate Base and E2-T1-S2 Capital Expenditures

IRRs - Issue 2.1

Board Staff	12, 13
AMPCO	6, 7, 8
CCC	1 to 4
Energy Probe	1 to 20
SEC	11 to 23
VECC	6 to 13

Undertakings

JT1.4
JT1.7
JT1.8
J2.4

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

Evidence: The evidence in relation to this issue includes the following:

E2-T1-S4 Working Capital Requirement plus two Appendices
(Note: E2-T1-S4 Appendix 1 was updated June 22, 2012)

IRRs - Issue 2.2

Board Staff	14 to 16
CCC	1
Energy Probe	1 to 3
VECC	14

Undertakings

None

2.3 Is the proposed Green Energy Act Plan appropriate?

Evidence: The evidence in relation to this issue includes the following:

E2-T2-S3 Green Energy Act Plan Capital Expenditures plus two Appendices
E4-T9-S1 Green Energy Act Plan OM&A Costs

IRRs - Issue 2.3

Board Staff	17 to 20
AMPCO	9 to 16
CCC	1
VECC	15 to 17

Undertakings

None

2.4 Is the capitalization policy and allocation procedure for 2013 and 2014 appropriate?

Evidence: The evidence in relation to this issue includes the following:

E2-T1-S1 Rate Base - Overview
E2-T2-S1 Appendix 1 – Internal Capital and Operating Expenditures Guidelines

IRRs - Issue 2.4

None

Operating Revenue

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

Evidence: The evidence in relation to this issue includes the following:

E3-T1-S1 Load Forecast Methodology Overview
E3-T1-S2 Multivariate Regression Model Results
E3-T2-S1 Variance Analysis

IRRs - Issue 3.1

Board Staff	21 to 29
CCC	1, 2
Energy Probe	1 to 15
VECC	18 to 16

Undertakings

JT2.23 to JT2.45
J3.3 to J3.6

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

Evidence: The evidence in relation to this issue includes the following:

E3-T3-S1 Other Revenue plus 3 Appendices, plus Appendix 2-C

IRRs - Issue 3.2

Board Staff	30
CCC	1, 2
Energy Probe	1 to 5
VECC	27, 28

Undertakings

JT2.33
JT2.34

Operating Costs

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

Evidence: The evidence in relation to this issue includes the following:

E4-T1-S1 Operating Costs Manager's Summary
E4-T1-S2 to S13 (OM&A costs for each business unit) plus Appendices 2-D, 2-E, 2-F, 2-G, 2-H, 2-I
E4-T2-S1 Variance Analysis Overview plus Appendix 2-J
E4-T3-S1 Employee Compensation Breakdown plus Appendix 2-K
E4-T4-S1 Shared Services/Corporate Cost Allocation plus Appendix 2-L plus Appendices 1 to 7
E4-T5-S1 Purchasing Strategy plus 2 Appendices
E4-T6-S1 Depreciation/Amortization/Depletion
E4-T7-S1 Taxes (PILs, Capital Tax, and Property Taxes) plus 2 Appendices
E4-T8-S1 Charitable Donations and Low-Income Energy Assistance Programs
E4-T9-S1 The Green Energy Act Plan Operating Costs

IRRs - Issue 4.1

Board Staff	31 to 38
CCC	1 to 21
Energy Probe	1 to 40
SEC	24 to 50
VECC	29 to 42

Undertakings

JT1.5, JT1.6, JT1.10, JT1.11, JT1.12, JT1.13
JT2.1 to JT2.12
J3.1 and J3.2

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

Evidence: The evidence in relation to this issue includes the following:

E4-T6-S1 Depreciation, Amortization, Depletion
E2-T1-S3 Accumulated Depreciation
E2-T1-S1 Rate Base - Overview

IRRs - Issue 4.2

Board Staff	39
Energy Probe	1, 2
SEC	51, 52

Undertakings

None

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

Evidence: The evidence in relation to this issue includes the following:

E4-T7-S1 Taxes (PILs, Capital Tax, and Property Taxes) plus 2 Appendices
Exhibit 1 Tab 2 Appendix 2-C (i).
Exhibit 1 Tab 2 Appendix 2-C (ii)
E4-T1-S4 Engineering and Operations Operating Costs
E4-T1-S11 Facilities Management Services Operating Costs

IRRs - Issue 4.3

Board Staff 40, 41
Energy Probe 1 to 5

Undertakings

None

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

Evidence: The evidence in relation to this issue includes the following:

E4-T4-S1 Shared Services, Corporate Cost Allocation plus Appendices 1 to 7 plus Appendix 2-L
E4-T1-S8 Shared Services Operating Costs

IRRs - Issue 4.4

Board Staff	42, 43
CCC	1 to 7
Energy Probe	1 to 6
SEC	53 to 61
VECC	43

Undertakings

JTC2.15 to JTC2.21

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?

Evidence: The evidence in relation to this issue includes the following:

E5-T1-S1 Cost of Capital and Capital Structure plus Appendix 2-N

IRRs - Issue 5.1

None

Undertakings

None

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

Evidence: The evidence in relation to this issue includes the following:

E5-T1-S1 Cost of Capital and Capital Structure plus Appendix 2-N

IRRs - Issue 5.2

CCC 1
Energy Probe 1, 2
VECC 44, 45

Undertakings

None

Cost Allocation

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

Evidence: The evidence in relation to this issue includes the following:

E7-T1-S1 Cost Allocation plus Appendix 1 plus Appendix 2-O, all as updated on May 17, 2012

IRRs - Issue 6.1

Board Staff 44
AMPCO 17
CCC 1
Energy Probe 1 to 3
VECC 46 to 49

Undertakings

None

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

Evidence: The evidence in relation to this issue includes the following:

E7-T1-S1 Cost Allocation

IRRs - Issue 6.2

Board Staff	45
AMPCO	18, 19
Energy Probe	1
VECC	50

Undertakings
None

Rate Design

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

Evidence: The evidence in relation to this issue includes the following:

E8-T1-S1 Fixed Variable Proportion

IRRs - Issue 7.1

AMPCO	20, 21
Energy Probe	1
VECC	51

Undertakings

None

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?

Evidence: The evidence in relation to this issue includes the following:

E8-T6-S1 Low Voltage Service Rates

E7-T1-S1 Cost Allocation Study Overview
E8-T1-S1 Fixed Variable Proportion
E8-T8-S1 Rate Schedules

IRRs - Issue 7.2

None

Undertakings

None

7.3 Are the proposed Total Loss Adjustment Factors appropriate?

Evidence: The evidence in relation to this issue includes the following:

E8-T7-S1 Distribution System Loss Adjustment Factors plus Appendix 2-P

IRRs - Issue 7.3

None

Undertakings

None

7.4 Are the proposed retail transmission service rates appropriate?

Evidence: The evidence in relation to this issue includes the following:

E8-T2-S1 Retail Transmission Service Rates

IRRs - Issue 7.4

Energy Probe 1

Undertakings

None

7.5 Is the proposed Tariff of Rates and Charges for 2013 and 2014 appropriate?

Evidence: The evidence in relation to this issue includes the following:

E8-T8-S1 Rate Schedules plus Appendix 2-U
E8-T9-S1 Bill Impacts plus Appendix 2-V
E1-T2-S1 Manager's Summary as updated May 17, 2012

IRRs - Issue 7.5

Energy Probe	1 to 3
SEC	62, 63
VECC	52, 53

Undertakings

None

Deferral and Variance Accounts

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

Evidence: The evidence in relation to this issue includes the following:

E9-T1-S1 Disposition of Deferral and Variance Accounts plus Appendices 1 to 3 plus Appendix 2-T

IRRs - Issue 8.1

Board Staff	46 to 50
Energy Probe	1, 2

Undertakings

None

8.2 Are the proposed rate riders appropriate?

Evidence: The evidence in relation to this issue includes the following:

E9-T1-S1 Appendix 3 Proposed Rate Riders for 2013 Test Year

IRRs - Issue 8.2

None

Undertakings

None

8.3 Are the deferral and variance accounts, including both existing and proposed new accounts, appropriate?

E9-T1-S1 Disposition of Deferral and Variance Accounts plus Appendices 1 to 3 plus Appendix 2-T

IRRs - Issue 8.3

SEC 64

Undertakings

None

Modified International Financial Reporting Standards

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

Evidence: The evidence in relation to this issue includes the following:

E2-T2-S3 Changes in Methodology
E1-T2-S1 Manager's Summary as updated May 17, 2012
E1-T3-S1 Audited Financial Statements
E2-T1-S2 Gross Assets – PP&E

IRRs - Issue 9.1

Board Staff 51 to 54
Energy Probe 1
SEC 65, 66

Undertakings

None

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

Evidence: The evidence in relation to this issue includes the following:

E9-T1-S1 Disposition of Deferral and Variance Accounts

IRRs - Issue 9.2

Board Staff 55, 56

Undertakings

None

9.3 Have all impacts of the transition to MIFRS been properly identified, and is the treatment of each of those impacts appropriate?

Evidence: The evidence in relation to this issue includes the following:

E2-T2-S3 Changes in Methodology
E1-T2-S1 Manager's Summary
E9-T1-S1 Disposition of Deferral and Variance Accounts

IRRs - Issue 9.3

None

Undertakings

None

Smart Meters

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

Evidence: The evidence in relation to this issue includes the following:

E9-T2-S1 Smart Meters plus Appendix 1 plus Appendix 2-Q
E4-T1-S6 Metering Operating Costs

IRRs - Issue 10.1

Board Staff	57 to 66
AMPCO	22a
CCC	1 to 3
Energy Probe 1	

Undertakings

None

10.2 Is the proposed treatment of stranded meter costs appropriate?

Evidence: The evidence in relation to this issue includes the following:

E9-T2-S2 Stranded Meters plus Appendix 2-R
E4-T1-S6 Metering Operating Costs

IRRs - Issue 10.2

Board Staff	67
CCC	1

Undertakings

None