**ENERSOURCE HYDRO MISSISSAUGA**

**2013 RATE APPLICATION (EB-2012-0033)**

**VECC FINAL ARGUMENT NOTES**

**1. GENERAL ISSUES**

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

* Enersource is seeking approval of a two year “ICR” (Incremental Capital and Return) model. The model establishes a fixed 2013 OM&A ($59.8 million) and makes three adjustments in 2014 to the 2013 revenue requirement:
  + a capital adjustment in respect to amortization and depreciation ($1.5 million),
  + an income tax adjustment ($0.688k) and
  + a return adjustment ($1.8 million).
* This results in an additional revenue requirement in 2014 of $3.3 million ($136.5k in 2013 and 139.8k in 2014).[[1]](#endnote-1)
* Is it just and reasonable to charge Enersource ratepayers an extra 3.3 million dollars? No. Reasons are:
* The ICR model proposed by Enersource conflicts with the Board’s current IRM policy.
* The Board’s IRM policy is designed to maintain consistency, stability ,predictability and to bring a measure of equality in the regulatory framework affecting electric LDCs. The Enersource proposal is subversive of those goals.
* Enersource has not demonstrated that its circumstances are significantly different from any other electric distribution utility. The current IRM policy contemplates adjustments in cases of extra ordinary capital programs. In this case there are no significant changes in capital spending patterns and therefore no reason to depart from Board approved policy.
* Enersource, by their own admission, did not complete **any** analysis of the financial implication of its ICR model vis-à-vis the standard cost of service followed by IRM. Therefore they cannot substantiate in any way a claim that the utility might be better or worse off under their ICM than under the Board’s approved IRM policy.[[2]](#endnote-2) [[3]](#endnote-3)
* There are risks to ratepayers if the Board approves Enersource’s ICM plan. If Enersource underspends its capital forecast ratepayers receive no value for the increase in rates being sought in 2014.
* Enersource had its last cost of service rates set for 2008 rates. At the time the Utility was provided the opportunity to earn 8.57%[[4]](#endnote-4).
* When asked to provide the shareholder return the Utility provided an “adjusted number” which removed CDM, smart meter income and what it described as other non-utility expenses. This calculation shows that between 2009 and 2011 the average return to shareholders was 7.66%[[5]](#endnote-5).
* VECC has calculated the returns based on the year-end financial statements filed in this case. We have summarized those in Exhibit K5.4 This shows the actual returns since 2008 were an average of 8.85%. Or about 30 basis points higher than the Board approved 2008 figure upon which rates were based[[6]](#endnote-6).
* Under cost of service and 3 year IRM Enersource has not only had a reasonable opportunity to make the returns provided by the Board – it has exceeded that expectation.
* So the proposition put forward that Enersource’s shareholder has not a received fair and reasonable opportunity to earn a return fair return during the past 4 years on its invested capital is simply wrong in fact.
* The issue OM&A has risen by over 47% from Board approved and 68% from 2008 actual spending – customer growth has been about 9-10% and inflation in the same range - leading to an expect growth of 20% in OM&A.
* Conclusion - that inability to reach Board approved returns is the result of Enersource’s inability to control OM&A costs.
* Enersource should have one year COS then apply IRM (or subsequent policies of Board under Regulatory Framework).
* VECC would agree with the written argument of Energy Probe that if the Board were to accept some form of the ICR proposal that it should also reflect a higher revenue forecast for that year.
  + If the Board accepts some form of the 2014 ICR proposal, Energy Probe submits that the Board should also reflect a higher revenue forecast for 2014, as is illustrated in Undertaking J3.6. The increase in revenues is the result of customer additions in both 2013 and 2014. The customers added in 2013 will generate a full year of revenues in 2014 and the 2014 additions generate revenues for part of the year. (Energy Probe Argument page 6).[[7]](#endnote-7)
* These submissions are consistent with the written submissions of Board Staff – and we could support their submissions on the issue.

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

* We have no real proposal from the Applicant on this issue[[8]](#endnote-8).
  + *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* (page 10 of Enersource Argument in Chief)
* The impact or not of the Renewed Regulatory Framework weighs no differently on Enersource than any of the other 80 utilities having their rates reviewed by the OEB. In the absence of direction to the contrary the Board should expect Enersource to follow the current IRM process.
* From the Board perspective – allowing Enersource to have a unique framework then why should not every COS filer for 2013 rates have their own unique system for rates beyond the first Cost of Service year. What would that mean for the Board’s Regulatory Framework exercise (obviously a rhetorical question)

**1.4 Is service quality acceptable?**

* Service quality is an important aspect of understanding whether a utility is maintaining investment and hence whether it has appropriate compensation to operate well.
* Enersource believes that is has service quality “second to none”. While perhaps not that good, we agree that Enersource’s reliability statistics are good and better than many in its comparable cohort of utilities[[9]](#endnote-9).
* Note that Enersource is happy to make comparisons based on standardized OEB gathered statistics – when those statistics show a favourable outcome.
* VECC concludes from the reliability statistics that Enersource has been able to operate effectively over the past years under the cost of service and IRM policies set by the Board.[[10]](#endnote-10)

**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?**

* We have seen a number of rate year alignments. We have generally taken no position on this issue. .

**2. RATE BASE**

**Table 2: Continuity of Calculated Rate Base, 2008-2014 ($000s)**

|  |  |  |  |  |  |  |  |  |
| --- | --- | --- | --- | --- | --- | --- | --- | --- |
| **Description** | **2008**  **Board**  **Approved** | **2008**  **Actual** | **2009**  **Actual** | **2010**  **Actual** | **2011**  **Actual MIFRS** | **2012**  **Bridge Year**  **MIFRS** | **2013\***  **Test Year**  **MIFRS** | **2014\***  **ICR Year**  **MIFRS** |
| Asset Values at Cost | $ 794,248 | $ 785,012 | $ 826,146 | $ 868,888 | $ 695,580 | $ 531,521 | $ 578,268\* | $ 620,109 |
| Construction Work in  Progress | $ (5,182) | $ (12,211) | $ (10,043) | $ (6,624) | $ (6,510) | $ (4,570) | $ 4,519) | $ (4,519) |
| Accumulated Depreciation | $ (378,429) | $ (363,426) | $ (386,709) | $ (413,366) | $ (225,286) | $ (34,289) | $ (58,621) | $ (83,966) |
| **Net Assets in Rate Base** | **$ 410,637** | **$ 409,375** | **$ 429,395** | **$ 448,899** | **$ 463,784** | **$ 492,663** | **$ 519,647** | **$ 536,143** |
| Working Capital Allowance | $ 85,925 | $ 81,578 | $ 82,606 | $ 95,874 | $ 97,609 | $ 101,256 | $ 107,229 | $ 107,229 |
| **Rate Base** | **$ 496,562** | **$ 490,953** | **$ 512,001** | **$ 544,772** | **$ 561,393** | **$ 593,918** | **$ 626,876** | **$ 643,372** |
| IFRS-CGAAP Transitional  Rate base adjustment | $ - | $ - | $ - | $ - | $ - | $ - | $ (12,821) | $ - |
| **Adjusted Rate Base** | **$ 496,562** | **$ 490,953** | **$ 512,001** | **$ 544,772** | **$ 561,393** | **$ 593,918** | **$ 614,067** | **$ 643,384** |

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

* Generally rate base is without issue with the exception of two issues: the new building and capital contributions.
* New Building: Enersource has purchased a new building at 2185 Derry Road West that will serve as the new Administration Office, with staff starting to move in by September, 2012. The Mavis Road facility will be reconfigured back to its original intended use as an Operations Centre. This is discussed in detail at Exhibit 2 Tab 2 Schedule 5.
* SEC pursued at the hearing the idea that the new building is too large for Enersource’s need. The justification offered by Enersource is not entirely helpful. VECC makes no further submissions on the issue..
* Capital Contributions – Energy Probe has made substantive arguments on this issue using its own analysis based on the response to Energy Probe IR #3 Issue 2.1. Two other interrogatory responses show slightly different capital contributions SEC IR # 13 Issue 2.1 and VECC IR # 6 Issue 2.1. VECC IR uses consistent CGAAP figures while the Energy Probe uses a mixture of CGAAP and IFRS. The results though are the same – contribution forecast is too high[[11]](#endnote-11).
* It can be seen in SEC IR # 13 that, leaving aside the anomalous year of 2009 when contributions are reported as a net addition (NB I think this is probably due to timing of receipts) the current capital contribution forecast is the lowest in absolute dollars and as a percentage of total capital since 2000.
* In 2008 the Board approved $3,750,000 in contributions and the Utility actually had $6,916,000 in Contributions.
* On a consistent CGAAP basis VECC IR # 6 shows that in 2011 actual contributions were $3,603,000 while in 2012 and onward they are forecast to drop significantly to $2.9 million because of the an expected sudden change in away from capital projects that attract contributions.
* The appropriate forecast for contribution is the 2011 actuals of 3.6 million or $700,000 increase in the capital contribution level. That is on a CGAAP basis. On an IFRS basis contributions are 4.3 million and $2.8 in 2012 onward.
* VECC would therefore argue that the capital contribution forecast should be increased in the range of $700,000 to $1,500,000.

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

* Enersource filed a lead/lag study which derives a working capital expense of 13.5%. The Board default (without a study) is 13%. Energy Probe has made detailed argument (5 pages) on this issue concludes that Enersource should have get a working capital of 10.4% of power and controllable costs. VECC supports the Energy Probe argument.

**2.3 Is the proposed Green Energy Act Plan appropriate?**

* Board Staff have made argument in respect to past OM&A spending on the development of FIT/Microfit. They are suggesting these amounts should be socialized in accordance with regulations Enersource has argues the amounts in question are not material. VECC makes no submissions in this area.

**3. OPERATING REVENUE**

**3.1 Is the proposed load forecast for 2013 and 2014, including billing**

**determinants, appropriate?**

*Load Forecast Methodology*

* Enersource forecasts its total energy purchases using a regression model derived from historical data over the period 1996-2011[[12]](#endnote-12). The model uses a number of explanatory variables including population, employment, GDP, weather, calendar flags and a trend variable[[13]](#endnote-13). The forecast of total purchases is then adjusted for losses[[14]](#endnote-14) and assigned to individual customer classes. This assignment is based on the average historical percentage of sales by class, where for weather sensitive classes regression models were developed to “weather correct” the historical energy sales[[15]](#endnote-15). These class sales values are subsequently adjusted for CDM, as discussed later.
* VECC has reviewed the submissions made by Energy Probe with respect to Enersource’s load forecast methodology and agrees with its submissions regarding the inclusion of population as an explanatory variable in the load forecasting equation and the use of 31 years (as opposed to a shorter period such as 11 years) to determine weather-normal conditions.
* Overall, VECC submits that the forecast of total purchases should be based on the regression model set out in response to Issue 3.1 - Board Staff IR #25 d) using the median weather conditions of the last 11 years as “weather normal”.

*CDM Adjustment*

* Enersource has reduced the forecast of total purchases for 2013 developed using its regression model by 119,146,362 kWh[[16]](#endnote-16) in order to account for the impact of CDM. This value represents Enersource’s estimate of the incremental savings in 2013 from 2011, 2012 and 2013 OPA programs[[17]](#endnote-17). During the course of the current proceeding[[18]](#endnote-18), Enersource has indicated the specific contributions for each years’ programs were assumed to be as follows:
  + 2011 Programs – 53 GWh
  + 2012 Programs – 31 GWh
  + 2013 Programs – 35 GWh
* VECC has two issues with Enersource’s CDM adjustment. The first is that the 53 GWh contribution from 2011 programs is based on their original CDM “plan” and not actual savings achieved in 201118. The OPA reports that the actual annualized impact of Enercource’s 2011 CDM programs, assuming they’d all been implemented on January 1st, is 26.48 GWh[[19]](#endnote-19). This suggests that the impact of 2011 programs on the CDM in 2013 is overstated by roughly 26.5 GWh (i.e., 53-26.48).
* VECC’s second issue is that the data used to develop the load forecast regression model included 2011. As a result the forecast developed using the model will inherently have embedded in it the actual 2011 CDM savings. Enersource has estimated that the actual savings in 2011 from CDM programs implemented in that year were 7.18 GWh[[20]](#endnote-20). VECC submits that, in order to avoid double counting, this amount must also be removed from any CDM adjustment for 2013.
* Enersource has suggested when this amount is considered in the context of the entire 16 years of actuals the effect is only 0.45 GWh20. VECC submits that the Board should reject this view for three reasons. First, from a policy perspective the Board has made it clear that, for purposes of LRAM calculations, “Lost revenues are only accruable until new rates (based on a new revenue requirement and load forecast) are set by the Board, as the savings would be assumed to be incorporated in the load forecast at that time”.[[21]](#endnote-21) The corollary is that the load forecast is assumed to already incorporate any CDM savings prior to the test year.
* The second reason is that Enersource’s load forecast model incorporates a trend variable and Enersource’s own evidence states that “the impact of historical CDM programs on load in future years is incorporated in the load forecast presented in Table 1 above as a CDM trending variable is utilized in the load forecast model”.[[22]](#endnote-22)
* VECC’s third reason is that for both the forecast produced by the regression equation preferred by Enersource and the one provided in response to Board Staff IR #25 d) the time trend variable continues to increase over the forecast period[[23]](#endnote-23). This time trend variable has a coefficient of -18,692.7 in the regression equation estimated by Enersource[[24]](#endnote-24) and -15,883.3 in the regression equation estimated in response to Board Staff IR #25 d). Since the forecasts are done on a monthly basis, this means that time trend variable reduces forecast purchases on a year over year basis by an amount equal to 12 times the value of the coefficient which is 224.3 GWh in the case of Enersource’s model and 190.6 GWh in the case of the model provided in response to Board Staff #25 d).
* While it is reasonable to assume that the trending variable captures effects other than CDM[[25]](#endnote-25), to the extent it captures CDM impacts over the historical period (as acknowledged by Enersource[[26]](#endnote-26)), increasing the value of the variable for the bridge and test years leads to the inclusion of additional CDM impacts for these future years over and above what was experienced historically. No allowance has been made for this in Enersource’s CDM adjustment and VECC acknowledges that determining the appropriate allowance may be difficult. However, given this shortcoming, VECC submits it would be reasonable to credit the forecast produced by the model as including all of the CDM actually achieved in 2011.
* Based on the foregoing it is VECC’s submission that the CDM adjustment for 2013 should be 85.446 GWh. This value was calculated by reducing Enersource’s 119.146 GWh adjustment by 26.5 GWh to account for the actual vs. planned CDM savings in 2011 and by 7.2 GWh to remove the 2011 CDM savings already captured in the purchase forecast established using the regression model.

*Billing Demand Forecast*

* VECC has reviewed and supports Energy Probe’s submissions with respect to the billing kW forecast for 2013 in terms of both: i) accepting Enersouce’s removal of the 80,000 kW adjustment for the GS 50-499 class and ii) the use of historical kW to kWh ratios to determine billing demand determinants for the demand billed classes.

**3.2 Is the proposed forecast of other regulated rates and charges for**

**2013 and 2014 appropriate?**

* For 2012 and 2013 Enersource is forecasting Other Revenues of $5.18 M and $4.83 M respectively as compared to the $5.6 M actually received in 2011[[27]](#endnote-27). However, Enersource’s year-to-date Other Revenues for the first half of 2012 are actually $112,000 higher than those in 2011[[28]](#endnote-28). Extrapolating these results through the balance of 2012 suggests that results for 2012 could actually be higher than the 2011 by $224,000 as opposed to $420,000 lower as forecast by Enersource for an overall difference of more than $640,000.
* VECC submits that it would be reasonable to carry this understatement forward to 2013 and increase the Other Revenues for the test year by this amount.

**4. OM&A**

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

**Summary of OM&A Expenses – Exhibit 4, Tab 1, Appendix 2-E, pages 2-3[[29]](#endnote-29)**

|  |  |  |  |  |
| --- | --- | --- | --- | --- |
| CGAAP | **2008** | **2008** | **2009** | **2010** |
| **Board-approved** | **Actuals** | **Actuals** | **Actuals** |
| **Operations** | $ 13,339,679 | $ 11,702,739 | $ 13,445,543 | $ 14,770,356 |
| **Maintenance** | $ 3,746,644 | $ 3,295,253 | $ 3,487,547 | $ 3,263,481 |
| **Billing and Collecting** | $ 8,422,185 | $ 7,325,900 | $ 8,126,830 | $ 10,799,691 |
| **Community Relations** | $ - | $ - | $ - | $ - |
| **Administrative and General** | $ 15,247,150 | $ 13,044,178 | $ 15,600,037 | $ 15,896,443 |
| **Taxes Other Than Income Taxes** | $ 897,400 | $ 866,050 | $ 863,606 | $ 867,586 |
| **Enersource Smart Meter Adj\*** | **$ - 1,177,000** |  |  |  |
| **Total OM&A Expenses** | **$ 40,476,058** | **$ 36,234,120** | **$ 41,523,563** | **$ 45,598,558** |

|  |  |  |  |  |
| --- | --- | --- | --- | --- |
| MIFRS | **2011** | **2012 Bridge Year** | **2013 Test Year** | 2014 |
| **Actuals** | **Forecast** | **Forecast** |  |
| **Operations** | $ 16,040,763 | $ 16,852,502 | $ 17,431,212 |  |
| **Maintenance** | $ 3,797,642 | $ 4,699,136 | $ 5,446,624 |  |
| **Billing and Collecting** | $ 11,480,571 | $ 11,688,482 | $ 11,989,905 |  |
| **Community Relations** | $ - | $ - | - |  |
| **Administrative and General** | $ 18,599,779 | $ 22,693,565 | $ 25,031,495 |  |
| **Taxes Other Than Income Taxes** | $ 864,465 | $ 1,075,000 | $ 1,200,000 |  |
| **Enersource Meter Inspection Adj\*\*** |  |  | $ - 88,000\*\* |  |
| **Total OM&A Expenses - IFRS** | **$ 50,783,218** | **$ 57,008,685** | **$ 61,011,236\*** |  |
| **IFRS Overhead Burdens\*\*\*** | $ 2,525,000 | $ 3,022,000 | $ 2,774,000 |  |
| **Total OM&A CGAAP Comparable** | **$ 48,258,218** | **$ 53,986,685** | **$ 58,237,236** |  |

Notes

\* Enersource adjusted 2008 Board approved to include smart meter costs – $1,177,000 is removal of this amount.

\*\* Board Staff IR # 36 2013 OM&A reduced by $88,000 for cost of inspecting suite meters.

\*\*\* JT2.11

*Expected OM&A – the reality check*

* Board Staff and Energy Probe have relied on Undertaking JT2.11 for their OM&A figures. I have relied on Appendix 2-E of the evidence with two adjustments made by Enersource for (1) the removal of smart meter costs in 2008 and (2) the removal of meter inspection costs in 2013. Neither adjustment is disputed. The main difference between the tables is the inclusion of property taxes in the tables above.
* The Board will be familiar with the approach that VECC has taken in the 2012 cost of service applications. To check the reasonableness of the overall OM&A proposal we have employed an “expected cost growth” approach. This starts with the last Board approved OM&A (2008). Increases in costs since 2008 are presumed to be related to inflation and customer growth. To the expected inflation and growth cost we look at any incremental utility responsibilities or unavoidable activities that have arisen since 2008. Generally, these activities relate to an increased regulatory burden (GEA, OPA, OEB, IESO, CDM, and SPC etc.), smart meter activities (computer and transaction costs offset by meter reading cost reductions) and IFRS transition costs.
* Board Staff say $12 million is the excess amount above expected cost growth..
* Using the tables above we can remove the impact of IFRS transition and look at growth on a CGAAP basis. In 2008 the Board approved an OM&A about of $40.5 million. In that year Enersource actually spend only $36.2 million.
* In 2013 Enersource proposes that ratepayers provide - on a CGAAP comparable basis – 58.2 million. Enersource wants 44% more than it asked for in 2008 or 61% more than it actually spent in 2008!
* VECC has consistently applied an overall 10-11% inflation factor for the period 2008 to 2012 in all the 2012 cost of service applications it has reviewed. This range is based on evidence supplied by a number of 2012 cost of service applicants. So we would add about 2% for 2012 and ratepayers I think would expect it reasonable if costs keeping up with general inflation to see a 12-13% increase in distribution rates.
* In the alternative, inflation in the IRM period could be adjusted by a productivity factor. That would give a much smaller increase in the order of less than 1% a year. These figures can be found in response to SEC interrogatory #14 issue 2.1.
* In SEC #14, are Enersource’s customer growth figures. The annual increase is between 1.6% and 1.2% per year. [[30]](#endnote-30)
* So in total, one would expect that Enersource’s OM&A costs would have risen by about 20% since 2008. What would that be:
  + 20% of the 2008 Board approved - 40,476,058 = 8,095,211 or
  + We might expect OM&A based on Board approved to be $48,571,269
  + 20% of what Enersource actually spent in 2008 – 36,234,129 = 7,246,825
  + We might expect OM&A based on what Enersource spent in 2008 to be $43,480,954
* Remember this is all on a CGAAP basis so we have to add back for 2013 $2,774,000 for IFRStransition.
* But we are still a long way from the $61 million that Enersource is seeking in this application. We are closer to $51 than $61 million. VECC asks why the amount requested exceeds estimates built upon a common sense approach.
* VECC has generally acknowledged in these cases that since 2008 new incremental costs have arisen in the areas of smart meters and regulatory affairs. But that increment, usually in terms of a few FTEs or less than a million dollars would not bridge the large gap between what we would expect OM&A to be and what this Applicant is seeking.

*Comparators*

* The other “reality” check that we submit the Board should undertake is OM&A per customers. Enersource has resisted this measure – and for good reason They perform poorly on this measure. As we have shown in Exhibit K2.6 Enersource is a high cost utility[[31]](#endnote-31).
* The Board has been given two reasons from the Applicant on why you should ignore this evidence. The first is that the data is unreliable. Enersource tells us that it doesn’t know how the data of other utilities is collected. And while the data collected on load and system reliability can apparently relied upon that for OM&A cannot[[32]](#endnote-32).
* Here is how Mr. Macumber stated it:
  + MR. MACUMBER: 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 (Technical Conference VOl.1, page 163-164)[[33]](#endnote-33).
* You should reject this argument because it is simply not true. The data is reliable – the Board collects this data under what it calls a Uniform System of Accounts, it has an audit department that surveys and supervises this data. This hearing is premised on the principle that the regulatory accounts of utilities are valid and comparable. The Board’s filing guidelines require utilities to present data in uniform comparable ways. Enersource may say they don’t know how data is collected among utilities – but you do – and you – as an expert panel of the Board can rely on that understanding.
* VECCwould also point out that after refusing to file comparator information to our interrogatory request, after being asked to explain why they wouldn’t file that information at the technical conference - after all that – and 4 days before the hearing starts – lo and behold what does Enersource file? Exhibit K1.1 - comparator data.
* In Exhibit K1.1 we have comparator data that:
  + uses other utilities OM&A figures
  + uses other utilities capital expenditure figures[[34]](#endnote-34)
  + uses other utilities energy throughput
  + but leaves out most of the surrounding utilities like Brampton Hydro
* Other than those utilities who look better on an OM&A basis than Enersource, the only thing missing from what was asked in VECC Interrogatory 36 - **customer numbers!** It turns out it’s only the customer numbers that Enersource believes cannot be relied upon by the Board to collect in a reliable and comparable fashion! Well we believe the Board knows how to count numbers.
* The second argument of Enersource is that OM&A per customer is not a good unitized statistic. We are not going to argue that OM&A per customer is perfect – all statistics and comparisons have their limitations. But, we would argue, OM&A per customer is a far better statistics than the self-serving number that Enersource would have you consider – OM&A against throughput. This is just common sense. Two utilities identical except for the fact of one having a large industrial customer would have very similar OM&A per customer costs but widely different costs on a throughput basis. There is a reason the Board doesn’t publish this statistic – it has no value when comparing utilities cost structures.
* So if Enersource would prefer to not compare itself to the other utilities – what about if they are compared to themselves? Surely the data Enersource collects on itself can be relied upon. [If it isn’t there isn’t a bigger problem than just how badly it is performing in comparison to the competition].
* In Board Staff IR # 5 General issues Board staff asked Enersource to file a number of appendices that were required under the filing guidelines. One of these is Appendix 2-L. This Appendix shows the OM&A cost per customer over time. In 2008 this figure (rounded to the dollar) was either $222 based on the Board approved costs, or $196 based on what they spent. In 2013 this number is forecast to be $307. To be fair this is on an IFRS basis. The comparable CGAAP figure is $292. No matter how you look at this – it is a significant increase. Of at least 32% since 2008. No wonder they don’t want you to look at things on a OM&A cost per customer basis! [[35]](#endnote-35)/[[36]](#endnote-36)

*Room to reduce costs – specific OM&A issues*

* Energy Probe submits at page 28 of their argument that you should not look at OM&A on a specific basis, but rather use an envelope approach. We agree with this position. Like Energy Probe and Board Staff we have also looked at the specifics and there are certainly areas in which we submit the Applicant could make cuts without jeopardizing service to customers.

*Bad Debt Expense*

**Table 3: Bad Debt Expense and Late Payment Revenue, 2008 to 2013** **($000s) (E4/T1/S3/p.14)[[37]](#endnote-37)**

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

* Enersource has hired a new Accounts Receivable Manager and selected two new 3rd part collection agencies to mitigate these costs[[38]](#endnote-38). Yet as noted in Board staff IR #32 the costs have not fallen significantly. This was pursued in the Technical conference at pages 44 August 30 (1st Day). It was followed up at the hearing (SEC Vol. 3 – Volume is missing page number – but at page 95 of Word Doc)[[39]](#endnote-39).
* What SEC counsel Mr. Shepherd establishes is that Enersource is proposing to spend $343,000 on trying to reduce bad debt costs – but it is reducing is the forecast of bad debt costs.
* Enersource expected your Bad Debt to grow to $4.3 million, but that with its mitigation measure it has revised its bad debt to $3,550. So what Enersource is telling the Board is that it expects to reduce bad debt costs by $750,000 through its initiatives. It’s just that it has forecast a bad debt cost in 2013 that is $800,000 higher than its actual bad debt costs in 2011. Of course the question is where did the forecast of $4.3 million come from
* Board Vol. 2 pages 153 to 154 for a revealing exchange. The explanation was from VECC’s standpoint most unsatisfying. Mr. Macumber in explaining how he got to a forecast for 2013 debt that was significantly higher than the bad debt costs ever experienced by the Utility basically said it was “due to the economy” and “ever increasing electricity prices. We asked if Enersource had looked at the experience of other utilities – but were told by Mr. Macumber “ *All I can say is, from reading the paper of what has happened to the economy since 2008*”
* We submit this is not compelling evidence of the need for a significant increase in bad debt costs. The most compelling evidence is a continuation of the actual 2011 amount – 3,706,000. A reduction in bad debt of $750,000 from this amount would be provide a 2013 bad debt target of $2,956,000.

*Regulatory Costs*

* Table 2-H of Exhibit 4, Tab 1, page 1 show regulatory costs are going to increase from 1.2 million in 2010 to 1.68 million in 2013.[[40]](#endnote-40)
* Enersource has forecast the 2013 Cost of Service Application alone to cost over $650,000 [ Exhibit 4, Tab 1, Schedule 10 page 4] . Of this amount legal and Board hearing costs over the 2 year period are forecast at $425,000. The breakdown of $200,000 in legal costs is shown at JT1.13.[[41]](#endnote-41)
* These costs are in excess of shows the Part of this is an increase of one time costs of $162,500 as per Table 2-H for these proceedings, or if you look at Undertaking JT1.13 $200,000 in legal expenses.
* Since 2010 when all regulatory costs have been accounted for in one cost center costs ongoing costs have increased by (1.52 vs. 1.21) 25% excluding the one-time 2013 rate hearing costs.

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* In VECC’s submission this is excessive. A more reasonable increase would be around 15% (or a generous 5% per year). This would reduce ongoing costs by $228,000.
* VECC also believes that $650,000 for the 2013 filing is excessive and would be reasonably reduced by $150,000.[[42]](#endnote-42)

*Capitalization*

* Exhibit 4, Tab 3, Schedule 1, Appendix 2-K shows the change in capitalization rates. Energy Probe has made detailed arguments in respect to the change in forecast vs. actual capitalization rates and the rates forecast for 2013 under MIFRS. VECC supports those arguments (page 29 of Energy Probe Argument). The adjustment for this change would be in the order of $1.975 million.

*OM&A Summary*

* In their argument Energy Probe has suggested ways of achieving approximately another $2 million in savings in the Incentive Plan, Base Salaries, and the reduction of FTEs and Board of Director costs. In VECC submissions these are all reasonable alternatives for the utility.
* There are of course, many other ways for Enersource to attempt to get a handle on the spiralling costs. That intervenors can identify at least $5 million in obvious reductions is demonstrative of the ability to reach a lower target.
* In VECC’s submission a 10% increase in costs from 2011 actual costs would be just and reasonable – if not overly generous. Using 2011 costs allows the Board to consider the incremental costs in the areas of regulatory, smart grid, smart meters and CDM that have occurred since 2008. A 10% increase on an IFRS basis would provide a 2013 OM&A of $55,862,000. Or a reduction of $5.15 million to the proposed OM&A budget.
* This proposed increase from 2011 levels is significantly in excess of inflation and Enersource’s customer growth. The proposal is significantly less than the $10-12 million reduction that is suggested by a simple reality check of the increase in inflation and customer growth. And it would still leave Enersource as one of the highest cost distribution servers in Ontario. While VECC believes one could argue for significantly lower costs for this high cost Utility the reduction of only 5.15 million would provide sufficient funds so as to no jeopardized capital and service programs and would provide an opportunity for Enersource to develop an orderly program to reduce its costs over the long run.

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

* No submissions

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

* No submission
* **4.4 Is the proposed allocation of shared services and corporate costs appropriate?**
* Enersource has changed the allocation of costs from affiliate (83.8 to 93.4%). This change is coincident with a change in the business planning of the LDC (getting out of other businesses. Looks like what they are doing is simply reallocating the costs to the utility because of the loss of business by your affiliate. The evidence is that the work being done is the same as before. “Beginning in 2009 the method of allocating costs was revised to better align with the services being provided to each affiliate based on budgeted headcount or as a percentage of revenue. Please refer to the response to Board Staff Issue 4.4 IR #42 for further details.” (EP IR # 2 Issues 4.1)[[43]](#endnote-43).
* The testimony of Mr. Macumber at pages 158 to 159 of Volume 2 of the Hearing transcript attempts to explain the cost allocation change:.
  + *.MR. Janigan……..[intro]…….*

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

*MR. MACUMBER: In 2006 we sold our water heater business and sold our Enersource telecom. From 2006 to 2008, the intention was to grow our non-regulated business, which was agreed to in our shared services model about how much each of the non-regulated and regulated companies would pay. During 2008, I believe, or at the end of 2007, it was determined that we were not going to be growing the business, and a more accurate reflection of who should pay for the services should be revenue or head count. And we changed that, changed our service agreements between the two companies and changed the percentage of allocation of costs.*

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

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

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

*But since the non-regulated services company did not grow, in theory they overpaid*.[[44]](#endnote-44)

* To put it another way – Enersource hoped that it would have a more successful non-regulated business. When that didn’t happen it reallocated costs to the regulated utility. Were Enersource to simply use the prior cost allocation figures this would reduce OM&A by $1.2 million.
* Were Enersource to simply use the prior cost allocation figures this would reduce OM&A by $674,000 (93.4-83.8 = 9.6% of $7,020,280)[[45]](#endnote-45)/[[46]](#endnote-46)
* VECC submits Enersource should reduce OM&A by a further $674,000 due to the over allocation of non-utility staff to the utility functions.

**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?**

* No submissions

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

* VECC agrees with the arguments of Energy Probe in respect to Enersource’s use of an internal rate of return calculation instead of the actual long-term debt interest payments. The internal rate of return function provides the effective interest rate (i.e. with the effect of compounding). It is used to compare a stream of investments with different compounding terms. The exercise Enersource is engaged in is determining the actual interest cost so that these may be recovered in rates.

* As concluded by Energy Probe the methodology used by Enersource overstates the interest costs in the revenue requirement and should result in the reduction of $210,000.[[47]](#endnote-47)

**6. COST ALLOCATION**

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

* Enersource has used the Board’s revised Cost Allocation model consistent with the Cost Allocation review completed by the Board last year[[48]](#endnote-48). However, contrary to the Board’s EB-2010-0219 Report – Review of Electricity Distributor Cost Allocation, Enersource has not developed utility-specific weighting factors for either Services assets or Billing & Collecting and Meter Reading expenses but rather relied on the default values provided in the Board’s earlier cost allocation model[[49]](#endnote-49).
* Enersource has committed49 to reviewing these factors before filing its next cost allocation model. Based on this commitment, VECC submits that Enersource’s cost allocation methodology is appropriate for determining the status quo revenue to cost ratio for each class and serving as a basis for establishing any required adjustments for 2013.
* However, these cost allocation results will need to be revised and updated based on the revenue requirement and load forecast the Board ultimately approves.

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

* Based on its proposed revenue requirement and load forecast, Enersource’s cost allocation resulted[[50]](#endnote-50) in two classes (Large Use and USL) where the initial revenue to cost ratios were outside the Board Target Ranges as specified in its most recent Cost Allocation Review. In both cases, the starting ratios exceed the upper boundary of the Board’s target range for the class.
* Enersource’s proposal is to re-balance all classes to within 10% of unity for 2013 and not make any further adjustments for 2014[[51]](#endnote-51). This results in moving the ratios for Large Use and USL to well below the120% upper boundary for each class. It also results in the some minor reductions in the ratios for GS < 50 and GS> 50 although the starting ratios for both are well within the Board’s target range for each class. Finally, it results in an increase in the revenue to cost ratio for Residential (from 85% to 90%) even though the initial value satisfies the lower boundary for this class21.
* In VECC’s view Enersource’s proposals for revenue to cost ratios are inconsistent with the Board’s Cost Allocation Guidelines and previous Decisions by the Board on this matter.
* The Board’s approach, as outlined in its EB-2010-0219 Report[[52]](#endnote-52), is that:
  + Revenue to cost ratios should be adjusted so as be within the Board’s target range, subject to annual bill impacts, and
  + Distributors should endeavour to move their revenue-to-cost ratios closer to one if this is supported by improved cost allocations.
* This approach was confirmed in the Board’s Decision on Brant County’s 2011 Rates where it stated[[53]](#endnote-53):

The Board accepts the positions of Energy Probe, VECC and Board staff that no further movements within the ranges are appropriate for the Residential, GS < 50 kW, GS 50 –4,999 kW and USL rate classes as the Ratios are all within the Board approved ranges, and there is no updated study or data to support a reallocation of ratios already within the approved ranges.

* In the same Decision, the Board went on to state that53:

As the Board noted in its 2007 Cost Allocation Report regarding revenue to cost ratios, while cost causality is a fundamental principle in setting rates, limitations in data affect the ability or desirability of moving immediately to revenue to cost framework around unity. As noted by Board Staff, any point in the Board’s ranges is as statistically significant as any other, so these ranges are being used until the data is further refined.

As Brant County has not updated its data, the Board finds that there is no reason to depart from its usual policy as set out in the report. The Board will therefore not approve Brant County’s proposal.

* In VECC’s view, Enersource has not made any improvements to its cost allocation methodology that would warrant moving the revenue to cost ratios closer to one than required by the Board’s target ranges for each class:
  + Enersource has employed the cost allocation model released by the Board in August of last year that reflected the Board’s determinations following its Cost Allocation policy review issued earlier that year[[54]](#endnote-54) and has not made any improvements or modifications.
  + In fact, as noted earlier, Enersource has not updated the allocation factors used for Services, Billing & Collecting and Meter Reading as required by the Board’s August 2011 Report[[55]](#endnote-55). Therefore, in this area, the cost allocation has not been revised to meet the standards set by the Board in conjunction with its current target revenue to cost ranges.
  + Some may point to the fact that Enersource has updated the load data used in its cost allocation. However, in VECCs’ view this cannot be viewed as an improvement. For its 2008 Rates, Enersources’ cost allocation used load data from 2004 – four years out of data. In comparison, the load analysis underlying the cost allocation for 2013 relies on data from various sources and years that range from 2007-2011[[56]](#endnote-56) – two to six years out of date. As result, the updated data analysis has just managed to ensure that the load data used is of the same vintage (i.e. roughly four years old) as that used previously.
* VECC notes that this question of whether electricity distributors should move their revenue to cost ratios closer to one than required by the Board’s target ranges also came up in the 2011 cost of service Rate Application Decisions for Toronto Hydro[[57]](#endnote-57), and Horizon[[58]](#endnote-58). In each case the Board determined that, for those distributors whose status quo revenue to cost ratios are outside the Board’s target range the ratios used for rate setting should only be moved to the boundary of the Board’s range for the customer class concerned as illustrated by the following extract from the Toronto Decision57.

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

*Based on these findings and those set out above, the Board directs THESL to*

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

* Furthermore, the previously referenced Brant County Decision confirmed that, for customer classes whose revenue to cost ratios are already within the Board’s target ranges no further movement is required
* In light of the Board’s stated policy and the supporting precedents, VECC submits that the revenue to cost ratios for the Large Use and USL classes should both the reduced to 120% - the upper boundary of the Board’s target range for each class.
* In order to address the revenue shortfall from these reductions, VECC submits that the Residential revenue to cost ratio should be increased from the 85% calculated by the cost allocation. VECC estimates that the increase required to offset the lost revenue represents less than one percentage point on the Residential class’ revenue to cost ratio. VECC notes that its proposed approach for achieving revenue neutrality by increasing the revenue to cost ratio for the class/classes that have the lowest ratios based on the status quo allocation is consistent with that adopted by Horizon Utilities for its Rate Order[[59]](#endnote-59) and approved by the OEB[[60]](#endnote-60).

**7. RATE DESIGN**

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

* Enersource proposes to maintain the current fixed-variable split for each of the customer classes[[61]](#endnote-61). In its initial Application, Enersource calculated the fixed-variable splits using the variable revenues prior to any reduction for the transformer ownership allowance[[62]](#endnote-62) and allocated the cost of providing the transformer ownership allowance to all customer classes[[63]](#endnote-63), including those classes where no customers receive the discount. However, in its Argument-in-Chief, Enersource has agreed[[64]](#endnote-64) to use the same approach as virtually all other LDCs whereby: i) the fixed-variable split is calculated based on revenues net of the transformer ownership allowance and ii) the cost of the transformer ownership allowance is allocated directly to those classes where there are customers receiving it. VECC agrees with this approach to determining the fixed-variable split and submits it should be approved by the Board.

**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?**

* VECC has no issues with Enersource’s proposed Low Voltage Rates, its introduction of an Unmetered Scattered Load class or its merger of the Small Commercial<50 kW class into the General Service<50 kW class.

**7.3 Are the proposed Total Loss Adjustment Factors appropriate?**

* VECC has no issues with Enersource’s proposal to continue to use its currently approved loss factor of 1.036[[65]](#endnote-65).

**7.4 Are the proposed retail transmission service rates appropriate?**

* Enersource is not proposing any changes to its approved 2012 Retail Transmission Service Rates (RTSR) at this time. Rather, it proposes to update its request for 2013 RTSR when the Board issues the updated Guideline and filing module to reflect January 1, 2013 Uniform Transmission Rates[[66]](#endnote-66).
* VECC agrees with this approach and submits that interested parties should be provided with the opportunity to review/comment on Enersource’s proposed 2013 RTSR once they have been filed with the Board.

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

* VECC has no additional submissions on this issue over and above those made related to other issues.

**8. Deferral and Variance Accounts**

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

* No submissions

**8.2 Are the proposed rate riders appropriate?**

* No submissions

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

*New Deferral Account for Suite Meters*

* Enersource has forecasted $141,000 and $211,000 for the inspecting or certifying suite meters in 2012 and 2013 respectively. Enersource initially included the cost in the calculation of the 2013 revenue requirement.
* In response to Board Staff IR #36, Enersource removed the request for recovery and sought a deferral account to track the expenses; recovery will be sought in its next cost of service application
* VECC suppors the submission of Board staff to deny this request.
* Enersource does not individually track OM&A costs relating to suite metering. The only costs that are tracked separately related to suite metering are capital expenditures, which are provided in the table below. In a recent decision in Toronto Hydro the Board required that the Utility track suite metering cost separately and in anticipation of a separate suite metering class. [See VECC IR # 41 & CCC IR # 15]
* VECC would also argue that given the Board’s recent decision in respect to Toronto Hydro and Suite metering that the Board should order Enersource to establish distinct accounting of all OM&A and capital costs related to suite metering.
* This is a competitive business and we will want to look in the future to understand what costs are being incurred .

**9. 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?**

* VECC has no submissions
* **9.2 Are the proposed new MIFRS deferral and variance accounts appropriate?**

VECC has no submissions

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

* No submissions

**10. Smart Meters**

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

*Issue raised in Enersource Argument-in-Chief*

* Enersource appears to have made a new proposal in argument-in-chief on what it is calling “non-standard smart meter installations.” Board staff have responded (strongly) in their argument. The offending paragraph is reproduced below:

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.36

* Not sure what Enersource is getting at, but only submission I might make is that we support Board Staff that without an appropriate tariff the utility is bound by the tariffs it is seeking approval for including the standard miscellaneous service charges. And perhaps Enersource might seek to clarify what it is seeking.

*Updated SDMR*

* In response to Board Staff IR #58 Issue 10.1 Enersource updated its Smart Meter Disposition Rider. It was recalculated on a class specific basis. Energy Probe has noted this. Not sure we need to as Enersource says in the IR they will adopt the new methodology – but if you want.

**10.2 Is the proposed treatment of stranded meter costs appropriate?**

* The stranded meter rate rider proposed at Exhibit 9, Tab 2, and Schedule 2 is shown below (same table at page 24 of Board Staff Submission).

**Table 3: Stranded Meter Rate Rider by Customer Class**

|  |  |  |  |  |
| --- | --- | --- | --- | --- |
| Smart Meters Forecasted Installed at May 1, 2012 | **Residential**  167,525 | **GS < 50 kW**  17,627 | **GS > 50 kW**  1,410 | **Total**  186,562 |
| Smart Meters Installed as a Percentage of Total | 89.8% | 9.4% | 0.8% | 100.0% |
| Stranded Meters Balance to be Recovered ($000s) | $ 6,860 | $ 722 | $ 58 | $ 7,640 |
| Number of Customers - 2013 Forecast | 176,865 | 17,703 | 3,950 | 198,518 |
| **Rate Rider ($ per Customer/month)** | **$ 3.23** | **$ 3.40** | **$ 1.22** |  |

* The stranded meter costs are allocated by customer numbers. This methodology over allocates costs to the residential class.
* References: IR BS # 67 / Undertakings JT1.1/JT1.2 – seeks to see if 2006 cost allocation methodology could be used as proxy for difference costs.[[67]](#endnote-67)
* Contrary to expectations (they said they were amenable), Enersource has not adopted the revised SMRR calculated in JT1.2.
* Board Staff, Energy Probe and VECC all agree that the calculation of the SMRR in JT1.2 better represents the principles of cost causality then does the original proposal of Enersource. We submit they should adopt the riders as calculated in this Exhibit (both Energy Probe and Board Staff have written detailed submission on this.

**Costs**

VECC submits that its participation has been responsible in this proceeding and has been, to the best of its efforts non-duplicative. VECC submits that its participation has been helpful to a comprehensive adjudication and understanding of the issues and requests full reimbursement for its costs herein.

**All of which is respectfully submitted this 24th day of September, 2012**

**Michael Janigan**

**Counsel for VECC**

**REFERENCES**

1. **Issue1: General Issues notes 1-10**

   Hearing Exhibit 1 2013 from : Enersource\_Excel\_IRR3\_Issues General\_Board Staff\_Attachment2\_2013 Rev-Req\_Work\_Form\_20120723 / 2014 from: Enersource\_Excel\_IRR3\_Issues General\_Board Staff\_Attachment2\_2014 Rev-Req\_Work\_Form\_20120723 [↑](#endnote-ref-1)
2. Technical Conference Transcript, Volume 1, July 30, 2012, pages 43-44 [↑](#endnote-ref-2)
3. Exhibit I, Issue: 1.1, Board Staff, I.R. #8, Page 2 of 2 [↑](#endnote-ref-3)
4. Exhibit 1, Tab 3, Schedule 5, Appendix 1,Page 1 of 7 [↑](#endnote-ref-4)
5. Technical Conference July 30 & 31, 2012,Undertaking No. JT1.15,Page 1 of 1 [↑](#endnote-ref-5)
6. 2008 & 2009: Exhibit 1, Tab 3, Schedule 1, Appendix 1, pages 3-4 /2010 & 2011: Exhibit 1, Tab 3, Schedule 1, Appendix 3, pages 3-4 [↑](#endnote-ref-6)
7. Argument-in-Chief , page 6 [↑](#endnote-ref-7)
8. Exhibit I, Issue: 1.2, Board Staff, I.R. #11, Page 1 of 1 [↑](#endnote-ref-8)
9. Enersource Argument-in-Chief, page 4 [↑](#endnote-ref-9)
10. Issue: 1.4, Energy Probe, IR # 2, Page 3 of 3 [↑](#endnote-ref-10)
11. **Issue 2: Rate Base notes 11**

    Energy Probe IR #3 Issue 2.1. /SEC IR # 13 Issue 2.1 /VECC IR # 6 Issue 2.1. [↑](#endnote-ref-11)
12. **Issue 3: Operating Revenues notes 12-28**

    Exhibit 3, Tab 1, Schedule 1, page 2 [↑](#endnote-ref-12)
13. Exhibit 3, Tab 1, Schedule 2, page 16 [↑](#endnote-ref-13)
14. Response to Issue 3.1, Board Staff #29 c) [↑](#endnote-ref-14)
15. Technical Conference Undertaking JT2.24 [↑](#endnote-ref-15)
16. Exhibit 3 Tab 1, Schedule 2, page 6 [↑](#endnote-ref-16)
17. Technical Conference Undertaking JT2.39 d) [↑](#endnote-ref-17)
18. Technical Conference, July 31, 2012, page 135 [↑](#endnote-ref-18)
19. Response to Issue 3.1, VECC IR #20, Attachment #2 [↑](#endnote-ref-19)
20. Technical Conference Undertaking JT2.36 [↑](#endnote-ref-20)
21. EB-2008-0037, page 18 [↑](#endnote-ref-21)
22. Exhibit 3, Tab 1, Schedule 2, page 6 [↑](#endnote-ref-22)
23. Technical Conference, July 31, 2012, pages 147-148 [↑](#endnote-ref-23)
24. Exhibit 3, Tab 1, Schedule 2, page 16 [↑](#endnote-ref-24)
25. Exhibit 3, Tab 1, Schedule 1, page 7 [↑](#endnote-ref-25)
26. Exhibit 3, Tab 1, Schedule 1, page 7 and Exhibit 3, Tab 1, Schedule 2, page 6 [↑](#endnote-ref-26)
27. Exhibit 3, Tab 3, Schedule 1, page 2 [↑](#endnote-ref-27)
28. Response to Issue 3.2, Energy Probe #3 (Updated)

    **Operating Costs notes 29-46** [↑](#endnote-ref-28)
29. Exhibit 4, Tab 1, Appendix 2-E, pages 2-3 [↑](#endnote-ref-29)
30. Exhibit I, Issue: 2.1, SEC,IR # 14,Page 1 of 1 [↑](#endnote-ref-30)
31. Exhibit K2.6 [↑](#endnote-ref-31)
32. Exhibit I, Issue: 4.1, VECC, IR # 36 [↑](#endnote-ref-32)
33. Technical Conference VOl.1, page 163-164). [↑](#endnote-ref-33)
34. Exhibit K1.1 [↑](#endnote-ref-34)
35. Exhibit I, General, Board Staff, IR#5, Appendix 2-L, page 1 [↑](#endnote-ref-35)
36. Issue: 4.1, Energy Probe, IR # 15, page 2 of 2 [↑](#endnote-ref-36)
37. Exhibit 4, Tab 1, Schedule 3, page 14 [↑](#endnote-ref-37)
38. Issue 4.1, Board Staff, I.R. #32, page 1 of 2 [↑](#endnote-ref-38)
39. Hearing Transcript (SEC) Vol. 3 – Volume is missing page number – page 95 of Word Document [↑](#endnote-ref-39)
40. Exhibit 4, Tab 1, Table 2-H, page 1 [↑](#endnote-ref-40)
41. Exhibit JT1.13 [↑](#endnote-ref-41)
42. Exhibit 4, Tab 1, Schedule 10, page 4 of 4 [↑](#endnote-ref-42)
43. Board Staff Issue 4.4 IR #42 /EP IR # 2 Issues 4.1 [↑](#endnote-ref-43)
44. Hearing Transcript, Volume 2, page 158-159 / see also Technical Conference Transcript Volume, page 11-12 [↑](#endnote-ref-44)
45. Exhibit I, Issue 4.4, Energy Probe; IR 3b – Attachment; Page 1 of 1 /see also Exhibit 4, Tab 3, Schedule 1, Appendix 2-K [↑](#endnote-ref-45)
46. Technical Conference Volume 2, page 13

    **Issue 5: Capital Structure and Cost Capital notes 47** [↑](#endnote-ref-46)
47. Energy Probe Argument page 34

    **Issue 6: Cost Allocation notes 48-60** [↑](#endnote-ref-47)
48. Exhibit 7, Tab 1, Schedule 1, page 4 [↑](#endnote-ref-48)
49. Response to Issue 6.1, AMPCO IR #17 [↑](#endnote-ref-49)
50. Appendix 2-O, Updated May 17, 2012 [↑](#endnote-ref-50)
51. Exhibit 7, Tab 1, pages 9-10 (Updated May 17, 2012) [↑](#endnote-ref-51)
52. EB-2010-0219, pages 34 and 36 [↑](#endnote-ref-52)
53. EB-2010-0125, page 5 [↑](#endnote-ref-53)
54. Exhibit 7, Tab 1, pages 3 - 4 [↑](#endnote-ref-54)
55. Board Report EB-2010-0219, page 26 [↑](#endnote-ref-55)
56. Response to Issue 6.1, VECC IR 47 a) [↑](#endnote-ref-56)
57. EB-2010-0142, page 40 [↑](#endnote-ref-57)
58. EB-2010-0131, page 43 [↑](#endnote-ref-58)
59. EB-2010-0131, Response to Comments on DRO, July 28, 2011, page 13 [↑](#endnote-ref-59)
60. EB-2010-0131, Board Decision and Order on Draft Rate Order, August 3, 2011

    **Issue 7: Rate Design notes 61-66** [↑](#endnote-ref-60)
61. Exhibit 8, Tab 1, pages 4 [↑](#endnote-ref-61)
62. Response to Issue 7.1, VECC #51 d) [↑](#endnote-ref-62)
63. Response to Issue 6.1, CCC IR #1 [↑](#endnote-ref-63)
64. Enersource Argument-in-Chief, page 29 [↑](#endnote-ref-64)
65. Enersource Argument-in-Chief, page 30 [↑](#endnote-ref-65)
66. Exhibit 8, Tab 2, Schedule 1, page 3

    **Issue 9: notes 75** [↑](#endnote-ref-66)
67. Undertaking No. JT1.2 [↑](#endnote-ref-67)