EB-2012-0033

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

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

BEFORE: Cynthia Chaplin
Vice Chair and Presiding Member

Paula Conboy
Member

Christine Long
Member

DECISION AND ORDER
RATES
DECEMBER 13, 2012

The Proceeding

Enersource Hydro Mississauga Inc. ("Enersource") is a licensed electricity distributor serving approximately 250,000 customers in the City of Mississauga. Enersource filed an application on April 27, 2012, updated on May 17, 2012, under section 78 of the *Ontario Energy Board Act*, *1998*. Through this application Enersource seeks approval for changes to the rates that Enersource charges for electricity distribution, to be effective January 1, 2013 and January 1, 2014.

The Board issued a Notice of Application and Hearing on May 18, 2012. The Board granted intervenor status and cost eligibility to the following parties:

- Energy Probe Research Foundation (“Energy Probe”)
- Vulnerable Energy Consumers Coalition (“VECC”)
- Consumers Council of Canada (“CCC”)
- School Energy Coalition (“SEC”)
- Association of Major Power Consumers in Ontario (“AMPCO”)
- Ms. Lubo Volnyansky

The Board issued a number of procedural decisions and orders in the course of the proceeding. All of these are available on the Board’s website.

A transcribed Technical Conference took place on July 30 and 31, 2012 and a Settlement Conference was convened on August 8, 2012. The intervenors and Enersource were unable to settle any issues at the Settlement Conference.

The oral hearing took place on September 4, 6, 10 and 13, 2012.[1] Enersource filed its written Argument-in-Chief on September 17, 2012. The Board heard the submissions of the intervenors on September 24, 2012 and Enersource’s Reply Argument on September 28, 2012.[2]

This Decision addresses each of the issues on the Issues List:[3]

1. General
2. Rate Base
3. Operating Revenue
4. Operating Costs
5. Capital Structure and Cost of Capital
6. Cost Allocation
7. Rate Design
8. Deferral and Variance Accounts
9. Modified International Financial Reporting Standards
10. Smart Meter

1 – General Issues

[1] See Appendix A for a list of witnesses who appeared at the oral hearing.
[2] Written versions of some of these submissions were also filed by the parties.
[3] The Board approved Issues List is attached at Appendix B.

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

Enersource proposed that the Board set rates for 2013 and 2014. Rates for 2013 would be set using a traditional forward test year cost of service approach. Rates for 2014 would be set by increasing 2013 rates to include the revenue requirement effects of 2014 capital expenditures, including depreciation, return and PILs. The rates for cost of capital would not be changed, nor would the level of OM&A expenditures, or the forecast load. Enersource called this method for setting 2014 rates the Incremental Capital Return ("ICR") model.

This proposal is a departure from the Board's rate-setting policy in effect at the time of the application ("3rd Generation IRM"). (In this Decision, the Board refers to 3rd Generation IRM as "the policy", although this policy is being replaced by the Renewed Regulatory Framework for Electricity.) Enersource acknowledges that its proposal is a departure from the Board's policy, but takes the position that its proposal provides significant benefits, namely the timely recognition in rate base of capital expenditures and rate smoothing. In putting forth its proposal, Enersource did not analyse the outcomes that would flow from its remaining on 3rd Generation IRM, although it did provide some calculations during the oral hearing in response to an Undertaking.

No intervenors supported Enersource's proposal. Most intervenors argued that Enersource had provided no compelling reason for the Board to depart from its established policy.

Board Findings

Enersource is seeking different treatment than that established in the Board's 3rd Generation IRM policy. The Board is guided by its policies in its decision making and conforms to those policies unless there are compelling reasons to do otherwise. The Board must therefore consider whether there are compelling reasons to determine that Enersource's alternative rate-setting method is appropriate.

Energy Probe argued that Enersource's proposal is comparable to early rebasing for 2014 and that therefore the Board should apply the standard criteria for that type of request. These criteria were articulated by the Board in its April 20, 2010 letter in which it stated that a distributor would need to "clearly demonstrate why and how it cannot adequately manage its resources and financial needs during the remainder of its IRM plan period." Enersource does not view its application as early rebasing, and has stated clearly that it is not claiming that it is unable to adequately manage its resources and financial needs for 2014 under the Board's current policy.

The Board does not agree that Enersource's proposal amounts to an early rebasing request for 2014. In an early rebasing, the distributor is applying for a cost of service rebasing to be followed by three years with rates adjusted according to the 3rd Generation IRM annual adjustment mechanism. Enersource's proposal does not contemplate this kind of rate adjustment for the years beyond 2014. Enersource's request is essentially a two-year cost of service application. The company is requesting that the Board set rates for 2013 based on its 2013 revenue requirement and set rates for 2014 based on its 2014 revenue requirement. Although many of the revenue requirement elements would remain unchanged between 2013 and 2014, 2014 would still be a new revenue requirement, with new rates, with no particular expectation for how rates would be set for 2015 and beyond. The company has argued that its proposal should be considered in the context of the Board's policy consultation on the Renewed Regulatory Framework for Electricity, as a sort of "pilot" for how the Board might resolve some of the issues raised in that consultation. The Board has received two year cost of service proposals in the past; in that respect the proposal is not new.

Enersource did not explicitly put forth criteria by which its proposal to deviate from the Board's policy should be assessed. However, the company did agree with the suggestion that an appropriate criterion could be whether the proposal is superior to the Board's policy in the circumstances of this application. A number of parties, and CCC in particular, argued that the Board's test for early rebasing should apply.

For purposes of this application, the Board will adopt two criteria: 1) whether the proposed approach is superior to the Board's policy in light of Enersource's circumstances and 2) whether Enersource can manage its resources and financial needs under the current policy. Having considered these criteria, the Board finds that Enersource's proposal is not superior in the circumstances and the company can manage adequately under the current policy, for the reasons detailed below.

Enersource has advanced two main arguments for why its proposal is superior to the current policy in light of Enersource's circumstances: rate smoothing and early recognition in rates of capital expenditures. The Board will address each in turn.

Enersource submitted that its approach will smooth the magnitude of the rate increases which would otherwise be faced by customers under the Board's current policy. Enersource maintained that if capital expenditures are not explicitly and directly recognized in rates during the IRM term, then there will inevitably be a large rate increase at the time of rebasing due to the increase in rate base and, consequently, revenue requirement.

The Board does not agree with this analysis for two reasons.

First, rate smoothing would need to be demonstrated on a comparative basis, as argued by SEC. This would require an analysis of the likely trajectory of rates and costs over a typical IRM term and then a comparison with what Enersource is proposing. Enersource did not conduct this comparative analysis. The company resisted such analysis, primarily on the basis that it would require reliance on assumptions about factors outside the company's control. The Board notes that in the normal course a great deal of the analysis required for making a forward test year cost of service application requires assumptions about factors which are outside the company's control such as economic conditions, interest rates, customer growth, and weather. If the company is going to assert that its proposal is superior in the circumstances, then a comparative analysis would be an important component of demonstrating this. The Board agrees with AMPCO that a comparison "is essential for the Board to evaluate any proposed alternative to the status quo." The company did show the pattern of rate changes over the past IRM term and the current rebasing. And while the pattern – admittedly illustrative – showed a dramatic increase between the last year of IRM and the rebasing year 2013, during testimony it was revealed that the increase is not nearly as dramatic as depicted and the increase in the rebasing year is largely driven by the rise in OM&A, not the increase in rate base.

Second, even if Enersource's claim was correct that its approach would lead to smoother rates, the customers would only derive this benefit if the framework were in place for a term comparable to the 3rd Generation IRM (4 years). Enersource's proposal, however, is for only two years.

Enersource also argued that its approach allows for the prompt recognition in rates of capital expenditures, thereby facilitating capital planning. Enersource further argued "Delaying recovery of the cost of capital until a future rebasing would effectively deny recovery of prudently incurred costs."

The Board does not agree for two reasons. First, the Board finds that the argument that this approach facilitates capital planning is not persuasive. Rate-setting for two years only is not aligned with longer term capital planning. Second, and more importantly, one of the central principles of incentive ratemaking frameworks is the separation of costs from prices. Multi-year incentive schemes are established without an annual re-calibration of rate base. The Board recently affirmed this long-standing approach in its Report on the Renewed Regulatory Framework for Electricity ("RRFE Report"):

> *The Board's rate-setting policy in this Report represents a further development of the approach adopted by the Board when it first established Performance Based Regulation ("PBR") for electricity distributors in its January 18, 2000 Decision with Reasons:*
>
> > *… PBR is not just light-handed cost of service regulation. For the electricity distribution utilities in Ontario, PBR represents a fundamental shift from the historical cost of service regulation. It provides the utilities with incentives for behaviour which more closely resembles that of competitive, cost-minimizing, profit-maximizing companies. Customers and shareholders alike can gain from efficiency enhancing and cost-minimizing strategies that will ultimately yield lower rates with appropriate safeguards for service quality. Under PBR the regulated utility will be responsible for making its investments based on business conditions and the objectives of its shareholder within the constraints of the price cap, and subject to service quality standards set by the Board.*
>
> *Going into PBR, distribution rates are set based on a cost of service review. Subsequently, rates are adjusted based on changes to the input price index and the productivity and stretch factors set by the Board. PBR decouples the price (the distribution rate) that a distributor charges for its service from its cost. This is deliberate and is designed to incent the behaviours described by the Board in 2000. This approach provides the opportunity for distributors to earn, and potentially exceed, the allowed rate of return on equity. It is not necessary, nor would it be appropriate, for ratebase to be re-calibrated annually.*[4]

The Board has been clear that rate base re-calibration is generally not part of a multi-year ratemaking framework. Distributors are expected to respond to the incentives in the framework and the result will determine the returns shareholders earn. The Board therefore concurs with Energy Probe's submission: "Enersource already has the ability to compensate its shareholders for investments that are made every year during an IRM term. This ability is called productivity and efficiency improvements."

The Board has addressed the two areas in which Enersource took the position that its proposal was superior in the circumstances to the Board's policy. It is also relevant to consider whether there are any ways in which the Enersource proposal is inferior to the Board's policy. The Board concludes that there are a number of elements of the

[4] *Report of the Board: Renewed Regulatory Framework for Electricity Distributors: A Performance-Based Approach*, October 18, 2012, pp. 10-11.

Board's current policy which are not satisfactorily addressed under Enersource's proposal, including the total cost approach (as opposed to the separation of capital and OM&A expenditures), productivity incentives, and the regulatory principles of stability and predictability.

With respect to total costs, Enersource itself focussed on the importance of total cost and disagreed with the segregation of capital and operating costs inherent in some of the performance benchmark measures related to OM&A. (This is addressed in detail in the OM&A section of this Decision.) Enersource's proposal however, departs from the total cost approach, by adjusting rates for capital expenditures explicitly, and in isolation from OM&A expenditures. The Board's 3rd Generation IRM (and its recently announced 4th Generation IR), on the other hand, apply a total cost approach, where rates are set based on consideration of capital and operating expenditures, and then are adjusted annually without distinguishing between the two. This continues the Board`s long-standing policy of separating rates from costs. The Board therefore agrees with SEC and Board staff that it would be inconsistent and inappropriate to set rates based on a separation of OM&A and capital costs.

With respect to productivity incentives, Enersource's proposal incorporates no long term efficiency or productivity incentives, only a one-year freeze on OM&A. Accordingly, as Energy Probe argued, "the incentive to achieve productivity and efficiency gains is reduced under the Enersource proposal." This is a significant shortcoming in comparison to 3rd Generation IRM (and 4th Generation IR) which adopts a long-term approach to rate-setting.

With respect to regulatory predictability and stability, CCC noted that those are principles upon which all parties must rely. CCC went on to argue that Enersource's "one-off application that reflects its own particular desires for 2014" undermined those principles. The Board finds that Enersource's proposal provides less stability and predictability because it is only for two years.

The other criterion for the Board to consider is whether Enersource can manage its resources and financial needs adequately under the existing policy. Enersource provided little analysis of the impacts on its operational and financial needs of remaining on 3rd Generation IRM. There is no evidence that it cannot manage its needs adequately – as the company itself acknowledges. Enersource maintained that its capital expenditures are expected to be stable over the next four years. It took the position that no part of its 2014 capital expenditures would be eligible for recovery under the Incremental Capital Module. Despite the company's stated position, there was evidence that the company viewed some of the 2014 expenditures as being required, i.e. non-discretionary. However, Enersource had done no analysis of the 2014 capital budget to identify what expenditures would be considered discretionary and what would be non-discretionary. The Board's conclusion is that the company's view that none of its 2014 capital expenditures would qualify for the Incremental Capital Module is premature. It appears that the company did not consider the question in a thorough manner. A more thorough analysis of its budget and the Board's decisions in this area might lead Enersource to a different conclusion.

Having considered the two criteria, whether the proposed approach is superior to the Board's policy in the circumstances and whether Enersource can manage its resources and financial needs under the current policy, the Board finds that there is no compelling reasons to depart from the Board's policy. On that basis, the Board rejects Enersource's proposal that the Board set rates for 2014 as part of this proceeding.

As parties will be aware, the Board has now released its RRFE Report, which sets out the Board's new policy for rate-setting and provides three options for distributors. The Board notes that Enersource's proposal is not aligned with the approaches contained in that Report for the same reasons as set out above.

As the Board has determined that it will not set rates for 2014, for all of the subsequent issues, the Board will only make determinations for 2013 rates.

In accordance with the transition process outlined in the RRFE Report, Enersource has a number of options for rate-setting in 2014 and beyond:

- Enersource may remain on IRM for three years (2014, 2015 and 2016), after which it would be rebase for 2017 and move to the five-year 4^{th} Generation Incentive Regulation term.
- Enersource may apply for Custom Incentive Regulation to take effect as soon as January 1, 2015.
- Enersource may apply for the Annual Incentive Regulation Index to take effect as soon as January 1, 2014.

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

No findings are required on this issue because the Board has already decided not to set rates for 2014 as part of this proceeding.

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

There are no outstanding Board directions, so no findings are required.

Issue 1.4 – Is service quality acceptable?

Enersource reported on service quality indicators, in accordance with Chapter 7 of the Distribution System Code. Enersource noted that the company had met or exceeded the Board's minimum service quality standards, except the rescheduling of missed appointments in 2011.

The only submissions on this issue were with respect to reliability performance. Enersource's results on service reliability are shown in the following table.

Enersource Service Reliability Indices

2007 to 2011

Index	Includes outages caused by loss of supply					Excludes outages caused by loss of supply				
	2007	2008	2009	2010	2011	2007	2008	2009	2010	2011
SAIDI	0.65	0.33	0.61	0.58	0.89	0.61	0.28	0.57	0.55	0.73
SAIFI	0.78	0.73	1.16	1.32	1.97	0.61	0.42	0.92	1.10	1.54
CAIDI	0.83	0.45	0.53	0.44	0.45	1.01	0.67	0.62	0.50	0.47

SAIDI = System Average Interruption Duration Index
SAIFI = System Average Interruption Frequency Index
CAIDI = Customer Average Interruption Duration Index
Source Exhibit 1 Issue 1.4 VECC IR No. 3

Enersource acknowledged that the System Average Interruption Duration Index ("SAIDI") and System Average Interruption Frequency Index ("SAIFI") for 2011 were higher than in 2009 and 2010. The company explained that there are number of initiatives and programs, as described in its Asset Management Plan, to address the 2011 results. Enersource also submitted that based on information in the Board's Yearbooks, its performance was excellent compared to other distributors in its cohort.

AMPCO submitted that customers in the Large Use customer class have special needs that should be addressed separately and that Enersource should develop a customer specific reliability measure for this class which should also be benchmarked. AMPCO was of the view that improvements to service reliability for Large Use customers can be achieved through a reallocation of current spending. Enersource did not reply to AMPCO's submission.

Board Findings

The Board has no concerns with Enersource's service quality.

The Board will not, at this time, adopt AMPCO's proposal that service reliability for customers in the Large Use customer class be tracked and benchmarked. The Board is currently undertaking a consultation on service reliability standards and the issues raised by AMPCO are appropriately addressed there on a generic basis. In addition, as part of the Renewed Regulatory Framework for Electricity, the Board will be undertaking further work to set performance standards. AMPCO may wish to raise its proposal in that context as well.

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

Most intervenors made no submissions on this issue, and those that did (SEC and Energy Probe) accepted the company's proposal.

Board Findings

The Board is satisfied that the alignment of the rate year and the fiscal year is appropriate.

2. RATE BASE

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

Enersource applied for a 2013 rate base of $627 million. In comparison, the 2008 Board approved rate base was $497 million and the actual 2008 rate base was $491 million. Enersource explained that the increase of $130 million over the 2008 Board approved level is largely due to an increase in average net capital assets of $109 million and an increase in the working capital allowance of $21 million.

Enersource identified the following main drivers for the increase in net capital assets:

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

Intervenors focused on three issues in their submissions:

1. The purchase of the Derry Road office and the retrofit of the Mavis Road operations centre;
2. Customer capital contributions; and,
3. Working capital allowance.

The Board will address each issue in turn.

Derry Road and Mavis Road buildings

Until recently, Enersource had all of its employees and business functions located at Mavis Road. Enersource provided evidence in its application that these accommodations were no longer suitable to meet the company's needs. No party to the proceeding disputed this evidence.

In 2009, Enersource identified and assessed options for its building facility needs. It considered building on the existing Mavis Road property, buying new land to construct a new facility, and purchasing or leasing an existing building. Ultimately, Enersource purchased an existing building on Derry Road in 2012 to house its new administration and corporate head office. Enersource also decided to reconfigure the existing property at Mavis Road back to its original purpose as an operations centre. Enersource retained TAC Facilities Group to determine the space plan for the offices at Mavis and a new head office prior to the purchase of the Derry Road facilities.

The following table summarizes the capital costs for 2012 and 2013 included in the Enersource application.

Capital Expenditures

(in millions, CGAAP)	2012	2013	Total
Derry Road Location	$ 20.0	$ -	$ 20.0
Mavis Road Location	$ -	$ 4.0	$ 4.0
Total	$ 20.0	$ 4.0	$ 24.0

Source: E2-T2-S5 Table 2

No party disputed that Enersource required alternative office facilities; that it identified the reasonable options; or that it made the appropriate choice among those options. Parties did object to the space plan, which many parties, (SEC in particular) submitted was excessive.

The Mavis Road facility has currently approximately 70,000 square feet of office area and 60,000 square feet of industrial space. Enersource expects to convert the Mavis Road facility to an operations centre, however 41,000 of the available 70,000 square feet in office space remains unplanned. Enersource stated that it expects to house 127 staff in the available office space at the time of move in and a further 7 staff within 5 years. A further 100 outside staff will be serviced by the operations centre.

The total useable office space in the Derry Road facility is 79,000 square feet and Enersource stated that the head office space was planned for 176 at time of move in , 189 staff in 5 years, and 202 in 10 years.[5] The evidence is that about 150 staff occupied the space at move-in.

SEC argued that the office space planned for Enersource's facilities is about 60% too large. In SEC's view, there is 50,000 square feet of space that will be in excess of needs in the test year and for the foreseeable future. Energy Probe supported this argument. SEC pointed to industry standards and a comparison to the cost and size of PowerStream's recently built head office to substantiate its view. SEC also pointed to several of the individual elements of the space plan as indications of excess. These included:

1. A 1,000 square foot Executive Boardroom
2. Three large meeting rooms, totaling 3,750 square feet

[5] EI-Issue 2.1 Board staff IR #12 attachment 1 p. 101 and E2-T2-S5 appendix 4 p.1

3. A further 32 meeting rooms, including a number of dedicated meeting and work rooms

4. 4,647 square feet for the CEO's office area, including 380 square foot offices for the CEO and for the Chairman of the Board (the Chairman does not have an office now and does not work full-time for Enersource)

5. 5,676 square feet for the lobby and customer service areas. There will also be some customer service areas (undetermined as yet) at the Mavis Road location

SEC also noted that Enersource had only planned for 29,000 of the 70,000 square feet of office space at the Mavis Road facilities. In response, Enersource testified that it has not yet determined what the remaining 41,000 square feet would be used for but assured the Board that it would ultimately be required.

In SEC's view, ratepayers should not be required to fund the cost consequences of that excess space. SEC submitted that the Board should impute lease revenues of $1,825,000 in the Test Year to compensate for the rate base and operating costs associated with the 50,000 square feet of excess space.

Board Findings

This issue concerns expenditures which have largely already been incurred by the company. The expenditures were for Derry Road were incurred in 2012. Given that the issue concerns past expenditures which are now in dispute, the Board must conduct a prudence review. The Board has a well-established set of principles regarding the conduct of a prudence review:

- Decisions made by the utility's management should generally be presumed to be prudent unless challenged on reasonable grounds.
- To be prudent, a decision must have been reasonable under the circumstances that were known or ought to have been known to the utility at the time the decision was made.
- Hindsight should not be used in determining prudence, although consideration of the outcome of the decision may legitimately be used to overcome the presumption of prudence.
- Prudence must be determined in a retrospective factual inquiry, in that the evidence must be concerned with the time the decision was made and must be

> based on facts about the elements that could or did enter into the decision at the time.[6]

The Board finds that the company failed to ensure that the space plan was as efficient and as cost effective as reasonably possible. The Board will therefore disallow $2 million from the 2012 capital expenditures, which represents 10% of the capital expenditures for the Derry Road portion of the project, or 8% of the total renovation project for Derry Road and Mavis Road. The reasons for the Board's decision follow.

Enersource argued that it was extremely unusual for an economic regulator to delve into detailed office space planning. The Board does not agree. The scrutiny to which Enersource has been held in this proceeding is to ensure that ratepayers are funding expenditures that are prudent. Sometimes this requires going into detail, which is warranted with a project of this magnitude. The expenditure was $20 million in 2012, which is 31% of the total capital budget for that year. A further $4 million is forecast in 2013, which is 8.6% of 2013 capital expenditures. This is the single largest project the company has undertaken since last rebasing. The detailed examination was also necessary because Enersource did not provide objective quantitative evidence which the Board could rely upon in assessing the prudence of the expenditures.

The Board finds that Enersource has provided adequate evidence and analysis to show the inadequacy of the Mavis Road facilities, and the potential alternatives. The company provided detailed evidence regarding health and safety and other concerns with its Mavis Road facility. It also provided a comparative cost analysis of buying versus building new facilities. The Board finds, however, that the company has not provided adequate evidence that the space plan is cost-effective or efficient for ratepayers.

Enersource described having gone through an "iterative process" to determine its space plan, but the Board finds that there is no cogent or compelling evidence that the process included sufficient scrutiny or assessment from either internal or external sources to ensure that the company planned the space as efficiently as reasonably possible. TAC Group prepared the space plan for Enersource, and Mr. Kingdon from TAC Group testified at the hearing. Enersource did not offer Mr. Kingdon as an independent expert; he was put forward to provide evidence on the work he performed for Enersource and his experience on other projects. Mr. Kingdon was retained to determine the space plan

[6] Enbridge Gas Distribution, RP-2001-0032, Decision with Reasons, December 13, 2002, p. 63.

for the new head office (and the renovated offices at Mavis Road) based on what Enersource specified it needed and before the purchase of the new head office at Derry Road. There is no indication that his work included an assessment of whether Enersource's requirements were being met as efficiently as reasonably possible. There was no evidence by Mr. Kingdon or the company that the space plan was optimized in terms of size and cost or that overall constraints were applied to limit the space. This was also not addressed in any accompanying documents.

Mr. Kingdon testified that the space plan for Enersource was reasonable in his experience. However, his experience did not include any directly comparable entities. It would be part of prudent planning to compare space plans with other similarly regulated entities to ensure that the interests of ratepayers, in terms of minimizing costs, were adequately considered. In addition, his evidence regarding the reasonableness of the space plan was only qualitative. No rigorous quantitative analysis comparing space planning was provided. This is in no way a criticism of Mr. Kingdon. He conducted his work according to the specifications of the company. It was the company's responsibility to conduct or commission comparative work in this area. The Board finds that the company should reasonably have expected that the Board would require quantitative evidence to substantiate the prudence of its plans and the resulting costs, especially given the relative magnitude of the expenditure. The lack of this evidence is particularly notable given the extent of the evidence in other areas of this project (such as the need for new facilities and the cost comparisons of different approaches.)

SEC also argued that based on various industry standards the space per employee at Derry Road is excessive. Enersource argued that there was insufficient evidence on the record for the Board to reach any conclusions regarding industry standards. The Board can place little weight on the industry standard information offered by SEC because the Board does not have sufficient evidence to determine whether these standards are applicable to entities such as Enersource. However, it would have been prudent of Enersource to look to specific industry standards as a means of assessing the efficiency level of its space plan and substantiating its appropriateness. The evidence is that Enersource did not review external standards or explicitly assess its plan against such standards.

Enersource did have one direct comparator available to it. PowerStream recently constructed new office facilities, and information about that project is publicly available. SEC conducted a comparison between the Enersource space and PowerStream space and concluded that Enersource's space plan was excessive.

In responding to SEC's assertion that Enersource's square footage per employee is higher than that of PowerStream's head office, Enersource asserted that it falls well under the average square footage for utilities that is reported by surveys of the International Facility Management Association. However, this assertion was not part of Enersource's evidence supporting the proposal. It was taken from material filed in the PowerStream proceeding and was not substantiated or examined in this proceeding. As with the industry standard information offered by SEC, the Board will place little weight on this information.

A comparison of the space allocations per employee at the two office buildings shows the following:

Comparison of the Derry Road Office Facility to the PowerStream Head Office

	Derry Road	Power Stream
Capital cost	$20 million	$27.7 million
Square footage	79,000	92,000
Head office employees (projected)	189	270
Gross square feet per employee	418	341
Capital cost per employee	$105,820	$102,593
Capital cost/gross square feet	$253/sq.ft.	$310/sq.ft

Although Enersource has criticized this comparison on a variety of grounds, the Board finds that this comparison of two head offices for two reasonably similar distributors provides a reasonable comparative analysis. Because Enersource offered no alternative comparative or objective quantitative external analysis, the comparison with PowerStream is effectively the only objective external analysis upon which the Board may place any weight. The Board finds that this comparative evidence supports the conclusion that inadequate overall control to protect the interests of ratepayers was applied to space planning for the project.

Enersource maintains that it has planned for future growth in employees. While planning for some future growth is reasonable, the Board finds that the company has not substantiated that it requires space adequate to accommodate 202 employees when only 150 are using it currently; this is a 35% increase. Based on Enersource's five year projected occupancy of 189 (which is 26% growth over the move in number of 150 and 7% growth from the planned number of 176) the space allocation for Enersource is almost 23% higher than for PowerStream (which includes 8% for future growth). Even on the higher long-term forecast occupancy of 202, the space per employee for

Enersource is almost 15% higher than for PowerStream. The Board notes the space plan calls for 82,891 square feet five years after move-in, which is even higher than the actual space at Derry Road. The Board has based its analysis on the 79,000 at Derry Road, as that is the actual space now in existence, however, using the original planned space leads to an even greater difference from PowerStream at 439 square feet per person.

Enersource also argued that the analysis does not include the operating cost differentials or the capital cost differentials. While the comparison shows that the capital cost per employee is lower for Enersource, there is inadequate evidence to conduct a full life cycle cost comparison between Enersource and PowerStream for both capital and operating costs. What we do have is a comparison of two reasonably similar utilities, with significantly different space allocations. The lower capital costs and a lower cost per employee, even if the latter were substantiated, is not on the face of it justification for excess space. The space should have been planned with ratepayer interests in mind, and therefore with rigorous consideration of efficiency. Less total space would result in further savings for ratepayers over the proposed cost.

In addition, a number of specific space allocations were examined in some detail during the hearing:

- There are 32 meeting rooms across both facilities for 248 employees.
- Individual offices for many staff include space for meetings, and in addition there are meeting room and workroom space allocations which are provided to several groups on a dedicated basis.
- There are a further four large meeting rooms of 1,000 square feet or more: one is an executive boardroom at 1,000 square feet, and three large meeting rooms which can be combined to form a single room of 3,750 square feet.
- There is also a further 4,300 square feet for the lunch room, break rooms and coffee stations.

There is an absence of externally validated quantitative evidence that these space allocations are appropriate relative to industry standards and/or external comparisons, and therefore the Board finds that this is evidence that the space planning was done on a cumulative basis, with insufficient consideration given to controlling the total amount of space in the interest of ratepayers.

Finally, there remains 41,000 square feet of unused space at the Mavis Road office facility, for which there is no fixed plan. The analysis has focused on the head office space (as it compares to the PowerStream head office) but the evidence of the significant amount of unused and unplanned space at the original facility supports the finding that ratepayers are being asked to fund unjustified total space.

SEC has proposed that the Board should impute rent for the excess space. The Board will not adopt this approach. The Board regulates the distribution activities of Enersource and it would not be appropriate to render a decision that implies that the company should expand its scope to leasing facilities. This is not to say that the company could not have adopted the approach of renting out excess space until it is required for distribution activities. However, such an approach is potentially complex and in the absence of a proposal from the company to do so, the Board finds that it would be inappropriate to essentially mandate such an approach.

The Board will therefore disallow a portion of the Derry Road capital costs to reasonably reflect the level of excess head office space. However, there is insufficient evidence available to accurately quantify the optimal space and associated capital expenditure.

Based on the PowerStream comparison, the Board finds that the excess space is between 15% and 23%. However, the Board recognizes that there may not be a linear relationship between the space and the associated capital costs and therefore will not disallow 15% of the capital costs.

The Board will disallow $2 million as being representative of the excess space which has not been justified and which the Board consequently finds to be imprudent. This disallowance is 10% of the overall $20 million incurred in 2012 for the Derry Road facility. The amount is based on the PowerStream comparison and the Board's assessment of the company's evidence as to the space allocated to the various uses. The Board concludes that $2 million is appropriately representative of the excess costs. This disallowance will be treated as a reduction to 2012 capital expenditures. Enersource shall make the appropriate adjustments to 2013 ratebase and depreciation to reflect a revised capital expenditure in 2012 of $18 million.

Customer contributions

Customer contributions are up-front amounts that a distributor levies to recover part of the infrastructure costs incurred in servicing new development or additions and changes to existing development. The total amounts recovered are treated as a revenue offset.

The following table provides a breakdown of the customer contributions (aid to construction) for the period 2007 to 2013.

TABLE 1 – CUSTOMER CONTRIBUTIONS ($thousands)

	2007	2008	2009	2010	2011	Total 2007-2011	Fcst 2012	Fcst 2013
Capital Expenditures								
Ind & Com Services	5,897	4,729	5,634	3,372	3,452	23,084	2,926	2,560
New Subdivisions	9,029	3,761	-4,461	12,083	3,331	23,743	2,443	2,247
Road Projects	1,446	3,171	1,589	3,601	2,457	12,264	1,776	1,687
Total	16,372	11,661	2,762	19,056	9,240	59,091	7,145	6,494
Aid to Construction								
Ind & Com Services	751	2,548	3,162	3,112	1,911	11,484	1,600	1,600
New Subdivisions	8,826	1,980	-5,279	4,082	933	10,542	600	600
Road Projects	370	2,388	533	1,289	1,466	6,046	600	600
Total	9,947	6,916	-1,584	8,483	4,310	28,072	2,800	2,800
Ratio								
Ind & Com Services	12.70%	53.90%	56.10%	92.30%	55.40%	49.70%	54.70%	62.50%
New Subdivisions	97.80%	52.60%	118.30%	33.80%	28.00%	44.40%	24.60%	26.70%
Road Projects	25.60%	75.30%	33.50%	35.80%	59.70%	49.30%	33.80%	35.60%
Using 2007-2011 Averages								
Ind & Com Services						49.70%	1,456	1,274
New Subdivisions						44.40%	1,085	998
Road Projects						49.30%	876	832
Total							3,416	3,103

(Source: Issue 2.1, Energy Probe #3)

Energy Probe submitted that customer contributions in the areas of industrial and commercial services; new subdivisions; and road projects are all understated based on a comparison of capital contributions and gross capital expenditures over the period 2007 through 2011. Energy Probe's submissions were supported by SEC and VECC.

Energy Probe submitted that the evidence on this issue is not credible as Enersource is forecasting the same level of contributions for each of the three categories despite changes in the level of capital expenditures for these categories of investment in each year. Energy Probe argued that there should be a correlation between customer contributions and total capital expenditures.

Enersource explained that overall the level of contributions has been declining with the decreasing amount of available green space in its service territory. The Company stated that it reviews characteristics of capital projects and performs the economic evaluation calculations set out in the Distribution System Code to determine the level of customer contributions. Enersource also noted that the Board has recently amended the economic evaluation calculation to remove upstream costs. This has the effect of decreasing customer contributions.

With particular reference to the areas of concern for Energy Probe, Enersource noted that, adjusting for outliers, the relevant proportions of industrial and commercial services and new sub-divisions are relatively the same as in the past.

Enersource also indicated that the 2011 customer contribution figure for Roads Projects is unusually high that year given that a one-off MetroLinx project provided a 100% customer contribution.

Board findings

The Board accepts Enersource's forecast capital contributions for 2012 and 2013. The Board notes that the trend in the ratios of contributions to total costs for industrial and commercial services and new subdivisions are relatively flat, even decreasing slightly. In addition, the amendment in the Distribution System Code to remove upstream costs from the economic evaluation assists the Board to conclude that the proposed capital contributions for 2012 and 2013 are reasonable for rate making purposes. The Board finds that Enersource's process of evaluating the specific characteristics of upcoming projects to determine whether they attract a customer contribution more appropriate than forecasting contributions based on a trend analysis as suggested by Energy Probe.

Issue 2.1 – Is the proposed Working Capital Allowance for 2013 appropriate?

Enersource proposed a working capital allowance of $107 million for 2013, based on a working capital allowance factor of 13.5% of the sum of the cost of power and controllable expenses.

The proposed approach was developed by Navigant Consulting Inc. Enersource noted that it is the same approach that was approved by the Board for Toronto Hydro (EB-2009-0139), Hydro Ottawa (EB-2011-0054) and Hydro One Networks Inc. (EB-2009-0096). Enersource stated that the working capital allowance for 2013 increased by $21 million since 2008, mainly due to the inclusion of Global Adjustment Mechanism in the cost of power forecast.

Energy Probe (supported by SEC and VECC) accepted the results of the Navigant study with one exception related to the calculation of the service lag. A weighting is required because Enersource bills residential customers on a bimonthly basis and all other customers on a monthly basis. Energy Probe submitted that a service lag based on customer weights as proposed by Enersource does not reflect cash flow and recommended a service lag based on revenue weights as more appropriate to reflect cash flow. Energy Probe calculated that by using revenue weighted service lag the working capital allowance would be reduced to 10.4%. Applying a 10.4% to the $794 million cost of power and OM&A expenses would reduce rate base by about $24.6 million and the cost of capital by approximately $1.6 million (before factoring in the reduction in the gross deficiency due to PILs). Energy Probe submitted that if the Board has concerns about its proposed methodology, the 2013 default value of 13.0% should be used instead.

Enersource provided an interrogatory response which included an updated Working Capital Study based on 2010 actual amounts applied to the forecasted 2013 amounts. This resulted in a working capital allowance of 17.1%. However, the company did not seek to rely on this updated study, and retained its lower forecast based on the earlier study.

Energy Probe was critical of this updated study and working capital allowance stating that it would also reduce the service lag and result in a lower working capital allowance. Energy Probe also submitted that other modifications were included but not justified in Enersource’s update. Energy Probe concluded that the Board should not give any weight to the updated study.

Energy Probe also submitted that Enersource should adjust the calculation of the working capital allowance to reflect any changes to the load forecast and or any changes to the OM&A expense forecast based on the Board approved figures.

Finally, Energy Probe suggested that moving to monthly billing of residential customers would significantly reduce the working capital factor, rate base and ultimately revenue requirement. Energy Probe recommended that the Board direct Enersource to investigate the additional costs and working capital allowance reduction associated with moving from bimonthly to monthly billing and report the results as part of its next cost of service application.

In its Reply Argument, Enersource relied largely on what the Board has approved in other applications. The company outlined that its approach was developed by Navigant

Consulting who also used this approach for Toronto Hydro, Hydro Ottawa and Hydro One Networks Inc. and noted that the Board has approved this approach for all of these distributors. Enersource also highlighted that the Board had indicated in the Hydro Ottawa decision that the 11% proposed by Energy Probe was too low when compared to other distributors. Finally, Enersource noted that while an update to reflect 2010 figures would produce a working capital allowance of 17% it was not changing its original application for a working capital allowance of 13.5%.

Board findings

The Board has found the Navigant methodology to be appropriate in other applications and does not find compelling reasons to make a different finding in this application. Enersource's proposed working capital allowance is similar to that approved by the Board in those applications, and on that basis is reasonable. The Board also agrees with Enersource that applying a 10.4% working capital allowance is too low when testing and modifying only one element of the overall study and when compared to other distributors. The Board will not render a determination on the reasonableness of the updated study which suggests a working capital allowance of 17%; the study was not examined in any detail in the proceeding, and the company did not seek to rely on it.

The Board also notes that working capital allowance proposed by Enersource and supported by the Navigant study is comparable to the default value of 13% established by the Board for utilities that do not file a lead-lag study.

The Board will therefore accept Enersource's proposal of 13.5% as the working capital allowance factor. The determination of working capital is subject to adjustments the Board has made in this Decision for OM&A.

The Board sees merit in a cost benefit analysis of moving from bimonthly to monthly billing for residential customers, as suggested by Energy Probe. The Board directs Enersource to prepare a cost benefit analysis and to consider making the change if the analysis indicates it is warranted. The analysis and resulting decision will be reviewed at Enersource's next cost of service proceeding.

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

Enersource filed a basic Green Energy Plan (the "GEA Plan") which identifies the projects and expenditures associated with the connection of renewable generation to its system.[7] The plan was filed in accordance with the Filing Requirements: Distribution

[7] Also referred to as Renewable Enabling Investment (REI) and expansion work

System Plans – Filing under Deemed Conditions of Licence (EB-2009-0397), which requires distributors to identify the costs related to the connection of FIT and microFIT projects and/or to the implementation of a smart grid.[8]

The GEA Plan did not include any smart grid initiatives.

Enersource noted that there also are OM&A type expenses associated with the implementation of the GEA Plan, but the company did not identify the level of these costs.[9]

The Board's jurisdiction with respect to the cost recovery mechanism for connecting qualifying renewable generation facilities arises from section 79.1 (1) of the OEB Act. The section provides that some of the Board-approved costs incurred by a distributor to make an eligible investment for the purpose of connecting or enabling the connection of a qualifying generation facility to its distribution system may be recovered from all provincial ratepayers rather than solely from the ratepayers of the distributor. Ontario Regulation 330/09 sets out details in relation to the implementation of the cost recovery framework. In addition, the Report of the Board: The *Framework for Determining the Direct Benefits Accruing to Customers of a Distributor under Ontario Regulation 330/09* (EB-2009-0349), (the "*Framework*") provides further guidance with respect to determining direct benefits accruing to customers of a distributor. The level of direct benefits determines which costs will be recovered from the distributor's ratepayers and which costs will be recovered from all Ontario ratepayers.

Enersource initially proposed to recover all of the GEA Plan costs from its own ratepayers. Enersource explained that the costs are relatively immaterial, that to date it had been able to manage the costs within existing rates, and that GEA Plan activities could be viewed as normal distribution work.

However, in response to Board staff's cross-examination Enersource in its Argument-in-Chief agreed that the indirect capital costs of its Renewable Enabling Improvements for the period 2013 to 2016 should be recovered from all provincial ratepayers. Enersource proposed to use a standardized approach to calculate the amounts: direct costs

[8] March 25, 2010 version of the *Filing Requirements*
[9] These include costs to process and document the FIT program applications, perform inspections and connection impact assessments.

attributable to a distributor's ratepayers would be 6% and the balance, 94%, attributable to provincial ratepayers.[10]

Board staff noted that Enersource's cost attribution proposal excluded the capital costs for 2010 and 2011, the forecast costs for 2012, and the OM&A costs for 2013. Board staff submitted that Enersource should conform to the Framework and allocate the relevant capital costs between Enersource and provincial ratepayers for 2010, 2011, and 2012. In addition, Board staff submitted that Enersource should do the following:

(i) remove the non-Direct Benefits capital expenditures from its rate base and record them in account 1531 for recovery via the IESO protocols;

(ii) identify and remove from its proposed OM&A for 2013 initial OM&A associated with the GEA Plan; and

(iii) record the initial OM&A amounts in account 1532 for recovery via the IESO protocols.

Subject to addressing these matters, Board staff indicated that it had no concerns with Enersource's GEA Plan and saw no issues with the Board approving the plan.

Enersource in its Reply Argument agreed with the approach proposed by Board staff.

Board Findings

The Board approves Enersource's GEA Plan and the approach, proposed by Board staff and agreed to by Enersource, for the calculation and recording of costs eligible for recovery from all provincial rate payers. The revised approach is in keeping with the provincial legislation and the *Framework* set out by the Board.

The Board directs Enersource in its draft Rate Order to adjust its test year rate base by removing the impact of the GEA Plan-related capital expenditures incurred in 2010, 2011, and forecast for 2012 and for 2013 by the amounts shown in Table 2.3-2.

Enersource agreed with Board staff's position as to the appropriate treatment of GEA plan-related OM&A for 2013, but the company did not identify the level of OM&A expenses associated with the implementation of GEA Plan. The Board directs Enersource to remove from its OM&A for 2013 the one-time costs associated with the

[10] Filing Requirements, Part VII, Capital and OM&A Deferral Accounts for Renewable Generation Connection, p22-23 (March 25, 2010 version)

FIT and microFIT projects, if not otherwise eliminated, in accordance with the methodology outlined in the *Framework*. The Board expects Enersource to record these adjustments, as appropriate, in account 1531 – Renewable Connection Capital Deferral Account and Account 1532– Renewable Connection OM&A Deferral Account.

3. Operating Revenue

Issue 3.1 – Is the proposed load forecast for 2013, including billing determinants, appropriate?

Issues were raised in three areas: load forecast; conservation and demand management impacts; and billing determinants. The Board will address each in turn.

Load forecast

Enersource filed a 2013 load forecast based on a multivariate regression analysis. Variables include historical load data, demographic data from the City of Mississauga, historical weather data and economic data from the Conference Board of Canada. The methodology also uses the Gross Domestic Product (GDP), Consumer Price Index (CPI) and other economic planning data. Enersource also made an adjustment to reflect the conservation and demand management targets which is required to meet as a condition of its licence. Citing the economic downturn and increased housing density, Enersource forecast a decrease of 4.4% in kWh sales between weather normalized 2008 actuals and 2013 forecast - net of the impacts of any conservation programs. Enersource used 31 years of data for weather normalization purposes.

Energy Probe conducted an extensive cross-examination of the Enersource witnesses which tested the methodology and the appropriateness of the variables used by Enersource to establish its load forecast. Energy Probe suggested a number of alternative methods by which Enersource could have calculated its load forecast. Enersource's response was that the "goodness fit" of the model was actually worsened when using these suggested alternative methods.

Energy Probe's submission focussed on two main areas of the load forecast. First, Energy Probe objected to the inclusion of a population variable in the formula. Second, Energy Probe submitted that Enersource's forecast should be based on the last 11 years of weather data and not the 31 years of data used by Enersource. The Board will address each of these issues.

The population variable in the regression analysis carries a negative coefficient. Energy Probe put forward the position that this leads to a counter-intuitive result, specifically that load would decrease as population increased. Energy Probe submitted that removal of the population variable would increase the revenue forecast by approximately $300,000. Energy Probe also asked the Board to specifically set out in its Decision a requirement that Enersource provide all assumptions and methodologies related to its load forecast when filing a subsequent application with the Board.

Enersource took the position that the removal of the population variable would require other variables to be removed, which Enersource argued would adversely affect the reliability of the load forecast model. Enersource also cited redevelopment and population intensification as reasons why there could be an increase in population and a decrease in consumption, for example, the movement of people from single-dwelling homes to condominiums.

Energy Probe submitted that weather data in the load forecast model should be based on a shorter term, namely 11 years as opposed to 31 years, in order to produce a more representative view of present weather conditions which are being affected by climate change. VECC agreed with the position taken by Energy Probe.

Enersource disagreed, and instead took the position that the forecast should be based upon a more comprehensive 31 years of data. Enersource pointed to the IESO's use of 31 years of historical data to derive its 18-Month Outlook. Enersource also referenced Environment Canada and the World Meteorological Organization, both of whom use a longer term of 30 years of historical data.

In further countering the intervenors' two proposals for the load forecast methodology, Enersource relied upon the fact that since 2004, its load forecast has produced energy consumption forecasts within 0.3% of actual energy purchases and 1.7% of weather-corrected energy purchases. In addition, 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.

Board Findings

The Board is not satisfied on the basis of the evidence provided that removal of the population variable would not in turn lead to the requirement to address another variable(s) within the model in order to preserve the reliability of the model. As a result, the Board is not prepared to adopt a different methodology for purposes of determining the load forecast.

The Board is satisfied with the load forecast provided by Enersource. In addition to the evidence provided in respect of methodology, which the Board considers to be reasonable, the Board has considered the accuracy of previous forecasting in reaching this conclusion, and finds that Enersource's methodology is sufficiently reliable for purposes of determining the 2013 forecast.

The Board expects that Enersource will, in any future rate application process, submit the information required to both adhere to the Board's requirements and provide the information necessary to justify and support any application it puts before the Board. On this point, and contrary to Energy Probe's proposal, the Board will not make any further direction with respect to material to be filed in future applications.

Conservation and Demand Management

Beginning in 2011, targets for CDM reductions in consumption and demand became a condition of a distributor's licence. Four year targets were defined for each distributor. The standard practice for distributors has been to incorporate the reductions into the load forecast at an incremental 10% per year. Therefore, for most distributors, the expectation is that 10% of the distributor's overall target would be achieved in 2011.

The Board in its *Guidelines for Electricity Distributor Conservation and Demand Management* (EB-2012-0003) established that the Board would authorize a Lost Revenue Adjustment Variance Account ("LRAMVA") to capture, at the customer rate-class level, the difference between the level of CDM program activities included in the distributor's load forecast and the actual, verified impacts of authorized CDM activities between 2011 and 2014.

As a result, distributors are generally expected to include in their load forecast in cost of service proceedings, a CDM component – indicating the amount of CDM forecast. This CDM component not only allows the effects of conservation to be recognized as soon as possible, but helps to mitigate the variance between forecast and actual conservation achieved. Forecast load reduction and actual load reduction are compared and this comparison creates either a debit or credit in the LRAMVA.

The intervenors argued that the CDM adjustment amount for the test year should be reduced. Specifically, VECC submitted that Enersource had over-stated CDM in 2013 by 26.5GWh. In an undertaking response, Enersource provided its cumulative energy savings from planned CDM programs for 2011-2014.

The amounts are set out below:

2011 programs – 58.486GWh

2012 programs – 84.271GWh

2013 programs –119.146GWh

2014 programs – 155.37 GWh

VECC takes the position that the amount relied upon by Enersource in 2011 is based on Enersource's 2011 CDM plan rather than achieved actuals as reported by the OPA. In VECC's view, achieved actuals for 2011 assuming implementation on January 1st would be 26.48GWh. VECC submits therefore that CDM in 2013 is overstated by 26.5GWh. The Board notes that the evidence provided for 2013 through an undertaking response anticipated CDM programs in 2011 at 58 GWh, not the 53 GWh submitted by VECC based on earlier filed evidence. Therefore the amount of over-stating, according to VECC's view, would be slightly higher at 31.5 GWh (58-26.48). VECC argued that required changes to the load forecast would result in a 2013 CDM adjustment of 85.446GWh**.** Correcting for the updated evidence, the difference of 5 GWh would result in a revised adjustment, using VECC's approach, of 90.466 GWh.

VECC also took the position that the 7.18GWh of actual CDM savings in 2011 was embedded in Enersource's load forecast model. As a result, VECC submitted that the 7.18GWh should be removed from the model and the 2013 forecast in order to avoid double-counting.

Board Findings

The LRAMVA is designed to capture the difference between forecast and actual CDM impacts. In order to do that, a determination must be made as to what the CDM forecast amount is so as to eventually be able to reconcile that number with the CDM actual value. The Board will accept Enersource's evidence as to its projected CDM impacts. Enersource's 2013 cumulative forecast of 119.146 GWh will then be compared against actuals through the LRAMVA. The Board finds this treatment to be acceptable. The comparison between cumulative forecast and actuals will take place by rate class. Further particulars as to the settling of the LRAMVA are found in section 8.3 of the Decision.

The Board must also consider whether the load forecast must be changed in order to avoid double-counting of the 7.18 GWh savings in 2011 which is embedded in the load forecast model.

The Board is not convinced that the inclusion of the 7.18 GWh which has been included in the load forecast will have such a material effect over the term of the forecast that it necessitates Enersource adjusting its load forecast. As such, the Board will accept the load forecast as submitted.

Billing Demand Forecast

An issue was also raised by VECC in relation to the Billing Demand Forecast. VECC submitted that there should be an 80,000 kW adjustment from GS 50-499 in keeping with historical data. Enersource advised in an August 23, 2012 letter to the Board that the 80,000 kW adjustment had been made.

Board Findings

The Board expects that this adjustment will be reflected in Enersource's rate order.

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

Enersource forecast Other Revenue of $5.18 million in 2012 and $4.83 million in 2013. These amounts are lower than the actual Other Revenue of $5.6 million in 2011. Historical data for Other Revenue is set out below.

Other Revenue (2008-2012)

(in thousands)

OTHER REVENUE	2008 Approved	2008 Actual	2009 Actual	2010 Actual	2011 Actual	2012 Bridge	2013 Test	2011 YTD (june)	2012 YTD (june)
Specific Service Charges	$ 1,282	$ 1,330	$ 1,311	$ 1,283	$ 1,347	$ 1,330	$ 1,335	$ 639	$ 648
Late Payment Charges	$ 420	$ 408	$ 413	$ 1,379	$ 2,068	$ 1,800	$ 1,800	$ 1,052	$ 826
Retailer Service Charges	$ 329	$ 311	$ 303	$ 292	$ 244	$ 207	$ 193	$ 130	$ 105
Other Regulated Revenues	$ 1,260	$ 1,189	$ 1,124	$ 1,608	$ 1,212	$ 1,464	$ 1,452	$ 586	$ 627
Interest Revenue	$ 2,049	$ 1,957	$ 284	$ 187	$ 735	$ 377	$ 50	$ 267	$ 478
TOTAL	$ 5,340	$ 5,195	$ 3,435	$ 4,751	$ 5,605	$ 5,178	$ 4,830	$ 2,673	$ 2,685

Source: Exhibit 3 Tab3 Schedule 1 p.2 Table 1 and Undertaking resposne JT2.33

The intervenors took the position that the forecast was understated. Intervenors took two different approaches to the issue of Other Revenue. One approach was to request adjustments to specific revenue categories. In the second approach, intervenors considered Other Revenue as it stood Year to Date in 2012 and extrapolated Other Revenue for 2013 on that basis.

Energy Probe took the position that 2013 Other Revenue was under-forecast by approximately $500,000. Energy Probe submitted there were understatements in Interest Income ($425,000), Service Charge Revenue ($23,000), Pole Rental ($36,000) and the SSS administration charge ($15,000). Energy Probe arrived at these numbers by extrapolating 2012 levels to arrive at a 2013 forecast.

Enersource responded that the forecast Interest Income for 2013 included only Interest Income on cash balances for 2013. The company stated that the actual year-to-date June 2012 amount of $478,000 includes interest on cash balances related to regulatory assets and liabilities owed to customers that needs to be paid back. Enersource provided this explanation as the reason for the discrepancy between years. While the exclusion of interest on regulatory assets and liabilities represented the major reason for the change in Interest Income revenue, Enersource also advised that it had been able to employ better cash management strategies which resulted in its holding less cash and as a result receiving less Interest Income revenue.

VECC took a cumulative approach, noting that Enersource's actual Other Revenue as of June 2012 was $112,000 higher than actual Other Revenue as of June 2011. Extrapolating those half-year results, VECC argued that the balance of Other Revenue in 2012 could therefore be higher than 2011 by $224,000. VECC argued that it would be reasonable to carry the understatement forward to 2013 and increase Other Revenue by that amount.

Board Findings

The Board does not agree with the submissions of Energy Probe and VECC.

With respect to the position advanced by VECC, there was some confusion with respect to evidence provided by Enersource outlining the actual totals for June 2011 and June 2012. While the component parts of Other Revenue for June 2012 were correct as originally filed, the Other Revenue total amount was not. Further evidence filed by Enersource clarified the information. The Board is therefore satisfied that the projected variance between 2011 and 2012 actuals was lower than the amount advanced by VECC.

With respect to the submission advanced by Energy Probe, the Board is satisfied that the assumptions Enersource has relied upon in making these estimates are reasonable. While the reduction in Other Revenue from historical levels represents a significant decline, the Board is satisfied that Enersource was able to adequately explain the reasons for the reduction. Enersource's evidence in respect of the reasons for the decline in Interest Income revenue is also reasonable.

The Board notes that only the proposed adjustment to Interest Income was of any magnitude, while the other proposed adjustments were insignificant. Energy Probe advanced no substantive principle in support of these insignificant adjustments. The Board expects that in circumstances where the amount at issue is not material, there should be a key principle at issue.

4. Operating Costs

Issue 4.1 – Is the proposed 2013 OM&A forecast appropriate?

Enersource forecast total OM&A for 2013 at $61 million. This is $25 million higher than 2008 actuals. Enersource has framed its OM&A costs in the context of two envelopes: "Business Unit Activities" and "Other Key Drivers". The increase in Business Unit Activities OM&A since 2008 actual is $16 million, and the increase in Other Key Drivers is almost $9 million over the same period.

Historical and forecast OM&A expenses are set out below.

OM&A Expenses (2008-2013)

(in millions)	2008 Board Approved	2008 Actual CGAAP	2009 Actual CGAAP	2010 Actual CGAAP	2011 Actual CGAAP	2011 Actual IFRS	2012 Bridge Year	2013 Forecast
Business Unit Subtotal	$ 38.9	$ 34.9	$ 40.6	$ 41.9	$ 43.7	$ 43.7	$ 48.7	$ 51.0
Other Key Drivers	$ 1.6	$ 1.3	$ 1.3	$ 2.8	$ 3.8	$ 6.4	$ 7.8	$ 10.0
Total OM&A	$ 40.5	$ 36.1	$ 41.9	$ 44.7	$ 47.5	$ 50.0	$ 56.4	$ 61.0

Source: Exhibit 3 Tab3 Schedule 1 p.2 Table 1 and Undertaking resposne JT2.33
Any differences due to rounding

Enersource noted that the total forecast operating costs for "Business Unit Activities" for 2013 are about $51 million. Enersource pointed to increases in benefit expenses, overtime and contract costs and full-time equivalents and salaries, which together total about $12 million, to explain the increase in "Business Unit Activities" expenses since the 2008 Board approved level. Enersource pointed out that the 2013 level represents a 4.4% annual compound growth rate over the 2008 Board approved level.

In the area of Other Key Drivers, Enersource highlighted increases in overhead burdens, bad debt expense, asset management plan initiatives and operating costs related to the Derry Road facility, which together account for about $8 million in increased costs since the 2008 Board approved level.

Certain intervenors took the position that the amount of increase in OM&A expenses should be based on a top-down approach or a certain percentage increase in OM&A from 2008. Other intervenors advocated that certain component parts of the OM&A budget should be significantly reduced. Finally, some intervenors proposed a combination of both an envelope and specific item reduction method.

AMPCO advocated an annual increase of 2.5% from 2008 actuals.

SEC proposed a top-down approach whereby OM&A costs should be allowed to increase by 5% per year from 2008 actuals. The 5% represents inflation plus customer growth with an additional amount included. SEC also asked the Board to provide direction to Enersource with respect to exercising increased rigour in spending decisions and benchmarking.

Energy Probe proposed a 2.5% increase per year from the 2008 Board approved level. Energy Probe proposed that the reduction in OM&A could be achieved by expense reductions in various areas:

- the allocation from the Corporation to Enersource (approximately $530,000)
- capitalization ($2 million)
- property tax ($80,000)
- bad debt expense ($730,000)
- the incentive plan factor ($960,000)
- a reduction in base salary increase from 3.25% to 2.0% ($260,000)
- the elimination of 8 new positions ($730,000)
- expenses allocated to Enersource for the Corporation’s Board of Directors ($148,000)

VECC took the position that OM&A should be limited to a 10% increase from 2011 actual costs. VECC highlighted the need for specific reductions in bad debt expense ($750,000), regulatory filing costs ($500,000), regulatory costs ($228,000) and capitalization ($2 million).

Board Staff presented two alternatives. First, staff proposed a 15% increase from the 2008 Board approved level on the basis of a yearly inflation factor of 1.7% and a yearly growth factor of 1.2%. Using this escalation factor of 3% per annum from the 2008 Board approved level (including smart meter costs), the 2013 OM&A forecast would be $48 million or a reduction of $13 million from Enersource's requested amount of $61 million.

Alternatively, Board Staff proposed a reduction of approximately $3 million, to $58 million. Board Staff reached this amount by reducing Business Unit requirements by 50% ($2.8 million) arguing that the amount requested was not justified. Citing flat late payment revenue, Board staff also proposed a reduction in bad debt expense of $375,000.

Board Findings

In its Reply Argument, Enersource put forth the proposition that in a forward test year cost of service application the Board should be considering the "prudence" of forecast expenditures and that the Board should presume that the distributor is acting prudently. In this way, Enersource seeks to conflate the two types of examination the Board conducts: forward looking assessment of forecast costs and backward looking assessment of costs already incurred.

A "prudence review" is the review of expenditures after the fact. This is generally conducted in the context of reviewing past capital expenditures for inclusion in rate base or past expenditures included in a deferral account. The Board has well established principles which govern such reviews, which include the presumption of prudence on the part of utility management. The Board's consideration of the Derry Road building expenditures is an example of a prudence review.

In reviewing the forecast of test year expenditures, the Board applies different principles. There is no presumption of prudence; rather the onus is on the applicant to prove its case. This is clear in the OEB Act in section 78(8): "in an application made under this section, the burden of proof is on the applicant."

The applicant is seeking approval for rates; the Board must set rates which are just and reasonable. The Board must set those rates within an environment where it has a mere fraction of the information available to the applicant. For that reason, the Board, indeed all regulators, adopt a variety of approaches to conduct forward test year reviews. The active participation of intervenors, the thorough testing of evidence, the examination of procurement policies and other decision making processes and the application of those processes, and the comparison with other similar entities are amongst the tools used. For some issues, a detailed examination may be warranted; for other issues a higher level examination may be appropriate.

If the Board makes adjustments to the revenue requirement as a result of its review, it is not because the Board is micromanaging the utility or stating "I would have done something differently" (as suggested by Enersource in Reply Argument), it is because the company has not provided sufficient evidence in support of its position. Clearly the Board cannot, and should not, examine every transaction or "duplicate the role of management." However, the applicant must be prepared to withstand a searching enquiry into its proposals – including an examination of alternatives. Past performance by a distributor will certainly inform this review, as will comparison with other distributors.

In this Decision, the Board is not seeking to replace management's business judgment with its own. Rather, the Board is determining what costs may reasonably form part of the revenue requirement so as to ensure that the resulting rates are just and reasonable.

Enersource and the intervenors provided the Board with a wide array of percentages to show the magnitude of the OM&A expense increase since 2008. The Board will begin its analysis on the basis of 2008 actuals because this level represents what the company actually spent to run the utility in the last cost of service year. The OM&A amount requested for the 2013 year is 68.8% higher than the 2008 actual OM&A.

The Board has determined that this level of increase has not been justified. The Board will reduce the 2013 OM&A by $8.466 million. The reasons for this reduction are set out below.

In assessing Enersource's forecast OM&A costs, the Board has considered various issues.

Approach to budgeting

Enersource explained in its evidence that it had used a "bottom-up" approach to budgeting. The Board is concerned that there appeared to be little, if any, analysis of the reasonableness of the overall OM&A budget and its effect on rates and ratepayers. Throughout its evidence, Enersource repeatedly spoke of its budgeting approach as being built from the bottom up; there was little or no evidence of any process of overall or "top down" review of the budget. This is particularly significant given the level of total increase which the company is seeking. A review of overall costs should be a critical part of any method of budgeting chosen by a utility. Such a review is an important component of the budgeting process as it demonstrates that some level of overall restraint has been considered, and potentially brought to bear. The Board finds that Enersource has not demonstrated a sufficient level of review of its overall budget level, including the magnitude of the increase.

Control on expenditure increases

Enersource's application divides spending into two categories: Business Unit Activities and Other Key Drivers. The category of Other Key Drivers has grown at a rapid rate from 2008 actuals (about $1 million) to 2013 forecast ($10 million). The majority of these types of expenses are costs that a utility should expect to incur in the normal course of business. The Board is concerned that Enersource has not incorporated these additional expenses into its every day course of business and as such has not adjusted its operational expenditures to accommodate them within a reasonable total budget. The Board is of the view that a distributor must work to find efficiencies to pay for new expenses and cannot simply continue to add them to the budget, particularly when the increases are significant and incurred year after year. Where increases are required in some areas, the resultant action should be an effort to find savings in other areas. The very fact that the application was framed on the basis of an operating amount and an "extras" budget for key drivers demonstrates that Enersource is not viewing OM&A on a holistic basis and trying to cover new expenses with reductions in existing costs.

Cost/benefit analysis

Enersource was unable to provide examples of cost/benefit analyses that it had used when deciding whether to proceed with particular projects. Two examples of this were Enersource's evidence related to steps taken to reduce bad debt expense and its web self-service initiative. In the case of management of bad debt, Enersource could not quantify any perceived savings from hiring additional staff and contracting with collection agencies, yet the utility proceeded to incur these expenses. In the case of the web-based service initiative, again Enersource was unable to quantify what it expected to achieve in savings, but rather stated that the initiative was undertaken on the basis of customer expectations.

Efficiency levels and comparative analysis

During the interrogatory phase Enersource was asked to comment on its performance relative to other similar distributors, but the company declined to do so, citing the fact that it does not as a general practice compare itself to other utilities.

Enersource stated, when asked how it assesses whether it is performing as efficiently as possible;

> *I guess from the relatable performance measures we look at, SAIFI, SAIDI and CAIDI, which we've indicated are the only ones that we do compare to other utilities. We look at the OEB targets and internal targets and, frankly, we try to better them each year. We do not do comparables to other utilities. It's more of what the customer currently sees as value and trying to drive more value into the equation to the customer each year, year-over-year. We do not look at other utilities as comparables, so I would say it's between OEB targets, our own targets, of trying to get better each year.*[11]

Enersource explained that it does not compare itself to other distribution utilities on the basis of OM&A costs because other utilities may differ in many areas including type of customer and method of capitalization.

However, at the beginning of the oral hearing Enersource did acknowledge that a comparison to other utilities may be helpful to the Board:

> *Traditionally, Enersource does not compare itself against other utilities except for reliability. However, in this hearing procedure – process, it could be helpful for the Panel that we compare Enersource's performance against other utilities.*[12]

Enersource then introduced evidence showing a comparison to other utilities, using total costs per throughput, advocating this metric as the preferable measure to use:

> *From Enersource's management's point of view, to measure relative efficiency, two elements come into play. The first element is total dollars, capital and OM&A spent to deliver the product, and the second element is the amount of product we deliver. If we translate this into an equation, this effectiveness would be measured by total dollars spent over kilowatt-hours.*[13]

[11] Transcript Vol. 2, p.116
[12] Transcript Vol. 1, p.8.
[13] Transcript Vol. 1, p.7.

On this measure, Enersource's performance appeared strong. SEC introduced other comparative evidence on a number of cost measures, most of which suggested that Enersource's performance lags its peers. These measures included PP&E per customer, distribution revenue per customer, OM&A per customer and capital additions per customer. Enersource submitted that the Board should not consider OM&A costs in isolation and that total cost was a more representative measure. In Enersource's view, management should be able to make the decision between investing in capital and OM&A provided that it leads to the "lowest long-term energy cost for customers in terms of reliability."[14] Enersource submitted that the Board should consider the metric of total cost/throughput (kWh).

SEC submitted that Enersource has the highest kilowatt-hours per customer of any utility in the province with an average of 40,000 kilowatt-hours per customer, whereas the average across the province is 23,000. Enersource agreed that its customer mix allowed for a large throughput.[15] SEC argued that in comparison to other utilities, Enersource performs well on this measure because of the sheer quantum of kilowatt-hours supplied. SEC argued that Enersource also measured well on cost per peak kilowatt for the same reason.

The Board has on numerous occasions identified the importance of benchmarking and comparative analysis. It is one of the most effective tools the Board has to assess the relative level of efficiency of distributors. Enersource repeatedly resisted the suggestion that it should look to other utilities to assess its own level of efficiency and to examine whether more efficient approaches are available. The Board understands that no two distributors are exactly the same, but that does not mean that comparisons are irrelevant. The Board notes that within competitive industries companies routinely examine their competitors in an attempt to increase their own efficiency. The Board as an economic regulator acts as a proxy for competition, and therefore it is not surprising that comparative analysis would play a part in the Board's analysis. Enersource maintained that it could demonstrate its level of efficiency by comparing its own performance over time, and the Board agrees that this is one approach to examining efficiency; however, it says nothing about whether the company is as efficient as it could be. For that type of analysis, some form of external comparison or external analysis is required. The company repeatedly stated that it did not compare itself to other distributors when assessing its operations for efficiency.

[14] Enersource Final Argument p.21.
[15] Transcript Vol. 2, p.5.

Enersource likens the use of comparisons to a "top down" approach and asserts that no rigour or analysis informs this approach and even characterized it as "discretionary, even arbitrary." The Board does not agree. A wealth of information is available to distributors in the yearbooks and in distributor applications. Distributors can use this data to compare their performance to other distributors on both a quantitative and qualitative basis. As SEC suggested, the quantitative data is a diagnostic tool – and while not entirely determinative of utility performance, it is certainly indicative and will help to identify those areas which require deeper enquiry.

Enersource argued that the Board should not rely on the various OM&A metrics, but rather should rely on the total cost/kwh metric. The Board agrees that no single measure is determinative. However, there is merit to the various OM&A metrics. The Board is of the view that a comparison to other utilities on a variety of factors helps to better inform the utility of best practices and avoids the situation where a utility may be strong in one area, because of particular characteristics of its system, and lag behind its peers in all other areas. A strong result in only one area is not the desired outcome of a benchmarking analysis.

Enersource argued that the company is more efficient than many of its peers on the total cost per kwh measure. The Board does not agree. Although there is merit in examining a total cost measure, the Board in the past has expressed the drawbacks of the attempts of measuring total cost effectively on the basis of the information available at this time. Enersource characterized energy throughput as a "universal fundamental" that normalizes for the characteristics of customers which vary across utilities. However, this does not account for the fact that different types of customers do drive different costs. This is recognized by the cost allocation model and by Enersource's witnesses. There is also evidence on the record of this case that the total cost per kwh may result in misleading conclusions because the costs of serving a few very large customers may be less than serving numerous lower volume customers (consuming the same total volume). Therefore, differences in customer mix could have a significant impact on this measure. Comparing rates across distributors is another way of looking at total cost, and on this measure Enersource is somewhat lower than average for residential customers, but significantly above average for all other rate classes.

The Board notes that under the Renewed Regulatory Framework further work will be done to more effectively benchmark total cost. However, in the meantime, the Board finds that no strong conclusion can be drawn from the total cost measures put forward by the company.

While Enersource submits that it does review its OM&A expenses against itself on a year over year basis, on the OM&A measures, the company is clearly lagging its peers. More important, though, is the company's insistence that it should not have its performance compared with others – and that it does not itself compare itself with other distributors in any significant quantitative or qualitative way. As a result, the company can provide no externally corroborated evidence as to its level of efficiency. This is particularly relevant given the exceptionally large cost increases the company is seeking.

2013 Approved OM&A

The Board finds that Enersource has not provided sufficient evidence to substantiate the proposed level of OM&A expense increase. The Board must therefore determine the appropriate level of reduction. The Board will adopt an envelope approach and will derive an approved OM&A level based on 2011 actuals. Many parties argued that the Board should derive the approved 2013 level from either the 2008 actual or 2008 Board approved level. Rather, the Board finds that it would more appropriate to derive the 2013 level from the most recent actual year. To this 2011 actual, the Board will apply an escalation factor which includes an amount which is representative of customer growth and inflation over the longer period. The number of customers Enersource services has increased by approximately 1.2% from 2008 to 2013. Inflation has increased by about 1.7% annually. Together, these total about 3%. However, in recognition that costs do not increase one-for-one with growth in customers and in recognition that the company should be accommodating incremental expenses through efficiency improvements, the Board will reduce this escalation factor and will not incorporate any additional factor for costs the company has identified as incremental. The Board finds that a compound escalation factor of 2.5% from the 2011 actual is appropriate.

A 2.5% compound annual increase applied to the 2011 actual OM&A amount of $50.032 million results in a 2013 OM&A amount of $52.565 million. This results in a reduction of $8.446 in Enersource's 2013 OM&A forecast. The 2013 level of $52.565 million represents an approximate 6% average annual increase from the 2008 Board approved level, a 9% average annual increase from the 2008 actual and a 6.4% average annual increase from the 2009 actual. The Board finds that this level of increase is sufficient to accommodate inflation, customer growth, and incremental expenditures over the period. (The Board has disallowed capital costs associated with the Derry Road head office. The Board will not make any additional adjustment to OM&A in relation to that issue.)

The Board's mandate is not to direct an applicant on how to manage its utility and therefore the Board will not comment on specific areas in which Enersource should curtail OM&A spending. Rather the Board will leave it to the discretion of Enersource to manage its activities within the spending envelope. The Board's approval of just and reasonable rates takes into account the expectation that a distributor will exercise efficiencies in carrying out OM&A activities. To that end, the Board strongly urges Enersource to inform itself of best practices by comparing itself with other utilities in the exercise of its OM&A functions in order to ensure that it is undertaking these functions in the most cost effective manner.

Issue 4.2 – Is the proposed level of depreciation/amortization for 2013 appropriate?

Enersource has used the half year rule to calculate depreciation for capital additions during the test year. Depreciation has been calculated on a straight line basis over the estimated service lives of assets. Enersource submitted that the useful lives it adopted in its Useful Lives Study (*Enersource Corporation, Burlington Hydro, Oakville Hydro, Halton Hills Hydro & Milton Hydro Useful Life of Assets, dated December 10, 2009*) are consistent with the Asset Depreciation Study for the Ontario Energy Board (Kinectrics study), dated July 8, 2010. Enersource indicated that based on the results of Enersource's Useful Lives Study and internal analysis, the company revised its componentization structure and revised the estimated useful lives of its distribution system assets and other assets that form part of Property Plan and Equipment. The intervenors made no submissions on depreciation.

Board Findings

The proposed method of calculating depreciation/amortization is consistent with the Asset Depreciation Study commissioned by the Board and therefore the Board approves Enersource's approach.

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

Enersource has included $3.5 million for PILs and property tax in the 2013 revenue requirement.

Energy Probe submitted that the tax credit for PILS for 2013 should increase from $200,000 to $242,000. The amount represents co-op and apprentice tax credits. Enersource has used a forecast amount to arrive at the 2013 input of $200,000. Energy Probe, on the other hand, proposes the use of the 2011 actual amount which is $242,000. Enersource did not do a detailed forecast of the number of positions eligible for the tax credits nor the amount of credit for each of the positions.

Board Findings

The Board notes that amounts for co-op and apprentice tax credits could fluctuate from year to year depending upon the number of people Enersource has employed in those positions. As such, the Board will make no adjustment to Enersource's estimate for this factor.

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

Enersource Corporation (the "Corporation") and Enersource have entered into a service agreement, whereby employees of the Corporation provide various services to Enersource. These services include corporate governance, and administrative and operational services which include finance, human resources, corporate relations, internal audit and purchasing, as well as other services. As a result, certain costs are allocated from the Corporation to Enersource.

Corporate Cost Allocation (2008-2012)

(in thousands)	2008 Rates	2008 Actual	2009 Actual	2010 Actual	2011 Actual	2012 Bridge Year	2013 Test Year
Total Enersource Corporation Operating Costs	$ 10,154	$ 9,977	$ 9,689	$ 10,233	$ 10,006	$ 10,849	$ 11,644
Costs allocated to Enersource	$ 8,546	$ 8,358	$ 8,842	$ 9,721	$ 9,506	$ 10,131	$ 10,874

Source: Evidence April 27, 2012 - Exhibit 4 Tab1 Schedule 1 p. 10

Out of total expenses of almost $10 million in 2008, the Corporation allocated $8.4 million to Enersource. In 2009, the method of allocating costs changed. Enersource's percentage of costs increased from 83% to 94%. In 2013, the Corporation proposes to allocate $10.874 million of $11.644 million to Enersource.

VECC proposed that the allocation be reduced by $674,000 to account for what it described as an over-allocation of non-utility staff to utility functions.

AMPCO also challenged the change in allocation submitting that many of the services provided by the Corporation were done on a fixed cost basis and were independent of any customer growth. AMPCO was of the view that Enersource was allocated a greater portion of costs because there was a reduction of work done for other affiliates that were no longer active after 2008. Finally AMPCO pointed out that the significant cost increase had taken place despite the number of Corporation employees increasing by only 2 (from 50 to 52).

Enersource provided evidence that the Corporation has experienced a shift out of certain unregulated businesses, including telecom and the water heater business. Coincident with this change in focus, the Corporation and Enersource made the decision to change the way in which costs were allocated. It was decided that costs would be allocated on a revenue and headcount basis. Enersource's witnesses testified that there had been no change in the actual work that was being performed for the utility or in the time spent by those performing the services, but despite this, the method of allocating costs changed.

Board Findings

The Board finds that Enersource has failed to provide compelling evidence for why the proposed change in allocation is warranted. Instead, Enersource has acknowledged that there has been no increase in the type or amount of work performed by the Corporation for the utility. Enersource has relied upon a change in the way in which costs are calculated as the reason for making a change to the allocation. The Board finds that this explanation is not adequate justification for the cost increase. The Board has already reduced the OM&A level for 2013, and will make no further reduction for this cost item as it is part of the total OM&A level discussed above. The Board directs Enersource to address this issue further at its next cost of service proceeding.

5. Capital Structure and Cost of Capital

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

Enersource used the return on equity and short term rate contained in the Board's *Cost of Capital Parameter Updates for May 1, 2012 Cost of Service Applications*, dated

March 2, 2012. Enersource proposed that the return on equity and short term debt rates be updated with the Cost of Capital Parameters for 2013 rates as published. The intervenors made no submissions on the proposed capital structure.

Board Findings

The proposed capital structure is consistent with the Board's policy and is therefore approved. The Board has now released the cost of capital parameters for 2013 and Enersource is directed to incorporate these in the draft Rate Order.

Issue 5.2 – Is the proposed long term debt cost for 2013 appropriate?

Enersource has calculated the weighted average cost of long term debt using the Internal Rate of Return function resulting in a long term debt rate of 5.0914%.

The rate was based on new debt of $320 million, consisting of a 10 year debenture at 4.521% and $210 million for 30 years at 5.297%.

Energy Probe submitted that Enersource should have based the weighted average cost of the long term debt on the interest costs for the 2013 test year. Energy Probe noted that the interest costs in each year of the bond repayment schedule is $16,096,800. As a result, Energy Probe proposed that a long term debt rate of 5.03% be used, which reduces the revenue requirement by $210,000.

Enersource agreed to use the long term debt rate of 5.03% but only if the corresponding $126,059 in debt financing costs, which had previously been factored into the interest rate, are included as an increase in OM&A.

Board Findings

The Board accepts Enersource's argument that if issuance costs are removed from the debt rate calculation, they would need to be incorporated in costs in some other way. The Board has in other proceedings allowed for the recovery of issuance costs within the calculation of an effective rate, and the Board is prepared to do so in this case. Recent examples include Union Gas Limited 2013 Rates (EB-2011-021) and Hydro One Networks Inc. (Transmission) for 2013 and 2014 Rates (EB-2012-0031). As a result, the Board accepts 5.0914% as the cost of long-term debt.

6. Cost Allocation

Issue 6.1– Is the proposed cost allocation methodology for 2013 appropriate?

Enersource relied on the Report of the Board on the Review of Electricity Distribution Cost Allocation Policy (EB-2010-0219) in determining its cost allocation methodology. Intervenors were of the view that use of the Board's Cost Allocation Policy was appropriate but cautioned that the cost allocation methodology would need to be updated based on the revised revenue requirement and load forecast arising from the Board's Decision.

Board Findings

Enersource's proposed methodology for cost allocation follows the Board's policy and is therefore acceptable. The Board expects that Enersource will update the cost allocation methodology if necessary.

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

Enersource proposed to make changes to its revenue-to-cost ratios for 2013. These changes stem from a new cost allocation study conducted on 2013 costs and proposed rates. Enersource explained that its objective is to move each class closer to the Board target revenue-to-cost ratio.

Enersource's initial 2013 cost allocation study showed that two classes, GS Large Use and the USL class, fell outside the Board's target range. As a result, Enersource proposed to reallocate revenues among rate classes. Enersource explained that the revenue-to-cost ratio determined in the test year for the Residential Class based on the current rates was 85%, which was significantly lower than the 91.5% contained in the 2008 study. Accordingly, Enersource proposed adjusting the Residential Class from 85% to 90%.

Enersource proposed to make the following changes to rate classes.

Customer Class	2008 Settlement %	2013 Test Year %	2013 Test Year Proposed %	Target Revenue to Cost Ratio %
Residential	91.5	85	90	85-115
GS < 50kW	111	113	109	80-120
Small Commercial < 50kW	111	na	na	80-120
GS 50kW- 499kW	111	112	109	80-120
GS 500kW - 4999 kW	91.5	108	108	80-120
GS Large Use (> 5000kW)	111	124	109	85-115
Street lighting	91.5	96	96	70-120
Unmetered Scattered Load	111	147	109	80-120

SEC agreed with the Enersource proposal.

Energy Probe took the position that only the two classes outside the Board approved ranges should be reallocated. Energy Probe submitted that the allocations for these two classes should move to the top of the approved range and submitted that changing the Residential Class allocation from 85 to 86% would be sufficient to ensure revenue neutrality.

VECC submitted that Enersource's proposal was inconsistent with Board policy. VECC proposed moving the GS Large Use and USL classes down to 120%**.** VECC suggested that moving the Residential Class from 85% to 86% would be sufficient to ensure revenue neutrality.

Finally, AMPCO submitted that the proposed ratios did not demonstrate a material change toward unity for most rate classes. AMPCO took the position that the Residential Class should not move from 91.5% (as established in the 2008 settlement) to 90% and rather should stay at 91.5%. In AMPCO's view, reducing the ratio from the 2008 level would represent a move away from unity. Furthermore, AMPCO submitted that all ratios should move to 100% on a phased basis over the next two years. AMPCO did however submit that Enersource's 2013 study and cost allocation model does reflect an improvement in data and modelling since the 2008 study.

Board Findings

The Board in its Report on the Review of Electricity Distribution Cost Allocation Policy, (EB-2010-0219) addressed the importance of reasonably allocating the costs of providing services to various classes of consumers in establishing rates that are just and reasonable. Enersource provided evidence detailing the specifics of its cost allocation study. The company advised that its 2013 cost allocation study was more accurate than its first study in 2008. The Board accepts this evidence, and therefore will use the current study, and not the 2008 study, as the starting point for considering further changes to the ratios.

The current study shows that two rate classes fall outside the Board's target range. In order to rectify this, Enersource proposed to bring the two rate classes within the Board's target range and as a result raise the cost allocation of the Residential Class to 90%. The Board's Report does not state as one of its principles that any movement to within a range must be to the top of the target range as proposed by VECC, or that all ratios should move to unity as proposed by AMPCO. Rather the Board's policy sets out that distributors should endeavour to move their revenue-to-cost ratios closer to one if that is supported by improved cost allocations. The Board accepts Enersource's proposal on the basis that it is consistent with the Board's policy. The Board notes that these changes can be made without triggering the need for mitigation.

7. Rate Design

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

Enersource did not propose any changes to the existing ratios with respect to the fixed to variable split of the revenue requirement allocated to each customer class.

Board Findings

No changes to the ratios were proposed, and no party objected to company's proposals in this area. The Board finds that the fixed/variable split for each rate class for 2013 is appropriate.

Issue 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?

<u>Low Voltage Service Rate</u>

Enersource currently records the charges from Hydro One Networks Inc. related to Low Voltage ("LV") to account 1550, which is a Group1 deferral and variance account. For

2013 Enersource proposed the creation of an LV rate to recover these charges from its customers. The revenue generated from this new LV rate would be recorded in account 1550 and would offset the LV charges that are currently recorded in the same account. Enersource provided the calculation by customer class of the proposed LV rate and indicated that the methodology it utilized was the same as the methodology found in the 2006 Electricity Distribution Handbook. VECC and Energy Probe submitted that they had no issues with the proposed LV rates.

Board Findings

The Board is satisfied that Enersource has derived the LV rate appropriately, and approves the proposal.

<u>Unmetered Scattered Load</u>

Enersource proposed to add a separate, new Unmetered Scattered Load ("USL") rate class to the Tariff of Rates and Charges for 2013. Under the existing tariff, USL customers are included within the Small Commercial rate class. Enersource included the new USL class in the Allocation Model utilized to prepare the rates proposed for 2013. Energy Probe submitted that Enersource's proposal is in compliance with the Board's policy[16] and that the policy has been properly implemented in Enersource's proposal.

Board Findings

The Board agrees that the proposal is consistent with the Board's policy in this area and approves the proposal.

<u>Merging of Classes</u>

Enersource proposed to merge the Small Commercial rate class (excluding USL customers) with the General Service less than 50 kW ("GS<50 kW") rate class. Enersource submitted that this is reasonable since, with the removal of the USL customers from the Small Commercial rate class, few customers remain within the Small Commercial and those customers which do remain are similar to and have the same quantity threshold as GS<50 kW customers. Enersource further argued that the Small Commercial rate class customers are not sufficiently different from GS<50 kW customers in service setup, billing, collections, or meter reading profiles to require a

[16] EB-2010-0219 Report of the Board on the Review of Electricity Distribution Cost Allocation Policy dated March 31, 2011, where at Section 2.5.4 the Board indicated that it expected each distributor to include a separate USL rate class as part of the cost of service application in both the CA Model and in the Tariff of Rates and Charges.

separate rate class. Neither the intervenors nor Board staff objected to this proposal to merge the Small Commercial (excluding USL customers) with the GS< 50kW rate class.

Board Findings

The Board approves the proposal.

Issue 7.3 – Are the proposed Total Loss Adjustment Factors appropriate?

For the 2013 Test Year Enersource proposed to continue with the current Board approved Total Loss Factor (“TLF”) of 1.0360 for Secondary Metered Customers <5000 kW,[17] and of 1.0045 for Primary Metered Customers >5000 kW and of 1.0145 for Secondary Metered Customers > 5000kW. Enersource noted that its actual TLF for the past five years has averaged 1.0379 which is higher than its current and proposed level. Enersource summited that excluding 2007, a year which experienced an unusually high TLF, results in a four year analysis that is more accurately aligned with the current, and proposed, TLF.

Neither the intervenors nor Board staff objected to the continuation of the existing TLFs as proposed by Enersource.

Board Findings

The Board approves the proposed loss factors.

Issue 7.4 – Are the proposed retail transmission service rates appropriate?

Enersource did not initially seek to adjust its existing Retail Transmission Service Rates (“RTSR”) on the basis that it would update its request for 2013 RTSR at the time the Board issues the updated Guidelines and associated filing module to reflect the January 1, 2013 Uniform Transmission Rates. VECC agreed with this approach and submitted that interested parties should be provided with the opportunity to review and comment on Enersource’s proposed 2013 RTSR once they have been filed with the Board.

Board Findings

[17] The TLF for Primary Metered Customers <5000 kW is calculated by multiplying the TLF for Secondary Metered Customers <5000 kW by 0.99

The Board concludes that the current RTSR should remain unchanged. The Board expects that the timing for the announcement of new Uniform Transmission Rates 2013 will make it impractical to revise Enersource's 2013 RTSR. Enersource may apply for revised RTSR as part of an IRM application. In any event, the continued operation of the associated variance account will keep the company and ratepayers whole.

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

Enersource filed a proposed Tariff of Rates and Charges for 2013 which reflected the specific proposals presented in the evidence.

Board Findings

The Board directs Enersource to include a revised Tariff of Rates and Charges for 2013 with its draft Rate Order to be filed in accordance with the Decision and Order. Further direction regarding the preparation of the draft Rate Order appears at the end of this Decision.

8. Deferral and Variance Accounts

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

In the Report of the Board on Electricity Distributors' Deferral and Variance Account Review Initiative (EB-2008-0046 July 31, 2009) the Board determined that at the time of rebasing all deferral and variance account balances should be reviewed and disposed of unless otherwise justified by the distributor or as required by a specific Board Decision or guideline. The Board has previously determined that volumetric rate riders should be used to dispose of the account balances, consistent with its findings in the Board's combined Decision for the Recovery of Regulatory Assets - Phase 2 Decision dated December 9, 2004. The Board has also determined that the default disposition period used to clear the account balances through a rate rider should be one year.

Enersource requested disposition of its Group 1 and Group 2 deferral and variance account ("DVA") balances as of December 31, 2011 and the forecasted interest through

December 31, 2012. Enersource filed a number of updates to the balances through the course of the proceeding.

Tables 1 and 2 below show the updated DVA balances as requested in Enersource's Argument in Chief.

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

Account Number	Account Descriptions	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	-$155	-$7,960
1582	RSVA - One Time Wholesale Market Service	$0	$29	$0	$0	$29
1584	RSVA - Retail Transmission Network	-$5,712	-$138	$6,353	$7	$510
1586	RSVA - Retail Transmission Connection	-$4,840	-$119	$5,414	$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	$0	$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		

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

Account Number	Account Descriptions	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	$1,490	$27	$22	$26	$1,565
1508	Other Regulatory Assets - Sub-Account Deferred Incremental Capital Charges	$44	$1	$1	$0	$46
1518	Retail Cost Variance Account - Retail	$296	$11	$4	$0	$312
1548	Retail Cost Variance Account - STR	$316	$25	$5	$0	$346
1572	Extra-Ordinary Costs (PCBs)	$1,211	$26	$18	$37	$1,291
1592	PILs and Tax Variances	$75	-$28	-$14	-$1,032	-$998
1592	PILs and Tax Variances - Sub Account PST Savings	-$749	$0	$0	$749	$0
1592	PILs and Tax Variances - Sub Account PST Savings (Contra)	$749	$0	$0	-$749	$0
1592	PILs and Tax Variances - Sub Account PST Savings (50% portion owing to customers, upto Dec. 2012)	$0	$0	$0	-$547	-$547
	Total Group 2 Accounts:	$3,432	$62	$36	-$1,516	$2,015

Enersource proposed to refund the Group 1 and Group 2 DVA balances, including interest based on the Board's prescribed interest rates, of approximately $894,000 over a one-year period commencing January 1, 2013. This amount excludes the disposition of smart meter balances and consists of a refund of approximately $2,999,000 to be allocated to all customer classes and a recovery of approximately $2,105,000 from customers that are not on the regulated price plan.

No parties raised any issues with respect to Enersource's DVA balances.

Board Findings

The Board approves the final disposition of Group 1 and Group 2 DVA balances as set out in Tables 1 and 2 above, including interest to December 31, 2012, for a net credit balance of $894,000. These balances are to be disposed of over one year commencing January 1, 2013.

The treatment of Enersource's Smart Meter Disposition Rate Rider and Stranded Meter Rate Rider are addressed under issue 10 in this Decision.

Issue 8.2 – Are the proposed rate riders appropriate?

Enersource proposed the following rate riders to clear the account balances :

- Rate Rider # 1 –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.

Enersource requested that the rate riders be effective for one year from January 1, 2013 to December 31, 2013. Energy Probe submitted that the rate riders were appropriately calculated. No other parties raised any issues with the rate riders.

Board Findings

The Board approves a rate rider calculated based on a per KWh basis over one year and applicable to all customers to dispose of Groups 1 and 2 deferral and variance accounts. The Board will not approve the refund of MIFRS deferred adjustment, and recovery of OCI MIFRS post-employment adjustment in the calculation of Rate Rider #1 for the reasons set out under Issue 9 of this Decision. Enersource is directed to recalculate Rate Rider #1 with these adjustments and file the final rider for approval with its Draft Rate Order.

The Board approves Rate Rider # 2 to dispose of Global Adjustment Sub-Account applicable to non-regulated price plan customers and applied on a per kWh basis.

The Board will approve Rate Rider # 3 as set out under set out under Issue 10 of this Decision.

The Board will approve Rate Rider # 4 as set out under set out under Issue 10 of this Decision.

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

In addition to continuing the existing DVA accounts, Enersource requested a new deferral account to capture costs for inspecting or certifying suite meters. However, this request was subsequently withdrawn in the company's Reply Argument

Board Findings

The Board approves the continuation of the existing accounts. The proposed new accounts are addressed elsewhere in this Decision.

LRAMVA

The Board in its Guidelines for Electricity Distributor Conservation and Demand Management (EB-2012-0003) established that the Board would authorize a Lost Revenue Adjustment Variance Account ("LRAMVA") to capture, at the customer rate-class level, the difference between the level of CDM program activities included in the distributor's load forecast and the actual, verified impacts of authorized CDM activities between 2011 and 2014.

The cumulative CDM forecast by rate class to which the CDM actuals will be compared is shown in the table below.

Customer Class	2013 CDM Forecast
Residential	35,842,920
Small Commercial	-
Unmetered Scattered Load	-
GS < 50kW	39,519,293
GS 50kW- 499kW	6,718,613
GS 500kW - 4999 kW	7,166,687
GS Large Use (> 5000kW)	8,983,655
Street lighting	20,915,195
Total	119,146,362

Source: Exhibit 3 Tab 1 Schedule 2 p. 6 Table 3.

9. Modified International Financial Reporting Standards

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

Enersource adopted International Financial Reporting Standards ("IFRS") for financial reporting effective January 1, 2012. The adoption of IFRS changes the manner in which Enersource performs its accounting and the reporting of financial results, and creates impacts on regulated rates and charges.

Enersource filed its application based on MIFRS and proposed to refund customers the credit balance of $13,825,000 in Account 1575. The balance is based on a proposed return on rate base for one year and includes an adjustment for PILS, and was updated during the course of the proceeding to exclude Construction Work in Progress. The revised proposed balance is $14,071,013. Enersource proposed to refund this amount to customers over one year through a separate rate rider.

Board Staff submitted that Enersource's proposal deviated from the Board's policy as set out in the *Addendum to the Report of the Board: Implementing International Financial Reporting Standards in an Incentive Rate Mechanism* (EB-2008-0408 "the Addendum Report") dated June 13, 2011. Staff submitted that the Board's policy is to reflect the "adjusting amount" as an adjustment to depreciation and to include the return on rate base calculation on the unamortized balance in revenue requirement. Board Staff acknowledged, however, that under either method, the refund amount to customers should theoretically be the same, all else being equal.

Board Staff also noted that a four year disposition period has been used for other cost of service applications. Based on a four year period, Board Staff calculated that the refund would total $16,474,719. The increase of $2,403,706 in the refund is due to Weighted Average Cost of Capital applied over a longer term.

Board Staff also submitted that the PILS adjustment of $-171,414 should be excluded from Enersource's PP&E deferral account to be consistent with past deferral account practices. Enersource accepted this proposal.

SEC and Energy Probe expressed concern regarding Enersource's deviation from Board policy, noting that a separate rate rider may pose issues for rate increases under the IRM formula in subsequent years. Enersource responded that the proposed one year disposition period is designed to mitigate rate volatility. However SEC's conclusion that Enersource's rate increases are not justified would in SEC's view limit the need for such mitigation. SEC argued that if there is a proposed reduction in rates in 2013, customers will see an incremental increase in bills in 2014 when a one year disposition period is completed. SEC and Energy Probe both submitted that the clearance of this account should be over four years and in the manner consistent with the Board's policy, rather than through a rate rider. SEC agreed with Board Staff's return calculations over a four year disposition period.

Enersource also responded that a one year disposition period would reduce intergenerational inequities for customers compared to a one-time adjustment to rate base (which refunds customers over a four year period), and would more closely align with the length of time over which the IFRS-CGAAP transitional differences arose.

In its Argument in Chief, Enersource added a request for a variance account 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 Transition PP&E Amounts and the amounts billed. No party objected to this newly proposed variance account.

Board Findings

The disposition method as per Board policy has been consistently used by other distributors and the Board does not find a compelling reason to depart from its policy in this application.

The Board agrees with Board Staff that the refund resulting from disposition of the Account 1575 using a separate rate rider or the prescribed method in Board policies may theoretically be the same. However, the Board shares the concerns expressed by SEC and Energy Probe regarding Enersource's deviation from Board policy. Enersource's proposal to remove $14,071,013 from revenue requirement and subsequent disposition through a one year rate rider may complicate future rate adjustments under the IRM period. Under a separate rate rider approach, the amortization of the adjusting amount is not treated as an adjustment to depreciation expense and the return on rate base calculation on the unamortized balance is not included in the applicable revenue requirement calculations, and thus not included in the revenue requirement determination.

The Board also shares the concern raised by SEC that Enersource's proposed rate rider approach would cause an incremental increase in customer rates starting in 2014 when the one-year disposition is completed. An amortization over four years provides consistent annual financial reporting to the Board. This information, compiled in the Yearbook of Electricity Distributors, is used for a variety of purposes including the development of cohort analyses in the Board's IRM. Accordingly, the four-year amortization period provides for a consistency in rate impacts and measured financial performance over the next four years.

The Board will not approve disposition through a rate rider; nor will it approve a variance account to track variances between the amount approved to be refunded to customers and the amounts billed. As articulated in the Board's policy clearing an account on the basis of forecast numbers is a departure from the Board's standard practice. However, the Board recognizes that this is a unique account, which is "cleared" through an adjustment to rate base, which itself includes components that are forecasted for the bridge and test years, for example capital additions and working capital allowance.

The Board approves the disposition of $16,474,719 in Account 1575 to be amortised over four years to align with Enersource's expected rebasing cycle. The period of amortization may be revisited by a subsequent panel should Enersource chose to rebase under an alternative cycle under the Board's Renewed Regulatory Framework for Electricity.

The Board directs Enersource to adjust depreciation expense, the weighted average cost of capital and the revenue requirement in the manner as specified by the Board policy.

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

Enersource requested that the Board approve one new deferral account related to MIFRS: MIFRS Other Post-Employment Benefits Adjustment Account. This account would 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.

Enersource proposed that this deferral account would capture the impact of other post-employment benefits ("OPEB") adjustments related to future transactions, as described below, and also past transactions.

Regarding past transactions, the proposed deferral account would capture:

1. The impact from the other post-employment benefits adjustment resulting from the transition to MIFRS. The net impact of this adjustment at the date of transition of January 1, 2011 was a reduction of the other post-employment benefits accrued liability of $150,000. This amount would be returned to ratepayers through Enersource's proposal to record a credit in the requested deferral account.

2. The recognition of actuarial gains and losses which would be recorded in Other Comprehensive Income ("OCI") under IFRS. Under CGAAP, these amounts would have been amortized in OM&A using the corridor approach.

> Enersource early adopted the amended IFRS standard, IAS 19, which eliminates the corridor approach. The 2011 actuarial loss relating to the other post-employment benefits obligation was $769,000. The amount would be collected from ratepayers through Enersource's proposal to record a debit to the requested deferral account.

If the account is established, Enersource would record a net amount of $619,000 debit balance in the account and proposes to recover the amount from customers over one year.

Board Staff noted that the Addendum Report requires utilities to demonstrate the likelihood of a large cost impact upon transition to IFRS when seeking an individual account for IFRS related impacts. Board Staff submitted that the requested amount for recovery is below Enersource's materiality threshold of $658,000 and that Enersource has not demonstrated a large cost impact. SEC and Energy Probe agreed with Board Staff. Board Staff and SEC further submitted that the requested recovery should not include any amounts in relation to 2011 during which Enersource was under IRM as this would constitute an inclusion of "out of period" amounts and be contrary to the rule against retroactive rate making.

Enersource also proposed to accumulate all future re-measurements of OCI in the requested deferral account and proposed to dispose the cumulative balance in future cost of service rate applications if the balance reaches the materiality threshold. Enersource indicated that it was unable to forecast whether any actuarial gain or loss will be recognized in any given year. Board Staff submitted that though it is difficult to forecast future actuarial gains and losses, demonstrating materiality is one of the tests for establishing a new deferral or variance account and Enersource has not done so in this case. Enersource also indicated that given the amount requested for disposition, a recovery period of longer than one year would result in a $0.00/kWh rate rider for certain customer classes. As a result, Board staff submitted that Enersource was unable to demonstrate that there is a large cost impact.

Staff suggested that it is open to Enersource to file an application in the future to recover/refund future actuarial gains or losses from the other post-employment benefits, if the amount is material.

SEC supported the establishment of the variance account going forward to deal with annual fluctuations in the accounting charges for pensions and OPEBs, using a relatively long disposition period so that the effect is to smooth the impacts over time. SEC noted that the Board approved a similar variance account for Hydro Ottawa in EB-2011-0054. SEC acknowledged that Enersource did not provide any evidence that the entries in this account would be material, and in the normal course should therefore not be approved. However, SEC submitted that a variance account should be established as annual adjustments in pension and OPEBs are very unpredictable, and are sensitive to small changes in long-term interest and discount rates. In the event that amounts accumulating in the account turn out not to be material, SEC argued that the Board could deal with that at the time disposition is being proposed.

Enersource responded that its request for a deferral account is reasonable because actuarial gains and losses are unpredictable and the net actuarial loss incurred is close to the materiality threshold. In its Reply Argument, Enersource sought approval to carry the balance in a proposed new OCI deferral account if the Board did not approve the disposition of the $619,000 in the P&OPEB transition account. Enersource asserted that as a result the balance would not be considered an out period adjustment. Enersource confirmed that it would only seek disposition of future cumulative balances only if the materiality threshold is met.

Board Findings

Enersource's request can be separated into two components: a request to recover or carry forward $619,000 related to 2011, which results from a reduction in the accrued liability for other post-employment benefits and a recognition of actuarial gains and losses in Other Comprehensive Income; and a deferral account going forward to capture annual fluctuations in the accounting charges for OPEB.

The Board agrees with SEC that in the absence of an existing deferral or variance account, and given that the amount cannot be treated as a Z factor due to materiality, the recovery of $619,000 from ratepayers for 2011 would be retroactive ratemaking.

In its Addendum Report, the Board indicated that distributors could seek approval to establish an individual account if they can demonstrate the likelihood of a large cost impact upon transition to IFRS. The Board will therefore approve the establishment of a prospective OPEB deferral account, which will capture the actuarial gains and losses related to OPEB, effective in 2013 subject to the materiality threshold being met. The

Board notes however, that Enersource did not include any amounts for actuarial gains and losses related to the OPEB in its base rates. Therefore, the Board is authorizing the establishment of a deferral account rather than a variance account for Enersource to record and track the cumulative actuarial gains and losses related to OPEB as they are incurred. Given that actuarial gains and losses are non-cash items, interest carry charges shall not apply to the balance in this account. The Board agrees with SEC that annual adjustments in OPEB can be unpredictable and sensitive to changes in various factors. To be eligible for clearance in a future rate proceeding, the OPEB amount must be material. Enersource may come forward for disposition in a future application for the amount accumulated in the deferral account, if any.

The Board further notes that this deferral account is being established in the absence of Board policy on the OPEB issue. The account will therefore continue until the earlier of:

- A decision by the Board to implement a policy respect to the OPEB which differs from the approach approved here, and
- The next rebasing application for Enersource

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

Enersource submitted that it has used the Board Report for policy guidance on the transition to IFRS, and specifically its requirements for regulatory accounting, regulatory reporting, and the filing requirements.

SEC and Energy Probe submitted that Enersource has identified and provided for all of the material impacts of IFRS.

Board Findings

The Board agrees that subject to the findings above, all MIFRS transition impacts have been property identified and the treatments of those impacts have been addressed appropriately.

10 Smart Meters

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

Enersource stated that its Smart Metering Integration Plan will be substantially complete before 2013, with all major expenditures incurred and virtually all customer accounts registered with the Meter Data Management and Repository.

Enersource is seeking approval of $27million in smart meter capital costs and $2 million in operating expenses for smart meters installed between January 1, 2008 and December 31, 2012, and authorization to transfer the approved amounts from the smart meter deferral accounts 1555 and 1556 to the appropriate fixed asset, revenue, and expense accounts. Enersource confirmed that smart meter costs previously reviewed and approved for recovery are not included in the smart meter costs for which it is seeking recovery in this Application.

Enersource's smart meter cost recovery includes the recovery of costs "beyond minimum functionality" in two areas:

- Smart meters installed for GS > 50 kW customers; and
- Costs for CIS enhancements and TOU billing

No parties opposed these costs.

Enersource used the Board's 2013 Smart Meter Model to calculate the Smart Meter Disposition Rider ("SMDR") to recover, for smart meters installed from 2008 to 2012, the deferred revenue requirement net of Smart Meter Funding Adder revenues and associated interest for the same period. The proposed SMDRs are a refund of $0.71 per month to the residential class; a recovery of $14.16 per month from the GS < 50 kW class and a refund of $0.71 per month to the GS > 50 kW class. Enersource proposed that all SMDRs be effective for one year, from January 1, 2013 to December 31, 2013. No party objected to the proposed class-specific SMDRs.

There was one issue that did attract Board staff and intervenor objection. In its evidence, Enersource noted that there remain a small number of situations where it has attempted but has been unable to install a smart meter due to either a customer refusal, lack of cooperation, or other installation challenges. Enersource is seeking Board approval to charge applicable customers for actual incremental costs incurred by the company in the "non-standard" installation and reading of smart meters, and related non-standard communication infrastructure. Enersource stated that such incremental costs are driven by customer requests for non-standard installation (e.g. accommodating customers who oppose wireless communication) and metering equipment beyond Enersource's standard smart meter installation. Board Staff submitted that this evidence was not in Enersource's application and therefore not available for testing. Enersource responded that its evidence contained estimates of these costs in 2012 only.

Board Findings

The Board approves Enersource's smarter meter costs and the resulting class specific SMDRs. In granting its approval for the historically incurred costs and the costs that were projected for 2012, the Board considers Enersource to have completed its smart meter deployment. As of January 1, 2013, no capital and operating costs for smart meters shall be tracked in Accounts 1555 and 1556. When smart meters are installed for new customers, these customers will pay rates that reflect the recovery of smart meter costs. These additional smart meter costs shall be recorded in regular capital and operating expense accounts (e.g. Account 1860 for meter capital costs) as is the case with other regular distribution assets and costs.

The Board will not provide Enersource with the explicit approval to pass through actual incremental costs incurred by the company in the "non-standard" installation and reading of smart meters, and related non-standard communication infrastructure. There is simply no quantitative evidence to support the need or quantum of such a charge. There was no evidence as to the level of costs in 2013, and Enersource's claim during argument that the costs might include ongoing incremental monthly charges suggests the possible creation of a different rate class for a very small number of customers, which would be difficult to justify.

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

On December 15, 2011, the Board issued Guideline G-2011-0001: Smart Meter Funding and Cost Recovery – Final Disposition ["Guideline G-2011-0001"]. In the Guideline the Board indicated that the net book value of the stranded meters should be removed from rate base and allowed for recovery by means of separate rate riders for the applicable customer classes. The stranded meter costs, for recovery purposes, would be comprised of the gross costs of the stranded meters, less any capital contributions, accumulated depreciation and any net proceeds received from the disposition of the meters. This treatment would ensure that distributors are held whole with respect to the cost recovery of stranded meters as required by Ontario Regulation 426/06 Smart Meters: Cost Recovery.

Enersource proposed to remove the forecasted stranded meter net book value of $7.640 million (as of December 31, 2012) from its rate base and recover the amount through separate Stranded Meter Rate Riders ("SMRRs") for the applicable customer classes over a one year period. Enersource originally proposed to allocate the residual net book value of stranded conventional meters based on the number of smart meters installed. The proposed SMRRs were $3.22 per month for residential customers, $3.40 per month for GS < 50 kW customers, and $1.22 per month for GS > 50 kW customers.

Board staff proposed that the allocation method based on the 2006-2007 cost allocation study (and as calculated in Undertaking JT1.2) is a preferable approach. This would ensure consistency with Ontario Regulation 426/06 which mandates that distributors be held whole with respect to the investment in conventional meters. This approach would also avoid the over-collection from residential customers that would have occurred under Enersource's original allocation proposal due to the different costs for meters deployed in different customer classes. This was supported by Energy Probe and subsequently agreed to by Enersource in its Reply Argument. The resulting proposed rate riders are $1.59 per month to the residential class; $15.28 per month from the GS < 50 kW class and $21.60 per month to the GS > 50 kW class.

Board Findings

The Board approves the recovery of $7.640 million, which is the residual net book value of stranded conventional meters that were replaced by smart meters, through the class-specific stranded meter rate riders as calculated in Undertaking JT1.2. The Stranded Meter Rate Riders shall be in effect for one year, from January 1 to December 31, 2013.

IMPLEMENTATION

Effective Date

Enersource applied for rates effective January 1, 2013. Neither the intervenors nor Board staff objected to this proposed effective date. Enersource filed its application on time and did not in any significant way delay the proceeding. Therefore, new rates will be made effective January 1, 2013, although they will be implemented February 1, 2013. The Board will allow Enersource to recover the foregone incremental revenue for January as outlined below.

The Board will make Enersource's rates interim effective January 1, 2013.

Rate Order Process

Enersource is directed to file a draft Rate Order that reflects the Board's findings in this Decision. The Board directs Enersource to file detailed supporting material, including all relevant calculations showing the impact of this Decision on its proposed revenue requirement, the allocation of the approved revenue requirement to the classes and the determination of the final rates, including bill impacts. Supporting documentation shall include, but not be limited to, the filing of a completed version of the Revenue Requirement Work Form excel spreadsheet which can be found on the Board's website. A draft accounting order for the requested MIFRS OBEP deferral account shall also be included.

Enersource shall estimate the foregone revenue for January, and calculate a rate rider by class which would recover the forgone revenue, including an appropriate charge determinant. The term of the rate rider shall be from February 1, 2013 to December 31, 2013, and no variance account will be used to track any under/over-recovery. Any other rate riders determined as part of this Decision will similarly be adjusted to reduce the term by one month.

ORDER

1. The Board declares Enersource's existing rates interim, effective January 1, 2013.

2. Enersource shall file with the Board, and shall also send to intervenors, a draft Rate Order attaching a proposed Tariff of Rates and Charges reflecting the Board's findings in this Decision by **December 20, 2012**. The draft Rate Order shall also include customer rate impacts and detailed supporting information showing the calculation of the final rates including the Revenue Requirement Work Form in Microsoft Excel format.

3. Board staff and intervenors shall file any comments on the draft Rate Order with the Board and send to Enersource by **January 7, 2013**.

4. Enersource shall file with the Board and send to intervenors responses to any comments on its draft Rate Order by **January 11, 2013**.

Cost Awards

The Board may grant cost awards to eligible parties pursuant to its power under section 30 of the Ontario Energy Board Act, 1998. When determining the amount of the cost awards, the Board will apply the principles set out in section 5 of the Board's Practice Direction on Cost Awards. The maximum hourly rates set out in the Board's Cost Awards Tariff will also be applied.

1. Intervenors shall file with the Board and send to Enersource their respective cost claims within **7 business days** from the date of issuance of the final Rate Order.

2. Enersource shall file with the Board and send to intervenors any objections to the claimed costs within **10 business days** from the date of issuance of the final Rate Order.

3. Intervenors shall file with the Board and send to Enersource any responses to any objections for cost claims within **17 business days** of the date of issuance of the final Rate Order.

4. Enersource shall pay the Board's costs incidental to this proceeding upon receipt of the Board's invoice.

All filings with the Board must quote the file number EB-2012-0033, and be made through the Board's web portal at www.pes.ontarioenergyboard.ca, and consist of two paper copies and one electronic copy in searchable / unrestricted PDF format. Filings must be received by the Board by 4:45 p.m. on the stated date. Parties should use the document naming conventions and document submission standards outlined in the RESS Document Guideline found at www.ontarioenergyboard.ca. If the web portal is not available, parties may e-mail their documents to the attention of the Board Secretary at BoardSec@ontarioenergyboard.ca. All other filings not filed via the Board's web portal should be filed in accordance with the Board's Practice Directions on Cost Awards.

DATED at Toronto, December 13, 2012

ONTARIO ENERGY BOARD

Original Signed By

Kirsten Walli

Board Secretary

Appendix A

To Decision and Order

Enersource Hydro Mississauga Inc.

2013 Electricity Distribution Rates

EB-2012-0033

December 13, 2012

APPENDIX A

List of Witnesses

(Appearing on behalf of Enersource Hydro Mississauga Inc.)

Enersource Hydro Mississauga Inc.

• John Bonadie	Director, Revenue
• Branco Boras	Metering Supervisor, Residential Services
• Gia DeJulio	Director, Regulatory Affairs
• Edlira Gjevori	Capital Manager
• William Killeen	Regulatory Affairs Advisor
• James Macumber	Vice President, Finance
• JP Michaud	Senior Manager, substations and Faculties
• Doug Morrison	Director, Customer Operations
• Danny Nunes	Director, Information Technology
• Dan Pastoric	Executive Vice President and Chief Operating Officer
• Sam Ramtahal	Manager, Strategic Projects
• David Rankin	Manager, Metering and Smart Metering
• Martin Sultana	Manager, Rates

TAC Facilities Group

• Brent Kingdon	President and General Manager, TAC Facilities Group Inc.

Appendix B

To Decision and Order

Enersource Hydro Mississauga Inc.

2013 Electricity Distribution Rates

EB-2012-0033

December 13, 2012

FINAL ISSUES LIST

1. General

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

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

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

1.4 Is service quality acceptable?

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?

2. Rate Base

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

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

2.3 Is the proposed Green Energy Act Plan appropriate?

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

3. Operating Revenue

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

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

4. Operating Costs

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

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

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

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

5. Capital Structure and Cost of Capital

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

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

6. Cost Allocation

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

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

7. Rate Design

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

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?

7.3 Are the proposed Total Loss Adjustment Factors appropriate?

7.4 Are the proposed retail transmission service rates appropriate?

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

8. Deferral and Variance Accounts

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

8.2 Are the proposed rate riders appropriate?

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

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?

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

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

10. Smart Meters

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

10.2 Is the proposed treatment of stranded meter costs appropriate?