ONTARIO ENERGY BOARD

BOARD STAFF SUBMISSION

Enersource Hydro Mississauga Inc.

EB-2012-0033

September 21, 2012

Background:

Enersource Hydro Mississauga Inc. ("Enersource" or the "Applicant") filed an application (the "Application") with the Ontario Energy Board (the "Board") under section 78 of the *Ontario Energy Board Act*, *1998*, seeking approval for changes to the rates that Enersource charges for electricity distribution. An oral hearing was held at the offices of the Board on September 4, 6, and 10th. Enersource filed its argument-in-chief- on Monday September 17th.

This is the argument and submission of Board staff with respect to the Application. The submission is structured to reflect those areas of the Application and those issues on the Final Issues List which Board staff conducted cross examination. Specifically, this submission addresses the following:

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

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

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

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

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

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

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

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

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

While Board staff did not cross examine on all areas of the Application this does not reflect Board staff's acceptance of what the Applicant has put forward in its Application. Rather, Board staff takes no position on the outstanding issues with the exception of costs related to the New Administration Building which is identified as a driver for the increase in OM&A. Board staff is concerned with the size of the building and cost impact, both on OM&A and rate base. Board staff notes that there was extensive cross examination on this matter at the oral hearing by the School Energy Coalition

("SEC") and subject to the submissions on this matter by SEC, staff may have further submissions at the oral argument phase of this proceeding.

With respect to other issues not addressed in this submission, Board staff submits that Enersource bears the onus and burden of proof with respect to all aspects of its Application.

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

Background:

In addition to setting rates on a cost of service basis for 2013 Enersource is also proposing to establish rates for 2014 using an Incremental Capital Return ("ICR") model. The model was developed by Enersource and the resulting revenue requirement and rates for 2014 reflect the following:

- Board-approved OM&A expenses for 2013 held unchanged for 2014;
- Board-approved % return on rate base held unchanged from 2013 with 2014 rate base reflecting 2013 and 2014 capital expenditures;
- Full year depreciation expense for 2013 and half year for 2014 ; and
- PILs for 2014 relating to incremental capital and return.

The revenue requirement for 2014 generated under ICR totals $134.983M, an increase of $3.307M over the revenue requirement of $131.676M proposed for 2013. [1]

As to why Enersource is not intending to use IRM-ICM for 2014 Enersource stated that:

> Enersource is not proposing an approach that makes use of the ICM because it is of the view that Enersource's proposed approach is more just and reasonable than the ICM model because it smoothes the amount of one-time rate increases for rebasing years under the current model, and more accurately provides compensation for cost of capital.[2]

Enersource confirmed that it was not saying that it would be unable to adequately manage its resources and financial needs and so this is not a justification to deviate from IRM.[3]

Enersource also acknowledged that it was deviating from the Board's 3rd Generation IRM policy[4] and that it did not prepare an analysis comparing the ICR approach with the Board's IRM-ICM.[5] In this regard, Enersource indicated that it did not, in assessing its options, consider IRM-ICM. Enersource did not run the model that ICM requires to determine the amount of eligible non-discretionary capital under an IRM application

[1] Exhibit I Issue General Board staff IR No.3
[2] Exhibit I Issue 1.1 CCC IR No. 4
[3] Transcript (Sept. 4, 2012) Vol.1 p.41 line 21-23 and p.139 line 1-16
[4] Transcript (Sept. 4, 2012) Vol.1 p.41 line 6-10
[5] Exhibit I Issue General Board staff IR No.8

because Enersource characterized most of Enersource's 2014 capital expenditures as discretionary. On this basis Enersource concluded that it would not be able to satisfy the criteria of an ICM application. [6]

However, Enersource under cross examination stated that there are 2014 projects that are completely non-discretionary[7] and that it cannot split the 2014 capital projects between discretionary and non-discretionary.[8]

Discussion and Submission

Board staff notes that Enersource on a number of occasions in cross examination indicated that it is not experiencing financial hardship and so this clearly is not part of the rationale for proposing ICR for 2014. Enersource provided two reasons in support of the ICR approach; rate smoothing and obtaining an adequate/accurate return on capital for its investments.[9]

Board staff has concerns with the alternative treatment proposed by Enersource to set rates for 2014 for several reasons.

First, Board staff submits that the ICR is contrary to the principles of good rate-making. The ICR is a hybrid approach in that it is not aligned with the comprehensive price cap form of IR which was espoused by the Board in its July 14, 2008 Report. As a hybrid approach it selectively chooses certain elements that impact a utility's revenue requirement and load that impact rates. The elements reflected include full year impact of 2013 capital expenditures on 2014 rate base, 2014 capital expenditures, return on 2014 rate base, associated PILs on incremental capital and return on equity and 2014 depreciation expense. Other elements, such as OM&A, Load, Distribution Revenues, and Other Revenues, are excluded from further forecasting and remain unchanged between 2013 and 2014. Since last rebasing Enersource's customer numbers have increased by about 1.5% annual and load by about 1.1%. [10]

There is normally a relationship between the level of capital spending and (i) incremental load and revenues, (ii) incremental OM&A to support the new capital investment, (iii) reductions to OM&A to reflect less maintenance and repair costs associated with new replacement installations and (iv) decreases to OM&A to reflect the efficiencies that result from capital investments. In the normal course, Board staff would not be opposed to the

[6] Transcript (Sept. 4, 2012) Vol.1 p.45
[7] Transcript (Sept. 4, 2012) Vol.1 p.98
[8] Transcript (Sept. 6, 2012) Vol.2 p.89

[10] Source Exhibit 3 Tab 2-Schedule1 p 31 attachment 6: Number of customers: 2008 actual is 185,116 and 2011actual is 193,983. Exhibit 3 Tab 2-Schedule1 p 2 Billing determinant load (weather normalized): 2008 actual 2,162,551 MWH and 2011actual is 2,137,683)

approach of setting rates for two test years in a cost of service proceeding. This has been done in the past for Hydro One Networks, both distribution and transmission, Toronto Hydro, Algoma Power and OPG. However, Enersource's ICR proposal is very selective in how it links costs with prices. Absent the total picture, any testing or assessment of the resulting revenue requirement is incomplete and lacking in regulatory rigour.

Second, Board staff submits that there is inadequate analysis underpinning Enersource's decision to adopt the ICR rather than employ the Board's IRM-ICM model for 2014.

Enersource did not prepare nor present an analysis for its senior management and it's Board of Directors that included a comparison between ICR and IRM-ICM; nor was one included in its initial evidence. It was only as an undertaking during cross-examination that Enersource provided a calculation of what the revenue requirement would have been for 2014 when strictly applying the price cap adjustment index to the proposed revenue requirement for 2013. [11] The re-calculated revenue requirement for 2014 totaled $132.216M based on an average price cap adjustment index of 0.41%.

Board staff notes that the re-calculated revenue requirement for 2014 filed by Enersource does not include an ICM component. Enersource indicated in its interrogatory responses that it believed it was not eligible for an ICM, since it would not be able to satisfy the requirements because most of its capital expenditures are discretionary. Board staff notes that this position is contrary to the position taken by other distributors in IRM-ICM applications, where they attested to the fact that most if not all of their capital budgets for those particular years were non-discretionary[12] and which the Board accepted. While Board staff acknowledges that each distributor is unique to a certain degree, Board staff does not understand how an entire capital budget could be discretionary.

Nevertheless, under cross examination Enersource disclosed that it had not performed an analysis to confirm how much of the 2014 capital budget would in fact be discretionary and how much would be considered non-discretionary, thereby not allowing parties to test Enersource's assumptions used in determining discretionary spending, and to assess how much incremental capital would be available under the ICM.[13]

Board staff submits that without a comparison to a viable alternative to Enersource's unique proposal, the Board may wish to disallow the ICR (i.e. not set rates for 2014) as Enersource has not met the burden of proof regarding the reasonableness of its particular approach to setting 2014 rates.

Third, notwithstanding all of the above, Board staff notes that if it is accepted that all the

[11] Undertaking J2.1
[12] EB-2010-0104 and EB-2010-0130.
[13] Transcript (Sept. 6, 2012) Vol.2 p.89

capital expenditures are discretionary, then there does not appear to be a pressing need for ICR based rates in 2014 in any event, since Enersource would have the flexibly to prioritize and schedule its capital projects between 2013 and the next rebasing year. Enersource indicated that there is nothing unique about the 2014 capital budget as compared to other years[14], including the 2013 rebasing year. If that is true, then Enersource would have the flexibly to smooth its capital spending over the course of the IRM term and this would minimize any impacts arising from the next rebasing application. At a total level, Enersource's asset management plan projects capital expenditures to be largely flat over the 2013 to 2016 period as shown in the excerpt below. [15]

Description	Actual					Forecast				
	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016
System Capacity – Growth Driven	9,320	10,299	15,791	10,207	10,385	9,312	11,134	10,329	10,507	10,686
System Sustainment – Reliability Driven	13,457	15,790	19,291	16,316	12,707	14,483	16,326	18,329	19,319	20,939
System Expansion & Upgrades – Customer	6,537	6,888	5,363	11,899	6,269	6,274	5,342	5,749	5,037	4,975
Non-System Requirements - Regulatory Driven	8,279	6,157	9,410	8,763	3,747	4,401	183	219	256	293
Non-System Requirements – Internally-Driven	8,588	11,603	8,456	5,530	9,052	29,472	13,187	10,725	9,646	9,317
TOTAL CAPITAL	46,180	50,737	58,310	52,714	42,159	63,942	46,173	45,351	44,766	46,209

Table 17.6–Table of Enersource Total Capital Budget Expenditures (in $'000)

Fourth, Board staff has a further concern with respect to the rate smoothing argument. The argument is essentially that by increasing rates now, customers benefit because there will be less of an increase in rates at that next cost of service rate application. While this is true, it also means that, all in, customers will have paid higher rates through the subject period. Board staff submits that the value proposition for this approach to rate smoothing (for the rate paying customer) has not been appropriately tested and should not be a key consideration in the Board's determination.

Based on the four concerns with the alternative treatment for the setting of 2014 rates noted above, Board staff submits that the Board may wish to deny Enersource's request to set rates for 2014 as proposed in this proceeding.

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

Board staff submits that the rate setting approach for the years subsequent to 2014 will be

[14] Transcript (Sept.4, 2012) Vol12 p.54 ln 1-9
[15] Exhibit 2-Tab2-Schedule 2-appendix 1 p. 129

informed by the Renewed Regulatory Framework for Electricity ("RRFE"). Board staff submits that it would be premature to set an approach for 2015 and 2016 at this time.

Board staff notes that specific details of the RRFE are expected to be released shortly, and the RRFE is planned to be available for 2014 rate-setting.

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

Background

In accordance with the *Filing Requirements: Distribution System Plans – Filing under Deemed Conditions of Licence* (EB-2009-0397)[16], Enersource filed a Green Energy Plan (the "GEA Plan" or the "Plan") in this cost-of-service application, where it outlined works and expenditures created by the connection of renewable generation to its system.

GEA Plans are limited to addressing costs around the connection of FIT and microFIT projects, and costs relative to the implementation of smart grid. Enersource's evidence did not include any smart grid initiative. The total number of FIT and microFIT applications Enersource received as at the end of the first quarter of 2012 is reflected in the table below:

	# Applications Received	# Projects Connected	Ratio Connections vs. Applications
MicroFIT (≤10kW)	640	85	13%
FIT (>10kW)	429	12	3%
Total	1069	97	9%

Source: GEA Plan, Table 2 – Applications Received & Projects Connected as of End of 2012Q1

The financial implications of the filed GEA Plan are shown below.

[16] March 25, 2010 version of the *Filing Requirements*

	2010	2011	2012	2013	2014	2015	2016	Total
MicroFIT (≤10kW)	19	32	35	50	60	70	80	
FIT (>10kW)	3	7	20	25	30	35	40	
Total	22	39	55	75	90	105	120	506
CAPEX	n/a	$197,413	$133,000	$183,000	$219,000	$256,000	$293,000	$1,281,413

Source: GEA Plan, Tables 3 & 6– Actual & Forecasted Renewable Energy Connections by Year and CAPEX

All the upgrades identified are Renewable Enabling Improvements (REIs)[17], and have caused a surge in work that has resulted in an increase in the workload of the pre-existing Customer Engineering team and the addition of:

- 2 co-op intern Engineering students to assist with processing FIT program applications and documentation (16-month term Engineering students were selected due to the risk and uncertainty of the program demand);
- A contracted independent Professional Engineer Field Inspector with relevant medium-voltage customer relation experience to be used as needed;
- A contracted Services Engineering firm to perform Connection Impact Assessments (CIAs) on behalf of Enersource.

Over the life of the Plan (2012-2016), capital expenditures are projected to total $1,084,000, with the test years of 2013 and 2014 constituting 37% of that at $402,000 and totals about $1.3 M when the 2011 actual expenditures are added.

With respect to the historical treatment of these costs, Enersource indicated that it treated these costs as normal or usual business activity expenditures.

Discussion and Submission

Enersource in its argument-in-chief informs the Board that it will socialize capital costs for the 2013-2016 period in accordance with the *Framework for Determining Direct Benefits Accruing to Customers of a Distributor under Ontario Regulation 330/09* (the "*Framework*"). However, it appears that no portion of the GEA Plan related capital costs incurred in 2010, 2011 and forecasted for 2012 will be borne

[17] Expansion work is identified in the GEA Plan but not included in the capital expenditures for 2013 and 2014 and the remaining years of the plan. Enersource indicated that it did not include the expansion costs since the probability of materializing is very low (cf. response to Board staff IR 18(d)).

by ratepayers on a province-wide basis since none of the costs have been set aside or recorded in a deferral account for future disposition. Board staff would have expected to see some level of a province-wide allocation for these historical years.

In its argument-in-chief, Enersource indicates that it is not seeking recovery of any GEA plan OM&A. At the September 6, 2012 hearing, Enersource said that costs related to the two co-op engineering students, the contracted engineering field inspector, and the contracted services engineering firm have been absorbed and are not included in the 2013 test year for cost recovery. The *Framework* allows for initial OM&A to be incurred for the purpose of enabling the connection of a renewable generation facility to be socialized amongst all provincial ratepayers. Board staff is of the view that the nature of the work of the additional human resources identified in Enersource's Plan, such as the processing of FIT applications and documentation, field inspections, and CIAs, are likely incurred in the initial stages of connecting a project and could therefore be reasonably categorized as initial OM&A. Board staff submits that the record is not clear as to the quanta of OM&A costs associated with the GEA plan. Board staff recommends that these costs be identified, and appropriately socialized.

Enersource in its interrogatory responses and through cross-examination made it clear that it viewed the GEA Plan activities for all intents and purposes as normal distribution work and, at any rate, of nominal or small size.

However, Board staff submits that Enersource should conform to provincial legislation and appropriately allocate capital costs stemming from the connection of renewable generation between Enersource and provincial ratepayers for 2010, 2011, and 2012. Enersource should remove the non-Direct Benefits capital expenditures from its rate base and record them in account 1531 for recovery via the IESO protocols. Enersource should also identify and exclude from its proposed OM&A for 2013 initial OM&A associated with the GEA Plan and record them in account 1532 for recovery via the IESO protocols.

Subject to addressing the above concerns, Board staff has no concerns with Enersource's GEA Plan and sees no issues with the Board approving the plan.

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

Background

Enersource's OM&A (including property taxes) proposed for 2013 totals $61,011,000. Table A (see the last page of the submission on Issue 4.1) prepared by Board staff provides an overview history of OM&A expenditure and customer growth since 2008.[18]

Discussion and Submission:

Board staff tested the appropriateness of the forecast on an envelope basis. This allows for an initial assessment of the reasonableness of the requested amount and the impact that inflation and customer growth would have had on costs since the last time rates were rebased.

The OM&A proposed budget for 2013 is 46.5% higher than the amount approved by the Board in Enersource 's last cost of service proceeding which set 2008 rates. Over that same period the number of customers served increased by 6.1%. Or put another way, OM&A costs increased on average by 7.9% annually while the number of customers increased by about 1.2%. Setting aside, for the moment the Board's expectation that during the IRM term the distributor should manage its affairs to become more efficient and less costly (and with some exceptions, the utility keeps what they earn), it can be argued that OM&A would increase, all else equal, by the rate of inflation.[19] Board staff calculates that the CPI between 2008 and 2011 increased by about 1.7% annually.[20] Assuming that inflation continues at this level for 2012 and 2013, the percentage increase in OM&A between 2008 and 2013 would be about 8.8%. Inflation and growth together would then account for about 15% of the increase between 2008 and 2013.

An OM&A budget for 2013 calculated on this basis, reflecting the impact of inflation and customer growth, would total about $47.9M [21]

The difference between $47.9M and the amount proposed by Enersource, $60.011M, is $12.1M. The $12.1M increase would be comprised of increments other than due to inflation and customer growth.

[18] Exhibit K2.3 p.4 Board staff Compendium for Cross Examination
[19] The annual price cap increase (GDPIPI less productivity less stretch factor) for Enersource during the IRM period averaged about 0.6% annually (source: Exhibit I Issue1.1 Board staff IR No. 10)
[20] Statistics Canada. Table 326-0022 - Consumer Price Index (CPI), seasonally adjusted, 2009 basket, monthly (2002=100)
[21] $41.653M times 1.15 = $47.9 M

Enersource listed five key drivers in addition to Business Unit[22] requirements as driving the increase in its OM&A requirements[23]; these include IFRS overhead burdens, Bad Debt Expense, Asset Management Plan initiative, one- time costs and the new Administration Building. Board staff in this submission addresses two of these drivers, the Business Units requirements and Bad Debt Expense.

The Business Units requirements increased by $5.6 M in excess of what would be expected due to inflation and customer growth. [24] Of this amount about $1.1M is due to the increase, from about 84% to 94%, in the allocation of Corporate Costs.

Board staff is of the view that this $5.6M increase in Business Unit requirements is excessive on any measure. The Business Units which reflect the ongoing direct and supporting operations of the company should be able to manage their costs within an overall estimate that provides for inflation, customer growth plus a reasonable amount for special circumstances. Board staff submits that no more than half of the $5.6M would be an ample increment over and above that provided to cover inflation and customer growth. Board staff notes that its calculation of the costs due to customer growth is generous. For this particular analysis Board staff used a one to one relationship, that is to say customer growth of 1% means that an additional 1% of OM&A is needed to serve that customer. In any business the OM&A percentage would likely be less due to such cost characteristics such as fixed costs and economies of scale.

The 2013 OM&A budget proposed by Enersource includes $3.550M for Bad Debt expense. This represents an increase of $1.975M or 125% over 2008 Board approved. The expenditure history since 2008 is shown in the table below. [25]

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[22] The Business Units are: Health Safety and Security, Customer Care, Engineering and Operations, Metering, Executive/Administration/Corporate Allocation, ISTS, Regulatory Affairs, Facilities Management, Other Expenses.
[23] Exhibit 4 Tab1 Schedule 1 p. 2
[24] $51.703 minus($40.078M times 1.15) = $5.6M
[25] Source: Exhibit 4-Tab1-Schedule3 p.14 table 3

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

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

Enersource also indicated that it has hired an Accounts Receivables Manager and selected two new third party collection agencies to mitigate the growing trend in uncollectable accounts receivable. In response to Energy Probe Issue 4.1 interrogatory No.5, Enersource stated that it reduced its Bad Debt expense for 2013 by $750,000 (from $4,300 to $3,550) to reflect the savings expected with the hiring of the Manager and engagement of the collection agencies.[26]

Board question the basic assumption underpinning the calculation of the projected savings, and that is that the level of accounts receivable will continue to grow, if not flatten or decrease. From table 3 above it appears that Late Payment Revenue, which can be viewed as an economic indicator of the customers' ability to pay, is flat between 2012 and 2013. If late payment revenue is flat, it is reasonable to expect that Bad Debt Expense would remain flat as well.

Board staff submits that the initial forecasted Bad Debt expense, to which the $750,000 was applied, should be reduced by at least half of the initially forecasted increment between 2012 and 2013.

Board staff notes that in the event the Board disallows half the amount for Business Units requirements and Bad Debt Expense as noted by Board staff above, the total approved OM&A for 2013 would be $57.836, a 13.8% increase over 2011 actuals.

Board staff also notes that the New Administration Building is identified as a driver for the increase in OM&A. Board staff is concerned with the size of the building and cost impact, both on OM&A and rate base. Board staff notes that there was extensive cross examination on this matter at the oral hearing by the School Energy Coalition and subject to the submissions on this matter by SEC, staff may have further submissions at the oral argument phase of this proceeding.

[26] The hiring of the Manager and collection agency engagement increase operating costs by $343,000Source: Exhibit I Issue 4.1 Energy Probe Interrogatory No.5.

Table A

	OM&A	2008 Board Approved	2008 Actual	2009 Actual	2010 Actual	2011 Actual (IFRS)	2012 Bridge	2013 Test Year	2013Test Year vs. 2008 Brd. App'd		2013 Test Year vs. 2008 actual	
									2008-2013	Ave. Annual	2008-2013	Ave. Annual
(1)(2)	OM&A Updated	$ 41,653,058	$ 36,234,120	$ 41,523,563	$ 45,598,558	$ 50,783,218	$ 57,008,685	$ 61,011,000				
	yearly increase (dec.)		(13.0%)	14.6%	9.8%	11.4%	12.3%	7.0%	46.5%	7.9%	68.4%	11.0%
(3)	Smart Meter Component	($1,177,058)	($94,120)	$332,437	($918,558)	($751,218)	($634,685)	($727,000)				
	OM&A (excluding Smart Meter)	$ 40,476,000	$ 36,140,000	$ 41,856,000	$ 44,680,000	$ 50,032,000	$ 56,374,000	$ 60,284,000				
	yearly increase (dec.)		(10.7%)	15.8%	6.7%	12.0%	12.7%	6.9%	48.9%	8.3%	66.8%	10.8%
(4)	Customers (Ave.)	187,551	185,116	188,136	191,156	193,983	196,534	198,990				
	Yearly % inc.		-1.3%	1.6%	1.6%	1.5%	1.3%	1.2%	6.1%	1.2%	7.5%	1.5%
(4)	Customer& Connections (Ave.)	238,914	236,360	239,713	243,071	246,146	248,978	251,917				
	yearly increase (dec.)		-1.1%	1.4%	1.4%	1.3%	1.2%	1.2%	5.4%	1.1%	6.6%	1.3%
(5)	IRM increase			1.18%	0.18%	0.18%	0.88%					
	Note1: Includes Property Taxes	$ 897,400	$ 866,050	$ 863,606	$ 867,586	$ 864,465	$ 1,075,000	$ 1,200,000				
	Note2: reflects Suite Metering Inspection cost Adj. in 2013 ($88k) per IR Issue 4.1 Brd Staff #36 & includes Smart Meters											
	Note 3: Per Undertaking JT2.11 (OM&A excluding SMART Meter costs in 2008-2012) & see Brd Staff Issue 4.1 No. 34											
	OM&A per E4-T1-S1 table 1	$ 41,653,058	$ 36,234,120	$ 41,523,563	$ 45,598,558	$ 50,783,218	$ 57,008,685	$ 61,011,000				
	less revised table 1 per JT2.11	$ 40,476,000	$ 36,140,000	$ 41,856,000	$ 44,680,000	$ 50,032,000	$ 56,374,000	$ 60,284,000				
	equals Smart Meter amount	$ 1,177,058	$ 94,120	($332,437)	$ 918,558	$ 751,218	$ 634,685	$ 727,000				
	Note 4: E3-T1-S2 p.31 attachment 6											
	Note 5: source: IR Issue 1.1 Brd Staff 10: the cumulative increase over 2009 to 2012 is about 2.4%										v1 aug.24	

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

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

A- Request to Establish a Deferral Account for MIFRS Post Employment Adjustment (including the recognition of actuarial gains and losses) and the Disposition of Associated Balances

Background:

Enersource is requesting a deferral account to capture the impact of post-employment adjustments. In particular, the deferral account is to capture:

1) The impact from post-employment adjustment resulting from the transition to MIFRS, where the net impact at the date of transition was a reduction of post-employment accrued liability of $150,000.
2) The recognition of actuarial gains and losses in Other Comprehensive Income ("OCI") instead of having the actuarial gains and losses amortized in OM&A using the corridor approach. Enersource adopted early the amended IFRS standard to eliminate the corridor approach. The 2011 actuarial loss relating to post-employment obligation was $769,000. Enersource is also proposing to accumulate all future re-measurements of OCI in the requested deferral account and will request to dispose the cumulative balance in future cost of service rate applications.

In total, Enersource is requesting to recover in this application a net of $619,000 over a one-year term.

Discussion and Submission:

Requested Recovery

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

> The Board will not approve the creation of a generic account for IFRS related impacts on P&OPEB accounts occurring at the date of transition.

> The option remains for these utilities to seek an individual account if they can demonstrate the likelihood of a large cost impact upon transition to IFRS.

As per *Filing Requirements for Electricity Transmission and Distribution Applications (EB-2006-0170)*, section 2.4.4 Materiality Thresholds, the default materiality threshold that would apply to Enersource is 0.5% of distribution revenue requirement for a distributor with a distribution revenue requirement greater than $10 million and less than or equal to $200 million. Enersource's materiality threshold based on the updated revenue requirement of $131,675,771[27] is $658,000. Board staff notes that the requested amount for recovery is $619,000, below Enersource's materiality threshold.

In addition, in Exhibit 9, Tab 1, Schedule 1, Page 20 of Enersource's application, Enersource has indicated the following:

> Due to 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 such, Board staff submits that Enersource has not demonstrated that there is a large cost impact.

Enersource has indicated they are unable to forecast whether any actuarial gain or loss will be recognized in any given year[28]. In Enersource's assessment of materiality of the proposed deferral account, Enersource has proposed to dispose of the future cumulative deferred balance only if it is a material amount at the time of disposition.[29] Enersource has proposed to dispose of $619,000 in the current proceeding, despite the amount being under the materiality threshold. As such, Board staff is of the view that the request for the recovery be denied in this application.

<u>Request to Establish Deferral Account</u>

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[27] Response to Interrogatories, Exhibit 1, Issue: General RRWF, Board Staff IR# 3 – Appendix 2-C(i), Page 10

[B] Response to Interrogatories, Exhibit 1, Issue 9.2, Board Staff IRR #56,

[29] Argument in Chief, Exhibit 9, Tab 1, Schedule 2, Page 3, Other Comprehensive Income MIFRS Post-Employment Adjustment, Request for New Deferral Account, Draft Accounting Order, filed September 17, 2012

Enersource has requested to establish a deferral account to accumulate future actuarial gains and losses. Board staff agrees that it is difficult to forecast future actuarial gains and losses. However, demonstrating materiality is one of the tests for establishing new deferral and variance accounts. It is open to Enersource to file an application to the Board in the future to recover/refund future actuarial gains or losses from post-employment benefits, if the amount is material. If the Board approves this request however, Board staff submits that the deferral account should not include any amounts in relation to 2011 and 2012, since these years were under an IRM regime, and since this would also constitute inclusion of "out of period" amounts because the account would not be approved or come into effect until 2013.

B- Request to Establish a Deferral Account for Inspecting or Certifying Installed Suite Meters

Background:

Enersource has forecasted to incur $141,000 and $211,000 for the inspecting or certifying suite meters in 2012 and 2013 respectively. Enersource initially included the cost in the calculation of the 2013 revenue requirement.[30] In response to Board Staff interrogatory No.36, Enersource removed the request for recovery and sought a deferral account to track the expenses; recovery will be sought in its next cost of service application.

Discussion and Submission:

Board staff notes that per the *Filing Requirements for Electricity Transmission and Distribution Applications (EB-2006-0170)*, June 28, 2012, in the event an applicant seeks to establish a new deferral/variance account, one of the eligibility criteria to be met is materiality. Page 55 of the Filing Requirements specifies the following regarding materiality:

> Materiality – The forecasted amounts must exceed the Board-defined materiality threshold and have a significant influence on the operation of the distributor; otherwise they should be expensed in the normal course and addressed through organizational productivity improvements.

[30] Application - Exhibit 4, Tab 1, Schedule 6, page 6

As indicated in the previous discussion of Enersource's request to establish a deferral account for MIFRS post-employment adjustments, Enersource's materiality threshold is $658,000. Enersource has currently forecasted inspection/certification costs of $352,000. In Board Staff's cross examination, Enersource also indicated that the $352,000 was the original forecast; however, as Enersource has yet to settle on a contract with the company that will perform the work, Enersource does not have sufficient evidence to establish a more accurate forecast of total costs.[31] Given the lack of information regarding of the level of costs to be incurred, Board staff submits that the Board has sufficient reason to deny the request for the establishment of the deferral account. In the event the Board approves this request, Board staff submits that the deferral account should not include any amounts in relation to 2012, since 2012 is under an IRM regime and would also constitute recovery of "out of period" costs because the account would not be approved or come into effect until 2013.

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

Account 1575 IFRS – CGAAP Transitional PP&E Amounts

Background:

Enersource has calculated a total credit of $14,071,013[32] in Account 1575 IFRS – CGAAP Transitional PP&E Amounts ("PP&E deferral account"). Enersource has proposed to refund customers over a one year period through a separate rate rider. Enersource has indicated that the one year refund period is requested to reduce intergenerational inequities for customers compared to a one-time adjustment to rate base that would refund customers over a four year period, to mitigate rate volatility and more closely align the length of time over which the IFRS-CGAAP transitional differences arose.[33]

Included in the $14,071,013, is a proposed a return on rate base for a one year period. Board staff notes that Enersource used a 6.582% rate of return, which Board staff understands to be the weighted average cost of capital.

Discussion and Submission:

[31] Oral Hearing Transcript, Volume 3, Page 108-110
[32] Response to Interrogatories, Exhibit 1, Issue: General – Filing Requirements, Board Staff IR# 5 – Attachment Appendix 2-EA, Page 1
[33] Response to Interrogatories, Exhibit 1, Issue:9.1, Board Staff IR #55, Page 2

Board staff has reviewed Enersource's evidence and will discuss the following issues related to the disposition of the PP&E deferral account:

1) Comparison of the impact to customers between the Board's policy and Enersource's proposal relating to the disposition method (including the disposition period):

2) Proposed PILS inclusion

<u>Comparison of the impact to customers between Enersource's proposal and Board policy</u>

Page 32 of the *Addendum to the Report of the Board: Implementing International Financial Reporting Standards in an Incentive Rate Mechanism (EB-2008-0408)* dated June 13, 2011 states the following regarding the PP&E deferral account:

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

Enersource has proposed to deviate from the aforementioned Report of the Board and refund the 'adjusting amount' and the return on rate base to customers using a separate rate rider. Whether the disposition method is through revenue requirement as per the Report of the Board or through a separate rate rider as proposed by Enersource, Board staff submits that the refund amount to customers should theoretically be the same regardless of the aforementioned disposition methods, all else being equal.

The area of difference pertains to the disposition period. Enersource has proposed a disposition period of one year. Board's staff observation has noted that, in practice for many applicants who have filed a 2012 cost of service application (such as Rideau St. Lawrence Distribution Company, Grimsby Power Inc., Guelph Hydro Electric Systems Inc., Lakefront Utilities Inc.); a four year disposition period is used. The Board has also approved a four year disposition period in Halton Hills Hydro Inc.'s application under EB-2011-0271. Board staff also notes that the four year amortization aligns with the planned frequency of a distributor's normal rebasing cycle. The difference in the disposition period impacts the return on rate base amount that is refunded/recovered from customers. The difference in the total refund amount between Enersource's proposal using a one year disposition period and that as per the Report of the Board using a four year disposition period, is as follows:

Disposition Period	**Enersource's Proposal (1 Year)**	**Per Report of Board (4 Years)**	**Difference**
Net PP&E as at Dec. 31, 2012 under CGAAP	497,769,236	497,769,236	
Net PP&E as at Dec. 31, 2012 under IFRS	510,810,461	510,810,461	
Difference in closing net PP&E	-13,041,225	-13,041,225	
Return on Rate Base (Note 1)	-858,373	-3,433,494	
PILS (Note 2)	-171,414	N/A	
Total Amount to Refund	**-14,071,012**	**-16,474,719**	**-2,403,706**

Note 1: Calculated using WACC of 6.582% for a one year and four year period. Per Page 32 of the Addendum of the Report of the Board, "the unamortized balance in the deferral account will attract the same level of return in determining revenue requirement in a cost of service application as other PP&E balances". Board staff is of the view that consistent with the Revenue Requirement Work Form, the return remains the same annually through the 4 year disposition period.
Note 2: There is no PILS adjustment as per Report of Board. Please see discussion below.

As per the above chart, had Enersource used the default four year disposition period, there would be a refund of $3,433,494, i.e. a greater refund of $2,403,706, associated with the WACC on the $13,041,225 credit balance to customers spread over a four year period. Board staff is of the view that even though Enersource's proposed disposition deviates from the Report of the Board, Enersource's proposed disposition adheres to the overall concepts of the PP&E deferral account as specified in the Report. As a result, Staff submits it is appropriate that the accelerated refund of $13,041,225 to customers should yield a lower WACC amount, which in this case, should be $858,373 over one year and not $3,433,494 associated with a four-year refund period. As for the use of a refund mechanism that is different from what was established in the Report, Board staff notes that at the time of the Report, the rate setting framework included a four year rebasing cycle (i.e. rebasing plus three years of IRM adjustments).

Proposed PILS inclusion

Enersource has proposed the PILS effect to be included in the calculation of the amount in the PP&E deferral account. Board staff is of the view that PILS should not be included in the calculation. Board guidance on the PP&E deferral account does not consider PILS. In addition, other deferral accounts such as Account 1508 - Other Regulatory Assets, Sub-account Deferred IFRS Transition Costs have historically not included any PILS adjustment. Board staff also observed that in Guelph Hydro's rate order (EB-2011-0123), Guelph Hydro's proposed inclusion of PILS on the disposition of its Account 1575 balance was disallowed. To be consistent with past deferral account practices, Board staff submits that the PILS adjustment of $ -171,414 should be excluded from Enersource's PP&E deferral account.

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

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

Background

In its Application, Enersource applied for disposition and recovery of its costs for the deployment and operation of smart meters, in accordance with Chapter 2 of the Filing Requirements for Transmission and Distribution Applications and with *Guideline G-2011-0001: Smart Meter Funding and Cost Recovery – Final Disposition* ("Guideline G-2011-0001").

This is not the first application in which Enersource's costs for smart meter deployment and installation have been reviewed and approved. A summary of Enersource's smart meter deployment and cost recovery is provided in Board staff IR # 57. [34] In part d) of that interrogatory response Enersource confirmed that smart meter costs previously reviewed and approved for recovery are not included in the smart meter costs for which Enersource is seeking recovery in this Application.

Enersource proposed a uniform Smart Meter Disposition Rider ("SMDR") to recover the deferred revenue requirement for the installation and operation of smart meters installed from January 1, 2008 to December 31, 2012, less Smart Meter Funding Adder ("SMFA") revenues and associated interest on the SMFA principal to

[34] Response to Board staff interrogatory # 57, Exhibit I/Issue 10.1

December 31, 2012. The operation of all smart meters and related infrastructure, and the capital costs for new smart meters and associated capital investments for the 2013 test year are factored into the determination of the 2013 test year rate base and revenue requirement, and, ultimately, into the 2013 distribution rates.

In response to a Board staff interrogatory,[35] Enersource revised its proposal to allow for class-specific SMDRs, as follows:

Customer Class	**SMDR ($/month from January 1, 2013 to December 31, 2013)**
Residential	($0.71)
GS < 50 kW	$14.16
GS 50-499 kW	($0.11)

Discussion and Submission

In making its proposals for smart meter cost recovery, Enersource used Board-issued smart meter models, first Version 2.21 and then Version 3.00. Board staff submits that Enersource's proposal for class-specific SMDRs as provided in response to Board staff interrogatory # 58 is appropriate, and consistent with Board policy and practice.

While the GS > 50 kW SMDR of ($0.11) per month for one year appears anomalous, as the costs for smart meters and their installation is higher for these customers, this is due to the fact that smart meters are being deployed to customers in this class as customer meters are repaired or resealed. Thus, not all customers in this class have smart meters to take advantage of the AMI communications infrastructure. The SMFA revenues collected from all customers in this class and associated interest still exceeds the deferred revenue requirement for the smart meters that have been, or will be deployed, to customers in this class by December 31, 2012, thus resulting in a small credit to be returned to customers in this class.

While Board staff submits that Enersource's proposal for smart meter cost disposition and recovery is consistent with Board policy and practice as documented in Guideline G-2011-0001 and as approved by the Board in an increasing number of recent decisions, there is one exception.

In its Argument-in-Chief, Enersource states, at paragraph 176:

[35] Response to Board staff interrogatory # 58, Exhibit I/Issue 10.1

176. In order to improve Enersource's likelihood of reaching 100% compliance, it is also seeking Board approval to charge applicable customers for actual incremental costs incurred by Enersource in the non-standard installation and reading of smart meters, and related non-standard communication infrastructure. Such incremental costs are driven by customer requests for non-standard installation and metering equipment relative to Enersource's standard smart meter installation.[36]

Board staff submits that this proposal was not in Enersource's evidence. In its Application, Enersource documented in its pre-filed evidence that outstanding meter replacements were to be done in 2012 and would have a budgeted capital cost of $1.488 million and $635,000 OM&A.[37] Board staff observes that these numbers correspond with the 2012 capital and OM&A costs in the Smart Meter Model Version 3.0 filed by Enersource in response to Board staff IR # 58; thus the calculated SMDRs ecover these budgeted costs.

However, Board staff has several concerns with Enersource's proposal with respect to non-standard installations going forward. Board staff is concerned that the proposal in paragraph 176 of the AIC is a new proposal, and one for which there has been no opportunity to test the evidence. Board staff objects to this proposal for this reason and for those following, and submits that it should be denied.

First, it is not clear what Enersource means by "non-standard" installation of smart meters, "non-standard" reading of smart meters and "non-standard" communication infrastructure. There is no information on the estimated numbers and costs related to "non-standard" installations and operations.

Second, it is not clear what specific approval or mechanism Enersource is now proposing. Would these costs be recorded in new or existing deferral accounts, or is Enersource proposing specific rates and charges?

Third, Board staff submits that this proposal is inconsistent with the Board's policy and practice with respect to smart meter cost recovery. In this Application, Enersource has filed for final disposition of costs related to completion (i.e. 100% deployment) of its smart meter program. The SMDR trues up the variance between what Enersource should have recovered as the revenue requirement for installed smart meters to December 31, 2012 against what it actually received as SMFA

[36] AIC, September 17, 2012, pp. 39-40
[37] Exhibit 9/Tab 2/Schedule 1/page 3

revenues and associated interest on the monthly SMFA revenue principal. Going forward, costs for installation and operation of smart meters are incorporated into the 2013 rate base, and OM&A expenses included in the 2013 revenue requirement, so that, assuming approval, rates going forward will recover the capital-related and operating costs for smart meters akin to the treatment for any other distribution assets and operations. Enersource is thus held whole with respect to recovery of the historically deferred cost recovery and ongoing cost recovery; there are no costs that Board staff is aware of that would be additional to what has been applied for. Board staff is also unaware of any other applications where approval for this incremental cost recovery of "non-standard" equipment and operations for smart meters has been sought, or such cost recovery treatment approved by the Board.

In light of the above, Board submits that Enersource's proposal documented in paragraph 176 of the AIC should be denied.

With these comments, Board staff submits that Enersource, as noted in this Application, will have deployed smart meters to 100% of residential and GS < 50 kW customers and has effectively completed smart meter deployment. As of January 1, 2013, costs for investment in and operation of smart meters should be recorded in typical capital and operating expense accounts, akin to the treatment of other distribution capital (e.g. poles, wires, transformers, vehicles, etc.) and operating costs; no further entries should be recorded in Accounts 1555 and 1556 and the accounts should be closed.

Stranded Meters

Background

In its Application, Enersource has applied for recovery of the residual net book value ("NBV") of stranded conventional meters that were replaced by smart meters.[38] O.Reg. 426/06 specifies that utilities should be held whole with respect to the investment in conventional meters that became obsolete with the Provincial Government's direction for smart meter deployment authorized by regulation in 2006.[39] Enersource's proposal for the stranded meter rate rider is also made with consideration to Guideline G-2011-0001.

Enersource has documented a NBV of stranded meters of $7.640 million as of

[38] Exhibit 9/Tab 2/Schedule 2
[39] O.Reg. 426/06, section 3.

December 31, 2012.[40] In its Application, Enersource proposed the following Stranded Meter Rate Riders ("SMRRs"):[41]

Class	**Residential**	**GS < 50 kW**	**GS 50-499 kW**
Stranded Meter Rate Rider (per month, January 1 to December 31, 2013)	$3.23	$3.40	$1.22

Enersource documented that it had used the number of smart meters installed in a customer class to allocate the NBV of stranded conventional meters, in the absence of detailed data for a more proper allocation. Parties posed questions about this through interrogatories and during the Technical Conference.[42] In response to questioning during the Technical Conference, Enersource filed undertakings JT1.1 and JT1.2.

JT1.1 provided the results of sheet I7.1 of Enersource's 2007 Cost Allocation Informational Filing, and shows the capital weighted meter cost ("CWMC") which is used to allocate the costs from account 1860, and possibly factors into the allocation of some other capital and operating expenses for allocating the revenue requirement appropriately amongst customer classes for recovery through distribution rates. Based on the concept of cost causality, and reflecting the fact that meters in certain classes are more expensive (e.g. polyphase versus single-phase, load rating based on a customer's peak demand), the CWMC is used to apportion the aggregate costs in accounts, particularly Account 1860 – Meters, so that the costs are recovered from the customers for which the costs are incurred and any cross-subsidization is minimized.

Enersource has used the Cost Allocation model in the determination of its proposed rates, and sheet I7.1 shows the CWMC used in the determination of the proposed distribution rates for 2013. Looking at that sheet, a row labelled on the left as "Cost Relative to Residential Average Cost" shows numbers as follows: 1 for Residential (as expected), 4.92 for GS < 50 kW, 6.71 for GS 50-499 kW, and so on. In other words, relative to a meter for a residential customer, the capital cost for a meter for a GS < 50 kW customer costs 4.92 times as much, and a GS 50 – 499 kW customer costs 6.71 times as much. This is logical and reasonable.

However, Board staff submits that it is inappropriate to use the results from the cost

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[40] Exhibit 9/Tab 2/Schedule 2/Table 2
[41] Exhibit 9/Tab 2/Schedule 2/Table 3
[42] Board staff interrogatory # 67 Exhibit I/Issue 10.2, CCC interrogatory # 1 Exhibit I/Issue 10.2 and Technical Conference transcript Day 1, July 30, 2012, p.15/l.4 to p.23/l.28.

allocation study in this Application to determine class-specific SMRRs, as the cost allocation reflects the smart meters deployed by Enersource and excludes the conventional meters stranded by replacement by smart meters. For this, we need to go back to the earlier study in 2006-2007. The results shown in I7.1 of the 2007 Cost Allocation study shown in JT1.1 give the following CWMC: 1 for Residential, 9.16 for GS < 50 kW and 35.96 for GS > 50 kW. Based on these factors, Enersource estimated that SMRRs for recovery over one year from January 1 to December 31, 2013 would be $1.59 per month for Residential, $15.28 for GS < 50 kW and $21.60 for GS > 50 kW, in its response Undertaking JT1.2. However, while Enersouce did respond to the second part of Undertaking JT1.2, which was "would Enersource use that data in order to recalculate the rider, the stranded meter rider, and if not then provide a reason why that would not be a good methodology to use" By providing the above numbers, they were silent as to whether they supported the use of these revised riders.

Under oral cross examination on September 10 (Day 3), Enersource's witnesses stated that they were amenable to either approach:

[MS. HELT]: Is Enersource proposing the class-specific stranded meter rate riders as shown in JT1.2, which is on the screen now, or the ones which you proposed in Exhibit 9, tab 2, schedule 2, which was the first table we looked at?

MR. SULTANA: We believe that there are pros and cons to both approaches.

The first approach, where the net book value is scattered equally among the classes, there's no requirement to record the net book value for each of the separate customer classes separately.

Secondly, with regards to the amounts shown in this undertaking, it's based on a 2006 cost allocation methodology, and as was discussed at the technical conference, there were some concerns regarding the model accuracy in terms of the cost allocation model.

Enersource is amenable to using either approach, again, but there are pros and cons to picking one over the other.

MS. HELT: But you would agree that Enersource has already stated that this is the methodology approved by the Board in another 2012 cost of service application?

MR. SULTANA: No. I that believe that reference to

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Guelph is referring to the fact that they just took their
total costs and divided evenly based on customer numbers,
similar to the push that was done originally by Enersource.[43]
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Board staff notes that Enersource, in its AIC, states:

> 179. Enersource proposes the recovery period to be twelve months, effective January 1, 2013. Table 3 of Exhibit 9 Tab 2 Schedule 2 Stranded Meters shows the proposed stranded meter rate rider by customer class.[44]

Board staff submits that Enersource's witnesses stated that they were amenable to either approach during the oral hearing, as quoted above, however the AIC only makes reference to Enersource's original Application.

Discussion and Submission

Board staff submits that the weighted SMRRs as calculated in JT1.2 are preferable to the smart meter-weighted counts proposed by Enersource in its Application. There are several reasons for this.

First, weighting by the number of installed smart meters treats the residual net book value of the meters the same across all affected customer classes. However, the meter costs are not the same, as Enersource's witnesses agreed during the Technical Conference[45], and as shown in JT1.1. The costs for meters differ by class, and to treat the costs commonly for all would result in a cross-subsidy of the general service customers by residential customers.

Board staff submits that that is not the intention in the regulation[46], or in the Board's Guideline G-2011-0001that there be a re-allocation of costs for stranded conventional meters. The Board, in section 3.7 of Guideline G-2011-0001 states that a distributor should make a proposal for cost allocation of costs amongst suitable classes as part of its SMRR proposal. [47]

Board staff submits that the meter count weighted SMRRs proposed by Enersource result in an unrealistic allocation and recovery of costs, particularly from residential

[43] Transcript, Vol. 3, September 10, 2012, page 156/l. 20 to page 157/l. 16
[44] AIC, September 17, 2012, page 40
[45] Transcript, Technical Conference Vol. 1, July 30, 2012, 2012, page 19, ll. 6-27.
[46] O.Reg. 426/06, section 3.
[47] Guideline G-2011-0001, section 3.7, page 23.

customers. Enersource proposed in its Application a Residential SMRR of $3.23 per month for one year. This would result in a recovery of $38.76 from each residential customer in Enersource's service territory.

Board staff submits that this would over-recover from residential customers. From sheet I7.1 from the 2007 Cost Allocation Informational Filing filed in JT1.1, the average residential meter capital cost was documented as $55.32, and this would have largely represented conventional meters using 2006 data. $38.76 represents nearly 73% of the average residential meter cost.

Board staff observes that Enersource was one of the distributors named in O.Reg. 427/06 filed on August 29, 2006 to undertake discretionary metering activities (i.e. deployment of smart meters), and that it commenced deployment in 2006, with costs to April 30, 2007 reviewed as part of the combined smart meter proceeding EB-2007-0063. From when it started deploying smart meters, it should have ceased deployment of conventional meters in the Residential and GS < 50 kW customer classes. This suggests that, by December 31, 2012, no conventional residential meter replaced by a smart meter should be less than 6 years old. Given the typical useful life ("TUL") of 25 years used to depreciate metering assets in the past, that is nearly 25% of the TUL. In other words, no meter should be less than 25% depreciated, and stranded conventional meters would range from about 25% to fully depreciated.

Based on a uniform age distribution in the past, probably relatively realistic given installation of new meters for growth and replacement of meters for failure or end of life, and recognizing that meters installed from 1983 to 1986 would become fully depreciated after 25 years (even though they were reflected in Enersource's 2008 rate base and revenue requirement and hence approved rates would still recover depreciation expense and a return on capital and associated PILs through rates), Board staff estimates that the average remaining life – and hence average net book value for the purposes of determining the SMRR – would be less than 7.5 years out of 25, or 30% of total life and gross book value, as of December 31, 2012. 30% of the residential meter cost of $55.32 from JT1.1 would be $16.00, or $1.33 per month for 12 months. This is reasonably close to the $1.59 residential SMRR calculated in JT1.2; the variance may be due to differences in the age distribution from 2006 to now, as older meters became fully depreciated. Board staff submits that the $1.59 from JT1.2 is a better estimate based on the principle of cost allocation than is the original proposal of $3.23 per month for the residential SMRR.

That Enersource's meter count-weighted proposal would over-recover from residential customers is due the fact that it ignores the different meter costs in the classes, and hence shifts costs from the GS classes with more expensive meters to the small GS and residential class.

While the SMRR for the GS 50-499 kW class would seem anomalous as the average cost for these meters is still higher, Board staff understands that the rationale for this is that the stranded/replaced meters for this class represents only a fraction of the customers in this class. In other words, the costs are spread over a larger number of customers in the class. Customers in this class whose meters have not been replaced at this time may have their meters replaced upon resealing or repair and thus that these customers may also benefit from remote communication of usage data and SCADA-type problem identification when their meters may be replaced.

As noted above, Enersource's witnesses stated that they are amenable to either proposal. And they are held whole, consistent with section 3 of O.Reg. 426/06. Given that Enersource's proposed meter count-weighted proposal in its application would result in a re-allocation of costs and over-collection from residential customers, Board staff submits that the SMRRs calculated in JT1.2 would be preferable on a principled basis.

-All of which is respectfully submitted-