Cost Allocation Policy Review

Options and Preferred Alternatives

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Executive Summary

The Ontario Energy Board announced in a September 2, 2010 letter to distributors and stakeholders that it had initiated a consultation process (EB-2010-0219) to review certain specific issues related to electricity distribution cost allocation policy. The letter listed the specific cost allocation policy issues that would be addressed in this process.

This report presents a number of options as well as the preferred alternative for each identified issue. It will be the basis for stakeholder review and comments as part of Proceeding EB-2010-0219.

The preferred alternatives are summarized below.

Creation of MicroFIT Rate Class

The Board should not create a separate MicroFIT rate class in the cost allocation model, but continue to use the currently identified USoA accounts to establish the uniform provincial fixed rate for microFIT. Each distributor should be allowed to establish its own microFIT rate to better reflect cost causality for each distributor.

Cost Allocation to Unmetered Load

A separate sheet should be added to the Board's cost allocation model that will include the default values used for these types of customers. This would more clearly indicate to distributors the option of using their own values in place of the default values, and include descriptions of how the default values were developed.

For distributors that do not have a separate class for USL, the distributor should be required to demonstrate that the revenue:cost ratio for these types of customers would still be within the Board's recommended range.

Treatment of Transformer Ownership Allowance

The Board should modify the cost allocation model to ensure that only the customer classes that include customers providing their own transformation are included in the determination of the TOA.

Allocation of Miscellaneous Revenues

The major components included in Miscellaneous revenues should be identified and allocated to customer classes in a way that corresponds to the allocation of the corresponding costs. The remaining Miscellaneous revenues should be allocated to the customer classes in the same proportion as composite OM&A.

Miscellaneous revenues and related costs should be included in the determination of revenue:cost ratios in the cost allocation model.

Weighting Factors for Services and Billing Costs

A separate input sheet should be developed that would include the default weighting factors. It should explain the reasons behind the different weighting factors and give distributors the option of substituting their own values for the default values, if appropriate.

Allocation of Host Distributors Costs to Embedded Distributors

Host distributors should continue to use Schedule 10.7 of the 2006 EDR Handbook and this schedule should be incorporated into the cost allocation model. The Board should establish thresholds above which host distributors would be required to set separate charges for embedded distributors. The recommended thresholds are:

1. If the embedded distributor represents more than 10% of the host distributor's total volume sales, or
2. If the embedded distributor is larger than 500 kW average demand per month

Allocation of Costs to Load Displacement Generation

Standby charges should be established for new load displacement generation above a certain size, for example 500 kW. The costs attributable to customers with load displacement generation should be determined by undertaking a specific customer avoided costs analysis. In lieu of a specific customer analysis, default avoided costs values could be used as a simplified approach. A simplified approach should also be followed to establish the benefits that load displacement generation may provide. For example, the Board could choose, based on its own judgement, a 5% reduction in allocated costs. .

Unless the distributor chooses to follow the above recommendation for existing standby charges, they should continue to be allowed to maintain on an interim basis their standby charges until more research has been evaluated on this issue, including rate design approaches.

Refine the three widest Target Ranges, which are associated with the following rate classes: General Service 50 to 4,999 kW, Street Lighting, and Sentinel Lighting

For the General Service class 50 kW to 4,999 kW, the top range should be reduced to 1.40. The bottom range should be left unchanged at 0.80.

For street lighting and sentinel lighting customer classes, the bottom range should be increased gradually over 3 to 4 years when distributors apply for rebasing, to match the bottom range of the General Service less than 50 kW class of 0.80. The top range should be left unchanged at 1.20.

Address accounting changes and the transition to IFRS

There is no demonstrated need to modify the cost allocation model to address the accounting reporting changes.

The accounts identified in Attachment A should be added to the cost allocation model.

1 INTRODUCTION

1.1 PROJECT DESCRIPTION

The letter from the Board dated September 2, 2010 provided a background description for the Cost Allocation issues to be considered in this project and provided reasons for undertaking a review of certain elements of its costs allocation policies.

Among the reasons provided are: the experience gained from applications submitted to the Board, the fact that no separate consultation is currently scheduled on issues such as standby rates for load displacement generation, the creation of a new microFIT rate class since the cost allocation report was issued in 2007, and adjustments that have been made to the revenue:cost ratios to have them fall within or at the beginning or the end of the target ranges.. The implementation of the International Financial Reporting Standards ("IFRS") is not expected to impact the cost allocation methodology but the Board is prepared to accommodate an update, if required. Finally, the Board expects that within two to three years a more comprehensive review of the cost allocation policies could be undertaken, when sufficient smart meter data is expected to be available.

1.2 PROJECT OBJECTIVES

The letter from the Board dated September 2, 2010 states the following matters will be addressed in this project:

1. The creation of the microFIT rate class;
2. Refining the following specific components of the cost allocation methodology:
    - The cost allocation to unmetered loads (i.e., unmetered scattered loads, street lighting and sentinel lighting);
    - The treatment of the transformer ownership allowance;

- The allocation of Miscellaneous revenues;
- The weighting factors for services and billing costs;
- The allocation of host distributor costs to embedded distributor(s).

3. The review of options for allocating costs to load displacement generation;
4. The refining of the three widest Target Ranges, which are associated with the following rate classes: General Service 50 to 4,999 kW, Street Lighting, and Sentinel Lighting; and
5. Addressing accounting changes and the transition to IFRS.

1.3 STRUCTURE OF THE REPORT AND TIMELINE

The issues identified by the Board as described in section 1.2 above are included in this report. The remaining sections of this report include the following sections for each identified issue:

- Current Situation
- Previously Undertaken Work
- Issues Identified by Distributors and/or Stakeholders
- Options to Deal with Issues Raised
- Preferred Alternative

The list of alternatives is not intended to be an exhaustive list and only the alternatives considered to be more viable have been included in this report.

The timeline for this project includes issuing this Elenchus report in October for comments, and a Stakeholder meeting planned for November 18, 2010 where Elenchus will present the alternatives it explored as well as the recommended approach for each issue so that Stakeholders can provide initial feedback. Written comments from Stakeholders are due to be submitted to the OEB by December 2, 2010.

The Board will then determine the next steps for this consultation process, which may be the issuance of a Board report identifying any proposed revisions that the Board believes to be appropriate at this time. If the Board makes any revisions to its policy, a revised cost allocation model implementing the required changes will subsequently be issued.

2 UPDATING COST ALLOCATION METHODOLOGY TO INCORPORATE NEW DEVELOPMENTS

2.1 NEW MICROFIT RATE CLASS

2.1.1 CURRENT SITUATION

Ontario's Feed-In Tariff (FIT) program for renewable energy generation is a cornerstone of the province's *Green Energy and Green Economy Act, 2009* (the "Green Energy Act"). The program was launched in September 2009, and the Ontario Power Authority ("OPA") started accepting applications on October 1, 2009.

The program includes a stream called microFIT, which is designed to encourage homeowners, businesses and others to generate renewable energy with projects of 10 kilowatts (kW) or less. The Ontario government has recently proposed a minor change to the solar microFIT regulations that would allow an increase in the size of facilities from 10 kW to 12 kW. This would allow small solar technologies with input name plate capacity greater than 10 kW but with output capacity of less than 10 kW to remain exempt from the requirement of obtaining a more onerous Renewal Energy Approval. The Ministry of Energy is asking for comments by November 21st.

The microFIT program is designed to make it simpler and faster to get small-scale renewable projects installed and producing power. Participants in the microFIT program are guaranteed a certain rate for the power they produce and feed into the Ontario grid.

This new customer class is different from other customer classes because connections under microFIT are associated with a main account, use the same assets as the main account, and the power consumption associated with the accounts is expected to be negligible.

On September 21, 2009, in anticipation of the initiation of the OPA microFIT program, the Ontario Energy Board issued a Notice of a Proceeding and Procedural Order No. 1 to commence a proceeding on its own motion to determine a just and reasonable rate to be charged by an electricity distributor for the recovery of costs associated with an embedded generator account having a nameplate capacity of 10 kW or less (embedded micro generator) that meets the eligibility requirements of the OPA's microFIT program. The Board assigned file number EB-2009-0326 to this proceeding.

In the Board's decision issued February 23, 2010 it is stated that the system design issues and related costs/benefits are out of scope in proceeding EB-2009-0326 and the Board maintained the principle that the costs to be included in the microFIT charge are strictly related to the administrative activities associated with the customer and will not include any costs related to system operation.

The Board also decided that the costs should be recovered only through a fixed monthly service charge. A variation of generation output does not result in a variation of the administrative costs associated with the microFIT customer class.

The Board also found that a single, province-wide rate for all distributors should be established at this time and the Board gave two reasons for this[1]:

1. A rate based on the weighted average of the current cost experiences of the distributors was established in order to promote renewable sources of energy. A province wide rate will provide a single input cost component to the microFIT program province wide. The narrowing of the cost assumptions being made by both the OPA and microFIT program applicants will enhance the attractiveness and effectiveness of the program.

[1] Decision and Order, Proceeding EB-2009-0326, issued February 23, 2010, pages 15-16

2. As previous cost allocation studies have demonstrated, variations in the manner in which distributors account for costs associated with customer classes exists and results in materially disparate outcomes. The Board has recognized this reality in its cost allocation report of November 28, 2007 (Application of Cost Allocation for Electricity Distributors, EB-2007-0667). Steps have been taken in recent rate decisions to alleviate the situation but the development of a more uniform cost allocation methodology across all distributors is still a work in progress. The material variation could be magnified if a sub-set of accounts associated with a customer class is parsed off and compared in isolation. Aggregating the cost experiences of the distributors on a weighted average basis will establish a reasonable starting point for a new customer class and avoid the exacerbation of the problem cited above of having a wide range of cost input assumptions for the microFIT program.

   The Board is of the view that over time and with empirical information regarding the costs associated with the microFIT class, the Board will be in a better position to consider the effectiveness of the microFIT rate in both the promotion of renewable generation and the appropriate allocation of costs. If it is determined that the actual costs for these customers are significantly disparate across distributors then the Board may consider moving to utility specific rates at some point in the future[2].

2.1.2 Description of Previously Undertaken Work with respect to microFIT

The Board recognized the need for an appropriate cost recovery mechanism for the distributors, and the need to support the implementation of the microFIT initiative. Therefore, the Board, as part of Proceeding EB-2009-0326, ordered in September 21, 2009 the establishment of a service classification and a rate for embedded micro generators for every licensed distributor on an interim basis. The interim rate was the fixed monthly charge equal to the distributor's existing residential monthly service charge.

2 ibid

The Board's Decision and Order regarding the Proceeding was issued February 23, 2010. In the Decision, the Board approved the following service classification definition, which is to be used by all licensed electricity distributors:

> *microFIT Generator*
>
> *"This classification applies to an electricity generation facility contracted under the Ontario Power Authority's microFIT program and connected to the distributor's distribution system."*[3]

Further, in the Decision, the Board found that a single, province-wide fixed monthly charge for all distributors will be determined, based on the customer weighted average of the 9 cost elements listed below:

1. Customer Premises - Operation Labour (Account 5070);
2. Customer Premises - Materials and Expenses (Account 5075);
3. Meter Expenses (Account 5065);
4. Maintenance of Meters (Account 5175);
5. Meter Reading Expense (Account 5310);
6. Customer Billing (Account 5315);
7. Amortization Expense – General Plant assigned to Meters;
8. Administration and General expenses allocated to Operating and Maintenance expenses for meters; and
9. Allocated PILS (only general plant assigned to meters).

The Board stated in the Decision that it intended to adopt September 21, 2009 (the date of the establishment of the interim rate), as the effective date for the new rate.

Accordingly, the Board ordered distributors to provide the Board values for each of the cost elements outlined above within 20 days of the issuance of the Decision, i.e. by March 15, 2010, so that the Board could determine the level of the province-wide fixed monthly charge, In the interests of practicality, the Board decided that the calculated

[3] ibid, page 6

rate would be acceptable if it were based on input representing at least one third of the electricity distributors and at least one half of all residential electricity customers in the province.

By March 15, 2010, the Board had received cost element values from 62 electricity distributors representing 3,798,083 residential electricity customers in the province. This met the minimum response required to calculate the rate.

On March 17, 2010, the Board ordered that the province-wide fixed monthly charge for all electricity distributors related to the microFIT Generator rate class be $5.25 per month, effective September 21, 2009.

Based on data that distributors submitted for the 9 USoA accounts identified by the Board, the range of distributor specific microFIT charge would be between $2 and $12 compared to the $5.25 weighted provincial average approved by the Board.

The Board has also initiated a separate proceeding to deal with the issue of the differences amongst distributors on the connection costs for "micro-embedded generation facilities", in Proceeding EB-2010-0206, dated July 22, 2010.

2.1.3 Issues Identified by Distributors and/or Stakeholders

Distributors and stakeholders have commented on this issue prior to the Board issuing its Decision and also as part of Proceeding EB-2009-0326.

Some Distributors are of the view that the accounts identified by the Board do not include all the costs that distributors incur when connecting microFIT generators.

Other distributors may feel that a provincial rate does not reflect their specific situation and prefer that their own costs be reflected in the microFIT rate. Some Generators believe they should not be subject to charges as they provide an overall benefit to all consumers of electricity. According to this argument, the cost of serving microFIT generators should be socialized and be borne by all electricity consumers.

The main principle though, in determining what the appropriate charge should be, is that microFIT customers should be responsible for the costs they impose on distributors and that other distributors' customers should not be subsidizing them.

2.1.4 Options to Deal with Issues Raised

There are three broad options that can deal with this issue:

Option #1: The same accounts identified by the Board should continue to be used to establish the microFIT charge.

Option #2: The Board could request a sample of distributors that now have experience with microFIT connections to list all the costs they incur in providing services to these types of customers and identify if there is a need to depart from the 9 identified USoA accounts, so that an appropriate charge could be determined.

Option #3: A separate customer class called microFIT could be added to the cost allocation model. It would include the related assets and costs attributable to this new microFIT customer class.

Two variants of each of these options also need to be considered:

Variant A: The current approach of establishing a uniform province-wide rate for microFIT generators could be continued.

Variant B: The charges could be distributor-specific, based on their own costs, the same way other distribution rates are established.

2.1.5 Preferred Alternative: Establish a Fixed Monthly Charge for microFIT Connections

The preferred approach of Option # 1, would confirm that the USoA accounts currently used to establish the uniform provincial fixed rate for microFIT ensure that all the related costs have been appropriately captured. The Board has just recently completed the review of the appropriate USoA accounts and there is no need to repeat the analysis so soon after that review.

The alternative of Option # 2 is premature. There has not been enough experience with this type of activity to allow distributors with experience in connecting microFIT generators to identify the connection costs they incur.

The third option of establishing a separate customer class in the cost allocation model is not necessary, because only 9 specific USoA accounts have been established to determine the microFIT charge and the remaining USoA accounts in the cost allocation model do not impact the microFIT class. While this report has rejected option #3, it may be useful to consider what changes would have to be made if it is approved: If a separate class is created in the cost allocation model, the weighting factors for Services and Billing would need to be developed. For Services, the weighting factor should be zero as it is assumed that the microFIT connection is served using the same services as the main account. For Billing, the weighting factor should be the same as for the Residential class since in most cases microFIT connections are tied to a main residential account, but are issued separate bills

To facilitate the determination of the microFIT charge, a separate sheet that would extract the 9 USoA identified accounts would be added to the cost allocation model; this would determine the microFIT charge. The separate sheet would be similar to the separate sheet O3.1 that determines the transformer ownership allowance in the model.

With respect to the variants identified, each distributor would be allowed to establish their own microFIT rate, just as each distributor establishes their own distribution rates based on their own costs. This would better reflect the cost causality for each distributor. If the distributor elects to apply for its own specific rate and it is substantially different than the provincial weighted average rate, the distributor may need to explain the reasons for the large difference.

Recommendation: Continue to use the USoA accounts currently identified to establish the uniform provincial fixed rate for microFIT.

Each distributor should be allowed to establish its own microFIT rate to better reflect cost causality for each distributor.

3 REFINEMENTS TO COST ALLOCATION METHODOLOGY

3.1 UNMETERED LOADS

3.1.1 CURRENT SITUATION

Unmetered scattered loads, (USL), street lighting and sentinel lighting are customer classifications used to group specific types of distributors' customers that do not utilize metering equipments because their electricity consumption is predictable and can be determined accurately based on the connected load, e.g. the size of lights, or the cable TV amplifier rating. There have been technologies changes in the last few years with respect to the size of TV amplifiers and the more widespread use of heating and cooling devices.

For cost allocation purposes, different allocators are used for these types of customer classes than are used for other customer classes and certain costs like metering costs are not allocated to these customer classes. Most distributors in Ontario treat USL as a separate customer class. If USL is not a separate customer class, it is included in the General Service below 50 kW customer class.

This last approach has been subject to increasing scrutiny. In a recent OEB Decision, a distributor was ordered to determine revenue:cost ratios for USL as a separate class[4], and has faced questions on whether the inclusion of the USL class within the General Service below 50kW class may put the revenue:cost ratio for USL as a group outside the target revenue:cost ratio range approved by the Board.

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[4] Hydro One Networks Inc. 2010-2011 Distribution Rates, EB-2009-0096, Decision with Reasons, April 9, 2010, page 70

In another recent decision questioning whether weighting factors have been applied properly, The Board asked a distributor to review the assumptions on the weighting factor it used when providing street light connections with a summary bill[5].

3.1.2 DESCRIPTION OF PREVIOUSLY UNDERTAKEN WORK FOR ALLOCATING COSTS TO UNMETERED LOADS

The current cost allocation model allows distributors to use different weighting factors to allocate certain costs to street lighting, sentinel lighting and USL customers.

The default weighting factors currently in the cost allocation model for these customer classes are:

	Street Light	Sentinel Lights	USL
Services	1.0	1.0	1.0
Billing	1.0	0.1	5.0

For the Services weighting factors, Board Staff in page 38 of the User Instructions issued November 15, 2006, and revised December 8, 2006 explain that:

> *"In particular, notice that the default of the index for many classes is entered as 1. If a class has more connections than customers, this index operates on the number of connections. As a result, a default weight of 1 may be too high for simple unmetered load connections."*

In other words, a weighting factor of 1 assumes that there is one connection per account. If an unmetered account has multiple connections per accounts, the weighting factor should be less than 1. As an illustration, if there are 10 connections for an

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5 Kitchener-Wilmot Hydro Inc. 2010 Distribution Rates, EB-2009-0267, Corrected Decision and Order, April 7, 2010, page 37

unmetered account, a 0.1 weighting factor would be more appropriate than using a weighting factor of one.

In Proceeding EB-2005-0317, Cost Allocation Review, Board issued a Direction on September 29, 2006, concerning the Cost Allocation Methodology for Electricity Distributors. On page 87, the policy states that: “The billing costs are to be allocated using the number of bills issued by a distributor for USL customers based on the invoicing approach used by the distributor.”

These default billing weighting factors were developed in order to reflect the varying amount of effort required in issuing bills to the different customer classes. Different invoicing approaches are used by distributors. They can include:

a) A separate account and invoice for each connection.
b) A separate account for each connection and a single summary bill produced by an off-line process.
c) A single bill, aggregated within the billing system.

3.1.3 ISSUES IDENTIFIED BY DISTRIBUTORS AND/OR STAKEHOLDERS

Many distributors are unaware that the current cost allocation model allows them to use their own weighting factors to reflect the many connections that can be attached to one account for these types of customers. A more user-friendly model may be helpful to distributors.

Some USL representative customers believe that USL have unique load profiles that are different from other small general service customers, and so feel that USL type connections should be treated as a separate customer class[6].

[6] Hydro One Networks Inc. 2008 Distribution Rates, EB-2007-0681,Decision with Reasons, December 18, 2008, page 27

The main principle in determining what the allocated costs should be is that these customers should be responsible for the costs they impose on distributors and that other distributors' customers should not be subsidizing unmetered load customers.

3.1.4 Options to Deal with Issues Raised

There are five options that could deal with the issue of weighting factors:

Option #1: Make the cost allocation model more user-friendly by adding a separate input sheet that would include all the different weighting factors that distributors can use. The sheet would include the default values and instructions for distributors on how to substitute the default values with values that are more reflective of their own circumstances.

Option #1A: Update, if necessary, the default allocators used in the cost allocation model for these types of customers with information obtained from distributors' experience with these types of customers. If data is not available, a process to collect the required data is needed.

Option #2: Acquire information from other jurisdictions to identify the variety of approaches that have been followed with respect to the allocation of costs to USL type customers.

Options to deal with the issue of customer classification for USL:

Option #3: Require all distributors to treat USL as a separate customer class

Option #4: Develop revenue:cost ratios for USL if they are included in the General Service below 50 kW class and not established as a separate customer class.

3.1.5 Preferred Alternative for Allocating Costs to Unmetered Loads

This report recommends Option # 1, which would require adding a separate sheet to the cost allocation model that will include the default values used for these types of customer and would more clearly indicate to distributors the option of using their own values in place of the default values. An additional description of how the default values were developed would assist distributors in developing their own values and help them understand the purpose of using these values.

Option # 1A: is not recommended. There is no need to update the default values at this time, as utilities have the option to substitute their own values for the default values if they are more appropriate.

There is also no need, as suggested in Option # 2, to undertake research on how other jurisdictions allocate costs to USL. The additional effort is not justifiable at this time.

The proposal in Option # 3 to force distributors to add an additional customer class for USL when it currently does not exist, is also not necessary, as long as the treatment of USL is accompanied by a proper rate design that provides a credit to USL customers for the non-provision of metering services. The derivation of this USL credit is already built into the cost allocation model.

If distributors are including USL as part of their General Service customer class, they should be required, as stated in Option # 4, to confirm that this treatment results in USL-type customers having revenue:cost ratios that are within the Board approved ranges for USL as a separate customer class. In order to be able to do this, a separate customer class would need to be created in the cost allocation model, but if the distributor already has multiple customer classes, the distributor may choose not to expand the number of customer classes in the tariff sheet to create a new USL customer class.

Recommendation: A separate sheet should be added to the cost allocation model that will include the default values used for these types of customer and that would give the option to distributors of using their own values in place of the default values with descriptions of how the default values were developed.

For distributors that do not have a separate class for USL, the distributor should be required to demonstrate that the revenue:cost ratio for these types of customers would still be within the Board's recommended range.

3.2 TRANSFORMER OWNERSHIP ALLOWANCE

3.2.1 CURRENT SITUATION

Distributors incur transformation costs to be able to deliver electricity to customers. The costs of transformation assets and related maintenance are included in the distribution rates approved by the OEB for distributors. In certain circumstances customers provide their own transformation equipment resulting in distributors not having to provide these assets to customers. Customers that provide their own transformation equipment are entitled to receive a discount from the approved distribution rates to compensate them for providing their own transformation equipment. The discount provided is called Transformer Ownership Allowance (TOA) and should reflect the distributors' avoided transformation costs.

The allocation of the costs of the TOA though may not be done properly in the current cost allocation model as the costs are charged to other customer classes that do not have customers receiving the allowance. Another issue is the complexity of the data used to calculate the allowance.

3.2.2 DESCRIPTION OF PREVIOUSLY UNDERTAKEN WORK FOR DETERMINING TRANSFORMER OWNERSHIP ALLOWANCE

The revised Chapter 2 of the Filing Requirements for Transmission and Distribution Applications (June 28, 2010), Exhibit 7/Section 2.8.2, it states:

> *The applicant will calculate distribution revenue from each customer class net of any transformer ownership allowance. In particular, if some customers in the GS>50 kW class provide their own transformers, revenue from the class should be calculated using the approved rate for the customers that the distributor provides with a transformer, and the approved rate less the transformer ownership allowance for those customers that provide their own transformer. The applicant should also ensure that transformer costs (Account 1850 and related accounts) are allocated to the classes in proportion to the load on the transformers supplied by the distributor (in the Board-issued model Sheet I8 - LTNCP).*
>
> *If relying on the Informational Filing, the applicant should note that there were limitations in the cost allocation model distributed by the Board with respect to the*

treatment of the transformer ownership allowance. If using that model, the applicant must:

- *Remove the "cost" associated with transformer ownership allowance from the revenue requirement (Worksheet I3);*
- *Subtract the "revenue" associated with the transformer ownership allowance from the approved revenue of the affected rates class(es) (worksheet I6, row 29); and,*
- *File Sheet O1 before and after removal of the transformer ownership allowance.*

The Cost Allocation Model calculates a line transformer and a substation transformer allowance by identifying the USoA accounts that include transformation type costs.

3.2.3 ISSUES IDENTIFIED BY DISTRIBUTORS AND/OR STAKEHOLDERS

Vulnerable Energy Consumers Coalition (VECC) raised an issue in Proceeding EB-2008-0245, Thunder Bay Hydro Electricity Distribution Inc. – 2009 Electricity Distribution Rate Application, with regards to the treatment of the transformer ownership allowance in the current OEB Cost Allocation model. VECC points out that it results in an over-allocation of costs to classes where customers generally do not own their own transformers (e.g. Residential and GS<50 kW). This circumstance arises because the model not only allocates to these classes the full cost of the transformers used to serve them, but also a share of the discount given to those classes eligible for the TOA. In principle the discount is an intra-class issue for those classes where some customers own their transformer and other don't. The Cost Allocation model recognizes that some customers own their transformers. However, unless a discount is introduced for these customers (and paid for by the other customers in the same class) those customers in the class who own their transformer will pay too much and those who don't will not bear full cost responsibility for the transformers they use[7].

The Cost Allocation informational filing was inconsistent with this approach as it included the transformer ownership allowance discount as a cost and allocated it to all customer classes.

The Board has accepted and implemented VECC's argument. In the Decision with Reasons in Proceeding EB-2008-0245, dated June 3, 2009, page 35, the Board stated that:

> *The Board is satisfied that the revision argued for by VECC with respect to the exclusion of the transformer ownership allowance from cost and class revenues should be adopted.*

The main principle in determining what the appropriate allowance should be is clear: customers providing their own transformation facilities should get credit for the avoided distributors' cost of not having to provide transformation facilities to these customers.

In addition to the issues of how the TOA should be allocated across rate classes, distributors commented on the complexity of deriving an LDC specific TOA. More specifically they noted the data needed for Sheet 03.1 "Line Transformer Unit Cost" and Sheet 03.2 "Substation Transformer Unit Cost" may not be readily available and that the results from the model are uneven and sometimes do not seem to correlate with distribution rates.

3.2.4 Options to Deal with Issues Raised

Five options were identified to deal with this issue:

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[7] Thunder Bay Hydro Electricity Distribution Inc. – 2009 Electricity Distribution Rate Application, EB-2008-0245, VECC Argument, page 16 to 18, paragraphs 7.4 to 7.7

Option #1: Modify the cost allocation model so that the cost of the TOA would be charged to the other customers in the same class and there would be no impact on other customer classes. As well, simpler instructions would be added, perhaps with a numerical example, showing distributors how they can better use this aspect of the cost allocation model.

Option #2: Maintain the current methodology and add simpler instructions, perhaps with a numerical example, on how distributors can use this aspect of the cost allocation model better.

Option #3: Establish customer classes that include the requirement that the customer provides their own transformation facilities. These customer classes would include all customers that own their transformation assets and therefore there would be no need to determine TOA.

Option #4: Recommend simplification of the current methodology for determining the transformer ownership allowance. Test the availability of the data and TOA methodology using distributors' data

Option #5: Perform an avoided transformation costs analysis for a sample of distributors and compare the results with the TOA calculated in the cost allocation model to ensure the reasonableness of the results.

3.2.5 Preferred Alternative for determining Transformer Ownership Allowance

The report recommends Option #1, the option of modifying the cost allocation model to ensure that only the customer classes with customers that provide their own transformation are included in the determination of the TOA. The costs of the allowance would be recovered only from the remaining customers in the same class. Customer classes where no customer owns their transformers or where the class requirement for customers is to provide their own transformation assets would be excluded from the calculation of TOA. This will ensure that in determining the TOA, cost causality principles are applied. Also, distributors should be given instructions on how to identify the appropriate data to determine the TOA as required by the model.

Option # 2 is not appropriate. The current method of Allocating TOA to other customer classes does not reflect cost causality principles and, therefore is not recommended.

Option # 3, which would create customer classes where all the customers either own or do not own their transformers, is not recommended because it would result in more customer classes being created for all distributors.

If instructions are provided with the cost allocation model, there would be no need for Option #4, to simplify the TOA calculations in the cost allocation model, or Option # 5, which called for a separate avoided transformation cost analysis. Distributors' concerns about the validity of the TOA calculations can be addressed by ensuring the model is being used properly and distributors are using the proper data.

Recommendation: Modify the cost allocation model to ensure that only the customer classes that include customers that provide their own transformation are included in the determination of the TOA.

3.3 ALLOCATION OF MISCELLANEOUS REVENUES

3.3.1 CURRENT SITUATION

Distributors collect Miscellaneous revenues from their customers in addition to the revenues collected from distribution rates. The additional revenues are, for example, for late payment charges, rental of specific equipment like sentinel lights, and specific activities performed by distributors at the request of individual customers. The costs of providing these services are included in the distributors' revenue requirement. To ensure that customers are treated fairly, the allocation of the costs to customer classes for these services should be the same as the allocation of the revenue collected for these services from customers. This ensures that costs and revenues are allocated properly to all customer classes based on cost causality principles.

Miscellaneous revenues are comprised of 30 different accounts. Based on data from the 2006 Electricity Distribution Rates process, 92% of Miscellaneous revenue comes from four major accounts for most distributors. These accounts are:

1. Late Payment charges
2. Account set up and charge/change of occupancy charge (plus credit agency costs if applicable)
3. Specific Charge for Access to the Power Poles $/pole/year
4. Collection of account charge - no disconnection

In the natural gas industry things are handled differently. Miscellaneous revenues, like late payment penalties or meter and service alteration charges, are functionalized into the same functions that include the related costs.

3.3.2 Description of previously undertaken work for allocating Miscellaneous revenues

Accounts 4082 Retail Services Revenues, 4084 Service Transaction Requests (STR) Revenues, 4090 Electric Services Incidental to Energy Sales and 4235 Miscellaneous Service Revenues are all allocated in the cost allocation model on the basis of Weighted Number of Bills.

Account 4225 Late payment charges, is allocated on the basis of historical bad debt expense information.

All the other accounts are allocated on the basis of the NFA (net fixed assets) allocator which is based on the allocation of all fixed assets.

3.3.3 Issues identified by distributors and/or stakeholders

The main principle in determining what the appropriate allocation methodology should be is to allocate Miscellaneous revenues and related costs to the customer classes using the same allocators and Miscellaneous revenues and related costs should be included in the determination of revenue:cost ratios

VECC noted that the Cost Allocation Informational filing includes both distribution service revenues and Miscellaneous revenues in the revenue values that determine the revenue:cost ratios, whereas the Board 2009 3rd generation Incentive Regulation Mechanism Supplementary Filing Module assumed that all revenues are derived from Distribution Service rates.[8] Consequently, the Board revised its 3rd generation Incentive Regulation Mechanism Supplementary Filing Module in 2010, to ensure that Miscellaneous revenues are included in the determination of the revenue:cost ratios.

3.3.4 Options to Deal with Issues Raised

Five options were identified to deal with this issue:

Option #1: Allocate Miscellaneous revenues to the customer classes in the cost allocation model in the same proportion as the costs incurred to provide these services are allocated to the customer classes. The major account components included in Miscellaneous revenue should be identified and revenues should be allocated to customer classes in the same way as the related costs are allocated to the customer classes. The remaining Miscellaneous revenues should be allocated to the customer classes in the same proportion as the composite OM&A.

Option #2A: As a default, all Miscellaneous revenues could be allocated to the customer classes in the same proportion as distribution revenues are allocated to the customer classes.

Option #2B: The composite OM&A could also be used as an allocator for all Miscellaneous revenues.

Option #3: Treat Miscellaneous revenues as it is done in natural gas industry, where the revenues are functionalized to the related cost functions when doing a cost allocation study.

[8] Wellington North Power Inc, 2009 Distribution Rates, EB-2008-0217, Decision and Order, March 17, 2009, page 8 and VECC Submission, page 3

Option #4: Continue to allocate Miscellaneous Revenues as it is currently done in the cost allocation model.

3.3.5 PREFERRED ALTERNATIVE FOR ALLOCATING MISCELLANEOUS REVENUES

Option #1 is recommended. The major components included in Miscellaneous revenues should be identified and the allocation of these revenue categories to customer classes should be similar to the allocation of the corresponding costs to ensure that cost and revenues are allocated in a similar way. The remaining Miscellaneous revenues should be allocated to the customer classes in the same proportion as composite OM&A. In this way, revenues and related costs are allocated using similar allocators to customer classes.

This treatment in effect is similar to, but would require less work by distributors than Option #3.It's similar to what occurs in the natural gas industry where the revenues are functionalized to the same functions that include the corresponding costs

Option #2B, the option of allocating all Miscellaneous revenues based on a composite of the OM&A costs, would more closely reflect the costs incurred to generate the Miscellaneous revenues than Option 2A, that of using a composite of distribution revenues. This is better than the status quo, but it does not properly reflect the costs incurred in the four major accounts. Option #4 is not recommended as it does not deal with the major account components of Miscellaneous revenues on a cost causality basis, the only exception being the correct treatment of Late Penalty charges.

Miscellaneous revenues and related costs should be included in the determination of revenue:cost ratios within the cost allocation model since all costs and revenues should be included in the determination of revenue:cost ratios for all customer classes. Under the current cost allocation model, the costs incurred to achieve Miscellaneous revenues are included in the distributor's revenue requirement and therefore in the derivation of revenue:cost ratios, but the related Miscellaneous Revenues are excluded from the derivation of the revenue:cost ratios.

Recommendation: The major components included in Miscellaneous revenues should be identified and allocated to customer classes of these revenue categories, in a manner similar to the allocation of the corresponding costs. The remaining Miscellaneous revenues should be allocated to the customer classes in the same proportion as composite OM&A.

Miscellaneous revenues and related costs should be included in the determination of revenue:cost ratios in the cost allocation model.

3.4 Weighting Factors for Services and Billing Costs

3.4.1 Current Situation

As discussed in Section 3.1.2 of this report, weighting factors are used in the cost allocation model to allocate certain costs to customer classes, and better reflect cost causality. For example, billing costs are allocated to the various customer classes based not just on the number of customers in each class, but also on the number of bills issued per year to customer classes and the complexity of the bills that are issued. Some customer classes may be billed every month and have more complex bills, while other customer classes may be billed only every second month and have simpler bills.

As is the case for unmetered load, distributors may not be applying the weighting factors used to allocate service and billing costs properly in the cost location studies model submitted to the OEB, resulting in costs not being properly allocated to customer classes

3.4.2 Description of Previously Undertaken Work for Establishing Weighting Factors for Service and Billing

The existing cost allocation model uses the following weighting factors to allocate Service and Billing costs;

	Residential	GS <50	GS>50-Regular	GS>50-TOU	GS >50-Intermediate	Large Use >5MW	Street Light	Sentinel	Unmetered Scattered Load	Embedded Distributor	Back-up/Standby Power
Weighting Factor – Services	1.0	2.0	10.0	10.0	10.0	30.0	1.0	1.0	1.0	1.0	1.0
Weighting Factor – Billings	1.0	2.0	7.0	7.0	7.0	15.0	1.0	0.1	5.0	1.0	1.0

3.4.3 Issues identified by distributors and/or stakeholders

Some Distributors are not aware they have the option to apply customized weighting factors in the allocation of Service and Billing costs.

3.4.4 Options to Deal with Issues Raised

Two options were identified to deal with this issue:

Option #1. The cost allocation model could be modified by adding a separate input sheet that would allow users to apply their own weighting factors when allocating Service and Billing costs. This would make it easier for the distributors to use the weighting factors.

Option # 1A. Update the default values currently used in the cost allocation model to confirm that the values are still valid.

3.4.5 Preferred Alternative for establishing weighting factors for Service and Billing

Option #1 should be developed so that a separate input sheet would be added that would include the default weighting factors, explain the reasons behind the different weighting factors and allow distributors to substitute their own values for the default values, if appropriate. This would ensure that the cost allocation model reflects cost causality principles, is being used as intended, and is consistent with the recommendation in Section 3.1.5 of this report.

At this time there is no need to update the default values as in Option 1A, as distributors can substitute the default vales with their own values in order to better reflect their own costs when the default values do not properly reflect their own circumstances.

Recommendation: A separate input sheet should be developed that would include the default weighting factors, explain the reasons behind the different weighting factors and include an option for distributors to substitute their own values for the default values, where appropriate.

3.5 ALLOCATION OF HOST DISTRIBUTORS COSTS TO EMBEDDED DISTRIBUTORS

3.5.1 CURRENT SITUATION

Many distributors in Ontario are embedded in host distributors. Embedded distributors receive their power through the assets of host distributors, the largest host distributor in Ontario being Hydro One Networks. Host distributors charge embedded distributors for the cost of providing services and embedded distributors in turn recover these costs from their own customers. Recently an embedded distributor has questioned the allocation of costs by host distributors in the electricity industry. In many instances, host distributors do not have a separate customer class for embedded distributors and embedded distributors are included in the General Service customer class of the host distributor. Usually embedded distributors use fewer assets than other General Service customers of the host distributor. By grouping embedded distributors as General Service customers, embedded distributors may end up paying more than the cost of the assets they use.

Embedded distributors may have different characteristics and size than other General Service customers and tend to use similar assets as the larger customers of the host distributor. For example, a large embedded distributor would probably be served at sub-transmission voltages of 27.6 kV or 44 kV, while smaller embedded distributors may be served at primary voltages below 13.8 kV. Therefore, there may be instances where the embedded distributor may be more like a large user customer than a General Service customer and may even require its own customer classification.

In the natural gas industry host-embedded relationships and resulting costs seem to be dealt with through a rate or contract between distributors. As an example Union Gas has a "Large Wholesale Service Rate - M9" that NRG purchases firm gas supply under. The rate schedule describes it as a rate for *"...a distributor who enters into a contract to purchase and/or receive delivery of a firm supply of gas for distribution to its customers..."*[9]

3.5.2 DESCRIPTION OF PREVIOUSLY UNDERTAKEN WORK FOR ALLOCATING HOST DISTRIBUTORS' COSTS TO EMBEDDED DISTRIBUTORS

As part of the work undertaken by the Board to develop the cost allocation model, much effort went into establishing a common definition for bulk, primary and secondary assets. A Distributor should split its assets into bulk, primary and secondary assets in order to properly identify the assets used by embedded distributors and larger customers. Hydro One is the only distributor in the province that breaks down its costs in the cost allocation model into bulk, primary and secondary services

There are seven host distributors in Ontario that charge a separate rate to their embedded distributors that are not part of the General Service customer class.

The 2006 Electricity Distribution Rate Handbook includes section 10.7, Low Voltage Charges, and Schedule 10.7, to assist distributors in determining rates for embedded distributors. The Schedule determines the percentage of assets that are used to provide services to embedded distributors.

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[9] EB-2005-0520/EB-2006-0502, Union Gas Limited 2007 Rates Application, Decision issued December 9, 2006

3.5.3 ISSUES IDENTIFIED BY DISTRIBUTORS AND/OR STAKEHOLDERS

If assets are only broken down into primary and secondary categories, and not into bulk, primary and secondary classifications, customers that use only the bulk system are subsidizing all other distributors' customers, because they are being allocated primary asset related costs that they may not use. Some larger customers and embedded distributors have challenged the methodology used by distributors for allocating costs to customer classes including larger customers and/or embedded distributors[10]. In a recent decision, the Board has ordered a distributor to create separate charges for an embedded distributor and not charge the distributor the General Service above 50 kW rates, even though this is a common practice among host distributors that do not have a separate embedded distributor customer class[11].

3.5.4 OPTIONS TO DEAL WITH ALLOCATING HOST DISTRIBUTORS' COSTS TO EMBEDDED DISTRIBUTORS

The report has identified five options to deal with this issue:

Option #1: Continue the existing approach and allow distributors to separate assets only between primary and secondary assets and not separately identify bulk assets. Distributors would continue to be allowed to apply the General Service customer classification to embedded distributors.

Option #2: Propose an approach that distributors can use to split assets between bulk, primary and secondary. The approach can be simplified to allow more distributors to use it. The shortcomings introduced by simplification and any lost accuracy is outweighed by the benefit of having a rough estimate that can be used to establish

[10] Brantford Power Inc. 2008 Distribution Rates and Motion by Brant County Power Inc. EB-2009-0063, Decision and Order, August 10, 2010

[11] ibid

an estimate for bulk costs. This could be used to establish charges for embedded distributors.

Option # 2A: Common definitions of bulk, primary and secondary could be established and applied to the majority of host distributors. For example “bulk” could be defined as assets that are used to serve the entire host distributor.

Option # 2B: An approach could be applied to electricity distributors that is analogous to the approach followed by natural gas utilities for identifying costs and signing contracts to supply embedded gas distributors.

Option # 2C. Schedule 10.7 of the 2006 EDR Handbook could continue to be used to determine the percentage of assets that are bulk. This percentage could then be applied to Sheet I 9 of the cost allocation model to allocate the USoA accounts to a new customer class for embedded distributors.

In situations where the embedded distributor is below a certain threshold, the Board could allow host distributors to continue to classify the embedded distributor as a General Service customer. Only if the embedded distributor is above a threshold will the host distributor be required to have separate charges for embedded distributor customer.

3.5.5 Preferred Alternative for allocating Host distributors’ costs to Embedded distributors

Option # 2C is the recommended option. Schedule 10.7 of the 2006 EDR Handbook should continue to be the approach followed by host distributors and this schedule should be incorporated into the cost allocation model. This alternative will result in an approach that will identify assets used by embedded distributors in circumstances where the embedded load is large and is a significant share of the host distributor. Long-term load transfer agreements would not be included as embedded-host relations, as these situations are planned to be eliminated. The additional effort needed to separate the assets used by large embedded distributors would result in a better reflection of cost causality principles for these larger customers.

In addition, the Board should establish a threshold above which host distributors would be required to establish separate charges for embedded distributors. The threshold should take into account the size of the embedded customer and its share of the load of the total utility.

The recommended thresholds are:

1. If the embedded distributor represents more than 10% of the host distributor's total volume sales, or
2. If the embedded distributor is larger than 500 kW average demand per month

Option #1 is not recommended as it does not properly reflect cost causality and embedded customers may be allocated costs for assets that they do not use.

Option # 2A, or a common definition of bulk, primary and secondary applicable to most distributors in Ontario, had been unsuccessfully attempted during the development of the cost allocation methodology. Host distributors in Ontario are diverse in how they serve embedded distributors and "one size fits all" definition could not be reached.

Option # 2C using Schedule 10.7, is a simplified approach to identify the share of assets used by embedded distributors, and is one that host distributors should be able to apply. Even if assumptions would need to be made in completing Schedule 10.7, a rough estimate of bulk assets is better than no estimate at all, and would better reflect cost causality principles by identifying assets utilized in serving embedded distributors.

Option # 2B, is not recommended because there are many more instances of host-embedded distributor relationships in electricity than there are in natural gas. Conceptually, creating a separate class that includes larger embedded distributors is a similar treatment of embedded distributors as it is done in the gas industry where contracts are signed instead.

Recommendation: Schedule 10.7 of the 2006 EDR Handbook should continue to be the approach followed by host distributors and this schedule should be incorporated into the cost allocation model. The Board should establish a threshold above which host distributors would be required to establish separate charges for embedded distributors. The recommended thresholds are:

If the embedded distributor represents more than 10% of the host distributor's total volume sales, or

If the embedded distributor is larger than 500 kW average demand per month

4 ALLOCATION OF COSTS TO LOAD DISPLACEMENT GENERATION

4.1.1 CURRENT SITUATION

Some customers may have installed their own generation facilities so that they can supply all or part of their electricity needs. When the customer owned generation equipment is not available, generally due to an outage, the customer is supplied by the distributor for all its electricity needs. The distributor incurs costs by having distribution facilities ready to deliver all of the customers' electricity needs and these costs of having these facilities available should be recovered from these types of customers by way of rates that are called standby rates. Standby rates ensure that other customers do not end up subsidizing customers that have their own generation. The question of how standby rates should be established has been an issue since 2006 and has not yet been resolved

This report will deal with alternatives related to the distribution cost allocation model. The suggested alternatives are not related to rate design alternatives, and don't deal with the practice of natural gas companies offering interruptible and firm natural gas supply contract terms. Offering Interruptible power would also require having special contracts when supplying standby power, as is being done in the natural gas industry.

4.1.2 DESCRIPTION OF PREVIOUSLY UNDERTAKEN WORK FOR ALLOCATING COSTS TO LOAD DISPLACEMENT GENERATION

The Board undertook an initiative to determine a Standard Methodology for the Quantification of DG Benefits. Power Advisory LLC prepared a report for the Board in Proceeding EB-2007-0630 that addressed this issue. In Proceeding RP-2005-0020/EB-2005-0529, the Board also approved, on an interim basis, the stand-by charges of distributors. In a subsequent decision, one distributor had its standby charges approved as final[12]. There are 16 distributors that have stand-by charges in Ontario.

4.1.3 ISSUES IDENTIFIED BY DISTRIBUTORS AND/OR STAKEHOLDERS

Standby rates incorporate many different approaches and a variety of charge determinants, including actual or anticipated maximum demand, kilowatt of reserved capacity, kVa rating, manufacturer's rated output of the co-generator, and various monthly service charges. Some of the rates were established a long time ago, before re-structuring of the market. Others are newer rates.

Prior to the issuing of the Board's Decision RP-2005-0020/EB-2005-0529, generators said they opposed standby rates that 'gross bill' the load. Such rates propose the same rate for standby service as they would if they were actually supplying electricity to the load. Utilities, on the other hand, argued that their costs are the same regardless of whether the load is used or not.[13]

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[12] Enersource 2008 Distribution Rates, EB-2007-0706, April 18, 2008

[13] Generic Issues related to 2006 Distributors Rate Applications, RP-2005-0020/EB-2005-0529, Decision With Reasons, March 21, 2006

The generators view at that time was that such gross billing charges are not cost-based, that they ignore the Board's 'Net Billing' decision with respect to network transmission rates, and fail to take into account the benefits distributed generation provides. Such rates, they argue, are a disincentive to investment in distributed generation, and therefore contrary to government policy.[14]

Generators were also of the view that there should not be a standby rate at all. This reflected their view that distributed generation can reduce transmission charges and transmission congestion, and can also reduce system-wide costs such as line losses, and voltage stabilization. Generators pointed out that distributed generation can be an alternative to new capital investment in distribution and transmission assets, including additional feeder lines, capacitor banks, and transformer stations.[15]

A generic methodology may need to accommodate generation projects of different sizes and types.

4.1.4 Options to Deal with Issues Raised

The options identified to deal with this issue are:

Option #1: Apply similar approaches to those used by other jurisdiction to establish standby rates in Ontario. For the interim standby rates that have already been approved, compare the approaches in other jurisdictions with the current approaches used for certain distributors.

Option #2: Sheet I 9, Direct Allocation, in the cost allocation model could be used to allocate costs to a new customer class that would include customers with load displacement generation behind their meter. All the appropriate costs would be identified and a corresponding standby rate could be developed.

[14] ibid
[15] ibid

Option # 3. To determine the costs of supplying new customers with load displacement generation, an avoided cost estimate could be used as a simplifying approach. The avoided costs could be based on distributors' own data or a default value could be used. For existing customers with load displacement generation, the Board could continue to apply the approved standby charges on an interim basis, until further analysis, including rate design options, has been evaluated.

Option #4: Another simplifying approach would be to consider only on-going costs when establishing standby charge.

Option #5: Undertake research on how the natural gas industry in Ontario charges customers for firm or interruptible natural gas supply and use the information gathered to determine standby charges and related contractual arrangements for electricity distributors, in situations where customers provide their own generation.

The above alternatives can be combined with the incorporation of an estimate of potential benefits that could be provided by load displacement generation. In order to address any potential benefit resulting from load displacement generation, a simplified approach could be pursued by establishing a value based on the Board's own judgment or empirical estimates to represent the benefits. Undertaking a specific evaluation of benefits is a costly and complex undertaking that would not be warranted because the costs of such an analysis would outweigh the benefits. Each generator facility would need to be evaluated individually in order to determine its benefits. This type of analysis could only be justified in the case of large generators, for example above 500 kW. In the case of new load displacement generators, the benefits that they provide should be determined at the time that the connection to the distributor is established and should be a joint exercise between the distributor and the customer with load displacement generation.

The benefits referred above would be for benefits provided that would not have been already reflected in any other cost component, for example as higher commodity contract price. As well, standby charges in the context that is being considered in this report are not a substitute for demand response programs to encourage customers to consume electricity during off-peak periods. The above alternatives can also be applied only in cases where load displacement generation is above a certain threshold size. If the generator is above a certain size, for example 5 MW, the rated capacity of the generator should also be considered in the rate design of standby charges and not just the customer's demand profile. In this example, this would mean that for purposes of rate design, regardless of the customer's demand, a value of 5 MW would be used as an estimate of the customers' demand when deriving standby charges.

The main principle in determining standby rates is that these customers should be responsible for the costs they impose on distributors and that other distributor customers should not be subsidizing customers that have their own generation facilities.

4.1.5 PREFERRED ALTERNATIVE FOR ALLOCATING COSTS TO LOAD DISPLACEMENT GENERATION

Option # 3 is recommended for now, Standby charges should be established for new load displacement generation above certain size, for example 500 kW. 500 kW was chosen as a threshold based on empirical estimates and reflects the level that could represent a significant load for most distributors. The costs attributable to customers with load displacement generation should be determined by undertaking a specific customer avoided costs analysis. In lieu of a specific customer analysis, default avoided costs values could be used as a simplified approach. A simplified approach should also be followed to establish the benefits that load displacement generation may provide. For example, the Board could choose, based on its own judgement, a 5% reduction to allocated costs. Existing standby charges should continue to be allowed on an interim basis until more research has been evaluated on this issue, including rate design approaches. Distributors that have interim approved standby charges may choose to establish new standby charges as described in the recommended alternative.

Avoided costs of interruptible power to supply standby power would be low, while avoided costs of firm standby services would include all connection costs. Interruptible power is not currently being offered by distributors in Ontario, but this type of service is being offered in other jurisdictions.

Only in circumstances where this type of customer class represents a significant proportion of the load served by a distributor, for example more than 10% of the distributors' total sales, should Option #2, a separate customer class be created to capture this type of customer. A separate rate customer class would require load data and the appropriate USoA accounts would need to be identified and allocated to this new customer class. The costs allocated to this new standby customer class would then be reduced by an estimate of the potential benefits that load displacement generation may provide in order to determine standby charges.

Option #4 is not recommended as it would not capture all the costs that distributors incur in providing standby services. This approach could be followed if it is decided that a marginal cost approach should be followed in establishing standby charges.

No similar situations have been identified in the natural gas industry that could be used as a guide for the electricity distribution sector and therefore Option #5 is also not pursued further.

If the generator is above a certain size, for example 5 MW, the rated capacity of the generator should be taken into consideration in the rate design and not just the customer's demand profile, as this size generator would probably represent a significant amount of load for distributors.

Recommendation: Standby charges should be established for new load displacement generation above certain size, for example 500 kW. In lieu of a specific customer analysis, default avoided costs values could be used as a simplified approach. A simplified approach should also be followed to establish the benefits that load displacement generation may provide. The Board, following its own judgement, could choose a 5% reduction to allocated costs.

Unless the distributor chooses to follow the above recommendation for existing standby charges, they should continue to be allowed to maintain on an interim basis their standby charges until more research has been evaluated on this issue, including rate design approaches,

5 REVENUE:COST RATIOS RANGE RECOMMENDATIONS

5.1.1 CURRENT SITUATION

Revenue:cost ratios are a measure used to determine to what extent rates charged to customers and resulting revenues from customers properly reflect the costs that these customers impose on distributors. Revenue:cost ratios are calculated using a cost allocation methodology to apportion revenues and costs to customer classes. Revenue:cost ratios of less than one are considered to indicate that distribution rates are not fully recovering the costs for a particular customer class and revenue:cost ratio above one would indicate that rates more than recover the costs imposed by the customer class. In other words, customer classes with revenue:cost ratios of less than one are considered to be subsidized by customer classes with revenue:cost ratios above one based on the cost allocation methodology being used. The OEB established a range of revenue:cost ratios by customer class that distributors have to strive to achieve when determining distribution rates. Since distributors started applying cost allocation studies in Ontario for the first time in 2008 to determine distribution rates, the

OEB recommended for certain customer classes a wider range of acceptable revenue:cost ratios than for other customer classes.

Three customer classes: General Service above 50 kW, Street Lights and Sentinel Lights have OEB recommended revenue:cost ratio ranges that are wider than the recommended revenue:cost ratio ranges for the other customer classes. Given the experience that distributors have now gained using the cost allocation model and that distributors have started to move customer classes to be within the recommended revenue:cost ratio ranges, the Board is of the view that this is an appropriate time to review the range of the recommended revenue:cost ratios for these three customer classes.

5.1.2 Description of previously undertaken work for determining the recommended revenue:cost ratio ranges for General Service 50 kW to 4,999 kW, Street Lighting and Sentinel Lighting

The OEB is currently recommending the following ranges for revenue:cost ratios:

1.	General Service 50 kW to 4,999 kW	0.80 to 1.80
2.	Street Lighting	0.70 to 1.20
3.	Sentinel Lighting	0.70 to 1.20

The reasons for the Board recommending a range approach for revenue:cost ratios are:

1. The Quality of accounting and load data,
2. Limited modelling experience,
3. The then concurrent rate design initiatives and
4. Managing the movement of rates closer to allocated costs.

The Board was taking an incremental approach in establishing revenue:cost ratios such that over time, as the issues identified above by the Board get resolved, the Board would be able to narrow the range of revenue:cost ratios and move them closer to the theoretical ideal value of 1.

5.1.3 ISSUES IDENTIFIED BY DISTRIBUTORS AND/OR STAKEHOLDERS

The three identified customer classes have the widest ranges in OEB recommended revenue:cost ratios. Distributors have now gained experience using the OEB cost allocation methodology and have started to move closer to cost based rates by implementing the results of the cost allocation model.

Distributors have also now gained experience with the input data necessary to use the cost allocation model and are familiar with the impact that any change in the assumptions will have in the determination of the revenue:cost ratios. [16]

Some stakeholders argued that the revenue:cost ratio should be as close as possible to one or should even be one, since any deviation from a value of one means that customer classes with revenue:cost ratio above one are subsidizing customer classes with revenue:cost ratios below one.

A summary of the range of revenue:cost ratios approved by the Board, based on what distributors have filed in their cost allocation studies are shown below.

[16] Kitchener Wilmot Hydro Inc. 2010 Rate Application, EB-2009-0267, number of Street Light connection assumptions.

	Lowest R/C ratio	Highest R/C ratio	Average R/C ratio	# of LDC with R/C ratio equal to the lowest limit range	# of LDCs with R/C ratio equal to the highest limit range
General Service 50 kW to 4,999 kW (27 LDCs)	0.80	1.63	1.07	5	0
Street Light (53 LDCs)	0.40	1.20	0.71	45	1
Sentinel Light (41 LDCs)	0.34	1.20	0.73	31	2

5.1.4 OPTIONS TO DEAL WITH ISSUES RAISED

Five separate options have been identified to deal with this issue:

Option # 1. Maintain the current revenue:cost ratio ranges until smart meter collected data can be used to update the customer classes load profiles.

Option # 2. Recommend the same narrower range for revenue:cost ratios for the customer classes.

Option # 3. Recommend a narrower range for revenue:cost ratios in a series of gradual steps

Option # 4. Recommend a revenue:cost ratio range for these three customer classes that is similar to the narrower range for the General Service less than 50 kW customer class, that is, 0.80 to 1.20.

Option # 5. Recommend a different and narrower revenue:cost ratio range for Street Light and Sentinel Light than for General Service 50 kW to 4,999 kW

The above alternatives can be combined with a review of the cost allocation model looking at how costs are being allocated to these three customer classes. This would specifically review the weighting factor allocators that may impact how revenues and costs are allocated to these customer classes, and would be an effort to improve the allocators for these customer classes.

5.1.5 PREFERRED ALTERNATIVE FOR DETERMINING THE RECOMMENDED REVENUE:COST RATIO RANGES FOR GENERAL SERVICE 50 KW TO 4,999 KW, STREET LIGHTING AND SENTINEL LIGHTING

Option #5 is recommended because it provides different and narrower ranges of revenue:cost ratios for these three customer classes.

For the General Service class 50 kW to 4,999 kW the top range should be reduced and brought down closer to the General Service less than 50 kW class upper range limit of 1.20. A value of 1.40 is recommended for now, down from the current value of 1.80. The bottom range should be left unchanged as it is consistent with the bottom range for the General Service less than 50 kW customer class of 0.80.

For Street Light and Sentinel Light customer classes, the bottom range should be increased gradually when distributors apply to the Board over 3 to 4 years for rebasing, to match the bottom range of the General Service less than 50 kW class of 0.80. The top range should be left unchanged at 1.20 which is consistent with the top range for the General Service less than 50 kW customer class.

The proposed narrowing of the revenue:cost ratio range reflects the fact that distributors have by now gained experience with using the cost allocation model. Some of the refinements considered in this policy review will improve the quality of the cost allocation model results. Distributors as well have started to move the revenue:cost ratios to within the recommended OEB ranges, therefore moving distribution rates towards being more cost based.

The proposed narrower range values also reflect the results of the revenue:cost ratios that distributors have implemented or are in the process of implementing as a result of the filing of their cost allocation studies and subsequent Board approvals.

Option #1 is not recommended as it would take a number of years until smart meter data is available and the revenue:cost ratio ranges for these three customer classes are the largest compared to the other customer classes. So the ranges should be narrowed now to reduce the cross-subsidization between customer classes.

Option #2 is not recommended as the three customer classes are different and have different revenue:cost ratio ranges that need to be addressed.

Option #4 is not recommended for now for the General Service 50 kW to 4,999 kW because it would be a significant change from the currently approved revenue:cost ratio for this customer class.

Recommendation: For the General Service class 50 kW to 4,999 kW the top range should be reduced to 1.40. The bottom range should be left unchanged at 0.80.

For Street Light and Sentinel Light customer classes the bottom range should be increased gradually over 3 to 4 years to match the bottom range of the General Service less than 50 kW class of 0.80. The top range should be left unchanged at 1.20.

6 ADDRESS ACCOUNTING CHANGES AND THE TRANSITION TO THE INTERNATIONAL FINANCIAL REPORTING STANDARDS

6.1.1 BACKGROUND

A number of accounts have been identified that have not been previously included in the cost allocation model. Attachment A includes a list of these accounts.

The Board initiated a consultation on December 23, 2008 to examine issues associated with the transition to International Financial Reporting Standards (“IFRS”). The consultation was conducted under file number EB-2008-0408. The consultation built on a series of planning meetings conducted with industry participants by Board staff in the fall of 2008 (EB-2008-0104, now completed).

As required by the Canadian Accounting Standards Board, the Canadian Generally Accepted Accounting Principles for publicly accountable enterprises will transition to IFRS, effective January 1, 2011. It is expected that most utilities regulated by the Board will be required to adopt IFRS. The adoption of IFRS is expected to change the manner in which utilities perform their accounting and the reporting of their financial results. This may create impacts on distribution rates or other charges.

The first phase of this consultation examined and set regulatory policy regarding the transition to IFRS (EB-2008-0104 and EB-2008-0408) and culminated with the issuance of Report of the Board, Transition to IFRS, July 28, 2009.

As stated in Report of the Board, Transition to IFRS, the Board undertook a depreciation study to assist electricity distributors with the transition to IFRS (EB-2010-0178).

Utilities are required to maintain various sets of accounting books for different purposes: external reporting purposes, accounting reporting purposes and regulatory purposes. The cost allocation model uses the assets and revenue requirement data based on the regulatory books.

In its September 2, 2010 letter the Board indicated that it did not believe that the transition to IFRS will trigger a need to update the Board’s cost allocation methodology. However, the Board also indicated that it was prepared to accommodate such an update as part of this consultation, if required. The September 2, 2010 letter also noted that the Board would consider the impact of other accounting changes that may have occurred since the issuance of its Report of the Board: Application of Cost Allocation for Electricity Distributors on November 28, 2007.

6.1.2 Description of previously undertaken work related to IFRS and the impact on distributors' rates

The Board is cognizant of the fact that adopting IFRS may have an impact on revenue requirements and therefore on distribution rates. As per the Board Decision in Proceeding EB-2008-0408 issued July 28, 2009, distributors will be required to report the impact of adopting IFRS on revenue requirements. If the impact of adopting IFRS is significant, distributors will need to propose an IFRS implementation plan that would address customers' bill impacts.

6.1.3 Issues identified by distributors and/or stakeholders

The implementation of IFRS may or may not have an impact on the cost allocation model. If implementation of IFRS results in a different revenue requirement, the impact on customers' bills may be dealt with by establishing variance accounts to track the cost changes and the costs tracked would be recovered in the future. The one-time costs related to implementing IFRS could also be amortized over multiple years. In these two scenarios, the cost allocation model would be un-affected.

If the IFRS will have an impact on regulatory books by altering the USoA accounts currently being used in the cost allocation model or what is included in a particular USoA account, the cost allocation model may have to reflect the changes in USoA accounts or changes in the allocators used to allocate the USoA accounts to customer classes.

6.1.4 Options to Deal with Issues Raised

The implementation of IFRS does not seem to have an impact on the cost allocation model. If issues are identified in the future impacting the cost allocation model, they will be addressed once the issues have been identified.

6.1.5 Preferred Alternative to incorporate IFRS changes

Utilities will be required to comply with the IFRS requirements but there is no need to modify the cost allocation model to address the accounting reporting changes, unless changes to USoA accounts or the content of a USoA account are identified.

Recommendation: There is no need to modify the cost allocation model to address the accounting reporting changes.

The accounts identified in Attachment A should be added to the cost allocation model

7 Summary of Preferred Alternatives

The preferred alternatives for each issue are summarized below.

Creation of MicroFIT Rate Class Preferred alternative

The preferred approach is to continue to use the USoA accounts currently identified to establish the uniform provincial fixed rate for microFIT. The Board has just recently completed the review of the appropriate USoA accounts and there is no need to repeat the analysis so soon afterward. Each distributor should be allowed to establish its own microFIT rate to better reflect cost causality for each distributor.

Cost Allocation to Unmetered Load Preferred Alternative

A separate sheet should be added to the cost allocation model that will include the default values used for these types of customers. This would more clearly indicate to distributors the option of using their own values in place of the default values. A description of how the default values were developed would assist distributors in developing their own values and help them to understand the purpose of using these values.

For distributors that do not have a separate class for USL, the distributor should be required to demonstrate that the revenue:cost ratio for these types of customers would still be within the Board's recommended range.

Treatment of Transformer Ownership Allowance Preferred Alternative

Modify the cost allocation model to ensure that only the customer classes that include customers providing their own transformation are included in the determination of the TOA. The costs of the allowance would be recovered only from the remaining customers in the same class. Customer classes where no customer owns their transformers or where the class requirement for customers is to provide their own transformation assets would thus be excluded from the calculation of TOA. This will ensure that in determining the TOA, cost causality principles are applied. Also, instructions should be provided to distributors identifying the appropriate data required by the model to determine the TOA.

Allocation of Miscellaneous Revenues Preferred Alternative

The major components included in Miscellaneous revenues should be identified and then allocated to customer classes of these revenue categories in a manner similar to the allocation of the corresponding costs. The remaining Miscellaneous revenues should be allocated to the customer classes in the same proportion as composite OM&A.

This treatment is similar in effect to the treatment in the natural gas industry where the revenues are functionalized to the same functions that include the corresponding costs.

Miscellaneous revenues and related costs should be included in the determination of revenue:cost ratios in the cost allocation model.

Weighting Factors for Services and Billing costs Preferred Alternative

A separate input sheet should be developed that would include the default weighting factors, explain the reasons behind the different weighting factors and include an option for distributors to substitute their own values for the default values , if appropriate. This would ensure that the cost allocation model is being used as intended and that it reflects cost causality principles.

Allocation of Host Distributors Costs to Embedded Distributors Preferred Alternative

Schedule 10.7 of the 2006 EDR Handbook should continue to be the approach followed by host distributors and this schedule should be incorporated into the cost allocation model. This alternative will result in an approach that identifies assets used by embedded distributors in circumstances where the embedded load is large and is a significant share of the host distributor. Long-term load transfer agreements would not be included as embedded-host relations, because these situations are planned to be eliminated. The additional effort needed to separate the assets used by large embedded distributors would result in a better reflection of cost causality principles for these larger customers.

In addition, the Board should establish a threshold above which host distributors would be required to establish separate charges for embedded distributors. The threshold should take into account the embedded customers' size and its share of the total utility's load.

The recommended thresholds are:

1. If the embedded distributor represents more than 10% of the host distributor's total volume sales, or
2. If the embedded distributor is larger than 500 kW average demand per month

Allocation of Costs to Load Displacement Generation Preferred Alternative

Standby charges should be established for new load displacement generation above a certain size, for example 500 kW. But this would only be a starting point until further research is undertaken in order to establish a common methodology in Ontario to determine standby charges. 500 kW was chosen as a threshold based on empirical estimates to reflect the level that could represent a significant load for most distributors. The costs attributable to customers with load displacement generation should be determined by undertaking a specific customer avoided costs analysis. In lieu of a specific customer analysis, default avoided costs values could be used as a simplified approach. A simplified approach should also be followed to establish the benefits that load displacement generation may provide. For example, the Board could, based on its own judgement choose a 5% reduction in allocated costs.

Unless the distributor chooses to follow the above recommendation for existing standby charges, they should continue to be allowed to maintain on an interim basis their standby charges until more research has been evaluated on this issue, including rate design approaches.

Refine the three widest Target Ranges, which are associated with the following rate classes: General Service 50 to 4,999 kW, Street Lighting, and Sentinel Lighting Preferred Alternative

A Different and narrower range of revenue:cost ratio for these three customer classes is being recommended.

For the General Service class 50 kW to 4,999 kW the top range should be reduced and brought down closer to the General Service less than 50 kW class upper range limit of 1.20. A value of 1.40 is recommended for now, down from the current value of 1.80. The bottom range should be left unchanged as it is consistent with the bottom range for the General Service less than 50 kW customer class of 0.80.

For Street Light and Sentinel Light customer classes, the bottom range should be increased gradually over 3 to 4 years as distributors apply to the Board for rebasing, to match the bottom range of the General Service less than 50 kW class of 0.80. The top range should be left unchanged at 1.20 which is consistent with the top range for the General Service less than 50 kW customer class.

Address accounting changes and the transition to IFRS Preferred Alternative

Utilities will be required to comply with the IFRS requirements but there is no need to modify the cost allocation model to address the accounting reporting changes, unless changes to USoA accounts or the content of a USoA account are identified.

The accounts identified in Attachment A should be added to the cost allocation model.

ATTACHMENT A

1521 – Special Purpose Charge Assessment Variance Account

1531 – Renewable Connection Capital Deferral

1532 – Renewable Connection OM&A Deferral

1534 – Smart Grid Capital Deferral

1535 – Smart Grid OM&A Deferral

1550 – LV Variance Account

1555 – Smart Meters Capital Variance Account

1556 – Smart Meters OM&A Variance Account

1566 – CDM Contra Account

1589 – 1588 Global Adjustment sub-account

1592 – 2006 PILs/Taxes Variance

4075 – Billed-LV

4750 – Charges-LV

5695 – Smart Meters OM&A Contra