EB-2005-0317

COST ALLOCATION REVIEW: STAFF PROPOSAL ON PRINCIPLES AND METHODOLOGIES

COMMENTS OF THE LONDON PROPERTY MANAGEMENT ASSOCIATION

General Comments

Cost allocation is a complex process. The principles and methodologies that underpin the functionalization, categorization and allocation of the various components of the overall revenue requirement need to be well understood and accepted by all parties involved in the process, including utilities, ratepayers and the regulator. While complete agreement between all parties on all aspects of cost allocation is not likely to occur, the current review is a significant step towards a generic cost allocation model. The informational filings due beginning in the fall of 2006, based on this common model, will be useful for all parties. However, it should be noted that a one-size fits all approach, while adequate for the current purposes of the informational filings, may not be appropriate for each utility when such studies are used for more than the current purpose. Different system designs and operating practices may not fit neatly into a generic model/process.

LPMA notes that with the installation of smart meters in the near future, load data is likely to transform the knowledge base of the industry. This information may have as of yet unknown impacts on cost allocation principles and methodologies. The associated time of use information that will be available for all customers may increase the level of detail required for a cost allocation study.

In summary, the cost allocation review should not be considered the end state. Rather, cost allocation should be viewed as a dynamic process.

The remainder of the comments provided are organized by chapter of the June 28, 2006 Staff Proposal.

Chapter 1

Section 1.1 - The common cost allocation principles and methodologies will govern the informational filings due from the distributors starting in the Fall of 2006, will it also be used for more detailed cost allocation filings by the utilities in conjunction with their future cost of service filings? If so, or if possibly so, this should be identified up front so that parties are not surprised by such a development in the future.

Section 1.5.2 – Rate classifications of a distributor are not well defined (i.e. class vs sub-class). Rate classifications should either be defined in this section or a reference to where the reader can find such a definition (Section 8.5). This would enable the reader to know up front how classes and sub-classes are being used in this document.

Section 1.5.4 – The word "reasonable" should be removed in this paragraph. Cost allocation does not provide reasonable or unreasonable figures. It simply provides figures based on the assumptions and methodologies used. "Reasonable" only enters into the discussion in the rate design stage.

Section 1.9 – Since about 20 utilities will not be filing their models until March 31, 2007, it would appear that the summary report from board Staff would not be available until some time after this. It would be more useful if Board Staff were to prepare a report after each tranche and provide that to stakeholders. Each successive report would be inclusive of the utilities in the previous report plus those that filed in the latest tranche. This would allow stakeholders to identify any trends or issues earlier.

Chapter 5

Section 5.2 – It may be advantageous to indicate in this section which accounts need to be grouped together if there is a direct allocation of assets and/or costs. The most notable "grouping" would be the gross value, accumulated depreciation and depreciation expense associated with a particular asset. This grouping may not be readily transparent to all parties. In addition, contributed capital that is specific to these directly allocated costs should be recognized.

This section also indicates that a distributor just adjust the appropriate allocation factors so that the rate classification to which costs for a specific function are directly allocated is not allocated further costs related to that function. However, it is not clear how these allocation factors would or could be adjusted in the model. Some specific examples may be helpful here.

Chapter 6

Section 6.1.1 – For continuity and for consistency with Section 7.1 it is suggested that the following sentence be included at the end of this section:

"Once functionalized, the costs will be categorized to demand-related and/or customer-related using specific categorization factors discussed in Chapter 7."

Section 6.2.2.2 – A reference to Section 6.3 should be included in this section for the handling of contributed capital.

Section 6.2.2.8 – Chapter 6 is about functionalization yet this section is a proposal related to allocation of bulk, primary and secondary sub-accounts. It may be more appropriate to move this section to one of the allocation chapters.

Section 6.3.4 – As noted above, there may be circumstances when contributed capital is associated with assets that will be allocated directly. This should be identified within the bulk, primary and secondary breakout.

This section talks about the default approach allocating capital contribution to the asset categories (i.e. bulk, primary, secondary). This is somewhat confusing as this is a functionalization not an allocation of the contributed capital.

Chapter 7

Section 7.3.1 – The first paragraph states that the basic customer model will be used for the "separate purpose of calculating lower end unit costs". It is recommended that this be modified to read "separate purpose of calculating lower end customer unit costs".

Section 7.4.2.2 , 7.4.2.3 & 7.4.2.4 – The step-function in Section 7.4.2.2 and dividing points found in Section 7.4.2.4 (i.e. 30 customer and 60 customer dividing points between low, medium and high density) may result in significantly different customer and demand categorization results for utilities that are close to one another in density, but on opposite sides of the dividing lines. Similarly, utilities within the same density category may be more dissimilar in relation to density than some in another density category. For examples, utilities in the medium density category with a density of 32 customers and 58 customer may be less similar to one another than to a low and high density utility, respectively.

Section 7.4.2.3 addresses this issue stating that the Board may want to consider refinements to the minimum system density definitions or stratum boundaries in the future. The proposal outlined in Appendix A to these comments utilizes the same density boundaries and customer/demand splits as in the staff proposal but provides a smoothing mechanism that would eliminate significant changes in customer/demand categorization for utilities near the dividing points.

Chapter 8

Section 8.2.4 – It is unclear how the 20% peak that will warrant use of 1 NCP is related to the formula for the NCP Test result of less than 83% which requires the 1 NCP methods to be used. It should shown, perhaps by way of an example, how the 20% peak translates into the 83% in the NCP test.

It may also be useful to provide an explanation in this section as to why there is only one NCP test, and not two, as proposed for the CP in Section 8.3.

Section 8.3.1 – FERC is mentioned in the second paragraph. If this is the first reference to FERC, it should be identified in full, i.e. Federal Energy Regulatory Commission.

Section 8.3.2 – As indicated above, a clarification of the 20% peak and the 83% referenced in CP Test #1 and in CP Test #2 may be useful.

Chapter 9

Section 9.3.2.1 – At the end of the first paragraph it is stated that metering capital costs will include capital costs, depreciation and related operating and maintenance expense. It is not clear why related operating and maintenance expenses are considered to be capital costs. If the intent is to state that metering related operating and maintenance expenses are allocated in the same manner as metering capital costs and deprecation, then this should be clarified.

Section 9.3.5 – It is unclear why bad debt expense is in Chapter 9, which is the allocation of customer-related costs. Since the proposal is to allocate these costs based on historical write-offs and not customers, this section may be better situated in Chapter 10. It is noted that Appendix 9.1 does not include the bad debt expense category.

Chapter 10

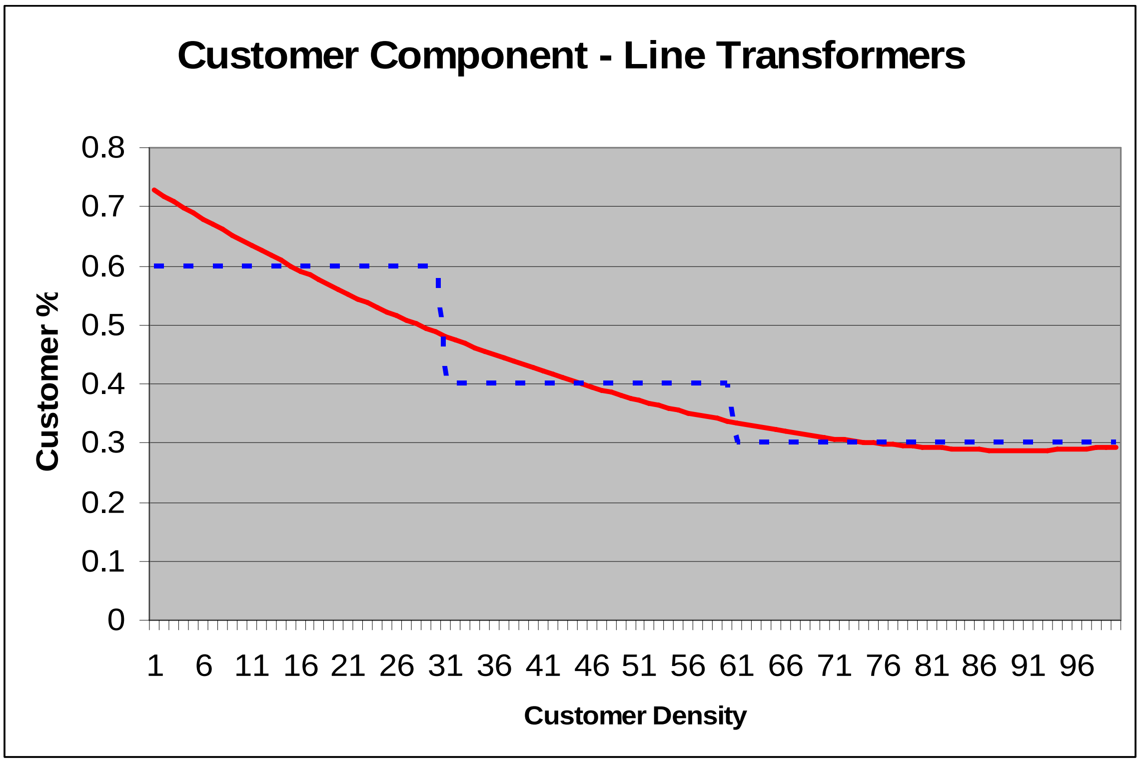
Section 10.2.2 – It may be more accurate to label the identifiable CIS costs as assets since the heading of this section is general plant.

Section 10.4.2 – Is it possible that the OM&A component included in the WCA calculation from the 2006 EDR model is not equal to 15% of the allocated OM&A? Is there a situation that could arise where these figures, for some reason, are different? A more general statement that the OM&A component included in the WCA calculation will be allocated based on the overall allocation of OM&A may be more appropriate and accurate.

Appendix A

The methodology presented in Sections 7.4.2.2 through 7.4.2.4 provide a step-function approach to categorization of customer and demand costs based on density. An inherent problem in this approach is the significant change in the customer-demand split that occurs at the density dividing points, while assuming no difference between utilities with significant different densities, but in the same grouping (i.e. low, medium or high).

One approach to smoothing the transition between different density categories is to fit a regression line to a representation of the data. The following graph shows the representation of the customer component of the line transformer costs.



The dashed line shows the step function as proposed by Staff. The solid line shows a fitted regression line that relates the percentage customer categorization to the density that goes through the points that represent 60% customer related costs for a utility with a density of 15 (midpoint point of low), 40% for a utility with a density of 45 (midpoint of medium), and 30% for a utility with a density of 75 (high). This smoothing eliminates the discontinuity at the break points between the density categories.

A review of the percentages found in Appendix 7.5 of the Staff Proposal confirm that that there is a wide variation in the customer component of line transformers, overhead feeders, underground feeders and combined OH/UG within medium and high density utilities based on the historical minimum system results from a number of Ontario studies. For example, medium density customer components for line transformers range from 26% to 71% and for high density customer components for line transformers range from 16% to 38%.