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July 18, 2006

VIA EMAIL AND COURIER

Mr. Peter H. O'Dell
Assistant Board Secretary
Ontario Energy Board
P.O. Box 2319
27th Floor
2300 Yonge Street
Toronto, ON
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Dear Mr. O'Dell:

Re: Cost Allocation Review: Staff Proposal on Principles and Methodologies (EB-2005-0317)

VECC'S Comments Re: June 28th, 2006 Staff Proposal

As Counsel to the Vulnerable Energy Consumer's Coalition (VECC), I am writing, per the Board's letter of June 28th, 2006, to provide our comments on the OEB Staff's Proposals regarding Cost Allocation Principles and Methodologies for Ontario Electricity Distributors. Cost allocation is a key step in the overall rate making process for electricity distributors and critical to ensure fair and equitable rates to distributors' customers.

The attached Comments identify a combination of issues that require clarification, omissions that need to be addressed, and recommendations with respect to aspects of the proposed methodologies that should be changed, Filing Questions that should be added and next steps. While, the list may appear extensive, VECC acknowledges and appreciates that significant effort has gone into the development of the Staff Proposal. The development of a comprehensive cost allocation model is a significant undertaking under any circumstances. In the case of Ontario, where there are over 80 electricity distributors and many have never performed a cost allocation study, it is challenging. The Board and Board Staff are to be commended for bringing the proposals to the point where they are to day.

However, the development of an effective and fair cost allocation methodology must be considered an evolutionary process where new concepts are tested, data reliability and availability are explored and methodologies are refined accordingly. Indeed, in other jurisdictions, cost allocation methodologies are subject to “continuous improvement” and such evolution is supported by the regulator.

As a result, VECC sees the completion of the current cost allocation model and informational filings as significant milestones but not the end of the cost allocation methodology development process. Indeed, the proposed Staff review of the information filings should be used to identify priorities for future development and refinements. Similarly, in support of future rate applications, individual distributors should be encouraged (and in some instances likely directed) to further improve the data inputs and assumptions used in their cost allocation studies.

VECC appreciates the opportunity to comment. If there are any questions or if clarification is required regarding the Comments please contact either Bill Harper (416-348-0193) or myself (416-767-1666).

Yours truly,

Michael Buonaguro
Counsel for VECC

EB-2005-0317

ONTARIO ENERGY BOARD

COST ALLOCATION REVIEW: STAFF PROPOSAL ON PRINCIPLES AND METHODOLOGIES

COMMENTS SUBMITTED BY THE VULNERABLE ENERGY CONSUMERS COALITION (VECC)

JULY 18, 2006

1. GENERAL COMMENTS

- VECC acknowledges and appreciates that significant effort has gone into the development of the Staff Proposal. The development of a comprehensive cost allocation model is a significant undertaking under any circumstances. In the case of Ontario, where there are over 80 electricity distributors and many have never performed a cost allocation study, it is particularly challenging. The Board and Board Staff are to be commended for bringing the proposals to the point where they are today.

- However, the development of an effective and fair cost allocation methodology must be considered an evolutionary process where new concepts are tested, data reliability and availability are explored and methodologies are refined accordingly. Indeed, in other jurisdictions, cost allocation methodologies are subject to "continuous improvement" and such evolution is supported by the regulator.

- Set out below are a series of Comments regarding issues that require clarification and omissions that need to be addressed as well as a number of Recommendations with respect to aspects of the proposed methodologies that should be changed. We have also composed Filing Questions and next steps that should be added.

- Finally, VECC has highlighted a number of areas where, without further refinement, the proposals will disadvantage residential and other small volume users. In VECC's view, caution must be exercised in implementing rate changes based on the results of the cost allocation informational filings until these issues have been addressed either generically or in individual distributors' future rate applications.

2. SPECIFIC COMMENTS AND RECOMMENDATIONS

Chapter 1 – Introduction

Section 1.5.2 – Cost Allocation Outputs

- Section 1.5.3 raises the possibility that since, for most distributors, the information filings will be based on 2004 data there could be significant changes between then and now that may impact on the conclusions to be drawn from the results with respect to "rate classifications". This same issue exists with regard to the cost allocation results and determining whether and the extent to which any inherent cross-subsidization exists between customers classes.

  Recommendation: Distributors should be directed to identify, as part of the Filing Summary, any major changes in either their distribution systems (e.g., installation of major new facilities), the composition of their customer classes, or the usage characteristics of their customer classes that could impact on the validity of the cost allocation results filed.

Section 1.5.6- Filing Questions

- A number of the Supplementary Questions are aimed at determining how costs are currently reported by Distributors in the Uniform System of Accounts (USoA). Depending upon the responses, the results of the cost allocation methodologies laid out in the Staff Proposal may not provide a reasonable measure of the revenue to cost relationships by customer class.

  Recommendation: As part of the planned Staff review of the informational filings (per Section 1.9), the responses to the various Filing Questions should be analyzed and an assessment made by Board Staff as to the consistency between how costs are actually reported by distributors and the reporting "assumptions" underlying the proposed cost allocation methodologies. Based on this assessment, priorities should be developed for improving both future cost reporting and the cost allocation analyses of individual distributors.

- In some places the text makes reference to "cost allocation principles" (e.g., Section 1.5.6, paragraph 2 and Section 1.10, paragraph 3); in other places reference is made to "cost allocation principles and methodologies" (e.g., Section 1.5.1, paragraph 1); while in still other places (e.g., Section 1.5.1, paragraphs 1 and 2) reference is made to "cost allocation methodology" established by the Board. The report prepared by Board Staff appears to be using the terms "principles" and "methodologies" interchangeably, although the terms have different meanings. If there are separate "principles" that have guided Board Staff in establishing its proposed "methodologies", they have not been clearly articulated. In VECC's view, what is presented in the Staff's Proposal is a set of "cost allocation methodologies".

Clearly, it would desirable if the first Chapter of the proposal set out (for comment) the cost allocation principles that underlie the proposed methodologies. However, this is not the case and, in VECC's view, it would be inappropriate for the OEB to seek to develop a set of "cost allocation principles" at this stage in process. Unless the Board initiates another round of comment, VECC considers that it is too late in the process to properly seek such input now.

However, should the Board wish to address cost allocation principles in its determinations, then VECC would suggest that the Board reference its H.R. 5 Report – Principles for Electricity Costing and Pricing. Here the Board determined that one of the primary objectives in rate making is that rates should be "fair" which is broadly defined as equal treatment of those causing equal costs[1]. In VECC's view, the purpose of a cost allocation study is to provide a measure of the fairness of rates by allocating costs to customer classes on the principle of cost causality. Based on this and other findings of the Board in the same report[2], already established principles for cost allocation appear to include:

- Tracking costs to rate classifications to the extent practical based on cost causality,
- Avoiding undue discrimination and
- Treating all consumption as new consumption.

Recommendation: There is a need to clearly distinguish between cost allocation "principles" and "methodologies". While it may have been desirable for the Staff Proposal to include a set of guiding "cost allocation principles", it would be inappropriate for the OEB to seek to develop a set of "cost allocation principles" at this stage in process. Such principles should be based on input from all parties (distributors and rate-payer representatives). Unless Board Staff wish to initiate another round of comment, it is too late in the process to properly seek such input now. Furthermore, the Board should not seek to independently establish a set of cost allocation principles without such input.

Section 1.7 – Model Runs to be Filed

- The purpose of Run 3 needs to be better explained. From the wording of the text in the sixth paragraph, it would appear that the items listed are the only ones that a distributor will be allowed to address in a 3rd Run. However, if the 3rd Run is meant to address issues that may be unique to a particular distributor, it is difficult to see how the list can be all inclusive.

  Recommendation: Distributors should allowed to include in the 3rd Run items that are not listed in the Staff Proposal provided both the item and the rationale for including it are clearly documented in the informational filing. In addition,

[1] H.R. 5 Report, page 30
[2] See pages viiii and 24.

Distributors should be encouraged to discuss any plans to include other items in their information cost allocation filings with Board Staff prior to their filing date.

Section 1.9 - Review of the Filings

- It will be important that the Staff report summarizing the overall outcome address more than just outliers in fixed customer charges and revenue to cost ratios. The report must address the findings arising from the responses to the "Filing Questions". In a number of instances, the responses to these questions will indicate the extent to which the cost allocation methodologies used are appropriate and, therefore, the results are reliable for purposes of any next steps that may be envisioned. Similarly, the Staff summary should include an assessment of how utilities have implemented a number of the proposed concepts that are either new and/or require distributor judgement. One example of this would be the split of assets and costs among bulk, primary and secondary.

  Recommendation: The Staff report summarizing the results of the cost allocation informational filings should also address:
    - Any findings or conclusions gleaned from an assessment of the responses to the Filing Questions,
    - Any findings or conclusions regarding the implementation of the bulk/primary/secondary concepts adopted for the filing, and
    - The extent to which distributors were able to utilize alternative inputs (as per Section 1.7, paragraph 8), where better data was available.

Section 1.10 – Potential Implementation in Rates

- This section states that "in light of the extensive effort given to this process and the deliberations with respect to cost allocation principles, parties should expect that the Board will give significant weight to the methodologies adopted in the final Board Report when deciding upon specific cost allocation matters in future rate hearings" (paragraph 3). While the development of the Staff Proposal has taken significant time and represents a considerable achievement, it is fair to say that in a many instances the proposed cost allocation methodology to used for the informational filings should not be viewed as final for a number of reasons:
    - There are a number of places where the methodology proposed does not meet industry standards due to data limitations (e.g., allocation of billing costs) and should be refined in the future;
    - There are instances where uncertainty exists as to where and how certain costs are reported by Distributors and thus the applicability of the proposed cost allocation methodologies. Indeed, the purpose of many of the proposed Filing Questions is provide insight on this issue;
    - There new concepts (such as bulk/primary/secondary) that have been introduced by the Staff Proposal. These concepts may need to be refined or revisited depending upon the results of the informational filings; and

- o In a number of areas, the Staff Proposal varies from the general consensus arrived at as a result of the deliberations of the Technical Advisory Team.

Recommendation: There will be a number of areas where the Board should not necessarily accept the cost allocation methodologies adopted for purposes of the informational filings when deciding upon specific cost allocation matters in a future rate proceeding. In addition, there are areas where the "cost allocation methodology" requires distributor judgement and this judgement should be tested in a future rate proceeding if it has a material effect on the results.

Chapter 2 – Rate Classifications for Filing

Chapter 2 indicates (page 9) that no further input is required on the "Rate Classifications for the Filings". The following comments are not related directly to the direction regarding the Rate Classifications to be included in each "Run" but rather deal with associated issues raised in the chapter.

2.3.1 - Test Year and Rate Classifications

According to this section, distributors may wish to identify significant changes in operation that would impact rate classifications in the future. Distributors should not be given the "option", but rather required to identify any such changes as part of the informational filing. This will assist the Board (and other parties) in determining whether the results are representative of actual utility circumstances going forward and establishing priorities for future rate applications.

Recommendation: Distributors should be required to indicate any changes in their customer base would impact on the future applicability of the rate classifications used in their 2006 approved rates.

2.3.2 –Elimination of Legacy "TOU" Rates

- By use of the term "also", the second paragraph suggests that there are legacy time of use distribution rates for customers other than "GS>50kW" that should be eliminated. However, there is no clear indication as to what these other rates are.

2.3.3 – New Large User Rate Classification

- This section should clarify the basis on which the 12 month average is to be determined (i.e., the actual 12 months for the test year underlying the 2006 rates).

2.3.5 – Common Separate Rate Classification for Embedded Distributors

- The wording in the fourth paragraph would suggest that there already is a separate embedded distributor class and the issue is whether or not to merge the embedded distributor class with another class. In reality the reverse is true – i.e., if the resulting unit costs are sufficiently distinctive then the merits of introducing a separate rate classification for embedded distributors could be discussed further.

Recommendation: The wording in the fourth paragraph should be changed to reflect the fact that, for host distributors modelling a separate rate classification for embedded distributors for the first time in Run 2, the question is whether a new class should be introduced.

2.4 – Optional Rate Classification Changes in Run 3

- Since consideration of "density rates" is excluded from Run 3, the Report should clearly indicate the difference between density rates and "zonal rates" – which are permitted in Run 3 according to the last paragraph in Section 2.4. It is VECC's understanding that zonal rates are based strictly on geographic location, are generally result of mergers or acquisitions and usually considered transitional. In contrast, density rates are based on the customer density regardless on geographic location and are a permanent rate classification.

  Recommendation: The Board should clarify the difference between zonal and density rates.

Chapter 3 – Load Data Directions

Chapter 3 indicates (page 17) that no further input is required on the "Load Data Directions". The following comments are not related directly to the directions regarding Load Data but rather deal with associated issues raised in the chapter.

3.2 – Load Data – General Requirements

- The current wording of the second paragraph could be interpreted as suggesting that "load data" is not required to support the addition of a new separate rate classification in Run 3. It would be more appropriate if the wording was changed to "should carefully consider what additional load data will be required".

3.6.1 – Filing Questions

- The second filing question asks for information as to size of the load displacement facility; whereas for rate classification purposes the focus is on stand-by requirements (which may be less than the size of the generation facility).

  Recommendation: The Filing Question should ask for both the size of the generation facility and the associated stand-by requirement.

- The cost allocation will be based on just one year's worth of load data for displacement generators and reflect the performance of the generator in that one particular year.

Recommendation: The Filing Questions should also ask for comment as to whether the load data developed for these customers is considered representative of the associated generation facilities' performance.

3.7 – Load Profile for Separate Unmetered Scattered Load Class

- The third paragraph on page 22 suggests that "if CATV power supply battery mats were not taken into account in a future test year filer's 2006 EDR Application, then the approved revenue requirement figures may need to be corrected for present filing purposes". A number of concerns arise as a result of this statement:
  - First, there was no suggestion in the May 2006 Staff Load Data Proposal that any adjustment would be needed to the approved 2006 revenue requirement for any reason.
  - Second, one of the basic building blocks of the cost allocation information filings is the 2006 approved revenue requirement and rates. Every effort should be made to maintain this foundation.
  - Finally, if the mats were not taken into account in the 2006 Application then neither the load forecast nor the cost of service reflect their existence. In this circumstance, there is no need for the load data to reflect the existence of battery mats or the approved revenue requirement to be "corrected".

Recommendation: The cost allocation informational filings should be based on the approved 2006 revenue requirement. There is no need to adjust this revenue requirement in the circumstance where a forward test year filer did not take battery mats into account.

Chapter 4 – Test Year and Revenue

4.1.3 – Proposal – Distributors that used a forward test year in the 2006 EDR Applications

- Forward test year filers should be required, as part of the cost allocation informational filing, to indicate whether the 2006 trial balance being used was submitted as part of their 2006 EDR Application or developed afterwards. This will allow Board Staff and other parties to know whether the detailed assignment to accounts has already be subject to review as part of the 2006 EDR process or not.

4.1.4 – Proposal – Distributors that will not have approved 2006 rates at the time of its (their) cost allocation filing

- It is important to note that, in all likelihood, for these distributors total revenues will not equal total costs. Revenues are based on approved (2005) rates and billing determinants consistent with those used by historical test year filers. On the other hand, costs are based on the 2004 trial balances, adjusted for the third tranche of MARR and the PIL assumed in the 2005 rates. This means that the standard when "judging" the revenue to cost ratios for individual customer classes will not be 1.0 but rather the distributor's overall revenue to cost ratio as calculated using these values.

- It is VECC's understanding that there are still a few distributors in the Province who filed 2006 EDR applications but, to date, have only received an interim Rate Order. While final rates for these distributors may be approved prior to the filing date for their informational filings there is need to address what approach will be taken if this is not the case.

  Recommendation: For distributors that have received only interim approval for their 2006 rates, the cost allocation filing should be based on the trial balance underlying interim approved rates. However, in their Filing Summary, these utilities should be required to indicate that the revenue requirement supporting the informational filing has not received "final approval" from the OEB.

4.1.6 – Filing Questions

- There are two critical issues with respect to the Services account (USoA #1855):
  - The first is whether the distributor has used the USoA definition to determine the facilities for which costs should be included in this account or whether a different set of facilities are captured in the account. The definition states that "This account shall include the cost installed of overhead and underground conductors leading from a point where wires leave the last pole of the overhead system or the transformers or manhole, or the top of the pole of the distribution line, to the point of connection with the customer's electrical panel. Conduit used for underground service conductors shall be included herein." However, there is some concern that distributors may also being including in the account the costs of additional upstream facilities.

    Recommendation: The final instructions to distributors should clearly indicate that the question is focused on determining what facilities the distributor has included in account #1855 and whether the facilities included match the definition in the USoA. It should also be highlighted that the responses will be used just for purposes of the informational filing and not for "compliance" purposes.

  - The second issue is whether the account captures the service drops for all customers or just those service drops operated at secondary voltages (i.e., < 750 volts). This is a critical issue and one that needs to be explicitly addressed by the Filing Questions. The current Staff Proposal assumes that the Services account captures only facilities providing service to customers served at secondary voltages and allocates the costs accordingly (see Appendix 6.1). However, if the account also includes services to customers served from higher voltages then the allocation of the account is incorrect[3].

[3] The Distribution System Code (section 3.1) permits distributors to provide basic connection facilities to non-residential customers and recover the costs as part of their revenue requirement.

On the other hand, if the account does not capture the service drops to customers served at bulk or primary voltages then any such facilities will be reported as part of overall bulk and primary system costs and customers served at secondary voltages will be inappropriately allocated a share of their costs. **Either way, if the distributor owns any of the service drop (connection) facilities for bulk or primary served customers then the current cost allocation methodologies will result in a misallocation of the costs, with residential and other secondary served customers cross-subsidizing other classes.**

Recommendation: a) The Filing Questions concerning Services should also determine if there are any distributor-owned service drops to customers served from primary or bulk facilities and, if so, where are the costs for these facilities reported. (Note: Even if the service drops have been fully paid for through capital contributions (post-restructuring), there will still be issues regarding the O&M costs associated with the facilities).

b) If the distributor does own such service drops, then the Board should require the distributor to refine its cost allocation informational filing before the results are used in any application supporting an actual adjustment in rates.

4.2.2 – Proposal – Definition of Revenue for Cost Allocation Filings

- The first paragraph directs all distributors to obtain their approved 2006 EDR model from the Board. On page 7, the Staff Report indicates that the cost allocation informational filings will be made public. Since the 2006 approved rates and revenue requirement form the base for these filings this information should be made public as well.

  Recommendation: The Board should make provision for the approved 2006 EDR models to be readily accessible to all interested parties.

- Appendix 4.1 identifies “rate base” as the allocation method for a number of the revenue off-set accounts. Rate base consists of fixed assets plus working capital. Presumably, the “rate base” referred to in Appendix 4.1 is just the fixed asset portion since the treatment of working capital is addressed in Section 10.4.

  Recommendation: The Board should clarify that the allocation base to be used for Revenue Off-sets (in Appendix 4.1) is not the full rate base but rather the fixed asset portion of the rate base.

- The proposed treatment of Late Payment Charges (#4225) calls for the allocation to be based on a three-year history. In contrast, the proposed allocation of Collection-related expenses (#5320, 5325 and 5330) is based on number of bills. From a cost causality perspective the two should be allocated in a similar manner. Indeed, as VECC understands it, the initial recommendations of the Technical Advisory Team call for a consistent treatment of these accounts, with all of them to be allocated based on number of bills. Ideally, both items would be allocated based an analysis of revenues/costs by class. For Collection-related expenses this would entail an analysis of the distributor's collection efforts (and costs) by customer class.

  Recommendation: From a cost causality perspective, a common allocation approach should be used for a) Late Payment Charges (#4225) and b) Collection-Related Expense Accounts (#5320, 5325 and 5330).

4.3 – Data Consistency

- In section 4.3.2 it is proposed that there will be additional output generated by the model to show the difference in revenue based on the kWhs in the 2006 EDR model and the kWhs provided by the load data service provider. There are two issues that will have to be addressed in making this comparison:
  - First, as VECC understands it, the class load data provided by the load data service provider is meant to reconcile with the wholesale power purchased by the distributor and will (therefore) include losses. However, the data used in the 2006 EDR model is billing data which generally excludes losses. Any comparison of the two will have to adjust for this.
  - Second, for a number of customer classes revenue is based on monthly peak demand (kWs) and not energy (kWhs). However, it is VECC's understanding that the load data service provider will not be providing estimates of billed kWs but only CP and NCP by customer class. In order to do a "revenue comparison" a methodology will need to be developed to estimate the billed kWs that would be consistent with the kWhs, as provided by the load data service provider.

  It is not clear from the Staff Proposal whether these issues have been identified and, in particular for the latter, solutions developed to address them.

Chapter 5 – Direct Allocation

5.2 – Proposal – Direct Allocation Methodology

- In VECC's view, direct allocation requires not only that the 100% of the use of a clearly identifiable distribution facility be attributable to one customer class but also that the costs of facility must be separately tracked and recorded in the distributor's financial accounts.

- Similar to the approach taken in section 6.2.2.5 with respect to delineation of bulk assets, distributors proposing direct allocation should be required to file single line diagram or a schematic of their system and indicate which assets it proposes to directly allocate.

- The initial paragraph suggests that direct allocation is limited to distribution facilities and their associated costs. However, as suggested by the examples provided in section 5.1 (i.e., "costs directly associated with load displacement assets"), there may be unique and identifiable O&M activities that can be directly allocated to one customer class.

  Recommendations: a) Direct allocation should only be permitted when the costs of the facility/activity concerned are tracked and recorded separately by the distributor.
  b) Those distributors proposing direct allocation should be directed to include (as a response to a Filing Question) a single line diagram/system schematic indicating the facilities concerned and any other facilities serving the same customer(s).
  c) The use of direct allocation should also include O&M costs where supporting documentation in terms of sub-account records and explanations as to the related activities can be provided.

Chapter 6 – Functionalization

6.1.2 – Proposal – Groupings of Accounts and Sub-accounts in Cost Allocation Filings

- Appendix 6.1 suggests that Contributions and Grants (#1995); Completed Construction not Classified – Electric (#2050) and Accumulated Amortization of Electric Utility Plant (#2105) will all be grouped together (i.e., Group #4) for purposes of cost allocation and reporting. There are two issues with this proposal:
  - First, this treatment suggests that the allocation of all three accounts is exactly the same. However, the cost allocation of these accounts is likely to be different. For example, it is unlikely that contributed capital will attributed to the various asset accounts in exactly the same manner as accumulated depreciation. Indeed, if they are treated the same, it will only because no better information was available and the overall results of the cost allocation filing will be "questionable".
  - Second, the Staff Proposal calls for the costs in these accounts to be assigned to various asset accounts[4]. Once assigned these costs will then be allocated in the same manner as the asset accounts they have been associated with. As a result, these accounts do not have a unique allocation factor of their own. Having said this, for purposes transparency, the cost allocation model should report how the costs in each of these accounts have been redistributed across the other asset accounts.

[4] Accumulated depreciation and Contributed Capital are discussed on pages 35 and 39 of the Staff Report respectively. It is VECC's understanding that Account #2050 was to be pro-rated to the other asset accounts based on their relative values. However, the proposed treatment of account #2050 does not appear to be directly discussed anywhere in the report.

Recommendation: The break out of Accounts #1995, #2050 and $2105 should be reported separately as part of the cost allocation informational filing.

- Similarly, Appendix 6.1 suggests that Amortization Expense – Property, Plant and Equipment (#5705); Amortization Expense – Limited Term Electric Plant (#5710) and Amortization of Intangibles and Other Electric Plant (#5720) will be grouped together (i.e., Group #25) for purposes of cost allocation and reporting. The same two issues exist with this proposal:
    - As before, this treatment suggests that the allocation of all three accounts is exactly the same – which is not likely to be the case. For example, depreciation is likely to have a unique assignment based on actual plant records (per page 35), while it is VECC's understanding that the other two accounts are likely to be prorated across all asset accounts using a general allocation factor such as the value of fixed assets.
    - Second, the costs in these accounts are to be assigned to other asset accounts. Once assigned these costs will then be allocated in the same manner as the accounts they have been associated with. As a result, these accounts do not have a unique allocation factor of their own. Having said this, for purposes transparency, the cost allocation model should report how the costs in each of these accounts have been redistributed across the other asset accounts.

Recommendation: The break out of Account #5705 should be reported separately from that of Accounts #5710 & 5720 as part of the cost allocation informational filing. The latter two accounts can be grouped together for reporting purposes provided they are pro-rated to the various asset accounts using the same methodology.

- No where in the draft Staff Proposal is there a legend defining the various "Classification Factors" listed in Appendix 6.1. Furthermore Appendix 6.1 makes reference to "classification factors", while Chapters 9, 10 and 11 appear to use the term "allocation factors". However, the two terms appear to be referring to the same "factors".

- The Chapter and associated appendices do not appear to address the functionalization of any LV Wheeling costs (per page27) that may be included in a distributor's revenue requirement. In VECC's view, such services typically support delivery to the entire utility and should generally be functionalized in a similar manner to distribution stations or "bulk" facilities.

6.2.2.2 – Proposal – Definition of Secondary

- Need to clarify that Secondary does not include all assets operating at below 750 V as it excludes those assets reported as Services (#1855).

6.2.2.4 – Proposal – Definition of Bulk

- The Staff Report indicates that “a functional approach must be adopted towards identifying the assets that may serve a bulk delivery function”. It then puts forward two definitions of “bulk”. The first is facilities that are built to support the system peak of the distribution system. The second is facilities that are directly involved in the delivery of power to larger users.

  The first of the two definitions is fairly straightforward and consistent with a “functional approach” in that it focuses on assets used to serve the distributor’s entire load. Furthermore, it would be consistent with the principle of cost causality to separate out those assets that were installed with consideration to the distributor’s peak (and therefore warrant allocation on the basis of coincident peak load) from assets that are installed more with the consideration of individual customers’ loads in mind (and therefore warrant allocation on the basis of non-coincident peak demand).

  However, the second definition is somewhat problematic as it appears (despite the text’s caveat to the contrary) to be based on what types of customers are served by the facilities as opposed to the function the facilities perform. For example, in reality, there is no distinction in terms of functional use between a 44 kV line that serves a large user and a similar line that connects to a distributing station that subsequently serves a local area within the distributor’s service territory. As a result, it is not acceptable to define one line as “bulk” and the other as “primary” simply based on the types of customers served.

  The use of a bulk (or sub-transmission) sub-function is not commonly found in cost allocation studies performed by Canadian electric utilities[5]. VECC is also aware that the Technical Advisory Team and Board Staff have struggled with this issue and that there is no standard definition that can be applied to all 85+ distributors in the Province. As a result, the definition of bulk, as put forward in Staff Report, is fairly conceptual and requires significant judgement on the part of distributors. Given this background, VECC believes that caution is warranted going forward. First, as mentioned above, the proposed Staff Summary (per page 7 of the Staff Proposal) should include an assessment of how distributors have interpreted and applied the “bulk” definition for their informational filings. Second, where the introduction of “bulk versus primary” assets is a key contributor to a distributor being identified as an outlier in terms of fixed customer charges or revenue to cost ratios, then the distributor’s application of the concept should be carefully considered as part of any proceeding seeking any “correction” in rates. VECC is also of the view that this is one of the key areas where – contrary to the suggestion on page 8 of the Staff Report – the cost allocation methodology is still in the early stage of development and the final Board Report should not be considered a significant precedent. Indeed, in VECC’s view, the informational filings will be critical in determining

[5] Manitoba Hydro is the only case out of 6 other Canadian provinces (whose practices VECC is familiar with) where a bulk/sub-transmission sub-function is used in the cost allocation methodology and there it is narrowly defined as 69 kV facilities.

whether the concept of a “bulk/primary” split is workable and what the working definition should be going forward.

Recommendation: The Board should acknowledge that while a reasonable attempt has been made to define “bulk facilities”, how the definition will be interpreted and applied by distributors remains to be seen and will only be known after the cost allocation informational filings have been received and reviewed. The Board should also acknowledge that it will likely be necessary to fine tune the definition of bulk and, perhaps, even refine how it has been applied by individual distributors before requirements for future rate adjustments can be determined.

6.2.2.6 – Proposal – Identifying Bulk, Primary and Secondary Costs

- This section of the Staff Proposal suggests various approaches for breaking out the costs of bulk, primary and secondary assets based on unit costs, demand/distance and simple kilometres of line. In VECC’s view, the only truly acceptable approach is unit costs. A combination of demand/distance is at best directionally correct and the simple use of kilometres will skew the results significantly[6]. However, since kilometres of line is the easiest of the three approaches to implement it is likely to be the one most frequently adopted by distributors. **The simple use of kilometres to determine bulk asset costs will bias the results against residential and other customer classes who typically use secondary as well as primary and bulk assets.** Given the judgement that distributors are being asked to exercise in determining whether bulk assets exist, VECC suggests that it is reasonable to request that the distributors’ estimate of the relative cost also be based judgement and involve more than just the relative kilometres of bulk versus primary versus secondary lines.

  Recommendation: The Board should require that distributors determine the cost of bulk, primary and secondary facilities based on the (relative) costs of each and not simply on basis of the kilometres of bulk, primary and secondary assets.

- This section of the Staff Proposal should also identify that various O&M accounts need to be split between bulk/primary/secondary. Presumably, these would include Accounts #5020, 5025, 5040, 5045, 5090, 5095, 5120, 5125, 5135, 5145 and 5150. The fact that these accounts need to also be split is not reflected in Appendix 6.1.

  Recommendation: The proposed cost allocation methodology must also include a split of distribution O&M expense between bulk, primary and secondary, where applicable.

[6] To demonstrate this, recent cost allocation studies performed by Hydro Quebec suggest that the cost of primary line is roughly twice that of secondary line on per km basis.

6.2.2.7 – Proposal – Treatment of Depreciation and Accumulated Depreciation

- This should be a separate (two-digit) section of the Staff Proposal. The treatment of Depreciation and Accumulated Depreciation applies to all asset accounts (just as does Contributed Capital). It should not be "positioned" as part of the bulk/primary/secondary breakout.

- As discussed earlier and noted in the Staff Proposal (page 35), ideally depreciation and accumulated depreciation are not simply prorated across the various asset accounts based on their relative gross book value but rather directly assigned based on internal records. This means that the relative allocation of depreciation and asset net book value to accounts will likely differ from the relative allocation of gross book value. Furthermore, it is rate base that is used to allocate a large number of revenue and expense items and therefore must be calculated by asset account. Similarly, depreciation forms a key part of the overall cost of service and a breakdown, by account and cost allocation sub-account, must be available.

  <u>Recommendation:</u> For each fixed asset account (and sub-account) included in a distributor's rate base there should be additional accounts in the cost allocation model which capture:
    - The annual depreciation associated with each fixed asset account – which will be allocated to customer classes in same manner as the corresponding asset accounts.
    - The accumulated depreciation associated with each asset account.
    - The net book value associated with each fixed asset account – which will be calculated based on the reported gross book value for fixed each asset less the accumulated depreciation associated with the asset.

- The Staff Proposal does not acknowledge or address any where the fact that, for rate setting purposes, rate base is calculated using the average of opening and closing annual net book values for fixed assets. As a result, it is not clear if distributors will be required to breakdown both the opening and closing test year values for accumulated depreciation.

  <u>Recommendation:</u> For cost allocation purposes, distributors should be required to break down both the opening and closing test year values for accumulated depreciation and the cost allocation model should use the average net book value of fixed assets – broken down by USoA accounts and "cost allocation" sub-accounts.

6.2.4.1 – >50 kV Assets Deemed to be Distribution

- It is important to clarify that this sub-account relates to >50kV assets deemed <u>by the Board</u> to be distribution.

- Contrary to the text, a capital contribution to Hydro One Networks (Transmission) would not be included in the distributor's rates but rather the distributor's rate base.

If the contribution is amortized, then the amortization would be included in the distributor's rates.

6.3.4- Proposal – Breaking Out Contributed Capital in Filings

- The Default Approach is likely to be adopted by many distributors due its ease of application. Unfortunately, the Default Approach could lead to a significant misallocation of contributed capital, particularly in instances where distributors own distributing stations and/or transformers > 50 kV. The impact of this misallocation on the cost allocation results will depend on the level of contributed capital relative to the overall value of the distributor's fixed assets. **In instances where significant capital contributions have been received in support of sub-division development, use of the default method could bias the cost allocation results against residential customers.**

  Based on the USoA requirements[7], it would appear that all distributors should have the records to adopt the "Preferred Approach" with respect to contributed capital.

  Recommendation: Distributors should be required to apply the Preferred Approach. In the event that the Board decides to allow distributors to use of the Default Approach then the Staff review undertaken following the informational filings should identify those distributors with significant capital contributions (e.g., more than 5% of fixed assets) who employed the default method for "functionalizing" contributed capital. These distributors should then be required to do further analysis before any future changes in rates are initiated to reflect the cost allocation results. To facilitate this process, the cost allocation model should identify (as one of its outputs) the method employed by the distributor for functionalizing contributed capital and percentage contributed capital represents of the distributor's total fixed assets.

Chapter 7 – Categorization

7.2 – Proposal – Identification of Accounts

- There are a number of USoA accounts that are 100% customer related and not identified in Appendix 7.2 (or Appendix 9.1). These include:
  - Energy Conservation (#5415)
  - Supervision (#5305)
  - Customer Billing (#5315)
  - Collecting (#5320)
  - Collecting – Cash Over and Short (#5325)
  - Collection Charges (#5330)
  - Bad Debt Expense (#5335)

[7] USoA, page 55 states: "This account shall be maintained so that the company can supply information as to the purpose of each contribution or grant, the conditions, if any, on which it was made, the amount of contributions or grants from governments or government agencies, corporations, individuals and others and the amount applicable to each Electric Plant in Service detail account (i.e. accounts 1606 to 1990)".

- Miscellaneous Customer Accounts Expense (#5340)

- The fourth paragraph makes reference to Appendix 7.4 and the fact that the expenses in various accounts will be pro-rated consistent with the method used to categorize a particular group of assets. However, there is no discussion in the text itself as to specifically what the expense accounts are (i.e., Accounts #5005, 5010, 5085 and 5105) or what assets these accounts are considered to support. It would be useful if the treatment of these four accounts and the underlying rationale was clearly documented in the body of the report, either in this Chapter or in Chapter 10.

- The last paragraph in this section addresses the treatment of a number of accounts that are allocated on a pro-rata basis using either the Rate Base or the O&M expense that has been allocated to customer classes based on defined allocation factors. For purposes of completeness, it would be useful if a separate appendix was included that clearly documents the USoA accounts that were subject to this treatment. Also, clear definitions are required for the terms General Plant and General Administration – as used in the cost allocation methodology since:
    - there is no General Administration USoA account or category of accounts, and
    - the General Plant category of accounts in the USoA includes accounts that are not subject to the proposed treatment (e.g., contributed capital).

  Finally, this category represents a fifth component over and above the four discussed in the first paragraph.

- Throughout the Staff Proposal the discussion of the cost allocation methodology makes reference to its application to assets and O&M expenses (e.g., paragraph 2). It is important to note that the allocation methods identified for asset accounts will also apply to the depreciation expenses associated with the accounts – which are a separate cost item in the revenue requirement.

- The Chapter and associated appendices do not appear to address the categorization of any LV Wheeling costs (per page 27) that have been included in the distributor's revenue requirement.

  <u>Recommendation:</u> In VECC's view, such LV Wheeling services should be categorized as 100% demand-related and generally allocated based on coincident peak, unless they clearly support service to only portion of the distributor's service area. In the later case, it would be appropriate to treat them similar to "bulk" facilities in a split system (per page 37).

7.4.1 – Introduction (Generic Minimum System Approach)

- The generic minimum system will also apply to the depreciation expenses associated with the various asset accounts identified in the third paragraph.

- Would also be worthwhile noting in the Proposal itself that the generic minimum system results are only applied to the primary and secondary sub-accounts (and not the bulk sub-accounts) associated with the identified Accounts.

7.4.2.4 – Proposal –Density Thresholds and Measurements for Cost Allocation Filings

- It is not immediately obvious why the host distributor's kilometres of line associated with embedded distribution service should be included in the density calculation for the embedded distributor. This is particularly the case if the cost of the embedded lines is categorized 100% as a demand-related cost. The same observation applies to lines that are functionalized as "bulk". Presumably, the density calculation is aimed at the determining the "customer density" associated with those assets subject to the joint "allocation" treatment. If this is the case then the density calculation should be based on primary and secondary lines. However, VECC understands that this issue was not discussed in any detail during the Technical Advisory Team meetings and more consideration (following the informational filings) should be given to the matter.

  Recommendation: The Filing Questions (section 7.4.3) should require the distributor to identify the impact that the inclusion of LV lines and bulk lines has on the density designation of the distributor.

7.7.1 – Background (Minimum System and Multi-Unit Dwellings)

- In many cases the multi-unit dwellings will be residential dwellings and, if individually metered, classified as residential customers. **In such cases, ignoring this issue will bias the results of the cost allocation methodology against residential customers**. It should be noted that there are additional (cost allocation-based) reasons why these circumstances should be identified if costs are to be allocated fairly on the principle of cost causality:
  - In some instances, such complexes may have paid for or own their transformer and be served at primary voltage.
  - Similarly, such complexes may have paid for/own the service drop and the allocation of contributed capital and/or Services should be adjusted accordingly. Alternatively, if distributor owned, only one service drop is required per multi-unit dwelling (and not one per residential customer).

  Again, failure to capture such circumstances will also bias the results of the cost allocation methodology against residential customers.

  Recommendation: To help determine the extent of the issue, the Filing Questions (section 7.7.2) should also request that the distributors identify how many of the multi-unit connection points provide service at primary vs. secondary voltages – for both residential and general service complexes.

Chapter 8 – Allocation of Demand-Related Costs

8.1 – Introduction

- Appendix 8.1 should also acknowledge that demand (exclusively) will be used to allocate:
  - o The depreciation costs associated with the various assets listed.
  - o The expenses associate with the "bulk" portion of a number of the O&M accounts listed in Appendix 8.2 (e.g., Accounts #5020, 5025, 5040, 5045, 5090, 5095, 5120, 5125, 5135, 5145 and 5150).
  - o Any LV Wheeling charges incurred by an embedded distributor.

- Appendix 8.2 includes accounts that are a) Split between demand and customer using the minimum system method and b) Allocated based on Accounts #1815-1855. However, there are a couple of shortcomings with the appendix:
  - o It fails to note that only the Primary and Secondary portions of the following O&M accounts should be included - Accounts #5020, 5025, 5040, 5045, 5090, 5095, 5120, 5125, 5135, 5145 and 5150.
  - o It does not capture the fact that the depreciation costs associated with the various plant accounts listed will also be allocated partially using demand.

8.2.3 – Background (NCP Options)

- There are two sources of potential concern regarding the 1NCP allocator. The first is the overall quality of the load research program used to develop the demand allocators. The second is that the estimation of the allocators is based on only one year's worth of data. In VECC's view the first issue is reasonable. However, if the concerns are really with the quality of the data then not only the 1 NCP but also the 4 and 12 NCPs could be considered suspect. One way of addressing this concern would be to "widen" the range of acceptable revenue to cost ratio results when considering the outcome of the allocation methodology.

  In VECC's view the second reason is not as compelling. VECC's notes that other utilities who have been continuously engaged in load research for a number of years still use the most recent year's load research results in their cost allocation methodology even if the results differ from those in previous years[8]. Furthermore, VECC questions why – if data reliability is a concern – there has been no direction given by the OEB that load research efforts must continue.

  Recommendations: If the reliability of load research data is considered suspect such that a sub-optimal allocator (such as 4 NCP) must be adopted to ensure "stability" of the results, then Board should direct distributors to continue their load research efforts and report their plans as part of the informational filing.

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[8] A good example of this is Manitoba Hydro.

8.2.4 – Proposal (Tests for Use of NCP in Filings)

- The first paragraph states that NCP will be the demand allocator used when allocating assets identified by a distributor as primary or secondary. As noted in Chapter 6 (pages 33-34) there are two situations under which a distributor could consider itself as having bulk assets and the second involves assets involved in the delivery of power to larger customers. Furthermore, it has been acknowledged in the Staff Proposal (page 37) that there could be circumstances where a distributor has a "split system" and bulk facilities are used to only some of the customers or customer classes. In these circumstances, the bulk facilities will not have been designed with a view to meeting system peak but rather the peaks of the subset of customers actually served by the facilities. In such circumstances NCP is likely to be a better "allocator" from a cost causality perspective.

  Recommendation: NCP should also be used to allocate "bulk" assets where the assets concerned are not used to service all the distributor's customers but rather a sub-set.

- The Staff Proposal does not have a section that discusses the allocation of Services (Account #1855). Ideally, in VECC's view, the costs associated with Services (e.g., depreciation, O&M, etc.) would be allocated to customer classes on a "weighted customer basis". This would entail weighting the number of customers/connections in each rate classification by the average cost of a connection. (Note: The approach is conceptually similar to that used for meters). However, the Staff Proposal calls (see Appendix 6.1) for these costs to be allocated based simply on the number of secondary customers/connections. **This approach will bias the results against residential customers** for two reasons: a) First, because (as discussed earlier under section 4.1.6) only secondary customers/connections are included, and b) Second, there is no recognition that services to larger customers (if included in the account) will likely cost more.

- The proposed NCP Test will not demonstrate that the 1 NCP value is correct or stable but only that it is pronounced. If there are truly concerns about the validity of the 1 NCP value (based on the load research performed to date), then the proposed test does not validate the 1 NCP value. Rather it leads to distributors using what is considered to be a "questionable" 1 NCP value in circumstances where it is materially different from the 4 NCP value. In VECC's view this hardly seems like an acceptable approach if there are truly concerns about the data.

  Recommendation: a) If the Board (based on input from its expert load research advisors) has concerns about the reliability of the 1 NCP estimates then 4 NCP should be adopted as the standard allocator. In the alternative, the Board could adopt the 1 NCP allocator as the standard allocator but widen its view as to the range of revenue to cost ratios that would be considered acceptable.

b) In VECC's view it is critical that the same allocator be used for each rate class. It would be totally inappropriate to use 1 NCP for one class and 4 NCP for another when allocating costs.

- No where in section 8.2 is there a discussion of the different definitions of NCP to support the terms used in Appendix 6.1. While some of the definitions are reasonably obvious (SNCP – secondary customers' NCP and PNCP – primary customers' NCP); some of the definitions are not. For example, it is not clear what the definitions are for DNCP versus DDNCP.

  Recommendation: There needs to be clear definitions of the various NCP allocators presented in Appendix 6.1 and details provided in the text that support the differences in their calculation and application.

8.3.2 – Proposal - Tests for Use of CP in Filings

- The first paragraph states that CP will be the demand allocator used when allocating assets that are solely defined to meet the distributor's peak – that is costs related to >50 kV and bulk assets. There are several shortcomings with this statement:
  - First, as discussed above, CP should only be used to allocate bulk assets where the assets have been designed to meet the distributor's peak – which is not the case for all bulk assets based on the definition proposed by Board Staff.
  - Second, the statement does not include distribution stations along with any related assets and expenses. It should be noted that Appendix 6.1 properly identifies distribution stations and their related assets and expenses as being allocated based on CP.
  - Third, although not discussed at all in the Staff Proposal, presumably embedded distributors would generally use CP to allocate LV Wheeling Charges.

- The second paragraph indicates that a distinction will be made between the distribution CP and the transmission transformation CP. However, in Appendix 6.1 there are three CP allocators presented (BCP, DCP and TCP) with no explanation as to what each represents.

  Recommendation: There needs to be clear definitions of the various CP allocators presented in Appendix 6.1 and consistent details provided in the text that support the differences in their calculation and application.

8.4.2 – Proposal – Measurement of Hourly Peak for NCP and CP

- The section makes reference to "the peak period". Presumably what is meant here is the peak hour.

8.5.2 – Proposal – Separate Treatment of Each Rate Class and Subclass for Cost Allocation Purposes

- With respect to paragraph 2, it is VECC's view that in Run 2 when separate rate classifications are considered for embedded distributors, Unmetered Scattered Loads and Load Displacement Generation (per Chapter 2), these classes should be treated similar to any other rate classification for purposes of sharing diversity.

- Paragraph 3 suggests that boundary smoothing mechanisms are especially appropriate when a customer shifts from GS<50 kW to GS>50 kW if it is considered they represent subclasses. In VECC's view the issues and the impacts associated with customers moving from one rate classification to another are the same whether the two are considered subclasses or completely different rate classes (i.e., the issues need to be addressed in both instances).

<u>Chapter 9 – Allocation of Customer-Related Costs</u>

9.1 – Introduction

- The first paragraph acknowledges that service drops are a "customer-related" cost but (as noted earlier in these comments) the cost allocation treatment of service drops is not addressed in this chapter nor, indeed, anywhere in the main document. Appendix 6.1 indicates that the allocation factor for Services (#1855) is number of secondary customers. A number of problems with both the definition of Services and proposed allocation of costs associated with the Services account (see comments re sections 4.1.6 and 8.2.4) have already been identified. A further issue that requires clarification is how Services will be allocated in the case of unmetered scatter loads. Based on the discussion in section 11.5, VECC assumes that number of connections will be used as the allocator. This should be confimed.

  <u>Recommendation:</u> Chapter 9 should include a sub-section that deals with the allocation of Services.

9.2 – Definition of Customer and Connection for Filings

- Appendix 9.1 includes both those accounts that are a) Split between demand and customer using the minimum system method and b) Allocated based on Accounts #1815-1855. However, there are a few of shortcomings with the appendix:
    - It fails to note that only the Primary and Secondary portions of the following O&M accounts should be included - Accounts #5020, 5025, 5040, 5045, 5090, 5095, 5120, 5125, 5135, 5145 and 5150.
    - It does not capture the fact that the depreciation costs associated with the various plant accounts listed will also be allocated partially using a "customer-related" allocation factor.
    - It does not include the Energy Conservation account - #5415

- It does not include the various O&M accounts associated with billing and collecting (Accounts #5315, 5320, 5325, 5330, 5335 and 5340)

- The chapter does not specifically address what definition of customer/connection to use for customer-related distribution costs identified using the minimum system method. Based on the third paragraph, one would assume that for streetlights, sentinel lights and unmetered scattered loads the Proposal is to use the number of connections (i.e., actual number of devices). However, in the case of streetlights, one “connection” frequently links a number of fixtures to the distribution system and simply using the number of devices may overstate the number of physical connections to the distributor’s system.

  Recommendation: Where better information is available, distributors should be allowed to apply a connection factor to the number of streetlight fixtures for purposes of determining the customer allocation factor to be applied to minimum system-related customer costs.

9.3.1.1 – Background (Billing Activities)

- The Staff Proposal states that “a common allocator used to allocate customer-related costs that are related to billing activities is the number of bills issued”. However, research undertaken for the Technical Advisory Team and VECC’s own experience both suggest that a weighting factor is generally applied to the number of bills by customer class in order to reflect the relative effort put into preparing and validating the bills for different customer classes. Furthermore, this weighting factor typically results in a higher proportion of costs being allocated to those customer classes representing larger customers than if the allocation was based strictly on number of bills. **Thus the proposal to use number of bills can be regarded as a simplifying assumption and one that biases the results to the detriment of residential customers.**

9.3.1.1 – Proposal – Allocation of Billing Activities)

- The Staff Proposal suggests that “one way of calculating this number (i.e., # of bills) is by applying the billing frequency for one year by the test year customer numbers used in the 2006 EDR Model”. In the case of street lighting, many distributors reported in their 2006 EDR Model the total number of fixtures. In such circumstances, application of the proposed approach would significantly overstate the number of bills associated with this rate classification. It should be noted that this issue is addressed (on a generic basis) in section 11.5.2. It would be useful if a forward reference was included in section 9.3.1.1 noting where further discussion on billing costs for USL customers can be found.

- In the fourth paragraph, distributors are directed to use better information to allocate billing activity costs if available.

Recommendation: For those distributors that rely simply on number of bills to allocate these costs, an additional Filing Question should be posed asking for comment/commentary on the variation in the per customer cost of billing and collecting by customer class.

9.3.2.1 – Background (Meter Capital Costs)

- The statement in the last paragraph that "the separation of costs attributable to conventional and interval meters is not readily available" appears to be at odds with Appendix 9.2 which provides relative cost factors for the two types of meters.

9.3.3.1 – Background (Meter Reading Costs)

- The statement in the last paragraph that "the separation of meter reading costs attributable to conventional and interval meters is not readily available" appears to be at odds with Appendix 9.3 which provides relative meter reading cost factors for the two types of meters.

9.3.2.2 – Proposal – Allocation of Meter Reading Costs

- The fourth paragraph states that a different factor must be used where "a meter type exists for a distributor that is materially (defined as at least 10%) different in cost than the standard meter types incorporated in the model". While the statement suggests that the 10% difference applies to the cost of meter, presumably what is meant is a 10% difference in the cost of meter reading.

9.3.4.1 – Background (Conservation and Demand Management Costs)

- The second paragraph makes reference to the treatment of CDM expense in the 2006 EDR process. It was VECC's understanding at the start of the 2006 EDR process that cost allocation matters were not to be addressed but rather carried forward to the current process. As result, VECC was surprised that the Board's RP-2004-0018 Decision called for changes in the cost allocation of CDM costs. In VECC's view it would be appropriate to revisit the entire question of cost allocation for CDM expenses as part of this exercise.

- VECC agrees with the statement in the first paragraph that "the general purpose of CDM costs is to reduce energy consumption and peak demand". VECC also agrees with the position that "it would be desirable to allocate these costs based on a combination of energy consumed and demand used". CDM expenditures represent an alternative to investments in supply-side resources (e.g., generation, transmission, etc.). Therefore it is appropriate, from a cost-causality perspective, that these costs be allocated based on demand and energy.

In theory, CDM expenditures by a distributor will reduce provincial energy and capacity requirements and therefore benefit all users of electricity. While it is impractical for a distributor to allocate CDM costs to all provincial consumers, a somewhat similar result is achieved if all distributors pursue CDM programs and recover the cost from their respective customer bases.

In its RP-2004-0018 Decision, the Board indicated that direct CDM operating expenses should be allocated by participant customer class. The rationale was that the "class" benefited from the program and should therefore bear the costs. In VECC's view there are a couple of problems with this approach:

- As noted previously, all customers benefit when individual consumers reduce/manage their electricity use. Obtaining the equivalent of supply resources from consumers in the form of CDM is equivalent to obtaining new resources from transmitters and generators. The question therefore exists as to why one would treat the expenditures differently for purposes of cost allocation.
- Allocating the CDM costs to a customer class presumes that all customers in the class can participate in the programs and benefit (in the form of lower bills) accordingly. This is not the case. As VECC has argued in other forums, low income and fixed income consumers are not in a position to participate and benefit from many of the CDM programs offered.

<u>Recommendation:</u> All CDM expenses (both capital expenses along with <u>direct</u> and indirect operating expenses) should be allocated to customer classes based on a combination of energy consumed and demand used.

9.3.4.2 – Proposal – Allocation of CDM Costs

- The Staff Proposal is to allocate the capital and indirect CDM costs based 50% on energy and 50% demand. There is no rationale provided for the 50/50 split. Indeed, it is VECC's experience that 50/50 is typically proposed when there is no rationale or better approach available**. In VECC's view, the 50/50 split is inappropriate and will bias the results to the detriment of low load factor rate classes such as residential**. Indeed, based on the avoided costs accompanying the Board's TRC Guide, energy costs generally represent over 80% of total avoided costs[9]. Adopting an 80/20 energy/demand split would be more appropriate and still likely under estimate the energy portion.

  <u>Recommendation:</u> If the Board wishes to use a combination of energy and demand to allocate CDM costs then the energy portion should be at least 80%, if not higher. For simplicity purposes the Board may wish to consider using a 100% energy allocation factor.

[9] For the period 2010 to 2014, energy costs represent over 80% of total avoided costs for a load profile that has a 70% load factor in each period. Profiles with a higher orientation to the peak periods would have an even higher percentage of energy costs.

- The text of the Staff Proposal does not address the cost allocation treatment of Account #5415 (Energy Conservation). The same allocator should be used for this account as for Account #1565 (C&DM Expenditures).

9.3.5.1 – Background (Bad Debt Expense)

- The Staff Proposal is to allocate bad debt expense based on three year history of expense by rate classification but to exclude from the history extraordinary bad debts. VECC acknowledges that generally practice elsewhere is to use historical write-off history to allocated bad debt expense. However, VECC does not support the exclusion of extraordinary write-offs from the determination of the allocation base. By virtue of their size large customers are more likely to trigger extraordinary bad debt write-offs (e.g., It would be virtually impossible for a residential customer to trigger an extraordinary write-off whereas write-offs for a large user are more than likely to do so). Hence, simple exclusion of extraordinary bad debt expense will not "normalize" the results for rate classifications with larger customers and, **therefore, the Staff Proposal will tend to disadvantage rate classes with small volume customers, such as residential**. On the other hand, extraordinary bad debt is not a frequent occurrence. To balance these two considerations, a portion of actual extraordinary bad debt expense should be included in the allocation base.

  Recommendation: The allocation base for bad debt expense should be based on a three historical average – by rate classification. For purposes of determining the average, the annual bad debt expense for each rate classification should include 10% of extraordinary bad debt write-offs.

9.3.5.2 – Proposal – Allocation of Bad Debt Expense

- The Staff Proposal is to not allocate any bad debt expense to any new rate classifications created for the informational filings, unless historical data is available. VECC does not agree with the approach. If there is no historical data available, then the bad debt expense allocated to an existing customer classification should be pro-rated across the new rate classifications derived from it. A reasonable basis for pro-ration would be the total revenues attributable to each new rate class.

  Recommendation: If historical bad debt data is not available for those rate classifications that are being considered as new rate classifications in the filings, then bad debt expenses allocated to the existing rate classification should be redistributed to the new rate classifications derived from it based on the revenues for each rate class[10].

[10] During the Technical Advisory Team meetings it was generally agreed that embedded distributor should not attract bad debt expense. In VECC's view, this should be the only exception allowed to this recommendation.

Chapter 10 – Allocation of Other Costs

10.2.1 – Background (General Plant)

- In this section the Staff Proposal suggests that General Plant will be allocated based on "a composite of the distribution net fixed assets". In the following section, a pro rata allocation based on distribution rate base assets is proposed as the standard methodology. However, there is a difference between net fixed assets and rate base assets. The value of rate base assets will be net of capital contributions and should be based on opening and closing balances. In contrast, net fixed assets represent gross book value less accumulated depreciation and are undefined as to the calculation timeframe. In VECC's view, use of net fixed assets (with no adjustment for contributed capital) is a better measure of the scope of the assets General Plant is supporting and therefore, from a cost causality perspective, should be the pro rata allocation factor used.

  Recommendation: General Plant should be allocated on a pro rata basis using a composite of distribution net fixed assets (average of opening and closing balances for the test year) with no adjustment for contributed capital.

10.3.2 – Proposal (Allocation of A&G)

- The Staff Proposal is to allocate property insurance and community safety programs that serve to safeguard the distributor's assets using "rate base" as the allocator. VECC assumes that the proposed allocator is distribution rate base assets and not the entire rate base – including working capital. Also, as noted above, there is a difference between rate base assets and net fixed assets. For purposes of allocating property insurance and community safety programs, VECC considers net fixed assets to be the better measure of cost causality.

  Recommendation: Property insurance and community safety programs should be allocated on a pro rata basis using a composite of distribution net fixed assets (average of opening and closing balances for the test year) with no adjustment for contributed capital.

10.4.2 – Proposal – Allocation of WCA

- The Staff Proposal is to allocate the cost of power (COP) component of working capital based on energy, excluding wholesale market participants. In VECC view, the COP component should be allocated based on the distributor's cost of power billings to each rate class. Energy is rough proxy for this value. The proposal also has other shortcomings. The exclusion of market participants fails to capture the fact that while distributors do not bill such customers for commodity purchases the distributors do bill them for transmission services and have associated working capital requirements.

Recommendation: Where the information is available, distributors should be directed to allocate the COP component of working capital to rate classifications based on the annual COP billings to the customers in each classification.

Chapter 11 – Cost Allocation and Unit Cost Calculations for Specialized Rate Classifications

11.1 – Other Specialized Rate Classifications

- The Staff Proposal states that "if a utility-specific rate classification *will be dropped*, an explanation should be included in the Filing Summary and the effect should be modeled in Run 3". VECC understands that existing rate classifications may be dropped in Run 3 if the distributor intends to include such a proposal as part of its next rate application and wishes to provide an estimate of the impacts of doing so. The Board should confirm if this is what is meant by the wording "will be dropped".

11.2.2 – Proposal – Cost Allocation and Unit Cost Methodology for Embedded Distributor Classification.

- The Staff Proposal indicates (paragraph 2) that distance is an acceptable option when sub-accounts are created but not an acceptable as an allocator (footnote #9). VECC finds this distinction to be problematic. Both activities effectively involve the allocation of assets and their associated costs. In VECC view, if distance is not acceptable as an allocation factor, it should not be an acceptable option for assigning costs to sub-accounts. This observation is consistent with comments made above with respect to section 6.2.2.6.

11.3.1 – Background (Density-Based Classifications)

- The second paragraph seems to suggest that, in the past, there were common definitions used by all Ontario distributors regarding urban and suburban customers. To VECC's knowledge this was not the case and definitions varied across distributors.

11.5 Unmetered Scattered Loads (USL)

- The last paragraph suggests that a separate rate classification is proposed for USL. However, as VECC understands it (and as discussed in section 1.5.3), the purpose of the information filings is to provide the Board with information that may lead at a later date to a proposal to implement a separate rate classification for USL.

11.5.2 Proposal – Cost Allocation Methodology (USL)

- It is not clear from the text of the Staff Proposal, but VECC assumes that the proposed cost allocation methodology for USL applies to all three "Runs" of the cost allocation model. For example, if USL is part of the GS<50kW Class in Run 1, then the Class will not be attract meter costs for these customers. The Board should clarify and confirm this.

- With the exception of the O&M expense accounts noted (per page 76), it is VECC's understanding that USL will attract other applicable operation and maintenance expenses on the same basis as all other rate classes. Assuming this is the case, the wording on page 76, last paragraph should be changed accordingly to remove any suggestion that the treatment of USL is different for these accounts.

- The Staff Proposal indicates (page 77) that collection expenses will be allocated to USL in the same fashion as other customer rate classes if data is available. However, for other rate classes collection costs are allocated on the same basis as billing costs. As result, VECC assumes that collection costs will be allocated to USL using the same methodology as prescribed for billing related costs.

11.5.3.2- USL Metering Credit Proposal

- The Staff Proposal does not clearly outline the basis on which the USL meter credit would be credited back to USL customers or how the cost of credit would be recovered. While these are more rate design issues, it is VECC's view that the allowance should be credited back to USL customers on a connection basis and the cost recovered from the GS<50 kW Class. This presupposes that the customer charge is applied per metered customer/connection.

11.6.2.2 – Proposal – Rate Classification Threshold

- The Staff Proposal does not specify precisely how "standby service requirements" are to be determined for purposes of applying the 500 kW threshold. A simple approach would be to use the installed capacity of the load displacement generator(s) as the indicator of standby service requirements. However, in some cases load displacement generation is integrated with the customer's operation such that overall load requirements (and therefore stand by requirements) are lower when the "generator" is not operating. In other cases, the customer has the ability to reduce its electricity requirements when standby service is required.

  <u>Recommendation:</u> For purposes of the cost allocation informational filings and application of the 500 kW standby classification threshold, VECC suggests that standby requirements should be based on the capacity of the load displace generation unless the distributor has a formal contract with the customer specifying an alternative value.

11.6.3.1 – Background (Cost Allocation Methodology Where Existing Load Displacement Customers are part of a Main Rate Classification)

- The third paragraph makes reference to other savings and costs that should be taken into account during the cost allocation filings and before finalizing a standby rate. In VECC's view the discussion in this section and elsewhere mixes rate setting and cost allocation considerations. From a cost allocation perspective, the focus is on properly allocating the costs included in the test year's distribution revenue requirement. It is reasonable for the Staff Proposal to "flag" issues associated with rate design for standby service but these should be noted separately and clearly distinguished from the cost allocation process.

There may be either additional costs (e.g. operating costs associated with load displacement generators when first connected) or savings (e.g., deferring new distribution system assets) associated with load displacement generation and the provision of standby service that are not captured in the revenue requirement. Section 11.6.3.2 (Step 3, first paragraph) requires the distributor to identify and include such costs, even if they are not reflected in the trial balance that supports the 2006 approved rates. The same section also appears to require[11] the distributor to directly allocate such costs or benefits to the rate classifications with standby service. VECC does not agree with this proposal for the following reasons:

- These costs/savings do not form part of the approved 2006 revenue requirement and no determination has been made by the OEB that they should be included in the revenue requirement. To include them is inconsistent with the starting premise for the informational filings as discussed in section 4.1.
- While it may be reasonable to take such costs/savings into account for rate design with respect to load displacement generator and their standby service, it is not clear that they need to be included directly in the revenue requirement in order to do so. There are other mechanisms that could be used to recover such costs (e.g., capital contributions) or recognize such savings (e.g., offset to required capital contributions, deferral accounts and billing credits). Considerations as to the types of additional[12] costs and savings that should be accounted for and how best to recover/credit them to customers are matters that need to be more fully discussed. The current forum has not provided this opportunity and this comment process is not the right mechanism to fully and properly explore these issues. The upcoming Rate Design discussions are a better forum.
- If such costs/savings are included an offsetting credit/debit will have to be established and allocated to customer classes in order for the overall revenue requirement to remain unchanged. Otherwise, the overall revenue to cost ratio for the distributor will not reconcile to 1.0. The Staff Proposal contains no discussion of this matter.

Recommendation: For purposes of the cost allocation informational filings, distributors should be requested to identify (via a Filing Question) additional costs and savings associated with load displacement generation and standby service. Such information will prove useful in the upcoming rate design discussions. However, only those cost recognized or assumed to be in the trial balance that

[11] Step 3, 1st paragraph, last sentence.
[12] Additional in the sense that they do not form part of the standard revenue requirement.

supports the 2006 approved rates should be included in actual cost allocation modelling and runs prepared by distributors.

11.6.4.3- Proposal – Number of New Rate Classifications

- The Staff Proposal calls for all standby customers to be included in a single rate class for purposes of preparing Run 2. VECC assumes that this requirement applies to all distributors, even those who currently have approval for more that one separate standby rate classification and modelled more than one standby rate classification in Run 1. This matter should be clarified. Also, while VECC understands the rationale for creating just one standby class, it would useful if distributors indicated in their Filing what the customer make up of the class was.

  Recommendation: Distributors modelling a separate standby rate classification in Run 2 should be required to answer a "Filing Question" regarding the make up of the class (i.e., number of customers formally GS>50 kW, Intermediate or Large Users).

Chapter 12 – Unit Cost Outputs

12.2.1 Background (Substation and Secondary Transformation Ownership Unit Costs)

- The paragraph identifies the fact that a customer may own other primary assets and secondary assets (apart for transformation) and could still be paying for these additional facilities in their standard rates. This would occur in circumstances where the overall rate class has attracted a portion of such costs by virtue of the fact that other customers in the class use the services of the associated assets. However, the Staff Proposal suggests that an allowance for ownership of bulk assets is not an issue. VECC disagrees.

  The situation can arise where bulk assets are only used to supply part of a distributor's service area[13] and therefore some customers don't use the assets – but also don't own their own. In VECC's view, a bulk ownership allowance would be applicable in such circumstances. The rationale is same and based on the fact that otherwise customers will be paying through their standard rates for facilities that the distributor does not own/use in serving them. From a cost causality perspective, the question is not whether the customer owns the asset but rather whether the utility needs to own and operate such assets in order to serve the customer. If the answer is no, then the customer's rates should not reflect the cost of the facilities.

  Recommendation: Section 12.2.2 should include a cost pool for bulk conductors/poles which would be applicable in those circumstances where bulk facilities are not used to service all customers in the distributor's service area.

[13] See reference to "split system" on page 37 of the Staff Proposal.

12.2.2.1 Proposal – Substation Transformation Ownership Allowance Unit Cost Output

- The list of costs included in this section does not properly reflect the costs associated with Substation Transformation.

  <u>Recommendation:</u> The list of costs to be included in the new substation transformation ownership allowance unit cost calculation should be revised as follows:
  - Only depreciation of the <50 kW portion of account 1825 – Storage Battery Equipment (i.e., sub-account 1825-2) should be included.
  - The list should include depreciation on the sub-accounts 1805-2 (Land Station<50 kW); 1806-2 (Land Rights Station < 50 kW); 1808-2 (Building and Fixtures <50 kW); and 1810-2 (Leasehold Improvement < 50 kW).
  - The list should include a pro rata share of accounts 5005, 5010, 5085 and 5105 based on the distribution assets identified above
  - The list should include account 5012 (Stations Buildings and Fixtures Expense).
  - The allocation of General Plant and Administration & General Expenses should be revised to reflect the preceding points. Also, the allocation base for A&G expense is O&M previously allocated and not rate base.
  - The “mini” rate base should also be revised to reflect the preceding points

12.2.2.2 Proposal – Substation Transformation Ownership Allowance Unit Cost Output

- The list of costs include in this section does not properly reflect the costs associated with Secondary Transformation.

  <u>Recommendation:</u> The list of costs to be included in the new secondary transformation ownership allowance unit cost calculation should be revised as follows:
  - The list should include a pro rata share of accounts 5005, 5010, 5085 and 5105 based on the associated distribution assets.
  - The allocation of Administration & General Expenses should be revised to reflect the preceding point. Also, the allocation base for A&G expense is O&M previously allocated and not rate base.

12.2.2.3 Proposal – Primary and Secondary Conductors and Poles Cost Pools Calculation

- The list of costs included in Appendix 12.2 does not properly reflect the costs associated with Primary and Secondary Conductors and Poles.

  <u>Recommendation:</u> The list of costs to be included in both the Primary and Secondary Conductor cost pools should be revised as follows:
    - The list should include a pro rata share of accounts 5005, 5010, 5085 and 5105 based on the associated distribution assets.
    - The allocation of Administration & General Expenses should be revised to reflect the preceding point. Also, the allocation base for A&G expense is O&M previously allocated and not rate base.