Ontario

Ontario Energy Board

Cost Allocation Review: Staff Proposal on Principles and Methodologies

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Chapter 1

1. Introduction

1.1 Purpose of Proposal

This report sets out Board Staff's proposal for common cost allocation principles and methodologies to govern the cost allocation review informational filings due from licensed electricity distributors starting in the Fall of 2006.

Written comments from stakeholders are welcome and should be forwarded to the Board Secretary by July 18th, 2006. All comments received will be posted.

After considering stakeholders' comments, the Board will issue final directions on common cost allocation principles and methodologies in a report anticipated to be released in August 2006. A cost allocation review filing model and accompanying instructions, consistent with the Board's approved principles, will also be issued in August.

1.2 Scope of the Review

The Chair of the Ontario Energy Board advised stakeholders in a letter dated March 9, 2005 that a cost allocation review would proceed and that the review would be based "primarily on the existing rate classifications and a limited number of rate design issues".

As elaborated in the September 2005 Staff Discussion Paper, discussions on a number of topics were outside the scope of the present consultations, including smoothing of rate classification boundaries, substantial changes to the fixed/variable distribution rate philosophy, rate classification changes to current density, seasonal and polyphase rates, and new time of use distribution rates.

Issues involving acceptable revenue-to-cost ratios, rate impacts and mitigation measures are outside of the scope of the initial filing process.

As previously announced, Board Staff will be commencing a separate comprehensive study of distribution rate design. The "Electricity Distribution Rate Review" is scheduled to proceed later in 2006. Comments from that process, along with information from the current filings, will be considered when the Board decides how best to proceed on rate classification and rate design matters.

1.3 Preliminary Technical and Modeling Discussions

The planned scope of the project was discussed at a kickoff meeting on July 20, 2005. Technical consultations were organized in three phases from September 2005 to June 2006 dealing with 1) cost allocation policies and principles, 2) select rate classification and rate design policy issues, and 3) implementation and modeling issues. A Technical Advisory Team (see Appendix 1.1) consisting of stakeholders representing large, medium and smaller distributors, as well as ratepayer groups, was established and met for each phase. In addition, public Technical Workshops (five in total) were held to update all stakeholders on progress of the project. [1]

Project Staff would like to acknowledge the effort and assistance of the Technical Advisory Team and Staff's consultants, in the design and testing of the OEB cost allocation review filing model. The first round of testers consists of Newmarket Hydro, Lakeland Power, and Waterloo North Hydro. They benefited from updated load data supplied by the HONI Load Data Team. The second round of testers will include Hydro Ottawa, Hearst Power, Milton Hydro, and Toronto Hydro.

The Board would like to thank stakeholders for their very extensive input to the consultation process.

1.4 Load Data Requirements

Certain load data issues were examined in earlier consultations, which led to the Board's 2003 Load Data Report and November 10th, 2003 Load Data Collection Directions. Further aspects of the load data requirements for cost allocation filings were addressed during the present consultations. A Staff Proposal regarding rate classifications to be modeled, and associated load data requirements, was issued for public comment in May 2006. The Board has reviewed the stakeholder comments. The resulting Board directions in these areas are incorporated in Chapter 2 "Rate Classifications to be Modeled" and Chapter 3 "Load Data Requirements". No additional stakeholder comments required.

[1] See project webpage for copies of all earlier presentation materials at http://www.oeb.gov.on.ca/html/en/industryrelations/ongoingprojects_costallocation_review.htm

1.5 Objectives of the Informational Filings

1.5.1 Common Cost Allocation Methodology

The Board will establish a common cost allocation methodology for use by Ontario electricity distributors. To assist in the completion and review of the filings, certain default values will also be incorporated into the filing model. Using a consistent methodology, along with various utility-specific inputs, the upcoming filings will provide the Board with the information required to undertake the cost allocation review.

A common cost allocation methodology will be developed for standby rates, but all aspects of finalizing such rates will not be examined in this process.

1.5.2 Cost Allocation Outputs

The filing will provide the revenue to cost ratios, and rates of return, for each rate classification of a distributor. This information will document the extent of any inherent cross-subsidization between rate classifications.

1.5.3 Rate Classification Information

The filing will model the implications of the following potential rate classification changes**:**

- eliminating the legacy rate class known as "Time of Use", including placing customers currently in a GS>50 kW "TOU" rate classification into GS, discrete demand range, GS Intermediate, or GS >50 kW classifications
- adding a new embedded distributor rate classification for all host distributors
- adding a new Large Use classification where a distributor has a customer with a demand above 5,000 kW in its GS classification
- adding a common separate rate classification for scattered unmetered loads (the model will also calculate an appropriate metering credit if USL customers stay within the GS<50 kW classification)
- adding a common separate rate classification for distributors serving customers with significant load displacement facilities (the model will also consider appropriate cost allocation treatment if load displacement customers remain part of a main rate classification).

For the bulk of distributors that used a historical test year in their 2006 applications, rate classification changes will be assessed using 2004 data. The filings should indicate if there is a significant change since that date which may impact rate classifications (such as the introduction of heating mats for certain USL loads starting in 2005).

It is anticipated the results from the forthcoming separate Electricity Distribution Rate Review will be available when the Board considers implementation of any changes to current rate classifications (or other rate design issues).

1.5.4 Customer Unit Cost Information

The model will produce customer unit costs per month for each rate classification. To assist with reviewing the range of current fixed monthly customer service charges, the model will generate reasonable lower and upper customer unit costs.

Along with the above cost data, other established rate design goals, which may include non-cost considerations, will be considered before the Board implements any changes to current fixed monthly service charges.

1.5.5 Alternative to current Transformer Ownership Allowance

The filings will include a common cost-based alternative to the current transformer ownership allowance. New substation and secondary transformation ownership allowances will be modeled and other relevant costs will be gathered.

1.5.6 Filing Questions

The filings will include supplementary questions that all distributors must answer where applicable. They will generate information useful on a variety of matters: identification of assets used 90% plus by one customer classification; applicability of generic minimum system results; wholesale market participant costs; accounting treatment of certain key accounts.

In addition to the above, distributors will be asked if the use of the approved cost allocation principles have led to any anomalous results and if so, to provide a further explanation of these results.

1.5.7 Summary of the Cost Allocation Filing

In addition to filing the completed model, all distributors will be required to file an accompanying Summary of Filing ("Filing Summary").

The recommendations below make reference to various matters to be addressed in the Filing Summary. The Filing Summary will include "General Comments" where the distributor's management can add any general comments regarding the interpretation of the filing results.

1.6 The OEB Cost Allocation Filing Model

The final OEB cost allocation review filing model and accompanying instructions are planned for release in August to all distributors and registered ratepayer groups in this process. OEB Applications Staff will rollout the Board-approved model to distributors starting in September 2006. Details will be announced later.

All licensed electricity distributors will be required to submit a cost allocation filing.

At present, it is anticipated the standard cost allocation filing model will be used by all distributors except:

- Hydro One Networks Inc.
- Hydro One Remote Communities
- Distributors with generation assets in their approved rate base
- Distributors with zonal rates that are to be modeled in Run 1 and Run 2.

In the above cases, the distributor must create its own filing model.[2] Any other distributor wishing to file its own model will not be allowed to do so unless approval is sought and given beforehand. Any distributor-specific model must be consistent with the cost allocation principles and methodologies to be adopted in the Board's August Report. If the distributor finds it necessary to supplement or adjust the Board-approved cost principles, a full explanation must be provided in its Filing Summary.

[2] Note the Board's standard model will be made available for modification by those distributors who need to file their own model. Affected distributors are encouraged to contact Board Staff.

1.7 Model Runs to be Filed

All distributors will be required to submit a 1st and 2nd Run of the filing model. The 1st Run will generally be based on the distributor's approved 2006 rate classifications including any approved interim rates. Special rules will apply, however, to distributors that are merging with another distributor which will allow them to file a simpler filing if there is a strong likehood that separate rate classifications will not be maintained.

In Run 2, the select potential rate classification additions and deletions identified by the Board must also be modeled.

The model to be issued will generally remain "closed" when used in Run 1 and Run 2. Any exceptions will be noted in the August model instructions.

If a distributor makes any changes to the standard model during Run 1 or Run 2 (for example, where the general principles adopted in the August report did not cover some unique circumstance such as generation assets in the approved rate base), an explanation must be included to the distributor's Filing Summary.

For purposes of the optional Run 3, the model will be "open". The distributor's Filing Summary must explain any changes made to the Run 3 version submitted.

A distributor will be allowed to model the following items in an optional Run 3 filing:

- the deletion of a rate classification with supporting rationale
- the addition of a new rate classification beyond those modeled in Run 2, with supporting rationale and cost/load data
- density and seasonal classifications may not be added in Run 3
- polyphase rate classifications my not be deleted in Run 3
- use of 12 NCP, where supporting justification is provided based on the cost characteristics of the distributor's system
- use of default minimum system results from another density stratum, where the distributor can provide strong reasons to justify classification into another density stratum
- use of a distributor-specific minimum system study and PLCC calculation, with supporting explanation of details
- use of the alternative load data option when modeling a separate load displacement generation rate classification.

Where a Run 3 of the model is filed, the Filing Summary must include additional supporting explanation and documentation.

In some cases, alternatives are provided where better data is available. It is intended that these options be incorporated in all runs of the model, and that supporting explanation and documentation be provided in the Filing Summary.

1.8 Filing Process

Distributors will be required to submit their cost allocation filings to the Board in one of the four following tranches (for details, see Appendix 1.2):

1) November 2006

2) January 2007

3) February 2007

4) March 2007.

Distributors are encouraged to work closely with their load data service provider to ensure the required load data is obtained on a timely basis.

The filing requirements have been designed taking into account the need for reasonably reliable results, as well as the efficient preparation and review of the filings. Additional background work (such as utility-specific minimum system or PLCC studies) is not encouraged for these filings.

The filings will be made public.

1.9 Review of Filings

Following the review of the submissions, Staff will prepare a report summarizing the overall outcome. For example, the filings will be analyzed to identify outliers in fixed customer charges and in revenue to cost ratios. Recommendations for next steps will be included. Stakeholders will be invited to comment on the results and the Staff recommendations.

1.10 Potential Future Implementation in Rates

After reviewing the results from the cost allocation filings, and considering the overall regulatory context including results from the forthcoming distribution rate design consultations, the Board will decide upon the priorities for, and timing of, any adjustments to future rate design and cost allocations.

Certain distributors may be directed by the Board to address specified matters in future rate applications. The earliest potential implementation dates for new rates following the review are November 2007 but more likely May 2008 when certain utilities file full cost of service rates applications.

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.

Depending upon the outcome of the review, the Board may consider a generic rate hearing to address select matters.

Chapter 2

2. Rate Classifications for the Filings

2.1 Background

When establishing the scope of the cost allocation review, the Board decided to base the review primarily on the approved 2006 rate classifications. These are to be incorporated in Run 1 of the filing model.

The Board has also decided to gather information on a limited number of rate classification changes. These will be incorporated in Run 2 of the filing model. The upcoming filings are of an informational nature and will not result in any changes to rate schedules at this time.

Distributors will be allowed the option of filing a Run 3 of the model to provide information on certain additional rate classification changes proposed by the distributor, providing suitable supporting data is provided.

For the cost allocation filings, the term “rate classification” will refer to any separate rate class or subclass. There are certain rates which are not based on a fully separate rate classification for cost allocation purposes (in particular, USL and standby rates for most distributors in Run1, where no separate load data will be required and special cost methodologies developed).

If, in the future, a distributor receives approval to create a new rate classification, stakeholders have suggested changes in the treatment of Retail Transmission Service Rate could also be discussed.

2.1.1 May 26, 2006 Staff Proposal and Final Board Directions

A “Staff Proposal regarding Rate Classifications and Associated Load Data Requirements” was issued for stakeholder comment in May 2006. Eleven written comments were received from ten stakeholders. They are posted on the OEB web page.

The Board thanks all stakeholders for their comments. Those written comments, as well as further comments at the final June 15th Technical Workshop, were considered when the directions set out in Chapters 2 and 3 of this report were finalized. No further stakeholder comments are required on Chapters 2 and 3.

2.2 Run 1 of the Filings

Run 1 of the filing should generally reflect the distributor's approved rate classifications, including any rate classifications approved on an interim basis. Distributors should consider the following when completing Run 1 of the model.

2.2.1 Modeling

The OEB cost allocation model will include the rate classifications common to the bulk of distributors. The standard model that will be issued will include space for several additional utility-specific rate classifications.

2.2.2 Merging Distributors

Separate rules (see Chapter 3 for details) will apply to distributors that have merged and where there is a significant prospect that separate rate classifications will not be maintained. Where applicable, separate zonal rates will not need to be included in Run 1 or Run 2 of the filing. All distributors who have undertaken mergers are requested to carefully review those rules.

2.2.3 Embedded Distributors

For the Run 1, as discussed, the distributor should model its currently-approved rate structure. If the approved charge to an embedded distributor is represented as a separate rate classification in the 2006 rate order for the host distributor and those approved rates are different than the approved rates of any other rate classification, then it can be generally assumed that the embedded distributor has a separate rate classification and this should be modeled in the Run 1.

Distributor could be providing service to an embedded distributor but be charging standard rates for this service. In this case, these customers will be considered to be in the standard classification for the Run 1. For the Run 2, these customers will be grouped in a separate embedded distributor rate classification.

2.2.4 Unmetered Scattered Loads in Run 1 and USL Metering Credit

Certain customer loads have traditionally not been metered by most distributors. Specific examples include such loads as: bus shelters, phone booths, CATV amplifiers, pipeline and telecommunication cathodic protection devises, sewage flow monitors, heaters for sewage flow monitors, traffic lighting and traffic control equipment on the street, billboard lighting, sign lights, highway cameras, city traffic cameras, general city monitoring cameras, railway crossing signals, and decorative seasonal lighting. The 2003 consultations also suggested that a few distributors differed on the scope of uses included in USL versus other rate classifications.

During Technical Advisory Team discussions, some stakeholders discussed the costs and benefits of metering these devices above a certain threshold. The cost allocation review project is not the appropriate forum to address such matters. Thus, for the purpose of the cost allocation filings, the definition of USL underlying the distributor's 2006 EDR approved rates must be applied.

Prior to unbundling and developing the service charge and volumetric rate structure, USL paid for energy on a usage basis consistent with those customers classified as General Service. With unbundling, in most cases each USL connection was charged a service charge. During the process of developing the 2006 EDR Handbook, certain parties suggested that charging the same service charge as a General Service <50 kW customer for each connection was unfair.

During the 2006 EDR stakeholders consultations, a solution was developed that, pending detailed cost allocation studies, distributors that bill USL customers the GS < 50 kW monthly service charge on a per connection basis would be required to reduce the monthly service charge by 50%. Many distributors received 2006 rate orders based on the this methodology.

As it appears certain aspects of costs of these customers are reasonably distinct, there are merits in considering either the establishment of a fully separate USL rate classification or treating them as GS < 50 kW customers with an appropriate credit.

While USL charges are generally shown on the approved 2006 EDR rate orders as a separate items, there was often no full underlying cost data supporting the new rates (for example, no updated load data was provided). Therefore, for the purpose of Run 1 of the cost allocation filing, distributors should carefully consider the underlying substance of their current USL rates. If the rate was set based on the 2006 EDR interim methodology, then it would be accurate and helpful to not model it as a separate rate classification in Run 1. Chapter 11 will set out a metering credit methodology for use in such cases. This approach is expected to apply to most distributors in Run 1. This would not apply, for example, to any distributor that did detailed cost analysis prior to 2006 to support a distinct USL rate classification.

2.2.5 Load Displacement Generation Rate Classification for Run 1

The Technical Advisory Team reviewed North American materials which indicated there were two main ways to approach standby rate classification:

treatment as a full separate rate classification with associated load data and treatment as an adjustment to a main rate classification charge. Distributors have advised both approaches are effectively being used in Ontario at present. Both approaches will be modeled in the informational filings.

Those distributors with currently-approved standby rates will be required to model standby rates in Run 1 of the filing.

As the goal of the filing is to promote accurate cost allocation, in Run 1 the distributor must model the standby rate classification approach that effectively underlies the currently-approved standby rates. Distributors should consider the substance of the matter.

For greater guidance, if the rates for standby service in the 2006 rate order are equivalent to, or derived from, one of the standard rate classifications, then it is not a separate classification for cost allocation purposes in Run 1. Otherwise, it can be often safely assumed that the distributor has a separate rate classification for standby service for Run 1. If the distributor has more detailed knowledge of the original basis for its design for standby service, then it should also consider this information when determining how the current standby rate should best be modeled for cost allocation purposes.

In some cases a distributor could be providing standby service and charging standard rates for this service. In this case, these customers will be considered to be in the standard classification for Run 1.

A common threshold will be introduced for the definition of the new load displacement generation rate classification to be modeled in Run 2. For Run 1, distributors should use the definition that underlies their currently-approved standby rates.

2.3 Run 2 of the Filings

In Run 2 of the filing model, selected rate classification changes must be incorporated. Specifics are listed below.

The Board will consider implementation following the cost allocation review. The results of the Electricity Distribution Rate Design Review will be taken into account.

2.3.1 Test Year and Rate Classifications

For historic test year filers, the applicability of the classification changes will be assessed using 2004 data. For example, if a historic test year filer became a host distributor for an embedded distributor in 2005, it should not add an embedded distributor rate classification in Run 2 of its filing.

As part of its Filing Summary, a distributor may wish to identify for future reference any significant changes to its operations that would impact rate classification statistics (e.g., addition of a customer in 2005 or 2006 with a demand greater than 5,000 kW where the distributor does not currently have a Large User classification).

2.3.2 Elimination of Legacy “TOU” rates

The legacy distribution rates known as “Time of Use” must be eliminated in Run 2 of the filing.

This will also apply to legacy TOU rates for GS>50 kW customers. These customers should be placed within one of the following rate classification alternatives for Run 2.

> Alternative 1) If the customers fit within a discrete demand range (for example 1000 kW to 5,000 kW), then it should be renamed as a GS rate classification referencing the given demand range and remain as a separate rate classification in Run 2. All other GS>50 kW customers that fall within the identified demand range should also be included. Some distributors have and/or may have multiple discrete demand range classifications. In such cases, the Filing Summary should explain the treatment.
>
> Alternative 2) If the distributor can document that it has been using this rate classification to serve the same purpose as the traditional General Service Intermediate classification adopted by the former regulator, then it should be renamed as a General Service “Intermediate” Classification for Run 2 and remain as a separate rate classification. The Filing Summary must include an explanation and justification, including reference to the legacy test that a customer in the classification represents at least 10% of the utility’s load.
>
> Alternative 3) If Alternatives 1 or 2 do not apply, the distributor should roll these customers into the existing GS>50 kW rate classification for Run 2.

Once the distributor chooses the appropriate alternative, the same general cost allocation principles approved for use with other rate classifications should be applied to the replacement GS rate classification.

The merits of new distribution TOU rates were outside the scope of this project. However, where a distributor currently has such a rate, even on an interim basis, it should be included in its filing. The distributor must explain in its Filing Summary how it has modeled this situation.

2.3.4 New Large User Rate Classification

In some cases, a distributor may have a customer in a General Service classification that on a 12 month average has demand of 5,000 kWs or more. If this occurred in the test year underlying 2006 rates, then for the purposes of the cost allocation filing, a new Large User rate classification must be added in Run 2 of the filing.

The same cost allocation principles approved for use with other rate classifications should be applied to a new or current Large User rate classification.

2.3.5 Common Separate Rate Classification for Embedded Distributors

There are a number of host distributors that are providing a distribution service to embedded distributors.

In many cases, host distributors that provide service to embedded distributors have treated them as General Service customers. However, there are some cost causality factors that suggest establishing a separate classification should be explored. For example, embedded distributors may have a lower credit risk, and there is an expectation that the direct allocation process will be more applicable to these customers.

The Board wishes to explore the concept of a common embedded distributor classification for host distributors. Therefore a separate embedded distributor rate classification must be modeled in the Run 2 of the cost allocation filings by all distributors who served as host distributors in their test year.

Some stakeholders in the present consultations questioned the strength of the cost rationale for a separate embedded distributor rate classification. If the resulting unit costs are not sufficiently distinctive, then the merits of merging this rate classification with another suitable classification could be discussed further.

Some distributors on the Technical Advisory Team plan to use the optional Run 3 to model other alternative arrangements where the embedded distributor is included in a broader new rate classification. This is acceptable provided suitable load data is provided and the costs are allocated using the approved principles.

2.3.6 Common Separate Rate Classification for Unmetered Scattered Loads

To provide further relevant information to the Board, Run 2 will require all distributors (including those whose 2006 EDR orders expressly identify USL customers as part of the GS<50 kW classification) to model USL as a fully separate rate classification. The separate USL rate classification in Run 2 will include both photo-sensitive and non-photo sensitive loads, to promote simplicity in rate classification. Supporting load data will be required and details are set out in Chapter 3.

2.3.7 Rate Classification for Customers with Substantial Load Displacement Generation

In Run 2 of the filing, all distributors serving customers with significant load displacement generation will be required to model standby rates as a fully separate rate classification. This requirement will apply both to distributors with currently-approved standby rates, and to distributors with known load displacement customers (as of 2004, for historic test year filers) but without standby rates.

Stakeholders have raised questions about the appropriate materiality considerations for modeling a new rate classification. A threshold will be adopted for the purpose of Run 2. Customers with a standby service requirement of 500 kW or greater requiring standby service will be included in the new load displacement generation rate classification.

Run 2 will incorporate a single separate rate classification for customers with load displacement generation. This is intended to strengthen the reliability of the data underlying the separate rate classification.

If a distributor has concerns about the reliability of the load data gathered for modeling the separate standby rate classification, then these concerns should be identified in its Filing Summary. If no reasonable load data was available at all, the distributor must explain why, and should use a non-separate rate classification methodology for Run 2.

2.4 Optional Rate Classification Changes in Run 3

A distributor will be allowed to model the following items in an optional Run 3 filing:

- the deletion of a rate classification with supporting rationale

- the addition of a new rate classification beyond those modeled in Run 2, with supporting rationale and cost/load data
- density and seasonal classifications may not be added in Run 3
- polyphase rate classifications my not be deleted in Run 3
- use of 12 NCP, where supporting justification is provided based on the cost characteristics of the distributor's system
- use of default minimum system results from another density stratum, where the distributor can provide strong reasons to justify classification into another density stratum
- use of a distributor-specific minimum system study and PLCC calculation, with supporting explanation of details
- use of the alternative load data option when modeling a separate load displacement generation rate classification.

Where a Run 3 of the model is filed, the Filing Summary must include additional supporting explanation and documentation.

A distributor who does not currently have a density and/or seasonal based rate classifications will not be allowed to add such a rate classification in Run 3, as the merits of such additions were not within scope of the present consultations**.**

The project's scope also excludes consideration of polyphase rates. These are not common but may have underlying cost allocation support, and any distributor(s)with such an established rate will not be allowed to drop it in Run 3 of the model.

Run 3 should also be used where a distributor has been directed to model a specific item (e.g. Merchant Generation rates) by the Board.

If a distributor is interested in incorporating zonal rates in its optional Run 3, separate load and cost data must be produced.

Chapter 3

3. Load Data Directions

3.1 Introduction

The Chapter sets out further Board Directions on load data requirements for the cost allocation filings.

Stakeholder comments on the May 2006 Staff Load Data Proposal were reviewed and considered when these Directions were finalized. No further comments are required from stakeholders.

The Directions in Chapters 2 and 3 are intended to allow distributors and their load data service provider(s) to start finalizing individual-utility load profiles from this date forward.

All distributors are reminded of the importance of obtaining their load data on a timely basis. The co-operation and attention of all parties is appreciated to meet the planned filing schedule starting in the Fall of 2006. The proposed sequence in which distributors should give their local load data-related information to the HONI Load Data Team has been discussed at prior Workshops. All electricity distributors must obtain updated load data.

3.2 Load Data - General Requirements

All distributors are expected to provide reasonable supporting load data for each separate rate classification to be modeled in Run 1, 2 or 3 of the cost allocation filing.

Distributors proposing to add a new separate rate classification in the optional Run 3 of the model should carefully consider whether additional load data will be required.

The attached Appendix 3.1 summarizes the specific load data required for each rate classification to be modeled. When reviewing the summary, it should be noted:

- Appropriate load data will be required in Run 1 and Run 2 even where a distributor drops a rate classification in Run 3.

- Separate load data was not required to be collected for the GS<50 kW classification. For the cost allocation filings, the residual load shape arising from the total distributor load, after the loads of the other rate classifications have been removed, can be used.

- For classifications where interval meter data is available, for example Large Users, Intermediate Use, and Embedded Distributors, such interval meter data should be used.

- For Street Lighting and Sentinel Lighting, the distributor's Board-approved load profile must be used, along with the distributor's data as to installed load.

- Load data will not be required in Run 1 for those distributors whose current USL or standby charge will not be modeled as a separate rate classification. The load data requirements for when these customers are modeled as separate rate classifications are set out below. The Filing Summary should identify if the distributor has another group of customers for which load data is not required since its charge is set using a rate design adjustment.

- The Board has not prescribed load data requirements for Merchant Generation, or Hybrid Facilities, at this time. Any distributor who opts to model this as a new separate customer classification must consider load data requirements and provide an explanation in its Filing Summary. Additional explanation will be required if a load data methodology is used that differs from that used for the new load displacement generation rate classification in Run 2 or Run 3.

3.3 Load Data Requirements for Merging Distributors

For Run 1, distributors will generally be required to model all their currently-approved rate classifications and provide supporting load data.

Separate rules will apply to distributors that have merged and there is a significant prospect that separate rate classifications will not be maintained. If applicable, the effect can be to reduce the number of rate classifications that must be modeled, and correspondingly reduce the required load data.

The rules are as follows: If a distributor has Board approval for harmonizing rates prior to, or as part of its 2006 EDR application, or if it has a specific commitment for harmonization in its 2006 EDR application or as part of its MAADs approval by the time of its cost allocation filing, then separate load profiles are not required for each of the merging distributors.

In the above cases, separate zonal rates will not need to be included in Run 1 or Run 2 of the filing.

3.4 Information Required for Completion of Utility-specific Load Profiles

A large group of distributors earlier gathered province-wide load data for the residential and GS>50 kW rate classifications. This load data has been analysed by the Hydro One Load Data Team to develop generic load shapes for these rate classifications.

For the Residential rate classification, utility-specific load profiles will generally be constructed using the above generic load shapes, along with updated local appliance saturation information, distributor consumption data and other distributor information. A distributor must state in its Filing Summary whether:

- It undertook an updated residential appliance saturation survey.
- It borrowed residential appliance saturation survey results from a neighbouring distributor; and, if so, identify the other distributor and provide confirmation that a test was undertaken to confirm that the distributors were a good match for sharing results.
- It estimated residential appliance saturation, and, if so, the basis of such an estimation (e.g. kWh data).

For the GS>50kW rate classification, load profiles will be constructed using the above generic load shapes, along with industrial grouping data supplied by the distributor, distributor consumption data and other distributor information.

Most distributors have indicated they will be using the Hydro One Load Data Team to prepare their utility-specific load profiles. Distributors are requested to contact LoadResearch@HydroOne.com to obtain the most current version of the additional utility-specific information the Hydro One Load Data Team requires.

3.4.1 Filing Questions

Any distributor who is not using the Hydro One Load Data Team to prepare its utility-specific load profile must provide the name of its alternative service provider and their relevant qualifications. If such a distributor made use of the generic Residential and GS>50 kW load data information, then a summary must be provided of the methodology used to reliably create the utility-specific load profile.

3.5 Weather Normalization of Load Data

The Board instructed in its letter of March 7, 2006, that all distributors must weather normalize their utility-specific load profiles using the established Hydro One methodology.

A summary of the above methodology was provided at the June 15th Technical Workshop.[3]

3.5.1 Filing Question

Any distributor who is not using the Hydro One Load Data Team must confirm that the Hydro One methodology was used to weather normalize its load profile.

3. 6 Load Profile for Separate Load Displacement Generation Rate Classification

When a separate rate classification is modeled in Run 2 for customers with load displacement facilities and standby service requirements greater than 500 kW, the required load data for the classification must be based on the actual metered usage of such load displacement customer(s).

Only one separate standby rate classification will be modeled in Run 2. This must be undertaken by distributors with current-approved standby rates, and by all distributors with load displacement customers (with standby service requirements above 500 kW) but no current standby rates.

Distributors are expected to apply a reasonable effort to identify their load displacement customers with standby service requirements above 500 kW. The distributor's Filing Summary must identify any concerns or qualifications about the reliability of the load data collected. If the distributor believes it has not gathered minimally-acceptable load data, then it must explain in its Filing Summary what efforts were made and propose other treatment for Run 2 of its filing (for example, treating such standby rate customers as part of the appropriate main rate classification(s) and applying the Run 1 cost allocation methodology again).

Distributors may file a Run 3 of the filing in which the load data for the separate standby rate classification is modeled by an alternative method of adding the actual, or estimated if actual not available, metered generator load displacement

[3] The document is posted on the project web page. See http://www.oeb.gov.on.ca/html/en/industryrelations/ongoingprojects_costallocation_review.htm

to the metered usage. An equivalent additional amount must also be added to the total load of the distributor.

The basis and calculation of the above estimation must be explained in the distributor's Filing Summary. If applying this load data approach, it must be consistently applied to all standby customers in the classification and not just those for whom actual data is available. Therefore substantiated estimates will be required for the remainder.

3.6.1 Filing Questions

1) Please indicate the number of customers in the distributor's service territory that have load displacement generation equipment above 500 kW.

2) To the extent the distributor has the information available, categorize the above load displacement facilities by size and type of generation (wind, gas-fired, cogeneration etc.).

3.7 Load Profile for Separate Unmetered Scattered Load Class

Where USL[4] is to be treated as a separate rate classification in the model, the combined load profile must be calculated as follows:

Step 1) Non-Photo-sensitive Loads

Non-photo-sensitive loads must use a deemed load profile, constructed from the combined load shapes of the various types of non-photo-sensitive loads that make up the classification.

The total kWh consumption of each type of unmetered scattered load for purposes of development of the utility-specific load shape and demand allocators will be the kWh consumption estimate used by the distributor for billing purposes in the test year (and weather-normalized where applicable). For most types of non-photo-sensitive unmetered loads, a flat load profile will be used.

Step 2) CATV Battery Mats

For CATV power supplies (excluding any battery mat component), a flat load shape must be used for the present filings.

[4] Note photo-sensitive and non-photo-sensitive users are to be treated as part of the same single USL rate classification.

A separate load shape will be applied to the weather-normalized consumption of CATV power supply battery mats, where they are in service in the distributor’s test year.

Distributors that filed their 2006 rate applications on a forward test year basis and whose test year load includes CATV power supply battery mats, must obtain information on the number and installed capacity of battery mats (e.g. from the local cable company). If there is a concern about the information available, this should be noted in the Filing Summary.

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. The Filing Summary should discuss the matter and justify the extent of the adjustments implemented.

As no battery mats were in place in Ontario prior to 2005, the bulk of the distributors that based their 2006 rate applications on historic year (2004) data need will not need to make an adjustment for battery mats.

Step 3) Photo-sensitive Loads

The total kWh consumption of each type of unmetered scattered load for purposes of development of the utility-specific load shape and demand allocators will be the kWh consumption estimate used by the distributor for billing purposes in the test year (and weather-normalized where applicable). For most types of non-photo-sensitive unmetered loads, a flat load profile will be used.

For photo-sensitive loads, the distributor’s Board-approved load profile for street lighting must be used.

Step 4) Combining Results

The resulting load shapes under steps 1), 2) and 3) will be combined to create a single separate USL load profile.

3. 8 Confidentiality of Individual Customer Load Data

If there is only one customer in any separate rate classification, then its load profile must be hidden in the model filed. The resulting model outputs will remain public. The distributor will have to do this, as it may prove difficult to build this as an automatic feature in the standard filing model. The filing instructions will provide further guidance.

3.9 Filing Question

If there is a significant change in the relative load profiles for a historic test year filer (e.g. introduction of battery mats for USL loads, addition or loss of a major large user), a distributor should identify this in its Filing Summary for future reference.

Chapter 4

4. Test Year and Revenue

Recommendations on the test year and revenue to be used in the cost allocation filings are presented in this chapter.

4.1 Test Year

4.1.1 Background

Cost allocation studies are generally performed using data for a one year reference period or "test year".

For the purpose of the upcoming filings, the revenue requirement, as defined below, and the data underlying the approved 2006 distribution rates will be the basis of the cost allocation studies. Rules will be developed where a distributor does not have an approved 2006 revenue requirement.

4.1.2 Proposal – Distributors that used a historical test year in the EDR 2006 application

For distributors that used a historical test year in their 2006 EDR applications, the underlying 2004 trial balances will be the basis of the cost data to be filed for the cost allocation review, subject to the following adjustments:

i) the Board-approved tier 1 and tier 2 adjustments
ii) cost of capital and PILS as included in approved 2006 EDR rates
iii) any additional adjustments ordered by the Board in its final rate decisions.

The adjustment to distribution rates for smart meters ordered in the Board's Decision RP-2005-0020/EB-2005-0529 will be excluded, as the cost of smart meters has not been included in the cost data. No other adjustments will be allowed.

The account data underlying the trial balances for the 2006 rates should not include cost and revenues related to non-utility operations and to non-recurring regulatory accounts tracking deferrals and variances.

In some cases, a distributor will need to move dollars within the approved revenue requirement envelope from one account in the approved modified 2004 trial balance to another account to reflect a better cost allocation methodology.

The filing model has been designed to handle these accounting adjustments. By way of illustration, if meter reading costs were included in Account 5630 - Outside Services Employed, then these costs should be removed from this account and added to Account 5310 - Meter Reading Expense to ensure meter reading costs are allocated using the proper allocator (Account 5630 will be allocated using the O&M allocator, while meter reading expenses will be allocated based on a weighted meter reading cost allocator).

4.1.3 Proposal - Distributors that used a forward test year in the 2006 EDR applications

For distributors that had earlier filed using a forward test year (i.e. Hydro One Networks Inc., Hydro Ottawa Limited, and Toronto Hydro-Electric System Limited), the trial balance underlying the Board-approved 2006 rates should be used for the cost allocation filings. No additional adjustments should be made.

It is understood that the trial balance for some of these 2006 EDR applications did not include details of all the accounts included in the trial balance, but that the application was based on grouping of accounts. For the purpose of the cost allocation review filings, a distributor that used a forward test year in its approved 2006 rate order and did not provide a detailed trial balance in its 2006 rate application, will need to regroup the trial balance in accordance with the grouping process described in this report.

Similar to the historic test year filers, the costs and revenues associated with non-utility operations and with non-recurring regulatory accounts that track deferrals and variances should be excluded. In addition, the adjustment to distribution rates for smart meters ordered in the Board’s Decision RP-2005-0020/EB-2005-0529 will be excluded, as the cost of smart meters has not been included in the cost data. No other adjustments will be allowed.

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

In the case of any distributor that will not have approved 2006 rates at the time of its cost allocation filing, the distributor will still have filed a 2004 trial balance as part of its regulatory reporting requirements. The filed 2004 trial balance must be used by such a distributor as the main source of financial information for the cost allocation filing. This will be consistent with the data underlying the cost allocation filings of most other distributors.

Consistent with the approach used in the 2006 EDR process, the net fixed asset components in the 2004 trial balance that support the calculation of the rate base will be adjusted to reflect the average of the 2003 and 2004 values. If further direction is required on the averaging of net fixed assets, a distributor should refer to the 2006 Electricity Distribution Rate Handbook.

The 2004 trial balances will also be adjusted for the third tranche of Market Based Rate of Return (MBRR) and estimated PILs assumed in the 2005 rates. The costs and revenues associated with non-utility operations and non-recurring regulatory accounts should be removed.

Revenue will be determined by applying the distributor's current approved rates, excluding regulatory assets, to the billing determinants consistent with those used by a distributor that filed for 2006 rates. The billing determinant for number of customers by rate classification is the 2004 year end number of customers. The volumetric billing determinants will be the three-year average (2002-2004) of rate classification usage per customer (i.e. kWh per customer or kW per customer as applicable) applied to the number of customers by rate classification at year end 2004.

4.1.5 Proposal-Pro Forma Adjustments

Except where specifically required, pro forma adjustments to the revenue requirement and cost structure supporting the approved 2006 rates are not to be made in the filings.

If a distributor feels there has been a change in the operation of its utility that would significantly impact the approved revenue requirement and rates (for example, a large use customer connects to the distribution system) then the distributor may disclose this information in its Filing summary.

4.1.6 Filing Questions

It may be of assistance to the Board in future cost allocation discussions to better understand how a distributor attributes various costs to certain accounts. The following questions must be answered in these filings:

1. Services (Account 1855) is a significant account in the cost allocation study and it is important that the proper costs are recorded in this account. Please refer to the APH for the definition. As a distributor, if the accounting treatment is different, explain the accounting treatment of this account and estimate the impact (e.g. gross book value).

2. As a distributor, summarize the capitalization policies (such as treatment of overhead allocation and types of expenses capitalized instead of being charged to O&M). The distributor may wish to refer to its 2006 EDR application.

3. Outside Services Employed (Account 5630) may have costs relating to multiple functions. Disclose the functions that are charged to this account (e.g. meter reading, call centre, etc.).

4. Disclose in which account(s) Customer Information System Expenses are currently recorded and the activities it includes.

4.2 Revenues

4.2.1 Background

A key output of the cost allocation filing will be a comparison of revenues and costs by rate classification. To the extent possible, revenues and costs should be determined on the same basis. It is therefore important that the meaning of “revenue” be accurately defined.

4.2.2 Proposal – Definition of Revenue for Cost Allocation Filings

The service revenue requirement on sheet 5-1 of the distributor’s approved 2006 EDR model will be the basis of ensuring all the proper costs have been included in the cost allocation filing. It is important that all distributors obtain their approved 2006 EDR model.

The revenue per rate classification inherent in a distributor’s approved 2006 revenue requirement must be used as the revenue in the cost allocation revenue/cost ratio calculation. This means the revenue per rate classification for cost allocation purposes will be defined as the sum of:

i) The base revenue requirement allocated by rate classification shown in sheet 7-1 of the approved 2006 EDR.
ii) The revenue off-sets allocated to the rate classification as defined below.
iii) The allocation by rate classification of LV Wheeling Costs from sheet 7-2.
iv) The allocation by rate classification of CDM from sheet 7-3.

The regulatory asset adders and the adjustment for smart meters will not be included as revenue in the cost allocation filings.

Appendix 4.1 outlines each account included in the revenue off-sets and the allocation method to be used to allocate these accounts to each rate classification. In general, Accounts 4082, 4084, 4090, 4225 and 4235 form a large proportion of the total revenue off-sets.

4.3 Data Consistency

4.3.1 Background

Some stakeholders raised concerns that the energy and load data used in the 2006 EDR model are not consistent with the energy and load data being used in developing the load profiles (i.e. 2004) for the cost allocation filings. As a result, there is a perceived data mismatch issue. However, others have suggested using one set of data for developing the demand allocators purposes and another set of data for the determination of revenue is not inconsistent as they serve two different purposes.

In the 2006 EDR model, the kWhs and kWs used to determine the rate class revenue requirement are based on a three year average usage per customer applied to the 2004 year end customer numbers, implicitly normalizing on a three-year basis. Whereas the Board has stated that the kWhs and kWs used in developing load profiles for the cost allocation demand allocators will be weather normalized based on the average weather experienced over the past 31 years.

4.3.2 Proposal – Data Consistency

It is proposed that for information purposes only, there will be an 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.

Chapter 5

5. Direct Allocation

Recommendations on the direct allocation method to be used in the cost allocation filings are presented in this chapter.

5.1 Background

As an initial step in a cost allocation study, a distributor should identify significant distribution facilities that are dedicated exclusively to only one customer rate classification. The costs of such facilities should be directly allocated to the customer classification that it is exclusively dedicated to.

Direct allocations may not prove common in practice, as more than one customer classification may make some use of the facilities in question. Direct allocation would also not be suitable where the customer takes advantage of other parts of the system for additional reliability. To prepare and review proposed direct allocations will take time and effort and therefore is not encouraged for items that a distributor considers insignificant.

Consultations indicated direct allocation should be explored in the following circumstances:

- Transformer Station owned by the distributor that is 100% dedicated to customer(s) in the same classification.
- A feeder that is 100% dedicated to customer(s) in the same classification.
- Costs directly associated with load displacement assets.

The Technical Advisory Team suggested where there are any assets that are “predominantly”, i.e. at least 90%, but not exclusively dedicated to one customer classification, distributors should disclose this in their filings so ratepayers can carefully review their allocation in future cases.

Where the full requirements for direct allocation cannot be met, a distributor will still be required to consider whether the functionalization process applies to more accurately allocate costs of facilities to rate classifications based on how they use various parts of the distribution system.

5.2 Proposal – Direct Allocation Methodology

Direct allocation must be applied if, and only if, 100% of the use of a clearly identifiable and significant distribution facility can be tracked directly to a single rate classification.

If a distributor proposes to use direct allocation, it must support its filing with the following:

Supporting accounting records must exist and a summary must be filed for the specific facility in question. Supporting system design information, such as a one-line schematic drawing of the facility in question and the customers served, must also be provided.

When direct allocation is used, the distributor must 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, except where there are joint costs that apply to the customer classification. The Filing Summary should confirm the adjustment occurred.

The filing model will take into account direct allocation by allowing a distributor to define which cost in the trial balance that supports the 2006 approved rates should be directly allocated to a specific rate classification.

5.3 Filing Question

If a distributor can identify any significant assets that are at least 90%, but not exclusively, dedicated to one customer classification, then the distributor should disclose this information in its Filing Summary.

Chapter 6

6. Functionalization

Recommendations on the process to functionalize costs in the cost allocation filings are presented in this chapter.

6.1 Grouping

6.1.1 Background

The process of functionalization of costs is an important step in the cost allocation process, as it sets up the framework for the categorization and allocation steps. The functionalization step is the process that groups relatively homogeneous costs together into functions.

In some cases, further breakdown of the major accounts is required to properly reflect specific functions. Each function, therefore, will have corresponding accounts or sub-accounts. The Uniform System of Accounts ("USoA" or "accounts") for Ontario distributors will facilitate a common approach towards functionalization in the cost allocation filings.

For cost allocation purposes, the ultimate grouping of accounts will be done at the level of refinement necessary to implement the various proposed allocators. A lesser or greater level of disaggregation is not considered reasonable for the goals of the filings.

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

In the cost allocation filings, each adjusted 2004 account shown in column P of Sheet 2-4 of the approved 2006 EDR application will be grouped into one of the 33 groups for cost allocation purposes. In addition, for those accounts that will be further broken down into sub-accounts in the cost allocation model, the sub-accounts will also be grouped.

The final grouping in the cost allocation filings will be based on the approved common categorization and allocation methodologies. The recommended comprehensive mapping of each account or sub-account to a group is shown in Appendix 6.1

6.2 Breakout of Accounts into Sub-accounts

6.2.1 Introduction

The objective of breaking out accounts into sub-accounts is to reflect the costs ultimately associated with specific assets according to the role of these assets in the distribution system, i.e., their function. This in turn will affect the share of costs allocated to the various rate classifications.

For example, Account 1835 - Overhead Conductors and Devices contains the assets associated with providing the overhead conductor function. To more accurately undertake cost allocation, this account could be further divided into sub-accounts such as bulk, primary and secondary. Once each applicable account has been subdivided into sub-accounts that reflect specific functions, the costs can be allocated to rate classifications based on whether the given customer classification does or does not use the particular function.

For the purposes of the cost allocation filings, certain major accounts will be broken down into sub-accounts (see Chapter 7 for a list of major accounts and sub-accounts) to reflect the following functions:

- Bulk (if any)
- Primary
- Secondary
- >50kV assets deemed to be distribution.

Every distributor will have primary and secondary sub-accounts. But not all distributors will have bulk asset sub-accounts. A distributor should explain in the Filing Summary if it believes it does have bulk assets. The comments below are intended to assist a distributor in identifying any bulk assets.

An input sheet has been provided in the model to accept the sub-account information by function.

6.2.2 Bulk, Primary and Secondary Functions

6.2.2.1 Background

The bulk, primary and secondary sub-accounts relate to assets associated with performing bulk, primary and/or secondary functions within a distribution system. Discussions with stakeholders revealed that a “one size fits all” definition of bulk, such as a simple voltage-based test, would not be workable for all distributors. As a result, using the guidance below, a distributor should consider its individual circumstances to determine and explain in its filing whether each of the following individual assets include costs on a combined basis associated with the bulk, primary, and secondary functions.

1830	Poles, Towers and Fixtures
1835	Overhead Conductors and Devices
1840	Underground Conduit
1845	Underground Conductors and Devices

If there are amounts included in these accounts that perform bulk, primary, and/or secondary functions, then they need to be split into sub-accounts to reflect those different functions. Suggestions on how to implement this are provided below.

6.2.2.2 Proposal – Definition of Secondary

For this function, a voltage-based definition will be adopted: the secondary sub-accounts will cover all assets owned by the distributor operating at <750V, whether financed through contributed capital or rates.

6.2.2.3 Proposal – Definition of Primary

The primary sub-accounts will cover all assets that are not identified as bulk assets (if applicable) or as secondary assets.

6.2.2.4 Proposal – Definition of Bulk

A functional approach must be adopted towards identifying the assets that may serve a bulk delivery function in some distribution systems.

A distributor will be required to exercise its judgement and detailed knowledge of how its system functions to identify, and explain in its cost allocation filing, any assets that serve a bulk function. Various factors that are helpful for a distributor to consider are listed below.

A key test to determine if any bulk assets exist in a given distributor's system is to identify all facilities that were built to support the system peak of its distribution system. Distributors must distinguish between assets that were built to support the distribution system's peak (for example, feeders that supply substations) or the customer's peak. Assets built to support the distribution system's peak will be treated as bulk assets for the cost allocation filings. [5]

[5] Assets built to support the customer's peak are primary or secondary assets, and the above voltage-based test should be applied to identify secondary assets.

If and only if a distributor determines that it has bulk assets, then the assets used to deliver power to the Distribution Station(s) are also part of the bulk assets.

If a distributor has assets that are directly involved in the delivery of power to larger users (e.g. Large Users, GS Intermediate, or Embedded Distributors), then the distributor should carefully consider whether such assets serve a bulk function. For instance, a 44kV line with a large user connected to it would usually be a bulk asset. Embedded distributors are often connected to bulk assets. Large customers in a separate rate classification are often connected to bulk assets. But each distributor must exercise its own judgement as there are known exceptions to these generalizations. Distributors are reminded the key test is the function the asset serves, rather than the nature of the user *per se*.

Factors that suggest bulk assets do not exist include:

- the assets have a delivery voltage of <13kV
- circuits that are below three phase
- the distribution system is designed and operated in a fully-integrated manner (local judgement required; explanation required in filing).

It is possible that within a distributor, a portion of assets that operate at the same voltage level (normally over 13 kV) could be serving a bulk function and the remainder a primary function. In such cases, the assets should be subdivided depending on the function for which the assets are actually used. This would be a matter for a distributor to decide and justify based on detailed knowledge of its system characteristics.

6.2.2.5 Proposal – Supporting Distribution System Information

All distributors will be required to include in their filings a single line diagram or schematic of their distribution system.

Where a distributor believes it has assets that serve a bulk function, then the Filing Summary must explain the distributor's reasoning including, where relevant, reference to the above factors. An explanation must also be added to the required diagram or schematic indicating which specific assets have been identified as bulk and the customers by rate classification that are served from such bulk assets.

6.2.2.6 Proposal – Identifying Bulk, Primary and Secondary Costs

Once the bulk, primary and secondary assets have been identified based on the above guidance, it is necessary to break out the associated costs. As the accounting granularity is presently not available to do the above breakout, the distributor's staff should provide an estimate of the percentage of costs of the assets in each of the bulk, primary and secondary buckets. This percentage will be applied to the total cost in the asset account. For contributed capital refer to section 6.3.

The Filing Summary must explain the specific method the distributor used to break out its costs between bulk, primary and secondary assets. There are several potential methods, and a rationale and description of the method chosen must be included in the filing. Examples of methods include:

- A distributor could determine the unit cost of installing bulk, primary and secondary assets and then apply the kilometres of line for the bulk, primary and secondary assets to these unit costs. The result from each type of asset could be divided by the total for all assets and this percentage could be used to determine costs by asset type.

- In a similar manner, a distributor could determine the demand that is moved through each type of asset then apply the kilometres of line for the bulk, primary and secondary assets to these demand amounts. The result from each type of asset could be divided by the total for all assets and this percentage could be used to determine costs by asset type.

- A distributor could determine the kilometres of line for the bulk, primary and secondary assets and use the proportion of each to the total to determine the percentage of costs by asset type.

6.2.2.7 Proposal - Treatment of Depreciation and Accumulated Deprecation

In most cases, accumulated depreciation and depreciation expenses assigned to the various assets will be determined based on the break-out of assets to the various functions. If distributors have better information available in regard to the break out of accumulated depreciation and depreciation expenses, then this information must be used. Further guidance may be provided in the Board-issued filing instructions.

6.2.2.8 Proposal – Allocation of Bulk, Primary and Secondary Sub-accounts

The bulk, primary and secondary sub-accounts should be allocated to the corresponding rate classifications that use those assets. In particular:

- secondary costs will only be allocated to those rate classifications that use secondary assets
- primary costs will only be allocated to those rate classifications that use primary assets
- bulk costs will be allocated to those rate classifications that use bulk assets. For many distributors, bulk costs will be allocated to all classifications since the bulk assets deliver power to the primary and secondary assets.

If only a proportion of a classification uses a group of assets, then the dollars will be allocated based on the percentage of customers for customer-related costs and the percentage of load for demand-related costs.

6.2.2.9 Proposal - Customer Data for Bulk, Primary and Secondary

For each rate classification, a distributor will need to provide the number of customers that use the bulk (if any), primary and secondary assets. The customer numbers are <u>not</u> the number of customers that take power from the assets but the number of customers that are supplied through the assets directly and indirectly connected. This would include customers who are connected to a distribution system station that is connected to what is identified by the distributor as a bulk system. The examples in Appendix 6.2 have been developed to assist with the understanding of how the customer number is entered into the filing model to implement the separation of bulk, primary and secondary assets.

6.2.3 Adjusting Load Data re Bulk, Primary and Secondary

6.2.3.1 Background

The load data supplied by the distributor's load data service provider will have to be adjusted by the distributor to reflect its split into bulk (if any), primary and secondary. The break out will not be undertaken by the load data service provider. The break out must be undertaken by the distributor and entered into the model. A suggested methodology is set out below. Further guidance may be provided in the filing instructions.

6.2.3.2 Proposal – Adjusting Load Data re Bulk, Primary and Secondary

The load data supplied by the distributor's load data service provider will have to be adjusted by the distributor to reflect its split into bulk (if any), primary and secondary.

The coincident peak (CP) for bulk (BCP) is the CP for those customers for whom power is delivered through any bulk assets (includes customers fed from primary and secondary assets through the bulk assets).

The distribution system CP (DCP) supplied by the distributors load data service provider must be multiplied by the percentage of load that uses any bulk assets identified to obtain the BCP. This percentage will be based on an engineering estimate of the load fed through the bulk system. For most distributors that have bulk assets, the BCP will be 100% of the DCP. However, there could be a few distributors that have a split system.

In some cases, a distributor will have only part of a customer classification that is fed by bulk. In such a circumstance, the BCP for that classification should be calculated as illustrated below:

If the DCP is 500 MW for a particular class but only 50% of that class load comes through bulk assets, then the BCP = 50% X 500 MW = 250 MW.

Similarly, the NCP must be adjusted for primary and secondary asset use. The distributor's load data service provider will provide the system NCP for each classification (DNCP). The primary NCP (PNCP) for each classification (if applicable) will be calculated by multiplying the DNCP by the percentage of load in that classification that uses the primary assets.

In the same manner, the DNCP must be adjusted for those customer classifications that use the secondary assets.

6.2.4 >50kV Assets Deemed to be Distribution

6.2.4.1 Background

This sub-account relates to >50 kV assets deemed to be distribution. Typically, >50 kV asset is a Transformer Station (TS) that a distributor owns and operates. The costs of these >50kV assets that transform power from transmission voltage to the distributor supply voltage are included in the distributor's distribution rates. If Hydro One has required a distributor to make a capital contribution towards the construction of a Hydro One-owned TS, then this capital contribution is also a >50 kV asset included in the distributor's distribution rates.

6.2.4.2 Proposal – Treatment of >50kV Assets Deemed to be Distribution

In order to establish a consistent approach in understanding the pure distribution costs associated with each rate classification within a distributor, costs associated with the >50 kV assets will be identified and shown separately within the filings.

Generally, a distributor with >50kV assets would include these assets under Account 1815 Transformer Station Equipment. There is no need to split this account between >50kV assets and <50 kV assets as it is all >50kV assets. When a distributor does have >50kV assets, it must consider if the accounts shown below include costs that are associated with these assets as well as assets that are <50kV assets. If this is the case, these accounts will need be split into sub-accounts to reflect >50kV assets and the <50kV assets.

1805	Land
1806	Land Rights
1808	Buildings and Fixtures
1810	Leasehold Improvements
1825	Storage Battery Equipment

6.3 Capital Contribution

6.3.1 Introduction

Contributed Capital is a third-party contribution made towards the cost of constructing the distributor's distribution assets. Formerly, these contributions were included in rate base and were rolled into equity when distributors were required to transfer their assets to corporations.

Currently, capital contributions are accounted for as reductions to the cost of related capital assets and are amortized at rates corresponding to the useful lives of those related capital assets.

Contributed capital is determined by the distributor's Conditions of Service which outlines demarcation points, basic service, and the economic valuation model. The amount of contributed capital can vary greatly between distributors due to differences in load growth and contributed capital policies.

Distributors' accounting records may not support the level of detail required by the cost allocation filings. Furthermore, the treatment of contributed capital may vary between distributors. The objective below is to ensure the proper allocation of contributed capital between the asset classes and, eventually, customer classifications.

6.3.2 Background - Determination of Contributions

The level of contributions are determined by the net present value of the total costs of a project, offset by the revenue stream generated by the project's new customers.

In addition to extensions, upstream costs may have been included as costs of the project. These are growth-related capital costs that the distributor was required to expend in order to provide distribution services, but are not specifically attributable to the project. Examples of such growth related costs are substations, feeders, etc.

6.3.3 Background - Source of Capital Contributions

<u>Residential</u>

These contributions are generally for subdivisions and are determined by the outputs of the economic valuation model.

<u>General Service and Large Uses</u>

These installations are varied and can include transformation and other distribution plant.

<u>Road Widenings/Relocations</u>

Road widenings and improvements, related to capital programs, are undertaken by municipalities and regional authorities and can involve removal and relocation of distribution assets. Transformation costs would not typically be involved. Cost sharing is generally determined by a standard formula according to applicable legislation.

6.3.4 Proposal - Breaking out of Contributed Capital in Filings

The following outlines the preferred and default approaches to assign capital contribution to the various assets. The Filing Summary must identify which approach was used.

<u>Preferred Approach</u>

If the distributor can conduct a detailed analysis of contributed capital by either asset type or rate classification, then it must do so and provide its methodology and supporting information in its Filing Summary. The supporting analysis must explicitly identify capital contributions associated with bulk (if any), primary and secondary assets.

Default Approach

If the distributor is not able to use the preferred approach, then the percentage of the gross capital dollars of the assets on which contributed capital was collected must be used to allocate capital contribution to the assets.

A distributor will assign capital contributions to the various assets outside the model and enter the results of the assignment in the appropriate input sheet of the model.

Chapter 7

7. Categorization

Recommendations on the process to categorize costs in the cost allocation filings are presented in this chapter.

7.1 Introduction

The categorization step, also referred to as “classification”, consists of subdividing distribution assets and O& M expenses into the following cost-based groupings:

- demand-related, and/or
- customer-related.

Distribution assets and distribution operating and maintenance expenses are classified into demand and customer-related components based on their cost causality characteristics. Generic minimum system results will be incorporated into the filing model to divide joint costs into their customer and demand-related proportions.

Once categorized, the costs will be allocated to various rate classifications using specific allocators discussed in Chapters 8 to 10.

7.2 Proposal – Identification of Accounts

For the cost allocation filings, functionalized grouped costs will be ultimately classified into one of the four components:

- 100% demand related
- 100% customer related
- Joint related (both Customer and Demand-related)
- Pro-rata related to other costs.

Certain functionalized costs are classified entirely as being demand or customer-related (see Appendices 7.1 and 7.2 respectively for complete listings). For instance, metering, billing and collection are entirely categorized as customer-related, while distribution stations are entirely categorized as demand-related costs.

Certain distribution assets and related O&M expenses (see Appendix 7.3 for complete list) are categorized as jointly demand and customer-related. These are expenses that are incurred to provide service to a customer and are also required to meet customer demand. The customer component of such accounts is that portion of the expenses or the assets that vary with the number of customers. As an example, the number of poles and transformers on a distribution system varies, in part, with the number of customers served by the distributor. But these items also provide capacity on the distributor's system to meet demand.

With regard to pro-rata related accounts (see Appendix 7.4 for complete listing), in most cases operation and maintenance (O&M) accounts support a specific type of asset class. In such circumstances, the O&M accounts are generally categorized to demand and customer components consistent with the method used to categorize the assets that are supported by the O&M account. However, there are a few other cases where the O&M accounts support a group of assets and these accounts (e.g. Account 5005 - Operation Supervision and Engineering) are categorized on a pro-rata basis consistent with the method used to categorize the group of assets.

Items such as General Plant, General Administration, Miscellaneous Revenue, Payment in Lieu of Income Taxes ("PILs"), Return on Debt, and Return on Equity are generally not categorized but are allocated to each rate class using the allocation method outlined in Chapter 10 – Allocation of Other Costs.

7.3 Categorization of Joint Related Assets and Expenses into Demand and Customer Portions

7.3.1 Background

Three principal options for categorizing joint distribution assets and operating expenses were initially identified. Each approach has been approved by various regulators across North America. The minimum system approach is ultimately favoured for use in the filings as the common categorization method. This will be the sole categorization method used in the model for classifying joint costs. The basic customer method will also be used in the model but for the separate purpose of calculating lower end unit costs to assist with future rate design.

Option 1: Zero Intercept Method

The zero intercept method uses a statistical calculation to determine the amount of distribution costs that should be categorized as customer-related versus demand related. The zero intercept method seeks to identify that portion of plant related to a hypothetical no load or zero intercept situation. The technique is to relate installed cost to current carrying capacity or demand rating, create a curve for various sizes of the equipment involved, using regression techniques, and extend the curve to a no load intercept. The cost related to the zero intercept is the customer component. Due to the difficulty of use and interpretation of this statistically-based method, its use as the standard filing methodology for distributors is not recommended.

Option 2: Minimum System Method

The minimum system method assumes that a minimum-size distribution system can be built to serve the minimum load requirements of the customer. The minimum system method involves determining the minimum size pole, conductor, cable, transformer, and service that is currently installed by the distributor. Once determined for each primary plant account, the minimum size distribution system is classified as customer-related costs. The demand-related costs for each account are the difference between the total investment in the account and customer-related costs.

There are various approaches to define the minimum system. Moreover, judgment is required to address various implementation details with this methodology. The present report did not seek to recommend a common minimum system methodology for use by the Ontario electricity distribution sector. Instead, as explained below, the results of numerous past Ontario minimum system studies were examined and generic results recommended for incorporation into the filing model.

The minimum system is capable of carrying a small amount of demand, and, if unaddressed, this can contribute to the minimum system approach tending to generate a higher customer-related component than the zero-intercept approach.

To address this concern, a generic Peak Load Carrying Capability ("PLCC") adjustment will be made to the minimum system to bring it conceptually more in line with the zero-intercept method. A further discussion on the PLCC adjustment, which has been implemented in various past Ontario cost allocation studies, is provided below.

Past empirical work in Ontario led to the development of a "modified" minimum system approach in which the traditional demand component was further split into demand and energy. For simplicity, the present filings will assume that distribution assets and expenses are classified as either demand or customer-related. This is consistent with common North American practice.

Option 3: Basic Customer Method

This approach categorizes as customer-related costs only those capital and operating expenses that are directly associated with adding another customer. Examples of such costs are the capital and operating costs associated with meters and service drops.

There is a key difference between this method and the two discussed above. The zero intercept and minimum system methods both take into account some portion of the capital costs of the upstream distribution infrastructure, such as transformers and primary conductors. The basic customer method effectively takes a short-term view of cost causality and does not take into account the expenses incurred to build the upstream distribution system over time. This approach will not be recommended as the categorization method for cost allocation purposes.

One of the additional goals of the filing, however, is to produce unit cost information which will be helpful as a factor to consider in future review of fixed monthly service charges. The basic customer method, which is used in various U.S. jurisdictions, is considered useful to build into the filing model to create a lower end customer unit cost per month for each rate classification.

7.3.2 Proposal – Use of Minimum System Method and Basic Customer Method in Filings

For cost allocation purposes, the minimum system approach will be used as the common categorization method. Generic minimum system results will be recommended below for use in splitting joint costs into their respective customer and demand-related components. A standard PLCC adjustment, as described below, will also be made. The model will incorporate all of these elements.

The minimum system results will be used when the model calculates revenue to cost ratios for each rate classification. This will be the only categorization method employed for such purpose.

To assist with a future review of fixed monthly customer charges, the model will also produce unit costs per customer per month for each rate classification (see Chapter 12 for further details). The basic customer method will be used to establish the lower range of such unit costs. The customer costs resulting from the minimum system approach, as adjusted for PLCC, will be used to establish the upper range of the customer unit costs.

7.4 Generic Minimum System Approach

7.4.1 Introduction

The cost and time to undertake individual minimum system studies is significant. In addition, practitioners have varying judgements on key implementation details. Therefore, on the grounds of both practicality and consistency, generic minimum system results will be incorporated into the cost allocation filings.

All distributors will be grouped into high, medium or low density groupings, and separate generic minimum system results proposed for each grouping.

The generic minimum system results will be applied to the following joint-cost accounts:

- Line Transformers (account 1850)
- "Distribution" which includes poles and conductors and is defined as accounts 1830 -1845
- Related O&M accounts

7.4.2 Common Categorization Factors

7.4.2.1 Background – Past Ontario Studies

Past Ontario minimum system results were reviewed in detail. Some of the individual studies examined were undertaken as far back as the mid-1980's. Consultations indicated that the cost causality features of distribution system design have not varied dramatically over that period, so that the past Ontario minimum system results are considered to remain useful guides. They are summarized in Appendix 7.5

The medium and high density results reflect several minimum system studies. The proposed rural density results are based on a single, older Ontario Hydro study.

7.4.2.2 Proposal – Generic Minimum System Results in Filings

The following generic categorization percentages will be built into the filing model:

Low-density distributor:

line transformers	60% customers/40% demand
distribution	60% customers/40% demand

Medium-density distributor:

line transformers	40% customers/60% demand
distribution	40% customers/60% demand

High-density distributor:

line transformers	30% customers/70% demand
distribution	35% customers/65% demand.

7.4.2.3 Background - Stratification of Minimum System Results

Technical Advisory Team discussions took place on how to fairly and consistently define density for purposes of the cost allocation filings. The question is of practical importance as the density stratum, a distributor is assigned to, will affect the calculation of both the revenue to cost ratios and the customer unit cost upper range.

It was noted apparent inconsistencies are evident in how density is calculated by various distributors in their RRR filings. The new common definition of density recommended below is intended to promote greater consistency for the cost allocation filings.

The recommendations proposed below are unlikely to address all the potential concerns about appropriateness of the density measurement employed, and this factor should be added to the other modeling qualifications when interpreting the cost allocation filing results.

The Board may wish to consider refinements to the minimum system density definitions or stratum boundaries in the future.

7.4.2.4 Proposal – Density Thresholds and Measurements for Cost Allocation Filings

For purposes of applying the generic minimum system results only, 30 customers per kilometre will be the dividing line between a low and medium density distributor, and 60 customers per kilometre will be the dividing line between a medium and high density distributor.

For a distributor that used a historic test year in the 2006 EDR process, the above should be calculated using 2004 data. A distributor that based its 2006 rate filing on a forward test year should use the most up-to-date actual data available.

To promote greater consistency in the determination of the appropriate minimum system density-based stratum results to employ in a distributor's cost allocation filing, the following common density measurement methodology must be employed:

- To determine line length (i.e. not per circuit length since there can be multiple circuits per line), the distributor should consider the distance along the road the lines travel. As road distance will only be considered for line length, a double pole line, going down both sides of the road for 2 kilometres should be considered as 2 kilometres and not 4.

- The number of customers will not include any customers or connections that are unmetered (i.e. streetlights, sentinel lights and unmetered scattered loads). Note this is considered a helpful approach for the present test only, and a different definition of "customer" will be used elsewhere in the filings.

- In the case where an embedded distributor is paying for distribution services received from a host distributor, then the kilometres of line associated with embedded distribution service should be included in the density calculation of the embedded distributor.

If a distributor can document reasons to justify classification into another density stratum*,* an explanation along with supporting documentation should be provided in the Filing Summary and the distributor should file a Run 3 of the model using categorization results for the alternative density stratum proposed.

Regardless of whether a distributor has density rate classifications, a single minimum system result will apply to the whole distributor. The allocation process to deal with the different density classifications is outlined in Chapter 11.

7.4.3 Filing Questions

The Board is interested in understanding certain factors that could impact interpretation of the filing results or the need for future minimum system studies in certain situations. The following specific filing questions must be answered:

- Does the distribution system have a large downtown network system if the distributor is an urban utility? If yes, provide a brief description.

- Does the distributor have a significant underground distribution system? If yes, provide a brief description.

- If the distributor is a low density distributor for filing purposes, consider and advise if there is any factor(s) which may lead to the low density generic minimum system result not being reasonably reflective of the specific system's characteristics.

7.5 Peak Load Carrying Capability (PLCC) Adjustment

7.5.1 Background – PLCC Adjustment

The minimum distribution system will carry a small amount of demand. The actual amount of demand capability within the minimum system is a function of load density, minimum required clearances, minimum equipment standards, temperature, and other engineering considerations.

Under traditional cost allocation techniques, each customer/connection attracts an equal allocation of the minimum system, plus each classification is allocated demand costs based on the total classification's non-coincident peaks. As such, it has been argued that a classification's non-coincident demand allocator is too large, because a portion of these peak demand-related costs are being covered through the per customer/connection minimum system allocation.

The correction of the problem of over allocating or double-counting demand can be achieved by the application of a PLCC adjustment. This adjustment will determine how much demand for a rate classification can be met by the minimum system (number of customers/connections x PLCC for minimum system) and will credit this amount against the classification's non-coincident peak demands used for determining demand allocators. The adjusted classification's non-coincident peaks can then be used to allocate the distributor's demand-related costs, eliminating the double-counting. The number of customers/connections used for the PLCC should match the number of customers/connections used to allocate the customer component of the distributor's capital and O&M costs associated with poles, conductors and transformers.

Implementing a PLCC adjustment will be consistent with past Ontario cost allocation studies. The Technical Advisory Team reviewed past Canadian studies and found the results of the peak load carrying capability ranged from 0.2 kW to 1.0 kW /customer/connection. A PLCC adjustment of 0.4 kW /customer/connection is proposed as a reasonable figure for a generic adjustment.

The precise amount of a PLCC adjustment should match the definition of the minimum system adopted. As no single definition of an approved minimum system methodology has been recommended, no distributor-specific PLCC will be allowed unless a distributor first conducts it own minimum system study.

7.5.2 Proposal – PLCC Adjustment in Filings

The cost allocation filings must incorporate a common PLCC adjustment of 0.4 kW /customer/connection. The details will be built into the standard filing model.

Cost Allocation Adjustment

The PLCC in kW/customer/connection should be multiplied by each rate classification's number of customers/connections. For the purposes of the PLCC adjustment, the model will first consider if there are connections assigned to the rate classification. If this is not the case, the number of customers for the rate classification will be used. The product of 0.4 kW per customer/connection and the number of customers/connections will determine how much of the classification's demand is met by the minimum system. This demand capacity is then subtracted from each classification's non-coincident peak at primary and secondary assets. The adjusted non-coincident peaks at primary and secondary are then used to allocate a distributor's capital and O&M costs for poles, conductors and transformers. This adjusted demand cannot be lower than zero. No PLCC adjustment is appropriate for substations or bulk delivery facilities as there are no customer-related costs associated with these facilities.

The number of customers/connections associated with street lighting and unmetered scattered loads typically is based on the number of connections each group has on its distribution system. For street lighting and unmetered scattered loads, the number of connections for these customers will be used to determine the PLCC adjustment for these customers. It is expected that when these customers are in a separate rate classification, in some cases the PLCC adjustment will reduce the demand allocator to zero and thus no demand-related costs associated with the minimum system will be allocated to the rate classification. This is considered a reasonable outcome, as there are a number of cases where the connection will use less than 0.4 kW of load.

Customer Unit Cost Adjustment

Another output of the filing model is customer and demand unit costs by rate schedule. In order for these unit costs to reflect the results of the PLCC adjustment, an appropriate amount of customer-related costs must be moved into the demand-related costs before unit costs are calculated. This adjustment will be incorporated into the cost allocation model. Note the adjustment will not change the total cost allocated to the rate classification.

Distributor-specific PLCC Adjustment

If, and only if, a distributor files its own minimum system study, it must also file and explain its own PLCC adjustment.

7.5.3 Filing Question

If any distributor suspects the generic minimum system result and/or the generic PLCC adjustment has contributed to an anomalous filing result for a rate classification, an explanation should be included in the filing.

7.6 Distributor-Specific Minimum System Study

7.6.1 Background

One distributor undertook a new minimum system study at the time of unbundling and has asked whether these results may be used in the present filings. A similar issue would arise if a distributor completed a new minimum system study before its scheduled filing date. It should be cautioned, however, that the use of the approved generic minimum system results is encouraged to make the overall filing and review process more efficient. As the generic results are considered reasonably reliable, delays in the filing timelines based on non-mandatory further minimum system analyses are not acceptable.

7.6.2 Proposal – Use of Distributor-Specific Minimum System Study

While use of the generic minimum system results is encouraged for these filings, if a distributor does undertake a new minimum system study before its filing date, then the distributor may use the minimum study results in Run 3 of the cost allocation model to be filed.

If a distributor has an existing minimum system study completed after its distribution rates were unbundled, then it may use these results in Run 3 of the cost allocation model to be filed.

Any distributor that uses its own minimum system study must also provide the following in the Filing Summary:

- the date of its minimum system study
- a general description of the methodology used
- definition and size of the “minimum” system assumed in the study
- treatment of overhead and underground assets
- treatment of any large urban network systems
- has the distributor amalgamated with another distribution company since the study was completed? If so, has the study been updated to reflect the amalgamation?
- PLCC methodology followed and size of adjustment proposed.

The Filing Summary should include discussion of the materiality of the difference in results from use of the generic minimum system results versus the utility-specific study.

7.7 *Minimum System and Multi-unit Dwellings*

7.7.1 Background

The minimum system will currently allocate certain customer-related costs to individually metered customers in multi-unit complexes. However, the multi-unit complexes have sometimes been considered as single customers for minimum system cost allocation.

An adjustment will not be included in the present cost allocation filings since it is understood that it can be difficult for distributors to ensure the load data and the customer/connection information properly reflects multi-unit complexes.

7.7.2 Filing Questions

In order to assist future minimum system studies, the following questions must be answered in the filings to gather further information on the matter:

1. Estimate the number of individually metered residential customers who reside in multi-unit dwellings and the number of LDC connection points which supply the multi-unit complexes.
2. Estimate the number of individually metered general service customers that are located in multi-unit complexes and the number of LDC connection points which supply the multi-unit complexes.
3. Estimate the number of individually metered mixed use customers (i.e. residential and general service).

Chapter 8

8. Allocation of Demand-Related Costs

Recommendations on how to allocate demand-related costs in the cost allocation filings are presented in this Chapter.

8.1 Introduction

The accounts/sub-accounts that, following the categorization step, are allocated on demand in total or in part are listed in Appendices 8.1 and 8.2.

There are several technical factors to consider when properly allocating the demand-related component of distributor costs. Some distributor assets are designed to meet the individual customer's maximum demand, while other assets are built to meet the aggregate or diversified maximum demands of many customers. For example, when designing a substation, the engineer must ensure that there is sufficient capacity to meet the diversified peaks of all customers within a discrete geographic area. Alternatively, line transformers are usually sized based upon the individual customer's maximum demand.

Two approaches will be used when allocating demand-related costs:

- Coincident Peak ("CP") is the demand of any customer classification at the time of the distributor system peak.
- Non-Coincident Peak ("NCP") is the peak demand for a customer classification regardless of the time of occurrence.

Specific recommendations will be set out below as to the appropriate use of CP and NCP.

In past cost allocation studies, use was also made of Individual Class Non-Coincident Peak ("NCPI"), which is the sum of the peak demands of individual customers within a classification regardless of the time of occurrence.
In order to maintain ease of preparation and review, and as other methods are used to allocate some of the underlying costs, use of NCPI will not be recommended.

8.2 Non-Coincident Peak ("NCP") Method

8.2.1 Introduction

Some version of NCP is generally used in Canada to allocate most demand-related distribution costs. The reasons include:

- In most cases, distribution assets are sized to meet the maximum demand for a group of customers and not the system coincident peak of the distributor.
- NCP allocates a fairer share of demand-related costs to rate classifications that use the assets, but that may not be consuming much electricity at the time of the system coincident peak.
- Customers have better control over their NCP than over their CP.

8.2.2 NCP Options

8.2.3 Background

There are various specific forms of an NCP allocator, and stakeholder discussions focused on the merits of the following:

- 1 NCP - This option involves the use of highest monthly non-coincident demand peak.
- 4 NCP - This option involves the use of the average of the four highest monthly non-coincident demand peaks.
- 12 NCP - This option involves the use of the average of the 12 monthly non-coincident demand peaks.

1 NCP

1 NCP is the most common version of NCP used in other jurisdictions. It is a widely-held view amongst stakeholders that the demand capacity of a distribution system is generally designed to handle the greatest single peak whenever that may occur.

But local load data experts have cautioned in both the 2003 and 2006 consultations about the reliability of using 1 NCP as the main demand allocator for cost allocation, given the limited length of time for which updated load data was collected. Staff will recommend its use only when a stable and pronounced peak can be confirmed through the available load data.

4 NCP

A criterion accepted in prior Ontario cost allocation analyses is the importance of choosing a stable cost allocation methodology. 4 NCP will function as a more stable methodology than 1 NCP and has advantages in this regard. In addition, 4 NCP will not blunt cost causality as strongly as 12 NCP. As such, it will be the starting point of the recommended common demand allocator.

The intended policy objective is not to promote rate stability *per se* for any given rate classification, but rather to adopt a method for general use that will not lead to widely differing results if a single data point is used and proves not reliable. The issue is particularly important in Ontario as detailed load data research has recommenced after a number of years in abeyance. Also, the common filing requirements must take into account the wide variety of circumstances amongst distributors across the Province (for example, where distributors are summer and winter peaking, and use of 1 NCP may lead to unstable results over time under some circumstances).

More detailed analysis also suggests accurately tracking cost causality may be complex in some distribution systems and therefore 1 NCP should not be assumed to best reflect cost causality in all circumstances.

12 NCP

It is understood that 12 NCP was the demand allocator used when historic bundled rates were established under the former regulator. The technical case for use of 12 NCP was clearer in the past when generation costs were part of the bundled costs to be allocated. In an unbundled environment, use of 12 NCP in other jurisdictions is uncommon. On that basis, use of 12 NCP in either Run 1 or Run 2 of the filings is not recommended.

Stakeholders cautioned that customers that are more weather sensitive (residential, seasonal, farm classification customers in particular) could be adversely impacted if 1 NCP were preferred over 12 NCP. Staff suggest that the filings submitted should nevertheless be based on sound cost allocation principles.

For the purpose of determining the rate classification to which a customer is assigned, the Board has adopted the use of a customer's average 12 month NCPI. In this context, the merit of using 12 NCPI is to protect the customer from frequent rate reclassification. However, the main objective of the cost allocation studies is to reliably reflect cost causality in the costs allocated to the various rate classifications, and Staff believe this will best be achieved by using a combination of 1NCP and 4 NCP. Use of 12 NCPI (or 12 NCP) may unduly mute the cost causality for cost allocation purposes.

Use of 12 NCP in the Run 3 will not be allowed unless the distributor also provides supporting justification in the filing based on the cost characteristics of its distribution system. The use of 12 NCP is not expected to be common on such cost causality grounds.

8.2.4 Proposal - Tests for Use of NCP in Filings

NCP will be the demand allocator used when allocating assets identified by a distributor as primary or secondary.

4 NCP will be the starting point for the common demand allocator to be used in the present filings. 1 NCP will be used where the NCP test, outlined below, confirms the existence of a stable, “pronounced” peak. The test below has been designed so that a 20% peak will warrant use of 1 NCP rather than 4 NCP.

The following test, which will be incorporated in the cost allocation model, will be used to determine which version of NCP to use when allocating primary and secondary assets:

$$\text{NCP Test} = \frac{(A + B + C + D) / 4}{(A)}$$

(A) = sum of the highest monthly NCPs for all rate classifications
(B) = sum of the second highest monthly NCPs for all rate classifications
(C) = sum of the third highest monthly NCPs for all rate classifications
(D) = sum of the fourth highest monthly NCPs for all rate classifications.

A, B, C and D will be provided by the distributor’s load data service provider.

An NCP test result of 83 percent or greater indicates that the distributor must use a 4 NCP method for allocating demand costs. In the event of a test result lower than 83 percent, the 1 NCP method must be used.

The above methodology must be followed by all distributors in Run 1 and Run 2 of the filing. A distributor may use 12 NCP in its optional Run 3, provided that the distributor also provides supporting justification in its Filing Summary based on the cost characteristics of its distribution system. In such cases, the general discussion in their Filing Summary may highlight the impacts of the varying NCP allocators used in Runs1 and 2 versus Run 3.

8.3 Coincident Peak ("CP") Method

8.3.1 Background

CP is the generally preferred demand allocator for distribution assets that are designed to serve a distributor's system peak. In the cost allocation filings, assets identified as >50 kV and bulk by a distributor (see Chapter 6) must be allocated based on CP.

The FERC has developed various tests to determine the appropriate CP to be used when allocating transmission costs. This approach has been adapted for use in the current cost allocation filings. The test below has been designed so that a 20% peak will warrant use of 1 CP rather than 4 CP. The type of CP allocator used can impact the cost allocated to the rate classifications. For example, street lights may benefit from 12 CP as opposed to 1 CP under certain circumstances.

8.3.2 Proposal - Tests for Use of CP in Filings

For distribution assets and related O&M accounts that are solely designed to meet the distributor's system demand, CP will be used as the demand allocator. For the current filings, this will consist of all costs related to >50 kV and bulk assets (if any).

Classification CP will be further subdivided into transmission transformation CP and distribution CP. Transmission transformation CP represents the coincident peak of all customers that use the >50kV assets deemed to be distribution assets.

The choice of 1CP, 4CP or 12 CP will be determined by the application of the test described below. As with the NCP test, the CP test will be incorporated in the standard filing model.

CP Test #1

This test calculates the average of the twelve monthly system peaks as a percentage of the highest monthly system peak as follows:

> CP Test #1 = Average of 12 Monthly System Peaks ÷ Annual System Peak.

A CP Test #1 result of 83 percent or greater indicates that the distributor must use the 12 CP method for allocating demand costs that are to be allocated on a CP basis. If the test result is less than 83 percent, CP Test #2 must be conducted.

CP Test #2

This test calculates the average of the four highest monthly peaks as a percentage of the greatest monthly peak as follows:

> CP Test #2 = Average of the 4 highest Monthly System Peaks ÷ Annual System Peak.

A CP Test #2 result of 83 percent or greater indicates that the distributor must use the 4 CP method for allocating demand costs.

A CP Test #2 result of less than 83 percent indicates that the distributor must use the 1 CP method for allocating demand costs.

8.4 *Measurement of Peak for Demand Allocation*

8.4.1 Background

Using a one hour (i.e. clock hour) measurement of peak is the most common approach when determining the demand allocator for electricity sector cost allocation studies. A few jurisdictions (for example, Manitoba) use a longer period. It is considered that use of a one hour measurement period of peak, along with the use of above-mentioned 4 NCP/ 1 NCP test, will provide an appropriate balance of policy objectives.

8.4.2 Proposal – Measurement of Hourly Peak for NCP and CP

For cost allocation purposes, the definition of peak for NCP or CP will be the standard one hour (clock hour) measurement of the peak period.

8.5 Allocation of Benefits of Diversity

8.5.1 Background

When customers with differing consumption patterns are pooled into a customer classification, this results in the sharing of the benefits of the diversity of their consumption patterns. These benefits arise because the classification's peak will be lower than the sum of the individual customer peaks. This means that the demand allocation of costs to that classification will be lower than if the allocator was based on the sum of the individual customer peaks.

There are two possible approaches to sharing the benefits of diversity:

i) where diversity is shared within each separate rate classification (i.e. “class” or “subclass”)

ii) where the diversity is shared within a given class and the sub-classes that collectively form the main class share the benefits of that class diversity on a pro-rata basis.

It is understood that approach i) is more generally used for cost allocation purposes by electricity utilities in other jurisdictions. In addition, consultations indicated it was challenging to agree where to place each rate classification under approach ii). On the other hand, some stakeholders suggested that approach ii) is more consistent with certain aspects of past Ontario rate design practice. Reference was also made to the distinction between class and subclass raised during the 2006 EDR process. On balance, use of approach i) is considered preferable for the cost allocation filings because of greater simplicity and consistency with general North American cost allocation practices.

Whether unmetered scattered loads and standby rates are to be treated as fully separate rate classifications with their own load data profiles, or as rate design adjustments to the charges of an existing rate classification, will have implications for the overall sharing of the benefits of diversity.

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

Each “rate classification” (i.e. class or subclass) will be treated as independent and separate for cost allocation modeling and load data requirement purposes.

Diversity will be shared within each separate rate classification (e.g. GS<50 kW and GS>50 kW) and not between any rate classifications.

Charges that are based on rate design adjustments (such as many current USL and standby rates) will not be modeled as a full separate rate classification for cost allocation purposes, although the model will calculate relevant costs by other means. Diversity will be shared between those customers and the main classification with which they share demand costs.

The above recommendations are for present cost allocation purposes only, and are not intended to prejudice any future policy discussions on rate design issues that may be impacted by a full resolution of the class versus subclass distinction. Some stakeholders have argued, for instance, 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.

8.6 Line Losses

8.6.1 Background

There is presently an approved methodology for treating line losses, which makes some distinctions regarding the line losses to be assumed by each rate classification.

The tariff for a distributor generally has two Total Loss Factors (TLF), one for customers whose meter is on the secondary side of the line transformer, and one for customers metered on the primary side. Nearly all customers are "secondary metered". The TLF for secondary metered customers is 1% higher, reflecting the losses that are assumed to have occurred in the transformer. Distributors with Large Use customers have an additional pair of TLFs, imputing only the losses in the transformer station and the next step-down transformer. The terms "primary" and "secondary" are also used for the Large Use TLFs, again to recognize whether the customer is metered on the high side or low side of the local transformer.

A few distributors have additional TLFs in the approved tariff. The main example would be a host distributor with a TLF for the embedded distributor, where this is distinguished from the TLF for its Large Use customers. There may be other examples as well, arising from the particulars of the distributor's 2006 EDR application.

At present, the lower TLF applicable to Large Use customers provides some recognition of the fact that they do not use the lower voltage system, and they do not pay for the losses that occur in that part of the system.

Note the words "primary" and "secondary" are used in the tariff in a different way than they will be used in the present filings. While not specifically designed for cost allocation purposes, the approved TLF for secondary, primary and large use does provide some level of segregating line losses among differing uses.

Stakeholders discussed if further segregating line losses into bulk, primary, and secondary functions might allow line losses to be allocated in a more refined manner, and the costs and benefits of doing so. The view was that the benefits would be modest and a full analysis of the topic potentially complex. Therefore, the status quo is recommended for the present filings, but additional questions will be asked to gather further relevant information.

8.6.2 Proposal – Treatment of Line Losses in Filings

In the cost allocation filings, distributors will use the same loss factors as approved in their 2006 EDR applications when adjusting their metered load data to arrive at the demand allocators.

8.6.3 Filing Questions

To provide further general input to any future line losses discussions, the present filings will gather the following additional information:

1. What are the technical distribution system energy losses (% of energy purchased)?

2. Please provide an estimate of "non-technical" energy losses (e.g. theft of power, billing accruals, metering problems).

3. Please provide an estimate of the line losses broken out according to following major system components: > 50 kV, bulk, primary and secondary assets. Please use the same definitions as in the cost allocations filings.

Chapter 9

9. Allocation of Customer-Related Costs

Recommendations on how to allocate customer-related costs in the cost allocation filings are presented in this chapter.

9.1 Introduction

Customer-related costs are commonly allocated by using the number of customers by rate classification, or by using weighted customer allocation factors. The weightings of customer allocation factors are typically developed by taking into consideration, in addition to the number of customers, factors such as investment costs (for example, for metering and service drops), and the level of effort and complexities involved in providing service to the various customer groups.

The weightings of allocation factors generally vary by asset and type of O&M expense to better reflect their specific cost characteristics. For instance, the relative proportion of the cost allocated to a particular rate classification may vary depending on the type of asset or service (for example, metering equipment compared to service drops). In the case of meter reading, the weighted allocation factors would typically take into consideration the meter reading frequency per rate classification, as well as customer density.

9.2 Definition of Customer and Connection for Filings

The accounts/sub-accounts that are allocated based on the number of customers or connections are shown in Appendix 9.1.

For the purpose of the cost allocation filings, a “customer” is generally defined[6] by a meter point that measures energy consumed over a period of time.

For unmetered loads, the number of connections will be used to allocate some customer-related costs. For street lights, sentinel lights and unmetered scattered loads, the number of connections will be the actual number of devices.

[6] A specialized definition of “customers” will be used when determining the number of customers that use bulk, primary and secondary assets (see Appendix 6.2; Proposal - Customer Data for Bulk, Primary and Secondary).

9.3 Allocation of Customer-Related Costs

9.3.1 Billing Activities

9.3.1.1 Background

A common allocator used to allocate customer-related costs that are related to billing activities is the number of bills issued. The major accounts allocated on this basis are billing, collecting and associated supervision, and customer care costs. Within billing, this includes postage, stationary and handling expenses. Within collections, this includes payment processing expenses per bill payment remitted.

Since these costs are not recorded in separate accounts, they may be difficult to isolate. These costs may also be recorded differently across distributors. Creation of separate accounts which are recorded consistently could be considered for recording these costs. In the future as a more detailed understanding of these costs is obtained, this could lead to more refined cost allocation for costs such as CIS, call centre and key account expenses (for example, an activity based approach could be considered).

9.3.1.2 Proposal – Allocation of Billing Activities

The number of bills will be used to allocate costs associated with billing activities which include billing, collecting, and associated supervision and customer care costs. For the purposes of the cost allocation filings, billing activities will also include CIS, call centre and key account expenses.

A “bill” is defined as an invoice sent to a customer that includes the charges for distribution services. One way of calculating this number is by applying the billing frequency for one year by the test year customer numbers used in the 2006 EDR model.

In most cases, the charges for sentinel lights appear as one line on the standard bill of a Residential or General Service customer. In such instances, it is recommended that for cost allocation purposes, each sentinel light would represent 10% of a standard Residential or General Service bill. This adjustment will need to be made by the distributor to the “number of bills” for sentinel lights to be entered in the cost allocation filing model.

Some distributors may have better information to allocate costs associated with billing activities to each rate classification. In such cases, these distributors must use this better information in all runs of the cost allocation filing and provide an explanation and support of the alternative allocation methodology in the Filing Summary.

9.3.1.3 Filing Questions

The following questions must be answered:

1) Identify under what accounts expenses associated with the following activities are included: Call Centre, Customer Information System, Key Accounts and Payment Processing.

2) Also indicate the percentage of these costs embedded in the above accounts.

9.3.2 Meter Capital Costs

9.3.2.1 Background

The capital costs associated with metering vary according to the type of metering device installed. For Residential and General Service rate classifications, the most common type of metering device is the electromechanical induction meter. In contrast, large user consumers generally have interval meters. For cost allocation purposes, metering capital costs will include capital costs, depreciation, and related operating and maintenance expense.

It is appropriate to use a weighted number of meters to allocate the costs associated with meter capital between rate classifications. A weighted number of meters takes into account both the number of metering points and the capital costs of the applicable metering devices for each customer rate classification.

The Technical Advisory Team developed standard installed costs per meter. Information on installed costs per meter for common meter types was provided by some distributor members. Current costs were used and considered acceptable because only the relative ratios are being used. It is believed that the resultant relative costs of installed meters between rate classifications based on these standard meter costs is reasonably applicable to a wide range of distributors, even if the absolute dollar value of the cost of meters differs.

The Technical Advisory Team indicated that the separation of costs attributable to conventional and interval meters is not readily available because these costs have not been separately recorded by distributors.

9.3.2.2 Proposal – Allocation of Meter Capital Costs

Default installed meter capital costs will be provided for use when allocating meter capital costs. These are listed in Appendix 9.2

A distributor will enter the estimated number of installed meters of each type within each rate classification. The total installed metering cost per classification is calculated within the model by multiplying the number of installed meters entered by the default cost per meter.

An allocation percentage for each rate classification is calculated by dividing the total installed metering cost per classification by the total installed metering cost for all classifications. This percentage is applied to the costs associated with meter capital to allocate these meter costs to each rate classification.

Average weighted meter costs per rate classification and weighted factors per rate classification are calculated within the model and are reported as a separate output to assist in understanding the percentage allocation calculations.

Flexibility has been built into the model to enter, for all model runs, three additional meter types and installation costs. These must be used where a meter type exists for a distributor that is materially different in cost, defined as 10% or more different from the cost of the standard meter types provided. The model defaults must be used if actual costs differ by less than 10%.

Small distributors have advised that their unit costs of acquiring certain meters may be higher than those distributors that purchase in large quantities. If the difference is material, the distributor should enter distributor-specific information into the model to better reflect its conditions. When such distributor-specific information is used, an explanation and supporting detail must be included in the distributor's Filing Summary.

9.3.3 Meter Reading Costs

9.3.3.1 Background

At present, the meters for most Residential and General Service < 50 kW customers are read manually. The frequency of meter readings may vary by rate classification and by distributor. It is therefore appropriate to use an allocator that reflects a weighted number of meter readings to allocate the cost of these reads. In addition, the weighted number should take into consideration density and the meter reading frequency. For example, it is generally more expensive to read individual meters for customers that are farther apart than the meters for customers that are located in close proximity.

The majority of interval meters for the larger user customers are read electronically and do not require physical meter reading.

From a cost allocation perspective, rate classifications, and customer groups within a classification, that have interval meters should not be attributed any physical meter reading costs. However, some expenses such as telephone lines and data validation may be incurred. If so, they should be allocated to these customer groups.

The Technical Advisory Team developed standard weighted factors for meter reading costs. The resulting relative costs of meter reading between rate classifications based on these standard weighted factors is considered reasonably applicable to a wide range of distributors, even if the absolute dollar amount differs.

The Technical Advisory Team indicated that the separation of meter reading costs attributable to conventional and interval meters is not readily available because these costs have not been separately recorded by distributors.

9.3.3.2 Proposal – Allocation of Meter Reading Costs

Default "relationship factors" related to meter reading costs will be provided for use when allocating meter reading costs. Details are set out in Appendix 9.3

The cost to read a residential urban outside meter will be the base against which every other type of meter read will be compared. A relationship factor will be developed relative to that base for each type of meter read. A distributor will enter the estimated number of installed meters of each type within each rate classification into the model.

The relationship factors will be applied to the installed meters within a classification to determine a total "relative" cost of meter reading for the rate classification. An allocation percentage for each classification is calculated by dividing the total relative meter reading cost per classification by the total relative meter reading cost for all classifications. This percentage is applied to the costs associated with meter reading to allocate these costs to each rate classification.

Flexibility has been built into the model to allow entry of five additional meter types and meter reading cost factors. These 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. Where a distributor does have materially better information on its meter reading costs, then this information must be included in the cost allocation model for all runs and supporting documentation must be provided as part of the distributor's Filing Summary. The defaults must be used if actual costs differ by less than 10% from the former.

9.3.4 Conservation and Demand Management (“CDM”) Costs

9.3.4.1 Background

The general purpose of CDM costs is to reduce energy consumption and peak demand. Under this viewpoint, for cost allocation purposes it would be desirable to allocate these costs based on a combination of energy consumed and demand used.

It is understood that the same general approach has been followed in other jurisdictions. For purposes of the 2006 EDR process, however, it proved satisfactory to apportion CDM expenses among rate classifications based on their respective share of distribution revenue. More detailed cost allocation is the objective of the present filings.

9.3.4.2 Proposal – Allocation of CDM Costs

In the cost allocation filings, the capital and indirect or overhead components of CDM costs will be allocated across all rate classifications based on a combination of the energy consumed and the demand used by the rate classification. The allocation of CDM costs will reflect a 50% energy and a 50% demand allocator.

9.3.5 Bad Debt Expense

9.3.5.1 Background

Bad debt expense includes the amounts of uncollectible utility revenues. Many distributors monitor their bad debt write-offs at the rate classification level. The Accounting Procedures Handbook (Article 220) requires distributors to maintain records demonstrating uncollectible amounts by category, customer class, etc.

It was noted that extraordinary bad debts were excluded from 2006 revenue requirement, which in turn tended to “normalize” the level of bad debt included in the approved revenue requirement. As a result, a rate classification will not be impacted by an extraordinary bad debt. For cost allocation filing purposes, extraordinary bad debt will also be excluded from the data that supports the allocation factors used to allocate bad debt.
It is understood that the most common approach in other jurisdictions is that bad debt costs could be directly allocated to specific customer rate classifications based on their respective contribution to historical write-offs. Staff recommend adoption of this viewpoint. The underlying cost allocation principle is that the differing bad debt experience of each classification is the relevant cost consideration when allocating bad debt expenses.

There is no consensus on the issue, as some stakeholders believe it is fairer if customers share the responsibility for bad debts in proportion to their revenues. Staff considers the recommended position as more firmly grounded in sound cost allocation.

9.3.5.2 Proposal – Allocation of Bad Debt Expense

Bad debt expense must be directly allocated to specific customer rate classifications based on their respective contribution to historical write-offs.

For historical test year filers, an average of bad debt data by rate classification for 2002, 2003 and 2004 must be used to allocate bad debt[7]. For the future test year filers, the three year average of bad debt will include 2003, 2004 and 2005. For those rate classifications that are being considered as new rate classifications (i.e. Standby and USL) in the filings, bad debt will not be allocated to these classifications unless the historical data is available.

[7] Late payment revenue will also be allocated based on the same three year average of late payment charges by rate classification.

Chapter 10

10. Allocation of Other Costs

Recommendations on how to allocate “other” costs in the cost allocation filings are presented in this chapter. Generally these are costs that are neither customer nor demand-related.

10.1 Background

Some components of the revenue requirement cannot be directly allocated, or allocated to customer rate classifications by using the functionalization, categorization and allocation process described earlier.

Instead, other methods are commonly used to allocate these costs. They include:

- an allocation pro rata to the allocated O&M
- an allocation pro rata to the allocated rate base
- the use of labour ratios or headcount
- detailed analyses (e.g. based on usage).

Expenses and capital expenditures falling into this category include:

- general plant
- administrative and general expenses (A&G)
- working capital allowance
- PILs, other taxes, cost of debt, and return on equity.

10.2 General Plant

10.2.1 Background

General plant includes the capital cost and depreciation (if applicable) associated with buildings, leasehold improvements, land, land rights, general computer equipment, office furniture and transportation equipment. These are not directly related to distribution but are essential to the operation of a distributor.

Costs that are classified as General Plant are commonly allocated to customer classifications based on a composite of the distribution net fixed assets, excluding General Plant assets, which are allocated to the customer classification.

10.2.2 Proposal – Allocation of General Plant

A *pro rata* allocation of distribution plant to distribution rate base assets will be the standard methodology for allocating general plant.

Distributors that have detailed analysis on the allocation of general plant must use this better information in all runs of the cost allocation model filed and provide supporting explanation and documentation in the Filing Summary. For example, identifiable CIS costs could be segregated out and allocated to each rate classification in the same manner as billing and collecting costs.

10.3 Administrative and General Expenses (A&G)

10.3.1 Background

This category includes costs that support all aspects of the overall organization such as executive, management and general administration salaries and expenses, employee pensions and benefits, office supplies, franchise requirements and regulatory affairs.

The method recommended below is considered a reasonable allocation.

10.3.2 Proposal – Allocation of A & G

Except for property insurance and community safety program costs, a *pro rata* allocation of O&M with backing out of A&G will be the common methodology for allocating general expenses. For property insurance and community safety programs that serve to safeguard the distributor's assets, the rate base will be used as the allocator for these costs.

10.4 Working Capital Allowance ("WCA")

10.4.1 Background

The working capital allowance forms part of rate base and is the working capital deemed to be required by a distributor to support its operations. For 2006 rates, in most cases the WCA for electricity distributors is 15% of the sum of the cost of power (COP) and certain distribution expenses excluding depreciation. There is one distributor that does not use 15% but has another Board-approved percentage that is based on a specific lead-lag study.

10.4.2 Proposal – Allocation of WCA

The COP component will be allocated based on energy. The energy factors will exclude wholesale market participants since they transact directly with the IESO for commodity and wholesale market service requirements.

The OM&A component included in the WCA calculation will be incorporated in the cost allocation process as 15% of the allocated OM&A. If a distributor has a Board-approved working capital allowance different than 15%, then this percentage must be used for the WCA calculations.

10.5 PILs, Other Taxes, Cost of Debt, and Return on Equity

10.5.1 Background

These items are directly related to the value of the rate base.

10.5.2 Proposal – Allocation of PILs, Other Taxes, Cost of Debt, and Return on Equity

A *pro rata* allocation of rate base will be used to allocate PILs, Other Taxes, Cost of Debt, and Return on Equity.

Chapter 11

11. Cost Allocation and Unit Cost Calculations for Specialized Rate Classifications

Recommendations on cost allocation and unit cost calculations for the following specialized rate classifications are presented in this chapter.

- Embedded distributor
- Density
- Seasonal
- Unmetered scattered loads (USL)
- Standby.

11.1 Other Specialized Rate Classifications

A few other utility-specific rate classifications exist (such as small commercial rate or water sewage facility rate). The affected distributor should apply the recommended cost allocation principles and meet the load data requirements. Any special aspects should be noted and discussed in the distributor's Filing Summary.

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.

11.2 Embedded Distributor Classification

11.2.1 Background

Various approaches were used in the past to allocate costs to this rate classification. It is also understood that the rate structure has varied.
The present filings will introduce a common cost allocation methodology and customer unit cost calculation. [8] If any special situations arise for a host distributor serving several embedded distributors, these should be addressed and explained in the Filing Summary.

[8] The general comments are also considered applicable when allocating costs to larger GS customer classifications or Large Users. A two-part distribution rate will be modeled for all customers.

The methodology below will be applied in Run 1 by all distributors with a current separate rate for embedded distributors and where those rates are different than the approved rates of any other rate classification. The methodology must be applied in Run 2 by all distributors serving embedded distributors (in their 2006 EDR test year) to model a new embedded distributor rate classification. The Board will later decide upon the merits of implementing a common classification for embedded distributors.

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

The same general principles proposed elsewhere in this report must be applied when allocating costs to this rate classification.

For instance, the host distributor should consider if any assets can be directly assigned under the 100% use test.

Host distributors should pay special attention that accounts have been properly broken into sub-accounts to reflect the various functions (existence of bulk assets should be carefully reviewed; bulk assets likely, but do not always, exist in such circumstances). Distance[9] is considered one of the acceptable options when sub-accounts are created, but the merits of other options (see Chapter 6 for full discussion) should also be considered.

The same two-part customer unit cost calculation must be applied by all host distributors when modeling this rate classification. If a host distributor believes the unit costs do not warrant a separate rate classification for embedded distributors, this should be discussed further in its Filing Summary.

If the approved charge to an embedded distributor is represented as a separate rate classification in the 2006 rate order for the host distributor but the approved rates are the same rates as a main rate classification, then for Run 1 it will be assumed the embedded distributor is part of the main rate classification. In such a case, the host distributor shall ensure the customer and load data on the main rate classification includes the data of the embedded distributor.

If a distributor wishes to model an alternative to an embedded distributor classification, it can do so in its optional Run 3. The same general cost allocation and unit cost principles should be applied. Any deviations must be noted and justified in the Filing Summary.

[9] Distance must not be used as an allocator as this would be inconsistent with the general principles adopted in this report.

11.3 Density-Based Classifications

11.3.1 Background

It is recognized that distributors with lower density will have different minimum system drivers from distributors with higher density (see Chapter 7). In the case of distributors with density-based rate classifications, the cost allocation model applies the same density driver in the minimum system component to all such classifications.

However, the cost allocation model will need to recognize that the average density for some currently-approved rate classifications varies significantly. Under past Ontario rate classification definitions, “urban” customers have been defined based on an average customer density higher than 60 customers per km of line, while the “suburban” (i.e. rural) classification customers typically have an average density of 12 customers per km of line or lower and are generally located in more rural areas.[10]

The density of a rate classification is a direct cost driver, which means it takes more lines and poles to service customers with a density of 12 customers per km than it does to service customers with a density of 60 customers per km. However, it should not be assumed that the density relationship is linear. In other words, it may not take five times the lines and poles to service a group of customers with a density of 12 customers per km compared to a group of customers with a density of 60 customers per km.

Density classifications may be dropped in Run 3, but may not be added. Reasonable cost data must be provided in Run 1 and Run 2 for all currently-approved density classifications. The load data requirements must also be met. If a distributor plans to maintain density rates in the future, then background studies to support the different allocation of costs to the various density classifications should be undertaken.

11.3.2 Proposal – Cost Allocation Methodology for Density- Based Classifications

A distributor with density-based rate classifications is expected to be able to use the standard model in Run 1 and Run 2, but work must be undertaken to address some additional density-related inputs required.

[10] One distributor has three density based residential rate classifications.

The following common cost allocation methodology must be applied to all distributors with a density classification in their approved 2006 rates:

a) One categorization factor (i.e. generic minimum system result) must be used for the whole distributor.
b) The distributor must identify those costs that are influenced by density such as lines, poles and possibly line transformers. An explanation must be provided in the Filing Summary.
c) For meter reading costs, the standard cost allocation model already allows the distributor to allocate these cost to a rate classification based on density.
d) For the costs that have been identified in b), the distributor should weight the allocation factors used to allocate the cost to the various rate classifications by a density factor. The Filing Summary must include a specific explanation. A linear density-to-cost assumption is not acceptable without a supporting study. More detailed justification is expected for the density weighting factors if the classification is to be maintained.
e) Each distributor must use its own current density threshold(s).

11.3.3 Filing Question

If a distributor intends to maintain its density-based rates, it must provide the following additional information in its Filing Summary.

For each rate classification that is impacted by density, the distributor will need to provide a rationale for the density threshold used for that rate classification.

11.4 Seasonal Rate Classification

11.4.1 Background

The standard cost allocation principles will apply to any seasonal rate classification as no unique cost allocation issues were identified. There are few distributors with such separate rates currently in place.

Adding a new seasonal rate is outside the scope of project and will not be allowed in Run 3. Dropping a seasonal rate classification could be modeled in the Run 3; however, full supporting data must still be provided in Run 1 and Run 2.

A separate load data profile requirement has been established in the load data instructions for the seasonal classification and must be included in the filing.

Where density was one of the primary considerations in establishing the seasonal rate classification, the above cost allocation principles regarding density rates should also be considered.

The consultations identified potential rate impact issues in respect of the seasonal classifications if a shift were made to a 1 NCP test. The general comments in the distributor's Filing Summary could include any concerns about the results of applying the standard cost allocation methodologies to this classification.

11.4.2 Proposal – Cost Allocation Methodology for Seasonal Rate Classification[11]

Run 1 and Run 2 of the model must apply the recommended cost allocation and customer unit cost principles.

Distributors wishing to apply 12 NCP must file a Run 3 and provide a supporting explanation.

11.5 Unmetered Scattered Loads ("USL")

In the past, there had been variability in the treatment of unmetered scattered loads across the Province. The present filings are intended to lead to a common, cost-based methodology.

In Run 2 of the filing model, all distributors will be required to model USL as a fully separate rate classification.

The same approach must be applied in Run 1 by those few distributors whose 2006 approved USL charges function as a fully separate rate classification. This approach is not intended to apply to LDCs whose 2006 USL rate was set using the rate design compromise arrived at during the 2006 EDR consultations.

It is understood that it is more common in other jurisdictions to treat USL as a separate rate classification, as proposed under this option.

11.5.1 Cost Allocation Where Separate USL Rate Classification

The Technical Advisory Team examined this topic in detail. Set out below is the common methodology recommended for use by all distributors.

[11] The same cost allocation principles will apply to the Farm Rate classification.

11.5.2 Proposal – Cost Allocation Methodology

The cost allocation principles recommended elsewhere in the report should also be applied to this rate classification, subject to any special rules specifically provided for below.

Demand-Related Costs

The standard rules will be applied here. This separate rate classification, as with others, will require its own supporting load data as outlined in Chapter 3.

The standard PLCC adjustment (see Chapter 7) may reduce the demand allocator to zero but not negative.

Distribution and General Plant

Unmetered load customers will bear the full allocated costs of distribution facilities (and associated depreciation), with the exclusion of Load Management Controls – Customer Premises (Account 1970) and Meters (Account 1860).

A distributor that installs test meters on USL and has an ongoing verification program must allocate the corresponding meter costs to USL.

General plant will be allocated in proportion to the allocated distribution rate base.

Operation and Maintenance Expenses

Operation and maintenance expenses allocated to the USL classification will exclude the following accounts: customer premises (Accounts 5070, 5075), maintenance of meters (Account 5175), and meter expenses (Account 5065). Distributors that have installed verification meters on USL will allocate the corresponding meter related costs to USL.

Other applicable operation and maintenance expenses will be allocated in the same fashion as their respective distribution facilities.

Customer-Related Costs

Billing-related costs will be allocated based on the number of invoices sent to USL customers. However, distributors invoice USL customers differently. The different approaches include:

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

It is proposed that billing costs be allocated using the number of bills issued by a distributor for USL customers based on the invoicing approach used by the distributor. To the extent that some distributors may have incurred system costs to enable the consolidation of the bill for USL customers, such costs must be identified and allocated to this rate classification as it has benefited from the service.

Collection and bad debt expenses will be allocated to the unmetered scattered load rate classification in the same fashion as the other customer rate classifications if data is available.

USL customers must not be allocated costs related to meter reading expenses (Account 5310) since they are unmetered.

If known and identifiable, expenses such as tracking additions and deletions of connections or revising estimated consumption should be directly allocated.

Administrative and General (A&G) Expenses

All USL customers will be allocated their proportional share of A&G expenses.

Miscellaneous and Other Revenues

All USL customers will be allocated Miscellaneous and Other Revenues consistent with other classifications.

11.5.2.1 Filing Questions

The following information is to be included.

1. As a distributor, is there summary billing for USL customers?

2. Does the distributor do summary billing for other classifications other than USL? If yes, provide number of customers by classification and number of customer "sub accounts" that the summary bills include.

3. Provide the estimated cost of making summary bills available and the overall savings (savings on extra costs) realized by the distributor.

11.5.3 Cost Allocation Where USL Part of GS<50 kW with Credit

11.5.3.1 Background

The approach below is expected to apply to most distributors in Run 1, including all those whose 2006 USL charges were effectively based on the rate design compromise reached during the 2006 EDR process.[12]

For cost allocation purposes, it is considered more useful to model USL rates under these circumstances as follows: Demand costs will be treated as related to the GS<50 kW rate classification, while cost-justified adjustments will be made to reflect documented differing customer costs.

For purposes of the cost allocation filings, the process below will be used to determine an adjustment to standard rates reflecting the estimated reduction to rates that would occur when a customer is unmetered. The model will thus calculate a potential USL "metering credit".

11.5.3.2 USL Metering Credit Proposal

It is proposed that the following methodology be used to determine the metering credit for USL customers in Run 1. The first step is to identify the following items in the cost allocation model.

a) Depreciation on Account 1860 – Meter Assets
b) Meter expense – Account 5065
c) Customer Premises – Account 5070 and 5075
d) Meter Maintenance – Account 5175
e) Meter Reading – Account 5310
f) General plant allocated to meters

[12] This approach will not apply to those few distributors whose current USL charge functions as a fully separate rate classification (for example, where a separate USL rate classification is based on a prior cost allocation study).

g) Administration and general expenses allocated to meters
h) PILs and return on equity and debt that would be associated with a "mini" rate base that includes Account 1860 and general plant plus the working capital associated with Accounts 5065, 5070, 5075, 5175 and 5310 as well as the administration and general expenses allocated to meters.

In order to determine the unit cost to support the metering credit, the total costs associated with the above must be determined for the General Service < 50 kW classification and divided by the number of customers in this rate classification that have a meter.

Some stakeholders have suggested that an adjustment for billing costs should also be considered. However this step will not be included in the present filing requirements as the billing cost allocated to the standard class will reflect the billing characteristic of USL.

11.5.4 Unit Costs Where USL a Separate Classification and Future Rate Design Options

11.5.4.1 Background

Run 2 of the filings will provide the Board with information on costs for USL as a separate rate classification. Once costs have been allocated to this potential new rate classification, the question remains whether it is preferable to determine the unit costs on a per customer or per connection basis. Some costs are likely driven on a per connection basis, while others on a per customer basis.

The present filings will produce customer unit cost outputs for the Run 2 separate USL rate classification.

11.5.4.2 Proposal – Modeling Unit Costs Where USL a Separate Classification

The cost allocation filing model will calculate a standard two-part unit cost output for USL.

1. Customer-Related Unit Cost – Number of Connections

   The customer-related cost allocated to the USL classification will be divided by the number of connections to determine the customer-related unit cost.

2. Demand-Related Unit Cost – kWh

The demand-related cost allocated to the USL classification will be divided by the kWh associated with the USL classification to determine the demand-related unit cost.

Some parties have suggested that demand-related costs should be divided by the kW associated with the USL classification to determine the demand-related unit cost. However, this billing determinant is not readily available for a distributor. As a result, it will not be used in the calculation of the demand-related unit cost for USL customers.

11.6 Load Displacement Generation Rate Classification

11.6.1 Introduction

Standby rates refer to charges imposed by a distributor for distribution services provided to a customer with load displacement generation behind the customer's meter. The load displacement generation provides generation for self-service with no significant generation above the customer's load.

A common circumstance in regard to standby service is where the distributor is asked to provide backup electrical service to customers who have their own load displacement generation. Typically, these load displacement generators produce most of their own electricity and use the distributor's wires and obtain commodity supply to fill in the difference between their total electric demands and the energy produced with the load displacement generator. This standby rate service is typically used during the load displacement generator's routine maintenance of the turbine/generator and during force majeure situations.

The Board has examined standby charges in the generic decision RP-2005-0020/EB-2005-0529 (March 21st, 2006). The Board commented:

> "It is also evident that the new standby rates proposed in this proceeding by a number of distributors do not have a proper cost foundation due to lack of available data. The Board agrees that proper costs and benefits allocation should be employed in setting these rates. ….
>
> The Board also believes that a standard methodology across all utilities is preferable, but notes that a standard methodology does not necessarily mean identical rates.
>
> The starting point for the development of the standard methodology would be the proper allocation of costs to those that cause the cost, as well as quantification of the benefits."

The cost allocation filings will develop a common methodology to model the readily quantifiable distribution costs associated with standby rates, both as part of a standard rate classification and as a separate rate classification. Final evaluation of the merits of these two approaches will occur later.

The load data requirements when modeling standby rates as a separate rate classification are addressed in Chapter 3. Concerns have been expressed about the availability and reliability of load data for these customers. This part of the Report will focus on developing a common cost allocation approach for distribution costs associated with standby rates and the resulting unit costs.

Identification and quantification of benefits and costs arising from load displacement facilities on the other parts of overall electricity sector, such as the transmission system, will not be addressed in these filings. Some benefits from load displacement facilities may not accrue to the distributor.

Even with regard to the potential benefits on the distribution system arising from load displacement generation, members of the Technical Advisory Team have cautioned that full quantification of all potential benefits requires specialized studies that are unlikely to take place through these filings.

At present, a number of distributors have approved standby rates. In some cases, there is an additional approved administrative charge.

11.6.2 Threshold for Customers with Load Displacement Generation Rate Classification (Run 2)

11.6.2.1 Background

There have been discussions with stakeholders as to what might be the appropriate threshold at which a customer with load displacement facilities would be defined as a standby service customer for capturing in Run 2 of the cost allocation modeling.

As a practical matter, some stakeholders suggested that a threshold could be consistent with the net-metering threshold of 500 kW.

11.6.2.2 Proposal – Rate Classification Threshold

For the purposes of modeling costs to be allocated to standby service in Run 2 filing model, a customer will not be considered to be receiving a standby service unless the standby service requirements are greater than 500 kW. If the standby service is lower than that threshold, the customer should be treated as a standard customer in the classification of service it receives.

Calculation of total load for classification

A load associated with a customer receiving standby service will be the full load of the customer, which includes the load when the load displacement generator is running and the incremental load with the generator is not running. Therefore the section below will deal will the costs allocated to the full load of the customer and not just the load displacement component.

11.6.3 Cost Allocation Methodology Where Existing Load Displacement Customers are part of a Main Rate Classification (Run 1)

11.6.3.1 Background

From a distribution system perspective, standby service includes a commitment by the distributor to have sufficient conductor and transformation capacity available to meet the load displacement generator's total load requirements even when the load displacement generator is out of service.

Under this view, a useful preliminary step in determining standby rates could be use of the new cost-based rate information of other full service customers of similar size. This information will be readily available from filing the model and will be used in Step 1 below.

Standby service could lead to other savings or costs that should be taken into account before finalizing a standby rate. These should be taken into account during the cost allocation filings (see Step 2 and 3). Initial stakeholder comments were that it would be difficult to quantify some of these items. Nevertheless, the present filings provide an opportunity to start discussing and documenting distribution system savings and costs. The steps below will address this.

This methodology below should be followed in Run 1 for those distributors with current standby rates, where the form and substance suggest a separate rate classification does not underlie the approved rate. See Chapter 2 for details. It should also be used in Run 2 by any distributors with known load displacement customers but lacking minimally acceptable load data to calculate demand costs for a separate standby rate classification (an explanation should be provided in the filing).

It has been suggested by some stakeholders that Run 1, which assumes the customers with standby service are in a main rate classification, will provide more reliable results for future consideration by the Board. Stakeholders are concerned that in Run 2, the number of customers with standby service assigned to a new rate classification could be small. Any irregularity with one or more of these customers usage in the test year could lead to results which are not stable and predictive. Such concerns could be noted in the Filing Summary.

11.6.3.2 Proposal – Methodology for Calculating Initial Unit Costs for Standby Service as Part of a Main Rate Classification

Step 1) Initial Customer Unit Costs to be Calculated by Model

The cost allocation model will calculate a range of customer unit costs ($/customer/month) and a demand unit cost ($/kW/month) for all rate classifications. It is proposed that these same unit costs will be used as the first step in calculating new standby rates when the standby service is provided as a service under the umbrella of a main rate classification.

For instance, assume the lower and upper range of customer unit costs for a distributor's General Service > 50 kW classification are $200/month and $250/month respectively and the demand unit cost is $5/kW/month. For a customer with a load displacement generator whose load requirements from the distribution system would place them on the General Service > 50 kW rate, the filing model will generate preliminary standby service unit costs of $200/month to $250/month range for the customer component and $5/kW/month for the demand component.

Step 2) Mandatory Adjustments to be Modeled

Further adjustments to the above preliminary unit costs must be considered by a distributor. Specifically, the following potential adjustments must be considered for incorporation in the filing model:

- Within the 2006 approved rates, some distributors already include a special administration charge for standby customers to cover off the extra ongoing costs. The costs associated with this administration charge should be directly allocated to the classification that has the standby service customers. Please refer to Chapter 5 for the direct allocation methodology. In addition, the revenue from any special administration charges will be recognized in the revenue for this rate classification.

- Adjustments may be necessary to the allocation factors where special metering capital costs are included. Please refer to Chapter 9 in regard to the treatment of metering costs.

- Capital contributions may have been collected from customers with standby service and this should be reflected in the allocation of capital contribution.

Step 3) Further Adjustments to be Modeled

Further adjustments to the initial unit costs must be considered by distributors. Distributors must consider the list provided in Appendix 11.1 of additional potential distribution system savings and costs arising from the installation of load displacement facilities and determine whether any such costs have been recognized or assumed in the trial balance that supports the 2006 approved rates. If a distributor has knowledge of significant costs and benefits, then they must be directly allocated to the rate classification with the standby service.

If any other significant additional distribution system costs or benefits can be identified and quantified at the time of filing, outside of those items assumed in the approved trial balance, then this information should be included in the model submitted along with an explanation in the Filing Summary.

11.6.4 Cost Allocation Methodology Where Standby Rates are a Separate Rate Classification (Run 2)

11.6.4.1 Background

For Run 2 of the model, a single approach will be applied above the 500 kw threshold for all distributors with approved standby rates for load displacement customers: namely, the standby charges should be modeled as a separate rate classification, with full supporting data provided.

Use of this methodology assumes that the distributor was able to gather some relevant load data for modeling the separate rate classification approach.
The load data requirements for standby rates as a separate classification are set out in Chapter 3. Some distributors have advised suitable load data may not be available. The first cost allocation methodology should be used in both model runs in such cases, and a supporting explanation provided in the Filing Summary.

The methodology below will also be applied in Run 1 for those distributors where the underlying substance of their approved 2006 standby rates suggests a separate rate classification is appropriate for cost allocation modeling purposes.

11.6.4.2 Proposal – Cost Allocation Methodology Where Standby Rates Modeled as Separate Rate Classification

The same general cost allocation principles approved for use with other rate classifications must be applied to this classification (for example, the recommended distinction between bulk, primary and secondary distribution costs will likely be applicable to standby customers).

As discussed in Chapter 3, the default load data alternative must be used when modeling a separate standby rate classification in Run 2 (or Run 1). Distributors will have the option to use the load data alternative discussed in Chapter 3 for Run 3, but must fully document any estimates use.

The potential adjustments outlined in Steps 2 and 3 above also apply to that separate standby rate classification to be modeled and filed.

11.6.4.3 Proposal – Number of New Rate Classifications

To better reflect cost causality, it was originally thought that separate standby rate classifications will be required, where relevant, for GS>50, Intermediate and Large User customers. Questions have been raised about the reliability of the underlying load data. From a load data reliability perspective, it would be better to have more customers in the classification (i.e., have only one standby classification). Therefore the filing model will have a single standby classification in Run 2.

11.6.5 Filing Question

For a distributor that has approved interim standby rates, the following additional question must be answered as part of its cost allocation filing:

Where the distributor cannot presently quantify any additional cost and/or benefits under Step 3 of the above methodology, then the distributor must outline the elements that could be included in any future study designed to document the distribution costs and benefits from load displacement facilities.

11.6.6 Benefits of Diversity

11.6.6.1 Background

This issue has received considerable attention in other jurisdictions and therefore it is important to explicitly address. For example, it is understood FERC rules provide standby service rates “shall not be based upon assumption (unless supported by factual data) that forced outages or other reductions in electric output by all qualifying facilities on an electric utility’s system will occur simultaneously, or during the system peak, or both”.

The Technical Advisory Team cautioned it should not be assumed that there will be diversity benefits in all circumstances. The benefits of diversity are expected to grow as the number of load displacement facilities increases. The sharing of the benefits of diversity will likely differ under each of the two cost allocation methods proposed for standby service customers.

11.6.6.2 Proposal – Where Standby Rates Not Separate Classification

In most cases, Run 1 will have the customers with load displacement in a standard rate classification and the diversity of the total standard rate classification will be reflected in the unit costs. This means the combined diversity benefit associated with customers using standby service as well as all other customers in the classification will be reflected in the classification's unit costs.

11.6.6.3 Proposal – Where Standby Rates Separate Class

In Run 2, the customers with load displacement will be assigned to a separate rate classification and only the diversity benefit associated with the customers using standby service will be reflected in the classification's unit costs.

11.6.7 Standby Rate Design Options

Policy issues associated with rate design for distribution charges will be addressed separately in the Distribution Rate Design Review consultations planned for later in 2006.

The present model will produce a two part standby charge for all rate classifications, including standby charges.
This cost allocation review will provide:

- common cost allocation methodologies for distribution costs
- initial unit cost outputs from the cost allocation model, with some adjustments modeled
- comments in the distributor's Filing Summary

11.6.8 Merchant Generation

11.6.8.1 Background

A merchant generator is defined to be a generator that provides a significant amount of its generation into the distribution system but also provides the generation required to support the electricity needs of the merchant generation station. When the merchant generator is shut down, the distribution system will most likely need to support the load requirement of the merchant generation station and to provide whatever power is required to black start the merchant generator. This report will not address in-depth the issues surrounding distribution rates for merchant generation.

11.6.8.2 Proposal - Optional Modeling

Appropriate unit costs for merchant generation in place in the 2006 EDR test year can be modeled by an interested distributor in the Run 3 of the model. This will be required for a specific distributor under a prior Board decision.

In the above cases, the distributor's Filing Summary should discuss the general approach used (e.g. whether a fully separate rate classification was established), document supporting accounting and load data used, and explicitly identify if any cost allocation rules were utilized which differ from those contained in the present report.

11.6.9 Hybrid Facilities

There is also the situation where a generator is providing load displacement generation but also has significant generation above the customer's load. In this case the generator is performing a "hybrid" role of load displacement and merchant generation. As in the case of merchant generation, the report will not further address the issues surrounding distribution rates for hybrid facilities. However, appropriate unit costs for these facilities in place in the 2006 test year could be modeled by an interested distributor in the optional Run 3 of the model. In such cases, the distributor's Filing Summary should discuss the general approach used, document supporting accounting and load data used, and explicitly identify if any cost allocation rules were utilized which differs from those contained in the present report.

11.7 Specialized Situations

This Report sets out general cost allocation principles that are intended to cover the great majority of the situations to be faced by a typical distributor.

However, there may be specialized situations for which the Report does not provide guidance. For instance, there may be a distributor that includes generation assets in its rate base, but this is expected to be rare and no allocation rules have been recommended.

Where a distributor discovers a situation not covered by the principles herein, it should endeavour to follow sound cost allocation practice and provide an explanation in its Filing Summary.

Chapter 12

12. Unit Cost Outputs

In addition to producing information relevant to the rate recovery of costs between rate classifications, the cost allocation filings will gather customer unit cost information to assist with future discussions on the following rate design areas:

a) Review of the range of monthly customer service charges
b) Review of alternatives to the current transformer ownership allowance.

Recommendations on how the filing model will provide unit cost information in regard to the above areas are presented in this chapter. Filing questions regarding Wholesale Market Participants are also discussed below.

12.1 Monthly Service Charges

12.1.1 Introduction

The OEB's letter of June 24, 2005 advised that "the cost allocation filings will also contain updated information that is helpful to assess the cost basis of current monthly service charges". The filings will achieve this by calculating reasonable lower and upper end customer unit costs per month. The calculation will be applied to all currently approved rate classifications (Run1), as well as the select new rate classifications to be modeled in Run 2 or Run 3.

The present project will focus on identifying distribution system cost drivers, but a variety of rate design factors, including non-cost considerations, are commonly taken into account when setting the actual rates. The cost allocation review will assume continuation of a two-part distribution rate structure, but the underlying data collected will be of relevance to stakeholders interested in a one-part distribution rate structure.

12.1.2 Lower End Customer Unit Cost Calculation

12.1.2.1 Background

Three versions of the Basic Customer Method were reviewed for use to calculate the lower end of the customer unit costs. The most widely used method (Option 2) is recommended.

Option 1: Strict Avoided Cost

With a “strict avoided cost” approach, only meter related costs, billing and collection costs would be included. No administration and general overhead would be applied, which was considered to be a shortcoming of this approach.

Option 2: Directly Related Customer Costs

In this approach, additional costs viewed as directly related to the customer would be included, namely operations performed at the customers premises. An example would be a disconnect and a reconnect for safety reasons. Revenue from related operations such as Service Transaction Request revenue and Late Payment charges would be credited back to the cost centres. The calculation also includes an allocation of administration and general overhead. It is understood this approach towards the basic customer cost calculation is the most commonly used elsewhere.

Option 3: Basic Connection

In this option, the basic customer cost would include the basic connection costs as defined in the Distribution System Code in addition to the customer related costs identified in Option 2.

It is considered that using Option 2 will result in the most helpful range of results. Setting the floor at the higher level that would result from Option 3 would result in a very narrow range of reasonableness for customer unit costs, while the results from Option 1 would be unreasonably low as it did not include costs related to administration and general overhead.

12.1.2.2 Proposal – Calculation of Lower and Upper End Customer Unit Costs in Filings

Directly related customer costs (Option 2) will be used to determine a reasonable lower end unit cost per customer per month for each rate classification. Appendix 12.1 lists the specific costs to be included in the calculation. The filing model will incorporate the calculation.

The reasonable upper end unit cost per customer per month will be determined by the customer-related costs allocated using the generic minimum system results and the generic PLCC adjustment outlined in Chapter 7. The filing model will produce such outputs for each rate classification.

Smart Meter Adder

The above lower and upper end customer unit costs will both be adjusted to include the smart meter adder, to be consistent with the monthly fixed charges approved in the 2006 rate orders. A distributor will enter the smart meter adder into the cost allocation model by rate classification. A distributor will find the smart meter adder in the calculation of the approved monthly service charge outlined in sheet 8-5 of its approved 2006 EDR model.

12.2 Substation and Secondary Transformation Ownership Unit Costs

12.2.1 Background

Currently, a distributor provides a transformer allowance to those customers that own their transformation facilities. With a few exceptions, the present level of transformer ownership allowance is $0.60 per kW. The amount of the allowance has not been generically reviewed in recent years. The filings will use a new common methodology, and distributors will enter their own local cost data. To refine the calculation, a two part transformer allowance will be modeled (substation and secondary transformation). Information will be gathered on two other cost pools (primary and secondary conductors and poles) for future use.

It is understood that the present allowance is intended to reflect the costs to a distributor of providing step down transformation facilities to the customer's utilization voltage level. Since it is assumed that the distributor provides electricity at utilization voltage, the cost of this transformation is captured in and recovered through the distribution rates. Therefore, when a customer provides the step down transformation from primary to secondary, it should receive a credit of these costs already included in the distribution rates.

As a result of separating the distribution system into bulk, primary and secondary functions, as outlined in Chapter 6, it has become apparent that a customer may own other primary and secondary assets and could be paying for these additional facilities in their standard rates. For example, a General Service > 50 kW customer who is taking power from the primary assets would be paying for distributor-owned secondary transformation, poles and conductors in its standard rates but would not be using these facilities. The same would be the case where a customer is taking power from the bulk assets and their standard rates include primary and secondary costs.

It is understood that an allowance for ownership of bulk assets is not an issue since a customer that owns bulk assets would most likely not be connected to the distribution system.

Some would suggest that when a customer is taking power from primary assets it should not be charged for any costs associated with secondary assets that are recovered through the standard distribution rates. In a similar fashion, a customer taking power from bulk assets should not be charged any costs associated with secondary or primary assets that are recovered through the standard distribution rates.

Others would suggest customers who own their transformation facilities have historically received a credit for this ownership and this should continue. However, to provide an additional credit beyond transformation ownership allowance would not be consistent with being part of standard rate classification that shares the costs and benefits of being in the classification.

The present cost allocation process will collect the relevant information. This approach is followed below and full information will be collected on four underlying cost pools. However, to maintain a straight-forward filing, the present filing model will calculate new unit costs for substation and secondary transformation.

During consultations, questions were asked about the likely amount of a new transformation allowance compared to the volumetric distribution charge.

12.2.2 Proposal – Updated Cost Pools and Unit Cost Information

The filing model will collect the following cost pools by rate classification.

a) Substation transformation
b) Secondary transformation
c) Primary conductors/poles
d) Secondary conductors/poles.

For the purpose of determining updated unit costs, the starting point will be the standard unit costs that include all costs associated with transformation. The new transformation ownership allowance calculation will adjust, based on cost causality considerations, the standard unit costs for those customers that own their own assets.

The filing model will calculate new unit costs for both substation transformation and secondary transformation.

12.2.2.1 Proposal – Substation Transformation Ownership Allowance Unit Cost Output

The following costs will be included in the new substation transformation ownership allowance unit cost calculation to be produced by the filing model.

a) Depreciation on account 1820 - Distribution Station Equipment - Normally Primary below 50kV
b) Depreciation on account 1825 -Storage Battery Equipment
c) Operation expense on distribution stations – Accounts 5016 and 5017
d) Maintenance expense on distribution stations – Accounts 5114
e) General plant allocated to distribution station assets
f) Administration and general expenses allocated to distribution station assets
g) PILs and return on equity and debt that would be associated with a “mini” rate base that includes account 1820, 1825 and associated general plant plus the working capital associated with accounts 5016, 5017 and 5114; as well as the administration and general expenses allocated to the distribution station assets

In order to determine the unit cost underlying the substation transformation ownership allowance to be modeled, the total costs associated with the above will be determined by rate classification and divided by the appropriate kWs, kVa and/or kWhs (if applicable) for those customers that use distributor-owned substation transformation assets. The unit cost underlying the substation transformation ownership allowance will be calculated for all rate classifications that have substation transformation costs allocated to the rate classification.

12.2.2.2 Proposal – Secondary Transformation Ownership Allowance Unit Cost Output

The following costs will be included in the new secondary transformation ownership allowance unit cost calculation produced by the filing model.

a) Depreciation on account 1850 - Line Transformers.
b) Operation expense on overhead distribution transformers – Account 5035
c) Operation expense on underground distribution transformers – Account 5055
d) Maintenance expense on line transformers - Account 5160
e) General plant allocated to distribution transformer assets
f) Administration and general expenses allocated to distribution transformer assets

g) PILs and return on equity and debt that would be associated with a "mini" rate base that includes 1850 and associated general plant plus the working capital associated with accounts 5035, 5055 and 5160 as well as the administration and general expenses allocated to the distribution transformer assets.

In order to determine the unit cost underlying the secondary transformation ownership allowance to be modeled, the total costs associated with the above will be determined by rate classification and divided by the appropriate kWs, kVa and/or kWhs (if applicable) for those customers that use distributor-owned secondary transformation assets. The unit cost underlying the secondary transformation ownership allowance will be calculated for all rate classifications that have secondary transformation costs allocated to the rate classification including any classification(s) that bill volumetric distribution charges on a kWh basis such as the Residential classification.

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

Appendix 12.2 will list the primary and secondary conductors and poles cost pools to be generated by the filing model for future reference.

12.3 Filing Questions - Customers that are Wholesale Market Participants

These questions relate to customers who are connected to the distribution system but have chosen to be wholesale market participants (and that are not a generator). The information is expected to be of assistance if a credit for these customers is discussed sometime in the future**.**

a) Provide the number of customers, annual kWhs, and kWs (if applicable) by rate classification for those customers that are wholesale market participants. If a) is applicable, please answer b) and c).

b) Are there any other additional costs of providing service to customers, who are wholesale market participants, over and above the cost associated with a comparable customer who is not a wholesale market participant? If yes, identify the additional cost items and estimate the incremental cost amount.

c) Are there any costs that are avoided in providing service to customers who are wholesale market participants? If yes, identify the avoided cost items and estimate the value.

Appendices

Appendix 1.1

Technical Advisory Team Members: Phases 1, 2 or 3	**Name**
Alliance of LDCs	Jim Richardson
Alliance of LDCs – Newmarket	Dave Weir
AMPCO	Ken Snelson
AMPCO	Wayne Clark
Bob Mason and Associates	Bob Mason
Canadian Cable Telecommunications Association	Paula Zarnett
Canadian Niagara Power Inc.	Douglas Bradbury
Chatham - Kent Hydro Inc.	Jim Hogan
ECMI Coalition	Roger White
Enersource Hydro Mississauga Inc.	Ralph Amar
Enersource Hydro Mississauga Inc.	Kathi Litt
Horizon Utilities Corporation	Dan Gapic
Hydro One Brampton Networks Inc.	Scott Miller
Hydro One Networks Inc.	Mike Roger
Hydro One Networks Inc. (load data issues)	Stanley But
Hydro One Networks Inc. (modeling guest)	Steven Low
Innisfil Hydro Distribution Systems Limited	Laurie Ann Cooledge
Kitchener-Wilmot Hydro Inc	Margaret Nanninga
Lakeland Power Distribution Ltd.	Dave Proctor
London Hydro Inc.	Ian McKenzie
London Property Management Association & Energy Probe	Randy Aiken
Milton Hydro Distribution Inc.	Don Thorne
Hydro Ottawa Limited	Jane Scott
Power Workers' Union	Judy Kwik
PowerStream Inc	Bruce Bacon (Phases 1 & 2)
School Energy Coalition	Darryl Seal
Thunder Bay Hydro Electricity Distribution Inc.	Cynthia Domjancic
Toronto Hydro Electric System Limited	Tim Turner
Toronto Hydro Electric System Limited	Anthony Lam
Veridian Connections Inc.	Laurie Stickwood
Vulnerable Energy Consumers Coalition	Bill Harper
Waterloo North Hydro Inc.	Chris Amos
Whitby Hydro Electric Corporation	Ramona Abi-Rashed

Appendix 1.2 - Draft Cost Allocation Filing Sequence

Cost Allocation Filing Tranche 1: November 30, 2006 (26 LDCs)

- Toronto Hydro-Electric System Limited
- Enersource Hydro Mississauga Inc.
- Hydro One Brampton Networks Inc.
- Oshawa PUC Networks Inc.
- Chatham Kent Hydro Inc.
- North Bay Hydro Distribution Ltd.
- Kingston Electricity Distribution Limited
- Newmarket Hydro Ltd.
- Milton Hydro Distribution Inc.
- Innisfil Hydro Distribution Systems Limited
- COLLUS Power Corp.
- Orillia Power Distribution Corporation
- E.L.K. Energy Inc.
- Wasaga Distribution Inc.
- Lakeland Power Distribution Ltd
- Orangeville Hydro Limited
- Lakefront Utilities Inc.
- Tillsonburg Hydro Inc.
- Niagara-On-The-Lake Hydro Inc.
- Tay Hydro Electric Distribution Company Inc.
- Middlesex Power Distribution Corporation
- Hearst Power Distribution Company Limited
- West Perth Power Inc.
- Atikokan Hydro Inc.
- Hydro 2000 Inc.
- Grand Valley Energy Inc.

Cost Allocation Filing Tranche 2: January 15, 2007 (21 LDCs)

- Hydro One Networks Inc.
- Hydro Ottawa Limited
- PowerStream Inc.
- Horizon Utilities Corporation
- ENWIN Powerlines Ltd.
- Barrie Hydro Distribution Inc.
- Burlington Hydro Inc.
- Thunder Bay Hydro Electricity Distribution Inc.
- Greater Sudbury Hydro Inc.
- Brantford Power Inc.
- Bluewater Power Distribution Corporation
- PUC Distribution Inc.
- Whitby Hydro Electric Corporation
- Canadian Niagara Power Inc.
- Halton Hills Hydro Inc.
- St. Thomas Energy Inc.
- Woodstock Hydro Services Inc.
- Kenora Hydro Electricity Corporation Ltd.
- Northern Ontario Wires Inc.
- West Coast Huron Energy Inc.
- Chapleau Public Utilities Corporation

Cost Allocation Filing Tranche 3: February 28, 2007 (20 LDCs)

- London Hydro Inc.
- Veridian Connections Inc.
- Kitchener-Wilmot Hydro Inc.
- Oakville Hydro Electricity Distribution Inc.
- Waterloo North Hydro Inc.
- Cambridge and North Dumfries Hydro Inc.
- Guelph Hydro Electric Systems Inc.
- Niagara Falls Hydro Inc.
- Peterborough Distribution Incorporated
- Essex Powerlines Corporation
- Welland Hydro-Electric System Corp.
- Haldimand County Hydro Inc.
- Festival Hydro Inc.
- Norfolk Power Distribution Inc.
- Peninsula West Utilities Limited
- Erie Thames Powerlines Corporation
- Grimsby Power Incorporated
- Brant County Power Inc.
- Midland Power Utility Corporation
- Parry Sound Power Corporation

Cost Allocation Filing Tranche 4: March 31, 2007 (20 LDCs)

- Westario Power Inc.
- Ottawa River Power Corporation
- Great Lakes Power Limited
- Centre Wellington Hydro Ltd.
- Fort Frances Power Corporation
- Renfrew Hydro Inc.
- Hydro Hawkesbury Inc.
- Rideau St. Lawrence Distribution Inc.
- Clinton Power Corporation
- Wellington North Power Inc.
- Espanola Regional Hydro Distribution Corporation
- Sioux Lookout Hydro Inc.
- Cooperative Hydro Embrun Inc.
- Dutton Hydro Limited
- Terrace Bay Superior Wires Inc.
- Fort Albany Power Corporation
- Kashechewan Power Corporation
- Attawapiskat Power Corporation
- Hydro One Remotes Communities Inc.
- Newbury Power Inc.

Appendix 3.1

Run 1: Rate Classifications and Summary of Load Data Requirements

Rate Classification - Residential	Data Requirements
1. **Residential Class** – accounts for individually metered residential sites taking electricity at ≤ 750 volts (also includes HONI urban class).	Generic load data/(LDC appliance survey if available)/LDC consumption data.
1a. **Residential Urban** – Residential accounts for areas with 15 or more customers per km.	Generic load data/(LDC appliance survey if available)/LDC consumption data.
1b. **Residential Suburban** – Residential accounts for areas with less than 15 customers per km.	Generic load data/ LDC appliance survey/LDC consumption data.
1c. **Residential Suburban Seasonal** – Residential suburban accounts that do not occupy premises at least 8 months out of the year, etc.	Generic load data/LDC appliance survey/LDC consumption data.
1d. **HONI Residential High Density**	Generic load data/appliance survey/consumption data.
1e. **HONI Residential Normal Density**	Generic load data/appliance survey/consumption data.
1f. **HONI Residential Seasonal High Density**	Generic load data/appliance survey/consumption data.
1g. **HONI Residential Seasonal Normal Density**	Generic load data/appliance survey/consumption data.
1h. **HONI Farm Rate Single-Phase**	Generic load data/appliance survey/consumption data.
1i. **Residential Interval Meter**	Interval Meter

Run 1: Rate Classifications and Load Data Requirements

Rate Classification – General Service ≤ 50 kW	**Data Requirements**
2. **General Service less than 50 kW** – non-residential accounts taking service at 750 volts or less with monthly average peak demand ≤ 50 kW.	Residual load shape
2a. **Special Small Commercial User** – non-residential account with forecast peak ≤ 50 kW.	Use residual profile for GS ≤ 50 KW for metered customers and profile for USL for unmetered customers.

Rate Classification – General Service > 50 kW	**Data Requirements**
3. **General Service greater than 50 kW** - non-residential accounts with monthly average peak demand > 50 kW.	Generic load data/LDC industrial grouping data/LDC consumption data.
3a. **GS >50 kW – TOU** non-residential accounts with monthly average peak demand > 50 kW with a TOU meter.	Interval data or if no interval data available use generic load data /LDC industrial grouping data/ LDC consumption data.
3b. **GS >50 kW Interval Metered –** GS >50 with interval metering.	Interval meter data
3c. **Water Sewage Treatment Plant Rate**	If Interval Meter data not available use industry grouping data profile with some adjustments for specific load.
3d. **HONI Farm Rate Three-Phase**	Generic load data consumption data.

Run 1: Rate Classifications and Load Data Requirements

Rate Classification – GS Intermediate Use	**Data Requirements**
4. **General Service Intermediate User or Discrete Demand Range** - Customer load within discrete demand range (e.g. 3000 kW - 5000 kW).	Interval meter data Utility to provide industry grouping breakouts to create load profiles.
4a. **HONI Industrial Commercial General Service Urban Density** - Energy metered customers charged on kWh basis, demand metered customers charged on kW basis.	Use interval meter data if available, otherwise use industry grouping breakouts.
4b. HONI **Industrial Commercial General Service Single Phase G1** - not located in urban zone - Energy metered customers charged on kWh basis, demand metered customers charged on kW basis.	Use Interval meter data if available, otherwise use industry grouping breakouts.
4c **HONI Industrial Commercial General Service Three Phase G3** – not located in urban zone - Energy metered customers charged on kWh basis, demand metered customers charged on kW basis.	Use interval meter data if available, otherwise use industry grouping breakouts.
4d. **HONI Industrial Commercial Sub-Transmission T**- not located in urban zone - Energy metered customers charged on kWh basis, demand metered customers charged on kW basis.	Use interval meter data if available, otherwise use industry grouping breakouts.

Run 1: Rate Classifications and Load Data Requirements

Rate Classification – Large User	Data Requirements
5. **Large User** - accounts with monthly average peak demand greater than 5000 kW.	Interval Meter data
5a. **Special 3TS Rate** - served from a dedicated transformer station.	Interval Meter data
5b. **Special Ford Annex Rate** – served from a dedicated transformer station.	Interval Meter data
5c. **Special Large Customer Rate** – An LDC has a large use rate with one customer.	Interval Meter data
5d. **HONI acquired utilities' Large User Rates**	Interval Meter data
5e. **HONI Direct Customers** - accounts with monthly average peak demand greater than 5000 kW treated as HONI LV distribution customers.	Interval Meter data

Run 1: Rate Classifications and Load Data Requirements

Rate Classification – Other	Data Requirements
6. **Street Lights**	Use distributor's OEB approved load profile.
6a. **Street Lights TOU**	It is assumed there is an approved load profile.
7. **Sentinel Lights**	Use distributor's OEB approved street light load profile.
8. **Unmetered Scattered Loads –** A distributor whose 2006 USL rate was set using the rate design compromise arrived at during the 2006 EDR consultations, must include USL in the General Service <50 kW classification. USL to include photosensitive and non-photosensitive USL loads. Future test year filers must make adjustment for treatment of heating mats.	Generally, use load profile of General Service < 50 kW classification (with USL metering credit tbd).
9. **Load Displacement Generation** – Load displacement customers that displace greater than 500 kWs of load. Usually to be included in appropriate main rate classification in Run 1.	For most distributors, no separate load data required as not separate rate classification in substance.
10. **Embedded Distributor –** host distributor transfers power to an embedded distributor. Generally to be modeled as separate rate classification in Run 1 where there is a separate charge in current rates (and that differs from other approved rates).	Interval Meter data

Run 2: Rate Classifications and Summary Load Data Requirements
Same as Run 1 with the following exceptions

NB: To use 2006 EDR data for historic test year when assess rate classification changes

Rate Classification	Data Requirements
3a. **GS >50 kW – TOU** Classification to be eliminated Rename as "Intermediate" if it meets legacy test for intermediate (customer load represents 10% or more of the utility's load); or rename classification as appropriate if it has a discrete demand range; otherwise, roll into GS > 50 kW classification. Elimination of legacy TOU customers will not apply to (HONI) interim TOU rate.	Interval data or if no interval data available use generic load data /LDC industrial grouping data/ LDC consumption data.
5a **New Large Use Class** - to address where LDC has GS customer above 5,000 kW.	If customer is part of GS>50kW or GS intermediate class etc., interval meter data should be available.
6a. **Street Lights TOU** Classification to be renamed "Street Lights" and rolled into Non TOU Street Light classification if applicable.	To be assumed there is an approved load profile.
8. **Unmetered Scattered Loads –** To be modeled as separate rate classification.	Refer to Chapter 3 of Report for details.
9. **Load Displacement Generation** – Load displacement customers that displace greater than 500 kWs of load. To be modeled as a (single) separate rate classification.	Actual metered usage for the customers with load displacement will be used to construct the load profiles.
10. **Embedded Distributor –** host distributor transfers power to an embedded distributor. To be modeled as separate classification.	Interval Meter data

Optional Run 3: Rate Classifications and Load Data Requirements
Same as Run 2 with the following exceptions:

Rate Classification	Data Requirements
9. **Load Displacement Generation** – Load displacement customers that displace greater than 500 kWs of load. May be modeled as a separate rate classification.	Add actual or estimated metered generator load displacement to the metered usage. If an estimated amount has been added to the metered usage, explanation and calculation must be filed.
10. **Merchant Generation**	Distributor to consider and justify appropriate load shape if modeled as separate rate classification.
11. **Hybrid Load Displacement/ Merchant Generation**	Distributor to consider and justify appropriate load shape if modeled as separate rate classification.
12. Other If distributor adds new separate rate classification, must also provide supporting load data.	Current density and seasonal classifications can be eliminated but new density and seasonal classifications are not allowed. NB: Distributor not allowed to eliminate current polyphase classification.

Appendix 4.1

Allocation of Revenue Off-set Accounts

Acct.	Description	Allocation Method to Rate Classification
4082	Retail Services Revenues	Number of bills
4084	Service Transaction Requests (STR) Revenues	Number of bills
4090	Electric Services Incidental to Energy Sales	Number of bills
4205	Interdepartmental Rents	Rate Base
4210	Rent from Electric Property	Rate Base
4215	Other Utility Operating Income	Rate Base
4220	Other Electric Revenues	Rate Base
4225	Late Payment Charges	Historical class allocation – 3 year average
4235	Miscellaneous Service Revenues	Number of bills
4240	Provision for Rate Refunds	Rate Base
4245	Government Assistance Directly Credited to Income	Rate Base
4305	Regulatory Debits	Rate Base
4310	Regulatory Credits	Rate Base
4315	Revenues from Electric Plant Leased to Others	Rate Base
4320	Expenses of Electric Plant Leased to Others	Rate Base
4325	Revenues from Merchandise, Jobbing, Etc.	Rate Base
4330	Costs and Expenses of Merchandising, Jobbing, Etc.	Rate Base
4335	Profits and Losses from Financial Instrument Hedges	Rate Base
4340	Profits and Losses from Financial Instrument Investments	Rate Base
4345	Gains from Disposition of Future Use Utility Plant	Rate Base
4350	Losses from Disposition of Future Use Utility Plant	Rate Base
4355	Gain on Disposition of Utility and Other Property	Rate Base
4360	Loss on Disposition of Utility and Other Property	Rate Base
4365	Gains from Disposition of Allowances for Emission	Rate Base
4370	Losses from Disposition of Allowances for Emission	Rate Base
4390	Miscellaneous Non-Operating Income	Rate Base
4395	Rate-Payer Benefit Including Interest	Rate Base
4398	Foreign Exchange Gains and Losses, Including Amortization	Rate Base
4405	Interest and Dividend Income	Rate Base
4415	Equity in Earnings of Subsidiary Companies	Rate Base

Appendix 6.1

Grouping of Accounts

USoA Account #	Accounts	Classification Allocator	Group
5005	Operation Supervision and Engineering	1815-1855	1
5010	Load Dispatching	1815-1855	1
5085	Miscellaneous Distribution Expense	1815-1855	1
5105	Maintenance Supervision and Engineering	1815-1855	1
1830-3	Poles, Towers and Fixtures - Subtransmission Bulk Delivery	BCP	2
1835-3	Overhead Conductors and Devices - Subtransmission Bulk Delivery	BCP	2
1840-3	Underground Conduit - Bulk Delivery	BCP	2
1845-3	Underground Conductors and Devices - Bulk Delivery	BCP	2
5030	Overhead Subtransmission Feeders – Operation	BCP	3
5050	Underground Subtransmission Feeders – Operation	BCP	3
1995	Contributions and Grants - Credit	Break out	4
2050	Completed Construction Not Classified—Electric	Break out	4
2105	Accum. Amortization of Electric Utility Plant - Property, Plant, & Equipment	Break out	4
4225	Late Payment Charges	CAR	5
5335	Bad Debt Expense	BDH	6
5070	Customer Premises - Operation Labour	CCA	7
5075	Customer Premises - Materials and Expenses	CCA	7
5130	Maintenance of Overhead Services	CCS	8
5155	Maintenance of Underground Services	CCS	8
1855	Services	CCS	9
1565	Conservation and Demand Management Expenditures and Recoveries	CEAD	10
5415	Energy Conservation	CEAD	11
4082	Retail Services Revenues	CNB	12
4084	Service Transaction Requests (STR) Revenues	CNB	12
4090	Electric Services Incidental to Energy	CNB	12

	Sales		
4235	Miscellaneous Service Revenues	CNB	12
5305	Supervision	CNB	13
5315	Customer Billing	CNB	13
5320	Collecting	CNB	13
5325	Collecting- Cash Over and Short	CNB	13
5330	Collection Charges	CNB	13
5340	Miscellaneous Customer Accounts Expenses	CNB	13
4080	Distribution Services Revenue	CREV	14
5065	Meter Expense	CWMC	15
5175	Maintenance of Meters	CWMC	15
1860	Meters	CWMC	16
5310	Meter Reading Expense	CWMR	17
1805-2	Land Station <50 kV	DCP	18
1806-2	Land Rights Station <50 kV	DCP	18
1808-2	Buildings and Fixtures < 50 KV	DCP	18
1810-2	Leasehold Improvements <50 kV	DCP	18
1820	Distribution Station Equipment - Normally Primary below 50 kV	DCP	18
1825-2	Storage Battery Equipment <50 kV	DCP	18
5012	Station Buildings and Fixtures Expense	DCP	19
5016	Distribution Station Equipment - Operation Labour	DCP	19
5017	Distribution Station Equipment - Operation Supplies and Expenses	DCP	19
5110	Maintenance of Buildings and Fixtures - Distribution Stations	DCP	19
5114	Maintenance of Distribution Station Equipment	DCP	19
1805	Land	DDCP	20
1806	Land Rights	DDCP	20
1808	Buildings and Fixtures	DDCP	20
1810	Leasehold Improvements	DDCP	20
1825	Storage Battery Equipment	DDCP	20
1830	Poles, Towers and Fixtures	DDNCP	21
1835	Overhead Conductors and Devices	DDNCP	21
1840	Underground Conduit	DDNCP	21
1845	Underground Conductors and Devices	DDNCP	21
5020	Overhead Distribution Lines and Feeders - Operation Labour	DNCP	22
5025	Overhead Distribution Lines & Feeders - Operation Supplies and Expenses	DNCP	22
5040	Underground Distribution Lines and Feeders - Operation Labour	DNCP	22

5045	Underground Distribution Lines & Feeders - Operation Supplies & Expenses	DNCP	22
5090	Underground Distribution Lines and Feeders - Rental Paid	DNCP	22
5095	Overhead Distribution Lines and Feeders - Rental Paid	DNCP	22
5120	Maintenance of Poles, Towers and Fixtures	DNCP	22
5125	Maintenance of Overhead Conductors and Devices	DNCP	22
5135	Overhead Distribution Lines and Feeders - Right of Way	DNCP	22
5145	Maintenance of Underground Conduit	DNCP	22
5150	Maintenance of Underground Conductors and Devices	DNCP	22
5405	Supervision	O&M	23
5410	Community Relations - Sundry	O&M	23
5425	Miscellaneous Customer Service and Informational Expenses	O&M	23
5505	Supervision	O&M	23
5510	Demonstrating and Selling Expense	O&M	23
5515	Advertising Expense	O&M	23
5520	Miscellaneous Sales Expense	O&M	23
5605	Executive Salaries and Expenses	O&M	23
5610	Management Salaries and Expenses	O&M	23
5615	General Administrative Salaries and Expenses	O&M	23
5620	Office Supplies and Expenses	O&M	23
5625	Administrative Expense Transferred Credit	O&M	23
5630	Outside Services Employed	O&M	23
5640	Injuries and Damages	O&M	23
5645	Employee Pensions and Benefits	O&M	23
5650	Franchise Requirements	O&M	23
5655	Regulatory Expenses	O&M	23
5660	General Advertising Expenses	O&M	23
5665	Miscellaneous General Expenses	O&M	23
5670	Rent	O&M	23
5675	Maintenance of General Plant	O&M	23
5680	Electrical Safety Authority Fees	O&M	23
5730	Amortization of Unrecovered Plant and Regulatory Study Costs	O&M	23
5735	Amortization of Deferred Development Costs	O&M	23
5740	Amortization of Deferred Charges	O&M	23

6205	Donations	O&M	23
6210	Life Insurance	O&M	23
6215	Penalties	O&M	23
6225	Other Deductions	O&M	23
5096	Other Rent	O&M	23
1830-4	Poles, Towers and Fixtures - Primary	PNCP	24
1835-4	Overhead Conductors and Devices – Primary	PNCP	24
1840-4	Underground Conduit - Primary	PNCP	24
1845-4	Underground Conductors and Devices – Primary	PNCP	24
5705	Amortization Expense - Property, Plant, and Equipment	PRORATED	25
5710	Amortization of Limited Term Electric Plant	PRORATED	25
5715	Amortization of Intangibles and Other Electric Plant	PRORATED	25
5720	Amortization of Electric Plant Acquisition Adjustments	PRORATED	25
1608	Franchises and Consents	RB	26
1905	Land	RB	26
1906	Land Rights	RB	26
1908	Buildings and Fixtures	RB	26
1910	Leasehold Improvements	RB	26
1915	Office Furniture and Equipment	RB	26
1920	Computer Equipment - Hardware	RB	26
1925	Computer Software	RB	26
1930	Transportation Equipment	RB	26
1935	Stores Equipment	RB	26
1940	Tools, Shop and Garage Equipment	RB	26
1945	Measurement and Testing Equipment	RB	26
1950	Power Operated Equipment	RB	26
1955	Communication Equipment	RB	26
1960	Miscellaneous Equipment	RB	26
1970	Load Management Controls - Customer Premises	RB	26
1975	Load Management Controls - Utility Premises	RB	26
1980	System Supervisory Equipment	RB	26
1990	Other Tangible Property	RB	26
2005	Property Under Capital Leases	RB	26
2010	Electric Plant Purchased or Sold	RB	26
2120	Accumulated Amortization of Electric Utility Plant - Intangibles	RB	26
3046	Balance Transferred From Income	RB	27
4205	Interdepartmental Rents	RB	28

4210	Rent from Electric Property	RB	28
4215	Other Utility Operating Income	RB	28
4220	Other Electric Revenues	RB	28
4240	Provision for Rate Refunds	RB	28
4245	Government Assistance Directly Credited to Income	RB	28
4305	Regulatory Debits	RB	28
4310	Regulatory Credits	RB	28
4315	Revenues from Electric Plant Leased to Others	RB	28
4320	Expenses of Electric Plant Leased to Others	RB	28
4325	Revenues from Merchandise, Jobbing, Etc.	RB	28
4330	Costs and Expenses of Merchandising, Jobbing, Etc.	RB	28
4335	Profits and Losses from Financial Instrument Hedges	RB	28
4340	Profits and Losses from Financial Instrument Investments	RB	28
4345	Gains from Disposition of Future Use Utility Plant	RB	28
4350	Losses from Disposition of Future Use Utility Plant	RB	28
4355	Gain on Disposition of Utility and Other Property	RB	28
4360	Loss on Disposition of Utility and Other Property	RB	28
4365	Gains from Disposition of Allowances for Emission	RB	28
4370	Losses from Disposition of Allowances for Emission	RB	28
4390	Miscellaneous Non-Operating Income	RB	28
4395	Rate-Payer Benefit Including Interest	RB	28
4398	Foreign Exchange Gains and Losses, Including Amortization	RB	28
4405	Interest and Dividend Income	RB	28
4415	Equity in Earnings of Subsidiary Companies	RB	28
5420	Community Safety Program	RB	29
5635	Property Insurance	RB	29
5685	Independent Market Operator Fees and Penalties	RB	29
6105	Taxes Other Than Income Taxes	RB	29
6110	Income Taxes	RB	29
1830-5	Poles, Towers and Fixtures – Secondary	SNCP	30

1835-5	Overhead Conductors and Devices – Secondary	SNCP	30
1840-5	Underground Conduit - Secondary	SNCP	30
1845-5	Underground Conductors and Devices – Secondary	SNCP	30
1850	Line Transformers	SNCP	30
5035	Overhead Distribution Transformers- Operation	SNCP	31
5055	Underground Distribution Transformers - Operation	SNCP	31
5160	Maintenance of Line Transformers	SNCP	31
1805-1	Land Station >50 kV	TCP	32
1806-1	Land Rights Station >50 kV	TCP	32
1808-1	Buildings and Fixtures > 50 kV	TCP	32
1810-1	Leasehold Improvements >50 kV	TCP	32
1815	Transformer Station Equipment - Normally Primary above 50 kV	TCP	32
1825-1	Storage Battery Equipment > 50 kV	TCP	32
5014	Transformer Station Equipment - Operation Labour	TCP	33
5015	Transformer Station Equipment - Operation Supplies and Expenses	TCP	33
5112	Maintenance of Transformer Station Equipment	TCP	33

Appendix 6.2

Identification of Customers Served at Bulk, Primary and Secondary

The examples in this Appendix have been developed to assist with the understanding of how the customer number is entered into the filing model to implement the separation of bulk, primary and secondary assets.

Example 1

The following is an example that assumes the distributor has bulk assets shared by 100% of the customers and includes the following customer characteristics for Residential, General Service < 50 kW, General Service > 50 kW and Large Use classifications:

a) Number of Customers by Rate Classification

Rate Classification	Number of Customers
Residential	1,000
General Service < 50 kW	500
General Service > 50 kW	100
Large Use	7

b) Number of Residential customers taking power from the secondary assets through the primary and bulk assets is 1,000.
c) Number of General Service < 50 kW customers taking power from the secondary assets through the primary and bulk assets is 500.
d) Number of General Service > 50 kW customers taking power from the secondary assets through the primary and bulk assets is 50.
e) Number of General Service > 50 kW customers taking power from the primary assets through the bulk assets is 50.
f) Number of Large Use customers taking power from the primary assets through the bulk assets is 2.
g) Number of Large Use customer taking power form the bulk assets is 5.

The following outlines the resulting numbers of customers using the various asset groupings, for Example 1.

Class	Bulk	Primary	Secondary
Residential	1,000	1,000	1,000
General Service <50 kW	500	500	500
General Service >50 kW	100	100	50
Large Use	7	2	

Example 2

The following is an example that assumes the distributor does not have bulk assets and includes the following customer characteristics for Residential, General Service < 50 kW, General Service > 50 kW and Large Use classifications:

a) Number of Customers by Rate Classification

Rate Classification	Number of Customers
Residential	1,000
General Service < 50 kW	500
General Service > 50 kW	100
Large Use	7

b) Number of Residential customers taking power from the secondary assets through the primary assets is 1,000.
c) Number of General Service < 50 kW customers taking power from the secondary assets through the primary assets is 500.
d) Number of General Service > 50 kW customers taking power from the secondary assets through the primary assets is 50.
e) Number of General Service > 50 kW customers taking power from the primary assets is 50.
f) Number of Large Use customers taking power from the primary assets is 7.

The following outlines the resulting numbers of customers using the various asset groupings, for Example 2:

Class	Bulk	Primary	Secondary
Residential		1,000	1,000
General Service <50 kW		500	500
General Service >50 kW		100	50
Large Use		7	

Example 3

The following is an example that assumes the distributor has a bulk system that does not provide service equally to all customers and includes the following customer characteristics for Residential, General Service < 50 kW, General Service > 50 kW and Large Use classifications:

a) Number of Customers by Rate Classification

Rate Classification	Number of Customers
Residential	1,000
General Service < 50 kW	500
General Service > 50 kW	100
Large Use	7

b) Number of Residential customers taking power from the secondary assets through the primary and bulk assets is 500.
c) Number of Residential customers taking power from the secondary assets through the primary assets only is 500.
d) Number of General Service < 50 kW customers taking power from the secondary assets through the primary and bulk assets is 250.
e) Number of General Service < 50 kW customers taking power from the secondary assets through the primary assets only is 250.
f) Number of General Service > 50 kW customers taking power from the secondary assets through the primary and bulk assets is 50.
g) Number of General Service > 50 kW customers taking power directly from the primary assets is 50.
h) Number of Large Use customers taking power from the primary assets through the bulk assets is 2.
i) Number of Large Use customers taking power from the primary assets directly is 3.
j) Number of Large Use customers taking power from the bulk assets is 2.

The following outlines the resulting numbers of customers using the various asset groupings, for Example 3:

Class	Bulk	Primary	Secondary
Residential	500	1,000	1,000
General Service <50 kW	250	500	500
General Service >50 kW	50	100	50
Large Use	4	5	

Appendix 7.1

100% Demand Related Accounts/Sub-accounts

1805	Land
1805-1	Land Station >50 kV
1805-2	Land Station <50 kV
1806	Land Rights
1806-1	Land Rights Station >50 kV
1806-2	Land Rights Station <50 kV
1808	Buildings and Fixtures
1808-1	Buildings and Fixtures > 50 kV
1808-2	Buildings and Fixtures < 50 KV
1810	Leasehold Improvements
1810-1	Leasehold Improvements >50 kV
1810-2	Leasehold Improvements <50 kV
1815	Transformer Station Equipment - Normally Primary above 50 kV
1820	Distribution Station Equipment - Normally Primary below 50 kV
1825	Storage Battery Equipment
1825-1	Storage Battery Equipment > 50 kV
1825-2	Storage Battery Equipment <50 kV
1830-3	Poles, Towers and Fixtures – Subtransmission Bulk Delivery
1835-3	Overhead Conductors and Devices - Subtransmission Bulk Delivery
1840-3	Underground Conduit – Bulk Delivery
1845-3	Underground Conductors and Devices - Bulk Delivery
5012	Station Buildings and Fixtures Expense
5014	Transformer Station Equipment - Operation Labour
5015	Transformer Station Equipment - Operation Supplies and Expenses
5016	Distribution Station Equipment - Operation Labour
5017	Distribution Station Equipment - Operation Supplies and Expenses
5030	Overhead Subtransmission Feeders – Operation
5050	Underground Subtransmission Feeders – Operation
5110	Maintenance of Buildings and Fixtures - Distribution Stations
5112	Maintenance of Transformer Station Equipment
5114	Maintenance of Distribution Station Equipment

Appendix 7.2

100% Customer Related Accounts/Sub-accounts

1855	Services
1860	Meters
1565	Conservation and Demand Management Expenditures and Recoveries
5065	Meter Expense
5070	Customer Premises - Operation Labour
5075	Customer Premises - Materials and Expenses
5130	Maintenance of Overhead Services
5155	Maintenance of Underground Services
5175	Maintenance of Meters

Appendix 7.3

Joint Related Accounts/Sub-accounts

1830	Poles, Towers and Fixtures
1830-4	Poles, Towers and Fixtures – Primary
1830-5	Poles, Towers and Fixtures – Secondary
1835	Overhead Conductors and Devices
1835-4	Overhead Conductors and Devices – Primary
1835-5	Overhead Conductors and Devices – Secondary
1840	Underground Conduit
1840-4	Underground Conduit – Primary
1840-5	Underground Conduit – Secondary
1845	Underground Conductors and Devices
1845-4	Underground Conductors and Devices – Primary
1845-5	Underground Conductors and Devices – Secondary
1850	Line Transformers
5020	Overhead Distribution Lines and Feeders - Operation Labour
5025	Overhead Distribution Lines & Feeders - Operation Supplies and Expenses
5035	Overhead Distribution Transformers- Operation
5040	Underground Distribution Lines and Feeders – Operation Labour
5045	Underground Distribution Lines & Feeders - Operation Supplies & Expenses
5055	Underground Distribution Transformers – Operation
5090	Underground Distribution Lines and Feeders - Rental Paid
5095	Overhead Distribution Lines and Feeders - Rental Paid
5120	Maintenance of Poles, Towers and Fixtures
5125	Maintenance of Overhead Conductors and Devices
5135	Overhead Distribution Lines and Feeders - Right of Way
5145	Maintenance of Underground Conduit
5150	Maintenance of Underground Conductors and Devices
5160	Maintenance of Line Transformers

Appendix 7.4

Pro-rata Related Accounts/Sub-accounts

5005	Operation Supervision and Engineering
5010	Load Dispatching
5085	Miscellaneous Distribution Expense
5105	Maintenance Supervision and Engineering

Appendix 7.5

Note 1 :	**Generic Minimum System Results – Ontario Studies**				
				Customer Component	
By Density			Density (Cust/km)	Line Transformer	Distribution
			Low	60%	60%
			Medium	40%	40%
			High	30%	35%
Results of Ontario Studies					
Average by Density			Low	62%	61%
			Medium	43%	43%
			High	31%	36%
			Average all	40%	43%
		Customer Component			
Utility Name	Density (Cust/km)	Line Transformer	Overhead Feeders	Underground Feeders	Combined OH/UG
Guelph - Bare Bone	Medium	27%	48%	34%	41%
Guelph - Smallest Installed	Medium	54%	99%	67%	83%
Milton	Medium	64%	44%	32%	38%
MEA 1998 study	Medium	27%	36%	15%	26%
Strata 1 (note 1)	Medium	42%	52%	25%	39%
Strata 2 (note 1)	Medium	26%	51%	27%	39%
Strata 3 (note 1)	Medium	29%	50%	29%	40%
Wasaga Beach	Medium	71%	61%	13%	37%
Rural Study (Ont Hydro)	Low	62%	61%	61%	61%
Etobicoke (Tx weighted oh/ug)	High	38%	63%	66%	65%
North York Hydro (Tx Weighted)	High	16%	32%	11%	22%
Toronto Hydro	High	23%	23%	23%	23%
Note 1 :					
MEA February 1998					
Strata 3 - utilities with over 40% of distribution plant underground					
Strata 2 - utilities with less than 40% and over 1000 Residential customers					
Strata 1 - Utilities with less than 40% underground and less than 1000 residential customers					
The 10 largest utilities were excluded from these stratifications.					

MEA February 1998					
Strata 3 - utilities with over 40% of distribution plant underground					
Strata 2 - utilities with less than 40% and over 1000 Residential customers					
Strata 1 - Utilities with less than 40% underground and less than 1000 residential customers					
The 10 largest utilities were excluded from these stratifications.					

Appendix 8.1

Demand-related Accounts
100% of Account/Sub-account Allocated with Demand

1805	Land
1805-1	Land Station >50 kV
1805-2	Land Station <50 kV
1806	Land Rights
1806-1	Land Rights Station >50 kV
1806-2	Land Rights Station <50 kV
1808	Buildings and Fixtures
1808-1	Buildings and Fixtures > 50 kV
1808-2	Buildings and Fixtures < 50 KV
1810	Leasehold Improvements
1810-1	Leasehold Improvements >50 kV
1810-2	Leasehold Improvements <50 kV
1815	Transformer Station Equipment - Normally Primary above 50 kV
1820	Distribution Station Equipment – Normally Primary below 50 kV
1825	Storage Battery Equipment
1825-1	Storage Battery Equipment > 50 kV
1825-2	Storage Battery Equipment <50 kV
1830-3	Poles, Towers and Fixtures - Subtransmission Bulk Delivery
1835-3	Overhead Conductors and Devices - Subtransmission Bulk Delivery
1840-3	Underground Conduit - Bulk Delivery
1845-3	Underground Conductors and Devices - Bulk Delivery
5012	Station Buildings and Fixtures Expense
5014	Transformer Station Equipment - Operation Labour
5015	Transformer Station Equipment - Operation Supplies and Expenses
5016	Distribution Station Equipment – Operation Labour
5017	Distribution Station Equipment – Operation Supplies and Expenses
5030	Overhead Subtransmission Feeders – Operation
5050	Underground Subtransmission Feeders – Operation
5110	Maintenance of Buildings and Fixtures - Distribution Stations
5112	Maintenance of Transformer Station Equipment
5114	Maintenance of Distribution Station Equipment

Appendix 8.2

Demand-related Accounts
Portion of Account/Sub-account Allocated with Demand

1830	Poles, Towers and Fixtures
1830-4	Poles, Towers and Fixtures – Primary
1830-5	Poles, Towers and Fixtures – Secondary
1835	Overhead Conductors and Devices
1835-4	Overhead Conductors and Devices – Primary
1835-5	Overhead Conductors and Devices – Secondary
1840	Underground Conduit
1840-4	Underground Conduit – Primary
1840-5	Underground Conduit – Secondary
1845	Underground Conductors and Devices
1845-4	Underground Conductors and Devices – Primary
1845-5	Underground Conductors and Devices – Secondary
1850	Line Transformers
5005	Operation Supervision and Engineering
5010	Load Dispatching
5020	Overhead Distribution Lines and Feeders - Operation Labour
5025	Overhead Distribution Lines & Feeders - Operation Supplies and Expenses
5035	Overhead Distribution Transformers- Operation
5040	Underground Distribution Lines and Feeders - Operation Labour
5045	Underground Distribution Lines & Feeders - Operation Supplies & Expenses
5055	Underground Distribution Transformers – Operation
5085	Miscellaneous Distribution Expense
5090	Underground Distribution Lines and Feeders - Rental Paid
5095	Overhead Distribution Lines and Feeders - Rental Paid
5105	Maintenance Supervision and Engineering
5120	Maintenance of Poles, Towers and Fixtures
5125	Maintenance of Overhead Conductors and Devices
5135	Overhead Distribution Lines and Feeders - Right of Way
5145	Maintenance of Underground Conduit
5150	Maintenance of Underground Conductors and Devices
5160	Maintenance of Line Transformers

Appendix 9.1

Customer-related Accounts
100% of Account/Sub-account Allocated with Customers

1855	Services
1860	Meters
1565	Conservation and Demand Management Expenditures and Recoveries
5065	Meter Expense
5070	Customer Premises – Operation Labour
5075	Customer Premises – Materials and Expenses
5130	Maintenance of Overhead Services
5155	Maintenance of Underground Services
5175	Maintenance of Meters

Customer-related Accounts
Portion of Account/Sub-account Allocated with Customers

1830	Poles, Towers and Fixtures
1830-4	Poles, Towers and Fixtures – Primary
1830-5	Poles, Towers and Fixtures – Secondary
1835	Overhead Conductors and Devices
1835-4	Overhead Conductors and Devices – Primary
1835-5	Overhead Conductors and Devices – Secondary
1840	Underground Conduit
1840-4	Underground Conduit – Primary
1840-5	Underground Conduit – Secondary
1845	Underground Conductors and Devices
1845-4	Underground Conductors and Devices – Primary
1845-5	Underground Conductors and Devices – Secondary
1850	Line Transformers
5005	Operation Supervision and Engineering
5010	Load Dispatching
5020	Overhead Distribution Lines and Feeders - Operation Labour
5025	Overhead Distribution Lines & Feeders - Operation Supplies and Expenses
5035	Overhead Distribution Transformers- Operation
5040	Underground Distribution Lines and Feeders - Operation Labour
5045	Underground Distribution Lines & Feeders - Operation Supplies & Expenses
5055	Underground Distribution Transformers – Operation
5085	Miscellaneous Distribution Expense
5090	Underground Distribution Lines and Feeders - Rental Paid

5095	Overhead Distribution Lines and Feeders - Rental Paid
5105	Maintenance Supervision and Engineering
5120	Maintenance of Poles, Towers and Fixtures
5125	Maintenance of Overhead Conductors and Devices
5135	Overhead Distribution Lines and Feeders - Right of Way
5145	Maintenance of Underground Conduit
5150	Maintenance of Underground Conductors and Devices
5160	Maintenance of Line Transformers

Appendix 9.2

Installed Meter Capital Costs

Meter Type	Installed Meter Capital Cost
Single Phase 200 Amp – Urban	50
Single Phase 200 Amp – Rural	150
Central Meter (Costs to be updated)	250
Network Meter (Costs to be updated)	225
Three-phase - No demand	210
Smart Meters (Costs to be updated)	300
Demand without IT (usually three-phase)	500
Demand with IT	2,100
Demand with IT and Interval Capability - Secondary	2,300
Demand with IT and Interval Capability - Primary	10,000
Demand with IT and Interval Capability -Special (WMP)	40,000

Appendix 9.3

Meter Reading Factors

Meter Type	Meter Reading Factors
Residential - Urban – Outside	1.00
Residential - Urban - Outside with other services	1.00
Residential - Urban – Inside	2.00
Residential - Urban – Inside - with other services	1.00
Residential - Rural - Outside with other services	2.00
GS – Walking	2.00
GS – Walking - with other services	3.00
GS – Vehicle with other services --- TOU Read	3.00
GS – Vehicle with other services	3.00
Interval	49.00

Appendix 11.1

Further Potential Adjustments to be Modeled

The initial costs calculated by the model, using the general cost allocation principles recommended, should be later adjusted to take into account additional savings and costs to the distribution system only[13] from use of load displacement facilities.

The Technical Advisory Team identified the following as potential cost reductions on a distribution system:

- ability to defer or avoid commissioning of new delivery system assets and associated operating costs
- extending the service life of distribution assets and/or reducing the maintenance of these assets
- generally reduced distribution line losses (but not in all cases)
- potentially enhanced distribution system flexibility and reliability such as continued service during widespread outages.

Some of the potential cost burdens on various parts of the distribution system may include:

- incremental engineering, contracting, metering, and/or billing costs
- incremental capital and/or maintenance costs (e.g. associated with switching operations, communications and monitoring)
- need to invest in different system controls and protections (e.g. may need to purchase or upgrade SCADA) and need to change operating practice with regard to safety.

Some of the unknown impacts may include:

- impact on voltage stability.

[13] Identification and quantification of benefits and costs arising from load displacement facilities on the other parts of overall electricity sector, such as the transmission system, will not be addressed in these filings.

Appendix 12.1

Accounts included in Calculation of Lower End Customer Unit Costs
(using directly related customer costs, inclusive of A&G allocation)

Account #	Accounts
Distribution Plant	
1860	Meters
Accum. Amortization	
2105	Amortization of Electricity Utility Plant – Meters only
Misc. Revenues	
4080	Distribution Services Revenue
4082	Retail Services Revenues
4084	Service Transaction Requests (STR) Revenues
4220	Other Electric Revenues
4225	Late Payment Charges
Operation	
5065	Meter Expense
5070	Customer Premises – Operation Labour
5075	Customer Premises – Materials and Expenses
Maintenance	
5175	Maintenance of Meters
Billing & Collection	
5310	Meter Reading Expense
5315	Customer Billing
5320	Collecting
5325	Collecting – Cash Over and Short
5330	Collection Charges
Amortization of Assets	
5705	Amortization Expense – Only meters

Appendix 12.2

Primary and Secondary Conductors and Poles Cost Pools Calculation

The costs set out in Appendix 12.2 will list the primary and secondary conductors and poles cost pool to be generated by the filing model for future reference. Please note the sub-account references outlined below are for modeling purposes only and do not relate to actual USoA references.

Proposal - Primary Conductors and Poles Cost Pools Calculation

a) Depreciation on sub-account 1830-4 - Poles, Towers and Fixtures – Primary
b) Depreciation on sub-account 1835-4 - Overhead Conductors and Devices – Primary
c) Depreciation on sub-account 1840-4 - Underground Conduit – Primary.
d) Depreciation on sub-account 1845-4 - Underground Conductors and Devices – Primary
e) Primary component of operation expense on overhead distribution lines and feeders – Accounts 5020 and 5025
f) Primary component of operation expense on underground distribution lines and feeders – Accounts 5040 and 5045
g) Primary component of underground distribution lines and feeders - rental paid – Account 5090
h) Primary component of overhead distribution lines and feeders - rental paid – Account 5095
i) Primary component of maintenance expense on poles, towers and fixtures - Account 5120
j) Primary component of maintenance expense on overhead conductors and devices – Account 5125
k) Primary component of maintenance expense on overhead distribution lines and feeders right of way – Account 5135
l) Primary component of maintenance expense on underground conduit – Account 5145
m) Primary component of maintenance expense on underground conductors and devices – Account 5150
n) General plant allocated to these primary assets.
o) Administration and general expenses allocated to these primary assets.
p) PILs and return on equity and debt that would be associated with a “mini” rate base that includes sub-accounts 1830-4, 1835-4, 1840-4, 1845-4, account and associated general plant plus the working capital associated with the primary component of Accounts 5020, 5025, 5040, 5045, 5090, 5095, 5120, 5125, 5135, 5145 and 5150 as well as the administration and general expenses allocated to these primary assets

Proposal - Secondary Conductors and Poles Cost Pool Calculation

The following costs will be included in the secondary conductors and poles cost pool to be generated by the filing model for future reference.

a) Depreciation on sub-account 1830-5 - Poles, Towers and Fixtures – Secondary
b) Depreciation on sub-account 1835-5 - Overhead Conductors and Devices – Secondary
c) Depreciation on sub-account 1840-5 - Underground Conduit – Secondary
d) Depreciation on sub-account 1845-5 - Underground Conductors and Devices – Secondary
e) Secondary component of operation expense on overhead distribution lines and feeders – Accounts 5020 and 5025
f) Secondary component of operation expense on underground distribution lines and feeders – Accounts 5040 and 5045
q) Secondary component of underground distribution lines and feeders - rental paid – Account 5090
r) Secondary component of overhead distribution lines and feeders - rental paid – Account 5095
s) Secondary component of maintenance expense on poles, towers and fixtures - Account 5120
g) Secondary component of maintenance expense on overhead conductors and devices – Account 5125
h) Secondary component of maintenance expense on overhead distribution lines and feeders – Account 5135
i) Secondary component of maintenance expense on underground conduit – Account 5145
j) Secondary component of maintenance expense on underground conductors and devices – Account 5150
k) General plant allocated to these secondary assets
l) Administration and general expenses allocated to these secondary assets
m) PILs and return on equity and debt that would be associated with a “mini” rate base that includes sub-accounts 1830-5, 1835-5, 1840-5, 1845-5, and associated general plant plus the working capital associated with the secondary component of Accounts 5020, 5025, 5040, 5045, 5090, 5095, 5120, 5125, 5135, 5145 and 5150 as well as the administration and general expenses allocated to these secondary assets