Ontario Energy Board **Commission de l'Énergie de l'Ontario**

Cost Allocation Review

Staff Discussion Paper

September, 2005

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COST ALLOCATION REVIEW (EB-2005-0317)

Section 1: Introduction

Periodic cost allocation studies are helpful to confirm that distribution rates for each customer class remain just and reasonable.

The 2001 Electricity Distribution Rate Handbook stated that prior to the implementation of a future incentive regulation plan, the Board would require electricity distributors to complete new cost allocation studies. The need for updated cost allocation studies was also raised by parties in the 2006 EDR process.

The Chair of the Ontario Energy Board confirmed in a letter to stakeholders dated March 9, 2005 that a review of cost allocation in the electricity distribution sector would proceed.

This review will require distributors to file updated cost allocation information that will be used by the Board to consider the need for adjustments to the current share of distribution costs paid by various classes of ratepayers.

1.1 Scope and Objectives

1.1.1 Scope of the Review

The March 9, 2005 letter indicated that the cost allocation review will be based "primarily on the existing rate classifications and a limited number of rate design issues". As explained below, certain potential rate design priorities have been added to the scope of the present review.

In a June 24, 2005 letter outlining the process for the cost allocation review, the Board said that it will undertake a separate comprehensive study of distribution rate design. Discussions regarding density rates, seasonal rates, polyphase rates, new Time of Use distribution rates, smoothing of rate classification boundaries, and substantial changes to the fixed/variable distribution rate philosophy will be deferred to that initiative. The Board will consider the need for generic updating of non-competitive charges and transformer allowances after this review is completed. Any Board actions on distribution line loss incentives or distributed generation will also be considered outside of this initiative.

1.1.2 Objectives of the Review

In late 2006, the Board will review the results of the updated cost allocation studies filed by distributors. After considering the filing results and the overall regulatory context, the

Board will decide upon the priorities for, and timing of, adjustments to future rates. Certain distributors may then be directed by the Board to address specified matters in their 2007 or subsequent rate applications.

Cost Allocation

The Board will analyze the cost allocation filings to identify with greater certainty the actual share of costs for serving different classes of customers. Distributors with significant variations between class costs and revenues may be directed to address the matter in a 2007 rate application.

Rate Design

The cost allocation filings will also contain updated information that is helpful to assess the cost basis of the current monthly service charges. After analyzing the filing results and other relevant considerations, the Board will consider whether adjustments should be implemented for 2007 to address any monthly service charges anomalies.

The review will also examine the need for, and implications of:

- adding a new rate class for scattered unmetered loads
- adding a new rate class for embedded distributors by host distributors
- eliminating the legacy rate class identified as “Time of Use”

This review will also include discussion of whether an additional rate grouping is desirable for larger users in the General Service >50 kW classification.

1.1.3 Objectives Of Staff Discussion Paper

The general purpose of this discussion paper is to facilitate the forthcoming consultations with stakeholders. The Paper:

- addresses the major steps in a cost allocation study
- identifies and informs stakeholders on the issues relating to cost allocation, rate design and practical implementation of the process
- sets out Staff’s preliminary proposals on the issues

Staff’s proposals will be reviewed and debated at the Technical Advisory team meetings. Further input from stakeholders will occur during the Technical Workshops.

1.2 Background

1.2.1 Consultation Process

On July 20, 2005, Board staff held a public meeting to review the planned consultation process, amongst other items. Written submissions were received and considered.

Following the release of the present Staff discussion paper, a small industry and ratepayer advisory team will meet to provide preliminary technical input to Board staff. Electricity distribution sector stakeholders with directly relevant expertise have been chosen from parties who indicated their interest in participating. The Technical Advisory Team will meet in three concentrated phases between September 2005 and March 2006. The three phases are:

- phase 1: OEB cost allocation principles and methodologies
- phase 2: priority rate design and rate classification matters
- phase 3: mandatory OEB filing requirements, OEB model design and data inputs.

The Technical Advisory Team discussions will build upon:

- the extensive technical work undertaken by the 2003 Working Group (meeting notes are available on the load data project's web page[1])
- the detailed comments in the Board's Load Data Collection Directions (issued November 10, 2003 and available on this project's web page)
- the cost allocation/rate design components of the 2006 EDR consultations (see Chapters 9 and 10 of the 2006 Electricity Distribution Rate Handbook and associated schedules).

Board Staff will also organize three Technical Workshops to allow for broader stakeholder discussions. A Workshop will follow each phase of the Advisory Team meetings.

Eligible parties such as ratepayer and public organizations that have requested funding for their participation will receive funding in accordance with the parameters discussed in the June 24, 2005 letter.

Final proposals regarding cost allocation principles and methodologies, and select rate classification/rate design matters, will be released for written comment from

[1] During the 2003 consultations, reference was made to a 2000 Report to Board Staff arising from earlier industry-led consultations. That 2000 Navigant Report is available on the load data web page.

stakeholders in January 2006. Staff proposals regarding mandatory OEB filing requirements will be released for written comment in May 2006.

Confirmation of the availability of the accounting and operational data to implement a suggested methodology will be a key objective of the consultations. Data availability will also affect the decision as to what proposed filing requirements should be made mandatory.

1.2.2 Development of OEB Filing Model

As the first phase of the Technical Advisory Team meetings progresses, the development of the new OEB cost allocation model will start. An outline of the model will be introduced at the October Technical Workshop. Two medium-sized distributors have agreed to test the first version of the model. The results will be discussed at a meeting in early January 2006.

A second version of the new OEB cost allocation model, addressing selected rate design matters, will be introduced at the April Technical Workshop. Three distributors (large, medium and small) have agreed to test this version and report their findings at a meeting in mid-June 2006.

1.2.3 Cost Allocation Informational Filings

In March 2006, following stakeholder consultations, the Board will issue a Report adopting common cost allocation principles and methodologies for the OEB cost allocation review. Select rate design priorities will also be addressed in that Report.

The Board will release its mandatory cost allocation review filing requirements and its cost allocation filing model in July 2006.

All Ontario electricity distributors will be required to file new cost allocation studies for Board informational purposes during the fall of 2006. The filings will be public. The studies must be consistent with Board-approved cost allocation principles/methodologies and filing requirements.

In order that distributors and the Board can undertake the review consistently and efficiently, the filing requirements and model will be prescriptive. Select alternative approaches will be allowed only where clearly justified on cost causality grounds. Materiality will also be a consideration.

Section 2: Overview of Cost Allocation

Cost allocation studies serve the following main purposes:

- to allocate the costs to provide service to the various customer rate classes based on cost causation principles
- to assess the reasonableness of the rates charged to customers in relation to their allocated costs
- to support the design of rates

Factors that affect the costs of distribution facilities and operations and maintenance expenses include the following:

i. customer density
ii. load factors
iii. distribution planning criteria
iv. vintage of plant

Cost allocation studies play a major role in assessing the reasonableness of rates. Principles or objectives other than cost causality may also be considered by regulators when setting just and reasonable rates. They can include rate stability, customer acceptance and supporting conservation.

The first step of a cost allocation study consists of identifying costs that can be directly assigned to a particular rate class. For common costs or costs that are attributable to multiple customer rate classes, such as distribution lines, a three-step process is used:

1. Functionalization
2. Categorization (or classification)
3. Allocation

At the functionalization stage, the revenue requirement and rate base are separated into major functional costs centres (e.g. distribution, metering, billing, customer care, etc.) and sub-functions if applicable (e.g. high and low voltage distribution lines).

At the categorization or classification stage, the functionalized costs are further arranged into groups based on cost defining characteristics. The most common classifications are demand, energy and customer-related costs.

In the last step, categorized costs are allocated to the various customer rate classes based on appropriate allocation factors.

The allocated costs by rate class are then compared to revenues, and revenue to costs ratios are derived. If the allocated costs are in excess of the revenues (revenue to cost ratio less than one), the rate class is under-contributing towards the recovery of the revenue requirement based on the conventions that underpin the study. Conversely, if the allocated costs are lower than the revenue under existing rates (revenue to cost ratio larger than one), the rate class would be over-contributing towards the recovery of the revenue requirement.

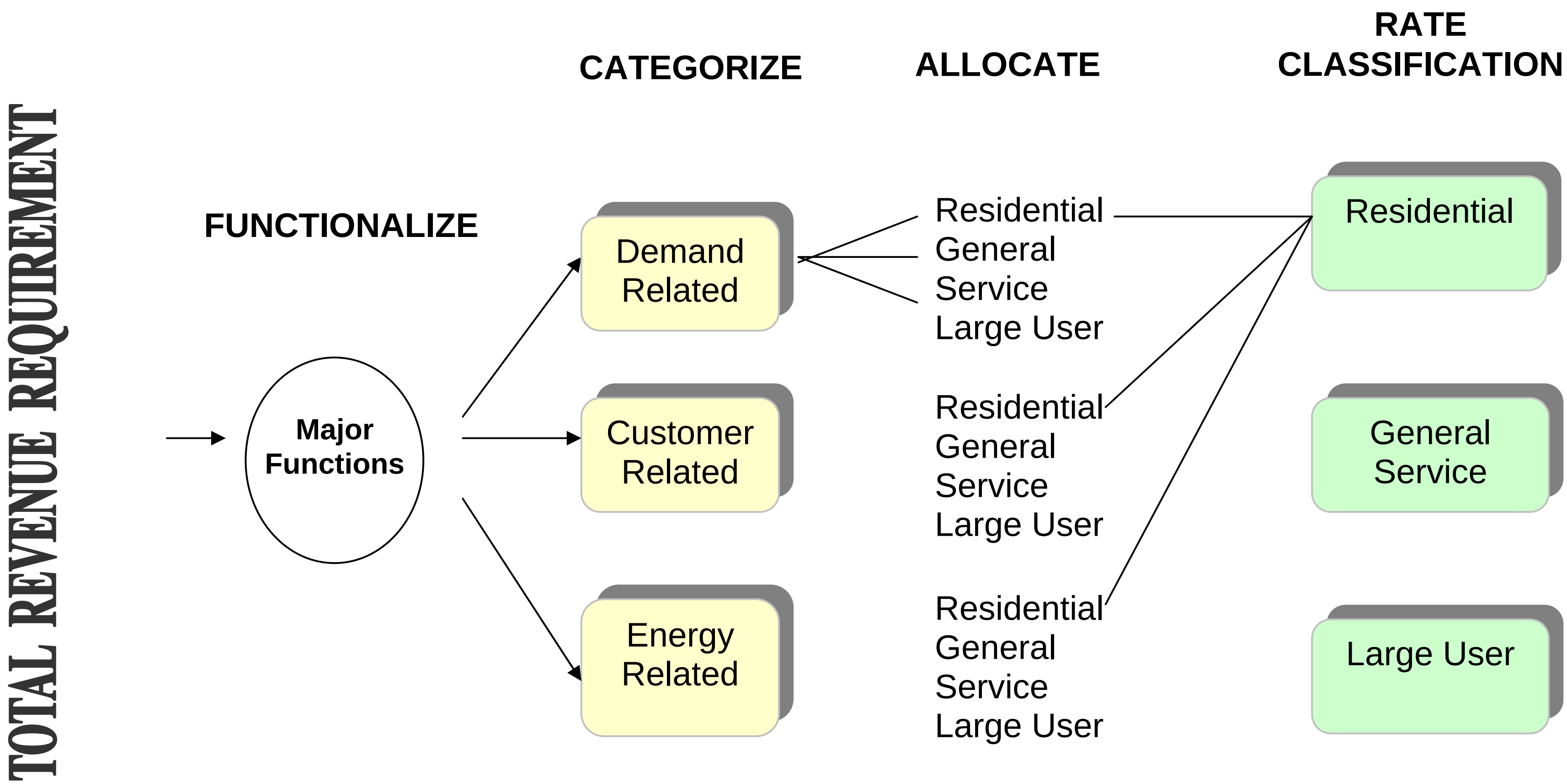
2.1 Financial Information Requirements

A cost allocation study will allocate the test period rate base and revenue requirement to the various customer groups.

The basic financial information required to perform a cost allocation study is extracted from the Uniform System of Accounts (USoA) classification that is applicable to all electricity distributors. It will therefore be imperative that all distributors adhere to the uniform system of account classification in the manner prescribed in the Accounting Procedures Handbook, Article 220.

Load research and customer-related data for the test period are also required to allocate demand-related and customer-related costs respectively.

MAJOR STEPS IN ALLOCATING COMMON COSTS



Section 3: Directly Assignable Costs

3.1 Background

The first step in the cost allocation studies consist of identifying and separating costs that can be directly assigned to a particular rate class.

For this project, “direct assignment” will be appropriate only where a given account relates solely to a specific rate class. Where there is no unique relationship between an account and rate class but the costs can nevertheless be tracked to a single class or a single user, “direct allocation” may be permitted.

Past experience indicates that only a modest number of accounts are generally directly assignable, as most costs are incurred to jointly serve several customer rate classes. Examples of costs that are directly assignable costs include the capital and operating expenses related to street and sentinel lighting.

In the case of the Ontario electricity distribution sector, a Uniform System of Accounts (USoA) is in place. This facilitates standard rules as to which accounts should be directly assigned in the cost allocation studies.

3.2 Issues and Options

Building on the work of the 2003 Working Group, the first step is to develop a list of accounts which must be directly assigned by all distributors to specified rate classes.

Appendix 1 identifies the accounts proposed by Staff that all utilities be required to directly assign. During the consultation process, comments will be sought on the completeness of the list of directly assignable accounts.

The draft model for testing will incorporate the proposed mandatory directly assignable accounts.

3.3 Initial Recommendations

Staff proposes that the accounts listed in Appendix 1 must be directly assigned.

The OEB filing model to be issued will incorporate the mandatory directly assignable accounts.

Section 4: Functionalization

4.1 Background

Functionalization is an important early step in the cost allocation process, as it sets up the framework for the categorization and allocation steps. Functionalization has been defined as:

> "The arrangement of costs according to the major operating functions of the utility, such as production, transmission or distribution, in order to facilitate a determination as to which customer groups are jointly responsible for such costs." [2]

While this definition applies to the wider range of functions in vertically-integrated utilities, the present functionalization process will strictly deal with distribution-related functions.

Sub-functionalization is the further breakdown of major functions into more specific functions.

In practice, each function or sub-function will include a list of corresponding accounts. The USoA for Ontario electricity distributors will thus facilitate a common approach towards functionalization process.

4.2 Issues and Options

Distribution utilities perform the following core functions:

- Distribution
- Sub-transmission
- Customer service
- Metering
- Administration and General

The core distribution function may be further broken down into sub-functional groupings, such as: line transformers, distribution station equipment, services and, primary and secondary lines. The other core functions could also be further sub-divided. A

[2] 2000 Navigant Report pg. 5

technically satisfactory alternative to further sub-functionalization is to simply utilize the appropriate data at the USoA account level.

A first option would be for the Board to prescribe common functions for all distributors. This would be guided by the USoA, especially since most accounts are already set up in a functional sequence.

A second option would be to follow the same common functions as adopted above, but, also allow distributors to request changes to the standard functions/sub-functions.

A third option would require the use of the USoA account as the level of detail for the entire study.

Staff notes that the USoA does not at present require that distributors record depreciation expense and accumulated depreciation by asset account. In order to improve the accuracy of their cost allocation studies, utilities could be required to reclassify their accumulated depreciation and depreciation balances to the corresponding rate base account. This information is normally available from supporting documentation underpinning the depreciation entries. Alternatively, utilities could be required to prorate their accumulated depreciation and depreciation expenses based on gross plant balances.

4.3 Initial Recommendations

Given the fact that the USoA is set up in a functional sequence and provides an adequate level of granularity to reasonably functionalize the revenue requirement and rate base, Staff recommends that the functionalization be carried out at the account level.

This approach will ensure that a minimum standard of consistency is used for all distributors and should also simplify the filing process.

In addition, Staff recommends that utilities should be required to reclassify their accumulated depreciation and depreciation balances to the corresponding rate base account where supporting information is otherwise available. In the absence of such documentation, utilities will be required to prorate their accumulated depreciation and depreciation expenses based on gross plant balances.

Section 5: Categorization

5.1 Background

Introduction

The categorization step, also referred to as “classification”, consists of further arranging functionalized expenses and assets into groups based on cost causality characteristics.

Generally, from a methodology perspective, the assets related to the distribution function are used as a proxy to determine how the related operation and maintenance (O&M) expenses are to be categorized.

For distribution assets and O&M expenses, the two principal categorization elements are:

- Demand-related
- Customer-related

Some functionalized costs can be classified entirely as being demand or customer-related. For instance, metering, billing and collection can be entirely categorized as customer-related, while sub-transmission facilities can be fully categorized as demand-related costs.

Certain distribution assets and related O&M expenses 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 requirements. The customer component of joint-related accounts is that portion of expense or asset that varies with the number of customers. As an example, the number of poles and transformers on a utility system varies, in part, with the number of customers served by the utility. These items also represent capacity on the utility system available to meet demand requirements. Thus they exhibit attributes of both demand and customer charges.” [3]

The following sections describe several methods for categorizing joint demand- and customer-related costs.

[3] 2000 Navigant Report, pg. 9

5.1.2 Major Approaches

The 2003 Working Group spent considerable time on the categorization of joint distribution assets and operating expenses. While the literature discusses a variety of techniques, this paper will focus on three principal approaches for categorizing joint distribution assets and operating expenses. These approaches have been approved by various regulators across North America.

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 below. 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 could be criticized for taking a short-term view of cost causality and ignoring the expenses incurred to build the upstream distribution system over time.

The use of this method is reported in the U.S., but there is less practical Canadian experience with it. During the consultations, stakeholder comments will be sought on the precise elements that should be included in the Basic Customer Method.

Zero–Intercept Method

The Zero-Intercept Method assumes that a portion of the upstream distribution system is customer-related rather than entirely demand-related.

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. This method has been summarized as follows:

> "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."[4]

[4] Electric Utility Cost Allocation Manual, NARUC January, 1992 pg. 92

The 2003 Working Group was concerned about the difficulty of use and interpretation of this statistically–based method. However, several large electricity utilities across Canada have successfully applied it.

Minimum System Method

This method has been described as follows:

> "Classifying distribution plant with the minimum-size method assumes that a minimum size distribution system can be built to serve the minimum loading requirements of the customer. The minimum-size method involves determining the minimum size pole, conductor, cable, transformer, and service that is currently installed by the utility. Normally, the average book cost for each piece of equipment determines the price of all installed units. 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. Comparative studies between the minimum-size and other methods show that it generally produces a larger customer component than the zero-intercept method."[5]

The Minimum System Method has been accepted by many regulators including the OEB. Features of this method however continue to generate considerable debate across North America. For example, the Minimum System may be capable of carrying a small amount of demand, therefore overstating the level of the customer-related component. A Peak-load Carrying Capacity Adjustment is discussed in the Allocation of Demand-related costs (section 6.2).

Note on Modified Minimum System

In the past, Ontario Hydro did some empirical work which led to the development of the Modified Minimum System Method. Its distinctive feature is that it further categorizes the demand-related component into demand and energy given the present two-part distribution rate design. Staff believes it preferable in the consultations to focus on the merits of the traditional Minimum System approach which is followed elsewhere across North America. This recommendation is also supported by the increased level of effort that would be involved in conducting a study using the modified method.

[5] Electric Utility Cost Allocation Manual, NARUC
January, 1992 pg. 90

5.2 Issues and Options for Categorizing Joint Costs into Customer and Demand Categories

5.2.1 Use of Generic Categorization Methods and Results

In the present context, the selection of cost allocation methodologies and their application must also take into account the need for distributors to execute, and the OEB to review, approximately ninety informational filings on a timely basis.

The Basic Customer Method is simple to apply. Therefore, it is realistic to expect that each distributor could use it in their informational filings.

In contrast, the two other methods are both time-consuming and technically demanding. Both also require detailed asset-by-asset financial data that many distributors may not have. Therefore Staff recommends against mandating that each Ontario distributor undertake their own specific Zero-Intercept or Minimum System studies. This is also reinforced by widespread cautions that, in some cases, the Zero-Intercept Method can yield negative values for the customer related-component of distribution costs, or generate a poor coefficient of correlation (r^2), particularly for conductors.

Instead, Staff has retained an external consultant to survey and report on the results of the Zero-Intercept and Minimum System Methods used by other utilities. The results may also be separated to reflect customer density. The goal is to provide generic results, by function or account, for distributors to use in their respective filings.

5.2.2 Use of Two Categorization Methods to Assist in Reviewing Future Rate Design

A key objective of the present informational cost allocation filing process is to identify potential anomalies in fixed monthly customer charges. This can best be achieved by including two different categorization methods to provide a range of reasonableness.

The first method would produce a reasonable cost-based floor for the review of fixed monthly customer charges. The Basic Customer Method is a suitable method for this task.

The second method would generate a reasonable cost-based ceiling. Either the Zero-Intercept or Minimum System Methods could serve this function.

The results of the survey of distributors that use these methods in other jurisdictions will be an input to the determination of reasonable categorization percentages.

The present consultations will not focus on where, within the above “reasonable” range, fixed monthly service charges should end up. Rather, the information provided by the ranges will assist the Board in identifying significant outliers.

5.2.3 Categorization Method to Review Class Revenue-to-Cost Ratios

The other major objective of the forthcoming cost allocation filings is to assess the revenue-to-cost ratios for the various customer rate classes of each distributor.

It may confuse the process to report two sets of revenue-to-cost ratios. Therefore, Staff recommends that only one categorization method be used to calculate the revenue-to-cost ratios.

Given that the Zero-Intercept and Minimum System Methods have a well-established tradition of acceptance by Canadian regulators, Staff recommends the use of one of these methods. Since the results will likely differ between the two approaches, stakeholder input will be sought on the choice of the most suitable method.

During the 2003 Working Group, greater attention was spent on the Minimum System Method. Points to note include:

- Some references suggest that, in theory, the Zero-Intercept Method more accurately separates the customer-related component from total distribution costs. The merits, and implications, of this view will be fully discussed.
- The final assessment of the fairness of the Minimum System Method should take into account a Peak-Load Carrying Capacity Adjustment (see section 6.2.4).

When considering the theoretical and practical merits of the Zero-Intercept and Minimum System Methods, the need to balance accuracy and simplicity, and the establishment of a reasonable set of default categorization results that are suitable for use by the majority of Ontario distributors in the upcoming round of filings, will be paramount.

Following discussions with the Technical Advisory Team, Staff will propose default categorization figures, based on the consultant’s survey, at the Technical Workshop.

5.2.4 Need for Distributor-Specific Categorization Studies

During the first phase of consultations, Staff wishes to focus on the development of defensible standard categorization results that are broadly applicable.

To maximize the flexibility of the generic approach, the consultant's survey will endeavour to report results for different types of utilities, based on the density of their customer base (e.g. customers per kilometre). Groupings by utility size (i.e., small, medium, and large distributors) may also be explored. Staff will seek out stakeholders' views on appropriate groupings.

Input will also be sought on whether there are known circumstances where the standard results will prove seriously inaccurate (e.g. possibly in the case of network systems).

If select utility-specific categorization studies proved advisable, implementation issues would be discussed later in the consultations.

5.3 Initial Recommendations

To provide the Board and stakeholders with the most useful information to assess variations in fixed monthly customer charges, the cost allocation filings should incorporate two different categorization methods.

Staff recommends that the first method should be the Basic Customer Method. A common methodology would be defined, with distributor-specific data input.

Staff will recommend a second method after reviewing the Zero-Intercept and Minimum System Method survey results. At the first Technical Workshop, Staff will propose generic categorization results for various groupings of distributors. Stakeholder comments will be sought on an appropriate grouping method, and in identifying circumstances where these generic results may not be suitable.

The second method will also be used when determining revenue-to-cost ratios.

Section 6: Allocation Methods

6.1 Background

The final stage of a cost allocation study is the allocation of costs to customer classes. At this stage, costs have been functionalized and categorized into demand and customer-related components.

For demand-related costs, allocation factors are usually derived from load data. For customer-related costs, allocation factors may be based on accounting records, number of customers, etc.

6.2 Allocation of Demand-Related Costs

6.2.1 Background

There are several technical factors to consider when allocating the demand-related component of distribution facilities. Some distribution facilities are designed to meet the individual customer's maximum demand, while other facilities 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. Transmission and sub-transmission lines are typically sized to meet an even more diversified peak, such as maximum coincident peaks.

There are two common methods for allocating joint demand-related costs:

- Coincident Peak ("CP") – The demands of any customer class at the time of the distribution system peak
- Non-coincident Peak ("NCP") – The sum of the peak demands for a class (NCPC), or individuals within a class (NCPI), regardless of time of occurrence.

Class non-coincident demands (diversified) are generally used to design primary conductors. In contrast, line transformers are further down the system where there is less diversity, and are usually allocated based upon individual non-coincident demand. Finally, at the secondary and service drop level, individual customer maximum demands (non-diversified) are normally used to design these specific facilities. For all of these assets, the 2003 Working Group noted that some version of non-coincident peak is commonly used to allocate the demand component of such distribution facilities.

If distribution facilities can be directly attributed to a single customer, the costs should be directly allocated.

6.2.2 Issues and Options

Direct Allocation

Some distribution facilities could be dedicated to only one customer. In such cases, the costs should be directly allocated to the customer. Care should however be taken not to directly allocate costs to a customer and later allocate the same function of costs to this customer through the joint demand allocation.

Direct allocations are not that common in practice, as many customers 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 distribution system for additional reliability.

Distributors will be required to provide supporting system design information if direct allocations are proposed (such as one-line schematic drawings of the facility in question). Detailed supporting accounting records should also be filed for the applicable facility.

To promote efficient completion and review of the informational filings, it is proposed that direct allocation be allowed only when the directly allocated costs are material. The appropriate materiality test will be discussed further.

During the consultations, stakeholders' views will be sought on whether the conditions required to make use of direct allocation are sufficiently clear.

Allocation of Joint Demand-Related Costs

Use of NCP as main allocator of joint distribution demand costs

The 2003 Working Group generally agreed that NCP should be the approved method used to allocate most demand-related distribution costs. The reasons included the following:

- In general, distribution facilities are the closest to the customer and are sized to meet the individual customer's or class's maximum demand and not the aggregated coincident demand of the distributor
- NCP allocates a fairer share of demand-related costs to customer classes that use the facilities, but are not consuming much electricity at the time of the system coincident peak (e.g. off-peak or seasonal users)

- Customers have better control over their NCP than over their CP. If customers are billed on CP, they will not know their respective contribution to the system coincident peak and they would not be able to determine their demand consumption until after their billing demand has been determined.

On balance, and subject to the qualifications below, Staff agrees with the arguments in favour of NCP (both individual and class NCP) as the primary allocator for joint demand-related distribution costs

Use of CP in specialized circumstances

The 2003 Working Group believed it preferable to use coincident demands (i.e., the customer class demand at the time of the distributor's peak) as a demand allocator where distribution facilities are designed giving full consideration to the diversity inherent in all of the loads served by that distributor. Under this approach, higher-voltage distribution and sub-transmission assets would tend to be allocated using CP rather than NCP. CP is the most common method for allocating transmission costs.

Staff will work with the Technical Advisory Team to develop clear rules as to when CP should be used in the cost allocation filings.

Specific examples of assets that would tend to be allocated using CP include higher voltage conductors that loop major substations, and a single substation that serves all of a distributor's load.

The issue is subtle since the key determinant is not voltage *per se*, but rather how the facility is used. Therefore, the appropriate treatment of higher voltage distribution assets should take into account utility-specific circumstances.

General Approach to the Allocation of Joint Demand-Related Costs

Combination of Methodologies

It is recommended that all distributors employ the following combination of methodologies in their filings to allocate joint demand-related costs:

- CP may be used to allocate the costs of some substations and higher-voltage distribution conductors, provided that the utility can provide adequate documentation that justifies this approach. Staff will seek stakeholder input on how to clearly define the circumstances in which CP should be used.
- For facilities closest to the customer, such as secondary conductors and line transformers, the individual Customer NCP (NCPI) should be used.

- For the remaining distribution assets, Class NCP (NCPC) should be used as the common method.

Potential other NCP allocators

The 2003 Working Group discussed allowing utilities the option of allocating demand-related distribution costs using the NCP of a number of months if it could be justified.

The discussion focused on the merits of allowing the optional use of 12 NCP as a demand allocator. The issue is of practical importance, as it is understood that 12 NCP was used to set legacy rates. A move to 1 NCP as the sole approved demand allocator could materially impact certain classes such as seasonal customers

Much of the past support in favour of the use of 12 NCP appears to have been based on the smoothing effect that this method produces on various customer classes. However, at the cost allocation stage, the emphasis should be placed on cost causality.

To promote consistency and efficiency during the review process, the use of an NCP allocator apart from 1 NCP will not be allowed unless compelling cost justifications exist. Further stakeholder comments are welcome including potential differences between summer and winter

Individual Customer NCP vs. Class NCP

Class NCP represents the non-coincident demand for each customer class and is determined by considering all of the customers in the class as one service point. Individual customer NCP represents the sum of all customers' maximum demand with a customer class. The diversity at the time of maximum demand explains the difference between individual NCP and class NCP.

As indicated above, in Staff's view the use of individual NCP is preferable at the final stages of the distribution system (i.e., secondary line transformers and secondary conductors).

Full specifics of the differences between appropriate use of class NCP versus individual NCP will be further discussed with stakeholders.

It is suggested the individual NCP allocator should apply to assets such as the secondary lines and transformers. These distribution assets are connected to the end users and, as a result, there is less diversity. Hence, the use of individual NCP is more appropriate. Class NCP may better reflect the secondary line transformers in highly dense areas with relatively large line transformers.

Meters and service drops also represent direct customer connections, but they are usually allocated based upon a weighted customer allocator.

6.2.4 Adjustments

Staff proposes that certain technical adjustments be made to the demand allocator factors.

Class NCP by Voltage

Line Losses

Demand allocation factors are derived from actual meter reading data. Meters are installed at different voltages. Adjustments must therefore be made for line/transformation losses to fairly compare interclass demand allocation factors.

Staff proposes that utilities use the same loss factors as the ones filed in the 2006 EDR applications when adjusting their metered load data to arrive at the demand allocators.

Primary v. Secondary

Customer loads should be adjusted to recognize the voltage at which they are metered.

For example, larger users can be excluded from the allocation of secondary voltage lines and transformers since they do not use secondary voltage facilities. On the other hand, residential and small commercial customers should share the costs of the primary and secondary lines (the joint cost portion) since they use both.

Based on the USoA, Ontario distributors may not have sufficient data to identify conductors by primary and secondary voltage. Staff suggests that appropriate additional filing requirements should be developed where other clear supporting information is available (such as engineering diagrams and asset details).

Any suggestions during the consultations for future improvements to the USoA to assist in tracking primary versus secondary distribution costs will be noted.

Peak-load Carrying Capacity (“PLCC”) Adjustment

A Minimum System has a certain load carrying capability which can be viewed as being demand-related. As a result, the customer-related costs will have a demand component in them. If no adjustment is made, some customers (e.g. small users) may be allocated a disproportionate share of demand-related costs.

If the Minimum System Method is preferred for categorization, Staff would recommend that distributors be required to also adjust for the PLCC of the assumed Minimum System.

The details of a PLCC adjustment are technical. Staff has asked their external consultant to survey results from other studies and propose a reasonable default figure.

Staff proposes that utilities have the option of conducting their own PLCC analysis and submitting it as part of the filing, provided the result differs materially from the use of the generic default PLCC adjustment. The appropriate materiality test will be discussed during the third phase of consultations.

6.2.5 Initial Recommendations regarding Demand Allocation

Where a distribution asset is used by a single user, and the amount involved is material, a direct allocation is recommended. The utility must provide full supporting engineering and accounting records to substantiate this conclusion.

For all demand-related costs that cannot be directly allocated, Staff recommends that distributors employ the following combination of allocation methods:

- Utilities should use CP to allocate the cost of any facilities that were designed to meet the distribution system coincident peak. This approach, also often used for transmission assets, better recognizes the benefits of diversity. The distributor must provide planning documentation to prove that the assets were indeed designed to handle CP load
- For facilities close to the individual customers, such as secondary lines and transformers, the Individual NCP should be used. Meters and service drops will be treated as a weighted customer component and allocated separately
- For remaining distribution assets, Class 1 NCP should be used.

The above recommendations are based on cost causality considerations. Comments are invited on whether a persuasive case exists, from a cost causality perspective, for allowing the optional use of 12 NCP.

In addition, all distributors should be required to make adjustments to the demand allocators:

- Utilities must make allowances for line losses, using the same factors as the 2006 EDR filing
- Where distributors possess additional relevant information (such as the engineering diagrams and asset details) to further refine the allocation of

primary and secondary voltage conductors, they should make appropriate adjustments

- If the Minimum System Method results are used in the filings (to be confirmed), then an adjustment should be made to the demand allocator to reflect PLCC. Default PLCC figures will be proposed. The use of distributor-specific figures will be allowed, as long as full supporting analysis is provided and the proposed figure differs materially from the default figure.

6.3 Allocation of Customer-Related Costs

6.3.1 Background

The accounts classified as customer-related include the following:

(i) Operating and Maintenance Expenses:

- Billing
- Collection
- Meter Reading
- Call Centre
- Bad Debt

(ii) Capital and Depreciation

- Metering
- Billing
- Portion of distribution costs categorized as being customer-related (i.e. services, line transformers, and primary and secondary lines)
- Customer Information System

Customer-related costs are commonly allocated by using the number of customers by rate class, 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 (e.g. for metering and service drops), and the level of effort and complexities involved in providing service to the various customer groups. For example, metering costs are commonly allocated based on weighted customer allocation factors. The derivation of the weighted allocation factors takes into account the number of customers (or meters) per rate class and the cost per meter (installed) for each customer rate class. A detailed sample calculation is found at Appendix 6.

The weightings of allocation factors generally vary by asset, and type of operating and maintenance expense to reflect their specific cost characteristics. For instance, the relative proportion of cost per rate class may vary for metering equipment in contrast to service drops. In the case of meter reading, the weighted allocation factors would typically take into consideration the meter reading frequency per rate class, as well as customer density.

6.3.2 Issues and Options

Billing

This account includes the operating costs associated with the issuance of bills, as well as handling, stationary, postage, and the charges for contract billing services performed by third parties.

Billing costs generally vary according to the number of bills issued, and could be allocated to the various customer rate classes based on:

- number of bills
- weighted number of bills

The weighted number of bills would take into account the effort and complexity involved in rendering a bill for a given customer class compared to another.

Collection

Collection efforts are conducted to recover accounts receivable, and manage the exposure to bad debts.

Collection costs could be allocated based on historical tracking of collection efforts by customer group, or alternatively they could be allocated consistent with the treatment of bad debt expenses.

The latter approach does not reflect that collection costs may be incurred even if there is no resulting bad debt.

Meter Reading

At the current time, most residential and small commercial customers' meters are read manually. However, the frequency of meter readings may vary by rate class and by distributor. In contrast, the majority of interval meters for the larger customers are read electronically and hence do not require physical meter reading.

From a cost allocation perspective, rate classes or sub-groups 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 potential allocation factors for meter reading are:

- number of meters
- number of customers
- number of meter readings
- weighted number of meter readings

The number of meters and number of customers do not take into account any variation in meter reading frequency that may exist among the applicable customer groups. Additionally, the number of customers as an allocator does not capture the potential situation of having a single customer having multiple meters.

In contrast, a weighted number of meter readings allocator could reflect customer density in addition to meter reading frequency. For example, it is generally more expensive to read customers that are further apart than customers that are located in close proximity to each other.

Call Centre

Activities in this category include responding to customer inquiries, and preparing educational and communication material.

Call centre costs generally vary as a function of the number of customers and could be allocated to the various customer rate classes based on:

- number of customers
- weighted number of customers

It is common practice to allocate call centre costs based on the number of customers per rate class. However, certain utilities may have records or more detailed analysis, such as time sheets or telephone logs, to track customer service costs at the rate class level.

Bad Debt

This account will include the amounts of uncollectible utility revenues.

Many utilities monitor their bad debt write-offs at the rate class level. The Accounting Procedures Handbook (Article 220) requires utilities to maintain records demonstrating uncollectible amounts by category, customer class, etc. One option would be to directly assign bad debt expenses to specific customer rate classes based on their respective contribution to historical write-offs.

Other options have all customers sharing the responsibility for bad debt equally, or in proportion to their distribution revenues.

An allocation based on the number of customers would treat all customer groups equally. This would disregard the fact that potential exposure to bad debt is a function of distribution revenues, and the probability of non-payment based on history and other exogenous variables.

Metering

The costs of metering vary according to the type of metering device installed. For residential and general service rate classes, the most common type of metering device is the electromechanical induction meter. In contrast, large user consumers are generally required to have interval meters.

Metering costs include the capital costs, depreciation, and operating and maintenance expenses. The options to allocate each of these components include the following:

(a) Capital and Depreciation

The following allocation factors could be used to allocate the capital costs and depreciation:

- number of meters
- weighted number of meters

The number of meters as an allocator assumes that metering costs are uniform across all customer rate classes.

In contrast, the 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 classes.

(b) Operating and Maintenance Expenses

Operating and maintenance expenses could be allocated based on a detailed analysis of the maintenance schedules per meter type, and their associated duration and labour costs.

A simplified approach would consist of allocating the operating and maintenance expenses in the same fashion as the capital costs and depreciation, or based on the number of meters.

Distribution Costs

The distribution costs that could be functionalized and categorized as being customer-related costs include the following major categories:

- line transformers
- primary lines
- secondary lines
- services

The customer-related portion of line transformers, and primary and secondary lines are commonly allocated based on the number of customers, adjusted to exclude specific classes, if applicable. For example, larger users are usually excluded from the allocation of primary and secondary voltage lines since they generally take service at the sub-transmission level. Similarly, the allocation factor for secondary demand facilities should not include customers served by the primary distribution system.

The capital costs and depreciation associated with service drops could be allocated based on the number of customers, or based on the weighted number of services to recognize that larger customers may require more expensive service drops.

Customer Information System (CIS)

CIS costs are commonly allocated in a fashion consistent with the treatment of billing and call centre costs. The allocation could hence be based on:

- number of bills
- weighted number of bills
- number of customers
- weighted number of customers

The weighted number of bills would take into account the effort and complexity involved in rendering a bill for a given customer class in relation to another.

6.3.3 Initial Recommendations

From a cost causality standpoint, it is recommended that weighted allocation factors be used for most customer-related costs since these costs generally vary as a function of several cost drivers. They include the number of customers, the investment costs by rate class, and the time and resources devoted to provide service to the various customer groups. The proposed detailed allocation factors are found at Appendix 4.

From a practical standpoint for both the utilities and the Board, it is recommended that standard weighted customer allocation factors by account be developed. The latter may be based on a survey of North American utilities, and would differentiate utilities by size (e.g. small, medium, and large). The survey results and the use of a range or average weighted customer allocation factors by rate class will be discussed during the consultation process.

Distributors will have the option of developing their own weighted customer allocation factors provided that they can justify that their particular circumstances warrants such an approach, and that they provide detailed documentation supporting their request. This could, for example, apply to utilities that have specialized rate classes that are not captured in the survey results or have specific circumstances that would materially alter the allocation of their customer-related costs. In order for alternatives weighting factors to be approved, distributor must provide detailed analysis that clearly demonstrates and supports the appropriateness of any alternative customer weighting factors.

Section 7: Allocation of Other Costs

7.1 Background

Some components of the revenue requirement cannot be either directly allocated, or allocated to customer rate classes by using the three-step process described in Section 2 of this paper. 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[6]
- the use of labour ratios or headcount
- detailed analyses (e.g. based on usage)

Expenses and capital expenditures falling into that category include:

- general plant
- administrative and general expenses (A&G)
- working capital allowance
- taxes

7.2 General Plant

7.2.1 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.

7.2.2 Options

The commonly used approaches to allocate these costs are:

(i) a *pro rata* allocation to the allocated distribution plant. Referred as “plant ratio method” in the 2000 Navigant Report.

[6] Referred as “composite allocation factors” in the 2000 Navigant Report.

(ii) an allocation based on labour factors or headcount

(iii) an allocation based on detailed analyses (e.g. based on usage).

An allocation in proportion to the allocated distribution plant assumes that general plant supports the overall distribution plant functions.

The use of labour ratios or head count as allocation factors is premised on a direct relationship between the number (or costs) of employees and the incurrence of general plant costs. For example, building costs, land, computer equipment, and office furniture can vary according to the size and composition of the workforce.

Lastly, the allocation of general plant can be performed by using detailed analysis. For example, floor space could be used to attribute building and land costs to the main functions performed by the utility. Similarly, labour ratios or headcount could be used to apportion computer equipment and office furniture.

7.2.3 Initial Recommendations

For ease of administration and implementation, it is proposed that general plant be allocated *pro rata* to the allocated distribution plant. This would be the standard method for the allocation of general plant.

It is also proposed that some flexibility be allowed to distributors that have detailed analyses, including labour ratios, to allocate general plant. The onus would be on the distributors to justify and provide detailed supporting documentation to their request.

7.3 Administrative and General Expenses (A&G)

7.3.1 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.

7.3.2 Options

Various approaches can be used to allocate A&G.

The first approach consists of allocating A&G in proportion to the labour component of the O&M expenses. This recognizes for example that employee pensions and benefits should be allocated in a fashion consistent with salaries.

Another commonly used approach is to allocate *pro rata* all A&G costs to the allocated O&M expenses, excluding A&G.

Lastly, the allocation of A&G can be performed by grouping similar accounts into sub-groupings based on the overall nature of the accounts. For example, some accounts are more closely related to plant activities, labour or customers and would be allocated as such.

7.3.3 Initial Recommendations

For ease of implementation, it is proposed that A&G be allocated *pro rata* to the allocated O&M expenses (excluding A&G). This would be the standard method of allocation.

It is also proposed that some flexibility would be permitted to distributors that have detailed analyses that allow them to group similar accounts into sub-groupings based on the overall nature of the accounts. For example, accounts that are more closely related to plant activities such as property insurance expense could be allocated in proportion to the allocated rate base. The onus would be on the distributors to justify and provide detailed supporting documentation to their request.

7.4 Working Capital Allowance

7.4.1 Background

The working capital allowance (WCA) forms part of rate base and is the working capital deemed to be required by a distributor to support its operations. For 2006 rates**,** the WCA for electricity distributors is calculated as 15% of the sum of the cost of power (COP) and certain distribution expenses with adjustments (excluding depreciation).[7]

7.4.2 Options

The first option consists of separating the WCA attributable to the COP from the portion associated with distribution expenses. The COP includes commodity, transmission and wholesale market service charges. Given that the breakdown by rate class by

[7] See Appendix B, Table B.2 of the 2006 Rate Handbook.

component is not readily available, it is proposed that the COP be allocated on the basis of energy. This method reflects that the commodity is the largest component of the COP. The WCA associated with the allowable distribution expenses would be allocated in the same fashion as the specific distribution expenses included in the WCA calculation.

The second option is a variant of the first option. Under this option, the treatment of the WCA attributable to the COP would be the same as that under the first option described above. However, for simplicity, the WCA associated with the allowable distribution expenses would be allocated *pro rata* to the allocated total O&M costs.

The third option would consider the accounting definition of WCA (current assets less current liabilities). The various components of the assets and liabilities would be allocated based on causality principles. For example, cash could be allocated based on class revenue, and material and supplies could be based on specific allocation factors reflecting the nature of the inventory. Given that the current assets less liabilities calculation will most likely differ from the deemed WCA calculation, an adjustment would be required to reconcile with the revenue requirement determination. This difference would have to be prorated.

7.4.3 Initial Recommendations

Staff recommends that the second option be the standard method for allocating WCA for all distributors. The WCA related to the COP would be allocated on the basis of energy. The WCA associated with the allowable distribution expenses would be allocated *pro rata* to the allocated total O&M costs.

7.5 Taxes

7.5.1 Background

For privately-owned utilities, taxes include income, capital and property taxes. In the case of municipally- or provincially-owned utilities, they are subject to payments in lieu of income and capital taxes, as well as various property taxes.

7.5.2 Options

Capital, income and property taxes are commonly allocated on the basis of the allocated distribution rate base given that they are largely asset-related.

Another method of allocation consists of going through the detailed income tax, capital and property tax calculations, and functionalize, categorize and allocate costs accordingly. This method is complex and rarely used.

7.5.3 Initial Recommendations

It is recommended that the standard method for allocating taxes be an allocation *pro rata* to the allocated rate base.

7.6 Miscellaneous and Other Revenues

7.6.1 Background

Miscellaneous and other revenues include:

- connection and disconnection fees
- net revenues from merchandising and jobbing contracts
- late payment charges

7.6.2 Options

Some miscellaneous revenues can be directly allocated as per Appendix 1 of this report. These revenues include Account 4225 (Late Payment Charges) and Account 4235 (Miscellaneous Service Charge).

The options commonly used to allocate non-directly allocable miscellaneous and other revenues are either allocation in proportion to the allocated distribution rate base, or based on detailed analyses.

7.6.3 Initial Recommendations

Considering materiality and simplicity in implementation, it is recommended that allocation in proportion to the allocated distribution rate base be the standard for allocating miscellaneous and other non-directly assignable revenues.

Section 8: Load Data Requirements

8.1 Load Data Requirements

8.1.1 Background

Use of Load Data in Establishing Demand Allocators

While there are a number of methods to allocate distribution demand-related costs, all require the use of load data. It is widely recognized that load data plays an important role in the accuracy of the cost allocation results. The American Public Power Association cost allocation manual explains (at page VII-1):

> “The presence (or absence) of data on demand loads is a key concern in a cost of service study. Demand, or capacity, costs are a large portion of total utility costs. Accurate allocation of these costs to customer classes of service depends, in large part, on the accuracy of demand load data available.”

8.1.2 OEB Load Data Directions

The former (2001) Electricity Distribution Rates Handbook (“DRH”) advised utilities:

> “Prior to the implementation of 2nd generation PBR the Board will require utilities to develop allocation studies that reflect: …. current load profiles of the various rate groups … The Board strongly encourages utilities to jointly sponsor these studies, achieving economies where possible through joint development of load data.”

Following detailed consultations and published recommendations,[8] the Board issued its Load Data Collection Directions (November 10, 2003). A copy of those directions is attached as Appendix 7. These directions require (among other things) that all utilities acquire at least 12 months of statistically reliable load data.

The Board’s Load Data Collection Directions were intended to facilitate cost effective joint collection of load data by Ontario electricity distributors. It is Staff’s understanding that a load research consortium has been formed which comprises a significant number of distributors that serve the majority of the electricity customers in the Province (for details, see Appendix K to the September 2003 Load Data Collection Report).

[8] See Report issued by The Cost Allocation Working Group (September 23, 2003). A copy of the working group minutes, Report and final Board directions can be found on the project web page.

8.1.3 Load Data Implementation Issues

There are a variety of technical questions dealing with how the new load data will be processed and prepared for use in the cost allocation model. These will be examined in detail during the third phase of the consultations.

For example, distributors with specialized rate classifications should be considering how they will acquire the updated load data. Careful consideration is required, as it is understood that the above industry research group may not produce data for specialized classes.

8.2 Weather Normalization of Load Data

8.2.1 Background

The 2003 Working Group spent considerable time examining the need for, and manner of, weather normalizing the load data to be used when allocating demand-related costs.[9]

The rationale for weather normalizing has been summarized as follows:

> "Weather normalization of peak demands results in a more stable allocation of demand-related costs to weather sensitive classes from year to year by adjusting the classes' actual peak demands to a peak demand reflective of normal or typical weather conditions". [10]

The objective of weather normalization is to adjust the actual demand to a calculated demand that is more reflective of the weather condition of a normal or typical year.

An experienced local load forecaster cautioned the 2003 Working Group that the issue was an important one for Ontario electricity distributors. He estimated that the size of weather effects in a year could range from 1%-2% for energy, and up to 10% for peak.

As Staff understands, the importance of weather normalization issue is compounded by the fact that summer weather was unusually cool in the year load data was mandated to be collected (summer 2004).

[9] See Section 16, The Cost Allocation Working Group First Report , Load Data Collection (September 23, 2003), pgs 38-40.
[10] Taken from Weather Normalization of System Peak Demands, Arkansas Power and Light Company, October 1988.

8.2.2 Issues and Options

Should weather normalization be required?

In the first phase of the consultations, Staff proposes to address the following two questions: 1) should utilities be required to weather normalize the load data collected? and, 2) if so, should a common weather normalization method be used?

Staff understands that the weather effect in Ontario is significant, as evident, for example, in the differences between the summers of 2004 and 2005. Moreover, industry can co-operate in the execution of the weather normalization and reduce the one-time costs. Therefore, in respect of question 1), Staff would recommend that all Ontario electricity distributors be required to weather normalize the load data collected for the upcoming cost allocation studies.

In regards to question 2), given the number of Ontario electricity distributors, and the goals of the cost allocation filings, Staff would recommend that a common methodology be used.

What methodology should be adopted?

The 2003 Working Group was advised that considerable work was done by the former Ontario Hydro to create a weather normalization model for load forecasting purposes. The model was not initially developed for cost allocation. The same basic methodology continues to be used today by some distributors such as Hydro One, as well as by OPG and the IESO.

Staff proposes that for the third phase of the discussions, this methodology be the starting point of discussion. However, Staff believes it is important that the methodology be reviewed.

Weather normalization methodologies have been the subject of extensive scrutiny and expert evidence in the Board's natural gas hearings (in particular, the Union Gas decision EB-2003-0063/EB-2003-0087). Staff believes that this experience should also be considered by electricity sector stakeholders to facilitate a more detailed discussion. However, due regard should be paid to underlying differences between the two sectors. For example, in the electricity sector, both heating degree days and cooling degree days are significant.

This area is highly technical. Therefore it is proposed the third phase discussions focus on a few key principles, such as:

- what number of years should be used to establish normal weather
- given that the weather has been warmer in the last few years, whether all years carry an equal weight or should there be a weighting towards more recent years
- the 2003 Working Group discussed normalizing to an average of annual peak values
- what variables are appropriate to take into account in the weather normalization models (for example, the Ontario Hydro method utilizes temperature, cloud cover and wind speed in the winter, and temperature, cloud cover and humidity in the summer)
- how should the weather normalization take into account substantial differences in weather conditions between regions, for example, Niagara Falls and North Bay.

8.2.3 Initial Recommendations

Given the importance of weather sensitive loads, Staff proposes that all Ontario electricity distributors be required to weather normalize the load data used in the cost allocation studies.

To ensure consistency when later reviewing the filings, Staff further proposes that a uniform weather normalization method be adopted.

- If the Board agrees to the above following stakeholder input, Staff proposes to later examine the details of a common weather normalization methodology. The methodology developed by Ontario Hydro will be the starting point for discussion.

Section 9: Cost Allocation Implementation Issues

9.1 Background

It is anticipated that in March 2006 the Board will issue a Report on Cost Allocation Principles and Methodologies. The subsequent third phase of consultations will then deal with implementation issues.

Following the third phase of consultations, the Board plans to issue the following in July 2006:

- a Board-approved cost allocation filing model with accompanying instructions
- general filing instructions
- a summary template, with attached schedules.

Key cost allocation implementation issues for discussion during the third phase of the consultation are highlighted below.

9.2 Cost Allocation Filing Period

A cost allocation study is performed by using the Board-approved revenue requirement and data for a one-year reference period or “test year”. A decision is required on the appropriate test year for the cost allocation studies.

Staff recommends that the revenue requirement underpinning the Board-approved 2006 rates be used as the starting point for the cost allocation informational filings scheduled for the fall of 2006.

For the majority of distributors that used a historical test year in their 2006 EDR filings, it is proposed that the underlying 2004 data (trial balances, etc.) should be the starting point for the upcoming cost allocation filings. For those utilities that filed on a future test year basis in their 2006 EDR applications, the appropriate trial balance supporting those applications should be the starting point for the cost allocation filings.

Certain adjustments to the 2006 revenue requirement will be required before it is used for cost allocation purposes. They include:

- non-utility operations
- non-recurring regulatory accounts for tracking deferrals and variances

The former consist of any non-distribution related activities (such as streetlighting or water heater rental and maintenance) that may be listed in a distributor's trial balance, but should not be included in the utility's cost allocation study for the regulated business.

Examples of the latter are accounts set up to record various deferrals as a result of regulatory rulings such as account 1574 Deferred Rate Impact Amounts and account 1588 RSVAPower.

*S*takeholder views will be sought on whether any other adjustments should be made to the 2006 revenue requirement.

9.3 Summary of the Study

A summary will be required with the cost allocation filings including an explanation of the study results.

In addition, the summary should include the rationale, and supporting documentation (including any materiality thresholds that may be applicable) for allowed alternative cost allocation methodologies. Specific examples of such supplemental information include:

- documentation to support requests for direct allocation of demand-related costs
- documentation to support the use of CP to allocate demand-related costs
- load study methodology, if a distributor collects data independently rather than through the industry research group (whose methodology the Board previously reviewed).

The summary will also provide the place for the distributor to disclose additional information or special circumstances that might assist the Board in understanding the filing. Schedules may be provided for the LDC to attach to the summary. Examples could include distributor-specific accounting or data issues.

9.4 Inputs to the Model

The inputs to the OEB cost allocation review filing model will be discussed as the modeling proceeds. Final recommendations will be made in the third phase of the consultations.

To assist users, it is anticipated that various standardized features will be incorporated into the model (for example, direct assignments, categorization factors, demand allocators, customer allocators, etc.) reflecting the Board-approved methodologies and principles.

Distributors may be required to file some utility specific data, such as:

- the full trial balance that supported the approved revenue requirement (e.g. 2004 for those utilities that filed on a historic test year in 2006 EDR)
- utility-specific load profiles per class
- revenues under existing rates (adjusted for regulatory assets and other rate riders) per rate class.

9.5 Other Data Issues

Data availability and consistency issues will be addressed during the third phase of the consultation.

Comments will be sought on the source of sufficiently disaggregated filing data, for example, where a distributor has outsourced significant functions.

The consultations will also confirm that there is consistency and a common understanding in how underlying costs and accounts should be mapped into the standard functions incorporated in the cost allocation model.

9.6 Output of the Model

The details of the various outputs from the cost allocation filing model will be finalized during the third phase consultations.

A standard set of outputs from the filing model will be prescribed. Given the key objectives of the cost allocation review, the following will be the major outputs:

- revenue-to-cost ratio for each customer rate class
- cost-based fixed monthly charge by rate class derived by using the Basic Customer Method
- cost-based fixed monthly charge by rate class derived by using the Minimum System or the Zero Intercept Methodology.

The model will be run once using the Basic Customer approach, and a second time using the generic categorization survey results (using either Minimum System or Zero-Intercept methods).

To facilitate a detailed review of the filing, the filing model will be organized so that additional technical information is produced in a standard format. Stakeholder comments will be sought. Examples include:

- summary dollar amounts of Direct Assignments, Functionalization, Categorization and Allocation. Separation by rate base and income statement accounts will also be discussed

- unit costs per rate base and income statement accounts

An appropriate audit trail should also be a feature of the model.

To facilitate future rate design discussions, some additional standard outputs may be added to the filing model, such as:

- bill and rate impact by components from using cost-based rates

- the percentage impact upon customers from any proposed new rate class.

9.7 Use of OEB Model

The purpose of the present cost allocation informational filings is to gather detailed cost-based information. Consistency in the filings received from distributors is a crucial goal. The need to review approximately ninety filings on an expeditious basis is a further important practical consideration.

Given the above, the Board is planning to issue a standard cost allocation filing model. That model will incorporate the cost allocation methodologies and principles approved by the Board. Written instructions on the use of the model will also be issued.

The proposed two rounds of model testing are intended to ensure that the final model is operational, and as user-friendly as possible.

To promote consistency and simplicity, Staff recommends that use of the Board filing model should be mandatory, unless a distributor applies for and receives an exemption from the Board.

During the third phase of the consultations, Staff will request stakeholders' views on developing an objective set of criteria as to when a utility's is sufficiently different from other distributors that the use of the Board’s mandated model is not suitable. The general intent, however, is that the standard OEB model be designed with enough flexibility to cover the great majority of Ontario distributors.

Distributors that use their own cost allocation model will need to ensure that their models are consistent with the Board-approved cost allocation methodologies and principles (for example, allocation factors to be used).

In addition, any distributor-specific model will be required to generate the same outputs as those obtained from the OEB model (e.g. class revenue to cost ratios, fixed monthly service charge floor and ceiling, etc.).

Section 10: Addition of a New Rate Class and Rate Design for Scattered Unmetered Loads

10.1 Background

The 2006 EDR Handbook (see section 10.2) defines scattered unmetered loads as a group of accounts that are not specifically metered. This group consists of bus shelters, telephone booths, CATV amplifiers, traffic signal lights and billboard lighting.

These loads are unmetered because their consumption is usually small, with a more or less constant profile, and they are generally tapped off the secondary lines. The principle is that it may not be practical to put in a meter to measure the consumption of a 100-watt light bulb in a phone booth or on traffic signals. The general expectation is that consumption can usually be reasonably estimated for these types of load. This is an area of some debate between utilities and customers.

Persistent concerns have been raised by customers in this group about the lack of consistency in how utilities bill these loads. It is understood that most utilities treat these as a GS<50 kW customer and bill each connection as a separate account. Some distributors have a lower monthly service charge but a higher volumetric charge, while others have a lower monthly and volumetric charge. Some distributors combine the multiple connections of a company and produce one bill for the customer (i.e. apply only one monthly service charge).

An interim solution was adopted for 2006: It required distributors that currently bill scattered unmetered customers on a per connection point basis using a small commercial or GS<50 kW monthly service charge to change the monthly service charge to 50% of the GS<50 kW monthly service charge.

10.2 Issues and Options

Staff recommends the “interim” approach be replaced by a full, cost-justified methodology. As a result, during the second phase of the consultations the following topics will be addressed:

Creation of a new class

From a cost–causality perspective, there are merits in considering the creation of a new rate class for scattered unmetered loads (for example, their load profiles are distinctive, and customer costs differ from regular GS customers). Furthermore, while caution should be exercised about "one-off" changes to the heterogeneous GS rate grouping[11], the issue is relatively discrete and therefore can be successfully addressed separately from the comprehensive rate design review. Finally, some distributors already treat such users as a separate class, and consistency across the Province is a valuable goal.

A strong case exists for requiring all distributors to treat scattered unmetered loads as a separate rate grouping in the upcoming cost allocation informational filings. This would allow the Board, following their review, to proceed with the potential implementation of a new common scattered unmetered class.

Cost allocation studies

Staff will seek stakeholder input on the development of a methodology to accurately track the costs for this new rate classification. This will ensure that other ratepayers are not unfairly treated by the creation of a new scattered unmetered load class.

Staff suggests that unmetered loads should bear the full allocated costs of the distribution assets, with some adjustment to service drops and service calls (for example, there are no lights-out calls).

Staff further proposes that the cost allocation methodology reflects the following considerations:

- as there are no meters, the cost of meter, meter reading and meter operations should be excluded

- the cost of billing should be adjusted because the bill is not sent to each connection but to one central office*.*

Input will be sought on whether there are any additional costs that should be allocated or excluded from this new class.

Rate Design

Once costs are fairly allocated to this new class, the question remains whether it is preferable to recover customer-related costs through a per customer or per connection charge or a combination of the two. Some costs are likely driven on a per connection basis, while others on a per customer basis.

[11] One of the comments provided after the June 2005 "kickoff" meeting in this project cautioned new rate classes should generally proceed under the auspices of a consistent overall rate design philosophy.

Note on Streetlighting

During the 2006 EDR process, a municipality raised concern about streetlighting rates.

The question of designing streetlighting rates on a per customer or per connection basis will be addressed when the same topic is discussed for the new scattered unmetered load class.

It should also be noted that the streetlighting load is generally off-peak in the summer and are on-peak during part of the winter months. The potential adjustments to account for the off-peak nature will also be discussed during these consultations.

10.3 Initial Recommendations

Staff recommends that a new scattered unmetered load class be set up as part of the cost allocation model and that a full cost allocation study be performed for the new class.

Staff further recommends that the fixed monthly charged be split into two components. A component of the fixed monthly charge will be applied on a per customer basis, while the other component will recover costs that relate to individual connections. Remaining distribution costs will be recovered through a volumetric charge.

Section 11 Addition of a New Rate Class for Larger Users in the General Service >50 kW Classification

11.1 Background

Over the years, various approaches have been taken towards rate classification for larger General Service customers in Ontario.

Before they became subject to regulation by the OEB, utilities were allowed to apply for a new GS intermediate class for customers with individual loads of less than 5,000 kW, representing individually more than 10% of the utility's load, and where the load profile of the customer significantly affected the rest of the general service customers when included in that class. The rate generally applied to larger loads.

Seven utilities have OEB-approved rates schedules with an intermediate GS class. The boundaries for such a class vary, with most in the 2.5MW to 3 MW range.

When the 2001 Distribution Rates Handbook was issued, a new definition of an intermediate subclass (3,000 kW to 5,000 kW) was included. However, that definition was applied by few, if any, distributors. The definition was dropped in the 2006 EDR Handbook.

As a result, at present there is no common intermediate GS class between 50 kW and 5000 kW. This may appear to be an unusually wide range.

Pending the announced comprehensive study of distribution rate design, the Board does not wish to enter into a full-scale review of GS rate design (for instance, the GS 50 kW boundary will not be re-examined for the present). But present consultations will try to make some progress on promoting greater consistency in the treatment of larger GS customers across the Province (for example, fixed variable splits for larger GS customers will be examined as part of the overall review of fixed monthly service charge anomalies).

11.2 Issues and Options

It is useful to seek stakeholder input on the merits of different ways to assess the need for, and implications of, a common approach towards a GS intermediate rate classification.

Several approaches are possible:

i) A survey could be undertaken of common GS intermediate class boundaries elsewhere and tentative suggestions made for Ontario. But such an approach would provide no specific underlying local cost justification.

ii) Distributors could be asked if there is a natural break in their delivery voltages that could serve as the boundary for a new common intermediate class. Staff cannot confirm this is the case, given the wide variations in service configurations amongst distributors in Ontario. Further discussion will be held with the Technical Advisory Team.

iii) The former 10% test (see above) could be reintroduced. This would result in varying intermediate class boundaries across the Province, but the underlying principle would be common.

iv) Load factors could be an appropriate cost causality factor to take into account when setting rate classifications. The Provincial load data research group had earlier agreed to examine the new GS load data its members collected and check if trends exist which could prove useful in GS rate design. Staff believes these results could prove relevant to the issue; however, detailed analysis may not be available until 2006Q1.

11.3 Initial Recommendations

Staff wishes to identify and obtain stakeholder comments on the various approaches towards the potential design of a new GS intermediate rate classification including the use of load factors, delivery voltages and the merits of reintroducing the former 10% test.

If implementation appears likely, Staff will also ask stakeholder views on how to minimize potentially adverse rate impacts and boundary concerns.

Section 12: Rates to Charge Embedded Distributors

12.1 Background

This section will deal with rate classification, cost allocation, and rate design issues in situations where a host utility transfers power to an embedded utility (also known as Low Voltage (LV) rates).

Staff understands that there are approximately 12 distributors across the Province that act, to varying degrees, as a host distributor for embedded distributors. Developing a consistent policy in this area is challenging as some utilities provide modest services, while others provide more extensive services and may have certain unique issues. The present consultations will focus on the issues of generic relevance to all host distributors.

12.2 Issues and Recommendations

Creation of a new class

At present, most of the utilities that provide supply delivery services do not have a separate class and treat the embedded distributors as GS customers. The notable exception is Hydro One Networks. LV rates were approved by the Board.

This topic was raised during the 2006 EDR process. The 2006 EDR Handbook (see section 10.7) allowed host distributors to come forward with applications for a new class. At least one distributor has applied.

There are several justifications for treating embedded distributors' customers as a separate class: their load factor is quite high and the assets used are generally quite specific though sometimes shared.

Staff therefore recommends that all host distributors be required to treat embedded distributors as a separate class in their upcoming cost allocation filings.

Allocating costs to the new class

Staff has identified two approaches to the issue.

The first would be to require that a cost allocation methodology be followed when allocating costs to the embedded distributor customer class. This would require that the costs be functionalized, categorized and allocated.

It is understood that another approach may have developed for certain purposes by the former Ontario Hydro. Staff believes, however, that these costs should be allocated in a generally consistent manner with other costs in the filings and therefore would not support use of a different approach.

Cost allocation issues for distributors that provide extensive embedded distributor services may prove somewhat more complex in practice. However, Staff believes the same cost allocation principles should apply to all distributors. During the consultations specific technical features of sub-transmission system configuration that raise special issues may be discussed.

Rate Design

Staff understands that when these types of rates are set in other jurisdictions, some consideration is given as to how transmission rates are designed. Certain features of a given utility's transmission rate design may not be suitable when designing distribution rates for charging embedded distributors.

In Ontario, transmission rate design for Hydro One Networks was approved by the Board. A key feature of the transmission rate design is the use of a load billing determinant only.

Staff would note, however, that all currently-approved distribution rates have two billing elements, namely a fixed and a variable component.

It is useful to have a consistent approach towards designing the structure of distribution rates. Moreover, Staff believes that some costs to provide embedded distributor services (e.g. metering and billing) are customer-related and should be recovered through a fixed monthly charge.

Staff therefore recommends a two-part rate structure. Stakeholder views will be sought on how to use the cost allocation results to design the new rates.

Section 13: Treatment of the rate sub-classification identified as “Time-Of-Use”

13.1 Background

Prior to the opening of the electricity market, Ontario Hydro was a generator, transmitter and distributor of electricity. It charged the municipal utilities for the cost of power, which included generation and transmission costs. The wholesale cost of power had two charge determinants, one based on the utility’s non-coincident peak and the other based on energy.

Around 1990, Ontario Hydro introduced a time differentiation into its wholesale rates. The charge determinants remained the same, but were now broken down by season and time of day. This was done to better reflect cost causality in the generation of the electricity. At that time, the maximum system peak occurred in the winter and as a result the costs and resultant rates were higher than in the summer. It was also determined that there were diurnal peak and off peak times and the rates were set to capture these cost differences.

To reflect these time differentiated wholesale rates at the retail level, some utilities established retail Time-of-Use (“TOU”) rates, primarily for the Large Users (over 5,000 kW) and higher demand GS customers.

In 2000, the Board required the distributors to “unbundle” their rates into distribution and cost of power components. During that exercise, a distributor treated its TOU sub-classes as any other group of customers and determined the split in costs between distribution and commodity using the guidelines that were established by the Board (in effect, there was no longer any cost causality rationale supporting the unbundled TOU sub-classification). As a result, the GS TOU sub-classes usually had distribution rates that were different from the equivalent regular GS classes.

When the market opened, the commodity component of the cost of power was no longer regulated. However, many distributors retained their TOU sub-class of customers with their different distribution rates. Most distributors eliminated the seasonal and diurnal peak and off-peak time periods.

13.2 Issues and Options

One option is to allow a distributor the discretion as to when these rate classifications are removed. This was the approach taken for 2006 rates (see section 10.3, 2006 EDR Handbook).

On the basis of consistency amonst distributors and for simplicity, an alternative option is to mandate the elimination of these sub-classifications.

13.3 Initial Recommendations

Staff recommends that the upcoming cost allocation studies assume the elimination of the sub-classification known as TOU and the absorption of the costs currently assigned to the equivalent non-TOU class.

As noted in the June 24th 2005 “kickoff” letter, the merits of introducing new redesigned true TOU distribution rates, which could take into account current conditions and policy objectives, will be considered after the pending comprehensive rate design paper is issued by Staff in 2006.

Section 14: Rate Design Implementation Issues

14.1 Filing Requirements for Adding/Deleting Rate Classifications

In addition to producing information relevant to the fair recovery of costs between classes, the upcoming informational filings will gather information to address two rate design areas: select rate classification changes, and a review of fixed monthly service charge. Rate design policy issues will be addressed in the second phase of the consultations, while related implementation details will be addressed in the third phase.

14.1.1 Background

As previously mentioned, this review will also examine the need for, and implications of, introducing new rate classes for scattered unmetered loads, embedded distributors, and larger GS customers, and eliminating the existing TOU distribution rates. Additional specialized rate classification may arise during discussions.

Important considerations for the Board in the process of adding or deleting customer rate classes are the financial implications on affected customers. For example, the implications for customers that are being re-classified as part of a new rate class or into an existing rate class, as well as the implications on remaining customers of a given rate class, should be understood and documented.

14.1.2 Issues and Options

Affected distributors should be required to perform and file a cost of service study with both the new and existing rate classifications. This would provide sensitivity analysis at all stages of the cost allocation process at the rate class level.

In addition to the above, distributors could be asked to quantify the impact on individual customers in a new rate class, and remaining and new customers in an existing rate class. This process could however be onerous for classes with many customers. A more practical approach could consist of setting pre-defined customer load profiles that would be typical to a given rate class. These typical load profiles would provide an indication of the rate and bill impacts at the customer level within a rate class.

The Board may be concerned about the impact on rate design simplicity if new rate classifications are proposed with minor cost differentials. The present process should address this issue by ensuring that the filing model produces sufficient relevant information.

14.1.3 Initial Recommendations

In order to assess the implications of adding or deleting a rate class at the rate class level, it is recommended that distributors be required to file a supplemental cost of service study with the new rate classification. The rate and bill impacts at the rate class level should be explicitly captured in a separate document.

In addition, distributors should be required to file rate and bill impacts at the customer level by using typical load profiles. Guidelines around the establishment of typical load profiles will be discussed as part of the consultation process.

14.2 Review of Fixed/Variable Distribution Splits

14.2.1 Background

Following receipt of all the informational filings in the fall of 2006, the Board should be in a position to identify fixed monthly service charge anomalies.
The Board may later request that certain distributors proceed to file rate applications to address significant rate issues.

As previously advised, the present consultations will not discuss what resulting fixed monthly charge represents an appropriate balance between cost causality and other rate design objectives (such as setting rates to induce a conservation culture or using marginal cost studies to send pricing signals).

The filing model must produce adequate information to allow the Board to conduct the above review. The third phase of the consultations will focus on what information is required to undertake that task.

14.2.2 Issues and Options

As previously indicated, Staff proposes that the review of the fixed monthly service charges be done by establishing a reasonable cost-based floor and ceiling. The cost-based floor will be based on the results of the Basic Customer Method while the ceiling will be set by using a survey of the Minimum System and Zero-Intercept results.

During the consultations, particular attention should be paid to the details of the Minimum System approach. In particular, during the 2003 consultations, it was identified that one version of the Minimum System tested in earlier Ontario Hydro reports produced very high monthly charges. Such results would be unsatisfactory for the present purposes, as it would reduce the Board's ability to identify anomalously high fixed monthly service charges.

During the 2003 consultations, some distributors noted that relatively higher fixed monthly service charges could be accompanied by lower variable charges. Total distribution charges should also be examined (although for lower volume consumers the amount of fixed monthly charges remains important).

The 2003 Working Group was presented with data suggesting variations in fixed monthly service charges were particularly acute among large users. This issue was also raised in the submissions received from interested stakeholders on the planned scope of the current review.

14.2.3 Initial Recommendations

Staff recommends that the filing model incorporate both the Basic Customer Method, as well as generic figures based on a survey of the Minimum System and Zero-Intercept results. The former will generate a cost-based floor for fixed monthly service charges, while the latter will establish the cost-based ceiling.

Staff proposes that the filing model produces fixed monthly service charge data for all current rate classes.

In cases where the current fixed monthly service charge falls outside of the above range, distributors will have an opportunity to provide additional explanation in their filing.

Staff further proposes that consideration be given to the total distribution charges for all customer rate classes.

14.3 Defining and Measuring Customer Peak Demand

14.3.1 Background

Distributors across the province currently use different methods to measure peak demand. Peak demand is the billing determinant that is used to recover demand based distribution charges.

Peak demand can be measured on the basis of:

- clock hour interval demand readings
- 15 minute interval demand readings
- a rolling 60 minute interval updated every 15 minutes

- maximum demand during a billing period

Clock hour interval demand readings are the basis for wholesale transmission charges, as well as, commodity settlement with load customers.

14.3.2 Options and Issues

The use of a particular method over another is likely to generate different peak demand results and therefore, different demand charges. This in turn would likely have ramifications on load research, cost allocation, and rate design.

Staff would like to investigate the merits and implications of having a common definition and measurement of peak demand across all distributors. In addition, Staff would welcome stakeholders' comments on the respective merits of the methods described above.

14.3.3 Initial Recommendations

Staff recommends that this topic be discussed as part the Technical Advisory Team discussion and associated Workshop during the second phase of the consultations.

In particular, Staff wishes to gather stakeholders' input on the merits and implications of having a common definition and measurement of peak demand across all distributors. Staff would also welcome comments on the respective merits of the methods described above.

Appendices

Appendix 1 – Direct Assignment of Accounts

Appendix 1 - Direct Assignment of Accounts		
USoA Account #	**Accounts**	**Direct Assignment**
	Distribution Plant	
1875	Street Lighting and Signal Systems	x
	General Plant	
1965	Water Heater Rental Units	x
1985	Sentinel Lighting Rental Units	x
	Customer Account Expenses	
5185	Water Heater Rentals - Labour	x
5186	Water Heater Rentals - Materials and Expenses	x
5190	Water Heater Controls - Labour	x
5192	Water Heater Controls - Materials and Expenses	x
5170	Sentinel Lights - Labour	x
5172	Sentinel Lights - Materials and Expenses	x
5165	Maintenance of Street Lighting and Signal Systems	x

Appendix 2 – Functionalization of Selected Accounts

Appendix 2 - Functionalization of Selected Accounts						
USoA Account #	Accounts	Functionalization				
		Distribution	Metering	A & G	Customer Services	Sub - transmission
	Distribution Plant					
1805	Land	x				
1806	Land Rights	x				
1808	Buildings and Fixtures	x				
1810	Leasehold Improvements	x				
1815	Transformer Station Equipment - Normally Primary above 50 kV					x
1820	Distribution Station Equipment - Normally Primary below 50 kV	x				
1825	Storage Battery Equipment	x				
1830	Poles, Towers and Fixtures	x				
1835	Overhead Conductors and Devices	x				
1840	Underground Conduit	x				
1845	Underground Conductors and Devices	x				
1850	Line Transformers	x				
1855	Services	x				
1860	Meters		x			
1565	Conservation and Demand Management Expenditures and Recoveries				x	
	Intangible Plant					

Appendix 2 - Functionalization of Selected Accounts						
USoA Account #	**Accounts**	**Functionalization**				
		Distribution	Metering	A & G	Customer Services	Sub - transmission
1608	Franchises and Consents			x		
	<u>Accumulated Amortization</u>					
2105	Accum. Amortization of Electric Utility Plant - Property, Plant, & Equipment			x		
2120	Accumulated Amortization of Electric Utility Plant - Intangibles			x		
	<u>Operation</u>					
5005	Operation Supervision and Engineering	x				
5010	Load Dispatching	x				
5012	Station Buildings and Fixtures Expense	x				
5014	Transformer Station Equipment - Operation Labour	x				
5015	Transformer Station Equipment - Operation Supplies and Expenses	x				
5016	Distribution Station Equipment - Operation Labour	x				
5017	Distribution Station Equipment - Operation Supplies and Expenses	x				
5020	Overhead Distribution Lines and Feeders - Operation Labour	x				
5025	Overhead Distribution Lines & Feeders - Operation Supplies and Expenses	x				
5030	Overhead Subtransmission Feeders - Operation					x
5035	Overhead Distribution Transformers- Operation	x				
5040	Underground Distribution Lines and Feeders - Operation Labour	x				

Appendix 2 - Functionalization of Selected Accounts						
USoA Account #	Accounts	Functionalization				
		Distribution	Metering	A & G	Customer Services	Sub - transmission
5045	Underground Distribution Lines & Feeders - Operation Supplies & Expenses	x				
5050	Underground Subtransmission Feeders - Operation					x
5055	Underground Distribution Transformers - Operation	x				
5065	Meter Expense		x			
5070	Customer Premises - Operation Labour				x	
5075	Customer Premises - Materials and Expenses				x	
5085	Miscellaneous Distribution Expense	x				
5090	Underground Distribution Lines and Feeders - Rental Paid	x				
5095	Overhead Distribution Lines and Feeders - Rental Paid	x				
5096	Other Rent	x				
	Maintenance					
5105	Maintenance Supervision and Engineering	x				
5110	Maintenance of Buildings and Fixtures - Distribution Stations	x				
5112	Maintenance of Transformer Station Equipment	x				
5114	Maintenance of Distribution Station Equipment	x				
5120	Maintenance of Poles, Towers and Fixtures	x				
5125	Maintenance of Overhead Conductors and Devices	x				
5130	Maintenance of Overhead Services	x				

Appendix 2 - Functionalization of Selected Accounts						
USoA Account #	**Accounts**	**Functionalization**				
		Distribution	Metering	A & G	Customer Services	Sub - transmission
5135	Overhead Distribution Lines and Feeders - Right of Way	x				
5145	Maintenance of Underground Conduit	x				
5150	Maintenance of Underground Conductors and Devices	x				
5155	Maintenance of Underground Services	x				
5160	Maintenance of Line Transformers	x				
5175	Maintenance of Meters		x			
	Billing and Collection					
5305	Supervision				x	
5310	Meter Reading Expense		x			
5315	Customer Billing				x	
5320	Collecting				x	
5325	Collecting- Cash Over and Short				x	
5330	Collection Charges				x	
5335	Bad Debt Expense				x	
5340	Miscellaneous Customer Accounts Expenses				x	
	Administrative and General Expenses					
5605	Executive Salaries and Expenses			x		

Appendix 2 - Functionalization of Selected Accounts						
USoA Account #	**Accounts**	**Functionalization**				
		Distribution	Metering	A & G	Customer Services	Sub - transmission
5610	Management Salaries and Expenses			x		
5615	General Administrative Salaries and Expenses			x		
5620	Office Supplies and Expenses			x		
5625	Administrative Expense Transferred Credit			x		
5630	Outside Services Employed			x		
5640	Injuries and Damages			x		
5645	Employee Pensions and Benefits			x		
5650	Franchise Requirements			x		
5655	Regulatory Expenses			x		
5665	Miscellaneous General Expenses			x		
5670	Rent			x		
5675	Maintenance of General Plant			x		
5680	Electrical Safety Authority Fees			x		
5505	Supervision			x		
5510	Demonstrating and Selling Expense			x		
5520	Miscellaneous Sales Expense			x		
6105	Taxes Other Than Income Taxes			x		
6215	Penalties			x		
6225	Other Deductions			x		

Appendix 2 - Functionalization of Selected Accounts						
USoA Account #	Accounts	Functionalization				
		Distribution	Metering	A & G	Customer Services	Sub - transmission
5635	Property Insurance			x		
6210	Life Insurance			x		
5515	Advertising Expense			x		
5660	General Advertising Expenses			x		
6205	Donations			x		
5405	Supervision			x		
5410	Community Relations - Sundry			x		
5420	Community Safety Program			x		
5425	Miscellaneous Customer Service and Informational Expenses			x		
5415	Energy Conservation			x		
	Amortization of Assets					
5705	Amortization Expense - Property, Plant, and Equipment	x				
5710	Amortization of Limited Term Electric Plant	x				
5715	Amortization of Intangibles and Other Electric Plant	x				
5730	Amortization of Unrecovered Plant and Regulatory Study Costs	x				
5735	Amortization of Deferred Development Costs	x				
5740	Amortization of Deferred Charges	x				

Appendix 3 – Categorization of Selected Accounts

Appendix 3 - Categorization of Selected Accounts				
USoA Account #	Accounts	Categorization		
		Demand	Customer	Joint
	Distribution Plant			
1805	Land			x
1806	Land Rights			x
1808	Buildings and Fixtures			x
1810	Leasehold Improvements			x
1815	Transformer Station Equipment - Normally Primary above 50 kV	x		
1820	Distribution Station Equipment - Normally Primary below 50 kV	x		
1825	Storage Battery Equipment			x
1830	Poles, Towers and Fixtures			x
1835	Overhead Conductors and Devices			x
1840	Underground Conduit			x
1845	Underground Conductors and Devices			x
1850	Line Transformers			x
1855	Services			x
1860	Meters		x	
1565	Conservation and Demand Management Expenditures and Recoveries		x	
	Intangible Plant			

Appendix 3 - Categorization of Selected Accounts				
USoA Account #	Accounts	Categorization		
		Demand	Customer	Joint
1608	Franchises and Consents		x	
	Accumulated Amortization			
2105	Accum. Amortization of Electric Utility Plant - Property, Plant, & Equipment			x
2120	Accumulated Amortization of Electric Utility Plant - Intangibles			x
	Operation			
5005	Operation Supervision and Engineering			x
5010	Load Dispatching			x
5012	Station Buildings and Fixtures Expense	x		
5014	Transformer Station Equipment - Operation Labour	x		
5015	Transformer Station Equipment - Operation Supplies and Expenses	x		
5016	Distribution Station Equipment - Operation Labour	x		
5017	Distribution Station Equipment - Operation Supplies and Expenses	x		
5020	Overhead Distribution Lines and Feeders - Operation Labour			x
5025	Overhead Distribution Lines & Feeders - Operation Supplies and Expenses			x
5030	Overhead Subtransmission Feeders - Operation			x
5035	Overhead Distribution Transformers- Operation			x
5040	Underground Distribution Lines and Feeders - Operation Labour			x
5045	Underground Distribution Lines & Feeders - Operation Supplies & Expenses			x

Appendix 3 - Categorization of Selected Accounts				
USoA Account #	Accounts	Categorization		
		Demand	Customer	Joint
5050	Underground Subtransmission Feeders - Operation			x
5055	Underground Distribution Transformers - Operation			X
5065	Meter Expense		x	
5070	Customer Premises - Operation Labour		x	
5075	Customer Premises - Materials and Expenses		x	
5085	Miscellaneous Distribution Expense			X
5090	Underground Distribution Lines and Feeders - Rental Paid			X
5095	Overhead Distribution Lines and Feeders - Rental Paid			X
5096	Other Rent			X
	Maintenance			
5105	Maintenance Supervision and Engineering			X
5110	Maintenance of Buildings and Fixtures - Distribution Stations			X
5112	Maintenance of Transformer Station Equipment	x		
5114	Maintenance of Distribution Station Equipment	x		
5120	Maintenance of Poles, Towers and Fixtures			X
5125	Maintenance of Overhead Conductors and Devices			X
5130	Maintenance of Overhead Services			X
5135	Overhead Distribution Lines and Feeders - Right of Way			X

Appendix 3 - Categorization of Selected Accounts				
USoA Account #	**Accounts**	**Categorization**		
		Demand	Customer	Joint
5145	Maintenance of Underground Conduit			X
5150	Maintenance of Underground Conductors and Devices			x
5155	Maintenance of Underground Services			X
5160	Maintenance of Line Transformers			X
5175	Maintenance of Meters		x	
	Billing and Collection			
5305	Supervision		x	
5310	Meter Reading Expense		x	
5315	Customer Billing		x	
5320	Collecting		x	
5325	Collecting- Cash Over and Short		x	
5330	Collection Charges		x	
5335	Bad Debt Expense		x	
5340	Miscellaneous Customer Accounts Expenses		x	
	Amortization of Assets			
5705	Amortization Expense - Property, Plant, and Equipment			X
5710	Amortization of Limited Term Electric Plant			X

Appendix 3 - Categorization of Selected Accounts				
USoA Account #	**Accounts**	**Categorization**		
		Demand	Customer	Joint
5715	Amortization of Intangibles and Other Electric Plant			X
5730	Amortization of Unrecovered Plant and Regulatory Study Costs			X
5735	Amortization of Deferred Development Costs			X
5740	Amortization of Deferred Charges			X

Appendix 4 - Allocation of Customer-Related Costs

Appendix 4 - Allocation of Customer-Related Costs							
USoA Account #	**Accounts**	**Allocation of Customer-Related Costs**					
		Number of customers	Weighted number of customers	Weighted number of meters	Weighted number of services	Weighted number of meter readings	Weighted number of bills
	Distribution Plant						
1805	Land	x					
1806	Land Rights	x					
1808	Buildings and Fixtures	x					
1810	Leasehold Improvements	x					
1825	Storage Battery Equipment	x					
1830	Poles, Towers and Fixtures	x					
1835	Overhead Conductors and Devices	x					
1840	Underground Conduit	x					
1845	Underground Conductors and Devices	x					
1850	Line Transformers	x					
1855	Services				x		
1860	Meters			x			
1565	Conservation and Demand Management Expenditures and Recoveries		x				

Appendix 4 - Allocation of Customer-Related Costs

USoA Account #	Accounts	Allocation of Customer-Related Costs					
		Number of customers	Weighted number of customers	Weighted number of meters	Weighted number of services	Weighted number of meter readings	Weighted number of bills
	Intangible Plant						
1608	Franchises and Consents		x				
	Accumulated Amortization						
2105	Accum. Amortization of Electric Utility Plant - Property, Plant, & Equipment	x					
2120	Accumulated Amortization of Electric Utility Plant - Intangibles	x					
	Operation						
5005	Operation Supervision and Engineering	x					
5010	Load Dispatching	x					
5020	Overhead Distribution Lines and Feeders - Operation Labour	x					
5025	Overhead Distribution Lines & Feeders - Operation Supplies and Expenses	x					
5030	Overhead Subtransmission Feeders - Operation	x					
5035	Overhead Distribution Transformers- Operation	x					
5040	Underground Distribution Lines and Feeders - Operation Labour	x					
5045	Underground Distribution Lines & Feeders - Operation Supplies & Expenses	x					

Appendix 4 - Allocation of Customer-Related Costs							
USoA Account #	Accounts	Allocation of Customer-Related Costs					
		Number of customers	Weighted number of customers	Weighted number of meters	Weighted number of services	Weighted number of meter readings	Weighted number of bills
5050	Underground Subtransmission Feeders - Operation	x					
5055	Underground Distribution Transformers - Operation	x					
5065	Meter Expense			x			
5070	Customer Premises - Operation Labour		x				
5075	Customer Premises - Materials and Expenses		x				
5085	Miscellaneous Distribution Expense	x					
5090	Underground Distribution Lines and Feeders - Rental Paid	x					
5095	Overhead Distribution Lines and Feeders - Rental Paid	x					
5096	Other Rent	x					
	Maintenance						
5105	Maintenance Supervision and Engineering	x					
5110	Maintenance of Buildings and Fixtures - Distribution Stations	x					
5120	Maintenance of Poles, Towers and Fixtures	x					
5125	Maintenance of Overhead Conductors and Devices	x					
5130	Maintenance of Overhead Services	x					
5135	Overhead Distribution Lines and Feeders - Right of Way	x					

Appendix 4 - Allocation of Customer-Related Costs							
USoA Account #	Accounts	Allocation of Customer-Related Costs					
		Number of customers	Weighted number of customers	Weighted number of meters	Weighted number of services	Weighted number of meter readings	Weighted number of bills
5145	Maintenance of Underground Conduit	x					
5150	Maintenance of Underground Conductors and Devices	x					
5155	Maintenance of Underground Services	x					
5160	Maintenance of Line Transformers	x					
5175	Maintenance of Meters			x			
	Billing and Collection						
5305	Supervision				x		
5310	Meter Reading Expense					x	
5315	Customer Billing						x
5320	Collecting				x		
5325	Collecting- Cash Over and Short				x		
5330	Collection Charges				x		
5335	Bad Debt Expense		x				
5340	Miscellaneous Customer Accounts Expenses		x				
	Amortization of Assets						

Appendix 4 - Allocation of Customer-Related Costs							
USoA Account #	Accounts	Allocation of Customer-Related Costs					
		Number of customers	Weighted number of customers	Weighted number of meters	Weighted number of services	Weighted number of meter readings	Weighted number of bills
5705	Amortization Expense - Property, Plant, and Equipment	x					
5710	Amortization of Limited Term Electric Plant	x					
5715	Amortization of Intangibles and Other Electric Plant	x					
5730	Amortization of Unrecovered Plant and Regulatory Study Costs	x					
5735	Amortization of Deferred Development Costs	x					
5740	Amortization of Deferred Charges	x					

Appendix 5 - Allocation of Demand Related Costs

Appendix 5 - Allocation of Demand Related Costs			
USoA Account #	**Accounts**	**Allocation - Demand Related**	
	Distribution Plant		
1805	Land	NCP	
1806	Land Rights	NCP	
1808	Buildings and Fixtures	NCP	
1810	Leasehold Improvements	NCP	
1815	Transformer Station Equipment - Normally Primary above 50 kV	CP	
1820	Distribution Station Equipment - Normally Primary below 50 kV	CP	
1825	Storage Battery Equipment	NCP	
1830	Poles, Towers and Fixtures	O-NCP	NCP for customers with overhead service only
1835	Overhead Conductors and Devices	OD-NCP	NCP for customers with overhead distribution service only
1840	Underground Conduit	U-NCP	NCP for customers with underground service only
1845	Underground Conductors and Devices	UD-NCP	NCP for customers with underground distribution service only
1850	Line Transformers	NCP	
1855	Services	S-NCP	NCP for customers that uses this asset
1565	Conservation and Demand Management Expenditures and Recoveries	CDM	
	Accumulated Amortization		
2105	Accum. Amortization of Electric Utility Plant - Property, Plant, & Equipment	Prorate by Gross assets	
2120	Accumulated Amortization of Electric Utility Plant - Intangibles	Prorate by Gross assets	

Appendix 5 - Allocation of Demand Related Costs			
USoA Account #	**Accounts**	**Allocation - Demand Related**	
	<u>Operation</u>		
5005	Operation Supervision and Engineering	NCP	
5010	Load Dispatching	NCP	
5012	Station Buildings and Fixtures Expense	CP	
5014	Transformer Station Equipment - Operation Labour	CP	
5015	Transformer Station Equipment - Operation Supplies and Expenses	CP	
5016	Distribution Station Equipment - Operation Labour	CP	
5017	Distribution Station Equipment - Operation Supplies and Expenses	CP	
5020	Overhead Distribution Lines and Feeders - Operation Labour	OD-NCP	
5025	Overhead Distribution Lines & Feeders - Operation Supplies and Expenses	OD-NCP	
5030	Overhead Subtransmission Feeders - Operation	OS-NCP	
5035	Overhead Distribution Transformers- Operation	OD-NCP	
5040	Underground Distribution Lines and Feeders - Operation Labour	UD-NCP	
5045	Underground Distribution Lines & Feeders - Operation Supplies & Expenses	UD-NCP	
5050	Underground Subtransmission Feeders - Operation	US-NCP	
5055	Underground Distribution Transformers - Operation	UD-NCP	
5065	Meter Expense		
5070	Customer Premises - Operation Labour		
5075	Customer Premises - Materials and Expenses		
5085	Miscellaneous Distribution Expense	NCP	

Appendix 5 - Allocation of Demand Related Costs			
USoA Account #	**Accounts**	**Allocation - Demand Related**	
5090	Underground Distribution Lines and Feeders - Rental Paid	UD-NCP	
5095	Overhead Distribution Lines and Feeders - Rental Paid	OD-NCP	
5096	Other Rent	NCP	
	Maintenance		
5105	Maintenance Supervision and Engineering	NCP	
5110	Maintenance of Buildings and Fixtures - Distribution Stations	NCP	
5112	Maintenance of Transformer Station Equipment	CP	
5114	Maintenance of Distribution Station Equipment	CP	
5120	Maintenance of Poles, Towers and Fixtures	OD-NCP	
5125	Maintenance of Overhead Conductors and Devices	OD-NCP	
5130	Maintenance of Overhead Services	ODS-NCP	
5135	Overhead Distribution Lines and Feeders - Right of Way	OD-NCP	
5145	Maintenance of Underground Conduit	UD-NCP	
5150	Maintenance of Underground Conductors and Devices	UD-NCP	
5155	Maintenance of Underground Services	UDS-NCP	
5160	Maintenance of Line Transformers	NCP	
5175	Maintenance of Meters		
	Amortization of Assets		

Appendix 5 - Allocation of Demand Related Costs			
USoA Account #	**Accounts**	**Allocation - Demand Related**	
5705	Amortization Expense - Property, Plant, and Equipment	NCP	
5710	Amortization of Limited Term Electric Plant	NCP	
5715	Amortization of Intangibles and Other Electric Plant	NCP	
5730	Amortization of Unrecovered Plant and Regulatory Study Costs	NCP	
5735	Amortization of Deferred Development Costs	NCP	
5740	Amortization of Deferred Charges	NCP	

Appendix 6 – Illustrative Example of the Derivation of a Weighted Customer Allocation Factor – Metering

Appendix 6
Illustrative Example of the Derivation of a Weighted Customer Allocation Factor - Metering

		Col.1	Col. 2	Col. 3	Col. 4
Customer Rate Class		**Cost per Meter (Installed)**	**Number of Meters**	**Weighted Metering Costs (1)**	**Weighted Factor (2)**
		($)		($)	
Residential					
	Meter 1	100	150,000	15,000,000	
	Meter 2	250	5,000	1,250,000	51.78%
				16,250,000	
GS < 50 kW					
	Meter 1	100	50,000	5,000,000	
	Meter 3	400	25,000	10,000,000	47.79%
				15,000,000	
GS >50 kW					
	Meter 3	400	100	40,000	
	Meter 4	1,500	30	45,000	0.27%
				85,000	
Large User	Meter 5	2,500	20	50,000	0.16%
				50,000	
Total Weighted Costs				31,385,000	100.00%

Notes:
(1) Weighted Metering Costs = Cost per Meter * Number of Meters

(2) Weighted Factor = Weighted Costs / Total Weighted Costs

Appendix 7 - Board's 2003 Load Data Collection Directions, RP-2003-0228

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Ontario

November 10, 2003

To: All Licensed Electricity Distribution Companies

Re: Load Data Collection Directions, RP-2003-0228

The Electricity Distribution Rates Handbook (see paragraph 1.4) states: "Prior to the implementation of 2nd generation PBR the Board will require utilities to develop cost allocation studies that reflect … current load profiles of the various rate groups".

The Ontario Energy Board's (the "Board's") correspondence of October 22, 2002 announced the formation of a Cost Allocation Working Group (the "Working Group") and enclosed a preliminary issues list for the cost allocations consultations. The Working Group was suspended after the introduction of Bill 210, but the Board's correspondence of March 14, 2003 announced the reactivation of the cost allocation consultations. The Board would like to thank the parties for their helpful participation.

The First Report of the Cost Allocation Working Group (the "Report") was issued on September 23, 2003 (copy available on the Board's web site). The body of the Report deals with general principles pertaining to updated load data. An Appendix contains a specific Province-wide joint load data collection proposal from over 40 distributors ("the Ontario Load Data Research Group") serving the majority of Ontario customers.

The Working Group's Report focused on the collection of appropriate load data for use in the cost allocation studies that will be part of the applications anticipated to be filed in 2005 in respect of 2006 rates. The updated load data will be used when a distributor allocates demand-related distribution costs amongst its rate classes. While the load data may eventually prove useful in other ways as well, these directions deal only with its use for cost allocation.

Upon release of the Report, stakeholders' written comments were invited by the Board. Written comments were received from the Upper Canada Energy Alliance, Hydro One, and Guelph Hydro Electric Systems Inc., all of whom were represented on the Working Group. The Board notes the lengthy comments from Guelph Hydro included several areas of disagreement from the Report's recommendations, although Guelph Hydro did not dissent when the Report was being finalized by the Working Group.

Additional written comments were received from Whitby Hydro Energy Services Corporation, an affiliate of a distributor (Whitby) represented on the Working Group. Rogers Cable TV also provided written comments on the Report (which were in addition to a written submission forwarded to the Working Group during the course of the consultations).

The Board has carefully considered the various recommendations and comments. The attached load data collection Directions review each specific technical issue examined by the Working Group, summarize the Group's recommendation and any subsequent comments received, and provide the Board's direction on the matter.

Part A of the attached load data collection Directions are applicable to all electricity distributors in the Province (including members of the Ontario Load Data Research Group).

Part B contains the Board's positive response to a specific Province-wide joint load data collection initiative proposed by the Ontario Load Data Research Group.

A Board letter to the Ontario Load Data Research Group, dated simultaneously with these Directions, is posted on the Board's web site (see "What's New"). The letter examines the issue of sharing load data among members of the Ontario Load Data Research Group for purposes of completing the required cost allocation studies, and it concludes that the proposed methodology is consistent with the terms of distributors' new licences. Subsequent sharing of the data collected by the Ontario Load Data Research Group with other distributors, for the purposes of the latter completing their cost allocation studies, is also consistent with the terms of distributors' licences.

The Directions set out below are issued by the Board pursuant to section 21.(1) of the *Ontario Energy Board Act, 1998* which provides that "the Board may at any time and on its own motion and without a hearing give directions or require the preparation of evidence incidental to the exercise of the powers conferred upon the Board by this of any other Act".

Staff will be instructed to prepare a standardized filing procedure for 2006 rate applications on the assumption that the cost of service filings will use load data collected as directed below. The applications will be required to highlight if the load data filed was not collected under the conditions and standards set out in the attached

Directions. Any distributor seeking to depart from the common load data collection procedures will be required to provide a full explanation of the circumstances justifying the request.

Distributors planning to apply for a new rate class in their 2006 rates application should follow the Directions to determine what load data must be filed in support of such a request. The Board will decide at that distributor's hearing whether implementation of a new rate class is appropriate.

Although the present Directions will not deal with financial data issues, distributors should also be considering what financial data will be needed to support current or planned rate classes when the cost allocation studies are undertaken.

Other Recommendations by Working Group

The Report dealt with several other matters, which the Board has reviewed and responds as follows:

Average v. Marginal Cost

The Working Group was asked to assess the merits of an average versus a marginal cost approach to undertaking the upcoming cost allocation studies. The Group recommended use of an average ("embedded") cost approach (as has been followed by Ontario natural gas distributors). Early resolution of this issue is needed, as it may impact the precise type of data to be collected by distributors.

The Board accepts the Working Group's recommendation. The cost allocation instructions to be issued by the Board will be based on an embedded/average cost approach.

The Board emphasizes that the above does not preclude an examination, at the rate design stage, on the role that might be played by marginal pricing principles.

Demand Allocator

The original issues list asked the Working Group to examine the merits of alternative demand allocators (such as non-coincident peak v. coincident peak), and the Report contained specific recommendations in this regard.

The Working Group noted that if 12 consecutive months of interval load data is collected, then the resulting load data will be comprehensive enough to support future use of a variety of demand allocators. The Board cautions stakeholders not to assume that the eventual Ontario cost allocation instructions will use a single demand allocator, as the Report indicates it is common practice to use different allocators for specific costs. In light of this, and the importance of this issue to a wide variety of stakeholders, the Board defers a decision on the demand allocator(s) to a later date.

Load Data Case Study

The Report indicated that Hydro One Brampton Inc. may be willing to act as a case study in which existing Province-wide load data would be used, along with other information, to produce distributor-specific load profiles. The case study would illustrate the methodology that the Ontario Load Data Research Group will use to produce new distributor-specific load profiles.

Given that the above methodology could be of wide interest, Board staff will be directed to review whether facilitating such a case study during stakeholder consultations is feasible.

Ontario Centre of Excellence for Load Data Research

The Working Group suggested that public authorities assist in the establishment of an Ontario Centre of Excellence to organize future load research on a variety of potentially useful topics in this jurisdiction.

The Board notes this suggestion. This matter will be further considered in due course.

Cost Allocation Financial Case Studies

The Working Group suggested that three cost allocation financial case studies be undertaken. The Board will not issue directions in this regard at present, as it wishes to focus on the immediate load data collection issues.

The Board understands the value stakeholders place on such case studies. After the Report was released, several other distributors also commented that case studies will prove invaluable in clarifying what financial data is needed to implement various options (for example, there was a concern many distributors will not be collecting the financial data needed to allow introduction of voltage based rates), and can provide an opportunity to address differences in understanding how to interpret the present system of accounts.

There are a number of related issues that need to be considered as well (such as what model to use). The Board will instruct staff to consider and advise on how some form of case studies could be incorporated into the agenda for the conclusions of the cost allocation consultations.

Stakeholders will be informed in due course about the next phase of the cost allocation consultations.

For inquiries about the cost allocation project, please contact John Vrantsidis at 416-440-8122 or vrantsjo@oeb.gov.on.ca.

Paul Pudge
Assistant Board Secretary

BOARD LOAD DATA COLLECTION DIRECTIONS

A) General Load Data Collection Directions

The Board hereby issues the following Directions to all Ontario electricity distributors regarding the upcoming collection of load data.

In these Directions, the term "rates classification" refers to both rate classes and subclasses (and any other rates grouping). As explained in paragraph 4.1.1 of the Electricity Distribution Rate Handbook, the current common rate classes consist of residential, general service, large use, street lighting and sentinel lights. The General Service class is divided into three subclasses: General Service less than 50 kW; General Service greater than 50 kW; and Intermediate (optional).

Issue 1) What type of load data should be collected?

To provide the full range of data that may be needed when subsequently completing the cost allocation studies, the Working Group recommended interval load data be collected.
The Board agrees.

The written comments from Guelph Hydro raised the question of the appropriate time interval to be used. Considering the accuracy desirable for load data to be collected for cost allocation purposes, the Board directs that the interval shall be no longer than one hour.

Issue 2) For what length of time should the load data be collected?

The Working Group recommended that at least 12 months of load data be collected. The Board directs that 12 consecutive months of usable load data be collected.

Issue 3) In order to ensure reliability of the load data gathered, what sampling methodologies are appropriate?

The Working Group recommended that any of the statistically-verifiable sampling methodologies discussed in the leading North American reference in the load data research field (AEIC's Load Research Manual, 2nd Edition) be accepted for use in Ontario.

The Board accepts this recommendation.

The Working Group also recommended that each electricity distributor in the Province be required to produce a distributor-specific load profile that meets the standard North American target accuracy of plus or minus 10% at a 90% level of confidence.

The Board agrees with this recommendation.

The Board further suggests that Ontario electricity distributors may wish to agree upon a common sampling methodology, so that sharing of load data can be promoted. For example, the Board notes the Working Group Report recommended stratification of the residential rate class by end use (base load, electric heating, electric water heating, and air conditioning).

Written comments received from Guelph Hydro suggested there may be advantages to stratification based on consumption level. As indicated above, the Board will not mandate a particular stratification method, therefore any distributor may choose the sampling method that best suits its unique circumstances, provided the sample size chosen is adequate to meet the required accuracy target. The Board would caution that a distributor that does not plan to have comprehensive appliance saturation data, as described in the Report, may find that the province-wide sample size is inadequate to yield the target accuracy.

Issue 4) <u>The Distribution Rate Handbook presently recommends "achieving economies where possible through joint development of load data" (para. 1.4). How can joint collection of load data be best implemented</u>?

The information examined by the Working Group confirmed that a statistically-designed, Province-wide sampling program is the lowest cost method for all Ontario distributors to gather new reliable load data.

The Board accepts this recommendation. The Board expects that any acceptable joint Province-wide load data sampling program follow the following principles: 1) the distributors that will be collecting the data must be geographically representative of the Province; 2) the participating distributors should include both urban and rural distributors; and 3) the residential customers sampled must represent a variety of lifestyles and consumption patterns.

The Working Group also recommended that, as a matter of principle, any single distributor, or group of distributors, be allowed to conduct their own load data research program, provided the results for each distributor meet the accuracy target of plus or minus 10% at a 90% confidence level.

The Board agrees with the above recommendation and will not direct that all distributors join a particular joint load data collection initiative. The Board notes, however, it appears that economies of scale favour Ontario-wide load data collection. If a distributor wishes to collect load data entirely on its own, it should be prepared to explain the reasons for such a choice, and fully document the sampling methodology used. If it later seeks recovery from rates for the cost of load data collection, it should be prepared to defend the prudency of collecting load data on its own.

Issue 5) *Is additional metering needed? Are there any practical constraints if additional metering is required?*

a) Re Timing: The Working Group advised that it is not feasible to commence load data collection on January 1, 2004 (as originally targeted), given that the Working Group understands acquiring new meters can take up to 10 weeks, meter installation up to an additional 8 weeks, and meter testing a further period.

The Board is concerned that the later in 2004 the load data collection commences, the later in 2005 the cost of service studies will be ready. The Board notes that the number of new sampling meters to be purchased and installed by the industry will be greatly reduced because of the Board's decisions below to allow joint collection of load data, and to allow a residual estimate of the load profile of the General Service less than 50 kW class. The Board also notes that the Report cited literature suggesting a co-operative load research program, as planned for Ontario, could allow quicker progress as distributors share their experience.

After considering all circumstances, the Board directs that the collection of 12 consecutive months of usable load data commence no later than February 1, 2004.

The Board commends the industry co-operation evident to date on this project and trusts the same will continue in order that the 2006 rate applications can be filed and reviewed on a timely basis.

b) Re Costs: The Working Group advised that the total "out-of-pocket" cost of new load data collection includes interval meter acquisition, meter installation and meter reading. Costs may also be incurred for professional advice to design the load research program(s).

Overall, the Working Group believed it would be uneconomic to direct that each Ontario distributor must undertake its own "full blown" load research program.

The Board agrees with this recommendation and, as indicated above, will accept load data collected under an appropriate joint load data collection initiative.

Issue 6) *Data Validation and Editing*

The Working Group recommended that distributors follow an industry generally-accepted procedure for data validation and editing.

The Working Group suggested that a specific example of an acceptable guide to data validation, estimation and editing is to be found in the IMO publication “Market Manual 5: Settlements” (see 5.2: Meter Data Processing).

The Board directs that distributors follow an industry generally-accepted procedure for data validation and editing. The procedures found in the above-noted IMO publication will be acceptable for this purpose.

Issue 7) Meter Accuracy.

The Working Group recommended that the individual customer metering to be installed for load data research purposes be within plus/minus 1% accuracy.

The Board accepts this recommendation.

It should be noted that the Board is not mandating the use of a Measurement Canada approved meter for load data collection purposes. As a practical matter, an interval sample meter should not be substituted for an approved billing meter, unless the interval meter chosen is also approved by Measurement Canada for billing.

Whitby Hydro Energy Services Corporation commented that there is a broad range of equipment options presently available from the various suppliers. The Board is not mandating use of a particular type or brand of interval metering equipment. Each distributor planning to install meters should make its own decisions.

Issue 8) Substation Metering.

The Working Group recommended that measuring the load profile at a transformer station or substation feeder (or by means of SCADA) could be used as a check on the reasonableness of the profiles derived from randomly-selected individual customers.

The Board agrees with the above recommendation and therefore expects that load data from a transformer, substation or SCADA can only be used to check the results of load data collected from statistically-verifiable interval metering of individual customers.

The Board believes that using system data in lieu of an adequate statistical sample, as effectively suggested by the Working Group members that dissented on this matter, could introduce an unacceptable margin of error into data that will be used to set rates.

Issue 9) Should the same load data collection rules apply to all Ontario electricity distributors?

The Working Group recommended that all cost allocation studies should be prepared with the same high quality load data. The Board accepts this recommendation and directs that all Ontario electricity distributors develop distributor-specific load profiles that meet the standard industry accuracy target of plus or minus 10% at a 90% confidence level. (As indicated elsewhere, it is permissible to follow a Province-wide approach to collecting the underlying data.)

Issue 10) Is it acceptable that the load profile of a rate classification be estimated as a residual?

The Working Group noted that the use of a residual estimate of a rate classification's load profile has been used in load data research studies in Ontario and elsewhere. A majority of the Working Group originally suggested that any rate classification could be chosen as the residual. However, the Report noted that those distributors joining in the planned Province-wide initiative had received technical advice to restrict use of the residual estimate to the most heterogeneous rate classification; namely, General Service customers with average monthly demand of less than 50 kW ("General Service<50 kW").

The Board believes the latter approach will generally lead to more reliable results and therefore directs that use of a residual estimate of a class load profile be acceptable for the General Service<50 kW classification only.

Issue 11) Relationship between load data to be collected and rate classifications.

The Working Group recommended that the present rate classifications be the starting point for designing the load research program and, as a result, each distributor should be considering what load data may be necessary for each of its current rate classifications.

The Working Group also recommended that if a distributor plans to introduce a new rate classification in its 2006 rates application, then it should be deciding now if additional load data is technically required for the new rate classification and, if so, how will such load data be obtained.

The Working Group understood that in a few special situations (see Issue 13 below), distributors will not have to take additional steps to install new sampling for a given or proposed rate classification (for example, if the class is already interval metered, or if the class does not have a distinct load profile).

The Board accepts the above recommendations and directs that, subject to the three exceptions noted below, updated reliable interval load data (gathered from either existing interval meters or newly installed interval sample meters) be collected for each rate classification (both current and new) a distributor plans to include in its 2006 rates application.

The Board also accepts that there are technically valid reasons to depart from the general requirement that separate load data be collected for each rate classification. In particular:

1) In some cases, a given rate classification may not have a significantly distinct load profile, and therefore the cost of service application will not require separate load data for that grouping (but appropriate load data from a broader rate classification will be used instead). For example, the Board agrees it can be reasonably assumed high- and low-density customers do not have significantly distinct load profiles. But the Board believes seasonal customers may have a distinct load profile and agrees that separate load data be collected, as proposed by the Ontario Load Data Research Group.

2) The Board specifically authorizes the use of a residual estimate for the General Service less than 50 kW subclass.

3) Deemed load profiles will be acceptable for street lighting, sentinel lighting and miscellaneous scattered unmetered uses, although the Board may review the reasonability of the method by which the deemed load profile was determined and verified.

The Working Group Report raised questions about the interpretation to be given to the comments in a footnote to paragraph 1.4 of the Distribution Rates Handbook ("A rate class is a class derived from a cost allocation study. A rate group is an arbitrary sub-set of the rate class."). The Board has determined that these comments are not relevant to the load data collection Directions.

The Board notes that the Report addressed the load data needs of a wide range of rate classifications. If the Directions do not comment upon the treatment of a specific rate classification, the distributor will still be required to collect and file appropriate load data for that classification as part of its cost of service study.

Issue 12) <u>Future Introduction of a new General Service Subclass</u>.

The RP-2000-0069 decision (see paragraph 3.5.7) indicated that "the Board will initiate a review of the rate design for the general service class". Several distributors, during the consultations or when subsequently commenting upon the Report, asked that the merits of a new General Service subclass be explored further. The Working Group also asked for any comments on this matter that might enable it to fine-tune the Province-wide sample design.

There was no consensus on what kW boundaries should be used for any new General Service subclass. Some commented each individual distributor would be best placed to determine if and where a new General Service subclass should be created, and therefore imposing a Province-wide new General Service subclass should be avoided. In light of these concerns, the Board will proceed cautiously in this area.

The Working Group Report advised that, amongst the members of the Ontario Load Data Research Group, thousands of interval meters are presently in place in the General Service greater than 50 kW grouping. The load data available from these meters may well prove broad enough to assist in a future review of General Service subclasses, and specific Directions to organize the available interval load data in a potentially helpful manner are included in Part B.

The Board also notes that accompanying financial data would likely be necessary, if a new General Service subclass were introduced.

Issue 13) Rate classifications potentially not requiring new sample metering.

The Working Group believed that not every rate classification will require its own new sample metering. In particular:

a) Street lighting and sentinel lights

The Working Group recommended individual distributors use their approved street lighting hours of use when calculating a "deemed" street lighting load profile.

The Board accepts this recommendation and directs accordingly.

The Board further directs that in the forthcoming cost allocation studies, each distributor provide particulars on how its deemed street lighting profile was calculated (that is, describe both assumed hours of use and consumption).

The Working Group also recommended that it is reasonable to apply the deemed street lighting load profile to sentinel lights. The Board accepts this recommendation and directs accordingly.

b) Other unmetered scattered loads

The Working Group recommended that each distributor establish and verify a deemed load profile for scattered unmetered loads. The Board accepts this recommendation and notes the importance of verifying a reasonable deemed load profile. The Board directs that, in the upcoming cost allocation studies, each distributor should give full details as to how the deemed profiles for its various scattered unmetered uses were determined.

As a practical matter, it would be preferable that the customers responsible for the loads in question should be in agreement that the deemed load profile used is reasonable.

In this regard, the Board notes that Rogers Cable TV forwarded written comments stating it had co-operated with some distributors in conducting joint spot metering of 20-30 power supplies and the parties would agree the results would be used to establish a single average value for that distributor.

The Board suggests that the remaining distributors may wish to voluntarily determine a mutually satisfactory deemed load profile with Rogers Cable TV (and any other cable operator having the same concerns), using the above methodology.

The Board also suggests that, in order to address any customer concerns, distributors review and verify how the deemed load profiles of any other scattered unmetered loads are determined. The Board will not make specific directions on this matter at this time. However, if any scattered unmetered customer remains unsatisfied with the deemed load profile applied by a given distributor, it can raise the matter at that distributor's rate hearing.

c) Low density rates and poly-phase rates

The Working Group noted that detailed cost data is required to support rate schedules that reflect differing customer density, and also to reflect three-phase versus single-phase service. But it understood that separate load data is not required in these situations because it is reasonable to believe that these rate classifications did not have significantly distinctive load profiles.

The Board accepts this recommendation, and will not direct that distributors file a separate load profile for low density rates or poly-phase rates. However, appropriate load data from the corresponding residential or general service class should be employed when completing the cost allocation studies.

d) Large Use Class

The Working Group assumed that all customers in a distributor's Large Use class are individually interval metered and therefore appropriate load data will be available. If this assumption proves incorrect for a particular distributor, the Board directs that distributor to take additional steps to develop the appropriate load data to support its cost allocation filing.

e) Intermediate Use

The Working Group assumed that all customers in a distributor's Intermediate Use subclass are individually interval metered and therefore appropriate load data will be available. If this assumption proves incorrect for a particular distributor, the Board directs that distributor to take additional steps to develop and file the appropriate load data to support its cost allocation study.

The Board further notes that while the Distribution Rates Handbook (see section 9.2) defines Intermediate Use as "individual customers whose monthly measured maximum demand (kW) averaged over the most recent 12 consecutive months is equal or greater than 3,000 kW", it appears distributors have in place approved Intermediate subclasses with a different boundary (as allowed under the former Ontario Hydro definition). In any review of General Service class rate design, the merits of a new definition of Intermediate Use may be examined.

f) Time of Use ("TOU") distribution rates

The Working Group assumed that if any distributor has approved TOU distribution rates, such customers will be individually interval metered and therefore the appropriate load data will be available.

The Board understands, however, that past TOU class energy data may have been accumulated using meters that did not record hourly energy consumption. In such cases, the Board directs that distributor to take additional measures to collect the appropriate interval load data to support its cost allocation filing for TOU distribution rates.

The Board expects that the future role that might be played by TOU distribution rates will be examined during the rate design consultations.

In the upcoming cost allocation studies, distributors wanting to maintain a TOU distribution rate should also address how distribution costs for such a rate classification are distinctive, aside from the cost of metering.

The above comments apply to any other new or existing rate classification based on meter characteristics.

g) Voltage-based rates

The Working Group was unsure of whether additional data would be needed to support the introduction of voltage-based rates for Large or Intermediate use customers. The Board directs that any distributor planning to include such a rate classification in its cost allocation filing include the appropriate load data, along with financial data.

h) Back-up rates for embedded generation

The Working Group was unsure of the potential load data needs for "back-up" rates in respect of embedded generation (to be used, for example, when a cogeneration facility is down for maintenance).

At this time, the Board directs that any distributor planning to include such a rate classification in its cost allocation filing include appropriate load and/or financial data.

Because of the specialized nature of the issues associated with this general topic, the Board will later decide if it is preferable to dispose of the matter as part of the generic cost allocation proceeding or separately.

Issue 13) Weather Normalization of Load Data

The Working Group added the issue of weather-normalizing load data to its agenda, and the Group's preliminary views on the topic were included in the Report.

Given the importance of the topic, its technical complexity, and the fact that a decision is not required at this time, the Board defers its review of this issue to a later date.

B) Board Response to Province-wide Joint Load Data Collection Proposal

The Report includes a joint load data collection proposal advanced by over forty Ontario electricity distributors serving about 80% of the customers in the Province. This group of distributors (the "Ontario Load Data Research Group") is geographically diverse and serves both urban and rural customers of varying lifestyles. The Board understands that a qualified load researcher will design their sampling program.

The Ontario Load Data Research Group requested Board approval of its specific joint load data collection initiative. The major components of the proposal provide that:

- About 600 residential class interval sample meters will be installed across the Province (along with a sample of 100 customers to be randomly selected from the interval meters currently installed amongst residential customers of the Research Group members). Seasonal residential customers will be included in this sample. New meters will be randomly installed, at locales recommended by a load research expert, using a stratified approach that reduces the numbers of meters required to obtain reliable results.

- Load data for the General Service>50 kW classification will be obtained from amongst the several thousand meters currently installed in this range by Research Group members.

- The General Service<50 kW subclass will be estimated as a residual. The Ontario Load Data Research Group has received a technical defence of its use in respect of the heterogeneous General Service<50 kW subclass. The Research Group also has access to a few hundred interval meters in this rate classification, which will provide new data to check and possibly refine the estimate.

- It will be assumed that all Intermediate and Large Use customers are interval metered already.

Guelph Hydro commented that the incidence of presently interval metered consumers in the 50 kW to 250 kW range may be sporadic. The Board acknowledges this possible concern, along with the fact that the available General Service meters were not installed in a deliberately random manner, but believes because the number of interval meters in the General Service> 50 kW range available amongst members of the Ontario Load Data Research group is so large, the load profile results will be of reasonable quality for use in cost allocation studies.

The directions below to explore the load data implications of moving the General Service 50kW boundary to 250 kW will allow further discussion of the concerns raised by Guelph Hydro.

The Board agrees that the joint load data collection proposal advanced by the Ontario Load Data Research Group is reasonable in the current Ontario context. The Board expects that the proposal proceed in the manner described (see Appendix to Group Report for full details). The Board expects that it be notified of any change in plans that would materially affect the results.

Because of the importance of the timely collection of load data to the overall cost allocation project time lines, the Board expects that the members of the Ontario Load Data Collection Group will commence load data collection by February 1, 2004. The Ontario Load Data Research Group is further expected to report to the Board by the end of December 22, 2003 on the status of their work.

The Group is also expected to report on February 2, 2004 identifying the location of any outstanding installation work to be done, reason for the delay, and updated installation schedule.

In response to a written inquiry from the Working Group, the Board has determined that appropriately structured joint collection of load data (as in the present proposal) can occur under the terms of distributors' new licences. For full details on the Board's interpretation of the application of sections 15.2(a) and 15.3 of the new distribution licences to the joint collection and sharing of load data, see the correspondence to the Working Group dated November 7, 2003, to be posted on the Board's web site under "What's New" (or see the Cost Allocation Working Group web page).

The remaining Ontario distributors can decide to collect load data individually, form another joint load data collection initiative, or acquire data from the Ontario Load Data Research Group. Statistical problems may arise if a distributor acquires the provincial load data but wishes to combine it with local load data collected using a different basis of stratification, or if local appliance saturation data is unavailable. The Board expects the same accuracy requirement (distributor-specific load profiles with a target accuracy of plus or minus 10% at 90% confidence) to apply in all cases.

The Board notes that members of the Ontario Load Data Research Group will be free to go to any party to convert the Provincial data to be collected into distributor-specific load profiles. An Appendix to the Working Group Report explains how a specific party proposes to use its expertise and software to do this task.

The Board expects that, whatever method is chosen, it must generate statistically-reliable individual distributor load profiles, targeted at an accuracy of plus or minus 10% at a 90% confidence level. The methodology outlined in the Report's Appendix will be an acceptable means by which to achieve this goal.

Load data research to support a future review of General Service Subclasses

The Ontario Load Data Research Group is expected to investigate whether the data available from the thousands of interval meters already installed amongst their members in the General Service>50 kW range can be used to inform future discussions on:

i) The merits of maintaining the three existing General Service subclasses but increase the present 50 kW boundary to 100 kW or 250 kW;

ii) The merits of maintaining the three existing General Service subclasses but lower the present 3000 kW Intermediate subclass boundary down to 1000 kW; and

iii) The merits of introducing a fourth common General Service subclass, with a boundary of 500 kW to 3,000 kW.

It is expected that the available data be organized to attempt to produce a load profile for each of the potential new General Service subclasses identified above.

At this time, the Board is not deciding on the desirability of a new Province-wide General Service subclass, nor on the related question of the appropriate boundary for such a new subclass. Rather, the goal is to organize the load data already available for the General Service class to facilitate informed future stakeholder discussions on these issues.

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