ELECTRICITY DISTRIBUTION

FUNCTIONALIZATION, CLASSIFICATION & ALLOCATION GUIDELINES

FOR THE

MUNICIPAL ELECTRIC ASSOCIATION

COST OF SERVICE / ALLOCATION MODEL

October, 2000

Navigant™
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1. Scope and Purpose of Guidelines

These guidelines are intended to aid users of the Municipal Electric Association cost of service/allocation model ("MEA Model") and others preparing cost of service/allocation presentations and filings and evaluating model results. In addition to these guidelines, model users should refer to the User Manual for the MEA Model.

For purposes of these guidelines, only the distribution cost of service[1] will be discussed. The guidelines provide a discussion of approaches for allocating the distribution cost of service which have been applied in other energy regulatory environments. These approaches have been incorporated in the MEA Model as the default methods for preparing a filing. However, if a utility deems a methodology other than those discussed in these guidelines to be appropriate, the utility should indicate how they propose to deviate from the default methods and provide justification for the their chosen approach. In all cases the methods chosen must reflect cost causation.

In future allocated cost of service studies, the Ontario Energy Board ("OEB") may require further assignment of the customer-related functions not currently reflected in the model. Additional accounts may be added to the Accounting Procedures Handbook to record the costs incurred in providing distribution service and customer service in order to track costs associated with specific services, functions, or activities. In general all methods chosen should be reasonable and documented. The documentation should also be available for Board review.

[1] The distribution cost of service refers to all revenue requirement costs (operating expenses + depreciation + taxes + return on rate base – other revenues) identified as belonging to the general category of regulated distribution services. The distribution cost of service does not include Generation and Production facility costs, if any, of the utility.

2. Introduction

The guidelines are organized into sections that address each step in preparing an allocated distribution cost of service using the MEA Model. The guideline discussions include appendices which indicate specific default methods and potential alternatives for analyzing distribution cost of service accounts. In addition, a summary flowchart of the functionalization, classification and allocation process is attached as Exhibit 1. Exhibit 2 is a summary flowchart of the MEA Model which will assist the reader in understanding the data flows in the model.

While the MEA Model is set with default classification and allocation choices, the final decision on an appropriate method depends on the utility's particular circumstances, the amount and quality of the data and Board regulatory policy. Different methods will cause varying impacts on end-use customers depending on the customer's type and amount of use. The following sections of these guidelines address the choices available in the MEA Model and possible alternatives but should not be considered the best or only choices for a particular utility.

As a first step in developing an allocated cost of service, direct assignment accounts[2] should be identified and separated from all other distribution cost of service expenses. As an example, since streetlighting operation and maintenance expenditures can be directly linked to the streetlighting class of customers, these costs qualify as direct assignment expenses. Discussion of the accounts that belong to this direct assignment category is provided in Section three of these guidelines.

Remaining revenue requirement components or amounts are allocated to individual rate classes using a three-step procedure: functionalization, classification and allocation. Section four describes the process of assigning the historic revenue requirement amounts to functional categories, such as distribution and metering. Section five describes the process of classifying functionalized costs to demand, customer and

[2] Direct assignment refers to costs in which a direct link can be made between the costs and services provided to specific customers.

energy components. Allocation, described in Section six, distributes classified expenses to customer tariff classes.

General expenses and revenue requirement components other than direct operations and maintenance commonly cannot be directly functionalized, classified and allocated ("assigned") to customer tariff classes. As a result, assignment of these costs is based on composite factors developed from other accounts that can be more readily associated with individual functions. Methods for assigning general items/other revenue requirement expenses are discussed in Section Seven of the guidelines.

Section Eight discusses the default customer service classes and load data included in the model. This section also includes a discussion of how load data should be reconciled if the utility chooses to use its own load data in place of the model default data.

In order to provide model users with a reference from these guidelines to the MEA Model, a table is provided in Appendix 1 that identifies MEA Model locations (by worksheet and exhibit names) that are most closely associated with each guideline Section.

3. Direct Assignment Expenses

Direct assignment of costs is always the preferred approach for allocating expenses to customer tariff classes and should be used where a direct link can be made between costs and the service provided to specific customers. However, usually only a small percentage of accounts can be assigned in this fashion because most costs are incurred by a utility to jointly serve many classes of customers. Appendix 2 identifies direct assignment accounts and the customer classes where these costs are assigned in the MEA model.

If a submitting utility can identify additional costs to assign directly to customer tariff classes, e.g. metering costs for large commercial customers, beyond those identified in Appendix 2, then the utility should directly assign and disclose those costs as well. Documentation describing the reasoning for directly assigning the additional accounts should be included in the filing submitted to the OEB.

4. Functionalization Methods

Functionalization is 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. Administrative and general expenses and costs associated with general plant are considered joint costs and are not functionalized to production, transmission or distribution directly, but are allocated to these functions on a basis appropriate to the particular cost (e.g. plant or labour ratios).[3] Functionalization begins with the utilities accounting records which are commonly kept according to the prescribed uniform system of accounts. Based on the accounting instructions accompanying the uniform system of accounts the utility's costs are recorded in specific accounts or sub-accounts. Cost functionalization is a further grouping of the accounts for purposes of analysis. Sheet "LOBs" (Lines of Business) in the MEA Model is the data entry section for account level data. Entry of this data functionalizes the utilities costs. In the restructured utility environment the Local Distribution Company ("LDC") is required to separate its different lines of business into those that are regulated and those that are subject to competition.

The major functions generally used for purposes of cost allocation are production, transmission and distribution. The production function includes all the costs involved in the generation of power or its purchase at wholesale and the delivery of such power into the bulk power transmission system at the bus-bars of the generating stations or at the points of interconnection with the adjoining systems. The transmission function includes all costs associated with the transfer of power from one geographical location to another within a system and also with the transfer of power to or from other utilities. The distribution function includes all costs associated with the transfer of power from the transmission system through the distribution system to the consumer. As the model will be used mainly for rate unbundling of distribution costs and allocating transmission costs, it is unlikely that a Local Distribution Company ("LDC") will have any costs allocated to the production function, except for these that retain local generation.

3 See Appendix 9 for examples of the derivation of allocation factors.

Within the distribution function, the MEA model functionalizes non-direct assignment distribution costs into four categories as follows:

- Distribution Service
- Customer Service: Metering
- Customer Service: Billing
- Customer Service: Other Customer-Services

Distribution Service includes most distribution plant (items such as overhead and underground poles, fixtures, conduits and transformers) with the exception of metering equipment. The Distribution Service category also includes expenses (including labour) associated with the operation and maintenance of distribution plant. Subtransmission[4] operation and maintenance accounts can be functionalized either to transmission or to distribution. The default method used in the MEA Model functionalizes these accounts to the distribution function. However, the design and function of a submitting utility's transmission system should determine the appropriate category to classify these expenses. If the utility believes subtransmission costs should be functionalized to the transmission function, they should note that their filing deviates from the default MEA Model functionalization approach and they should include justification as to why it is appropriate to reclassify subtransmission costs from distribution to transmission.

Metering includes the cost of metering equipment as well as metering expenses. Billing includes customer billing, collecting, collection charges, and bad debt expense. The other Customer Services category includes plant accounts such as installations and property on customer premises and expense accounts such as customer installation costs, customer assistance, retailer management, service transaction request costs, advertising and sales.

In Appendix 3, a table is provided that identifies the functionalization approaches that should be used to assign Distribution Plant items, Distribution Operation and Maintenance expenses, and Customer costs to the four allocated distribution cost of

[4] Subtransmission facilities transfer energy from the grid transmission system (which generally carries energy at 115 kilo volts (KV) or higher) to the distribution system (which generally carries energy at 50 KV or lower).

service functions. Accumulated depreciation should be assigned in the same manner as the respective plant accounts. Labour costs included in Appendix 3 accounts should be identified separately[5].

[5] Labour expenses should be separated from the rest of Appendix 3 account costs in order to develop labour ratios for assignment of administrative and general (A&G) costs to customer tariff classes. See Section 7.3 for further discussions on this matter.

5. Classification Methods

5.1 Introduction

The objective of cost classification is to arrange costs into groups that bear a relationship to a measurable cost-defining characteristic of the service being rendered. Once the functionalized costs are so arranged, i.e. classified, they can be allocated to the services on an appropriate basis. Functionalized costs are classified as:

- Demand related;
- Energy related, or;
- Customer related.

The Demand classification relates to providing capacity[6] to serve portions or all of system load requirements. The Energy related classification consists of those expenses that generally vary with changes in the unit consumption of kilowatt-hours, such as purchased power energy charges. The Customer related classification is related directly to each electric user and varies by the number and type of customers served. Customer costs include the minimum service, metering, accounting and other expenses necessary to connect a new customer to the system. These costs typically vary by the type of customer served, with large industrial customers being the most expensive group of users to connect to the system. Costs classified as energy related are often associated with the generation function. Therefore, no distribution costs are assigned to the energy function.[7] [8]

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[6] Capacity refers to the maximum amount of electric power for which a component of the electric system is rated either by the user or manufacturer. The level of investment in electrical equipment is primarily impacted by to the amount of capacity needed to meet peak load requirements of individual customers (for items such as service drops), groups of customers located on a portion of the electric system (for items such as distribution feeders) or the total electric system (for items such high voltage transmission lines).

[7] It should be noted, however, that for rate design purposes a portion of the distribution revenue requirement will be recovered through energy charges for those customer classes that do not have three part rates (demand + energy + customer).

[8] In 1985 the Municipal Electric Association carried out a study to establish the cause and effect relationship for failures in each distribution facility component. It was found that roughly two-thirds of distribution facilities were a function of peak demand and one-third attributable to energy usage. Accordingly, an enhanced version of the minimum size method, called the modified minimum system method, was developed based on these findings. Over the years, a number of Ontario utilties have used this method in their cost of service studies.

The distribution system generally consists of primary demand facilities (such as distribution substations and primary distribution feeders) and secondary demand facilities (such as lower voltage feeders and line transformers). Therefore, demand costs may be further classified as being either being primary or secondary in nature.

Some distribution plant accounts and associated operation and maintenance charges are classified 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 peak demand requirements. The customer component of joint related accounts is that portion of expense 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 peak demand requirements. Thus they exhibit attributes of both demand and customer charges.

In Appendix 4, a table is provided that identifies the approaches that should be used to classify Distribution Plant items, Distribution Operation and Maintenance expenses and Customer costs as either demand related (primary or secondary), customer related or both demand and customer related. The remainder of the section identifies methods for splitting jointly related demand and customer costs into separate demand and customer components.

The default approach used in the MEA Model for splitting joint costs into separate customer and demand categories is the minimum size method as defined in Section 5.2 below. The use of an alternate approach, such as the zero intercept method, would require the utility to prepare an analysis justifying the alternative approach. The "Classify" Sheet of the MEA Model contains the default minimum size factors. The utility can accept these values or conduct a study to determine the appropriate values for its system.

5.2 Minimum Size Method[9]

The minimum size method assumes a minimum size distribution system can be built to serve the minimum loading requirements of customers. This method identifies the minimum size pole, conductor, cable, transformer, and service that is currently installed by the utility. Average installed book cost (i.e. total book cost divided by total units) of the minimum sized component determines the price of all installed units of that equipment type. The analyst then multiplies the minimum size average book cost of equipment for each account by the total number of pieces in the account to determine customer cost component amount. The balance of costs for each account are classified as demand related.

5.3 Zero Intercept Method[9]

Based on the concern that there is a portion of demand capability in even the smallest available unit, the zero intercept method seeks to identify a portion of plant related to a hypothetical no-capacity or zero intercept situation. To do so, the method relates installed cost to capacity or the demand rating. Using a regression technique, a relationship for various sizes of equipment involved is created (size vs. cost/unit), which is then extended to a zero-size intercept. The per unit cost related to the zero intercept is the customer component. As may be apparent this requires much more data and calculation than does the minimum size method.

5.4 Comparison of minimum size versus zero intercept

The minimum size method can be influenced by factors such as:

- the choice of method used to identify minimum sized equipment: historical practice, current practice, or minimum requirement to meet safety standards (the higher the costs for a minimum system, the more costs allocated to the customer charge)
- recognition (or lack thereof) that even minimum system has a load carrying capability that can be viewed as demand related (and thus if not acknowledged

[9] Discussions about the minimum size and zero intercept methods are excerpted from the NARUC Cost Allocation Manual and from the Principals of Public Utility Rates by James Bonbright.

may lead to a disproportionate share of demand costs being allocated to certain customers).

The zero intercept method can be a more exact method (because zero intercept is a theoretically more sound way of identifying customer and demand component), but it is more data and calculation intensive as well. The biggest drawbacks to using the zero intercept method which make it less desirable to use than the minimum size approach are:

- the zero intercept method ignores the fact that a weak correlation exists between area/mileage of a distribution system and the number of customers served by the system because it makes no allowance for customer density.
- the zero intercept method can also produce erroneous results if input data contains abnormalities which causes data extrapolation to produce a negative or odd looking no load intercept (i.e. implying a negative or very odd looking customer charge)

5.5 Other Methods

Special considerations and/or historical practices may lead the utility to use a company specific method of determining the customer and demand categories. The continued use of these methods may be appropriate due to inter and intra-class impacts. The submitting utility should provide a detailed explanation of its proposed method, the reasons for the continued use of its method and an impact analysis of a switch to the models default method.

6. Allocation Methods

6.1 Introduction

The final step in developing an allocated cost of service is to allocate classified demand and customer expenses to each tariff customer class on an equitable and fairly apportioned basis. This section discusses these distribution demand allocation methods and customer charge allocation methods.

6.2 Demand Allocation Methods

Customers take service at different voltage levels, and the assumption in the model is that only those customers which utilize a component of the distribution system are to be allocated a portion of the cost related to these facilities. Therefore customers who take service at a higher voltage (transmission) level should be excluded from lower voltage (distribution) demand allocators entirely. Likewise, those groups taking service at the primary level should only be allocated primary demand costs. Only customers taking service at secondary voltage levels should be allocated a portion of the entire distribution system costs.

The degree of load diversity[10] on different components of the electric system may influence the choice of the allocator used to distribute costs related to those facilities. Greater load diversity usually indicates that the capacity on the distribution system required to ensure reliable and safe service is less than the sum of individual peak loads because these peaks are not coincident.

Primary demand costs are associated with distribution facilities that usually exhibit the greatest amount of load diversity on the distribution system. The maximum demand imposed on a system largely determines the size of the facility and, therefore, its cost. However, there is considerable variation between the sum of maximum demands of the individual customers and the maximum demand on the facility. Thus, greater diversity can lower primary demand unit costs and lower diversity can increase primary demand unit costs. Usually, primary distribution facilities are allocated to customers using the customer-class non-coincident peak demand (NCP) method which is the default allocator used in the MEA Model. This method apportions the diversity benefits without regard to the group contribution to the system coincident peak loads. Even a 100 percent load factor customer shares in the diversity benefits. However, due to the potential for greater diversity on the primary distribution system, costs can also be allocated using methods more typically applied to the transmission system. Two of these methods are the coincidental peak responsibility (CP) method and the average and excess method. All three allocation approaches are discussed in more detail in Appendix 5. The MEA Model includes default detailed load data that allows the user to choose the CP demand allocation method if the user believes that the default data is comparable to the utility's operations. If the default data is not comparable and the user does not have the utility specific data the NCP method should be used.

Generally, the NCP method is used to allocate primary distribution costs because customer class peaks are typically the main drivers to capacity requirements (and consequently costs) at this location in the system. However, in some systems, if diversity at the primary distribution level is similar enough to that at the transmission level for one to consider using the same transmission allocation method (e.g. peak responsibility or the average and excess methods) for distribution allocation as well.

The default method used in the MEA Model to allocate secondary demand costs is also the NCP method. However, since secondary demand costs are associated with distribution facilities that are much nearer to the customer premises, they may exhibit a much lower level of load diversity. Therefore, in order to reflect this lower diversity, as an alternative to using the NCP method, utilities may want to consider using individual customers' maximum demands as a secondary demand allocator. This alternative method is different from the NCP approach in that allocation is based on specific customer data rather than overall class peak usage.

[10] Diversity accounts for variations among the loads in distribution transformers, feeders, and substations at any given time. It is measured as the difference between the sum of the maximum of two or more individual loads and the coincident or combined maximum load.

The results each method has on the allocated cost study is highly dependent on the load data of the submitting utility. However, in general, if a utility uses the peak responsibility method or the average and excess method rather than the NCP approach to allocate primary demand costs, the resulting factors will tend to shift cost away from small to medium sized lower load factor[11] customers towards larger high load factor customers. This is because the peak responsibility method will not capture usage for customers whose consumption occurs mainly off the system peak (e.g. summer streetlighting). Since high load factor customers, by definition, use similar amounts of capacity on and off the system peak, their allocation factor will increase as a percentage of total usage, when measured at the system peak.

Customer characteristics (e.g. residential or commercial load, air conditioning or heating load) of individual electric systems dictate the most appropriate primary and secondary demand allocators to use. The design and operational characteristics of the distribution system should be considered to identify the allocation approaches that are most cost justified for each submitting utility.

6.3 Customer Costs Allocation Method

In most cases, expenses classified as customer costs should be allocated based upon the number of customers by tariff class or customers adjusted for weighting factors.[12] Weighting factors account for variances in the per unit costs of metering and customer service expenses necessary to serve each tariff class. Generally, weighted customer factors will shift allocation of expenses to large commercial and industrial classes in consideration of the higher metering and customer service costs required to serve these customer segments. Weighting factors will vary by cost component and utility and require separate studies to establish. The most common use of the weighting method is for meter costs. The cost of a residential meter is the base cost against which the meter costs of the other classes are measured. The factor by which the other classes meter

[11] Customer load factor is defined as the ratio of actual kilowatt-hours used to the amount that would have been used had the customer consumed energy uniformly during the entire measurement period (e.g. a day) at the rate of maximum demand.
[12] See Appendix 9 for an example.

cost exceeds the base cost becomes the weighting factor. For example, if a residential meter costs $50 and a commercial meter costs $175 the weighting factor would be 3.5.

As stated in footnote 6 to Appendix 4, an exception to the above is Account 5335, Bad Debt Expense. This account should be directly assigned to each rate class using accounts receivable records if this detail is available. Otherwise, it is appropriate to use class revenue responsibility to assign these costs to the tariff classes.

In Appendix 6 a table is provided that identifies the methods for allocating customer classified costs (as identified in Appendix 4) to each tariff class. It should be noted that Appendix 6 does not include the distribution plant and associated operation and maintenance accounts identified in Appendix 4 as being as jointly customer and demand related. Once the customer component of the Appendix 4 accounts is identified (using the default MEA model minimum system approach or other method proposed by the submitting utility), these costs should be allocated using the actual number of customers by tariff class of service. For example, it is noted in Appendix 4 that Account 1835, Overhead Conductors & Devices, should be jointly classified as both demand and customer related. After the customer component of Account 1835 is determined and separated from the total, these customer related costs should be allocated to the tariff classes using the actual number of customers by tariff class of service. The remaining costs in the account are classified as either primary or secondary demand related and allocated to the tariff classes using the demand allocation methods discussed in Section 6.2.

7. Assignment of All Other Costs

7.1 Introduction

Some components of the distribution revenue requirement can not be either directly assigned or indirectly attributed to customers using the procedures outlined in Sections Three through Six. Instead, composite factors based on the net result of assigning all other costs to customers are used as the basis for assigning these indirect costs. However, as stated earlier, if enough information is available to directly assign general costs to customer tariff classes, this approach should always supercede the composite assignment methods discussed in this guideline section.

This section groups accounts into five subcategories as follows:

1. General Plant
2. Administrative &General ("A&G") Expenses
3. Rate Base Items Other Than Plant Accounts
4. Other Revenue Requirements Expenses
5. Miscellaneous and Other Revenues

7.2 General Plant

Three general methods exist to assign these plant items: using an overall plant-based allocator (plant ratio method), performing a detailed classification analysis or utilizing labour ratios. In all three methods depreciation reserves should be allocated in the same fashion as their respective gross plant accounts.

In the first approach, the plant ratio method, a composite allocation factor is developed in the plant allocation process using the class ratio of all plant accounts excluding general plant.[13] This is done on the theory that general plant exists to support other plant functions. These factors are then applied to general plant to assign a portion of general plant to customer tariff classes.

[13] See Appendix 9 for an example.

In the second approach, performing a detailed classification analysis method, each account is evaluated to determine which item of plant and or expense already allocated can be used as a basis to classify each general plant account. For instance, office furniture and equipment could be classified based on a composite factor of selected accounts that reflects how furniture outlays are incurred. However, performing detailed analysis of all general plant accounts is time-consuming and is likely to yield a small incremental benefit when compared to the plant ratio approach.

Finally, another approach used in combination with the above is to develop labour expense ratios by determining the labour component of other assigned charges. Labour ratios are derived by summing the direct labour costs allocated to a service and dividing by the total direct labour costs. These ratios can be used to assign general plant costs that are labour related.

The default approach used in the MEA Model for allocating general plant accounts is the plant ratio method. Plant ratios are derived by summing the plant costs allocated to a service and dividing by the total plant costs. The MEA Model uses plant ratios developed on a gross plant basis to allocate the general plant accounts listed in Appendix 7. However, there is an exception to this guideline noted in Appendix 7 which relates to activity in certain accounts that can be directly traced to specific customer tariff classes. Therefore, direct assignment is the default approach used to assign these expenditures. Finally, although labour ratios are not utilized currently in the model to allocate any general plant accounts, submitting utilities may want to consider using labour ratios for allocating certain general plant accounts that have an indirect link to labour costs. These are also noted in Appendix 7.

7.3 A&G Expenses

The approach for assigning Administrative & General (A&G) accounts is similar in concept to that used to assign general plant accounts. The default method in the current model allocates most A&G costs based on total operating and maintenance expense assignments, excluding A&G and purchased power. The remaining accounts are allocated on the basis of gross plant, net plant or direct assignment. The second and preferred approach seeks to group similar A&G accounts into classified sub-groupings which are allocated on factors most closely related to the nature of the accounts. As shown in Appendix 8, accounts are grouped into three silos: those that are plant related, those that are labour related, and those that require special consideration or cannot readily be attributed to a particular type of activity. Plant related A&G accounts are assigned to customer tariff classes based on net plant-in-service ratios[14], labour related accounts are assigned to customer tariff classes based on overall labour ratios[15] and the balance of accounts are considered on an individual basis or are allocated based on overall O&M ratios exclusive of A&G and purchased power.

Appendix 8 provides a table that identifies the default methods to assign A&G costs to customer tariff classes included in the MEA Model.

7.4 Rate Base Items Other Than Plant Accounts

7.4.1 Introduction

Rate base is the original cost of the utility's plant, less accumulated depreciation, plus a reasonable allowance for working capital and any regulatory assets otherwise allowed. This section describes how three types of rate base accounts should be allocated to customer tariff classes. Generally these items are allocated using ratios based on

[14] Calculated as the ratio of net plant allocated to the class as a percentage of total net plant.

[15] The preferred approach for allocating A&G costs differs from the default method used in the model because it identifies certain labour and benefit A&G accounts (noted in Appendix 8) as being labour related. Allocation of labour related A&G expenses is based upon development of labour ratios that rely on the labour component of O&M expenses being identified separately from other costs. The existing model does not allow for labour costs to be input separately, but is intended to be modified in the future to offer this option.

operating expense and gross or net plant.[16] However, if a submitting utility has included other items in rate base not listed in this section, then assignment of these accounts should based on the nature of the underlying expense.

7.4.2 Organization Account

The model allocates these costs using composite ratios based on total gross plant allocated to each tariff class. Intangible plant items are generally allocated on the basis of gross plant on the assumption that intangible plant is generally considered to be related to the provision of all utility services and is therefore, allocated to all classes of utility plant.

7.4.3 Franchise and Consents

The model allocates these costs using composite ratios based on total gross plant allocated to each tariff class. Intangible plant items are generally allocated on the basis of gross plant on the assumption that intangible plant is generally considered to be related to the provision of all utility services and is therefore, allocated to all classes of utility plant.

7.4.4 Materials and Supplies

These costs should be allocated using composite ratios based on total net plant allocated to each tariff class. This is done on the assumption that the need for materials and supplies is directly related to the amount of plant.

7.5 Other Revenue Requirements Expenses

7.5.1 Introduction

This section describes how four types of general revenue requirement costs should be allocated to customer tariff classes. All other items should be allocated based on the underlying expenses.

[16] Gross plant is the original cost of the plant. Net plant is original cost less accumulated depreciation.

7.5.2 Distribution Plant Depreciation Expense

These costs should be allocated in the same manner as the respective Plant accounts. First, total distribution plant depreciation is determined by summing the expenses recorded in the USoA depreciation accounts. Then composite ratios based on total gross distribution plant allocated to each tariff class are used as the basis to allocate total distribution plant depreciation expense.

7.5.3 General Plant Depreciation Expense

These costs should be allocated in the same manner as the respective Plant accounts. First, total general plant depreciation is determined by summing the expenses recorded in the USoA depreciation accounts. Then composite ratios based on total gross general plant allocated to each tariff class are used as the basis to allocate total general plant depreciation expense.

7.5.4 Amortization

The MEA Model provides for the allocation of the amortization of contributed capital using composite ratios based on total gross distribution plant allocated to each tariff class. Utilities needing to amortizing other amounts will have to determine an appropriate allocation basis.

7.5.5 Interest Expense and Non operating Income

The MEA Model allocates these costs using composite ratios based on total operating and maintenance expense before A&G and purchased power allocated to each tariff class.

7.6 Miscellaneous and Other Revenues

7.6.1 Introduction

Many miscellaneous revenue accounts can be directly assigned to customer tariff classes. These accounts were identified in Appendix 2. This section addresses how the remaining miscellaneous revenue accounts can be allocated to customers.

7.6.2 Miscellaneous Revenue Accounts Allocated Using Net Plant

Account 4325, Revenues from Merchandise, Jobbing, etc.; Account 4330, Costs and Expenses from Merchandising, Jobbing, etc.; Account 4375, Revenue from Non-Utility Operations; Account 4380, Expenses of Non-Utility Operations; Account 4385, Non-Utility Rental Income should be allocated based on total net plant allocated to customer tariff classes.

7.6.3 Miscellaneous Revenue Accounts Allocated Using Gross Distribution Plant

Account 4335, Profits and Losses from Financial Instrument Hedges; Account 4340, Profits and Losses from Financial Instrument Investments; Account 4355, Gain on Disposition of Utility and Other Property; Account 4360, Loss on Disposition of Utility and Other Property; Account 4365, Gains from Disposition of Allowances for Emissions, and; Account 4370, Losses from Disposition of Allowances for Emission, should be allocated based on total gross distribution plant allocated to customer tariff classes.

8 Customer Service Classes and Load Data

8.1 Customer Service Classes

The purpose of a cost allocation study is to determine the costs necessary to serve a class of customers. Customer service classes are formed by recognizing common customer characteristics such as type, amount, and time of use. The MEA Model has 14 default customer classes, 13 defined and one undefined. The 13 defined classes in the MEA Model are:

- Residential – Regular (without electric heating);
- Residential – All Electric (with electric heating);
- Flat Rate Water Heater;
- Small Commercial – without Demand Meter;
- Medium Commercial – with Demand Meter;
- Large Commercial – Pulse Meter;
- Large Users;
- Street Lights;
- Commercial Lighting;
- Sentinel Lighting;
- Water Heater Tank Rental;
- Sentinel Lighting Rental, and;
- Other

8.2 Load Data

The MEA Model uses the NCP Demand allocation method as its default. The advantage of this method of allocation is the reduced level of load information required for the model to work. Under the NCP Demand allocation method the required information is kWhs sales at the meter by class of customer, class load factors, individual NCP demand (if demand metered), line loss, and the utility's total NCP-kW. If the utility believes that the default detailed load data is appropriate to its circumstances or if the utility has its applicable load data the coincident peak (CP) Demand allocation method can be used. In addition to the above information, coincidence factors (group, system, transmission and generation) will be needed. The user manual which accompanies the MEA Model discusses the models data requirements and how this data should be inputted into the model. Whichever method is selected the model uses the load data to produce the factors necessary to allocate costs to the various rate classes.

8.3 Reconciliation of Load Data

If the utility uses its own load data it should be based on its own detailed load research. In many cases values entered into the model depend on judgement and these need to be verified, or reconciled, against the historical load data. The MEA Model provides for this need.

The MEA Model's User Manual recommends that each item be separately reconciled one month at a time. The first reconciliation is the kWhs at the input voltage. Reconciliation refers to matching a known historical load to those calculated in the historical load data analysis. In this case, the object is to match the calculated total kWhs sales at the meter to the actual total kWhs used. The model calculates the percentage difference between the sales at the meter and actual kWhs by month. If there is a major difference between these two figures, particularly on a seasonal and total annual basis, or if any one month is off by ±10 percent, the User Manual recommends adjusting the assumed loss factors used in the historical load data analysis to match the known historical values. Total line losses, input plus primary, of between 4 percent to 8 percent is reasonable. If during the reconciliation of kWhs total line losses exceed this range, then line losses should be adjusted to within a reasonable range. Adjustments to individual load factors and/or coincidence peak factors may be necessary to reconcile the kWhs to ±10 percent (generally).

The final item to be reconciled in the load analysis is the coincidence peak, or demand (kW) at input. This reconciliation is similar to the reconciliation of kWhs or energy.
In reconciling the demand or coincidence peak, the assumed load factors and the two coincidence factors used for each class of service must be reviewed. These input items could affect the coincidence peak. Only those inputs that are based on judgement or weak information should be changed.

Appendix 1

Guideline Reference to MEA Model

Section/Appendix	Data Input References (Worksheet/Exhibit)	Primary Report Reference(s) (Worksheet/Exhibit) *	Secondary Report Reference(s) (Worksheet/Exhibit) **
Section 3 Direct Assignment Expenses/Appendix 2	Street Lighting: **LOB** Non-Exhibit L-1	**F&C** Exhibit F-1A/F-1C	**Financials** Non-Exhibit 1
	Sentinel Lighting: **LOB** Non-Exhibit L-1	**F&C** Exhibit F-2A	**Financials** Exhibit A-2
	Expenses for Stranded Asset, Rural Rate Assistance, Water Heating, Sentinel Lights, Street Lights: **LOB** Exhibit L-2	**F&C** Exhibit F-2A	**Financials** Exhibit A-2
	Misc. Revenues: **LOB** Exhibit L-2	**F&C** Exhibit F-2A	**Financials** Exhibit A-2
Section 4 Functionalization Methods/Appendix 3	Acct. 1615: **LOB** Non-Exhibit L-1	**F&C** Exhibit F-1A/F-1C	**Financials** Non-Exhibit 1
	Distr. Plant: **LOB** Non-Exhibit L-1	**F&C** Exhibit F-1A/F-1C	**Financials** Non-Exhibit 1
	Distr. O&M Expenses: **LOB** Exhibit L-2	**F&C** Exhibit F-2A	**Financials** Exhibit A-2
	Expenses for Billing, Collecting, Meter Reading, Cust. Serv., & Info. Sys.: **LOB** Exhibit L-2	**F&C** Exhibit F-2A	**Financials** Exhibit A-2
Section 5 Classification Methods/Appendix 4	Acct. 1615: **LOB** Non-Exhibit L-1	**F&C** Exhibit F-1A/F-1C	**Financials** Non-Exhibit 1
	Distr. Plant: **LOB** Non-Exhibit L-1	**F&C** Exhibit F-1A/F-1C	**Financials** Non-Exhibit 1
	Distr. O&M Expenses: **LOB** Exhibit L-2	**F&C** Exhibit F-2A	**Financials** Exhibit A-2
	Expenses for Billing, Collecting, Meter Reading, Cust. Serv. & Info. Sys.: **LOB** Exhibit L-2	**F&C** Exhibit F-2A	**Financials** Exhibit A-2

* Primary reports contain significant amounts of information related to a guideline Section.

** Secondary reports contain some references related to a guideline Section.

Appendix 1
Guideline Reference to MEA Model

Section/Appendix	Data Input References (Worksheet/Exhibit)	Primary Report Reference(s) (Worksheet/Exhibit) *	Secondary Report Reference(s) (Worksheet/Exhibit) **
Section 6 Allocation Methods/Appendices 5 & 6	NCP: **Loads** Non-Exhibit 2 **Loads** Non-Exhibit 4 Peak Responsibility: **Loads** Non-Exhibit 2 **Loads** Non-Exhibit 4 Average & Excess: **Loads** Non-Exhibit 2 **Loads** Non-Exhibit 4	**F&C** Exhibit F-1C/2C **Allocate** Exhibit E-1 **F&C** Exhibit F-1C/2C **Allocate** Non-Exhibit 9 **F&C** Exhibit F-1C/2C **Allocate** Non-Exhibit 8	**Summary** Exhibit G-1A/1-B **Summary** Exhibit G-1A/1-B **Summary** Exhibit G-1A/1-B
Section 7 Assignment of All Other Costs/Appendices 7, 8 & 9	Distr. Plant: **LOB** Non-Exhibit L-1 Meters, Cust. Accts.: **LOB** Exhibit L-2 Expenses for Billing, Collecting, Meter Reading, Cust. Serv. Info. Sys: **LOB** Exhibit L-2 Misc. Revenue Accts: **LOB** Exhibit L-2 Gen Plant Accts: **LOB** Non-Exhibit L-1 A&G Accts: **LOB** Exhibit L-2	**F&C** Exhibit F-1A **F&C** Exhibit F-2C **F&C** Exhibit F-2C **F&C** Exhibit F-2C **F&C** Exhibit F-1C **F&C** Exhibit F-2C	**Financials** Non-Exhibit **Summary** Non Exhibit 11 **F&C** Exhibit F-2A **F&C** Exhibit F-2A **F&C** Exhibit F-2A **F&C** Exhibit F-1A **F&C** Exhibit F-2A

* Primary reports contain significant amounts of information related to a guideline Section.

** Secondary reports contain some references related to a guideline Section.

Appendix 2
Direct Assignment of Selected Distribution Cost of Service Accounts

Account	Direct Assignment Customer Tariff Class
Distribution Plant	
Account 1875 (Street Lighting & Signal Systems)	Streetlighting (See Note 1)
Account 1985 (Sentinel Lighting Rental Units)	Sentinel Lighting (Rental) (See Note 1)
General Plant	
Account 1965 (Water Heater)	Water Heater Tank Rental (See Note 1)
Account 1970 (Load Mgt. Control – Cust. Premises	Water Heater Tank Rental (See Note 1)
Account 1975 (Load Management Controls – Utility Premises)	Water Heater Tank Rental (See Note 1)
Account 1985 (Sentinel Lighting Rental Units)	Sentinel Lighting (Rental) (See Note 1))
Customer Account Expenses	
Account 53-20/30/35 (Collecting, Collection Charges and Bad Debt Expense Accounts)	(See Note 2)
Account 5340 – Misecllaneous Customer Account Expenses	(See Note 2)
Account 5185 (Water Heater Maintenance – Labour)	Water Heater Tank Rental
Account 5186 (Water Heater Maintenance – Materials and Expenses)	Water Heater Tank Rental
Account 5190 (Water Heater Controls – Labour)	Water Heater Tank Rental
Account 5192 (Water Heater Controls – Materials and Expenses)	Water Heater Tank Rental
Account 5170 (Sentinel Lights - Labour)	Sentinel Lighting (Rental)
Account 5172 (Sentinel Lights – Materials and Expenses)	Sentinel Lighting (Rental)
Account 5165 (Maintenance of Street Lighting and Signal Systems)	Street Lighting
Account 5195 (Maintenance of Other Installations on Customer Premises)	Other

Appendix 2
Direct Assignment of Selected Distribution Cost of Service Accounts

Account	Direct Assignment Customer Tariff Class
Miscellaneous and Other Revenue	
Account 4225 (Late Payment Charges)	(See Note 3)
Account 4235 (Misc. Service Charge – includes reconnection charge, change of occupancy charge and dispute of meter test charge)	(See Note 3)
Account 4355 (Gain on disposition of utility and other property)	(See Note 3)
Account 4360 (Loss on disposition of utility and other property)	(See Note 3)

Note 1: Accumulated Depreciation reserve on distribution and general plant accounts should be directly assigned to customer tariff classes on the same basis as the plant account it is based.

Note 2: Accounts 53-20/30/35/40, Collecting, Collection Charges, Bad Debt Expense and Miscellaneous Customer Account Expenses, should be directly assigned to customer tariff classes using account receivable records if sufficient record keeping exists. If records are not available, then these expenses should be allocated to customer tariff classes using class revenue responsibility.

Note 3: Misc. Revenue sub accounts should be directly assigned based on the specific customer account records of each submitting utility.

Appendix 3
Functionalization of Selected Distribution Cost of Service Accounts

Account	Distribution	Metering	Billing	Other Customer Services
Distribution Plant				
Account 1805 Land	X			
Account 1806 Land Rights	X			
Account 1808 Buildings & Fixtures	X			
Account 1810 Leasehold Improvements	X			
Account 1815 Transformer Station Equipment – Normally Primary above 50kV	X			
Account 1820 Transformer Station Equipment – Normally Primary below 50kV	X			
Account 1825 Storage Battery	X			
Account 1830 Poles, Towers, & Fixtures	X			
Accounts 1835 Overhead Conductors & Devices	X			
Account 1840 Underground Conduits	X			
Accounts 1845 Underground Conductors & Devices	X			
Accounts 1850 Line Transformers	X			
Accounts 1855 Services	X			
Account 1860 Meters		X		
Account 1865 Other Installations at Customer Premises				X
Account 1870 Leased Property on Customer Premises				X

Appendix 3
Functionalization of Selected Distribution Cost of Service Accounts

Account	Distribution	Metering	Billing	Other Customer Services
Distribution Operations				
Accounts 5005 Operation Supervision and Engineering	Note 1	Note 1	Note 1	Note 1
Account 5010 Load Dispatch	X			
Account 5012 Station Buildings and Fixtures	X			
Account 5014 Transformer Station Equipment – Operating Labour	X			
Account 5015 Transformer Station Equipment – Operating Supplies and Expense	X			
Account 5016 Distribution Station Equipment – Operating Labour	X			
Account 5017 Distribution Station Equipment – Operating Supplies & Expense	X			
Accounts 5020 Overhead Distribution Line and Feeders – Operating Labour	X			
Accounts 5025 Overhead Distribution Line and Feeders – Operating Supplies & Expense	X			
Accounts 5030 Overhead Subtransmission Feeders – Operation	X			
Accounts 5035 Overhead Distribution Transmission Feeders – Operation	X			
Accounts 5040 Underground Distribution Lines & Feeders – Operating Labour	X			
Accounts 5045 Underground Distribution Lines & Feeders – Operation Supplies & Expense	X			
Accounts 5050 Underground Subtransmission Feeders – Operation	X			

Appendix 3
Functionalization of Selected Distribution Cost of Service Accounts

Account	Distribution	Metering	Billing	Other Customer Services
Accounts 5055 Underground Distribution Transformers	X			
Account 5060 Street Lighting & Signal System Expense	X			
Account 5065 Meter Expenses		X		
Account 5070 Customer Premises – Operating Labour				X
Account 5075 Customer Premises – Materials & Expenses				X
Account 5085 Misc. Distribution Expense	X			
Account 5090 Underground Distribution Transmission Feeders – Rental Paid	X			
Account 5095 Overhead Distribution Lines & Feeders – Rental Paid	X			
Account 5096 Other Rent	X			
Distribution Maintenance				
Account 5105 Maintenance Supervision & Engineering	Note 1	Note 1	Note 1	Note 1
Account 5110 Maintenance of Structures	X			
Account 5115 Maint. of Distribution Station Equipment	X			
Account 5120 Maint. of Poles, Towers and Fixtures	X			
Account 5125 Maint. of Overhead Conductors & Devices	X			
Account 5130 Maint. of Overhead Services	X			
Account 5135 Overhead Distribution Lines & Feeders – Right of Way	X			

Appendix 3
Functionalization of Selected Distribution Cost of Service Accounts

Account	Distribution	Metering	Billing	Other Customer Services
Account 5145 Maint. of Underground Conduit	X			
Account 5155 Maint. of Underground Services	X			
Account 5160 Maint. of Line Transformers	X			
Account 5175 Maint. of Meters		X		
Account 5178 Customer Installations Expenses – leased property				X
Account 5195 Maint. of other installations on Customer premises				X
Other Expenses				
Account 5205 Purchase of Transmission and System Services	X			
Account 5210 Transmission Charges	X			
Account 5215 Transmission Charges Recovered	X			
Customer Accounting, Customer Service & Information And Sales				
Account 5305 Supervision			X	
Account 5310 Meter Reading Expense		X		
Accounts 5315 Customer Billing			X	
Account 5320 Collecting			X (See Note 2)	
Accounts 5325 Collecting – Cash Over & Short			X	
Account 5330 Collection Charges			X (See Note 2)	
Account 5335 Bad Debt Expense			X (See Note 2)	
Account 5340 Miscellaneous Customer Account Expenses			X (See Note 3)	

Account	Distribution	Metering	Billing	Other Customer Services
Community Relations				
Account 5405 Supervision				X
Account 5410 Community Relations – Sundry				X
Account 5415 Energy Conservation				X
Account 5420 Community Safety Program				X
Account 5425 Misc. Customer Service & Information Expenses				X

Note 1: Should be functionalized based on the level of directly assigned expenses.

Note 2: Accounts 53-20/30/35 Collecting, Collection Charges and Bad Debt Expense should be directly assigned to customer tariff classes using account receivable records if sufficient record keeping exists.

Note 3: Account 5340, Misc. Customer Account Expenses includes accounts which should be directly assigned to customer tariff classes. These direct assignment accounts are identified in Appendix 2. All other Misc. Customer Account items are generally functionalized as billing related.

Appendix 4

Classification of Selected Distribution Cost of Service Accounts

Account	Demand (Primary/ Secondary)	Customer	Joint Demand/Customer
Distribution Plant			
Account 1805 Land	X (primary)		
Account 1806 Land Rights	X (primary)		
Account 1808 Building & Fixtures	X (primary)		
Account 1810 Leasehold Improvements	X(primary)		
Account 1815 Transformer Station Equipment – Normally primary above 50kV	X (primary)		
Account 1820 Transformer Station Equipment – Normally primary below 50kV	X (primary)		
Account 1825 Storage Battery Equipment	X (primary)		
Account 1830 Poles, Towers & Fixtures			X (primary/customer)
Accounts 1835 Overhead Conductors & Devices			X (primary/customer)
Account 1840 Underground Conduit			X (primary/customer)
Accounts 1845 Underground Conductors & Devices			X (primary/customer)
Accounts 1850 Line Transformers			X (secondary/customer)
Accounts 1855 (Services)		X (See note 1)	
Account 1860 (Meters)		X (See note 2)	
Account 1865 Other Installations on Customer Premises		X	
Account 1870 Leased Property on Customer Premises		X	

Appendix 4
Classification of Selected Distribution Cost of Service Accounts

Account	Demand (Primary/ Secondary)	Customer	Joint Demand/Customer
Distribution Operations			
Accounts 5005 Operation Supervision & Engineering	X (primary)		
Account 5010 Load Dispatch	X (primary)		
Account 5012 Station Buildings & Fixtures	X (primary)		
Account 5014 Transformer Station Equipment – Operating Labour	X (primary)		
Account 5015 Transformer Station Equipment – Operating Supplies and Expense	X (primary)		
Account 5016 Distribution Station Equipment – Operating Labour	X (primary)		
Account 5017 Distribution Station Equipment – Operating Supplies & Expense	X (primary)		
Account 5020 Overhead Distribution Line & Feeders - Operation Labour			X (See Note 3)
Account 5025 Overhead Distribution Line & Feeders – Operation Supplies & Expenses			X (See Note 3)
Account 5030 Overhead Subtransmission Feeders – Operation	X (primary)		
Account 5035 Overhead Distribution Transmission Feeders – Operation	X (primary)		
Accounts 5040 Underground Distribution Lines & Feeders – Operation Labour			X (See Note 4)
Account 5045 Underground Distribution Lines & Feeders – Operation Supplies & Expenses			X (See Note 4)

Account	Demand (Primary/ Secondary)	Customer	Joint Demand/Customer
Account 5050 Underground Subtranmission Feeders – Operation	X (primary)		
Account 5055 Underground Distribution Transformers – Operation	X (primary)		
Account 5065 Meter Expense		X	
Account 5090 Underground Distribution Lines & Feeders - Rental Paid	X (primary)		
Account 5095 Overhead Distribution Lines & Feeders – Rental Paid	X (primary)		
Account 5096 Other Rent	X (primary)		
Distribution Maintenance			
Account 5105 Maintenance Supervision & Engineering	X (primary)		
Account 5110 Maintenance of Structures	X (primary)		
Account 5115 Maint. of Distribution Station Equipment	X (primary)		
Account 5120 Maint. of Poles, Towers and Fixtures			X (See Note 3
Account 5125 Maint. of Overhead Conductors & Devices			X (See Note 3)
Account 5130 Maint. of Overhead Services			X (See Note 3)
Account 5135 Overhead Distribution Lines & Feeders – Right of Way	X (primary)		
Account 5145 Maint. of Underground Conduit	X (primary)		
Account 5155 Maint. of Underground Services			X (See Note 4)
Account 5160 Maint. of Line Transformers			X (See Note 4)
Account 5175 Maint. of Meters		X	
Account 5178 Customer Installations Expenses – leased property		X	

Appendix 4
Classification of Selected Distribution Cost of Service Accounts

Account	Demand (Primary/ Secondary)	Customer	Joint Demand/Customer
Account 5195 Maint. of other installations on Customer premises		X	
Billing & Collection (Labour Identified Separately)			
Account 5305 Supervision		X	
Account 5310 Meter Reading Expense		X	
Account 5315 Customer Billing		X	
Account 5320 Collecting		X	
Account 5325 Collecting – cash over & short		X	
Account 5330 Collection Charges		X	
Account 5335 Bad Debt Expense		X (See note 6)	
Account 5340 Misc. Customer Account Expense		X (See note 7)	
Community Relations			
Account 5405 Supervision		X	
Account 5410 Community Relations – Sundry		X	
Account 5415 Energy Conservation		X	
Account 5420 Community Safety Program		X	
Account 5425 Customer Service & Informational Expense		X	

Note 1: Account 1855 Services can also be partially classified as demand (secondary) to reflect more costly service drops for largest customers

Note 2: Account 1860 Meters for larger customers can also be partially classified as demand (secondary) to indicate that their higher level of usage requires installation of expensive time of use metering.

Note 3: Accounts are classified as demand and customer based on a composite factor comprised of plant accounts 1830 and 1835.

Note 4: Accounts are classified as demand and customer based on a composite factor comprised of plant accounts 1840 and 1845.

Note 5: Accounts are classified as demand and customer based on a factor comprised of plant account 1850.

Note 6: Account 5335, Bad Debt Expense, should be directly assigned to customer tariff classes using account receivable records if sufficient record keeping exists.

Note 7: Misc. Customer Account Expense includes certain accounts which should be directly assigned to customer tariff classes. These direct assignment accounts are identified in Appendix 2. All other Misc. Customer Account Expense items are generally classified as customer costs.

Appendix 5

Allocation Methods for Distribution Demand Costs[17]

Non-Coincident Peak Method (NCP)

NCP method allocates costs to each class of business on the basis of the maximum demand established by that class at any time during the period under study without regard to whether or not it coincides with the peak demand sustained by other classes. The base on which the allocation factors are computed is the sum of the non-coincident class peaks that is simply the arithmetic total of the class maximum values. For largest customers, existing time-of-use demand metering usually captures this data. For all other customers, this data is gathered through load research metering data. This method is not affected by shifts in the time of maximum class demands and allocates costs to classes regardless of use at the system peak.

Peak Responsibility Method

This method is also known as the coincident-peak method and allocates costs to each class in proportion to the contribution to the system peak made by that class at the time the peak occurs. Measurement is confined to a single day and therefore ignores load conditions existing on days other than the day of maximum system demand. For larger customers, existing demand metering usually captures this data. For all other customers, this data is gathered through load research metering data. This method assumes that costs should be divided among the customer classes creating the peak demand regardless of the magnitude of their demands at other times of the year or how long they may use the demands created. This method may produce different results if a shift in the time of the system peak occurs.

[17] Demand allocation methodology discussions are excerpted from The Art of Rate Design by Frank Walters and published by the Edison Electric Institute.

Appendix 5

Allocation Methods for Distribution Demand Costs

Average and excess method

This method is the most complex of three demand allocation methods. Average demand is that level of demand which would have been sustained if the same number of kilowatt-hours as actually consumed had been delivered on a uniform 24 hour a day around the clock basis instead of being supplied on the varying pattern experienced in actual practice. It is the least level of load under which that number of kilowatt-hours could be transmitted to the customer. It is arithmetically proportioned to the energy customer. Excess demand is the number of kilowatts by which the actual peak demand exceeds the average demand. As such it is a measure of how much the actual demand departs from the minimum load level required to deliver the same energy on a uniform or constant delivery basis. By relating the excess demand to the average demand the ratio gives a measure of the degree of variation in the consumers load. Under this method shifts in the system peak do not greatly affect the allocation of demand costs and recognition is given to the load factor characteristics of the various classes. The allocation of unused capacity is similar to the NCP method except that it is applied on the basis of excess class usage and is applied only to the portion of demand costs not allocated on a direct use basis.

Appendix 6
Allocation of Selected Customer Accounts

Account	Weighted Customer Account Services	Weighted Customer Meters & Metering	Class Revenue Responsibility
Distribution Plant			
Accounts 1855 Services		X	
Account 1860 Meters		X	
Account 1865 Other Installations at Customer Premises		X	
Distribution Operations (Labour Identified Separately)			
Account 5065 Meter Expenses		X	
Account 5070 Customers Premises – Operating Labor		X	
Account 5075 Customer Premises – Materials & Expenses	X		
Distribution Maintenance (Labour Identified Separately)			
Account 5175 Maint. of Meters		X	
Account 5178 Customer Installation Expenses – Leased Property	X		
Account 5195 Maint. of Other Installations on Customer Premises	X		
Billing and Collection (Labour Identified Separately)			
Account 5305 Supervision	X		
Account 5310 Meter Reading Expense		X	
Accounts 5315 Customer Billing	X		
Account 5320 Collecting	X		
Account 5325 Collecting	X		
Account 5325 Collecting – Cash Over & Short	X		
Account 5330 Collection Charges	X		
Account 5335 Bad Debt Expense			X (See Note 1)
Account 5340 Misc. Customer Account Exp.	X (See Note 2)		

Appendix 6
Allocation of Selected Customer Accounts

Account	Weighted Customer Account Services	Weighted Customer Meters & Metering	Class Revenue Responsibility
Community Relations			
Account 5405 Supervision	X		
Account 5410 Community Relations – Sundry	X		
Account 5415 Energy Conservation	X		
Account 5420 Community Safety Program	X		
Account 5425 Customer Service & Informational Expense	X		

Appendix 6
Allocation of Selected Customer Accounts

Definition of Allocation Methods

Actual Customers = The actual number of customers in each tariff class of service

Weighted Customer Account Services = Actual Customers weighted to reflect the relative cost of providing customer account services to each tariff class

Weighted Customer Meters & Metering = Actual Customers weighted to reflect the relative cost of providing meters/metering reading services to each tariff class

Class Revenue Responsibility = Revenues collected for each customer tariff class as a percentage of total tariff revenues

Notes

Note 1: Account 5335. Bad Debt Expense, should be directly assigned to customer tariff classes using account receivable records if sufficient record keeping exists. If records are not available, then uncollectible expenses should be allocated to customer tariff classes using class revenue responsibility.

Note 2: Misc. Customer Account Expense includes certain accounts which should be directly assigned to customer tariff classes. These direct assignment accounts are identified in Appendix 2. All other Misc. Customer Account Expense items are generally allocated using weighted customer account services.

Appendix 7
Assignment of Selected General Plant Accounts

Account/Methods of Allocation	Default Allocation Method-Gross Plant w/o General Plant *	Direct Assignment Exceptions	Alternate Allocation Method-Total Labour
General Plant Accounts			
Account 1905 Land	X		X (See Note 1)
Account 1906 Land Rights	X		X (See Note 1
Account 1908 Buildings & Fixtures	X		X (See Note 1)
Accounts 1910 Leasehold Improvements	X		X (See Note 1)
Account 1920 Computer Equipment – Hardware	X		X (See Note 1)
Account 1925 Computer Equipment – Software	X		X (See Note 1)
Account 1930 (Transportation Equipment)	X		
Account 1935 (Stores Equipment)	X		
Account 1940 (Tools, Shop and Garage Equipment)	X		
Account 1945 Measurement & Testing Equipment	X		
Account 1950 Power Operated Equipment	X		
Account 1955 Communication Equipment	X		X (See Note 1)
Account 1960 Misc. Equipment		X (See Note 2)	
Accounts 1965 Water Heaters Rental Units		X (See Note 2)	
Account 1970 Load Management Control – Utility Premise	X		
Account 1980 System Supervisory Equipment	X		
Account 1985 Sentinel Lighting Rental Units		X	
Account 1990 Other Tangible Property	X		
Account 1995 Contributions & Grants	X		X (See Note 1)

Note 1: Submitting utilities may consider using labour ratios (see example 9.2, Appendix 9) to allocate these accounts if a demonstration can be made that the related facilities and equipment are more closely linked to labour than plant accounts.

Note 2 Accounts 1965, 1970, and 1985 should be directly assigned to customer tariff classes.

* See Appendix 9 for an example of the gross plant allocation method.

Appendix 8
Assignment of Selected A&G Accounts

Account/Method of Allocation	Labour w/o A&G	Net Plant-In-Service	Total O&M w/o A&G and purchased power	Total Revenue
A&G Accounts				
Account 5605 Executive Salaries & Expenses)	X			
Account 5610 Management Salaries & Expenses	X			
Account 5615 General Admin. Salaries & Expenses	X			
Account 5620 Office Supplies	X			
Account 5625 Admin. Expense Transferred – Credit			X	
Account 5630 Outside Services Employed			X	
Account 5635 Property Insurance Expense		X		
Account 5640 Injuries and Damages	X			
Account 5645 Employee Pensions and Benefits	X			
Account 5650 Franchise Requirements				X
Account 5655 Regulatory Expenses			X	
Account 5660 General Advertising			X	
Account 5665 Misc. General Expenses			X	
Account 5670 Rents		X (See Note)		
Account 5675 Maint. General Plant			X	
Account 5680 Electric Safety Authority Fees			X	
Account 5685 Independent Market Operator Fees & Penalties				X

Note: In situations where rental payments are mostly related to rental office space, then labour excluding A&G should be used.

Appendix 9
Allocation Factor Examples

9.1 Basic Allocator

An example of a basic allocator is a Gross Plant allocator. In Example 1, Transmission is 32.59% of total plant, excluding general plant, and Distribution is 67.41% of total plant, excluding general. Using this ratio, general plant is allocated to the Transmission and Distribution functions. After this allocation, the combined total of Transmission plant and the allocated portion of General plant can be allocated to the tariff rate schedules.

Example 1 – Gross Plant Allocator

Item	Generation	Transmission	Distribution	General	Total
Gross Plant	$0	$15,786,582	$32,650,247		$48,436,829
Gross Plant Ratio/Allocator	0.00%	32.59%	67.41%		100.00%
General Plant				$3,808,521	
Allocation of General Plant	$0	$1,241,277	$2,567,244		$3,808,521

9.2 Labour Ratio Allocator

In Example 2, labour related Administrative and General costs are allocated to the Transmission and Distribution functions based on the total labour costs in the Transmission and Distribution Operations & Maintenance accounts. Similarly, Administrative and General costs more closely related to plant costs can be allocated on the basis of plant factors.

Example 2 – Labour Ratio Allocator

Item	Generation	Transmission	Distribution	Total
O&M Labour Costs	$0	$2,357,812	$6,854,765	$9,212,577
Labour Cost Ratio/Allocator	0.00%	25.59%	74.41%	100.00%
A&G Labour Related Costs				
Injuries & Damages	$0	$244,337	$710,350	$954,687
Pensions & Benefits	$0	$1,158,406	$3,367,783	$4,526,189

9.3 Composite Ratio/Allocators

A composite allocator is derived by combining two or more factors. In Example 3, a weighted customer allocator is calculated by combining the number of customers and meter and service costs. The number of customers by tariff class is obtained from the records of the utility. The allocator is determined by dividing the number of customers in a particular class by the total number of customers. The second factor is the meter and service costs. These are typically average installed costs which can be obtained from the records of the utility. A weighting factor is derived by using the costs of one class as the base, residential in this example, and dividing the cost of the other classes by this base. A weighted allocation factor is then determined by multiplying the number of customers in each class by each classes weight. In Example 3, the Residential Regular is 48.93% of the customers but has a weighted customer ratio of 7.44%.

Example 3 – Weighted Number of Customers Allocator

Item	**Residential-Regular**	**Residential-All Electric**	**Comm. w/o Demand Meter**	**Med. Comm. w/ Demand Meter**	**Lrg. Comm. Pulse Meter**	**Total**
No. of Customers	7,487	2,012	4,176	1,049	576	15,300
Customer Ratio/Allocator	48.93%	13.15%	27.29%	6.86%	3.76%	100.00%
Meter & Service Cost	$100	$100	$300	$2,000	$10,000	
Weighting Factor (Residential=1)	1	1	3	20	100	
Weighted No. of Customers	7,487	2,012	12,528	20,980	57,600	100,607
Weighted Customer Ratio/Allocator	7.44%	2.00%	12.45%	20.85%	57.25%	100.00%

Exhibit 1
Fictionalization, Classification & Allocation Process

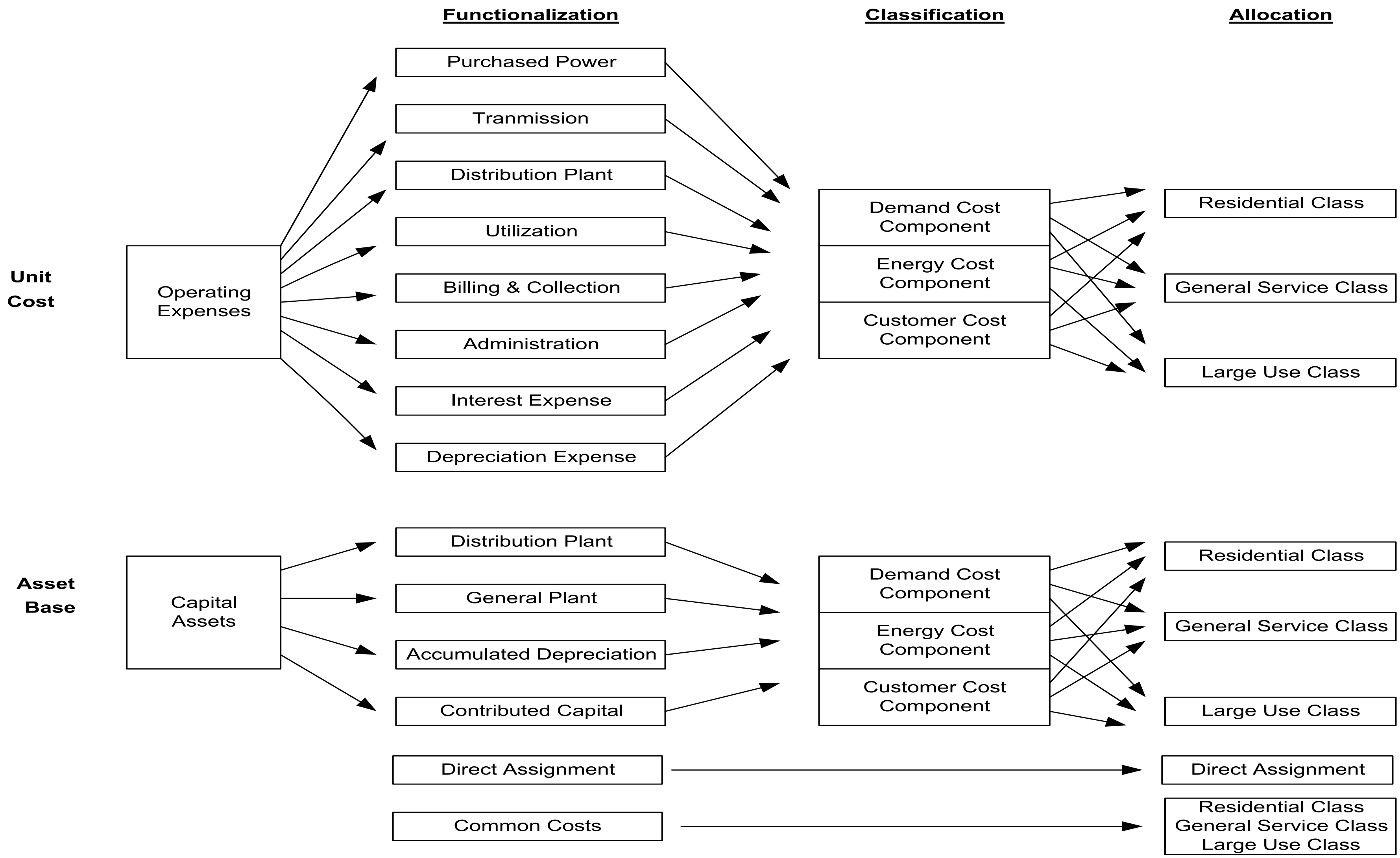
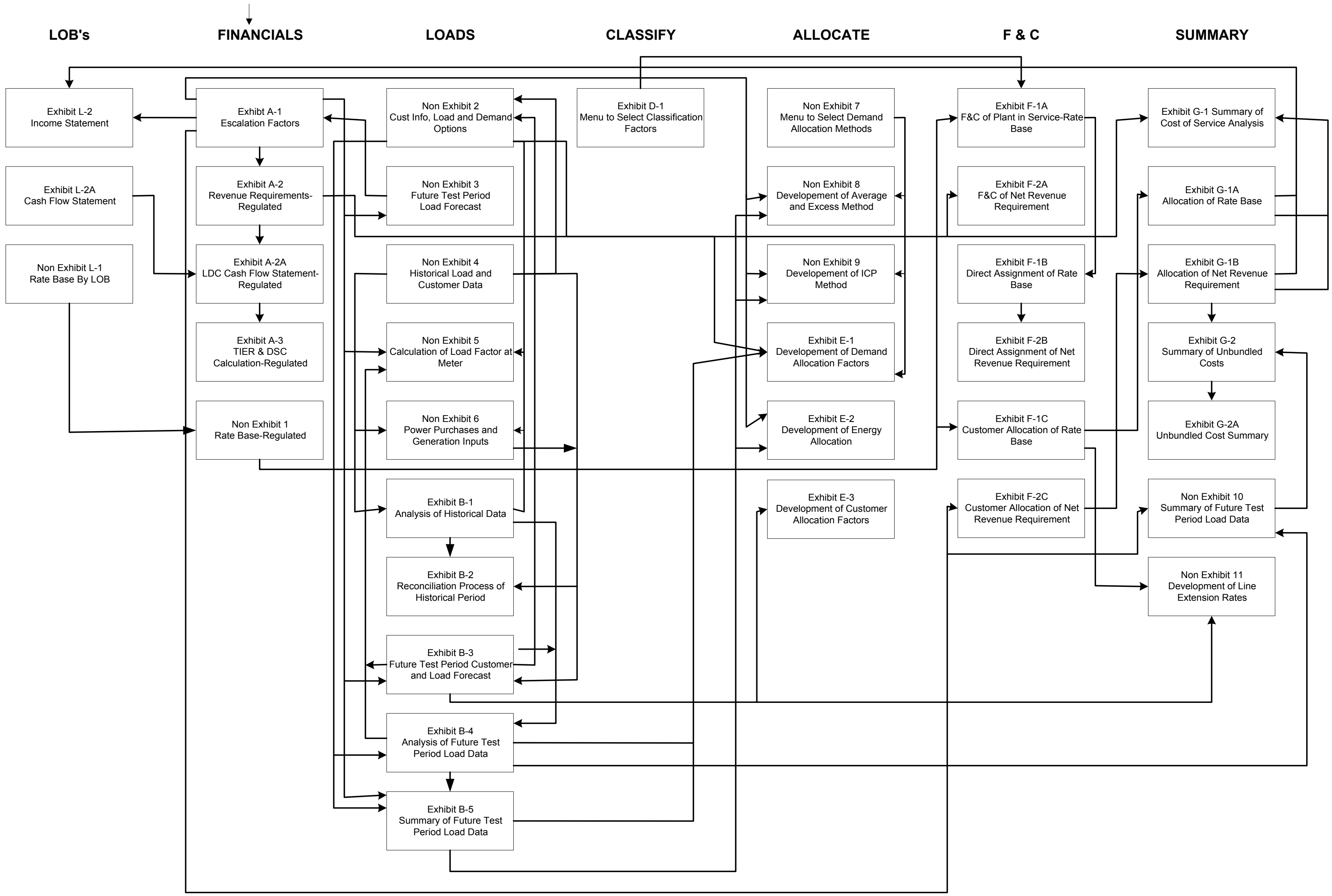


Exhibit 2
Summary Flow Chart



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