ARGUMENTATION FINALE DU DISTRIBUTEUR

EXTRAITS DE NARUC ET DE L'APPA

DIRECTION AFFAIRES RÉGLEMENTAIRES ET TARIFAIRES

Plan d'argumentation finale

Thème 4 : Répartition des coûts et interfinancement

- **Page 23, lignes 1 et 2 : « L'argument est sans fondement et va même à l'encontre des guides de références de NARUC (page 79) et de l'APPA (page X-4). »**

  Voir passages soulignés dans les extraits.

- **Page 23, lignes 37 à 39 : « Méthode reconnue dans l'industrie (NARUC, page 90 et APPA page IX-9). »**

  Voir passages soulignés dans les extraits.

ELECTRIC UTILITY COST ALLOCATION MANUAL

January, 1992

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3. The Average of the 12 Monthly System Coincident (12 CP) Peak Method

The 12 CP demand allocation method is based on the principle that a utility installs facilities to maintain a reasonably constant level of reliability throughout the year or that significant variations in monthly peak demands are not present. Under this method, no single peak demand or seasonal peak demands are of any significantly greater magnitude than any of the other monthly coincident peak demands. Thus, the relative importance of each month is considered.

To implement this method, data for the monthly coincident peak demands of each customer at each delivery point for the year must be available. For example, if the company's monthly system peak demand for August occurs on August 10th at 4 P.M., then data for each customers' demand at that specific point in time must be available. Additionally, similar data would be required for each day the company's system peak occurred in the other eleven months in the selected test year.

Customer responsibility under this allocation method is computed as follows:

$$\text{12CP Customer Group Demand Ratio} = \frac{\text{Cust Group 12CP Metered Demand + Demand Losses}}{\text{Transmission System 12CP Demand}}$$

Coincident peak demand data for individual customers such as municipal or cooperative systems is usually readily available by delivery point. The coincident peak demands of individual or groups of retail customers are not available since many retail loads are not demand metered. See Table 5-4 for sample application of this methodology.

TABLE 5-4

EXAMPLE OF 12 MONTHLY SYSTEM COINCIDENT PEAK ALLOCATION

Customer group CP demand total(MW)	4900
System CP demand total(MW)	142830
12 CP customer group demand ratio	.03431

From this breakdown it can be seen that each distribution account must be analyzed before it can be assigned to the appropriate functional category. Also, these accounts must be classified as demand-related, customer-related, or both. Some utilities assign distribution to customer-related expenses. Variations in the demands of various customer groups are used to develop the weighting factors for allocating costs to the appropriate group.

II. DEMAND AND CUSTOMER CLASSIFICATIONS 0F DISTRIBUTION PLANT ACCOUNTS

When the utility installs distribution plant to provide service to a customer and to meet the individual customer's peak demand requirements, the utility must classify distribution plant data separately into demand- and customer-related costs.

Classifying distribution plant as a demand cost assigns investment of that plant to a customer or group of customers based upon its contribution to some total peak load. The reason is that costs are incurred to serve area load, rather than a specific number of customers.

Distribution substations costs (which include Accounts 360 -Land and Land Rights, 361 - Structures and Improvements, and 362 -Station Equipment), are normally classified as demand-related. This classification is adopted because substations are normally built to serve a particular load and their size is not affected by the number of customers to be served.

Distribution plant Accounts 364 through 370 involve demand and customer costs. The customer component of distribution facilities is that portion of costs which varies with the number of customers. Thus, the number of poles, conductors, transformers, services, and meters are directly related to the number of customers on the utility's system. As shown in Table 6-1, each primary plant account can be separately classified into a demand and customer component. Two methods are used to determine the demand and customer components of distribution facilities. They are, the minimum-size-of-facilities method, and the minimum-intercept cost (zero-intercept or positive-intercept cost, as applicable) of facilities.

A. The Minimum-Size Method

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

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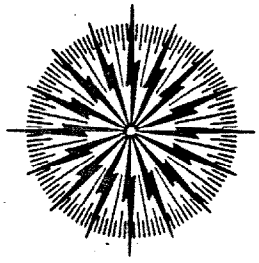

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Twelve Coincidental Peak Method (12CP)

If the electric utility has a demand load research program installed, 12CP has received increasing application in recent years for allocating demand costs. The method averages the contributions of each customer class for each of the twelve monthly coincidental peaks and allocates demand costs to the classes based on twelve monthly contributions to system peak demand.

12CP allocates demand costs over an annual period of time and, in this respect, can dilute, or reduce, the allocation of demand costs of those customer classes heavily contributing to sharp maximum system peak demands. If the power system has a high winter or summer peak demand relative to demands of other times, use of this method is questionable if a cost-price signal were desired to reduce peak demand.

Analysis of Demand Cost Allocation Methods

The best practical method of allocating demand costs for public power systems may be one selected on the basis of the operating characteristics of the utility system and identification of pricing problems faced by the utility. It should be recognized that no one best allocation method exists which can be continuously applied in all situations.

The purpose of selection of an allocation method should be to fairly represent cost as closely or as reasonably may be expected given a proper analysis of a power system's situation. The traditional methods of allocating demand costs reviewed herein have been used in historical or average embedded cost of service analysis. In today's present costing environment, utility systems may be organized and operating in a number of ways, all of which may be adequate and acceptable. Allocation methods may be viewed as a means of reflecting historical events or as a device for shaping the cost and rate future of the utility. Allocation methods may not be entirely cost related, but they perform an accounting allocation function, and represent known, or comparable, means of allocating costs to customer classes which have been accepted in past use.

Allocation methods are not theoretically perfect, although selection of an allocation method may better suit one purpose than another. PRM, for example, could have practical application for winter-summer rate differentials, off peak or interruptible rates. In its application to all customer classes, PRM may be discriminatory and a compromise with application of some other method may be appropriate.

Energy Cost Allocation Method

Energy costs are defined as those which vary with energy consumption of customer classes of service. Energy costs are fairly well defined in cost of service literature—fuel, fuel handling,

Classification of Distribution Plant—Demand Versus Customer Related

In classifying distribution plant, direct assignment of investment and primary-secondary cost separations having been made, the cost classification between the demand and customer related cost components may be performed.

Land and land rights and structures and improvements have traditionally been classified all demand related in accordance with the classification of station equipment (distribution substations). In the case example, however, these items have been classified one-half to demand and one-half to customer on the basis that a portion of such plant serves the common investment in facilities related to providing service to customers on the system.

Station equipment has been classified as all demand related investment in accordance with the traditional concept that such facilities are sized to meet noncoincidental capacity requirements.

The classification of land, structures and overhead and underground conductors, conduit and devices to demand and customer cost components is performed in Exhibit IX-1 on an arbitrary basis assigning one-half to demand and one-half to customer, recognizing that poles, conductor, transformers, etc., are required to serve customers regardless of demand requirements. Such an arbitrary 50-50 split may be acceptable when there is a lack of information upon which to make a more precise estimate. The 50-50 separation is considered a reasonable approximation of the separation which would occur if additional investigation of cost were to occur. Considerable variation, however, would be expected on a utility-to-utility basis. Actual analysis of cost is preferred if time and cost are not prohibitive, particularly for large power systems. For smaller utilities, the arbitrary method may be used.

Two methods used to more accurately identify the customer cost component of conductor and devices, conduit and line transformers are as follows:

1. *The Minimum Size Method.* This method assumes that the current cost of installing the minimum size pole, conductor, transformer, etc., is reasonably reflective of the customer related portion of investment in distribution plant. The current cost on a unit basis is multiplied by an appropriate number of customers per unit factor to determine the total dollar investment in plant that may be classified as customer related.

The minimum size method is considered the least desirable, but simplest, of the two methods described here to use in determining a customer cost separation of distribution plant