Similarly, when designing primary and secondary distribution feeders, the distribution engineer ensures that sufficient conductor and transformer capacity is available to meet the customer's loads at the primary- and secondary-distribution service levels. Local area loads are the major factors in sizing distribution equipment. Consequently, customer-class noncoincident demands (NCPs) and individual customer maximum demands are the load characteristics that are normally used to allocate the demand component of distribution facilities. The customer-class load characteristic used to allocate the demand component of distribution plant (whether customer class NCPs or the summation of individual customer maximum demands) depends on the load diversity that is present at the equipment to be allocated. The load diversity at distribution substations and primary feeders is usually high. For this reason, customer-class peaks are normally used for the allocation of these facilities. The facilities nearer the customer, such as secondary feeders and line transformers, have much lower load diversity. They are normally allocated according to the individual customer's maximum demands. Although these are the methods normally used for the allocation of distribution demand costs, some exceptions exist.

The load diversity differences for some utilities at the transmission and distribution substation levels may not be large. Consequently, some large distribution substations may be allocated using the same method as the transmission system. Before the cost analyst selects a method to allocate the different levels of distribution facilities, he must know the design and operational characteristics of the distribution system, as well as the demand losses at each level of the distribution system.

As previously indicated, the distribution system consists of several levels. The first level starts at the distribution substation, and the last level ends at the customer's meters. Power losses occur at each level and should be included in the demand allocators. Power losses are incorporated into the demand allocators by showing different demand loss factors at each predominant voltage level. The demand loss factor used to develop the primary-distribution demand allocator will be slightly larger than the demand loss factor used to develop the secondary demand allocator. When developing the distribution demand allocator, be aware that some customers take service at different voltage levels.

Cost analysts developing the allocator for distribution of substations or primary demand facilities must ensure that only the loads of those customers who benefit from these facilities are included in the allocator. For example, the loads of customers who take service at transmission level should not be reflected in the distribution substation or primary demand allocator. Similarly, when analysts develop the allocator for secondary demand facilities, the loads for customers served by the primary distribution system should not be included.

Utilities can gather load data to develop demand allocators, either through their load research program or their transformer load management program. In most cases, the load research program gathers data from meters on the customers' premises. A more complex procedure is to use the transformer load management program.

This procedure involves simulating load profiles for the various classes of equipment on the distribution system. This provides information on the nature of the load diversity between the customer and the substation, and its effect on equipment cost. Determining demand allocators through simulation provides a first-order load approximation, which represents the peak load for each type of distribution equipment.

The concept of peak load or "equipment peak" for each piece of distribution equipment can be understood by considering line transformers. If a given transformer's loading for each hour of a month can be calculated, a transformer load curve can be developed. By knowing the types of customers connected to each load management transformer, a simulated transformer load profile curve can be developed for the system. This can provide each customer's class demand at the time of the transformer's peak load. Similarly, an equipment peak can be defined for equipment at each level of the distribution system. Although the equipment peak obtained by this method may not be ideal, it will closely approximate the actual peak. Thus, this method should reflect the different load diversities among customers at each level of the distribution system. An illustration of the simulation procedure is provided in Appendix 6-A.

B. Allocation of Customer-Related Costs

When the demand-customer classification has been completed, most of the assumptions will have been made that affect the results of the completed cost of service study.

The allocation of the customer-related portion of the various plant accounts is based on the number of customers by classes of service, with appropriate weightings and adjustments. Weighting factors reflect differences in characteristics of customers within a given class, or between classes. Within a class, for instance, we may want to give more weighting of a certain plant account to rural customers, as compared to urban customers. The metering account is a clear example of an account requiring weighting for differences between classes. A metering arrangement for a single industrial customer may be 20 to 80 times as costly as the metering for one residential customer.

While customer allocation factors should be weighted to offset differences among various types of customers, highly refined weighting factors or detailed and time consuming studies may not seem worthwhile. Such factors applied in this final step of the cost study may affect the final results much less than such basic assumptions as the demand-allocation method or the technique for determining demand-customer classifications.

Expense allocations generally are based on the comparable plant allocator of the various classes. For instance, maintenance of overhead lines is generally assumed to be directly related to plant in overhead conductors and devices. Exceptions to this rule will occur in some accounts. Meter expenses, for example, are often a function of maintenance and testing schedules related more to revenue per customer than to the cost of the meters themselves.

APPENDIX 6-A

DERIVATION OF DEMAND ALLOCATOR THROUGH SIMULATION

The derivation of the demand allocator through simulation requires extensive data on the locations of various types of customers on the distribution system. This data may be available through the utility's transformer load management (TLM) system.

A TLM system may be used by a utility to provide data to minimize the loss of transformers from overload and to provide a data base for local area forecasts for engineering design. Such a data base can provide the location and size of line transformers, and identify the primary feeder leaving the substation that supplies each transformer. It can also provide the identity of the customer connected to each transformer and the usage levels of those customers. Additional sampling may be necessary to determine which transformers have secondary lines between the transformers and the customer service drops. In a simulation, the TLM data can be combined with the utility's load research data to obtain peak loading at points in the system not normally metered, as well as a matching set of the sales peak measurements normally made.

To calculate equipment peaks on an ongoing basis, a sample of transformers would have to be selected for load research metering, which could be projected to the total population of transformers. However, this may not be feasible because the cost of such a project could far outweigh the benefit derived. On the other hand, sales peaks calculated from existing load research sampling are available. This load research data could be used with the TLM data to simulate equipment peaks and their corresponding sales peaks. By comparing the peaks, we can select an appropriate allocator for each engineering category. The purpose of the simulation is not to calculate the allocators themselves, but to investigate the relationship between the equipment peaks and the sales peaks. This will allow us to choose appropriate sales peaks for allocating each engineering category.

From the TLM data, we can identify the specific transformer, three-phase circuit (feeder), and distribution substation serving each customer. Given the customer load profiles for each hour of a particular month, we can then add up the hourly load for each transformer, circuit, or substation, find its peak, and add totals by rate schedule to the equipment peaks. The key element of the simulation is the load profile of each customer.

How to generate a customer load profile and use it to simulate equipment peaks is shown below. Line transformers are used for illustration. After sorting the TLM data by transformer number, follow these steps:

Step 1 - Read a customer record from the TLM data file.

Step 2 - Test the transformer number to determine if a new transformer has been found. If not, proceed to Step 3; otherwise, go to Step 7.

Step 3 - From the TLM data, use the rate schedule and the KWH/day to identify a set of load profiles from the proper strata with the matching rate schedule.

Step 4 - Generate and use a pseudo-random number to select one of the load profiles within the identified set.

Step 5 - Combine the hourly loads for the selected load profile to yield the same total energy consumed in the TLM data. This is done by taking the TLM KWH/day divided by the KWH/day for the selected load profile and multiplying the result by the load for each hour of the selected load profile.

Step 6 - Add the customer's simulated hourly loads to the totals by rate schedule for the customer's transformer, and to the totals for the various sales peaks being generated. Now return to Step 1.

Step 7 - If you detect the end of data for a transformer, the transformer totals will contain simulated hourly loads for each hour of the month for that transformer. Search these loads to find the transformer's peak load hour. Add the loads for each rate schedule at the time of this peak to the equipment peak totals by rate schedule. Then clear the transformer totals and proceed to the next transformer in Step 3.

Determine the simulation of equipment peaks for substations and primary and secondary conductors in the same manner. The estimated equipment peaks for each month for each distribution component can then be compared to various class peaks (monthly coincident peaks, noncoincident peaks, etc.) that are available from load research data. The class peak factors that best match the equipment peaks should then be used to allocate each distribution component.

CHAPTER 7

CLASSIFICATION AND ALLOCATION OF CUSTOMER-RELATED COSTS

Customer-related costs (Accounts 901-917) include the costs of billing and collection, providing service information, and advertising and promotion of utility services. By their nature, it is difficult to determine the "cause" of these costs by any particular function of the utility's operation or by particular classes of their customers. An exception would be Account 904, Uncollectible Accounts. Many utilities monitor the uncollectible account levels by tariff schedule. Therefore, it may be appropriate to directly assign uncollectible accounts expense to specific customer classes.

I. FUNCTIONALIZATION

The usual approach in functionalizing customer accounts, customer service and the expense of information and sales is to assign these expenses to the distribution function and classify them as customer-related.

A less common approach is called the plant/labor method that functionalizes customer accounts, customer service, and sales expenses according to the previously determined functionalization of utility plant and labor costs. The amount of payroll costs included in generation-, transmission-, and distribution-related operation and maintenance expenses determine the labor component of this functionalization. Since the majority of a utility's labor costs tend to be in distribution, the plant/labor method will tend to emphasize the distribution functionalization of customer accounts, customer service, and sales expenses.

II. CLASSIFICATION AND ALLOCATION

When these expenses are functionalized by the plant/labor method, they will follow the previously determined classification and allocation of generation, transmission, and distribution facilities.

Where these accounts have been assigned to the distribution function and classified as customer-related, care must be taken in developing the proper allocators. Even with detailed records, cost directly assigned to the various customer classes may be very cumbersome and time consuming. Therefore, an allocation factor based upon the number of customers or the number of meters may be appropriate if weighting factors are applied to reflect differences in the cost of reading residential, commercial, and industrial meters.

A. Customer Account Expenses (Accounts 901 - 905)

These accounts are generally classified as customer-related. The exception may be Account 904, Uncollectible Accounts, which may be directly assigned to customer classes. Some analysts prefer to regard uncollectible accounts as a general cost of performing business by the utility, and would classify and allocate these costs based upon an overall allocation scheme, such as class revenue responsibility.

B. Customer Service and Informational Expenses (Accounts 906 - 910)

These accounts include the costs of encouraging safe and efficient use of the utility's service. Except for conservation and load management, these costs are classified as customer-related. Emphasis is placed upon the costs of responding to customer inquiries and preparing billing inserts.

Conservation and load management costs should be separately analyzed. These programs should be classified according to program goals. For example, a load management program for cycling air conditioning load is designed to save generation during peak hours. This program could be classified as generation-related and allocated on the basis of peak demand. The goal of other conservation programs may be to save electricity on an annual basis. These costs could be classified as generation-related and allocated on the basis of energy-usage allocation. However, if conservation costs are received through cost recovery similar to a fuel-cost recovery clause, allocating the costs between demand and energy may be too cumbersome. In such cases, the costs could be received through an energy clause. A demand-saving load management program actually saves marginal fuel costs, and therefore energy.

C. Sales Expenses (Accounts 911 - 917)

These accounts include the costs of exhibitions, displays, and advertising designed to promote utility service. These costs could be classified as customer-related, since the goal of demonstrations and advertising is to influence customers. Allocation of these costs, however, should be based upon some general allocation scheme, not numbers of customers. Although these costs are incurred to influence the usage decisions of customers, they cannot properly be said to vary with the number of customers. These costs should be either directly assigned to each customer class when data are available, or allocated based upon the overall revenue responsibility of each class.

CHAPTER 8

CLASSIFICATION AND ALLOCATION OF COMMON AND GENERAL PLANT INVESTMENTS AND ADMINISTRATIVE AND GENERAL EXPENSES

This chapter describes how general plant investments and administrative and general expenses are treated in a cost of service study. These accounts are listed in the general plant Accounts 389 through 399, and in the administrative and general Accounts 920 through 935.

I. GENERAL PLANT

General plant expenses include Accounts 389 through 399 and are that portion of the plant that are not included in production, transmission, or distribution accounts, but which are, nonetheless, necessary to provide electric service.

One approach to the functionalization, classification, and allocation of general plant is to assign the total dollar investment on the same basis as the sum of the allocated investments in production, transmission and distribution plant. This type of allocation rests on the theory that general plant supports the other plant functions.

Another method is more detailed. Each item of general plant or groups of general and common plant items is functionalized, classified, and allocated. For example, the investment in a general office building can be functionalized by estimating the space used in the building by the primary functions (production, transmission, distribution, customer accounting and customer information). This approach is more time-consuming and presents additional allocation questions such as how to allocate the common facilities such as the general corporate computer space, the Shareholder Relation Office space, etc.

Another suggested basis is the use of operating labor ratios. In performing the cost of service study, operation and maintenance expenses for production, transmission, distribution, customer accounting and customer information have already been functionalized, classified, and allocated. Consequently, the amount of labor, wages, and salaries assigned to each function is known, and a set of labor expense ratios is thus available for use in allocating accounts such as transportation equipment, communication equipment, investments or general office space.

II. ADMINISTRATIVE AND GENERAL EXPENSES

Administrative and general expenses include Accounts 920 through 935 and are allocated with an approach similar to that utilized for general plant. One methodology, the two-factor approach, allocates the administrative and general expense accounts on the basis of the sum of the other operating and maintenance expenses (excluding fuel and purchased power).

A more detailed methodology classifies the administrative and general expense accounts into three major components: those which are labor related; those which are plant related; and those which require special analysis for assignment or the application of the beneficiality criteria for assignment.

The following tabulation presents an example of the cost functionalization and allocation of administrative and general expenses using the three-factor approach and the two-factor approach.

Account	Operation	Three-Factor Allocation Basis	Two-Factor Allocation Basis
920	A & G Salaries	Labor - Salary and Wages	Labor - Salary and Wages
921	Office Supplies	Labor - Salary and Wage	Labor - Salary and Wages
922	Administration Expenses Transferred-Credit	Other - Subtotal of Operating Expenses Less Fuel and Purchased Power	Labor - Salary and Wages
923	Outside Services Employed	Other - Subtotal of Operating Expenses Less Fuel and Purchased Power	Labor - Salary and Wages
924	Property Insurance	Plant - Total Plant [1]	Plant - Total Plant
925	Injuries and Damages	Labor - Salary and Wages[2]	Labor - Salary and Wages
926	Pensions and Benefits	Labor - Salary and Wages	Labor - Salary and Wages
927	Franchise Requirements	Revenues or specific assignment	Revenues or specific assignment

[1] A utility that self-insures certain parts of its utility plant may require the adjustment of this allocator to only include that portion for which the expense is incurred.

[2] A detailed analysis of this account may be necessary to learn the nature and amount of the expenses being booked to it. Certain charges may be more closely related to certain plant accounts than to labor wages.

Account Operation		Three Factor Allocation Basis	Labor-Ratio Allocation Basis
928	Regulatory Commission Expenses	Other - Subtotal of Operating Expenses Less Fuel and Purchased Power	Labor - Salary and Wages
928	Duplicate Charge-Cr.	Other - Subtotal of Operating Expenses Less Fuel and Purchased Power	Labor - Salary and Wages
930.1	General Advertising Expenses	Other - Subtotal of Operating Expenses Less Fuel and Purchased Power	Labor - Salary and Wages
930.2	Miscellaneous General Expenses	Other - Subtotal of Operating Expenses Less Fuel and Purchased Power	Labor - Salary and Wages
931	Rents	Plant - Total Plant[3]	Plant - Total Plant
Maintenance		**Three Factor Allocation Basis**	**Labor-Ratio Allocation Basis**
935	General Plant	Plant - Gross Plant	Labor - Salary and Wages

[3]A detailed analysis of rental payments may be necessary to determine the correct allocation bias. If the expenses booked are predominantly for the rental of office space, the use of labor, wage and salary allocators would be more appropriate.

SECTION III

MARGINAL COST STUDIES

SECTION III reviews marginal cost of service studies. As noted in Chapter 2, in contrast to embedded studies where the issues primarily involve the allocation of costs taken from the company's books, the practical and theoretical debates in marginal cost studies center around the development of the costs themselves.

Chapter 9 discusses marginal production costs, including the costing methodologies and allocation to time periods and customer classes of the energy and capacity components.

Chapter 10 discusses the costing methodologies and allocation issues for marginal transmission, distribution and customer charges.

Use of marginal cost methodologies in ratemaking is based on arguments of economic efficiency. Pricing a utility's output at marginal cost, however, will only by rare coincidence recover the allowed revenue requirement.

Chapter 11 discusses the major approaches used to reconcile the marginal cost results to the revenue requirement.

CHAPTER 9

MARGINAL PRODUCTION COST

Marginal production cost is the change in the cost of producing electricity in response to a small change in customer usage. Marginal production cost includes an energy production component, referred to as marginal energy cost, and a generation-related reliability component, referred to as marginal capacity cost. Marginal capacity cost is one reliability-related component of the marginal costs associated with a change in customer usage. The other components, marginal transmission cost and marginal distribution cost, are discussed in Chapter 10. Together, these three reliability-related marginal costs are sometimes referred to as marginal demand cost. These marginal costs are used to calculate marginal cost revenues, which are used in cost allocation, as discussed in Chapter 11.

Marginal costs are commonly time-differentiated to reflect variations in the cost of serving additional customer usage during the course of a day or across seasons. Marginal production costs tend to be highest during peak load periods when generating units with the highest operating costs are on line and when the potential for generation-related load curtailments or interruptions is greatest. A costing period is a unit of time in which costs are separately identified and causally attributed to different classes of customers. Costing periods are often disaggregated hourly in marginal cost studies, particularly for determining marginal capacity costs which are usually strongly related to hourly system load levels. A rating period is a unit of time over which costs are averaged for the purpose of setting rates or prices. Rating periods are selected to group together periods with similar costs, while giving consideration to the administrative cost of time-differentiated rate structures. Where time-differentiated rates are employed, typical rate structures might be an on-peak and off-peak period, differentiated between a summer and winter season.

Two separate measures of marginal cost, long-run marginal cost and short-run marginal cost, can be employed in cost allocation studies. In economic terms, long-run marginal cost refers to the cost of serving a change in customer usage when all factors of production (i.e., capital facilities, fuel stock, personnel, etc.) can be varied to achieve least-cost production. Short-run marginal cost refers to the cost of serving a change in customer usage when some factors of production, usually capital facilities, are fixed. For example, if load rises unexpectedly, short-run marginal cost could be high as the utility seeks to meet this load with existing resources (i.e., the short-run perspective). Similarly, if a utility has surplus capacity, short-run marginal cost could be low, since capacity additions would provide relatively few benefits to the utility. When a utility system is optimally designed (utility facilities meet customer needs at lowest total cost), long-run and short-run marginal costs are equal.

A common source of confusion in marginal cost studies arises in considering the economic time frame of investment decisions. There is an incorrect tendency to equate long-run marginal cost with the economic life of new facilities, suggesting that long-run marginal cost has a multi-year character. In actuality, both short-run and long-run marginal costs are measured at a single point in time, such as a rate proceeding test year.[1]

There is considerable difference of opinion as to whether short-run or long-run marginal cost is appropriate for use in cost allocation. In competitive markets, prices tend to reflect short-run marginal costs, suggesting that this may be the appropriate basis for cost allocation. However, long-run marginal costs tend to be more stable and may send better price signals to customers making capital investment decisions than do short-run marginal costs.[2]

I. MARGINAL ENERGY COSTS

Marginal energy cost refers to the change in costs of operating and maintaining the utility generating system in response to a change in customer usage. Marginal energy costs consist of incremental fuel or purchased power costs[3] and variable operation and maintenance expenses incurred to meet the change in customer usage. Fixed fuel costs associated with committing generating units to operation are also a component of marginal energy costs when a change in customer usage results in a change in unit commitment.[4]

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[1]In contrast, analysis of investment decisions properly requires a <u>projection</u> of short-run marginal cost over the economic life of the investment. Long-run marginal cost is sometimes used to estimate projected short-run marginal cost (ignoring factors such as productivity change which may cause long-run marginal cost to vary over time), which perhaps contributes to the mistaken views regarding the economic time frame of long-run marginal cost.

[2]See, for example, the discussion in A. E. Kahn, <u>The Economics of Regulation: Principles and Institutions</u>, 1970, particularly Volume 1, Chapter 3.

[3]Incremental fuel costs are sometimes referred to as system lambda costs.

[4]These fixed fuel costs are commonly associated with conventional fossil fuel units which are used to follow load variations. These units often require a lengthy start-up period where a fuel input is required to bring the units to operational status. The cost of this fuel input is referred to as start-up fuel expenses. Also, at low levels of generation output, average fuel costs exceed incremental fuel costs because there are certain "overhead" costs, such as frictional losses and thermal losses, which occur inrrespective of the level of the level of generator output. These costs are sometimes referred to as "no-load" fuel costs since they are unrelated to the amount of load placed on the generating unit.

A. Costing Methodologies

The predominant methodology for developing marginal energy costs is the use of a production costing model to simulate the effect of a change in customer usage on the utility system production costs. Typically, a utility will operate its lower production cost resources whenever possible, relying on units with the highest energy production costs only when production potential from lower-cost resources has been fully utilized. Thus, the energy production costs for the most expensive generating units on line are indicative of marginal energy costs. However, utility generating systems are frequently complex, with physical operating constraints, contractual obligations, and spinning reserve requirements, sometimes making it difficult in practice to easily determine how costs change in response to a change in usage. A detailed simulation model reflecting the important characteristics of a utility's generating system can be a very useful tool for making a reasonable determination of marginal energy costs.

An alternative to using a production costing model is to develop an estimate of marginal energy costs for an historical period and apply this historical result to a test year forecast period. For historical studies, marginal energy costs can be expressed in terms of an equivalent incremental energy rate (in BTU/KWH), which reflects aggregate system fuel use efficiency. Expressing marginal energy costs in these units nets out the effect of changing fuel prices on marginal energy costs [5]. The use of historical studies should be approached with caution, however, when there is a significant change in system configuration (e.g., addition of a large baseload generating station), or where there are sizable variations in hydro availability. In these instances, system efficiency may change sufficiently to render historical studies unreliable as the basis for a test year forecast.

[5]The incremental energy rate, or IER, is conceptually similar to an incremental heat rate, but measures aggregate <u>system</u> efficiency rather than unit-specific efficiency. The IER is calculated by dividing marginal energy costs by the price of the fuel predominantely used in meeting a change in usage. When the price of this predominant fuel changes, marginal energy cost can be approximated as the fuel price (¢/BTU) times the IER (BTU/KWH).

1. Production Cost Modeling

There are numerous computer models suitable for performing a simulated utility dispatch and determining marginal energy costs that are commercially available[6]. These production cost models require a considerable degree of technical sophistication on the part of the user. In general, results are highly sensitive both to the structural description of the utility system contained in the input data and the actual values of the input data. Verification or "benchmarking" of model performance in measuring marginal energy costs is an important step which should be undertaken prior to relying on a model in regulatory proceedings.

Typically, production cost models produce an output report showing marginal energy costs by hour and month. These reported costs represent the incremental cost of changing the level of output from the most expensive generating unit on line to meet a small change in customer usage. However, these costs do not include the effect of temporal interdependencies which should be accounted for in marginal energy costs. For example, if a unit with a lengthy start-up cycle is started on Sunday evening to be available for a Monday afternoon peak, the costs of starting up the unit are properly ascribed to this Monday peak period.

The effect of such temporal interdependencies can be measured with a production cost model using the incremental-decremental load method. The production cost model is first run to establish a base case total production cost. Then, for each costing period, two additional model runs are performed, adjusting the input load profile upward and downward by a chosen amount. The change in total production cost per KWH change in load is calculated for both the incremental and decremental cases, and the results averaged to give marginal energy costs by costing period.

The results of a production cost model simulation for the utility case study are shown in Table 9-1. The analysis uses an incremental/decremental load method to account for fixed fuel expenses associated with the additional unit commitment needed to meet a change in load during on-peak and mid-peak periods. Off-peak marginal energy costs are derived directly from the production cost model's reported marginal energy costs, since changes in off-peak usage are not anticipated to affect unit commitment. and

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[6]Comparing and contrasting the efficacy of different production costing models is a complex undertaking that will not be attempted in this manual. The "state-of-the-art" in production cost modeling is envolving rapidly, with existing models increasing in sophistication and new models being developed.

mid-peak periods. Off-peak marginal energy costs are derived directly from the production cost model's reported marginal energy costs, since changes in off-peak usage are not anticipated to affect unit commitment.

TABLE 9-1

MARGINAL ENERGY COST CALCULATION USING AN INCREMENTAL/DECREMENTAL LOAD METHODOLOGY

(Based on a Gas Price of $2.70/MMBTU)

	500 MW Decrement	500 MW Increment	Combined
Summer On-Peak			
Change in Production Cost ($)	-9,120	+9,209	18,329
Change in KWH Production (GWH)	-261	+261	522
Marginal Cost (¢/KWH)			3.5
In BTU/KWH			12,993
Summer Mid -Peak			
Change in Production Cost ($)	-9,613	+9,631	19,244
Change in KWH Production (GWH)	-393	+393	786
Marginal Cost (¢/KWH)			2.4
In BTU/KWH			9,089
Summer Off-Peak			
Marginal Cost (¢/KWH)	-	-	2.2
In BTU/KWH			8,129
Winter On-Peak			
Change in Production Cost ($)	-9,930	+11,479	21,409
Change in KWH Production (GWH)	-348	+348	696
Marginal Cost (¢/KWH)			3.1
In BTU/KWH			11,393
Winter Mid-Peak			
Change in Production Cost ($)	-19,843	+19,411	39,254
Change in KWH Production (GWH)	-785	+785	1,576
Marginal Cost (/KWH)			2.5
In BTU/KWH			9,260
Winter Off-Peak			
Marginal Cost (¢/KWH)	-	-	2.4
In BTU/KWH			8,730

Note: These figures exclude variable operation and maintenance expenses of 0.3¢/KWH.

2. Historical Marginal Energy Costs

Where production cost model results are not available, use of historical data as a proxy to forecast future marginal energy costs may be considered. The starting point to estimating historical marginal energy costs is incremental fuel cost (system lambda) data. A number of adjustments to these system lambda costs may be necessary in order to properly calculate marginal energy costs. In low-load periods, production from baseload units or power purchases may be reduced below maximum output levels, while higher cost units are left in operation to respond to minute-to-minute changes in demand. In this instance, the cost of power from the baseload units or purchases with reduced output, not system lambda, represents marginal energy costs. Similarly, in a high-load period, the cost of power from on-line block-loaded peaking units would represent marginal energy cost, even though the cost of these units may not be reflected in the system lambda costs. In a system dominated by peaking hydro, but energy constrained, the cost of production from non-hydro units which serve to "fill the reservoir" represents marginal energy costs.

Another necessary adjustment would be to account for the fixed fuel costs associated with a change in unit commitment when there is a change in load. This fixed fuel cost can be estimated as follows. First, identify how an anticipated change in load affects production scheduling. For example, if production scheduling follows a weekly schedule, an increase in load might increase weekday unit commitment but not impact weekend operations. Second, identify what fraction of time different types of units would be next in line to be started or shut down in response to a change in load. Third, rely on engineering estimates to establish the fixed fuel costs for each type of unit. With this information, the fixed fuel cost adjustment can be estimated by taking the product of the probability of particular units being next in line times the fixed fuel cost for each unit. The fixed fuel cost can be allocated to time period by investigating how changes in load by costing period affect production scheduling. A simple approach would be to identify the probability of different costing periods being the peak, and using these probabilities to allocate fixed fuel costs to costing periods.

B. Allocation of Costs to Customer Group

Marginal energy costs vary among customer groups as a result of differences in the amount of energy losses between generation level and the point in the transmission/distribution system where power is provided to the customer. Energy losses tend to increase as power is transformed to successively lower voltages, so energy losses (and thus marginal energy costs) are greatest for customer groups served at lower voltages. Ideally, energy losses should be time-differentiated and should reflect incremental losses associated with a change in customer usage, rather than average losses, although incremental losses are difficult to measure and are seldom available. Table 9-2 shows marginal energy costs by customer group, taking into account

Ex. AA-D-29

time-differentiated average energy losses for the utility case study. The variation in average marginal energy costs in Table 9-2 is due solely to differences in energy losses, reflecting differences in service voltage among the customer groups.

TABLE 9-2

MARGINAL ENERGY COSTS
BY TIME PERIOD AND RETAIL CUSTOMER GROUP

(¢/KWH, at Sales Level)

	Summer			Winter		
Customer Group	On-Peak	Mid-Peak	Off-Peak	On-Peak	Mid-Peak	Off-Peak
Residential	4.18	3.00	2.70	3.68	3.05	2.86
Commercial	4.17	2.99	2.69	3.68	3.05	2.85
Industrial	4.08	2.94	2.64	3.57	2.96	2.80
Agriculture	4.18	3.00	2.70	3.68	3.05	2.86
Street Lighting	4.13	2.97	2.67	3.63	3.01	2.83

II. MARGINAL CAPACITY COSTS

In most utility systems, generating facilities are added primarily to meet the reliability requirements of the utility's customers.[7] These generating facilities must be capable of meeting the demands on the system with enough reserves to meet unexpected outages for some units. System planners employ deterministic criteria such as reserve margin standards (e.g., 20 percent above the forecast peak demand) or probabilistic criteria such as loss of load probability (LOLP) standards (e.g., one outage occurrence in ten years). Whichever approach is used, these standards implicitly reflect how valuable reliability is to utility customers. Customers are willing to pay for reliable service because of the costs that they incur as a result of an outage. More generally, this is referred to as shortage cost, including the cost of mitigating measures taken by the customer in addition to the direct cost of outages. Reasonable reliability standards balance the cost of improving reliability (marginal capacity cost) with the value of this additional reliability to customers (shortage cost).

[7]In some systems that rely heavily on hydro facilities, energy may be a constraining variable rather than capacity. New generating facilities are added primarily to generate additional energy to conserve limited water supplies. In such circumstance, marginal capacity costs are essentially zero.

A. Costing Methodologies

There are two methodologies in widespread use for determining marginal capacity costs, the peaker deferral method and the generation resource plan expansion method. The peaker deferral method uses the annual cost of a combustion or gas turbine peaker (or some other unit built solely for capacity) as the basis for marginal capacity cost. The generation resource plan expansion method starts with a "base case" generation resource plan, makes an incremental or decremental change in load, and investigates how costs change in response to the load change.

1. Peaker Deferral Method

Peakers are generating units that have relatively low capital cost and relatively high fuel costs and are generally run only a few hours per year. Since peakers are typically added in order to meet capacity requirements, peaker costs provide a measure of the cost of meeting additional capacity needs. If a utility installs a baseload unit to meet capacity requirements, the capital cost of the baseload unit can be viewed as including a reliability component equivalent to the capital cost of a peaker and an additional cost expended to lower operating costs. Thus, the peaker deferral method can be used even when a utility has no plans to add peakers to meet its reliability needs. The peaker deferral method measures long-run marginal cost, since it determines marginal capacity cost by adding new facilities to just meet an increase in load, without considering whether the existing utility system is optimally designed. The peaker deferral method compares the present worth cost of adding a peaker in the "test year" to the present worth cost of adding a peaker one year later. The difference is the annual (first-year) cost of the peaker. This cost is adjusted upward since, for reliability considerations, more than one MW of peaker capacity must be added for each MW of additional customer demand.[8] In the utility case study, the installed capital cost of the peaker is \$615/KW, resulting in a marginal capital cost of \$80/KW. Details on the derivation of this latter figure are provided in Appendix 9-A.

[8]The peaker deferral method is described in greater detail in National Economic Research Associates, A Framework for Maginal Cost-Based Time-Differentiated Pricing in the United States: Topic 1.3, Electric Utility Rate Design Study, February 21, 1977.

2. Generation Resource Plan Expansion Method

An alterntive approach to developing marginal production cost is to take the utilion resource plan as a base case, and then increment or decrement the load forecast on which the plan was based. An alternate least-cost resource plan is then developed which account the modified load forecast. The resulting revision to the generation resource plan captures the effect of the change in customer usage.[9]

Similar to the peaker deferral method, the annual costs of the base case and revised generation resource plans are calculated, and then discounted to present-worth values. The annual revenue requirements include both capital-related and fuel-related costs, so fuel savings associated with high capital cost generating units are reflected in the analysis. The difference between the present-worth value of the two cases is the marginal capacity cost of the specified change in customer usage.

In the utility case study, the least-cost response to an increase in customer load in the "test year" would result in returning a currently retired generating unit to service one year sooner. The increase in total production cost (capital and fuel costs) associated with this increased load case results in a marginal capacity cost of $21/KW. The derivation of this figure is provided in Appendix 9-A. In contrast to the peaker deferral method, the generation resource plan expansion method measures short-run marginal cost, since it explicitly accounts for the current design of the utility system. In the utility case study, the presence of a temporarily out-of-service generating unit indicates surplus capacity, which accounts for the difference between short-run marginal capacity cost and long-run marginal capacity cost.

B. Allocation to Time Period

LOLP refers to the likelihood that a generating system will be unable to serve some or all of the load at a particular moment in time due to outages of its generating units. LOLP tends to be greatest when customer usage is high. If LOLP in a period is 0.01, there is a one percent probability of being unable to serve some or all customer load. Similarly, if load increases by 100 KW in this period, on average, the utility will be unable to serve one KW of the additional load. Summing LOLP over all periods in a year gives a measure of how reliably the utility can serve additional load.

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[9]The generation resource plan expansion method is described in greater detail in C. J. Cicchetti, W. J. Gillen, and Paul Smolensky, The Marginal Cost and Pricing of Electricity: An Applied Approach. June 1976.

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If load increases in an on-peak period when usage is already high, the LOLP-weighted load is high and there is a relatively large impact on reliability which must be offset by an increase in generating resources. If load increases in an off-peak period when usage is low, the LOLP-weighted load is low and there may be relatively little impact on reliability. Similarly, when additional generating resources are added to a utility system, the incremental reliability improvement in each period is proportional to the LOLP in that period. Thus, LOLP's can be used to allocate marginal capacity costs to time periods. A simple example showing the derivation of LOLP and its application to allocating marginal capacity costs to time periods is shown in Appendix 9-B.

An actual allocation of marginal capacity costs to time periods is shown in Table 9-3, based on the utility case study. The LOLP's are based on a probabilistic outage model that takes into account historical forced outage rates, scheduled unit maintenance, and the potential for emergency interconnection support.

TABLE 9-3

ALLOCATION OF MARGINAL CAPACITY COST TO TIME PERIOD

Time Period	Hours	LOLP	Marginal Capacity Cost
Summer On-Peak	12:00 noon - 6:00 p.m.	0.716949	$57.31
Mid-Peak	8:00 a.m. - 12:00 noon		
	6:00 p.m. - 11:00 p.m.	0.124160	9.93
Off-Peak	11:00 p.m. - 8:00 a.m.		
	and all weekend hours	0.002532	0.20
Winter On-Peak	8:00 a.m. - 5:00 p.m.	0.054633	4.37
Mid-Peak	5:00 p.m. - 9:00 p.m.	0.087076	6.96
Off-Peak	9:00 p.m. - 8:00 a.m.		
	and all weekend hours	0.014650	1.17

C. Allocating Costs to Customer Groups

Marginal capacity costs vary by customer group, reflecting differences in losses between generation level and the point where the power is provided to the customer (sales level). Ideally, the loss factors used to adjust from sales to generation level should reflect incremental losses rather than simply reflecting average energy losses, although incremental losses are difficult to measure and are seldom available.

Table 9-4 shows marginal capacity costs by rating period, reflecting losses by customer group, based on the utility case study. This table is constructed for illustration only, by assuming that each customer group's usage is constant for all hours within the rating periods shown. In actuality, the revenue allocation described in Chapter 11 uses hourly customer group loads and hourly LOLP data to calculate hourly marginal capacity costs by customer group.

TABLE 9-4

AVERAGE MARGINAL CAPACITY COSTS
BY RATING PERIOD AND RETAIL CUSTOMER GROUP

($/KW month)

	Summer (4 Months)			Winter (8 Months)			
Customer Group	**On-Peak**	**Mid-Peak**	**Off-Peak**	**On-Peak**	**Mid-Peak**	**Off-Peak**	**Annual**
Residential	15.86	2.74	0.06	0.60	0.96	0.16	88.32
Commercial	15.79	2.72	0.06	0.60	0.96	0.16	87.96
Industrial	15.46	2.67	0.06	0.59	0.94	0.16	86.12
Agriculture	15.86	2.74	0.06	0.60	0.96	0.16	88.32
Street Lighting	15.69	2.71	0.06	0.60	0.95	0.16	87.36

In general, all customers receive the same level of reliability from the generation system, since it is seldom practical to provide service at different reliability levels. Sometimes customers are served under interruptible tariffs or have installed load management devices, however, which effectively provide a lower reliability service. The marginal capacity cost for these customers may be zero if the utility does not plan for, or build, capacity to serve the incremental load of these customers. If the utility continues to plan for serving these customer loads, but with a lower level of reliability, the marginal capacity cost for these customers is related to the marginal capacity cost for regular customers by their relative LOLP's.

APPENDIX 9-A

DERIVATION OF MARGINAL CAPACITY COSTS USING THE PEAK DEFERRAL AND GENERATION RESOURCE PLAN EXPANSION METHODS

This appendix provides an example of the application of the peaker deferral method and the generation resource plan expansion method to calculating marginal capacity cost.

A. Peaker Deferral Method

The peaker deferral method is described in greater detail in Topic 1.3 of the Electric Utility Rate Design Study, A Framework for Marginal Cost-Based Time-Differentiated Pricing in the United States (National Economic Research Associates, February 21, 1977). This method begins with a forecast of the capital and operating costs of a peaker.

Based on the capital and operating costs of a peaker, a future stream of annual revenue requirements is forecast over the expected life of the peaker and its future replacements. Next, this stream of annual revenue requirements is discounted to a single present-worth value using the utility cost of capital.[10] Next, the annual stream of revenue requirements is shifted forward assuming that construction of the peaker and its future replacements is deferred one year, and the resulting stream of revenue requirements is discounted to a single present-worth value. The difference between these two present-worth values is the deferral value -- the "cost" of operating a peaker for one year. Finally, this deferral value must be scaled upward to reflect that a peaker is not perfectly reliable, and may not always be available to meet peak demands. This can be done by comparing the reliability improvement provided by a "perfect" resource (one that is always available) to the reliability improvement provided by a peaker. This ratio, sometimes called a capacity response ratio (CRR), is then multiplied by the peaker deferral value to calculate marginal capacity cost.

[10] Arguably, a ratepayer discount rate may be more appropriate than the utility's cost of capital. Due to the difficulty of developing a ratepayer discount rate, utility cost of capital is commonly employed for discounting. The cost of capital should be based on the cost of acquiring new capital. This will generally differ from the authorized rate of return, which reflects the embedded cost of debt financing.

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A calculation of marginal capacity cost using the peak deferral method is illustrated in Table 9A-1, based on the utility case study. The calculation starts with the installed capital cost of a combustion turbine, including interconnection and appurtenant facilities and capitalized financing costs, of $614.97/KW.

TABLE 9A-1

DEVELOPMENT OF MARGINAL PRODUCTION COST USING THE PEAKER DEFERRAL METHOD

Line No.	Item	$/KW
1	Peaker Capital Cost	614.97
2	Deferral Value (Line (1) x 10.07%)	61.93
3	Operation and Maintenance Expense	6.39
4	Fuel Oil Inventory Carrying Cost	1.19
5	Subtotal (Line (2) + Line (3) + Line (4))	69.51
6	Marginal Capacity Cost (Line (5) x 1.15)	79.94

This initial capital investment (line 1) is then multiplied by an economic carrying charge of 10.07 percent to give the annual deferral value of the peaker (line 2). The economic carrying charge is conceptually similar to the levelized carrying charge which is frequently used in evaluating utility investments. While a levelized carrying charge produces costs which are level in nominal dollars over the life of an asset, the economic carrying charge produces costs which are level in inflation-adjusted dollars.[11] The economic carrying charge is the product of three components, as shown in the following equation:

Economic carrying charge = revenue requirement present-worth factor
x infinite series factor
x deferral value factor

The revenue requirement present-worth factor is calculated based on the initial capital investment as follows. A projection of annual revenue requirements associated with the $614.97/KW initial investment is made for the life of the investment. Included

[11]The development of the economic carrying charge in this section ignores the effect of technological obsolescence. The effect of incorporating technological obsolescence would be costs that decline over time (in inflation-adjusted dollars) at the rate of technological obsolescence (see Attachment C, "An Economic Concept of Annual Costs of Long-Lived Assets" in National Economic Research Associates, *op. cit.*).

in these annual revenue requirements are depreciation, return (using the cost of obtaining new capital), income taxes, property taxes, and other items which may be attributed to capital investment. These annual revenue requirements are then discounted using the utility's cost of capital, producing a result perhaps 30 to 40 percent above the initial capital cost, depending largely on the utility's debt-equity ratio and applicable tax rates. The ratio of the discounted revenue requirements to the initial capital investment is the revenue requirement present-worth factor.

The next component in the economic carrying charge calculation increases the discounted revenue requirements to reflect the discounted value of subsequent replacements. The simplest approach is to use an infinite series factor. Assuming that capital costs rise at an escalation rate i, that the utility cost of capital is r, and that peakers have a life of n years, the formula is as follows:

$$\text{Infinite Series Factor} = \frac{1}{1 - \left(\frac{1+i}{1+r}\right)^{n}}$$

The final component of the economic carrying charge is the deferral value factor. If the construction of the peaker is deferred by one year, each annual revenue requirement is discounted an additional year, but is increased due to escalation in the capital cost of the peaker and its replacements. The value of deferring construction of the peaker for one year is given by the difference between the discount rate and the inflation rate, expressed in original year dollars, as follows:

$$\text{Deferral Value Factor} = \frac{r-i}{1+r}$$

The next step in the calculation of marginal capacity cost is to add annual expenditures such as operation and maintenance expenses (line 3), and the cost of maintaining a fuel inventory (line 4). Finally, the subtotal of these expenses (line 5) is multiplied by a capacity response ratio, accounting for the reliability of the peaker compared with a perfect capacity resource, to give the marginal capacity cost (line 6).

The peaker deferral method produces a measure of long-run marginal cost, since it measures the cost of changing the utility's fixed assets in response to a change in demand, without taking into account a utility's existing capital investments.

Using a probabilistic outage model, loss of load probability (See Appendix 9-B) can be used to adjust long-run marginal costs developed from a peaker deferral method to reflect short-run marginal costs. This is accomplished by multiplying the marginal capacity cost from the peaker deferral method times the ratio of forecast LOLP to the LOLP planning standard. This can be seen in the following example. If the LOLP planning standard is 0.0002, then a 10,000 KW increase in demand will, on average, result in an expected 2 KW being unserved. Since this is the planning standard, the value to consumers of avoiding these 2 KW being unserved is just equal to the cost of adding an addiin demand will, on average, result in 1 KW being unserved. Adding an additional resource would benefit consumers, but only an expected 1 KW of unserved demand would be avoided. Thus, the benefit of avoiding the 1 KW of unserved load is one-half the cost of the additional resources necessary to serve this load. In this example, short-run marginal capacity cost is one-half the long-run marginal capacity cost.

B. Generation Resource Plan Expansion Method

The generation resource plan expansion method is described in greater detail in The Marginal Cost and Pricing of Electricity: An Applied Approach (C. J. Cicchetti, W. J. Gillen, and Paul Smolensky, June 1976). This method begins with the utility's current least-cost resource plan, increments or decrements load in the "test year" by some amount, and revises the least-cost resource plan accordingly. The present-worth cost of the two resource plans, including both capital and fuel costs, are compared, and the difference represents the marginal capacity cost for the chosen load increment.

The generation resource plan expansion method can be illustrated using the utility case study. In this case study, the utility has adequate resources to serve loads and, in addition, has surplus oil/gas units which are expected to be refurbished and returned to service to meet future load requirements. If load were to increase above forecast, this would accelerate the refurbishment of these units. For example, if load increased 200 MW, the refurbishment and return to service of a 225 MW unit would be advanced one year. The cost of this refurbishment is about $30 million and would result in perhaps a 15-year life extension. For simplicity, the annual cost of accelerating the capacity requirement is computed using the same economic carrying charge approach as developed above for the deferral of a peaker as follows:[12]

$$\text{Annual Cost (\$/KW)} = \frac{\text{(Capital Cost) x (Economic Carrying Charge)}}{\text{(Load Increment)}}$$

$$= \frac{(\$30{,}000{,}000) \times (0.1407)}{(200{,}000 \text{ KW})}$$

$$= \$21/\text{KW}$$

[12]The economic carrying charge is actually higher since the 15-year life extension is shorter than the expected 30-year life of the peaker. It would be more precise to identify the replacement capacity for the refurnished unit in the resource plan when it is eventually retired after 15 years, and take into consideration the effect of acclerating the unit's return to service on this furture replacement.

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This annual cost should be reduced by the annual benefit of any fuel savings resulting from the accelerated return to service of the unit. However, a production cost model analysis shows that there are virtually no fuel savings from returning the unit to service, since its operating costs are about the same as for the oil/gas units already in service.

In implementing this generation resource plan method, care must be taken to choose load increments that do not lead to lumpiness problems. If the load increment is small, there may not be an appreciable impact on the generation resource plan. On the other hand, a modest load change may be sufficient to tilt the scales toward a new generating resource plan, overstating the effect of the load change in general. One approach to dealing with potential lumpiness problems is to investigate a series of successive load increments, and then take an average of the marginal capacity costs determined for the successive increments.

Comparing this result with the peaker deferral method, the utility's short-run marginal capacity cost of $21/KW is about 26 percent of the long-run marginal capacity cost of $80/KW associated with meeting the capacity requirements by adding new generating facilities.

APPENDIX 9-B

A SIMPLE EXAMPLE OF THE DERIVATION OF LOSS OF LOAD PROBABILITIES

This appendix provides a simple example of how LOLP is developed and used to allocate marginal capacity costs to time periods. In the example shown in Table 9B-1, there are two time periods of equal length: an on-peak period where load is 250 MW and an off-peak period where load is 150 MW. The utility has four generating units totaling 600 MW, with various forced outage rates. Table 9B-1 calculates the probability of each combination of the four units being available. For example, there is a 0.0004 probability that all of the units are out of service simultaneously. Similarly, there is a 0.0324 probability that Units C and D are available (0.9 probability that each unit is available) while Units A and B are not available (0.1 probability that each unit is in a forced outage). Thus, there is a 0.0004 probability that the utility would be unable to serve any load, a 0.0076 probability that the utility would be unable to serve loads above 100 MW, a 0.0432 probability that the utility would be unable to service loads above 200 MW, and so forth. When load is 150 MW in the off-peak period, the utility will be unable to serve this load if all four units are not available, if only Unit C is available, or if only Unit D is available. The probability of these events occurring is 0.0076. Similarly, the probability of being unable to serve the 250 MW load in the on-peak period is 0.0432. The overall LOLP is 0.0508, with 85 percent of this LOLP resulting from the on-peak period. Thus, 85 percent of the marginal capacity costs are allocated to the on-peak period and 15 percent to the off-peak period.

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TABLE 9B-1
LOSS OF LOAD PROBABILITY EXAMPLE

Resources:

Size	Forced Outage Rate	Expected Availability
A: 200 MW	20%	80%
B: 200 MW	20%	80%
C: 100 MW	10%	90%
D: 100 MW	10%	90%

Probabilities:

Units	MW Available	Cumulative Available Probability	
None	0	(.2)(.2)(.1)(.1)=0.0004	0.0004
C	100	(.2)(.2)(.9)(.1)=0.0036	0.0040
D	100	(.2)(.2)(.1)(.9)=0.0036	0.0076
A	200	(.8)(.2)(.1)(.1)=0.0016	0.0092
B	200	(.2)(.8)(.1)(.1)=0.0016	0.0108
C, D	200	(.2)(.2)(.9)(.9)=0.0324	0.0432
A, C	300	(.8)(.2)(.9)(.1)=0.0144	0.0576
A, D	300	(.8)(.2)(.1)(.9)=0.0144	0.0720
B, C	300	(.2)(.8)(.9)(.1)=0.0144	0.0864
B, D	300	(.2)(.8)(.1)(.9)=0.0144	0.1008
A, B	400	(.8)(.8)(.1)(.1)=0.0064	0.1072
A, C, D	400	(.8)(.2)(.9)(.9)=0.1296	0.2368
B, C, D	400	(.2)(.8)(.9)(.9)=0.1296	0.3664
A, B, C	500	(.8)(.8)(.9)(.1)=0.0576	0.4240
A, B, D	500	(.8)(.8)(.1)(.9)=0.0576	0.4816
A, B, C, D	600	(.8)(.8)(.9)(.9)=0.5184	1.0000

Time Period Demand:

		LOLP	
On-Peak	250 MW	0.0432	85%
Off-Peak	150 MW	0.0076	15%
		0.0508	

CHAPTER 10

MARGINAL TRANSMISSION, DISTRIBUTION AND CUSTOMER COSTS

In contrast to marginal production costing methodology, analysts have devoted little attention to developing methodologies for costing marginal transmission, distribution and customer costs. An early evaluation noted: "... the determination of marginal costs for these functions, and especially distribution and customer costs, is much more difficult and less precise than for power supply, and it is not clear that the benefits are sufficient to justify the effort."[1] The referenced study, therefore, used average embedded costs, because they were both more familiar to ratemakers and analysts, and a reasonable approximation to the marginal costs. It is still common for analysts to use some variation of a projected embedded methodology for these elements, rather than a strictly marginal approach. While marginal cost concepts have been applied to transmission and distribution for the purpose of investigating wheeling rates, little of this analysis has found its way into the cost studies performed for retail ratemaking. The basic research into marginal costing methodologies for transmission, distribution and customer costs for retail rates was done in connection with the 1979-1981 NARUC Electric Utility Rate Design Study and most current work and testimony still refer back to those results.

I. TRANSMISSION

There are several basic approaches to the calculation of the marginal cost of transmission. However, the first step in any approach is the definition of the study period. Transmission investments are "lumpy" in that they usually occur in large amounts at intervals. Therefore, it is important to select a study horizon that is long enough to reflect the relationship between investments and load growth. To the extent that investments are related to load growth occurring outside the study period or there is

[1] J. W. Wilson, Report for the Rhode Island Division of Public Utilities, Public Utilities Commission and Governor's Energy Office (1978), pp. B-27-8.

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a significant change in the level of system reliability, the analyst may wish to adjust the calculation of the load growth to identify the investment more closely with the load it is intended to serve. Given the desirability of a fairly long study period, analysts will typically select the utility's entire planning period augmented by historical data to the extent that the analyst believes that the historical relationships will continue to obtain in the future.

For purposes of a marginal cost study, investment in the transmission system is generally assumed to be driven by increments in system peak load. As the transmission system was actually constructed for a variety of reasons, the second step in the calculation of the marginal cost of transmission is to identify and eliminate those investments that are not related to load growth. The non-demand related transmission investments can be categorized as:

1. Those related to remote siting of generation units (which are costed as part of the generation cost).
2. Those related to system interconnections and pool requirements (whose benefits are manifested in reduced reserve requirements and, therefore, are again costed with generation).
3. Those associated with large loads of individuals (which are therefore charged to the particular customer concerned).
4. Replacement of existing facilities without adding capacity to serve additional load (assuming that the economic carrying charge formula incorporates an infinite series factor).

Costs that remain should be related only to system load growth or to maintenance of system reliability.

A. Costing Methodologies

There are two basic approaches to estimating marginal transmission costs, and they begin to diverge at this step in their methodology. The first approach is the Projected Embedded Analyses of which there are two variations: the Functional Subtraction approach, which relates total transmission investment additions to load growth, and the Engineering approach, which relates individual facilities (line miles, transformers, etc.) to load growth. The second methodology is the System Planning approach, which uses a base case/decrement analysis.

1. Projected Embedded Analyses

As the name suggests, Projected Embedded Analyses are often based on a simple projection of past costs and practices into the future. A disadvantage of this approach is that it may fail to capture important technological and business related developments and therefore result in the over or underestimation of marginal capacity cost.

- Functional Subtraction Approach

The Functional Subtraction approach requires data in the form of annual load related investments in transmission and load growth for the same period. The period to be analyzed includes the transmission planner's planning period plus whatever historical period he believes appropriate. Transmission cost data must be sufficiently specific to enable the analyst to differentiate load growth related transmission expenditures from those more properly associated with either generation or a specific customer. Having chosen the study period and identified the load related investments in transmission by voltage level, the analyst performs the analysis in real dollars. This is done by converting the historical nominal data to current money values by applying either the Handy-Whitman plant costs indices or, if available, an inflation index particular to the utility. Projected investments are converted to real dollars by removing the inflation factor used by the planner in his computations.

The third step is to relate the real transmission investments to a measure of load growth at each voltage level, weather normalized if possible, stated in kilowatts. Non-coincident peak demand on the transmission system is the correct measure of load growth. However, given the system's integrated nature, for most purposes non-coincident peak demand on the transmission system is the same as the total system coincident peak.

The relationship between investment and load growth (\$/KW) is usually obtained by simply dividing the sum of investments for the period by the growth in peak load. There have been some attempts at regressing annual investments against load growth, using the equation Transmission Costs = a + b (peak demand), but the R^2's have been disappointingly low. However, given the assumption that transmission investments are "lumpy" and that one particular year's investment is not specifically related to that year's load growth, the lack of correlation should not be surprising. The best regression results are achieved by using least squares and regressing cumulative incremental investment against cumulative incremental load. Thus, the first year observation is the first year value of incremental investment and load, the second year observation is the sum of the first year and the second year values, the third year is the sum of the values for the first three years, and so on. See Table 10-1.

TABLE 10-1
Computation of Marginal Demand Cost of Transmission
Transmission-Related Additions to Plant
Per Added Kilowatt of Transmission System Peak Demand
(Functional Subtraction Approach)

Year	(1) Growth Related Net Addition (1988 $M)	(2) Cumulative Net Addition (1988 $M)	(3) Growth In System Peak (MW)	(4) Cumulative System Peak (MW)
Actual				
1976	44.1	44.1	888	888
1977	33.8	78	166	1054
1978	40	118	750	1804
1979	30	147.9	467	2271
1980	36.4	184.3	148	2419
1981	30.6	214.9	808	3227
1982	134.2	349.1	(538)	2689
1983	62.7	411.8	295	2984
1984	42.5	454.3	1685	4669
1985	148.3	602.6	(579)	4090
Projected				
1986	188.6	791.2	21	4111
1987	71.4	862.6	302	4413
1988	178.5	1041	446	4859
1989	83.6	1124.7	406	5265
1990	128.7	1250.4	407	5672
Total:	1250.4		5672	

Simplified Approach

Marginal Transmission Investment Costs = Column 1 Total/Column 3 Total = $220.45/KW

Regression Approach

Marginal Transmission Investment Costs = $249.40/KW

Y = A + B*X
Where Y is cumulative demand-related net additions to plant
X is cumulative additions to coincident peak demand.

A = -326.59
B = 0.2494

$R^2 = 0.84$

The fourth step is to convert the per kilowatt investment cost into an annualized transmission capacity cost by multiplying the former by a carrying charge rate. There are two forms in common use, the economic carrying charge and the standard annuity formula. During a period of zero inflation the two methods produce the same results, but during inflationary periods only the former takes due account of the impact of inflation on the value of plant assets.[2]

Since the addition of transmission capacity occasions increased operation and maintenance expenses, the marginal 0&M costs are calculated and added to the annualized transmission capacity costs. The expense per KW is usually found to be fairly constant and either the current year's expense or the average of the $/KW in current dollars over the historical portion of the study period is considered to be a good approximation of the marginal transmission operation and maintenance expense. The analyst takes the data from the FERC Form I, again being careful to include only those costs related to load growth. For example, he may exclude rents or that portion of expenses related to load dispatching associated with generation trade-offs. Total transmission 0&M expenses in current dollars are divided by system peak demand, and averaged if multiple years have been used. The result, either for the single current year or the average of several years, is then added to the annualized transmission capacity cost to obtain the total transmission marginal cost. Alternatively, 0&M expenses can be regressed on load growth or transmission investments, in which case the 0&M adjustment appears as a multiplier to the capacity cost rather than an adder.

The final step is to adjust the results for transmission's share of indirect costs including the marginal effect on general plant and working capital. See Table 10-2.

TABLE 10-2
Computation of Marginal Demand Costs of Transmission
(1988 $)

Description	Cost Per KW ($)
Transmission Investment per KW Change in Load (from Table 10-1)	249.40
Annual Costs (*10.9%)	27.18
Demand Related O&M Expense	4.52
General Plant Loading	1.05
Working Capital	0.48
Total Annual Cost of Transmission	33.23
Loss Adjustment (1.033)	34.33

[2]See Appendix 9-A for the derivation of the economic carrying charge.

o Engineering Approach

Like Functional Subtraction, the Engineering approach also relates changes in transmission investment to changes in system peak load. However, it first relates the addition of specific facilities (line miles, transformers, etc.) to growth in load over the chosen study period, and then computes the unit costs of each facility to derive the investment for transmission per added kilowatt of demand. The method has the advantage of more readily identifying those facilities added for the purpose of serving added load (and thereby excluding non-load related investment). It may be more difficult to apply, however, as it requires detailed records and distinctions that may come more easily to the utility company planner than to the outside observer.

Once the study period is selected, the analyst identifies the load growth related facilities that were or will be added each year at each voltage level. By either regression analysis or simple averages, the addition of facilities is related to the growth in coincident system peak. The result is expressed in line miles, transformers, etc. per added KW and monetized by applying a cost figure for each facility in real dollars. As with Functional Subtraction, the investment per added demand is annualized by a levelized carrying charge, or, more properly, an economic carrying charge (consistent with calculations for the other capacity components) and added to the associated annual operation and maintenance costs. The costs per KW for each facility are then totaled at each voltage level and adjusted for indirect costs.

2. The System Planning Approach

The System Planning approach is more nearly related to the marginal costing methodologies for generation than is the Projected Embedded approach. As such, it may be helpful to review what is meant by marginal capacity cost. The marginal cost of transmission or distribution capacity can be defined as the present worth of all costs, present and future, as they would be with a demand increment (decrement), less what they would be without the increment (decrement). This definition of marginal cost can be represented by a time-stream of discounted annual difference costs stretching to infinity. The stream of investments from this approach would be annualized by using an economic carrying charge.

Alternatively, the marginal capacity cost can be interpreted as the cost to the utility of bringing forward (delaying) by one year its future investments, including the stream of replacement investments, to meet the demand increment (decrement). Mathematically, this interpretation results in annual charges equal to the economic carrying charge on the marginal investments.

In order to simplify the calculation of marginal capacity cost it is common for the stream of difference costs to be truncated after a set number of years, usually the utility's planning period or the average economic life of the investments. However, if the period chosen is too short, truncation can result in serious underestimation of marginal capacity cost. In terms of the second definition this would be equivalent to neglecting the impact of the increment (decrement) on more distant investments. Truncating a component of the economic carrying charge as discussed in Appendix 9-A will mitigate some of those effects.

The System Planning approach is an application of the first incremental/decremental definition of marginal capacity cost and therefore the analyst should take care not to base his calculations on an unreasonably short planning horizon.

In contrast to the projected embedded studies for transmission cost, which may use some historical data, the study period for the system approach is forward-looking. As with the other methodologies, the relevant costs are those related to changes in load, and coincident system peak is the basic cost causation factor. The data required is thus the planner's base case of expected load growth and transmission investments, plus an incremental (decremental) case for the same period.

Planned transmission costs, investment and expenses, are identified and the marginal cost quantified by developing a differential time series of expenditures over the planning horizon using an increment or decrement to system peak load. A base case expansion plan is developed using the forecasted load over the future planning horizon. Investments are separated by voltage level where the utility has customers who take service directly from the high voltage lines. Those investments associated with load growth are identified and the total annual revenue requirements (including expense items) are derived in real or nominal dollars for each year at each voltage level.

The system planner is then asked to assume an increase or decrease in the coincident peak load and redesign transmission expenditures, still maintaining system reliability and continuing to meet the system planning criteria, and repeat the costing procedure. Thus, the marginal transmission capacity cost is the change in total costs associated with changes to budgeted transmission expenditures between the planner's base case and his incremental (decremental) case. The dollar stream representing the difference between the two cases is present worthed, aggregated and then annualized over the costing horizon. The resultant annualized figure is then divided by the amount of the increment (decrement) to obtain a $/KW marginal cost for transmission for each voltage level. The size

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of the increment (decrement) may vary according to the size of the utility and will certainly affect the result. A 50 MW change is often chosen as the smallest (most marginal) change that can be assumed and produce measurable differentiated cases.

3. Adjustments

- Loss Adjustment

Electric utility transmission and distribution systems are not capable of delivering to customers all of the electricity produced at the generation bus bar. The difference between the amount of electricity generated and the amount actually delivered to customers is called "losses".

Losses can be broadly classified as copper losses, core losses and dielectric losses. They are caused, respectively, by the production of heat, the establishment of magnetic fields and the leakage of current. The first of these varies in proportion to the square of the current and is therefore included under marginal energy costs. The latter two are fixed losses associated with specific equipment and therefore covered by marginal capacity costs.

Marginal capacity loss factors are applied to marginal capacity-related costs per kilowatt. These factors account for the fact that when a customer demands an additional kilowatt at the meter, more than a kilowatt of distribution, transmission and generation capacity must be added.

- Energy Adjustment

While most analysts assume that transmission is causally related to system peak and therefore is totally demand related, it has been argued, particularly in the literature concerning wheeling rates, that transmission embodies an energy component as well. For very small changes in load, transmission and generation are substitutes: additional generation can overcome the line losses in the transmission system, or extra transmission capacity can, by reducing losses, substitute for added generation. Thus, conceptually, it is proper to net out the energy savings from the marginal investment cost of transmission, leaving the residual to be demand related. There is no accepted methodology for quantifying this adjustment. One approach is to obtain a calculation of the energy loss/potential savings in $/period by multiplying the cost of 1 KW for each costing period times the energy loss in that period. Summing across the periods produces, in total dollars per kilowatt-year, the avoidable loss/potential savings. As some of this loss occurs at the generation level, it is appropriate to net out the portion of energy loss due to generation. The remainder is net energy savings in $/KW year attributable to increased transmission capacity that can then be capitalized into a $/KW computation.

B. Allocation of Costs to Time Periods

The attribution of marginal demand-related costs by time of use reflects the system planner's response to the goal of maintaining a target level of reliability in the generation, transmission and distribution components of the system. Thus, as the load varies according to time periods, so does the need to add capacity to maintain reliability. System planners evaluate generation, transmission and distribution components separately for their reliability, and ideally the transmission capacity cost responsibility would reflect the planner's sensitivity to such factors as the likelihood of weather related service disruptions. For costing purposes, however, most analysts use the same methodologies, and often the same attribution factors, for transmission as they do for generation. The reasoning is that in general the load characteristics of the transmission system are identical to those of the generation system, both being driven by the system coincident peak. Therefore, it is not considered necessary to perform transmission specific load studies as the results of such studies should not differ significantly from those of the generation load studies. To the extent that the transmission and generation load characteristics do differ, the methodology discussed under "Distribution" can be employed.

The methods employed, include attributing the costs uniformly across the peak period, or by means of transmission reliability indicies or loss of load probability (LOLP). However, where the LOLP data are heavily influenced by seasonal generation availability (e.g., hydro facilities) or generation maintenance schedules, the generation LOLP factors are not a good measure of the need to add transmission capacity.

None of the generation-tied allocation methods recognize the seasonal variation in the capability of transmission facilities. Transmission facilities have a lower carrying capability when ambient temperatures are high (i.e., summer). Therefore, winter peaking utilities and summer peaking utilities with significant winter peaks need some method for adjusting seasonal assignment factors if they are going to rely on generation related costing allocators for transmission.

II. DISTRIBUTION

A. Costing Methodologies

The major issue in establishing the marginal cost of the distribution system is the determination of what portion of the costs, if any, should be classified as customer related rather than demand and energy related. The issue is a carry-over of the unresolved argument in embedded cost studies with the added query of whether the distribution costs usually identified as customer related are, in fact, marginal.

Most analysts agree that distribution equipment that is uniquely dedicated to individual customers or specific customer classes can be classified as customer rather than demand related. Customer premises equipment (meters and service drops) are generally functionalized as customer rather than distribution costs and, in reality, this is the only equipment that is directly assignable for all customers, even the smallest ones. Beyond the customers' premises, however, there are distribution costs that may be classified as customer related. For example, some jurisdictions classify line transformers as customer-related often using a proxy based on average load as the allocation factor when this equipment is not uniquely dedicated to individual customers. In addition, for very large customers, more than merely meters, services, and transformers are directly assignable. Some have entire substations dedicated to them. As noted above in "Transmission," distribution costs of equipment dedicated to individual customers can be directly assigned to them, thus reducing the common distribution costs assigned to the remainder of the class.

The major debate over the classification of the distribution system, however, concerns the jointly used equipment rather than the dedicated equipment. At the margin, there is symmetry between the cost of adding one customer and the cost avoided when losing one customer. A number of analysts have argued, and commissions have accepted, that the customer component of the distribution system should only include those features of the secondary distribution system located on the customer's own property. Portions of the distribution system that serve more than one customer cannot be avoided should one customer cancel service. Similarly, if the customer component of the marginal distribution cost is described as the cost of adding a customer, but no energy flows to the system, there is no reason to add to the distribution lines that serve customers collectively or to increase the optimal investment in the lines that are carrying the combined load of all customers. Therefore, the marginal customer cost of the jointly used distribution system is zero.

Those analysts who believe that there is a significant customer component to the marginal cost of the jointly used portion of the distribution system argue that the distribution system is causally related to increases in both the number of customers and the kilowatts of demand. (They may also note that distribution costs are influenced by the concentration of such non-demand, non-customer factors as load, geographic terrain, climatic conditions and local zoning ordinances. However, no analyst has attempted to introduce and quantify these elements in a marginal cost of service study and absent area-specific rates depending on density and distance from load centers, there is no reason to do so.) Because of the non-interconnected character of the distribution system, the relevant demand parameter is non-coincident peak, preferably measured at the individual substation or even at lower voltages, rather than the system peak used for generation and transmission. This reflects the fact that each portion of the distribution network must be planned to serve the maximum load occurring on it and the utility's investment reflects the need to provide capacity to each separate load center. As some customers receive service directly from the primary distribution system, calculations must be performed separately for the different voltage levels.

The measured relationship for each voltage level is expressed by the equation:

Total Distribution Cost = a + b x demand on distribution + c x customers

The statistical difficulty with this equation is that the demand is highly correlated with the number of customers (multicollinearity) and that therefore it is not possible to identify the separate marginal effects of changes in demand and customers on cost. The proposed estimation techniques resolve the statistical dilemma by computing the customer responsibility separately and then relating the residual cost to load growth. To the extent that the distribution system is sized in part to reduce energy losses, an energy component must also be netted out of marginal cost in order to obtain the demand component.

The two most common approaches to calculate the customer related component in marginal as well as embedded studies are the zero intercept method and the minimum grid calculation. The zero intercept method re-defines the original equation to read:

Total Distribution Cost = a + b x demand on distribution

It solves the multicollinearity problem by eliminating the customer variable under the hypothesis that the constant "a" will then represent the non-variable, non-demand related portion of the costs, or the distribution facilities required when demand is zero. The method has been accused of "solving" the problem of multicollinearity by mis-specifying the equation. Statistically, removing a correlated variable (customers) from the equation will result in transferring some of the responsibility of the omitted variable to the coefficient of the remaining variable (demand). Application of the technique does not necessarily lead to results that make economic sense: negative constant terms are not uncommon. The approach is somewhat more successful when used to analyze cross-sectional data where the correlation is weaker or when applied to individual items of distribution equipment.

The minimum grid approach re-designs the distribution system to determine the cost in current year dollars of a hypothetical system that would serve all customers with voltage but not power (or with minimum demand of 0.5 KW), yet still satisfy the minimum standards for pole height and efficient conductor and transformer size. The calculations can be based either on the system as a whole or on a sample of areas reflecting different geographical, service and customer density characteristics.

When applying this approach, it is necessary to take care that the minimum size equipment being analyzed is, in fact, the minimum-sized equipment available, and not merely the minimum size stocked by or usually installed by the company. To the degree that the equipment being costed is larger than a true minimum, the minimum grid calculation will include costs more properly allocated to demand.

Figure 10-1 illustrates the results of the minimum grid approach for the marginal customer-related cost for a typical residential customer of the sample utility. In column 1 (Customer Specific Equipment) only line transformers, service and meters are functionalized to the customer category while all other distribution equipment is functionalized to the demand category. In column 2 (Minimum Distribution Method) all distribution equipment is first estimated at minimum size and functionalized as customer-related. The additional cost of equipment, sized to meet actual expected loads is functionalized as demand-related. For comparison, column 3 reflects the reconstruction cost for the as-built system. In the sample company, the minimum grid approach to determining the marginal customer-related cost of connecting an average customer produces a customer charge equal to 43 percent of costs of the distribution system (14 percent plus 29 percent) compared to the charge resulting from the alternative T-S-M approach, i.e., restricted to meter, service, line transformer and associated costs, which is only 28 percent of the distribution system costs.

The marginal demand related distribution costs are calculated in a manner similar to the marginal demand related transmission costs. The major differences are that, if considered appropriate, the marginal customer costs must be removed from the total costs incurred during the study period, and that the relevant load growth is non-coincident peak.

Removal of customer costs can be done in two ways. The cost of the minimum grid can be divided by the number of customers served to obtain a cost per customer to be included in the customer charge. The cost per customer at each voltage level can be multiplied by the number of customers added at each voltage level during the study period, and the sum subtracted from the total distribution investment in current year dollars. This residual is then considered the demand (or demand and energy) component of the marginal cost. Alternatively, the marginal customer costs can be removed by using a factor based on the ratio of investment in the minimum distribution grid to the investment in

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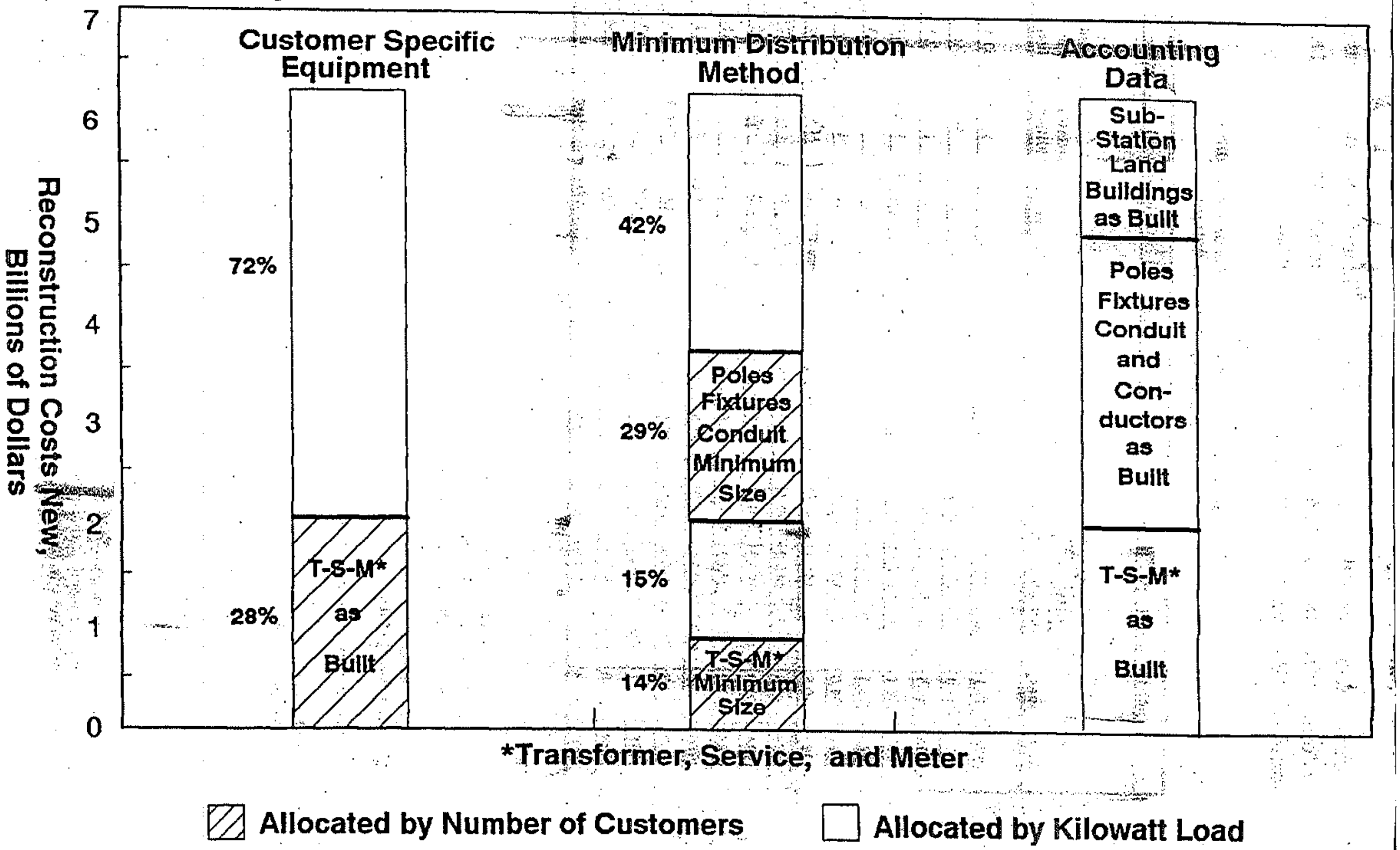
Figure 10-1

DIFFERING VIEWS OF THE ELECTRIC DISTRIBUTION SYSTEM



the total distribution system, calculated over the historical period. In the example, the customer related portion of the distribution system is 43 percent leaving a demand related portion of 57 percent. See Table 10-3, Column k footnote.

Table 10-3A
Demand Related Marginal Costs of Distribution
Minmum Grid Methodology

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)
Year	Lines	T-M-S	Total Lines	Total Repl.	New Business Lines	Land	Subs	TOTAL	Index	Reflated Additions	Demand Related Portion	Cumul. Demand Related Portion	Cumul. Non-Coin Peak Load Additions
1976	47.1	30.6	77.7	31.0	46.7	0.9	13.4	61.0	1.820	111.0	63.3	63.3	1078
1977	58.8	56.4	115.2	48.4	66.8	0.3	-13.0	54.1	1.675	90.6	51.7	114.9	1280
1978	58.5	63.6	122.1	44.8	67.3	0.6	7.3	75.2	1.696	127.5	72.7	187.6	2191
1979	68.1	69.7	137.8	55.1	82.7	0.5	12.3	95.5	1.422	135.8	77.4	265.0	2758
1980	73.5	56.0	132.5	82.1	50.4	0.3	18.8	69.5	1.319	91.7	52.3	317.3	2937
1981	94.0	73.2	167.2	103.7	63.5	2.2	22.2	87.9	1.197	105.2	60.0	377.3	3919
1982	90.5	65.2	155.7	96.5	59.2	0.4	31.1	90.7	1.101	99.9	56.9	434.2	3265
1983	76.6	71.6	148.2	99.3	48.9	0.0	31.6	80.5	1.079	86.9	49.5	483.7	3623
1984	91.0	104.3	195.3	130.9	64.4	3.5	23.0	90.9	1.071	97.4	55.5	539.2	5670
1985	138.8	114.0	252.8	169.4	83.4	4.3	17.7	105.4	1.092	115.1	65.6	604.8	4966
1986	153.1	106.5	259.6	174.0	85.6	11.8	76.4	173.8	1.071	186.1	106.1	710.9	4992
1987	158.7	108.2	266.9	178.8	88.1	2.1	70.5	160.7	1.038	166.8	95.1	806.0	5359
1988	161.1	108.9	270.0	178.2	91.8	0.0	31.5	123.3	1.000	123.3	70.3	876.3	5900
1989	159.6	107.7	267.3	173.7	93.6	0.5	19.1	113.2	0.961	108.8	62.0	938.3	6393
1990	168.3	113.6	281.9	186.1	93.8	1.9	26.3	122.0	0.925	114.7	65.4	1,003.6	6888

Regression Results: $Y = A + B * X$

Where Y is cumulative demand-related net additions to plant and X is cumulative additions to distribution level peak demand.

A = -134.608
B = 0.1591260869

Marginal demand costs of distribution = $159.13

(a) from study workpapers
(b) from study workpapers
(c) a + b
(d) from study workpapers: total replacements (repl.) portion of Lines and T-M-S
(e) c - d
(f) from stduy workpapers
(g) from study workpapers
(h) e + f + g
(i) Handy Whitman index
(j) h * i
(k) j * 57% (43% customer related derived from the average ratio of the mininum distribution system cost to total distribution system costs calculated in study workpapers).
(l) cumulates k
(m) cumulates peak Load additions in study workpapers

TABLE 10-3B
Demand Related Marginal Cost of Distribution
Customer Specific Equipment Methodology

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
Year	Lines	Replacement Lines	New Business Lines	Land	Subs	TOTAL	Index	Reflated Additions	Cumul. Demand Portion	Cumulative Non-Coin Peak Load
1976	47.1	18.8	28.3	0.9	13.4	61.0	1.820	77.532	77.532	1078
1977	58.8	24.7	34.1	0.3	-13.0	54.1	1.675	35.845	113.377	1280
1978	58.5	23.4	35.1	0.6	7.3	75.2	1.696	72.928	186.305	2191
1979	68.1	27.2	40.9	0.5	12.3	95.5	1.422	76.361	262.666	2758
1980	73.5	47.4	29.1	0.3	18.8	69.5	1.319	63.576	326.242	2937
1981	94.0	58.3	35.7	2.2	22.2	87.9	1.197	71.940	398.182	3919
1982	90.5	56.1	34.4	0.4	31.1	90.7	1.101	72.556	470.738	3265
1983	76.6	2.0	74.6	0.0	31.6	80.5	1.079	114.590	585.328	3623
1984	91.0	61.0	30.0	3.5	23.0	90.9	1.071	60.512	645.839	5670
1985	138.8	93.0	45.8	4.3	17.7	105.4	1.092	74.038	719.877	4966
1986	153.1	102.6	50.5	11.8	76.4	173.8	1.071	148.548	868.424	4992
1987	158.7	106.3	52.4	2.1	70.5	160.7	1.038	129.750	998.174	5359
1988	161.1	106.3	54.8	0.0	31.5	123.3	1.000	86.300	1984.474	5900
1989	159.6	103.7	55.9	0.5	19.1	113.2	0.961	72.556	1157.030	6393
1990	168.3	111.1	57.2	1.9	26.3	122.0	0.925	78.995	1236.025	6888

Regrression Results: $Y = A + B * X$

Where Y is cumulative demand-related net additions to plant and x is cumulative additions to distribution level peak demand

A = -222.003
B = 0.203536

Marginal demand costs of distribution = $203.54

(a) from study workpapers
(b) from study workpapers
(c) a - b
(d) from study workpapers
(e) from study workpapers
(f) c + d + e
(g) Handy Whitman Index
(h) f * g
(i) cumulative h
(j) cumulative peak Load additions in study workpapers

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The functional subtraction method, in which it is possible to remove all non-demand related costs including the minimum grid, provides the most straightforward calculation. An analyst who employs the engineering method would have to determine individually for each facility which portion of the facility or the investment was incurred to serve customers and what proportion was incurred to serve demand. In both cases, the capacity costs are annualized and adjusted for operation and maintenance costs and for indirect costs. Absent special operation and maintenance studies, it is reasonable to divide O&M costs between customer and demand components on the assumption that they are proportional to the split in the distribution investment. Again, as in the transmission calculation, further adjustments can also be made to account for the losses and the energy component of the distribution cost using the methods outlined above. See Table 10-4.

TABLE 10-4
Demand Related Marginal Cost of Distribution
Minimum Grid vs. Customer Specific Equipment Methodologies
(1988 $)

Description	Minimum Grid $ per KW	Customer Specific Equipment $ per KW
Distribution Investment per KW change in Load (From Tables 10-3A & 10-3B)	159.13	203.54
Annual Cost (*13.08%)	20.82	26.62
Demand Related O&M Expense	5.69	9.17
General Plant Loading	0.80	1.02
Working Capital	0.37	0.47
Total Annual Costs of Distribution/KW	27.67	37.28
Loss Adjustment (1.107%)	30.63	41.27

B. Non-Coincident Peak Demand

To calculate the marginal demand related distribution cost for a particular customer class, the analyst needs to determine, using available load data, the increase in peak demand on the distribution system due to a 1 KW increase in the maximum demand of the class. The peak demand on the distribution system is referred to as the non-coincident peak demand.

Unfortunately, most load research studies have tended to focus on the structure of class demands at the generation and at the customer levels and, therefore, very little is known about the demands on the mid-stream components of the transmission and distri-

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bution systems. Consequently, analysts have resorted to various simplifying assumptions in order to determine transmission and distribution system non-coincident peaks. For power systems which depend for the most part on their own resources, it is often assumed that the class composition of the transmission system non-coincident peak demand is identical to the composition of the coincident peak demand at the generation level. This assumption may need to be amended for power systems with important interconnections with other systems.

Unlike the transmission system, however, secondary distribution systems are designed to meet load growth in particular localities. This means, of course, that the non-coincident peak on any portion of the secondary system reflects the combined load of the customers served from it. Because of zoning and land use regulations, load on any particular portion of the secondary system will generally be dominated by either residential or commercial customers. (Industrial customers are more likely to be served directly from the primary distribution system.) This suggests that a close relationship exists between an increase in the maximum demand of the residential or commercial class and the increase in the secondary non-coincident peak (i.e., coincident factor close to unity) for any particular locality. Where customer classes served from the secondary distribution system are mixed this result needs to be amended to take account of the diversity between the classes. As the residential class far out-numbers the commercial class on most systems, the secondary distribution system as a whole will be primarily responsive to residential loads.

Logically, the class demand at the time of peak on the primary distribution system must lie between the previously determined transmission and secondary distribution class demands and it is common to take the statistical average of the two demands.

C. Allocation of Costs to Time Periods

Most analysts assume that the customer related marginal distribution costs do not vary by season or by time of day.

The method adopted to attribute marginal demand related distribution costs depends on the load characteristics of the distribution network. When distribution system components experience maximum demand during the peak costing period identified in the generation analysis, the allocation methods employed for generation (uniform allocation across peak period, probability of excess demand, loss of load probability), and sometimes simply the generation allocation factors themselves, can be used to attribute distribution costs to time periods. As noted above in the discussion on the allocation of transmission costs, if the generation allocators are used it may be necessary to adjust for the effect of the ambient temperature on line capacity and, therefore, on the seasonal allocation of costs. Load research at the distribution substation transformer level has indicated in a number of jurisdictions, however, that different segments of the distribution network peak at different times in the day and year, and are not closely related to the system peak. Those jurisdictions may find it more appropriate to adopt an equal allocation of distribution capacity costs or to allocate costs based on either the proportions of the number of substations that peak during the individual costing periods, or by relating the amount of distribution investment to the timing of the peak demand where the investment was made.

III. CUSTOMER

Marginal customer costs in the functionalization step of a marginal cost of service study are generally identified as those facilities and services that are specific to individual customers. These costs include the costs of the service drops, the costs of meters and metering and the customer accounts expenses. These costs are assumed to vary solely according to the number of customers on the utility's system, and are, therefore, classified 100 percent customer related as well. Jointly used facilities such as line transformers and interconnecting secondary conductors that have been functionalized as distribution costs and that the analyst may have classified as customer related, have been discussed above in the "Distribution" section.

A. Costing Methodologies

Most analysts assume that in current dollars there is little incremental change in the cost of customer related facilities and expenses. Since customer related facilities are added in small increments and exhibit little technological change, the effects of vintaging and technological change, which normally distinguish marginal and embedded costs, are reduced. Thus, while it would be possible to calculate over some planning horizon the change in customer related cost in constant dollars against the expected change in the number of customers, the analyst would not expect the resulting marginal cost to differ significantly from the average embedded cost. Therefore, most marginal cost studies adopt a form of embedded analysis to calculate the total investment cost which is then amortized using an economic carrying charge.

If the minimum grid methodology is used, the customer related investment cost is that calculated in the distribution portion of the study. Otherwise, the cost of meters and service drop investment is analyzed separately by the type of metering installation or by customer load class by determining the characteristics of the service required. While it would be possible to identify separate demand and customer components of meter

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costs assuming that the more complex metering can be identified with higher levels of demand, all metering costs are usually charged on a per customer basis and, therefore, there is no reason to distinguish between the two components. Annual costs of each type of equipment are calculated by multiplying the installed cost by an annual carrying charge, and adding a factor to reflect operation and maintenance expenses.

Customer accounts (meter reading and billing), service and informational expenses are usually analyzed over a recent historical period, with the expenses converted to current year dollars. The customers in each customer class are weighted based on an embedded study of costs per customer or on discussions with company personnel. The customer expenses are allocated to each load class based on the weighted number of customers. See Tables 10-5A and 10-5B.

B. Allocation of Costs to Time Periods

While a case could be made that there are seasonal variations to such customer accounts as meter reading and customer information, the data is typically not analyzed on a monthly basis and there is no attempt at seasonal differentiation in the cost studies.

Table 10-5A
Customer Related Marginal Costs - Minimum

	Residential		Commercial			Industrial		Agricultural
		GS-1	GS-P	GS2-S	Sub-T	Primary	Sec	
Customer Related Investment Cost	759.00	755.00	2723.00	2416.00	8290.00	8701.00	20262.00	1763.00
Annualized Cost	99.28	98.75	356.17	316.01	1084.33	1138.09	2650.27	230.60
Customer related O&M	17.00	17.00	62.00	55.00	189.00	198.00	462.00	40.00
General Plant Loading	3.82	3.80	13.71	12.17	41.75	43.82	102.04	8.88
Working Capital	1.69	1.68	6.05	5.37	18.43	19.35	45.05	3.92
Customer Account Expenses	26.00	42.00	42.00	42.00	886.00	886.00	886.00	79.00
Total Customer Marginal Cost	147.79	163.23	479.93	430.55	2219.51	2285.26	4145.36	362.40
Weighted Average	147.79		224.61			3599.08		362.40

Table 10-5B
Customer Related Marginal Costs - Customer Specific

	Residential	GS-1	Commercial GS-2	GS2-S	Sub-T	Industrial Primary	Sec	Agricultural
Customer Related Investment Cost	309.09	476.37	2007.83	5209.66	8473.46	8473.46	14716.85	2861.61
Annualized Cost	40.43	962.31	262.62	681.42	1108.33	1108.33	1924.96	374.30
Customer Related O&M-Same % as MG	6.92	10.73	45.72	118.60	193.18	192.82	335.56	64.93
Customer Install Equipment	0.46	0.47	1.68	1.49	9.43	5.45	12.54	1.09
General Plant Loading	1.56	2.40	10.11	26.23	42.67	42.67	74.11	14.41
Working Capital	0.69	1.06	4.46	11.58	18.84	18.84	32.72	6.36
Customer Account Expenses	26.00	42.00	42.00	42.00	886.00	886.00	886.00	79.00
Total Customer Marginal Cost	76.05	118.97	366.60	881.33	2258.43	2254.11	3265.90	540.09
Weighted Average Class MC	76.05		285.75			2970.31		540.09

CHAPTER 11

MARGINAL COST REVENUE RECONCILIATION PROCEDURES

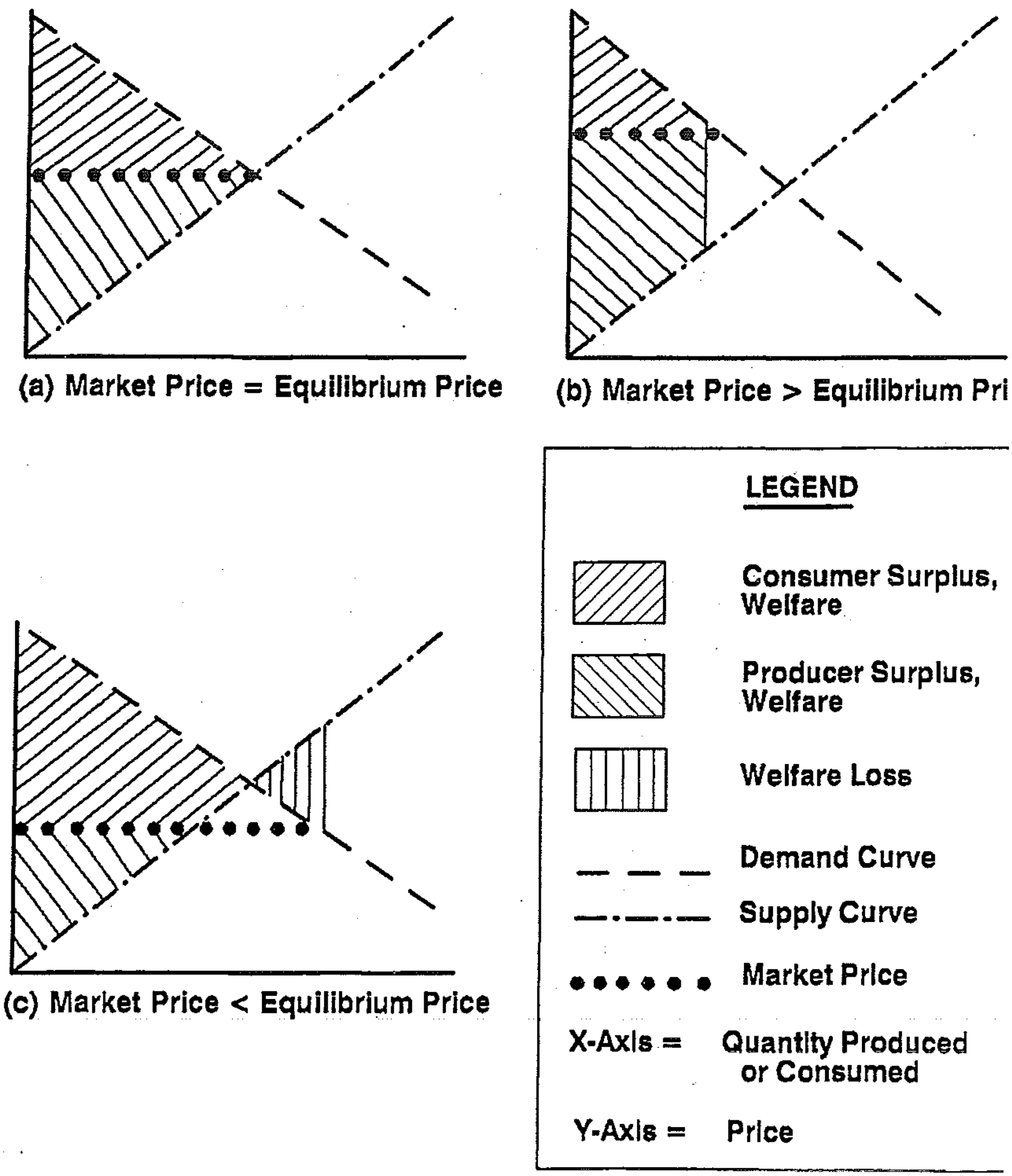
The major reason for allocating costs using marginal cost principles is to promote economic efficiency and societal welfare by simulating the pricing structure and resulting resource allocation of a competitive market. Competition drives production and consumption to where customers are willing to pay a price for the last or marginal unit consumed equal to the lowest price producers are willing to accept for their product. This situation occurs where the supply (marginal cost) and demand curves intersect. Since this equilibrium price is charged for all units of production, consumers pay a price lower than they would be willing to pay and producers charge a price higher than they would be willing to charge for all non-marginal units, generating benefits to both called "consumer surplus" and "producer surplus," respectively (Figure 11-1).

The sum of consumer and producer surpluses, which is one measure of societal welfare, is maximized where the supply and demand curves intersect (Figure 11-1A). A price differing from that at the intersection will result in lower production and consumption, reducing the sum of consumer and producer surpluses (Figures 11-1B and 11-1C). Marginal cost pricing will tend to move production and consumption to the equilibrium level where the two curves intersect.

Pricing a utility's output at marginal cost, however, will only, by rare coincidence, recover the ratemaking revenue requirement. Marginal and ratemaking costs vary in time, and often tend to move in opposite directions. For example, when new plant is added, ratemaking costs increase while short-run marginal costs decrease. Conversely, ratemaking costs are low relative to marginal costs when older, largely depreciated plant, continue to provide service. A second cause for disparity arises for companies which have yet to exhaust economies of scale. Because the cost of the next unit will be lower than all previous units for such companies, marginal costs must be necessarily lower than average or ratemaking costs. Finally, the manner of capital amortization will act to produce a systematic difference between annual revenues under marginal cost pricing

Ex. AA-D-29

Figure 11-1
SOCIETAL WELFARE



(a) Market Price = Equilibrium Price

(b) Market Price > Equilibrium Pri

(c) Market Price < Equilibrium Price

and conventional ratemaking treatment. In a competitive market, returns to capital assets are based more on the productive output of the asset than vintage. The simplest model assumes no changes in the supply and demand curve over time, leading to constant output and, therefore, constant real amortization of capital assets, often modeled with a real economic carrying charge. In contrast, ratemaking revenues, often based on original cost less accumulated depreciation, reflect the asset's vintage because such conventions produce real ratemaking revenue streams that start high and decline sharply over the life of the capital asset.

Since marginal and ratemaking costs seldom are equal, an allocation based on marginal cost must normally be modified to produce the revenue requirement. Some economists have argued that rates should directly equal marginal costs, with excess revenues taxed away and deficits made up through government subsidy. But this position has never been adopted by any U.S. jurisdiction. The method is also not perfectly accurate because the change in taxes from this strategy will produce an income effect that will change the consumption of all goods, including utility services.

I. REVENUE RECONCILIATION METHODS

Given the need to modify the allocation based on marginal cost to make it conform to the revenue requirement, the practical objectives have been to find modifications which minimize the distortion to the marginal cost price signal without doing any great injustice to normally held views of fairness and equity. Four major approaches, referred to by different names by different experts, have been proposed:

- Ramsey Pricing (Inverse Elasticity Method).
- Differential Adjustment of Marginal Cost Components.
- Equi-proportional Adjustment of Class Marginal Cost Assignments.
- Lump Sum Transfer Adjustment.

The four methods are somewhat interrelated. The first method produces differential adjustments to overall class cost assignments based on relative demand elasticity, while the second method makes differential adjustments to energy, demand, or customer cost components of the allocation based on their relative elasticity of demand. The third can be seen as a special case of Ramsey Pricing where all classes are assumed to have, from a practical standpoint, nearly the same demand elasticities. The fourth method involves directly charging marginal cost prices, and accomplishing revenue reconciliation with a separate rebate or surcharge on customer bills. In allocating the excess or deficit revenues to determine the rebate or surcharge, variations of the other three methods may be used.

The following sections will evaluate these four alternatives with respect to the criteria of efficiency, equity, rate stability, and administrative feasibility. The first method is generally viewed as the most efficient, but empirical problems render it administratively difficult, and it is clearly discriminatory. The second method is efficient, but it leads to rate instability over time because all the adjustments are often made in one rate component. The third method is viewed by many as most equitable. It normally produces the most stable revenue allocation over time, but some argue it is not efficient. The fourth method is the most efficient if there is no direct relationship between usage and the rebate or surcharge. However, without a linkage to usage, customer rebates and surcharges can be perceived as inequitable.

Table 11-1 develops an allocation based on marginal cost with no reconciliation to the revenue requirement. It shows marginal cost revenues, the revenues that would be collected from each class if all rates and charges were set at marginal cost. The allocation in Table 11-1 is subsequently modified in the following four tables to collect an exact ratemaking revenue requirement of $6,222,100,000. Tables 11-2 and 11-3 use inverse elasticity methods, Table 11-4 uses an adjustment to marginal customer cost revenues, and Table 11-5 uses an equi-proportional adjustment for each class.

The estimates in Table 11-1 are probably best regarded as long-run marginal costs since they encompass all elements of incremental service including demand growth and customer additions with investment cost components for capital equipment. Economists will argue that market prices will be determined by short-run marginal costs, and that these represent the most efficient pricing signals. This may be true given a fixed stock of customer electric equipment. However, given time to modify their electrical appliances, long-run cost signals may, in fact, have comparable efficiency. An allocation based on short-run costs will probably be unstable over time since short-run costs tend to be considerably more volatile than long-run costs.

Use of long-run marginal costs in the allocation offers the advantage of stability in customer bills and also sends a price signal that can guide long-term customer investments into energy using equipment. Short-run marginal costs can still be reflected in the final rate design in tailblock energy rates. This allows marginal usage to be priced directly at short-run marginal cost while still permitting bill stability and some signal to guide long-run customer investments, assuming that customers respond to both their total bill as well as their marginal rate.

TABLE 11-1

Ex. AA-D-29

CALCULATION OF MARGINAL COST REVENUES
Marginal Energy Costs

Class	Energy Use (GWH)			Marginal Costs (Cents/KWH)			Marginal Cost Revenues
	On-Peak	Mid-Peak	Off-Peak	On-Peak	Mid Peak	Off Peak	($1000)
	[1]	[2]	[3]	[4]	[5]	[6]	[7]= ([1]*[4]+[2]*[5]+[3]*[6])
Summer Period							
Residential	1454.6	2110.7	3620	4.18	3.00	2.70	221863.2
Commercial	2185.2	2514.1	3430.9	4.17	2.99	2.69	258585.6
Industrial	1478.8	2056.6	3482.4	4.08	2.94	2.64	212734.4
Agricultural	167.9	252.5	496.3	4.18	3.00	2.70	27993.32
Street Lighting	0	26.4	100.3	4.13	2.97	2.67	3462.09
Winter							
Residential	2078.4	2981.7	7414.7	3.68	3.05	2.86	379487.3
Commercial	1832.6	5398.4	6572.9	3.68	3.05	2.85	419418.5
Industrial	2626.4	4205.1	7271	3.57	2.96	2.80	421821.4
Agricultural	119.3	301.8	652.8	3.68	3.05	2.86	32265.22
Street Lighting	49.6	0.2	257.6	3.63	3.01	2.83	9096.58
	Annual Sales By Class			**Annual Average**			
Residential	19660.1			3.058736			601350.6
Commercial	21934.1			3.091096			678004.1
Industrial	21120.3			3.004483			634555.8
Agricultural	1990.6			3.027154			60258.54
Street Lighting	434.1			2.893036			12558.67
Total	65139.2			3.049972			1986727

Marginal cost rates are shown at the level of the system at which the customer takes service. These have been calculated by multiplying marginal costs at the generation level by the appropriate line loss factors to transmission, primary, and secondary distribution levels.

TABLE 11-1 (Continued)

Marginal Demand Costs

Class	Demand (MW)		Marginal Demand Costs ($/KW Year)			Marginal Demand Cost Revenues
	Coincident	Non-Coincident	Generation	Transmission	Distribution	($1000)
	[1]	[2]	[3]	[4]	[5]	[6]= [1]*[3]+[1]*[4]+[2]*[5]
Residential	5,170	5,420	88.32	34.33	41.27	857,803
Commercial	5,735	6,900	87.96	34.19	41.10	984,133
Industrial	3,720	4,332	86.12	33.47	40.24	619,195
Agricultural	420	447	88.32	34.33	41.27	70,016
Street Lighting	6	119	87.36	33.95	40.82	5,606
System average/total	15,052	17,218				2,536,754

Demand Costs are shown for the level at which the customer takes service, reflecting line loss factors.

Generation and transmission demand marginal cost revenues are calculated using LOLP-weighted hourly loads.
The LOLP-weighted loads incorporate not only the group's load during the single hour of the system's coincident peak, but also other high usage hours which impact overall system reliability. LOLP-weighted hourly demands are used to apportion the system's coincident peak load amongst the allocation rate groups.

Distribution marginal cost revenues are based on non-coincident demand, reflecting tge loss of load diversity benefits lower down in the system.

TABLE 11-1 (Continued)

Marginal Customer Costs

Class	Marginal Cost Per Customer ($/customer year)	Number of Customers	Marginal Customer Cost Revenues ($1000)
	[1]	[2]	[3]= [1]*[2]/1000
Residential	76.05	3,209,631	244,092
Commercial	285.75	458,978	131,153
Industrial	2970.31	2,421	7,191
Agricultural	540.09	26.635	14,385
Street Lighting	1723.39	19,974	34,113
System averge/total	115.92	3,717,459	430,935

Customer related access equipment is estimated as the costs of typically sized final line transformers, service drops, and meters (T-S-M). Street Lighting investments, in addition, include poles, brackets, and luminaires.

Investment costs are annualized by a real, or economic carrying charge rate (RECC) which amortizes the investment in a level stream of constant value dollars: equivalent to a nominal value dollar stream rising at the rate of inflation.

TABLE 11-1 (Continued)

Marginal Cost Revenue Summary ($1000)

Class	Energy	Demand	Customer	Total
Residential	601,351	857,803	244,092	1,703.246
Commercial	678,004	984,133	131,153	1,793,290
Industrial	634,556	619,195	7,191	1,260.942
Agricultural	60,259	70,016	14,385	144,660
Street Lighting	12,559	5,606	34,113	52,278
System Total	1,986,728	2,536,754	430,935	4,954,417

A. Inverse Elasticity Method

Ramsey Pricing, often referred to as inverse elasticity pricing, attempts to produce an approximation of the pattern of demand that would exist under direct marginal cost pricing. It does so by distributing system excess or deficit revenues, relative to marginal cost revenues, in an inverse relationship to a customer's elasticity of demand. By selectively loading excess or deficit revenues on customers whose demands are relatively insensitive to price, the overall level and interclass pattern of demand will deviate the least from direct marginal cost pricing. Those users who are most likely to modify their usage of society's scarce resources in response to price will be charged a price closer to the opportunity cost to society of scarce resources (marginal cost). Those consumers who are least likely to respond to price changes are charged prices which deviate the most from marginal costs.

The equational form of the rule is commonly expressed in either of two ways. The exact expression of the Ramsey pricing principle is achieved by setting the difference between the average price (P_i) for an allocation class and its marginal cost (MC_i), relative to its price, inversely proportional to the price elasticity of demand (E_i):

$$\frac{P_i - MC_i}{P_i} = \frac{K_a}{E_i} \quad \text{or,} \quad P_i = \frac{MC_i}{1 - \frac{K_a}{E_i}}$$

K_a is a constant necessary to reconcile the sum of class allocated revenues to the system ratemaking revenue requirement. The equation for K_a is a polynomial expression requiring iterative successive approximations. Table 11-2 provides an example.

To avoid a problem requiring iterative approximation, a Quasi-Ramsey price formula is frequently used. The equation is specified such that the difference between price and marginal cost, relative to marginal cost, is inversely proportional to elasticity:

$$\frac{P_i - MC_i}{MC_i} = \frac{K_b}{E_i} \quad \text{or,} \quad P_i = MC_i\left(\frac{K_b}{E_i} + 1\right)$$

A direct solution can be obtained for the system constant K_b. Table 11-3 gives an example.

The Quasi-Ramsey price equation is an approximation of the theoretically correct specification of the rule. It is simpler to solve than the theoretically correct equation and the level of error introduced by this approximation is allegedly of the same order of magnitude as the errors of measurement inherent in the other parameters such as elasticity estimates. It does not appear, however, that sufficient analysis has been performed to determine whether the level of error is acceptable. Problems in applying the inverse elasticity rule are discussed in greater detail in NARUC's Electric Utility Rate Design Study #69, Appendix A.[1]

Ramsey Pricing can be said to be efficient in that it deviates the least from an allocation of resources that would be produced under pure marginal cost pricing. If it results in higher prices for customers with low elasticities, the prices still reflect the greater value they receive. This is because customers with inelastic demand curves, either because their options are fewer or they have greater need for the service, derive greater consumer surplus. Conversely, if capacity shortages cause marginal costs to exceed average cost, charging customers with more options higher prices will force them to exercise those options; thereby, relieving capacity shortages. Nevertheless, Ramsey Pricing can be considered inequitable since it charges different customers different prices for the same product, based on value of service principles.

There are also a number of practical problems in applying Ramsey Pricing. The data related to elasticities and demand functions needed to apply the method are contestable or, in some jurisdictions, unavailable. Quantitative application of the method requires solving a system of equations, the data for which are not available.[2] Furthermore, elasticities may vary greatly over a small range of demand if closely priced substitutes or alternative sources of supply (cogeneration) are available, creating instability in the allocation over time. Finally, the variance in the demand elasticities between individual customers within a class may exceed the variance in the aggregate class demand elasticities on which the allocation is based. Thus, Ramsey Pricing would not produce the desired pattern of consumption of resources at the individual customer level without charging a different price to each customer based on the customer's elasticity.

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[1]Gordian Associates, Inc., An Evaluation of Reconciliation Procedures for the Design of Marginal Cost-Based Time-of-Use Rates, Electric Rate Design Study #69 (New York, November 7, 1979).

[2] See Ibid., Appendix A.

TABLE 11-2

EXACT RAMSEY PRICE REVENUE ALLOCATION
(Marginal Cost Revenue Allocation By Inverse Elasticity Rule)

Class	Sales (GWH)	Elasticity of Demand (E)	Inverse Elasticity (1/E)	Maringal Cost Revenue ($1000)	Ramsey Price Revenue ($1000)	(Ramsey - Marginal Cost) / Ramsey	Ramsey Price To I nverse Elasticity Ratio	Average Rate cents/KWH
	[1]	[2]	[3]	[4]	[5] = [4] / (1-(Ka/[2]))	[6] = ([5]-[4]/[5])	[7] = [6]/[3]	[8] = [5]/([1]*10)
See Footnote								
Residential	19,660	1.12	0.89	1,703,246	2,145,964	0.20630277	0.2310591	10.92
Commercial	21,934	1.23	0.81	1,793,290	2,208,085	0.18785293	0.2310591	10.07
Industrial	21,120	1.05	0.95	1,260,942	1,616,709	0.22005629	0.2310591	7.65
Agriculatural	1,992	1.05	0.95	144,660	185,475	0.22005629	0.2310591	9.31
Street Lighting	434	1.12	0.89	52,278	65,866	0.20630277	0.2310591	15.17
System avg/total	65,140			4,954,416	6,222,100		Ka= 0.2310591	9.55

Starting with the exact Ramsey Price equation, $(P_i-MC_i)/P_i= Ka/E_i$, prices are first converted to revenues and the equation is simplied to the form; Ramsey Rev. i= MC Rev. i/(Ka/E_i). The constant Ka, which will reconciled marginal costs and the system ratemaking revenue requirement, RR can be estimated by successive approximations to the equation;

$$RR - \sum_{i=1}^{i=n} \{MC\ Rev.i/(1-Ka/E_i)\}=0$$

In the example: 6,222,100-{1,703,246/(1-Ka/1.12)+1,793,290/(1-(Ka/1.23).....+ 52,278/(1-Ka/1.12)}= 0 with Ka= 0.231059.

Note that the Ka factor is equal to the relative difference between Ramsey Price and Marginal Cost Revenues divided by the inverse of the elasticity coefficient (See column [7]). The ratio is the same for all classes idicating that exact Ramsey Pricing has been achieved.

TABLE 11-3

QUASI-RAMSEY PRICE REVENUE ALLOCATION
(Marginal Cost Revenue Allocation By Approximate Inverse Elasticity Rule)

Class	Sales (GWH)	Elasticity of Demand (E)	Inverse Elasticity (1/E)	Marginal Cost Revenue ($1000)	Quasi-Ramsey Price Revenue ($1000)	(Ramsey - Marginal Costs) / Ramsey	Ramsey Price To Inverse Elasticity Ratio	Average Rate cents/KWH
	[1]	[2]	[3]	[4]	[5] Kb * ([4] / [2]) + [4]	[6] [5] - [4]) / [5]	[7]= [6] / [3]	[8]= [5] / ([1] * 10)
Residential	19,660	1.12	0.89	1,703,246	2,144,999	0.20594560	0.230659074	10.91
Commercial	21,934	1.23	0.81	1,793,290	2,216,802	0.19104638	0.234987042	10.11
Industrial	21,120	1.05	0.95	1,260,942	1,609,782	0.21670008	0.227535084	7.62
Agricultural	1,992	1.05	0.95	144,660	184,680	0.21670008	0.227535084	9.27
Street Lighting	434	1.12	0.89	52,278	65,837	0.20594560	0.230659074	15.17
System avg/total	65,140			4,954,416	6,222,100		Kb= 0.290482711	9.55

Starting with the Quasi-Ramsey Price formula, $(P_i\text{-}MC_i)/MC_i=Kb/E_i$, prices are converted to revenues , and the equation is rearranged to give the class Ramsey Price Revenue expression; P_i Rev.= Kb*(MC Rev. i/E_i)+MC rev.i.

Summing later expression over the "i" rate classses, a constant Kb can be found which will reconcile the marginal cost and ratemaking revenue requirement, RR, as follows:

$$Kb = (RR\text{-}\sum_{i=1}^{i=n} \{MC\ Rev.i\})/\sum \{MC\ Rev.i/E_i\}$$

In the example, Kb= (6,222, 100-4,954,416)/ ((1,703,246/1.12)+(1,793,290/1.23)....+(52,178/1.12)) = 0.29048

Note that in colum [7] the ratios vary amongst the rate classes, reflecting the fact that the deviations from marginal cost pricing are not exactly proportional to the inverse of the elasticity coefficients.

B. Differential Adjustment of Marginal Cost Components

This method makes differential adjustments to various marginal cost components primarily based on the elasticity of demand with respect to changes in the price of that component. It is generally alleged that the marginal customer cost component has the lowest elasticity. Sometimes, all reconciliation is made in the marginal customer cost component, and this approach has been called the "customer cost giveback" approach when marginal cost exceeds average cost.[3]

Ideally, this method offers the opportunity for the most efficient allocation by differentiating class revenue assignments by not only class elasticity of demand but also by elasticities for the individual components of energy, demand, and customer access. Since no data exist differentiating elasticities by rate component by class, this method only operates in practice by accomplishing reconciliation in what are believed to be the least elastic rate components (e.g., customer costs) without asking whether these elasticities differ by class. As such, the practical application of this method is generally only a very crude approximation of Ramsey Pricing.

In general, this method can be considered inequitable because of the varying size of the customer cost component relative to other marginal cost components for different customers. The customer cost component tends to be larger relative to the other components for small, low-use customers. Thus, small customer rates are increased when marginal costs exceed average costs and decreased when the opposite occurs. In states with lifeline or baseline requirements that set the residential first block rates below cost, this method can result in very high tailblock rates when average cost exceeds marginal cost. The cost allocation can also be very unstable over time with this method. But the method is easier to implement than Ramsey pricing if it is done without explicit elasticity data.

[3] Gordian Associates, *op. cit.*, pp. 24-26.

Table 11-4 illustrates the method by applying all the reconciliation adjustments to the customer cost component of the allocation. Since it was necessary to increase the size of the customer cost component several times to fill the gap between marginal cost revenues (Table 11-1) and the revenue requirement ($6.22 billion), the impact of this method on smaller customers is significant.

C. Equi-proportional (Percentage) Adjustment of Class Cost Assignments

This method entails increasing or decreasing marginal cost revenues for each class by the same proportion to conform the allocation to the ratemaking revenue requirement. It has been called Equal Percentage of Marginal Cost where a simple multiplier is applied to the allocation to each class to achieve the reconciliation.

The method is arithmetically simple. It is also viewed as highly equitable by those who see equity as relating to the costs a customer imposes on the system at the margin. It is also the most stable over time because it is not sensitive to changes in elasticities, and it is only somewhat sensitive to changes in the sizes of the marginal cost components relative to each other over time.

The method can be criticized as being less efficient than Ramsey Pricing or Differential Component methods which are based on elasticities of customer groups or marginal cost components. This criticism is perhaps less valid if the Equal Percentage method is seen as a special case of Ramsey pricing used in elasticities, and it is only somewhat sensitive to changes in the sizes of the marginal cost components relative to each other over time.when class elasticity data is so poor or intra-class variations in elasticity are so high that applying existing data in the allocation would result in an even more distorted allocation than merely assuming all customer classes have equal elasticities. Whether Ramsey pricing (using differing elasticities) is the proper model for a competitive market is also debatable. Such market differentiation is only successful where sufficient competition does not exist to eliminate price discrimination. Furthermore, the Equal Percentage method may better reflect the long-run tendencies of a private market. When no surpluses or deficits exist, marginal costs will equal average cost and all customers can be charged marginal cost without market differentiation. The EPMC multiplier aims to set marginal cost revenues equal to the revenue requirement (analogous to average cost) without differentiating rates between consumer groups as Ramsey Pricing does or between products (energy, demand, customer access) as the Differential Cost Adjustment method does.

TABLE 11-4

DIFFERENTIAL ADJUSTMENT OF MARGINAL COST COMPONENT ALLOCATION
(Least Elastic Component, Marginal Customer Cost, Adjusted To Meet The Revenue Requirement)

		Marginal Cost Revenues						
Class	Sales (GWH)	Energy ($1000)	Demand ($1000)	Customer ($1000)	Total Marginal Costs ($1000)	Adjusted Customer Costs ($1000)	Final Allocation ($1000)	Average Rate cents/KWH
	[1]	[2]	[3]	[4]	[5] [2]+[3]+[4]	[6]= [4]*K See Footnotes	[7] [2]+[3]+[6]	[8]= [7] / ([1]*10)
Residenital	19,660	601,351	857,803	244,092	1,703,246	962,141	2,421,295	12.32
Commercial	21,934	678,004	984,133	131,153	1,793,290	516,967	2,179,104	9.93
Industrial	21,120	634,556	619,195	7,191	1,260,942	28,345	1,282,097	6.07
Agricultural	1,992	60,259	70,016	14,385	144,660	56,703	186,977	9.39
Street Lighting	434	12,559	5,606	34,113	52,278	134,463	152,627	35.16
System avg/total	65,140	1,986,728	2,536,754	430,935	4,954,417	1,698,618	6,222,100	9.55

In this allocation the least elastic element of service, marginal customer costs, are proportionally scaled to meet the ratemaking revenue requirements. This sort of allocation can result in extreme instability particularly for rate classes where customer costs constitute a large fraction of the total cost of service. For example, see Street Lighting, where the average rate is more than double that obtained by other allocation methods. The basic reason for rate instability is due to the fact that customer costs are often more highly differentiated amongst the rate classes than either energy or demand costs. Hence, the scaling of marginal customer costs, up or down, to meet the revenue requirement, can produce disappropriate changes in class average rates.

The constant K needed to scale marginal customer to meet the rate making revenue requirement, RR, may be determined as follows:

K= 1+(RR-System Total MC Rev.)/System Marginal Customer Cost Rev.

In the example: K= 1+(6,222,100-4,954,417)/430,935 = 3.9417

Table 11-5 provides an illustration of the Equal Percentage method. The method is less severe than either of the previous two methods in the sense that it produces a lesser degree of rate spread between allocation classes.

D. Lump Sum Transfer Adjustment

The Lump Sum Transfer Adjustment method involves setting all rates to marginal cost and making up the difference between the revenue requirement and marginal cost revenues through a surcharge or rebate added to the bill. The key objective is to design this surcharge or rebate so that it will not influence usage, which would itself interfere with the marginal cost price signal.

Conceivably, there are many ways to distribute a rebate or surcharge. One proposal is to allocate an amount to each class equi-proportional to its marginal cost revenues, but to distribute within the class on an equal dollar per customer basis.[4] This will allow the rebate or surcharge to bear some resemblance to usage, but the resemblance is only approximate because of the per customer allocation within classes. The link between the rebate or surcharge and usage can be further reduced by basing the allocation of the difference between the revenue requirement and marginal cost revenues on relative class marginal cost revenues from a previous period. It is reasonable to surmise that the actual cost allocation resulting from this method, regardless of how it is collected, will be similar to what would result from the Equal Percentage method.

The main disadvantage of customer rebates and surcharges is that customers who are not familiar with the rate structure may react more to the overall bill than to the rates for incremental usage. Another disadvantage is that, as the link between usage and the rebate or surcharge is reduced, the perceived fairness of the method is decreased. Both these shortcomings can be mitigated by taxing or subsidizing the utility. This approach has never been used in any U.S. jurisdiction but is superior to accomplishing the reconciliation with utility rebates or surcharges to its customers. This method of taxing or subsidizing utilities has been used in Europe where utilities are nationalized. Theoretically, it could be implemented in municipal utilities in the U.S. which are owned and operated by local governments.

[4] Gordian Associates, *op. cit.*, pp. 31-33.

TABLE 11-5

EQUI-PROPORTIONAL ADJUSTMENT TO CLASS MARGINAL COSTS

(Equal Percentage of Marginal Cost Allocation)

		Marginal Cost Revenues					
Class	Sales (GWH)	Energy ($1000)	Demand ($1000)	Customer ($1000)	Total Marginal Costs ($1000)	Final Allocation ($1000)	Average Rate cents/KWH
	[1]	[2]	[3]	[4]	[5]= [2]+[3]+[4]	[6]= K*[5]	[7]= [6]/ ([1]*10)
Residential	19,660	601,351	857,803	244,092	1,703,246	2,139,055	10.88
Commercial	21,934	678,004	984,133	131,153	1,793,290	2,252,138	10.27
Industrial	21,120	634,556	619,195	7,191	1,260,942	1,583,579	7.50
Agricultural	1,992	60,259	70,016	14,385	144,660	181,674	9.12
Street Lighting	434	12,559	5,606	34,113	52,278	65,654	15.12
System average/total	65,140	1,986,728	2,536,754	430,935	4,954,417	6,222,100	9.55

The proportional constant K= (System Revenue Requirement/System Marginal Cost Revenues).

In the example: K= (6,222,100/4,741,996)= 1.2558693

II. CONCLUSION

All the described methods for reconciling marginal cost and ratemaking revenue requirements have strengths and weakness. No single method emerges as clearly superior in every respect and in all cases. The best choice will be controlled by the circumstances surrounding the specific utility in question. Table 11-6 provides a numerical comparison of the various reconciliation methods. Note that the Equal Percentage method results in the least degree of rate spread between the allocation classes.

TABLE 11-6

COMPARISON OF MARGINAL COST BASED REVENUE ALLOCATION RESULTS
(Class Average Rates, cents/KWH, to Collect the Ratemaking Revenue Requirement)

	Exact Ramsey Pricing	Quasi-Ramsey Pricing	Differential Adjustment-Customer Costs	Equi-Proportional Method
	[1]	[2]	[3]	[4]
Residential	10.92	10.91	12.32	10.88
Commercial	10.07	10.11	9.93	10.27
Industrial	7.65	7.62	6.07	7.50
Agricultural	9.31	9.27	9.39	9.12
Street Lighting	15.17	15.17	35.16	15.12
System Average	9.55	9.5	9.55	9.55

Where the utility's resource mix is nearly optimal without serious shortages or surpluses, improvements in efficiency may not be critical. The use of long-run marginal costs and the equal percentage of marginal cost revenue allocation method may be preferable in such situations. Short-run marginal costs would be primarily useful in designing specific rate components, particularly tail block energy rates. If equilibrium conditions result in marginal and ratemaking costs being nearly equal, use of a Ramsey Pricing method would produce results similar to an Equal Percentage method.

Conversely, where a utility's resource mix is suboptimal with significant capacity imbalances, the efficiency criteria may outweigh the problems of data acquisition, rate discrimination and sharp rate realignments associated with Ramsey Pricing or related methods using elasticity of demand. Sharp rate realignments to existing customers can be mitigated by allocating costs to existing sales using an Equal Percentage method and by limiting rate discounts or penalties based on demand elasticities only to clearly incremental sales or sales that could be lost to customer self-generation. Capacity surpluses can result in retail rates significantly higher than both the utility's marginal cost and the cost of self-generation, creating a threat of customer bypass. Extending rate discounts to customers or classes with high self-generation potential, even if it requires increasing the rates of more captive customers, can be more beneficial to captive customers than allowing potential self-generators to bypass the utility system, leaving the responsibility for covering fixed costs entirely to the remaining customers.

Though all these methods are second best solutions to direct marginal cost pricing, the system average rate can be brought closer to marginal cost in situations of substantial excess capacity through disallowances. If this is not possible, major rate realignments must be phased-in over several rate periods. Regulatory authorities, which must balance the welfare of the entire ratepayer population against that of significant individual customer groups, are often concerned with "rate shock". Rate shock can be moderated by limiting or capping class revenue assignments to produce changes in the class average rate deemed acceptable. Another method is to weight the system average rate change with the rate change suggested by the economically desired allocation, which will produce a partial approach to the latter.

APPENDIX A

DEVELOPMENT OF LOAD DATA

The allocation of demand-related costs cannot be accomplished without determining, by some means, the demands of the various rate classes and their interrelationships with a utility's total system demand. Since demand-related costs constitute a large portion, if not a majority, of a utility's fixed costs, it is important that the means of determining these demands for a utility yield accurate results. The way a utility often estimates these demands is to conduct periodic research studies of its load.

Load research studies require sampling of customers in those rate or customer classes where it is too expensive to have time-recording meters on all customers. Time-recording meters are installed on the sample of customers selected for each class. The load data collected for the sample of a class is then used to estimate statistically the demands of that class by hour or for designated hours. If the test year of the cost of service study does not coincide with the year (or period) for which the load research was collected, demands for the test period will have to be estimated using load factors estimated from the load study or perhaps by using a model that estimates weather and customer mix changes over time.

This appendix will be divided into four sections consisting of the various phases of a load research study: (1) design of study; (2) collection of data, including installation of meters; (3) estimation of historic loads by class; and (4) use of data, including the projection of class demands for future test years.

Reference will be made throughout this appendix to the term "rate class", which will mean all customers served on a particular rate by that utility. One exception to this is the possible inclusion, for load study purposes, of one or more smaller rates from the standpoint of number of customers or kilowatt-hour use with a larger rate to be considered as a single rate class. Since load studies are essential for the allocation of costs, and it is most meaningful to spread or collect costs by rate classes, the term "rate class" or "class" will be used here accordingly.

Statistical inference is not possible for data collected for judgmental or purposive samples because there is no statistical basis or theory for measuring the precision or reliability of results of judgmental sampling. Since one cannot objectively measure the precision of the demands calculated from judgmental sampling, judgmental sampling should not be used for load research studies. Therefore, this appendix will discuss only probability sampling. In probability sampling, all members of a class have a known, nonzero probability of selection into the sample. The nonzero probability of selection is a consequence of an objective, random procedure of selection.

I. DESIGN OF STUDY

A. Data to be Obtained

The first step in a load study is to determine the load data which must be obtained. The particular methodologies selected for allocating production, transmission and distribution plant will determine the specific load data needed for the cost of service study. In addition to its essential need for cost of service studies, load data is useful in (1) designing rates; (2) evaluating conservation measures; (3) forecasting system peaks; and (4) marketing research studies. Generally, the following data is of interest for cost allocation and design of rates.

1. **Coincident Demand (system peak hours).** This is the demand of a rate class at the time of a specified system peak hour(s).

2. **Class Noncoincident Demand (class peak).** This is the maximum demand of a rate class, regardless of when it occurs.

3. **Customer Noncoincident Maximum Demand (nonratcheted billing demand).** For an individual customer, this is simply the maximum demand during the month for that customer. For the rate class, it is the sum of the individual customer maximum demand regardless of when each customer's maximum demand occurs.

4. **Coincident Factor.** This is the ratio of the coincident demand of a class to either its customer summed noncoincident maximum demands or class noncoincident demand (class peak). It is the percent of class or customer maximum demand used at the time of the system peak. As defined, this can never be greater than unity.

5. **Diversity Factor.** This is the reciprocal of the coincidence factor and is not used as frequently in load study analysis as the coincidence factor. It reflects the extent to which customers or classes do not demand their maximum usage at the same time. As defined, this can never be less than one.

6. **On-peak and Off-peak Kilowatt-Hours.** These are defined as the kilowatt-hours of energy consumed by each class during the on-peak and off-peak periods. These energy values are necessary to allocate energy-related costs in a time-of-use cost of service study and to design time-of-use rates utilizing on-peak and off-peak energy prices.

7. **Load Factor.** This is the ratio of the average demand over a designated time period to the maximum demand occurring in that period. This term can refer to a customer, rate class or the total system. It is a measure of the energy consumed compared to the energy that would have been consumed if the group or customer had used power at its maximum rate established during the designated time period.

B. Selection of Design Precision

Precision expresses how closely the estimate from the sample is to the results that would have been obtained if measurements had been taken on all customers in the class. In order to assure perfect precision for each class demand determined in a load study, it would be necessary to meter individually every customer in every class. In spite of seeming far-fetched, metering every customer may be a desirable method for a class where the customers are large in size, limited in number and individually very different or highly variable. It is frequently practical, for example, to meter every customer over 800-1000 KW in maximum demand. Where large numbers of customers and smaller loads are involved, it becomes necessary to select a sample group of customers for each rate class to be studied.

Precision is the inverse of sampling error. Suppose you decide to select a sample of 275 customers from the residential class using a table of random numbers. The random numbers you use, and hence the customers you select, and the estimate you obtain will all vary with each application of the procedure. The variation this introduces into your sample-based estimate is called the sampling error of your estimate. The smaller the sampling error of your estimate, the closer the estimate is likely to be to the result that would have been obtained if measurements had been taken on the entire rate class. The size of the sampling error varies proportionately with the standard deviation of the population and inversely with the size of the sample. (The standard deviation is a measure of the variation in the population measurements on the variable under study.) Figure A-1 shows the relationships of the distribution of the customer demands (entire population) and the distribution of sample estimators of class demands.

Sampling error can be measured in standard errors. For example, if a simple random sample of 275 residential customers was taken from a population with a standard deviation of 2.23 kilowatts (KW), then the standard error of the per customer demand would be $2.23 \div \sqrt{275} = .13$. We could then say that approximately 68% of our estimates would be within one standard error, or .13 of the per customer demand of the entire class, and about 95% of our estimates would be within two standard errors.

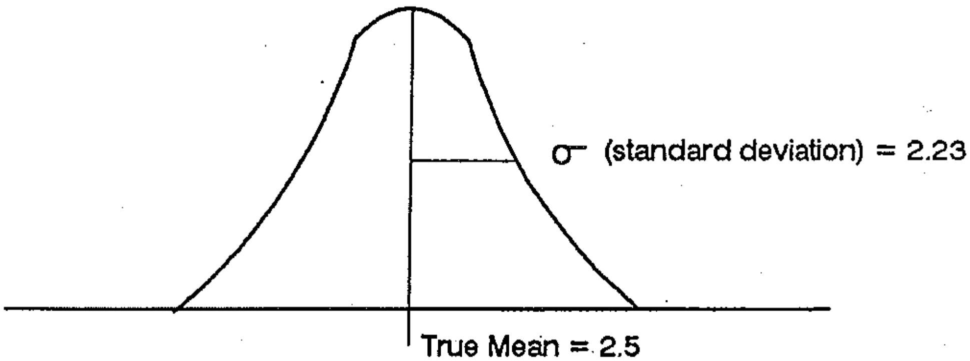
A confidence interval around an estimate is an interval which is designed to contain the class measured demand a specified percentage of the time. For example, an interval of two standard errors on each side of the estimated demand is approximately a 95% confidence interval. This means that if we hypothetically repeated our sampling procedure with new customers each time, about 95% of these calculated intervals around our estimates would enclose the actual class per customer demand. Thus, if our estimated demand were 2.96 KW per residential customer, we would be 95% confident that the interval 2.70 to 3.22 for our residential sample of 275 customers contains the actual class demand per customer. (Confidence interval = $\bar{x} \pm t_p$ (SE $(\bar{x})$; where t_p is a normal deviate which is set at the level of confidence one wants to use. This example is using 95% confidence or $t_p \simeq 2$. Therefore, the confidence interval is $2.96 \pm 2 \times .13$.)

The above confidence interval can be interpreted that our estimates are within ±.26 KW of the true per customer demand for 95% of all possible samples. This .26 KW might be satisfactory precision if the true demand were 2 KW but not if it were 1 KW. In the former case, the relative precision would be $\pm 100 \times (.26 \div 2)$ or $\pm$ 13%; in the latter case 100 $(.26 \div 1)$ or $\pm$ 26%. (Relative precision = 100 [2 x SE $(\bar{x})$/true per customer demand].) Relative precision expresses sampling error relative to the magnitude of the quantity being estimated. Load researchers generally prefer to choose their sample size on a specified relative precision rather than absolute precision because one relative precision level can be used for classes with very different demands. (Load researchers tend to use the terms accuracy or relative accuracy interchangeably when referring to relative precision of the sample design). However, accuracy refers to nonsampling errors in addition to the sampling errors that we have been discussing.) Sampling error can be reduced to zero by measuring all members of a class, but there can still be nonsampling errors such as meter malfunction, damage to meters, lost tapes and errors in tape translations. For example, if all the meters for a 100% time-recorded class measured .5 KW low, the relative precision of the mean demand estimate would be zero percent error but the accuracy would be minus .5. If the true demand were 2, the relative accuracy would be 100 [(1.5-2)/2] or -25%.

Many commissions require samples to be designed to yield estimates of peak hour demands with a relative precision of plus or minus 10% at a 90% confidence level. This is the standard established by the Federal Energy Regulatory Commission in its implementation of the Public Utility Regulatory Policies Act of 1978.

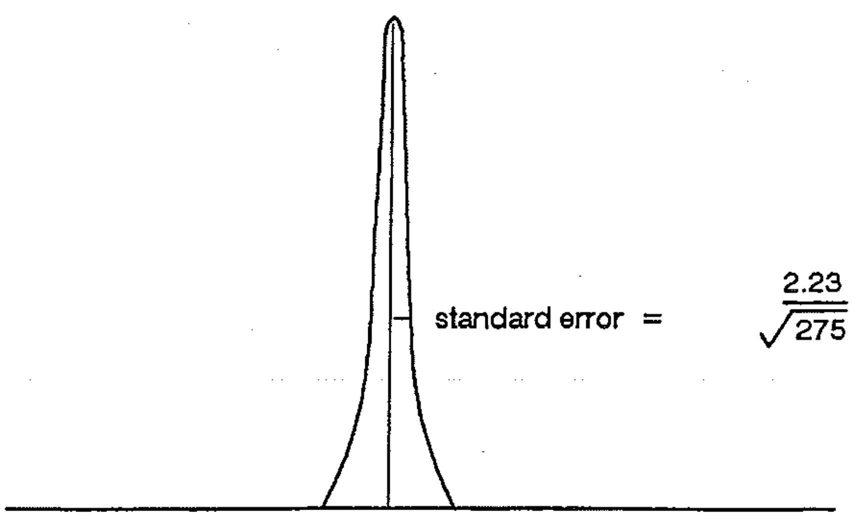
FIGURE A-1

DISTRIBUTION OF CUSTOMER DEMANDS AND AN ESTIMATOR OF CLASS DEMAND



Population of all demand measurements for the hour of interest.

Sample 1	$\bar{x} = 2.3$
Sample 2	$\bar{x} = 2.7$
Sample 3	$\bar{x} = 2.6$
⋮	⋮



Sampling distribution of $\bar{x}$'s.

C. Design of Sample

The precision of the demands estimated from a sample depends not only on the sample size, but also on the methods used to select the sample (i.e., the sample design) and the statistical procedure used to estimate demands. The primary aim of sample design is to choose the sample design with the smallest error. Two methods of random or probability sampling are used widely to select samples of rate classes: (1) simple random design; and (2) stratified sampling design.

In simple random sampling *n* (equal to the desired sample size) random numbers are taken from a table of random numbers with equal probability. These *n* selected random numbers then identify the customers (or premises) on the frame (numbered listing of all customers in the rate class) whose listing number corresponds to the selected random numbers. These identified customers constitute the selected sample. In simple random sampling each combination of *n* elements has the same chance of being selected into the sample as every other combination.

In a stratified sampling design the rate class is divided into distinct subgroups, called strata, on the basis of kilowatt-hour use or maximum demand. Within each stratum, a separate sample is selected using either simple random sampling or systematic random sampling,[1] most often the latter method. The primary reason for using stratification is to decrease the sampling error and thus increase the precision of the estimate. The use of stratification thus reduces the sample size needed for a specified level of relative precision. The increase or reduction in sample size for a set level of precision will depend on (1) how well the selected strata breakpoints decrease variability of demand within strata relative to the entire class; and (2) the allocation of the overall sample points to individual strata. Another reason for stratification might be to establish subgroups or domains which are of special interest. For example, customers in a metropolitan area may have special interest due to a proposed conservation of marketing program.

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[1]Systematic Random Sampling is an alternative to simple random sampling where by every Kth unit after a random start is selected. This method of probability sampling is commonly used in selecting customers for load studies due to its adaptability to computer selection from the company's billing records. Furthermore, systematic sampling yields a proportionate sample with respect to any ordering in the population. For example, if customers are listed by geographic region, a systematic sample will yield the same proportion of sample customers from each region. However, if the listing of customers reflects a trend or pattern in kilowatt-hour consumption or billing demand, the listing should be shuffled in some manner or the application of systematic sampling modified. (Statistics textbooks will discuss suggested modifications.) Systematic sampling is often used in conjunction with stratified sampling.

Since stratification will almost always be used in selecting samples of rate classes for load studies, the remainder of this appendix will discuss the development of the design of a stratified sample.

1. Analysis of Old Load Data and Customer Information on the Books and Records

Since the purpose of stratification is to reduce the sampling error by making the strata as homogeneous as possible on the particular hourly demands to be used in the cost study to allocate production plant, load data from past studies should be analyzed by class to identify all possible stratification variables. The variables under consideration for the stratification variable must have measurements in the billing or accounting records for every customer in that class. Correlations should be run for a number of variables, such as average monthly energy for twelve months, winter months, summer months, a combination of winter summer months and billing demand.

2. Selection of Stratification Variable

The correlation analysis will identify those variables which are most highly correlated with the demands to be estimated. The following steps are usually employed in the selection of the stratification variable:

- Choose possible stratification variable (from those variables which have higher correlations and have measurement values for most customers)
- Select tentative strata breakpoints
- Make a rough sample size calculation
- Allocate sample points to strata using Neyman allocation
- Check sample size calculation
- Try another design

In calculating the required sample size for a stratified sample, the standard deviation of the demand to be estimated must be used. Often the standard deviation of the variable of stratification is used erroneously. This will lead to sample size estimates that may be too small by an order of magnitude. Since the standard deviation of these demands for the entire rate class is unknown, an estimate from past load research for the class should be used. If no prior load research data is available, an estimate based on load research from a neighboring or similar utility should be used. After calculating the sample size for the possible stratification variables, determine which variable(s) requires the smallest number of sample points for at least the summer peak and winter peak hours.

In two-dimensional designs, each customer has two numbers assigned to him for stratification purposes. Two-dimensional designs are recommended for rate classes with a seasonal pattern of energy and when estimated demands in more than one peak hour are important (i.e., peak winter and peak summer demands are both important). This is because the two-dimensional design is most likely to group together premises of similar load pattern rather than premises similar on a single design hour. Thus, the design can be expected to yield more precise estimates for various peak hours for a given sample size or reduce the sample size required for a given level of precision. A commonly used two-dimensional design for residential and small general service samples is winter month(s) consumption (high and low) and summer month(s) consumption (high and low).

A small but growing number of load researchers are advocating the use of model-based sampling plans to determine the best stratification structure and overall sample size. A model-based sampling plan as now advocated generally uses more strata than traditional methods and allocates equal sample points to each strata. While this approach is somewhat more complicated than traditional methods, one researcher has found a five to six percent saving in required sample size over more conventional methods now in use.

3. Selection of Strata Breakpoints

After determining the stratification variable(s), the dimension of the plan, and the number of strata to be employed, a decision must be made on how to "cut" the stratification variable(s) to form strata. In the past, most load researchers have used the Dalenius-Hodges procedure [1951, 1957] to determine costs which in theory minimize the variance (yield the most precise estimate of demands) when used in conjunction with the Neyman procedure for allocating the number of sample points to strata.

There are several problems associated with the use of this procedure. First, it assumes that a mean per unit estimator is employed in the estimation process while almost all load researchers use the ratio estimator. Second, it involves unrealistic assumptions regarding the knowledge and form of the distribution of the demands to be estimated. Third, the procedure does not produce near optimal breakpoints when, as is generally true, the within-strata correlations are made. Thus, the Dalenius-Hodges technique should be considered only a rough guide in developing stratum cuts.

When developing the stratification strategy for a rate class with a small number of very large customers, a considerable reduction in standard error may be achieved by metering all these very large customers. This is because there is no contribution to the sampling error from any stratum that is 100% metered.

4. Determination of Sample Size

The size of sample required to achieve a specified precision with a specified level of confidence for a particular sample design is calculated using statistical formulas. The statistical formulas to calculate that sample size depend on the form of the estimator (i.e., ratio, mean per unit, or regression) since each estimator calculates variances or standard deviations differently. The sample size calculated will not assure that the specified level of accuracy will in fact be attained; it is a suggested guide. As mentioned previously, in calculating the required sample size, the estimate of standard deviation for the demand allocator in the cost of service study (i.e., the variable of interest) must be used, not the standard deviation of the stratification variable. If more than one hour is of interest, the required sample size should be calculated for various hours of interest from different seasons and the largest indicated sample size should be used. Since with many meter and recorder technologies there will often be missing data, the required sample size that has been calculated should be inflated by the usual percentage of missing data so that the expected number of good measurements will approximately equate to the required number of sample measurements. If there is a pattern to meter failure which is related to demand, bias (loss of accuracy) will result.

The question arises as to whether the sample size should also be inflated to account for customer refusals and sites where a load research meter cannot be installed. It is extremely important to develop field procedures which will keep non-response as small as possible because every non-response is a contributor to bias. There are generally two approaches to selecting alternate sample units for customers who refuse or for whom the meter cannot be installed. The first approach is to increase the calculated sample size to compensate for the expected loss of prime sample points and the second is to use a model to select alternates for each prime. The first method only compensates for the loss of precision due to a reduced sample size but does not address the bias caused by failing to measure certain types of customers. In the latter approach, a list of candidates located on the same or adjoining meter reader routes and having similar usage patterns is sometimes developed for each customer that cannot be used. From the list of suitable candidates for each sample prime customer lost, an alternate is selected randomly. This approach does not, however, totally eliminate the bias caused by non-response.

In stratified designs the sample points are generally allocated to strata where most of the variability exists. This method of allocation (sometimes called optimal allocation) is used to increase the precision of the sample or minimize the cost for a fixed level of precision. Generally, load researchers employ a form of optimal allocation called Ney-

Ex. AA-D-20

man allocation, which maximizes the precision of the sample. A sample allocated in proportion to the number of customers is essentially equal to a simple random sample. The preferred minimum number of observations per stratum is approximately thirty so that the normal distribution assumption involved in the statistical estimation procedure can be expected to be met approximately. If domain analysis will be done with the strata, the minimum sample size per stratum should be increased.

D. Form of Estimator

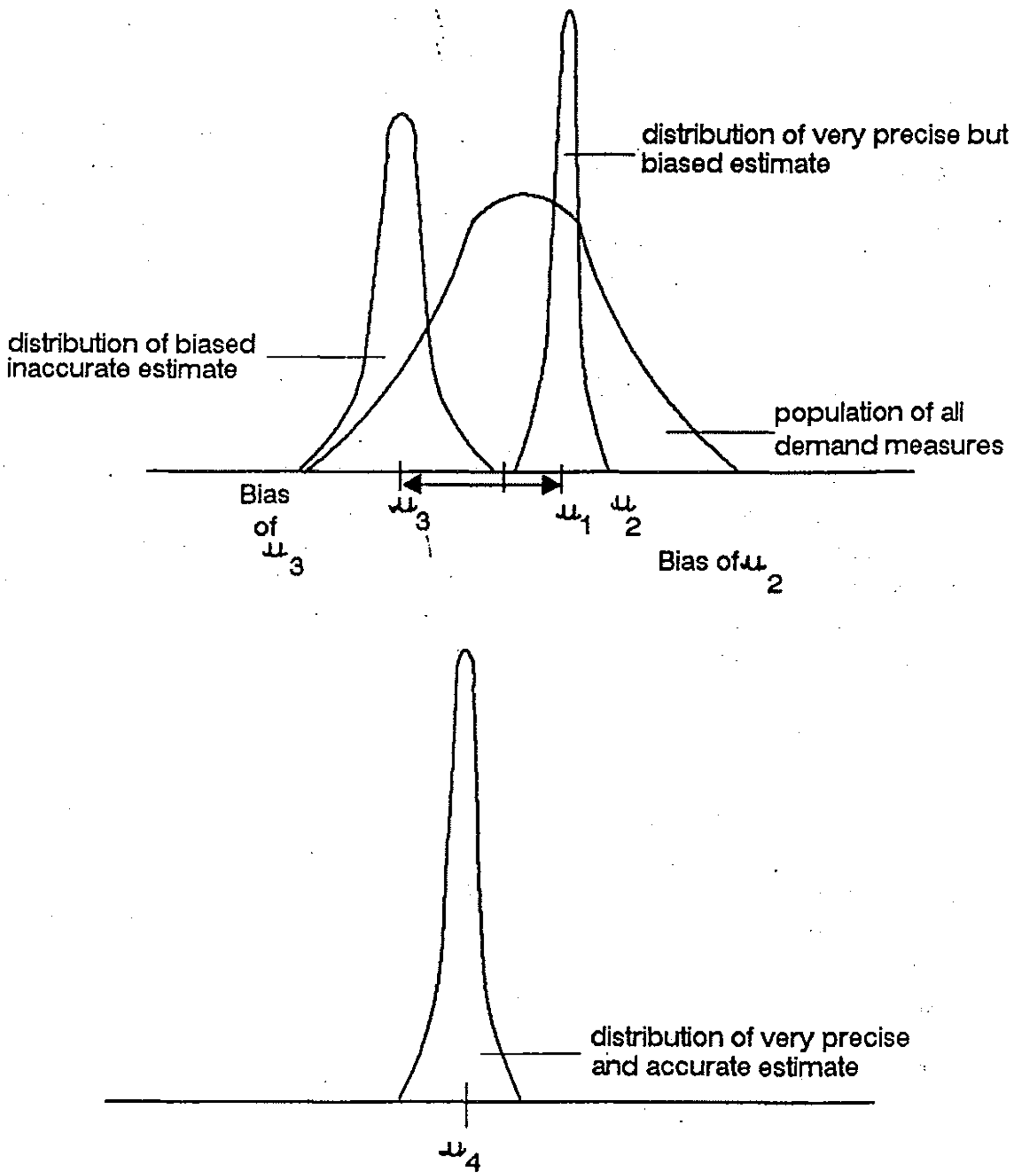
Prior to 1979, the mean per unit technique was used almost exclusively to estimate class demands from sample results. Since 1979 sampling statisticians familiar with the characteristics of load data and the problems of measuring it have developed applications of statistical theory to the estimation of demands at single hours and a combination of a number of hours. Due to the increased concern about the quality of load data collected through studies and the concern of reducing sampling cost, these developments were disseminated quite widely and many utilities started using the ratio and regression estimators. Recently, much research has been done demonstrating that the ratio estimator is better than the mean per unit estimator and many companies have changed to the ratio statistic.

Ratio and regression estimation use auxiliary data on the billing records for sample customers and the entire rate class to increase the precision of the estimate. When the auxiliary data is billed KWH, the estimation process resembles an application of estimating the load factor rather than the demand itself. In general, the higher the correlation between the auxiliary variable and the demand to be estimated, the greater the increase in precision. Ratio expansion uses energy in the statistical expansion from sample to rate class while mean per unit estimation employs number of customers. While the ratio estimator is technically biased, the degree of bias is extremely small for samples of even moderate size. (In statistical theory, bias refers to the difference between the expected value of the estimate and the true value being estimated.) The form of statistical estimation does not have to be the same in all rate classes. Figure A-2 is a comparison of the distribution of the population demand measures and the distributions of various estimators and shows the bias of these various estimators.

FIGURE A-2

Ex. AA-D-29

DISTRIBUTION OF CUSTOMER DEMANDS AND OF THREE ESTIMATORS OF CLASS DEMAND



μ_1 = mean of the population of demand measures

μ_2 = mean of precise but biased estimator of μ_1

μ_3 = mean of biased and imprecise estimator of μ_1

μ_4 = mean of precise, unbiased (if $\mu_4 = \mu_1$) estimator of μ_1

E. Selection of the Sample

The sample is selected from a frame or non-duplicative listing of all members (possible sampling units) of the rate class. Unfortunately, in utility research the frame is changing constantly. The dynamic nature of the frame is a concern because the frame from which we sample and consequently collect data is not the same frame about which we will make inferences. The magnitude of this problem can be reduced somewhat by using meter location (address) for the sampling unit as opposed to the customer's name. Since the frame used for sampling will not be representative of the rate class after a period of time due to new customers entering and old customers leaving, new samples should be selected every one or two years or some method should be developed to deal with entries and exits.

F. Selection of the Equipment

The implementation of a load study involves the using of metering, recording, and translation equipment. Currently, rotating disc and solid state meters are available; both of these types of meters may be modified to transmit pulses to a storage device such as a recorder. There are two types of recorders in general use: magnetic tape and solid state. In the magnetic tape recorder the pulses are recorded on a tape which is replaced monthly; a translation machine in a central office converts the data into a form readable by a computer. In addition, the translator checks the data for errors, inconsistencies, and outages or malfunctioning of the recorder.

In the solid state recorder the pulses transmitted by the meter are stored in a memory system which retains the latest thirty or more days of data. The data stored in the solid state recorder can be retrieved by the utility through a telephone line, a power line carrier system or a portable reader which is transported to the meter site to copy the data from the memory of the solid state recorder into its memory. The data which has been retrieved by one of the three methods will also be put through a translator. Since solid state recorders can be used with rotating disc meters, a number of metering and recording equipment options are available.

II. DATA COLLECTION

The success of a load study will require good organization and sufficient training of the field personnel to minimize non-response bias, equipment failure and other measurement problems.

A. Installation of Recorders

To reduce the potential bias from non-response, the importance of installing a recorder on each selected premise should be communicated to the employees installing the meters. Studies have shown that there is a difference, often significant, between the people who refuse and those who participate. Written procedures should be developed to deal with problems, such as different meter installations and customer refusals, and the likely impact of these problems. The employees installing recorders should have to explain in detail why they can't use the selected customer. The alternate should be provided only after review determines that the original selection cannot be used. Customers should not be offered a choice regarding participation; participation should be assumed except in extreme cases. A brochure on why load research is needed with load curves illustrating how the data is used is helpful for developing good customer relations and very low refusal rates.

B. Duration of Study

Data should be collected for at least twelve consecutive months to provide the data required by cost studies in today's ratemaking and costing environment. Also, the data should be collected during the same time period for all rate classes. Because the rate class population is constantly changing, meters should be reset on a new sample of customers every one or two years or some method (such as a "birthing" strata) should be used to account for customers entering or leaving the population. Note, account number changes usually do not mean the premise left the population.

C. Demographic Data

It is often important to obtain demographic and appliance saturation data on the load research sample to enhance the use of the load data for many other applications.

III. ESTIMATION OF LOADS

In this phase of the study computer programs are used to estimate statistically the demands of interest for each rate class sampled. Even though a specific estimator (i.e., mean per unit or ratio) was used during the design phase, this earlier decision does not preclude the use of other estimators in the estimation phase. One may use any estimator provided one does not switch to another estimator after the value is calculated. Sound judgment should be used in the selection of the estimator. The particular formulas used in the estimation process must reflect the design of the sample and whether the estimate is for one hour or a combination of a number of hours. Confidence intervals and the relative precision should be calculated for a specified level of confidence.

IV. USE OF DATA

A. Historic Test Year Coincident with Load Study

Coincident and class noncoincident demands for sampled rate classes would have been estimated statistically for all hours of interest for the cost study in the load estimation phase. In addition, demands should be calculated for all 100% time-recorded classes and the lighting classes. The sum of the coincident demands for all classes for any hour adjusted for losses will not equal the demand the utility generated in that hour. This is because of sampling and nonsampling errors.

When the historic test year is coincident with the year the load data was collected, the cost analyst can use the demands as estimated and calculated but usually an adjustment is made to the demands so that they sum to the actual demand of the utility in that hour. Sampling statisticians prefer that no adjustment be made because of the uncertainty as to whether the adjusted demands by class represent more accurately the class's proportion of the total demand than the statistically estimated demands. Some cost analysts have adjusted the estimated demands proportionately of only those classes that are not 100% time-recorded. This procedure, however, ignores the size of the sampling error of the various estimates and the measurement errors present in 100% time-recorded classes.

B. Projected Test Year or Historic Test Year Not Coincident with the Load Study

When the test year is not coincident with a time period when load research data was collected, the most recent load data must be used to develop projected demands for the test year. The preferred method for projecting coincident demands is to calculate monthly ratios of each class's estimated or calculated coincident demand to its actual KWH sales from the load data. These ratios are then applied to the class's projected test period KWH sales to derive the projected monthly coincident demands.

Similarly, it is recommended that class annual noncoincident demand should be derived by applying the annual class load factor calculated from the most recent load study to the projected annual KWH sales. The use of an annual load factor in contrast to a monthly load factor in the derivation of the class noncoincident class peak demand may, however, result in a larger deviation between the historic and projected coincidence factors. Thus, it is advisable to check the relationship of the projected class noncoincident demands and the projected coincident demands for the same month to that for the same demands estimated in the most recent load studies. The cost analyst may want to explore whether the use of other load relationships will yield projected noncoincident demands whose coincidence with system peak in the same month is more similar. If indicated, different load relationships can be used for different classes.

An example of data collected in a load study is shown in Table A-1.

TABLE A-1
LOAD STUDY DEMAND DATA[1]

	[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]
								Load Factor	
Rate Class	Average Number of Customers	MWH (Output to Line)	Average Demand MW (2) ÷ 8784[2]	Coincident Demand MW Winter	Coincident Demand MW Summer	Class Noncoincid. Demand (MW)	Coincidence Factor [4] ÷ [6]	Coincident Demand [3] ÷ [4]	Non-coincid. Demand [Class] [3] ÷ [6]
Residential	328,480	4,234,145	482	1208	938	1208	1.00	39.9%	39.9%
General Service Non Demand	37,975	642,751	73	119	149	166	.72	61.3	44.0
General Service Demand	5,517	2,368,914	270	338	399	469	.72	80.0	57.6
General Service Large Demand	121	2,696,647	307	322	357	382	.84	95.3	80.4
Street and Outdoor Lighting	142	103,928	12	3	0	22	.14	400.0	54.5
Total Company	372,235	10,046,386	1144	1990	1843			57.5	

[1] At generation level

[2] 8784 hours in a leap year