ELECTRIC UTILITY
COST ALLOCATION MANUAL

January, 1992

NATIONAL ASSOCIATION OF
REGULATORY UTILITY COMMISSIONERS

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PREFACE

This project was jointly assigned to the NARUC Staff Subcommittees on Electricity and Economics in February, 1985. Jack Doran, at the California PUC had led a task force in 1969 that wrote the original **Cost Allocation Manual**; the famous "Green Book". I was asked to put together a task force to revise it and include a Marginal Cost section.

I knew little about the subject and was not sure what I was getting into so I asked Jack how he had gone about drafting the first book. "Oh" he said, "There wasn't much to it. We each wrote a chapter and then exchanged them and rewrote them." What Jack did not tell me was that like most NARUC projects, the work was done after five o'clock and on weekends because the regular work always takes precedence. It is a good thing we did not realize how big a task we were tackling or we might never have started.

There was great interest in the project so when I asked for volunteers, I got plenty. We split into two working groups; embedded cost and marginal cost. Joe Jenkins from the Florida PSC headed up the Embedded Cost Working Group and Sarah Voll from the New Hampshire PUC took the Marginal Cost Working Group. We followed Jack's suggestions but, right from the beginning, we realized that once the chapters were technically correct, we would need a single editor to cast them all "into one hand" as Joe Jenkins put it. Steven Mintz from the Department of Energy volunteered for this task and has devoted tremendous effort to polishing the book into the final product you hold in your hands. Victoria Jow at the California PUC took Steven's final draft and desktop published the entire document using Ventura Publisher.

We set the following objectives for the manual:

- It should be simple enough to be used as a primer on the subject for new employees yet offer enough substance for experienced witnesses.
- It must be comprehensive yet fit in one volume.
- The writing style should be non-judgmental; not advocating any one particular method but trying to include all currently used methods with pros and cons.

It is with extreme gratitude that I acknowledge the energy and dedication contributed by the following task force members over the last five years.

Steven Mintz, Department of Energy, Editor; Joe Jenkins, Florida PSC, Leader, Embedded Cost Working Group; Sarah Voll, New Hampshire PUC, Leader, Marginal Cost Working Group; Victoria Jow, California PUC; John A. Anderson, ELCON; Jess Galura, Sacramento MUD; Chris Danforth, California PUC; Alfred Escamilla, Southern California Edison; Byron Harris, West Virginia CAD; Steve Houle, Texas Utility Electric Co.; Kevin Kelly, formally NRRI; Larry Klapow California PUC; Jim Ketter P.E., Missouri PSC; Ed Lucero, Price Waterhouse; J. Robert Malko, Utah State University; George McCluskey, New Hampshire PUC; Marge Meeter, Florida PSC; Gordon Murdock, The FERC; Dennis Nightingale, North Carolina UC; John Orecchio, The FERC; Carl Silsbee, Southern California Edison; Ben Turner, North Carolina UC; Dr. George Parkins, Colorado PUC; Warren Wendling, Colorado PUC; Schef Wright, formally Florida PSC; **IN MEMORIAL** Bob Kennedy Jr., Arkansas PSC.

Julian Ajello
California PUC

SECTION I

TERMINOLOGY AND PRINCIPLES OF COST ALLOCATION

SECTION I of the Cost Allocation Manual provides three chapters to familiarize the reader with the terminology and principles of cost of service studies and cost allocation theory.

Chapter 1 describes the nature of the electric utility industry in the United States. It provides a brief history of the industry, a description of the physical characteristics of the plant whose costs must be allocated and a discussion of the institutional structure of the industry.

Chapter 2 provides an overview of cost of service studies and summarizes the cost allocation process. It discusses the role played by cost of service studies in ratemaking and the development of the two major types of cost studies: embedded and marginal. It briefly outlines three issues of particular interest: treatment of joint and common costs, time differentiation and future costs and notes how the two types of studies deal with those issues. Finally, it describes the cost allocation process that is common to both types of studies.

Chapter 3 reviews the development of the utility's revenue requirement, including the concepts of a test year and the determination of the utility's rate base, rate of return and operating expenses.

CHAPTER 1

THE NATURE OF THE ELECTRIC UTILITY INDUSTRY IN THE U.S.

In order to understand the process of allocating the costs of electric utilities to their customers, it is helpful to review the industry in the context of how it developed, and its current physical and institutional characteristics. This first chapter will therefore provide a capsule history of the American electric utility industry. It will then address the physical characteristics of the industry, including generation, transmission and distribution, and review the concepts of energy and capacity. Finally, it will discuss the institutional structure of the industry, both the types of utility organizations and the levels of jurisdiction that regulate them.

I. CAPSULE HISTORY

The founder of the American electric utility industry was Thomas A. Edison. While not the originator of either electricity or lighting -- Sir Humphrey Davy invented the arc light in 1808, Michael Faraday introduced the dynamo in 1831, and a host of inventors had experimented with such technologies as arc lights for illumination, the telegraph, phonograph and telephone -- it was Edison who first developed the concept of a central station and system of delivery which could provide the energy for light, heat and power. In 1882, Edison opened the Pearl Street Station in New York City serving 85 customers with 400 lamps.

The early years of the electric industry were characterized by competition. Edison's efforts to create and finance central electric power stations were in competition with gas lighting companies and isolated power plants. Westinghouse Electric developed a new approach which, in contrast to Edison's direct current (DC) that could be transmitted for only a few miles, relied on an alternating current (AC) produced at 1000 volts, which could be transmitted over long distances and then transformed to 50 or 100 volts. Thus, it became possible to develop central generating plants located at hydroelectric or coal mining sites with transmission across long distances to load centers. At the local level, cities granted multiple, sometimes competing, franchises to companies providing either type of current for individual purposes (street lighting, domestic lighting, tramways, commercial power).

The electric industry grew rapidly during the last 20 years of the 19th century, multiplying the number of companies, pushing out from the urban centers to the surrounding rural areas, improving plant and transmission to achieve economies of scale, and expanding electrical uses beyond lighting. The number of independent systems declined as companies amalgamated to rationalize franchises, achieve load diversity and forestall competition. Financing for the capital intensive industry evolved into long term general mortgage bonds whose financiers required assurances that the longevity of the companies would equal the length of the bonds. Industry leaders like Samuel Insull of Chicago Edison began to seek the protection of state sponsored regulation as security against short-lived city franchises.

While operating companies became regulated by state commissions after 1900, holding companies remained unregulated. The original holding companies resulted from engineering and equipment firms receiving securities rather than cash for their goods, investment bankers taking over utilities they had financed, and consolidation to achieve operating efficiencies. By the 1920's, however, the holding company movement had become a mania, fueled in most part by the large profits gained by the promoters. In 1932, 73 percent of investor owned utilities nationwide were controlled by eight companies: Insull's company, for example, operated in 32 states and controlled assets of over half a billion dollars. The financial abuses of the holding companies led first to their investigation by the Federal Trade Commission in 1928, their partial collapse in the stock market crash of 1929 and the onset of the Great Depression, and finally their dismemberment under the Public Utility Holding Company Act of 1935.

The 1930's also saw the growth of public power. Municipal ownership had been a feature of the industry from its inception, with the municipals exceeding investor owned utilities in number, although not in either customers or capacity, through the mid-1920's. The Roosevelt Administration's promotion of such projects as the Boulder Dam and the sale of inexpensive federal power to publicly owned distribution companies encouraged many municipalities to take over their local distribution companies. Meanwhile, projects like the Tennessee Valley Authority and the Bonneville Power Administration and the financing of farmer cooperatives by the Rural Electrification Administration brought publicly owned electricity to the hitherto unserved rural populace.

The two decades following the Second World War are characterized by declining prices, due primarily to increased efficiencies in generation. Average plant size increased five-fold, and the heat rate (BTUs of energy required per kilowatt hour of electricity) and the cost of incremental generating plant per kilowatt both declined by 37 percent over the twenty year period. Financing for the capital investment was considered to be relatively risk-free and was therefore achieved at minimal cost. As a result, the price of electricity fell by 9 percent (compared to an increase in the Consumer Price Index of 75 percent). Usage per residential customer increased 155 percent and the amount of self-generation declined from 18 percent of total generation in 1945 to 8.8 percent in 1965.

Between 1965 and 1970, electricity prices remained stable and usage continued to increase although costs of construction, financing and operation began to rise. By the 1970's, utilities realized that the increasing cost of production was not a temporary phenomenon and began to reflect increased costs in rates. Production facilities that had been planned in a period of low inflation, constant demand growth and concern over reserve margins stemming from the 1965 Northeast blackout, were built in an era of high inflation, and increased construction and financing costs, and finally achieved commercial operation in an age of uncertain demand and competitive alternatives to utility generation. By the mid-1980's, all forms of generation appeared under attack: hydro-electric by advocates of alternate uses of rivers, nuclear because of concerns over cost and safety, and fossil fuel by environmentalists pointing to problems of air pollution, acid rain and the greenhouse effect. The bankruptcy of Public Service Company of New Hampshire in February 1988 owing to its investment in the Seabrook Nuclear Power Station is an extreme example of an electric utility industry unable to meet its obligations to both its customers for electrical generation and its creditors for the capital to finance it. Its problems were not unique, however, as its demise had been foreshadowed by the omission by Consolidated Edison of its common stock dividend in 1974, and Cincinnati G&E's cancellation of the 97 percent complete Zimmer plant and the default of the Washington Public Power Supply System on its bonds in 1983. Utilities began to turn to new options, on both the demand and supply side of the equation, to satisfy their markets' requirements for the energy services of light, motor power and heat.

II. PHYSICAL CHARACTERISTICS OF THE ELECTRICAL INDUSTRY

In the electric utility industry, power is produced by the utility company at central generating stations, transmitted over high voltage power lines to the load centers within its franchise area or to other points of delivery, and finally distributed at lower voltages to the ultimate customers. Those three components, generation, transmission and distribution, comprise the basic elements of the physical structure of the electric utility industry. First, however, a crucial concept in the planning, operation, and costing of the industry is understanding the difference between capacity and usage, or kilowatts and kilowatt-hours.

A. Kilowatts and Kilowatt-hours

Key to analyzing any electric utility cost of service study is an understanding of the difference between kilowatts (KW) and kilowatt-hours (KWH). In terms of physics, KWH equates to work and KW equates to power, where work is defined as force times the distance through which it acts, and power is defined as the work done per unit of time.

In the electric industry, work is termed energy; power is termed capacity or capability in discussions of generating plants, and demand in discussions of customer usage.

The basic unit in electricity is the watt, most familiar as the rating on light bulbs and appliances. A 100 watt bulb burning constantly for an hour would use 100 watt-hours of electricity. Thus, watts are a measure of capacity while watt-hours add the dimension of the time period during which the capacity is used. Since the watt is a very small unit of measurement (746 watts equal 1 horsepower), consumer bills are measured in kilowatt-hours (thousands of watt hours) and utility system generation is reported in megawatt-hours (millions of watt hours).

B. Generation

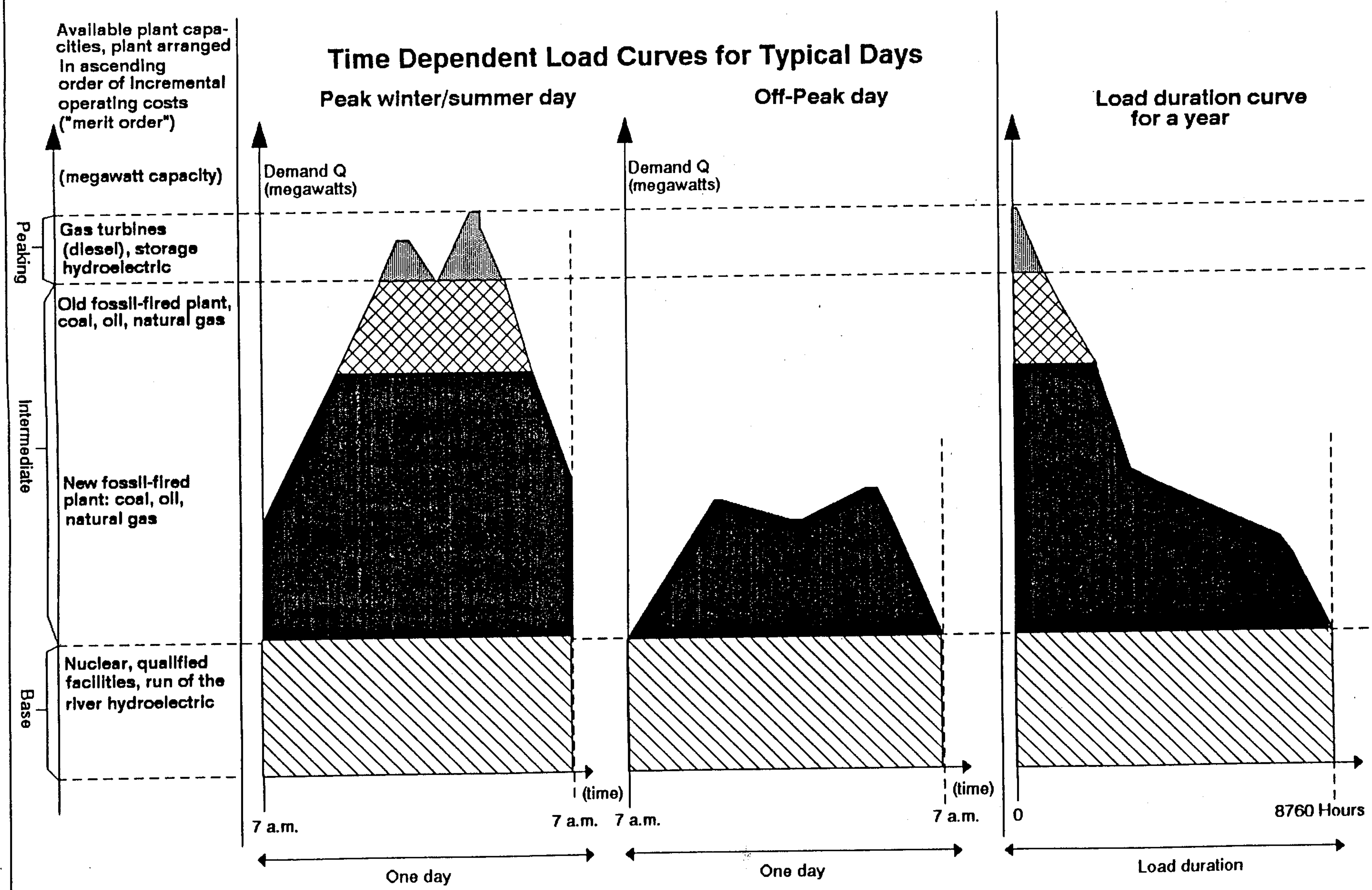
The demand for power on an electric system varies with time, with variations occurring for any given utility in a fairly predictable pattern during the hours of a day and the seasons of a year (see Figure 1-1). A graph that plots hours of the day against demand on the system will typically show low usage during the night hours, which rises to one or more peaks during the day hours as customers turn on their machinery (and heat or cool), and then gradually falls during the late evening hours. Similarly, the graph of a utility's annual demand will typically demonstrate the lower demand on the system in the spring and fall with greater usage exhibited in the winter and/or summer reflecting electric heat and air conditioning loads.

Such time differentiated graphs can be translated into load duration curves in which demand, rather than plotted against hours of the day or days of the year, is plotted against the number of hours of the year (up to all 8760) during which any particular level of demand occurs. The shape of the load duration curve over the year in large measure determines the utility planner's choice of generating plant needed to satisfy customer demand. The challenge to the system planner is to provide sufficient generating capacity to satisfy the peak demand, while recognizing that much of that plant will not be needed for a large part of the day and year. As different types of generating units are marked by different operational and cost characteristics, the utility will attempt to build the types of units that provide it with the flexibility to match supply to demand for every hour at the lowest possible cost.

Utilities generate most power by burning fossil fuels (coal, oil and natural gas), employing nuclear technology, and running hydro-electric plants. In addition, they purchase power both from other utilities and from independent power producers whose facilities may include run-of-the-river hydro-electric, wood, municipal solid waste, wind, geothermal, tidal, or electricity cogenerated with some form of heat used in district heating or in a manufacturing process.

The utility system operators load (dispatch) and unload generating stations sequentially in order of operating costs as demand rises and falls on the system. Base load

FIGURE 1-1
LOAD DISPATCHING



plants are constructed to meet the utility's minimum demand by operating continually throughout the day and year. They cannot be loaded and unloaded easily, either because of their operating characteristics (for example, nuclear) or because of contractual or legal requirements (purchases from small power producers or run-of-the-river hydro-electric). They tend to have high fixed costs that can and must be spread over many hours of the year, and lower operating (primarily fuel) costs. At the other extreme, peaking plants are constructed to satisfy the demand that may occur only for a few hours of the year. These plants must be easily loaded and unloaded onto the system and, since the hours of their operation are limited, must have low capital costs. Generally, they also have high fuel costs (e.g., gas turbines) although hydro-electric stations with some reservoir capacity may also be constructed as peakers because of the ease of instantaneous operation. Intermediate plants, fossil fuel stations burning coal, oil and natural gas, are dispatched less frequently than base load and more often than peakers. Dispatch of particular stations will vary according to relative fuel costs: in periods of particularly low oil prices, for example, oil-fired stations may operate as baseload rather than intermediate plants.

In recent years it has become apparent that utilities have the option of influencing their demand curves as well as varying their sources of supply. Thus, a utility with base load capacity but a rising peak demand may be able to shift some of its peak load to off-peak hours, to make better use of its base load facilities, rather than building additional peaking units.

C. Transmission

A utility's transmission system consists of highly integrated bulk power supply facilities, high voltage power lines and substations that transport power from the point of origin (either its own generation or delivery points from other utilities) to load centers (either in its own franchise territory or for delivery to other utilities). The transmission function is generally concluded at the high voltage side of a distribution substation owned by the utility or at points where the ownership of bulk power supply facilities changes.

In general, the transmission system is comprised of four types of subsystems that operate together. The backbone and inter-tie transmission facilities are the network of high voltage facilities through which a utility's major production sources, both on and off its system, are integrated. Generation step-up facilities are the substations through which power is transformed from a utility's generation voltages to its various transmission voltages. Subtransmission plant encompasses those lower voltage facilities on some utilities' systems whose function is to transfer electric energy from convenient points on a utility's backbone system to its distribution system. Radial transmission facilities are those that are not networked with other transmission lines but are used to serve specific loads directly.

The two principal characteristics that distinguish one transmission system from another are the voltages at which the bulk power supply facilities are designed and operated and the way in which those facilities are configured. Voltages can and do vary widely from one electric system to another. For example, where one system's predominant backbone transmission facilities may consist of 345 kilovolts (KV) or higher, another's may consist of only 115 KV, while still another may have a combination of facilities that operate at various voltages. Utilities also configure their transmission systems differently. Some are highly integrated, where facilities of the same or different voltages form networks that provide a number of alternative paths through which power may flow. Other systems may be essentially radial, with few or no alternative paths.

D. Distribution

The distribution facilities connect the customer with the transmission grid to provide the customer with access to the electrical power that has been generated and transmitted. The distribution plant includes substations, primary and secondary conductors, poles and line transformers that are jointly used and in the public right of way, as well as the services, meters and installations that are on the customer's own premises.

Typically, transmission and distribution plant is separated by large power transformers located in a substation. The substation power transformer "steps down" the voltage to a level that is more practical to install on and under city streets. Distribution substations usually have two or more circuits that radiate from the power transformer like spokes on a wheel, hence the expression, "radial distribution circuits". These circuits will often tie to each other for operating convenience and emergency service, but under normal operation an open switch keeps them electrically separate. Thus, in contrast to the transmission system where a change of load at any point on the system will result in a change in load on the entire system, a change in load on one part of the distribution system will not normally affect load on any other part of the distribution system.

Distribution circuits are divided into primary and secondary voltages with the primary voltages usually ranging between 35 KV and 4 KV and the secondary below 4 KV. Primary distribution voltages run between the power transformer in the substation and the smaller line transformers at the points of service. Advances in equipment and cable technology permit using the higher voltages for new installation. Since the ability to carry power in an electrical conductor is proportional to the square of the voltage, these higher primary voltages allow a reasonably sized conductor to carry power to more customers at greater distances.

Manufacturing standards for industrial electrical equipment, lighting, and appliances specify voltages at 480 volts or less. Therefore, at customer locations along the primary distribution circuit a smaller line transformer is installed to further reduce the voltage to the secondary level. Large industrial customers may install their own line transformers and take service at primary voltage. The utility may choose to install a transformer sized to the load and dedicated to exclusive use of other commercial and industrial customers. In high density customer areas such as housing tracts, a line transformer will be installed to serve many customers and secondary voltage lines will run from pole to pole. At each customer premise a line (service drop) is tapped off the secondary line directly to the customer's meter.

III. INSTITUTIONAL CHARACTERISTICS OF THE ELECTRIC INDUSTRY

The electric industry is a public utility, a term that denotes the special importance of the service it provides ("affected with the public interest") and its inherent technical characteristics that lead to ineffective competition ("natural monopoly"). The latter feature has been strongly associated with economies of scale and decreasing unit costs of production. While increasing economies of scale are no longer clearly evident in generation, the inefficiencies of duplicating transmission and distribution facilities, for reasons of both economics and aesthetics, remain. In the absence of competition to moderate prices in the naturally monopolistic electric industry, public policy has adopted three institutional forms of restraint: cooperatives, municipals, and regulated investor-owned utilities. It should be noted that under some state statutes the term "public" is also used to specifically denote public ownership (cooperatives and municipals).

A. Utility Organizations

In cooperative electric utilities, the ratepayers and owners are the same. Most investment capital is provided through loans, usually from the Rural Electrification Agency, and prices are set so that revenue covers costs of operation including debt service. The ratepayers/owners hire professional managers to operate the utility and, while they may vote on their retention at annual meetings, neither the managers nor the cooperative's officers are often voted out of office.

A municipal electric utility is operated by the political unit it serves, with its professional managers appointed by the elected officials. The municipality may furnish the necessary capital for the utility plant either through taxes or indebtedness, and utility rates can be set either to cover costs including debt service as separate enterprise funds, or to interact with other municipal finances. In the latter case, the municipality may chose either to subsidize utility services from tax sources or to generate profits to enhance fire, police and other municipal services. A variation on municipal utilities are the federally operated multi-state authorities like the Tennessee Valley Authority or the Bonneville Power Authority.

Investor-owned utilities (IOU's) are privately owned corporations whose investment capital is furnished by a combination of indebtedness and stockholder provided equity. Where prices in cooperatives are restrained by the owner/ratepayers, and in municipals by the voters/ratepayers, the directors of the IOU's are subject to no such constraints. Their primary goal is the long-term maximization of return to the stockholders, a goal that is by no means inconsistent with the goal of public policy that utilities provide safe and reliable service at just and reasonable rates. Consistency between private and public ends is assured, however, through governmental regulation of the IOU's.

All utilities share an interest in protecting their exclusive right to serve their franchised service territory because of the opportunities to increase profits and/or reduce unit costs through economies of scale. Only IOU's pay federal income taxes; state and local taxation depends on the controlling laws in the service areas where the different types of utilities operate. All IOU's are publicly regulated; regulation of cooperatives depends on the laws of the particular jurisdiction; municipals are often regulated only for service provided outside their municipal boundaries.

B. Regulative Jurisdictions

Public utility regulation in its present form is the end result of considerable experimentation and adjustments to changing conditions. Experimentation in the techniques of regulation has resulted over the decades in today's administrative commissions, a distinctly American contribution to government control of business.

The right to regulate stems from the United States Constitution. State regulation is based on the residual authority known generally as "state police powers", designed to protect the health, safety and general welfare of citizens. Utilities operating in interstate commerce, either because they operate in multi-state jurisdictions or sell in wholesale inter-utility transactions, are subject to control by federal agencies. A utility that operates in both inter- and intrastate commerce will be regulated by both federal and state jurisdictions and any lack of consistency between the two regulatory bodies can lead to over-collection or under-collection of revenue by the utility.

State commissions are charged with setting just and reasonable rates, in both level and design, and assuring safe and reliable service. In addition, state commissions grant utilities authority to engage in various forms of financing and they control the delineation of service territories. The extent of commission authority in each of these areas varies somewhat from state to state, depending on statutory language and judicial interpretation.

With some specific exceptions, all of investor-owned utilities wholesale (sales for resale) operations are under the control of the Federal Energy Regulatory Commission (FERC), formerly the Federal Power Commission (FPC). The statutory duties of the FERC are comparable to those of the state agencies. The Federal Power Act of 1935 vested the FPC with the authority to regulate the interstate sales of electric power. With the passage of this Act, the FPC and its successor the FERC, has authority over:

- The disposition, merger, or consolidation of facilities and the acquisition of the securities of another utility.
- The issuance of securities.
- The rates and services of the companies under its jurisdiction.
- Accounting and depreciation practices.
- The holding of certain interlocking positions in different companies by the same person.

For the most part, FERC rate and service regulations affect wholesale rates. Thus, FERC ratemaking policies, especially in regard to rate design, can have a significant impact on the intrastate systems that purchase electric power from a FERC-regulated investor-owned utility.

CHAPTER 2

OVERVIEW OF COST OF SERVICE STUDIES AND COST ALLOCATION

This chapter presents an overview of cost of service studies and cost allocation theory. It first introduces the role of cost of service studies in the regulatory process. Next, it summarizes the theory and methodologies of cost studies, with a comparison of accounting-based (embedded) cost methodologies and marginal cost methodologies. Finally, it introduces and briefly discusses the three major steps in the cost allocation process: the "functionalization" of investments and expenses, cost "classification" , and the "allocation" of costs among customer classes.

I. COST OF SERVICE STUDIES IN THE REGULATORY PROCESS

Cost of service studies are among the basic tools of ratemaking. While opinions vary on the appropriate methodologies to be used to perform cost studies, few analysts seriously question the standard that service should be provided at cost. Non-cost concepts and principles often modify the cost of service standard, but it remains the primary criterion for the reasonableness of rates.

The cost principle applies not only to the overall level of rates, but to the rates set for individual services, classes of customers, and segments of the utility's business. Cost studies are therefore used by regulators for the following purposes:

- To attribute costs to different categories of customers based on how those customers cause costs to be incurred.
- To determine how costs will be recovered from customers within each customer class.
- To calculate costs of individual types of service based on the costs each service requires the utility to expend.
- To determine the revenue requirement for the monopoly services offered by a utility operating in both monopoly and competitive markets.

- To separate costs between different regulatory jurisdictions.

Generically, the prime purpose of cost of service studies is to aid in the design of rates. The development of rates for a utility may be divided into four basic steps:

- Development of the test period total utility revenue requirement - The total revenue requirement is the level of revenue to be collected from all sources. This subject will be addressed in detail in Chapter 3.

- Calculation of the test period revenue requirement to be recovered through rates - This is simply the total revenue requirement of the utility from all sources less the amount from sources other than rates.

- The cost allocation procedure - The total revenue requirement of the utility is attributed to the various classes of customers in a fashion that reflects the cost of providing utility services to each class. The cost allocation process consists of three major parts: functionalization of costs, classification of costs, and allocation of costs among customer classes.

- Design of rates - Regulators design rates, the prices charged to customer classes, using the costs incurred by each class as a major determinant. Other non-cost attributes considered by regulators in designing rates include revenue-related considerations of effectiveness in yielding total revenue requirements, revenue stability for the company and rate continuity for the customer, as well as such practical criteria as simplicity and public acceptance.

II. THEORY AND METHODOLOGIES

Historically, regulation concerned itself with the overall level of a company's revenues and earnings and left the design of rates to the discretion of the utility. To the extent that utility managements justified their rate structures on cost, rather than rationales of value of service or "what the market will bear", they defined cost in engineering and accounting terms. Utilities developed cost studies that were based on monies actually spent (embedded) for plant and operating expenses and divided those costs (fully allocated or distributed them) among the classes of customers according to principles of cost causation. The task for the analyst was to allocate, among customers, the costs identified in the test year for which the revenue requirement had been calculated.

Through the years, the industry and its regulators have witnessed a gradual evolution of the concepts for allocation. Since generating units and transmission lines are sized according to the peak demand consumed, the individual contribution to peak demand came to be considered the appropriate factor for the allocation of the costs of those facilities. Costs incurred to supply energy such as fuel were rationalized to be allocatable by usage. Costs that vary by the number of customers and not their consumption were allocated by customer. While subsequent analysis has complicated the assignment of particular costs to various categories, cost allocation has generally evolved into three cost classifications: demand, energy and customer.

By the 1970's, the economic environment had changed for the electric utilities. In the new era of general inflation, high energy and construction costs, and competition, rates based on pre-inflationary historical costs led to poor price signals for customers, inefficient uses of resources for society, and repeated revenue deficiencies for the companies. Regulators and utilities began to inquire whether the principles of marginal cost were the appropriate reference for regulated utility rate structures in the United States. Such concepts had long been the theoretical economic framework for the analysis of competitive markets, and since the 1950's, the basis of utility rates in England and France.

Marginal cost theory is derived from the neo-classical economics of the nineteenth century which states that in a perfectly competitive equilibrium, the amount consumers are willing to pay for the last unit of a good or service, equals the cost of producing the last unit, i.e., its marginal cost. As a result, the amount customers are willing to pay for a good equals the value of the resources required to produce it, and society achieves the optimal level of output for any particular good or service. In a competitive market, this equilibrium is achieved as each firm expands its output until its marginal cost equals the price established by the forces of supply and demand. For the utility monopoly, the regulator attempts to achieve the same allocative efficiency by accepting the level of service demanded by customers (the utility's obligation to serve) as the given, and setting price (or rates) equal to the utility's marginal cost for that level of output. The analyst defines the cost as the change in cost due to the production of one unit more or less of the product, and various approaches have been advanced to measure the utility's marginal cost.

A deficiency of the marginal approach for ratemaking purposes is that marginal cost-based prices will yield the utility's allowed revenue requirement based on embedded costs only by rare coincidence. Since regulatory agencies are bound not to let the utility over-earn or under-earn, revenues from rates must be reconciled to the allowed revenue requirement. As the rates are reconciled to the revenue reqirements and prices diverge from marginal cost, the sought after marginal cost price signals may not be obtained. When prices do not exactly equal marginal cost there is no formal proof that the economic efficiency predicted by theory is achieved. Advocates of marginal cost pricing believe that approximations to marginal cost pricing must contribute to efficient resource allocation, although to an unspecifiable degree. Supporters of embedded cost pricing believe that the greater precision, verifiability and general simplicity of embedded cost methods outweigh any of the hoped for efficiency benefits of imperfect approximations to marginal cost pricing. This problem and various proposed solutions are addressed in Chapter 10.

It is important to note that the difference between an embedded cost of service study and a marginal cost of service study lies in their different concepts of cost. The embedded cost study uses the accounting costs on the company's books during the test year as the basis for the study. In contrast, the marginal cost study estimates the resource costs of the utility in providing the last unit of production. Once "cost" is determined, the procedures for allocating cost among services, jurisdictions and customers are largely the same. Thus, the practical and theoretical debates in marginal cost studies tend to center around the development of costs, while the debates in embedded cost studies focus on how the cost taken directly from the company's books should be divided among customers.

III. EMBEDDED AND MARGINAL COST STUDY ISSUES

There are three subjects of particular interest in the development of cost studies: treatment of joint and common costs, time-differentiation of rates, and incorporation of future costs. The following discussion will briefly address how the two types of studies deal with those issues.

A. Joint and Common Costs

Joint costs occur when the provision of one service is an automatic by-product of the production of another service. Common costs are incurred when an entity produces several services using the same facilities or inputs. The classic example of joint costs are beef and hides where it is not possible to allocate separate costs of raising cattle to the individual product. In the electric industry, the most common occurrence of joint costs is the time jointness of the costs of production where the capacity installed to serve peak demands is also available to serve demands at other times of the day or year. Overhead expenses such as the president's salary or the accounting and legal expenses are examples of costs that are common to all of the separate services offered by the utility.

In an embedded cost study the joint and common costs identified in the test year are allocated either on the basis of the overall ratios of those costs that have been directly assigned, or by a series of allocators that best reflect cost causation principles such as labor, wages or plant ratios, or by a detailed analysis of each account to determine beneficiality. The classification and treatment of the joint and common costs requires considerable judgment in an embedded cost study. (See Chapters 4 through 8 for a more detailed discussion).

In a marginal cost study, the variation of those common costs that vary with production is incorporated into the study through regression techniques and becomes a multiplier to the marginal cost per kilowatt or kilowatt-hour. There are fewer joint and common costs in marginal cost studies than in embedded because many of the common costs do not vary with changes in production. The presence of joint and common costs, both variable and non-variable, contributes to the inequality between the totals obtained from a marginal cost study and the revenue requirement based on the embedded test year costs.

B. Time Differentiation of Rates

Most time differentiation of rates stems from the recognition that costs vary by time. It is a popular misconception that time differentiated rates are a unique feature of marginal cost studies. To the contrary, both embedded and marginal cost studies can be designed to recognize cost variations by time period. It is true that marginal cost studies are designed to calculate the energy and capacity costs attributable to operating the last (marginal) unit of production during every hour of the year. The hours can then be grouped into peak, off-peak and shoulder periods for costing and pricing purposes. However, in embedded studies, the baseload, intermediate and peak periods can be identified, and different configurations of production plants and their associated energy costs, can be assigned to each period. (See Chapter 4.) Thus, the primary difference between the two types of studies in regard to the calculation of time differentiated rates is that the costs fall naturally out of a marginal cost study while embedded cost analysts are required to perform a separate costing step before allocating costs to the customer classes.

C. Future Costs

In most cost studies submitted to regulatory commissions, the accounting costs in embedded cost studies reflect the cost incurred in providing a given level of service over some time period in the past. Optimally, the utility's cost study and test year for revenue requirement purposes will be based on the most recent twelve months for which data are available, although regulators are often faced with the difficulties of stale test years. To the extent that the price of inputs, technology, and managerial and technical efficiency cause the cost of providing service in the past to differ from the cost of service in the future, rates based on historic test years will over- or under-collect during the years the rates are in effect. Within the context of embedded studies, solutions to the need to incorporate future costs include recognition of known and measurable changes to the test year costs, step increases between rate cases, fuel adjustment mechanisms to give immediate recognition to variations in fuel costs and the use of a forward-looking test year for the cost study. This last is the most comprehensive response to the need to reflect future costs within an embedded study. However, it has the disadvantage of relying on estimated costs rather than costs that are subject to verification and audit. Thus, in the eyes of many regulators, an embedded study based on a future test year loses one of the prime advantages it has over marginal cost studies.

In contrast to the standard embedded cost study, marginal costs by definition, are future costs. Marginal cost studies estimate either the short-run marginal costs, in which plant, equipment and organizational skills are fixed, but labor, materials and supplies can be varied to satisfy the change in production, or the long-run marginal costs, in which all inputs including production capacity can be adjusted. As a matter of practicality, marginal cost studies usually adopt an intermediate period tied to the planning horizon of the utility.

IV. SOURCES OF DATA

While the data for cost studies are generally provided by the utility company, the documents that are relevant depends on the type of cost study being performed. Embedded cost studies rely on the company's historical records or projections of these records, whose accuracy can be audited and verified either at the time of filing or at the end of the period projected. Marginal cost studies use the company's planning documents.

A. Data for Embedded Cost Studies

Where a cost of service study is made in conjunction with a rate case proceeding, the costs that are distributed to the various classes of service should be the costs used in determining the utility's overall revenue requirement. The principal items of historical information required to develop cost allocations based on accounting costs are plant investment data, including detailed property records, balance sheets, information on operating expenses and on performance of generating units, load research (information on KWH consumption and the patterns of that consumption) and system maps. These costs are contained in the books and records maintained by the company, and are proformed to recognize known and measurable changes. The utility files projected revenues, investment and costs for all accounts in cost studies using projected test years.

Electric utilities generally are required by law to keep their records according to the Uniform System of Accounts (USOA) as prescribed by the Federal Energy Regulatory Commission in the Code of Federal Regulations CFR Title 18, Subchapter C, Part 101. This code sets the guidelines for booking assets, liabilities, incomes and expenses into each account. Major categories of costs are listed as follows:

100 Series	Assets and other debits
200 Series	Liabilities and other credits
300 Series	Electric plant accounts
400 Series	Income, and revenue accounts
500 Series	Electric O&M expenses

900 Series	Customer accounts, customer service and informational sales, and general and administrative expenses

Series 600, 700 and 800 are not major categories of cost that are used for cost of service studies.

B. Data for Marginal Cost Studies

The focus of marginal cost studies is on the estimated change in costs that results from providing an increment of service. The planning documents of the utility form the basis of the analysis, with those plans in turn being based on such tools and information as the output of the production costing model and the optimized generation planning model, the parameters established for reliability, stability and capability responsibility, and load and fuel forecasts. Costing for generation requires information on outage rates, operating and maintenance costs, alternate fuel capabilities and retirement schedules of existing plants, on the expected market for capacity purchases and sales, and on the capital and operating costs of alternate future generating units including their associated transmission.

Cost information on transmission, and to a lesser extent, distribution, is obtained from the utility's models of power flow analysis, with their associated transient stability programs, switching surge analyses and loss studies, and geographically specific load forecasts. Based on this information, the transmission and distribution planner will have developed a system expansion plan, the budget for which provides the cost data for the transmission and distribution portions of the marginal cost study.

Future customer and general and administrative costs, and in less sophisticated studies distribution costs as well, are not thought to vary significantly from the immediate historically incurred costs. Therefore, the sources of data for a marginal study will be the historic account data.

V. THE COST ALLOCATION PROCESS

A. Cost Functionalization

Once the relevant data on investment and operating costs are gathered and the relevance determined by the type of study and unique circumstances of each utility, the costs are then separated according to function. The typical functions used in an electric utility cost allocation study are:

- Production or purchased power

- Transmission
- Distribution
- Customer service and facilities
- Administrative and general

Each utility is a unique entity whose design has been dictated by the customer density, the age of the system, the customer mix, the terrain, the climate, the design preferences of management, the planning for the future, and the individual power companies that have merged to form the utility. Some utilities have generation plant, while others are only distribution systems. Therefore, the degree or complexity of functionalization will depend on the individual utility and the regulatory environment. The advent of computers encouraged a trend towards more detailed functionalization.

The assignment of costs to each function will generally follow the accounting categories defined in the USOA. At times, however, there will be exceptions. In such cases, the purpose of functionalization, not the accounting treatment, must drive the distribution of the functional costs for the cost study.

Following are descriptions of the typical cost functions used in an electric utility cost allocation study.

1. The Production Function

The production function consists of the costs associated with power generation and wholesale purchases. This includes the fossil fired, nuclear, hydro, solar, wind and other generating units. The costs associated with the purchase of power and its delivery to the bulk transmission system are also included.

2. The Transmission Function

The transmission function includes the assets and expenses associated with the high voltage system utilized for the bulk transmission of power to and from interconnected utilities and to the various regions or load centers of the utility's system.

3. The Distribution Function

The distribution function encompasses the radial distribution system that connects the customer to the transmission system. The distribution function is normally extensively subdivided in order to recognize the non-utilization of certain types of plant by particular customer classes. Since customers served at the primary distribution voltage do not utilize the plant necessary to transform the voltage to the secondary levels, the cost causation criteria requires that they not be allocated the cost associated with the secondary distribution system.

4. The Customer Service and Facilities Function

The customer service and facilities function includes the plant and expenses that are associated with providing the service drop and meter, meter reading, billing and collection, and customer information and services. These investments and expenses are generally considered to be made and incurred on a basis related to the number of customers (by class) and are, therefore, of a fixed overhead nature.

5. Administrative and General Function

The administrative and general function includes the management costs, administrative buildings, etc. that cannot be directly assigned to the other major cost functions. These costs may be functionalized by relating them to specific groups of costs or other characteristics of the major cost functions, and then allocated on the same basis as the other costs within the function.

B. Classification of Costs

The next step is to separate the functionalized costs into classifications based on the components of utility service being provided. The three principal cost classifications for an electric utility are demand costs (costs that vary with the KW demand imposed by the customer), energy costs (costs that vary with the energy or KWH that the utility provides), and customer costs (costs that are directly related to the number of customers served).

After costs are functionalized into the primary functions, some can be identified as logically incurred to serve a particular customer or customer class. For example, a radial distribution line that serves only a particular customer may be assigned directly to that customer. Similarly, all the investment and expenses associated with luminaires and poles installed for street and private area lights are directly assigned to the lighting class(es). Segregation of these costs in a sense reverses the classification and allocation steps, as the costs are first allocated to the customer and subsequently classified as demand, energy or customer to determine how the customer is to be charged.

Typical cost classifications used in cost allocation studies are summarized below.

Typical Cost Function	Typical Cost Classification
Production	Demand Related Energy Related
Transmission	Demand Related Energy Related
Distribution	Demand Related Energy Related Customer Related
Customer Service	Customer Related Demand Related

The typical cost classifications shown above reflect the following types of assumptions regarding cost causation for electric utilities.

1. Production

Costs that are based on the generating capacity of the plant, such as depreciation, debt service and return on investment, are demand-related costs. Other costs, such as cost of fuel and certain operation and maintenance expenses, are directly related to the quantity of energy produced. In addition, capital costs that reduce fuel costs may be classified as energy related rather than demand related. In the case of purchased power, demand charges are normally assumed to be demand related and energy charges are normally assumed to be energy related. Fuel inventory may be either demand or energy related.

2. Transmission and Subtransmission

The costs of transmission and subtransmission are generally considered fixed costs that do not vary with the quantity of energy transmitted. However, to the extent that transmission investment enables a utility to avoid line losses, some portion of transmission may be classified as energy related.

3. Distribution

The costs of electric distribution systems are affected primarily by demand and by the number of customers. As in transmission, it may be possible to identify some energy component of the cost.

4. Customer Service

Costs functionalized as customer service are related to the number of customers and, therefore, can be classified as customer costs as well.

In any of these functions, costs that are associated with service to a specific customer or customer class may be directly assigned. Although cost classifications are usually based on considerations similar to those listed above, there are numerous instances in which other methods of cost classification are considered. These various circumstances will be discussed in the chapters in Sections II and III.

C. Allocation of Costs Among Customer Classes

After the costs have been functionalized and classified, the next step is to allocate them among the customer classes. To accomplish this, the customers served by the utility are separated into several groups based on the nature of the service provided and load characteristics. The three principal customer classes are residential, commercial, and industrial. It may be reasonable to subdivide the three classes based on characteristics such as size of load, the voltage level at which the customer is served and other service characteristics such as whether a residential customer is all-electric or not. Additional customer classes that may be established are street lighting, municipal, and agricultural.

Once the customer classes to be used in the cost allocation study have been designated, the functionalized and classified costs are allocated among the classes as follows:

- Demand-related costs - Allocated among the customer classes on the basis of demands (KW) imposed on the system during specific peak hours.
- Energy-related costs - Allocated among the customer classes on the basis of energy (KWH) which the system must supply to serve the customers.
- Customer-related costs - Allocated among the customer classes on the basis of the number of customers or the weighted number of customers. Normally, weighting the number of customers in the various classes is based on an analysis of the relative levels of customer-related costs (service lines, meters, meter reading, billing, etc.) per customer.

This manual only discusses the major costing methodologies. It recognizes that no single costing methodology will be superior to any other, and the choice of methodology will depend on the unique circumstances of each utilty. Individual costing methodologies are complex and have inspired numerous debates on application, assumptions and data. Further, the role of cost in ratemaking is itself not without controversy.

Dr. James Bonbright, whose Principles of Public Utility Rates is the classic examination of regulation and ratemaking, wrote:

> "Of all of the many problems of rate making that are bedeviled by unresolved disputes about issues of fairness, the one that deserves first rank for frustration is that concerned with the apportionment among different classes of consumers of the demand costs or capacity costs....Here, notions of 'fair apportionment' are almost sure to conflict with economists' convictions as to the relevant cost allocations. But these notions are themselves neither stable nor uniform, although they reveal a general tendency in favor of a fairly wide spreading out of the costs, as butter would be spread over bread in a well-made sandwich. Awareness of these unresolved conflicts about 'fair' cost apportionment has lead the British economist Professor W. Arthur Lewis to exclaim that, in rate determination, 'equity is the mother of confusion.'"

The purpose of this manual is to clarify, if not resolve, some of that confusion.

CHAPTER 3

DEVELOPING TOTAL REVENUE REQUIREMENTS

A utility, in order to remain viable, must be given the opportunity to recover its prudently incurred total cost of providing electric service to its various classes of customers. Cost of service is usually defined to include all of a utility's operating expenses, plus a reasonable return on its investment devoted to the service of the ratepaying public. Accordingly, it is incumbent on the utility to ensure that the rates it charges for electric services are sufficient to recover its total costs. The total theoretical revenues a utility is authorized to collect through its rates for its various types of service is called the total revenue requirement, or the total cost of service.

The total revenue requirement of a utility is equal to the sum of the costs to serve all its various classes of customers. Since a utility's rates are generally regulated by two or more governmental agencies, revenue requirements under different jurisdictions are usually established on the basis of cost allocation studies; but the rates so established can and often do reflect differing cost bases among jurisdictions.

The derivation of revenue requirements for each jurisdiction's classes of service requires findings in the following areas: (1) The proper development of rate base and fair rate of return to determine return allowances on investment; (2) allowable levels of operating expenses; and (3) proper recognition of other operating revenues, including those for opportunity-type sales of electricity. This chapter, therefore, will first discuss test year concepts, then, the major elements used to determine revenue requirements will be presented.

I. TEST YEAR CONCEPTS

Regulatory agencies recognize that the rates they establish are likely to remain in effect for an indeterminate period into the future. Consequently, rates so established are usually developed using the most current actual or projected cost and sales information for a selected time period. The period used is normally 12 months in length -- referred to as the test year or test period -- and normally includes cost and sales data which are expected to be representative of those that will be experienced during the time the rates are likely to remain in effect.

Three types of test periods are in common usage. Some agencies have adopted test periods which use the latest 12 months of historical data as the basis for setting rates. For instance, if a utility filed changed rates to become effective on January 1, 1987, the historical test year adopted to support those new rates might very well cover the actual data for the period July 1, 1985 to June 30, 1986.

Other agencies, however, have adopted the projected test year concept. In this situation, for rates proposed to be effective January 1, 1987, the utility might be required to support its proposal on data projected for the calendar year 1987.

The third type of test year uses a combination of actual and projected data. For a filing effective as of January 1, 1987, the utility might be required to base its rates on a test period using actual data for the last six months of 1986 and projected data for the first six months of 1987.

The type of test period adopted by a utility to support its rate proposals depends upon a number of factors, the most important of which is the requirement of the regulatory body within whose jurisdiction the utility operates. Other factors may include the degree of rate surveillance practiced by the regulator, the cost characteristics of the utility, including expected changes in the utility's pattern of operation, and automatic cost tracking mechanisms built into the utility's rates.

A. Pro Forma Adjustments of Historical Data

Where projected test periods are not used, rates must be developed on the basis of past cost experience. In order to reflect the cost conditions that may occur during the actual effectiveness of the rates, most agencies permit adjustments to the actual data to reflect changed conditions, to correct for unusual events during the recorded period, or to include costs estimated for a time period in the near future. The goal is to adjust the actual costs to present normal operating conditions as accurately as possible, so that rates resulting from a proceeding are appropriate for application in the immediate future. An example of costs that may require adjustment or normalization are power production and purchased power expense. The addition of new significant generating capacity to a system normally requires the adjustment of accounts to recognize the fixed charges and operating expense mixture change due to a different generation dispatch. Enacted legislation that amends Federal or State income tax provisions from those in effect during the actual test year would require the recalculation of income tax. It should be noted that use of a projected test period would generally obviate the need to make such adjustments for known and measurable changes because projected test periods are developed using forecast data which would presumably already reflect such changes. The revenue requirements calculated using a projected test year should be the same as those calculated using a historic test year plus all pro forma adjustments, including sales adjustments.

In addition to pro forma adjustments to the revenue requirements, most agencies allow reasonable regulatory expenses that are incurred by the utility in preparing, filing and defending its application. These regulatory expenses are often amortized over the period of time that the requested rates are expected to be in effect.

II. REVENUE REQUIREMENT DETERMINATIONS

Revenue requirements may be expressed in mathematical terms as follows:

$$RR = \left(\frac{T_r}{1-T_r} + 1\right) \times (OE + R + FITA + SITA - OR)$$

Where:

RR	=	Total retail service revenue requirement
T_r	=	Revenue tax rate, if applicable
OE	=	Operating expenses, excluding income and revenue taxes
R	=	Return
FITA	=	Federal income taxes allowable
SITA	=	State income taxes allowable
OR	=	Other operating revenue, exclusive of revenue taxes

The elements that are applied in the above formula are the test year costs, plus pro forma adjustments if a historical test year is used. These revenue requirement elements are discussed in the balance of this chapter.

A. Rate Base

Rate base is the investment basis established by a regulatory authority upon which a utility is allowed to earn a fair return. Generally, the amount established as the plant component of rate base represents the amount of property considered to be used and useful in the public service and may be based on a number of different valuation methods, e.g., fair value, reproduction cost or original cost.[1] Rate base also generally includes items other than investment property, i.e., cash working capital, which require capital funding by the utility to carry out its business affairs.

[1] In developing rate base, because of the various ages of plant and equipment, commissions have adopted a number of valuation methodologies. Three of the more commonly used methods are: (1) original cost, which is the cost of utility property at the time such property was brought into service; (2) fair value, which is based on the regulatory agency's judgment, may include consideration of reproduction cost, original cost, replacement cost, market value, or other elements; and (3) reproduction cost, which is the estimated cost to reproduce existing plant facilities in their present form and capabilities at current cost levels.

This subsection discusses the elements that are generally included in rate base, where rate base is based on net original investment costs. The development of such rate base is as follows:

RATE BASE

Original Cost of Electric Plant in Service

Less:	Accumulated depreciation reserves
:	Accumulated provision for deferred income taxes (Accounts 281-283)
:	Operating reserves
Plus:	Electric plant held for future use
:	Construction work in progress (if allowed)
:	Working capital
:	Accumulated provision for deferred income taxes (Account 190)
Equals:	Rate Base

1. Electric Plant in Service

Electric utility plant in service consists of all original cost investment expenditures that are installed by the utility to provide its electric services. As discussed in chapter 2, such plant investment is functionalized to four main categories -- production, transmission, distribution, and general and intangible plant -- for the purpose of properly assigning customer cost responsibilities in each. If the utility is a combination utility, i.e., it provides more than one type of utility service, such as gas, water or steam, then it may have plant that is common to all types of utility service. In this situation, common plant must be apportioned among the various utility operations to ensure that all types of the utility's customers share in the associated costs.

2. Accumulated Depreciation Reserves

Accumulated depreciation reserves represent, at some point in time, the total accrued annual depreciation expenses that the utility has charged to operating expenses for plant in service. The accrual, or depreciation rates, are based upon the utility's determination of the number of years of service expected from plant investments and the expected dismantlement costs when the units of property are removed from service, less the expected salvage value. The yearly depreciation expense amount is determined by multiplying the depreciation rate times the original cost of the plant investment. The total accumulated depreciation reserve amounts are deducted from the original plant in service investment amounts in the development of rate base.

3. Accumulated Provision For Deferred Income Taxes

The accumulated provision for deferred income taxes represents, at some point in time, the net accumulated annual income tax effects arising from timing differences between the periods in which transactions affected taxable income and the periods in which they entered into the determination of taxable income for book (ratemaking) purposes. For Accounts 281 through 283, the deferred amounts usually represent normalization of the book/tax timing differences where tax deductions exceed book expenses. For example, the additional tax deductions resulting from the use of some form of accelerated depreciation for tax purposes instead of straight-line or other non-accelerated depreciation methods used for book purposes, are normalized and recorded in Accounts 281 through 283. These amounts represent the taxes the utility will have to pay some time in the future when timing differences reverse, i.e., when book expense exceeds the amount available to be used as a tax deduction. Since these account balances are funded by the ratepayer and represent sums collected by the utility in advance of actual payment to Federal and State treasuries, they are used as reductions to rate base. Conversely, there are balances which are generated when the utility is required to pay taxes in advance of book (rate) recognition of certain items. These balances are added to rate base.

4. Electric Plant Held For Future Use

Electric plant held for future use refers to land and physical plant and equipment not currently used and useful in the provision of electric service, but which are owned and held by a utility for use some time in the future. These investments may include land which was purchased as the future site of a large generating station, or may include plant which was acquired for future use, or plant which was previously used in providing electric service, but was temporarily suspended from service pending its reuse at some future time. While land acquisitions for future use are routinely permitted in rate base by regulators, plant and equipment acquired for this purpose are not. As a general rule, plant investments held for future use, in order to normally qualify for rate base treatment, cannot remain in an indefinite status, but must be held under a definite plan of future use.

5. Construction Work In Progress

Construction work in progress (CWIP) represents the balance of funds invested in utility plant under construction, but not yet placed in service. Some or all of construction work in progress may be eligible for inclusion in rate base, depending on the practices and policies of the utility's regulators so that the utility can recover currently some or all of the carrying costs of new facilities prior to the plant actually entering service.

Where CWIP is not permitted in rate base, a utility is allowed to capitalize as part of its construction costs an allowance for funds used during construction (AFUDC) as deferred compensation for its construction financing costs. Afterwards, when construction is completed and plant enters rate base, the accumulated AFUDC will be included as part of the investment cost of the plant and will be captured as part of depreciation expenses charged annually to operating expenses over the book life of the facility.

6. Working Capital

Working capital is a rate base element that a utility is allowed in order for it to maintain the required operational supply inventories to meet its prepayment obligations and to provide it with the cash it needs to meet its operating expenses between the time it renders service and when it collects revenues for those services. The three principal categories of working capital are plant materials and supplies, prepayments and cash working capital. Plant materials and supplies include all fuel stock inventories, replacement equipment on hand but not yet placed in service, and supplies that will be needed on a continuous basis for the operation and maintenance of utility plant. Prepayments include items such as prepaid insurance, rents, taxes and interest. Cash working capital is an allowance that is granted by regulators to cover the day-to-day cash needs of a utility. Thus, funds continually invested in these three elements of working capital impose carrying costs on the utility for which it is entitled to be compensated, if such incurrence is found to be prudent.

B. Fair Rate of Return

A fair rate of return is one that will allow the utility to recover its costs of all classes of capital used to finance its rate base. These classes of capital are generally debt and stockholder common equity. The embedded costs of long-term debt and preferred stock are fixed and can be readily computed. The cost of a utility's common equity is reflected in the price that investors are willing to pay for the company's stock and that cost has to be estimated. The cost of common equity is, by far, the most controversial aspect of rate of return determinations. Methods used to arrive at the cost of common equity include the discounted cash flow, comparable earnings, risk premium, and the capital asset pricing model.

A utility is allowed the opportunity to earn a reasonable return on its investment that is prudent and dedicated to the public service. The return dollars a utility is entitled to collect is determined by multiplying the rate base by the rate of return, as follows:

$$R = RB \times r$$

Where:
R = Return
RB = Rate base
r = Rate of return (a percentage)

Return is the amount of money a utility may earn over and above operating expenses, net of income taxes. Included in the return amount is interest on debt, dividends for preferred stock as well as the allowed earnings on common equity.

C. Operating Expenses

Operating expenses are a group of expenses incurred in connection with a utility's operations and include: (1) operation and maintenance expenses; (2) depreciation expenses; (3) miscellaneous amortization expenses; (4) taxes other than income taxes; (5) income taxes; and (6) other operating revenues.

1. Operation and Maintenance Expenses

Operation and maintenance (O&M) expenses are the costs incurred by a utility in the course of supplying its services. O&M expenses include the costs of labor, maintenance, fuel, administrative expenses, regulatory commission expenses, materials and supplies, (to the extent such items are routine expenditures, not capital investments), purchased power and various other service-related expenses.

2. Depreciation Expense

Depreciation expense is the annual charge made against income to provide for distribution of the cost of plant over its estimated useful life. Among the factors considered in developing the annual charge are wear and tear, decay, obsolescence, and any additional requirements that may be imposed by regulators.

3. Miscellaneous Amortization Expenses

Miscellaneous amortization expenses represent costs incurred by a utility that are amortized over a specified period of time for rate purposes. Examples of such costs are cancelled plant amortizations and extraordinary property losses.

4. Taxes Other Than Income Taxes

Taxes other than income taxes include all payments a utility must make to various taxing authorities. Such taxes may be levied on utility sales and property; and for social security, unemployment compensation, franchise, and state and federal excise. Since the utility must pay these taxes in the process of doing business, such costs are eligible for recovery from customers. It should be noted that while revenue taxes (or gross receipts taxes) are considered as "other" taxes, such taxes are levied on all or a portion of the utility's revenues. Consequently, any incremental changes in a utility's revenue requirement determination will produce a corresponding change in these tax allowances.

5. Income Taxes

Income taxes, both federal and state, are levied on a utility's earnings. Consequently, such taxes represent a cost of doing business and are therefore recoverable from a utility's ratepayers. The development of income tax allowances included in rates is a complex process that requires familiarity with federal and state tax laws as well as accounting and ratemaking practices and principles that are adopted by the regulator.

6. Other Operating Revenues

Other operating revenues include all revenues received from sources other than retail sales of electricity. These amounts are collected by a utility for other services rendered. An example of these revenue sources is when a utility may provide space on its transmission or distribution poles for the use of cable television lines and receive revenues therefrom in the form of rental payments. In addition, revenues collected from non-firm opportunity sales or coordination type sales, are normally treated in the same manner as other operating revenues. The retail service customers are normally given credit for these revenues through a reduction in their revenue requirements since they are produced through the use of plant or utility personnel, the expenses of which are borne by the utility's retail service customers.

SECTION II

EMBEDDED COST STUDIES

SECTION II of the Cost Allocation Manual contains five chapters that detail the dominant method of cost allocation -- the embedded cost study; that is, cost allocation methods based on historical or known costs. Each chapter presents allocation methods for specific components of cost.

Chapter 4 describes embedded cost methods for allocating production costs. It first discusses functionalization and classification and differentiates between costs that are demand-related and energy-related. Next, a variety of methods that can be used to allocate production plant costs are presented with numerical examples. Finally, observations on choosing an embedded cost method are included along with data needs.

Chapter 5 discusses methods of transmission cost functionalization, with detailed attention paid to subfunctionalization methods. Next, several methods used to allocate transmission plant costs are presented. Finally, the treatment of wheeling costs is discussed.

Chapter 6 provides an overview of distribution plant cost allocation. It discusses the classification of distribution costs between energy, demand and customers. Two methods used to determine demand and customer components are outlined -- the minimum-size and minimum-intercept methods. Procedures used to calculate demand and allocation factors are finally presented.

Chapters 7 and 8 briefly outline the classification and allocation of customer-related costs and investment, administrative and general expenses, respectively.

CHAPTER 4

EMBEDDED COST METHODS FOR ALLOCATING PRODUCTION COSTS

Of all utility costs, the cost of production plant -- i.e., hydroelectric, oil and gas-fired, nuclear, geothermal, solar, wind, and other electric production plant -- is the major component of most electric utility bills. Cost analysts must devise methods to equitably allocate these costs among all customer classes such that the share of cost responsibility borne by each class approximates the costs imposed on the utility by that class.

The first three sections of this chapter discusses functionalization, classification and the classification of production function costs that are demand-related and energy-related. Section four contains a variety of methods that can be used to allocate production plant costs. The final three sections include observations regarding fuel expense data, operation and maintenance expenses for production and a summary and conclusion.

I. THE FIRST STEP: FUNCTIONALIZATION

Functionalization is the process of assigning company revenue requirements to specified utility functions: Production, Transmission, Distribution, Customer and General. Distinguishing each of the functions in more detail -- subfunctionalization -- is an optional, but potentially valuable, step in cost of service analysis. For example, production revenue requirements may be subfunctionalized by generation type -- fossil, steam, nuclear, hydroelectric, combustion turbines, diesels, geothermal, cogeneration, and other. Distribution may be subfunctionalized to lines (underground and overhead) substations, transformers, etc. Such subfunctional categories may enable the analyst to classify and allocate costs more directly; they may be of particular value where the costs of specific units or types of units are assigned to time periods. But, since this is a manual of cost allocation, and this is a chapter on production costs, we won't linger over functionalization or consider costs in other functions. The interested reader will consult generalized texts on the subject. It will suffice to say here that all utility costs are allocated after they are functionalized.

II. CLASSIFICATION IN GENERAL

Classification is a refinement of functionalized revenue requirements. Cost classification identifies the utility operation -- demand, energy, customer -- for which functionalized dollars are spent. Revenue requirements in the production and transmission functions are classified as demand-related or energy-related. Distribution revenue requirements are classified as either demand-, energy- or customer-related.

Cost classification is often integrated with functionalization; some analysts do not distinguish it as an independent step in the assignment of revenue requirements. Functionalization is to some extent reflected in the way the company keeps its books; plant accounts follow functional lines as do operation and maintenance (O&M) accounts. But to classify costs accurately the analyst more often refers to conventional rules and his own best judgment. Section IV of this chapter discusses three major methods for classifying and allocating production plant costs. We will see that the peak demand allocation methods rely on conventional classification while the energy weighting methods and the time-differentiated methods of allocation require much attention to classification and, indeed, are sophisticated classification methods with fairly simple allocation methods tacked on.

The chart below is a basic example of an integrated functionalization/classification scheme.

FUNCTIONALIZED CLASSIFICATION OF ELECTRIC UTILITY COSTS

	Cost Classes			
Functions	**Demand**	**Energy**	**Customer**	**Revenue**
Production Thermal	X	X	N/A	N/A
Hydro	X	X	N/A	N/A
Other	X	X	N/A	N/A
Transmission	X	X	X	N/A
Distribution	X	X	X	N/A
OH/UG Lines	X	X	X	N/A
Substations	X	X	X	N/A
Services	N/A	N/A	X	N/A
Meters	N/A	N/A	X	N/A
Customer	N/A	N/A	X	X

III. CLASSIFICATION OF PRODUCTION FUNCTION COSTS

Production plant costs can be classified in two ways between costs that are demand-related and those that are energy-related.

A. Cost Accounting Approach

Production plant costs are either fixed or variable. Fixed production costs are those revenue requirements associated with generating plant owned by the utility, including cost of capital, depreciation, taxes and fixed O&M. Variable costs are fuel costs, purchased power costs and some O&M expenses. Fixed production costs vary with capacity additions, not with energy produced from given plant capacity, and are classified as demand-related. Variable production costs change with the amount of energy produced, delivered or purchased and are classified as energy- related. Exhibit 4-1 summarizes typical classification of FERC Accounts 500-557.

EXHIBIT 4-1

CLASSIFICATION OF PRODUCTION PLANT

CLASSIFICATION OF RATE BASE[1]

Production Plant

FERC Uniform System of Accounts No.	Description	Demand Related	Customer Related
301-303	Intangible Plant	x	-
310-316	Steam Production	x	x
320-325	Nuclear Production	x	-
330-336	Hydraulic Production	x	x[2]
340-346	Other Production	x	-

Exhibit 4-1
(Continued)
CLASSIFICATION OF PRODUCTION PLANT

FERC Uniform System of Accounts No.	Description	Demand Related	Energy Related

CLASSIFICATION OF EXPENSES[1]
Production Plant

Steam Power Generation Operations

500	Operating Supervision & Engineering	Prorated On Labor[3]	Prorated On Labor[3]
501	Fuel	-	x
502	Steam Expenses	x[4]	x[4]
503-504	Steam From Other Sources & Transfer. Cr.	-	x
505	Electric Expenses	x[4]	x[4]
506	Miscellaneous Steam Pwr Expenses	x	-
507	Rents	x	-

Maintenance

510	Supervision & Engineering	Prorated On Labor[3]	Prorated On Labor[3]
511	Structures	x	-
512	Boiler Plant	-	x
513	Electric Plant	-	x
514	Miscellaneous Steam Plant	-	x

Nuclear Power Generation Operation

517	Operation Supervision & Engineering	Prorated On Labor[3]	Prorated On Labor[3]
518	Fuel	-	x
519	Coolants and Water	x[4]	x[4]
520	Steam Expense	x[4]	x[4]
521-522	Steam From Other Sources & Transfe. Cr.	-	x
523	Electric Expenses	x[4]	x[4]
524	Miscellaneous Nuclear Power Expenses	x	-
525	Rents	x	-

EXHIBIT 4-1

(Continued)

CLASSIFICATION OF EXPENSES[1]

FERC Uniform System of Accounts No.	Description	Demand Related	Energy Related
	Maintencance		
528	Supervision & Engineering	Prorated on Labor[3]	Prorated on Labor[3]
529	Structures	x	-
530	Reactor Plant Equipment	-	x
531	Electric Plant	-	x
532	Miscellaneous Nuclear Plant	-	x

Hydraulic Power Generation Operation

535	Operation Supervision and Engineering	Prorated on Labor[3]	Prorated on Labor[3]
536	Water for Power	x	-
537	Hydraulic Expenses	x	-
538	Electric Expense	x[4]	x[4]
539	Misc Hydraulic Power Expenses	x	-
540	Rents	x	-

Maintenance

541	Supervision & Engineering	Prorated On Labor[3]	Prorated On Labor[3]
542	Structures	x	-
543	Reservoirs, Dams, and Waterways	x	x
544	Electric Plant	x	x
545	Miscellaneous Hydraulic Plant	x	x

Exhibit 4-1
(Continued)

FERC Uniform System of Account	Description	Demand Related	Energy Related
	CLASSIFICATION OF EXPENSES[1]		
	Other Power Generation Operation		
546, 548-554	All Accounts	x	-
547	Fuel	-	x
	Other Power Supply Expenses		
555	Purchased Power	x[5]	x[5]
556	System Control & Load Dispatch	x	-
557	Other Expenses	x	-

[1] Direct assignment or "exclusive use" costs are assigned directly to the customer class or group that exclusively uses such facilities. The remaining costs are then classified to the respective cost components.

[2] In some instances, a portion of hydro rate base may be classified as energy related.

[3] The classification between demand-related and energy-related costs is carried out on the basis of the relative proportions of labor cost contained in the other accounts in the account grouping.

[4] Classified between demand and energy on the basis of labor expenses and material expenses. Labor expenses are considered demand-related, while material expenses are considered energy-related.

[5] As-billed basis.

The cost accounting approach to classification is based on the argument that plant capacity is fixed to meet demand and that the costs of plant capacity should be assigned to customers on the basis of their demands. Since plant output in KWH varies with system energy requirements, the argument continues, variable production costs should be allocated to customers on a KWH basis.

B. Cost Causation

Cost causation is a phrase referring to an attempt to determine what, or who, is causing costs to be incurred by the utility. For the generation function, cost causation attempts to determine what influences a utility's production plant investment decisions. Cost causation considers: (1) that utilities add capacity to meet critical system planning reliability criteria such as loss of load probability (LOLP), loss of load hours (LOLH), reserve margin, or expected unserved energy (EUE); and (2) that the utility's energy load or load duration curve is a major indicator of the type of plant needed. The type of plant installed determines the cost of the additional capacity. This approach is well represented among the energy weighting methods of cost allocation.

IV. METHODS FOR CLASSIFYING AND ALLOCATING PRODUCTION PLANT COSTS

In the past, utility analysts thought that production plant costs were driven only by system maximum peak demands. The prevailing belief was that utilities built plants exclusively to serve their annual system peaks as though only that single hour was important for planning. Correspondingly, cost of service analysts used a single maximum peak approach to allocate production costs. Over time it became apparent to some that hours other than the peak hour were critical from the system planner's perspective, and utilities moved toward multiple peak allocation methods. The Federal Energy Regulatory Commission began encouraging the use of a method based on the 12 monthly peak demands, and many utilities accordingly adopted this approach for allocating costs within their retail jurisdictions as well as their resale markets.

This section is divided into three parts. The first two contain a discussion of peak demand and energy weighted cost allocation methods. The third part covers time-differentiated cost of service methods for allocating production plant costs. Tables 4-1 through 4-4 contain illustrative load data supplied by the Southern California Edison Company for monthly peak demands, summer and winter peak demands, class noncoincident peak demands, on-peak and off-peak energy use. These data are used to illustrate the derivation of various demand and energy allocation factors throughout this Section as well as Section III.

The common objective of the methods reviewed in the following two parts is to allocate production plant costs to customer classes consistent with the cost impact that the class loads impose on the utility system. If the utility plans its generating capacity additions to serve its demand in the peak hour of the year, then the demand of each class in the peak hour is regarded as an appropriate basis for allocating demand-related production costs.

If the utility bases its generation expansion planning on reliability criteria -- such as loss of load probability or expected unserved energy -- that have significant values in a number of hours, then the classes' demands in hours other than the single peak hour may also provide an appropriate basis for allocating demand-related production costs. Use of multiple-hour methods also greatly reduces the possibility of atypical conditions influencing the load data used in the cost allocation.

TABLE 4-1

CLASS MW DEMANDS AT THE GENERATION LEVL IN THE TWELVE MONTHLY SYSTEM PEAK HOURS

(1988 Example Data)

Rate Class	January	February	March	April	May	June	July	August
DOM	3,887	3,863	2,669	2,103	2,881	3,338	4,537	4,735
LSMP	3,065	3,020	3,743	4,340	4,390	4,725	5,106	5,062
LP	2,536	2,401	2,818	2,888	3,102	3,067	3,219	3,347
AG&P	84	117	144	232	405	453	450	447
SL	94	105	28	0	0	0	0	0
Total	9,666	9,506	9,402	9,563	11,318	11,583	13,312	13,591

Rate Class	September	October	November	December	Total	Average
DOM	4,202	2,534	3,434	4,086	42,268	3,522
LSMP	5,106	4,736	3,644	3,137	50,614	4,218
LP	3,404	3,170	2,786	2,444	35,181	2,932
AG&P	360	284	138	75	3,189	266
SL	0	0	103	126	457	38
Total	13,072	10,724	10,105	9,868	131,709	10,976

Note: The rate classes and their abbreviations for the example utility are as follows:

DOM - Domestic Service
LSMP - Lighting, Small and Medium Power
LP - Large Power
AG&P - Agricultural and Pumping
SL - Street Lighting

TABLE 4-2

CLASS MW DEMANDS AT THE GENERATION LEVEL IN THE 3 SUMMER AND 3 WINTER SYSTEM PEAK HOURS

(1988 Example Data)

	Winter				Summer			
Rate Class	January	February	December	Average	July	August	September	Average
DOM	3,887	3,863	4,086	3,946	4,537	4,735	4,202	4,491
LSMP	3,065	3,020	3,137	3,074	5,106	5,062	5,106	5,092
LP	2,536	2,401	2,444	2,460	3,219	3,347	3,404	3,323
A&P	84	117	75	92	450	447	360	419
SL	94	105	126	108	0	0	0	0
Total	9,666	9,506	9,868	9,680	13,312	13,591	13,072	13,325

Peak demand methods include the single coincident peak method, the summer and winter peak method, the twelve monthly coincident peak method, multiple coincident peak method, and an all peak hours approach. Energy weighting methods include the average and excess method, equivalent peaker method, the base and peak method, and methods using judgmentally determined energy weightings, such as the peak and average method and variants thereof.

A. Peak Demand Methods

Cost of service methods that utilize a peak demand approach are characterized by two features: First, all production plant costs are classified as demand-related. Second, these costs are allocated among the rate classes on factors that measure the class contribution to system peak. A customer or class of customers contributes to the system maximum peak to the extent that it is imposing demand at the time of -- coincident with -- the system peak. The customer's demand at the time of the system peak is that customer's "coincident" peak. The variations in the methods are generally around the number of system peak hours analyzed, which inturn depends on the utility's annual load shape and on system planning considerations.

Peak demand methods do not allocate production plant costs to classes whose usage occurs outside peak hours, to interruptible (curtailable) customers.

TABLE 4-3
DEMAND ALLOCATION FACTORS

Rate Class	MW Demand At Annual System Peak (MW)	1 CP Alloc. Factor (Percent)	Average of the 12 Monthly CP Demands (MW)	12 CP Alloc. Factor (Percent)	Average of the 3 Summer CP Demands (MW)	Average of the 3 Winter CP Demands (MW)	3S/3W Alloc. Factor (Percent)	Noncoinc. Peak Demand MW	NCP Alloc. Factor (Percent)
DOM	4,735	34.84	3,522	32.09	4,491	3,946	36.67	5,357	36.94
LSMP	5,062	37.25	4,218	38.43	5,092	3,074	35.50	5,062	34.91
LP	3,347	24.63	2,932	26.71	3,323	2,460	25.14	3,385	23.34
AG&P	447	3.29	266	2.42	419	92	2.22	572	3.94
SL	0	0.00	38	0.35	0	108	0.47	126	0.87
Total	13,591	100.00	10,976	100.00	13,325	9,680	100.00	14,502	100.0

Note: Some columns may not add to indicated totals due to rounding.

TABLE 4-4
ENERGY ALLOCATION FACTORS

Rate Class	Total Annual Energy Used (MWH)	Total Energy Allocation Factor (%)	On-Peak Energy Cons. (MWH)	On-Peak Energy Allocation Factor (%)	Off-Peak Energy Cons. (MWH)	Off-Peak Energy Allocation Factor (%)
DOM	21,433,001	30.96	3,950,368	32.13	17,482,633	30.71
LSMP	23,439,008	33.86	4.452,310	36.21	18,986,698	33.35
LP	21,602,999	31.21	3,474,929	28.26	18,128,070	31.85
AG&P	2,229,000	3.22	335,865	2.73	1,893,135	3.33
SL	513,600	0.74	80,889	0.66	432,711	0.76
Total	69,217,608	100.00	12,294,361	100.00	56,923,247	100.00

Note: Some columns may not add to indicated totals due to rounding.

1. Single Coincident Peak Method (1-CP)

Objective: The objective of the single coincident peak method is to allocate production plant costs to customer classes according to the load of the customer classes at the time of the utility's highest measured one-hour demand in the test year, the class coincident peak load.

Data Requirements: The 1-CP method uses recorded and/or estimated monthly class peak demands. In a large system, this may require complex statistical sampling and data manipulation. A competent load research effort is a valuable asset.

Implementation: Table 4-1 contains illustrative load data for five customer classes for 12 months of a test year. The analyst simply translates class load at the time of the system peak into a percentage of the company's total system peak, and applies that percentage to the company's production-demand revenue requirements; that is, to the revenue requirements that are functionalized to production and classified to demand. This operation is shown in Table 4-5.

TABLE 4-5

CLASS ALLOCATION FACTORS AND ALLOCATED PRODUCTION PLANT REVENUE REQUIREMENT USING THE SINGLE COINCIDENT PEAK METHOD

Rate Class	MW Demand at Generator at System Peak	Allocation Factor	Total Class Production Plant Revenue Requirement
DOM	4,735	34.84	369,461,692
LSMP	5,062	37.25	394,976,787
LP	3,347	24.63	261,159,089
AG&P	447	3.29	34,878,432
SL	0	0.00	0
TOTAL	13,591	100.00	$ 1,060,476,000

2. Summer and Winter Peak Method

Objective: The objective of the summer and winter peak method is to reflect the effect of two distinct seasonal peaks on customer cost assignment. If the summer and winter peaks are close in value, and if both significantly affect the utility's generation expansion planning, this approach may be appropriate.

Implementation: The number of summer and winter peak hours may be determined judgmentally or by applying specified criteria. One method is simply to average the class contributions to the summer peak hour demand and the winter peak hour demand. Another method is to choose those summer and winter hours where the peak demand or reliability index passes a specified threshold value. Clearly, the selection of the hours is critical and the establishment of selection criteria is particularly important. These cost of service judgements must be made jointly with system planners and supported with good data. The analyst should review FERC cases, where this issue often comes up. Table 4-6 shows the allocators and resulting allocations of production plant revenue responsibility for the example using the three highest summer and three highest winter coincident peak demand hours.

TABLE 4-6

CLASS ALLOCATION FACTORS AND ALLOCATED PRODUCTION PLANT REVENUE REQUIREMENT USING THE SUMMER AND WINTER PEAK METHOD

Rate Class	Average of the 3 Summer CP Demands (MW)	Average of the 3 Winter CP Demands (MW)	Demand Allocation Factor	Total Class Production Plant Revenue Requirmt
DOM	4,491	3,946	36.67	388,925,712
LSMP	5,092	3,074	35.50	376,433,254
LP	3,323	2,460	25.14	266,582,600
AG&P	419	92	2.22	23,555,889
SL	0	108	0.47	4,978,544
TOTAL	13,325	9,680	100.00	$ 1,060,476,000

3. The Sum of the Twelve Monthly Coincident Peak (12 CP) Method

Objective: This method uses an allocator based on the class contribution to the 12 monthly maximum system peaks. This method is usually used when the monthly peaks lie within a narrow range; i.e., when the annual load shape is not spiky. The 12-CP method may be appropriate when the utility plans its maintenance so as to have equal reserve margins, LOLPs or other reliability index values in all months.

Data Requirements: Reliable monthly load research data for each class of customers and for the total system is the minimum data requirement. The data can be recorded and/or estimated.

Implementation: Table 4-7 shows the derivation of the 12 CP allocator and the resulting allocation of production plant costs for the example case.

TABLE 4-7

CLASS ALLOCATION FACTORS AND ALLOCATED PRODUCTION PLANT REVENUE REQUIREMENT USING THE TWELVE COINCIDENT PEAK METHOD

Rate Class	Average of 12 Coincident Peaks At Generation (MW)	Allocation Factor	Total Class Production Plant Revenue Requirement
DOM	3,522	32.09	340,287,579
LSMP	4,218	38.43	407,533,507
LP	2,932	26.71	283,283,130
AG&P	266	2.42	25,700,311
SL	38	0.35	3,671,473
TOTAL	10,976	100.00	$ 1,060,476,000

4. Multiple Coincident Peak Method

This section discusses the general approach of using the classes' demands in a certain number of hours to derive the allocation factors for production plant costs. The number of hours may be determined judgmentally; e.g., the 10 or 20 hours in the year with the highest system demands, or by applying specified criteria. Criteria for determining which hours to use include: (1) all hours of the year with demands within 5 percent or 10 percent of the system's peak demand, and (2) all hours of the year in which a specified reliability index (loss of load probability, loss of load hours, expected unserved energy, or reserve margin) passes an established threshold value. This may result in a fairly large number of hours being included in the development of the demand allocator.

5. All Peak Hours Approach

This method resembles the multiple CP approach except it bases the allocation of demand-related production plant costs on the classes' contributions to all defined, rather than certain specified, on-peak hours. This method requires scrutiny of all hours of the year to determine which are most likely to contribute to the need for the utility to add production plant. If the on-peak rating periods -- i.e., the hours or periods in which on-peak rates apply -- are properly defined, then all hours in the on-peak period are critical from the utility's planning perspective. Table 4-8 shows the allocators and resulting cost allocation based on the classes' shares of on-peak KWH for the example utility. For the example utility, the on-peak periods are from 5:00 p.m. to 9:00 p.m. on winter weekdays and from 12:00 noon to 6:00 p.m. on summer weekdays.

The on-peak hours may be defined using various criteria, such as those hours with a preponderance of actual peak demands, those with the majority of annual loss of load probabilities, loss of load hours or those in which other reliability indexes register critical values. Using this method requires satisfactory load research and computer capability to estimate the classes' loads in the defined on-peak periods.

TABLE 4-8

CLASS ALLOCATION FACTORS AND ALLOCATED PRODUCTION PLANT REVENUE REQUIREMENT USING THE ALL PEAK HOURS APPROACH

Rate Class	Class On-Peak MWH At Generation	Allocation Factor	Total Class Production Plant Revenue Requirement
DOM	3,950,368	32.13	340,747,311
LSMP	4,452,310	36.21	384,043,376
LP	3,474,929	28.26	299,737,319
AG&P	335,865	2.73	28,970,743
SL	80,889	0.66	6,977,251
TOTAL	12,294,361	100.00	$ 1,060,476,000

Notes: The on-peak periods for the example utility are from 5:00 p.m. to 9:00 p.m. on weekdays in January through May and October through December, and from 12:00 noon to 6:00 p.m. on weekdays in June through September. Some columns may not add to indicated totals due to rounding.

6. Summary: Peak Demand Responsibility Methods

Table 4-9 is a summary of the allocation factors and revenue allocations for the methods described above. The most important observations to be drawn from this information are:

- The number of hours chosen as the basis for the demand allocator can have a significant effect on the revenue allocation, even for relatively small numbers of hours.
- The greater the number of hours used, the more the allocation will reflect energy requirements. If all 8,760 hours of a year were used, the demand and a KWH (energy) allocation factors would be the same.

TABLE 4-9

SUMMARY OF ALLOCATION FACTORS AND REVENUE RESPONSIBILITY FOR PEAK DEMAND COST ALLOCATION METHODS

	1 CP Method		3 Summer and 3 Winter Peak Method	
Rate Class	Allocation Factor (%)	Revenue Requirement	Allocation Factor (%)	Revenue Requirement
DOM	34.84	369,461,692	36.67	388,925,712
LSMP	37.25	394,976,787	35.50	376,433,254
LP	24.63	261,159,089	25.14	266,582,600
AG&P	3.29	34,878,432	2.22	23,555,889
SL	0.00	0	0.47	4,978,544
TOTAL	100.00	$ 1,060,476,000	100.00	$ 1,060,476,000

	12 CP Method		All Peak Hours Approach	
Rate Class	Allocation Factor (%)	Revenue Requirement	Allocation Factor (%)	Revenue Requirement
DOM	32.09	340,287,579	32.13	340,747,311
LSMP	38.43	407,533,507	36.21	384,043,376
LP	26.71	283,283,130	28.26	299,737,319
AG&P	2.42	25,700,311	2.73	28,970,743
SL	0.35	3,671,473	0.66	6,977,251
TOTAL	100.00	$ 1,060,476,000	100.00	$ 1,060,476,000

Note: Some columns may not add to totals due to rounding.

B. Energy Weighting Methods

There is evidence that energy loads are a major determinant of production plant costs. Thus, cost of service analysis may incorporate energy weighting into the treatment of production plant costs. One way to incorporate an energy weighting is to classify part of the utility's production plant costs as energy-related and to allocate those costs to classes on the basis of class energy consumption. Table 4-4 shows allocators for the example utility for total energy, on-peak energy, and off-peak energy use.

In some cases, an energy allocator (annual KWH consumption or average demand) is used to allocate part of the production plant costs among the classes, but part or all of these costs remain classified as demand-related. Such methods can be characterized as partial energy weighting methods in that they take the first step of allocating some portion of production plant costs to the classes on the basis of their energy loads but do not take the second step of classifying the costs as energy- related.

1. Average and Excess Method

Objective: The cost of service analyst may believe that average demand rather than coincident peak demand is a better allocator of production plant costs. The average and excess method is an appropriate method for the analyst to use. The method allocates production plant costs to rate classes using factors that combine the classes' average demands and non-coincident peak (NCP) demands.

Data Requirements: The required data are: the annual maximum and average demands for each customer class and the system load factor. All production plant costs are usually classified as demand-related. The allocation factor consists of two parts. The first component of each class's allocation factor is its proportion of total average demand (or energy consumption) times the system load factor. This effectively uses an average demand or total energy allocator to allocate that portion of the utility's generating capacity that would be needed if all customers used energy at a constant 100 percent load factor. The second component of each class's allocation factor is called the "excess demand factor." It is the proportion of the difference between the sum of all classes' non-coincident peaks and the system average demand. The difference may be negative for curtailable rate classes. This component is multiplied by the remaining proportion of production plant -- i.e., by 1 minus the system load factor -- and then added to the first component to obtain the "total allocator." Table 4-10A shows the derivation of the allocation factors and the resulting allocation of production plant costs using the average and excess method.

TABLE 4-10A

CLASS ALLOCATION FACTORS AND ALLOCATED PRODUCTION PLANT REVENUE REQUIREMENT USING THE AVERAGE AND EXCESS METHOD

Class Rate	Demand Allocation Factor - NCP MW	Average Demand (MW)	Excess Demand (NCP MW - Avg. MW)	Average Demand Component of Alloc. Factor	Excess Demand Component of Alloc. Factor	Total Allocation Factor (%)	Class Production Plant Revenue Requirement
DOM	5,357	2,440	2,917	17.95	18.51	36.46	386,683,685
LSMP	5,062	2,669	2,393	19.64	15.18	34.82	369,289,317
LP	3,385	2,459	926	18.09	5.88	23.97	254,184,071
AG&P	572	254	318	1.87	2.02	3.89	41,218,363
SL	126	58	68	0.43	0.43	0.86	9,101,564
TOTAL	14,502	7,880	6,622	57.98	42.02	100.00	$1,060,476,000

Notes: The system load factor is 57.98 percent, calculated by dividing the average demand of 7,880 MW by the systen coincident peak demand of 13,591 MW. This example shows production plant classified as demand-related.

Some columns may not add to indicated totals due to rounding.

If your objective is -- as it should be using this method --to reflect the impact of average demand on production plant costs, then it is a mistake to allocate the excess demand with a coincident peak allocation factor because it produces allocation factors that are identical to those derived using a CP method. Rather, use the NCP to allocate the excess demands.

The example on Table 4-10B illustrates this problem. In the example, the excess demand component of the allocation factor for the Street Lighting and Outdoor Lighting (SL/OL) class is <u>negative</u> and <u>reduces</u> the class's allocation factor to what it would be if a single CP method were used in the first place. (See third column of Table 4-3.)

TABLE 4-10B

CLASS ALLOCATION FACTORS AND ALLOCATED PRODUCTION PLANT REVENUE REQUIREMENT USING THE AVERAGE AND EXCESS METHOD (SINGLE CP DEMAND FACTOR)

Rate Class	Demand Allocation Factor - Single CP NCP MW	Average Demand (MW)	Excess Demand (Single CP MW - Avg. MW)	Average Demand Component of Allocation Factor	Excess Demand Component of Allocation Factor	Total Allocation Factor (%)	Class Production Plant Revenue Requirement
DOM	4,735	2,440	2,295	17.95	16.89	34.84	369,461,692
LSMP	5,062	2,669	2,393	19.64	17.61	37.25	394,976,787
LP	3,347	2,459	888	18.09	6.53	24.63	261,159,089
AG&P	447	254	193	1.87	1.42	3.29	34,878,432
SL	0	58	-58	0.43	-0.43	0.00	0
TOTAL	13,591	7,880	5,711	57.98	42.02	100.00	$1,060,476,000

Notes: The system load factor is 57.98 percent, calculated by dividing the average demand of 7,880 MW by the systen coincident peak demand of 13,591 MW. This example shows all production plant classified as demand-related. Note that the total allocation factors are exactly equal to those derived using the single coincident peak method shown in the third column of Table 4-3.

Some columns may not add to indicated totals due to rounding.

Some analysts argue that the percentage of total production plant that is equal to the system load factor percentage should be classified as energy-related and not demand-related. This could be important because, although classifying the system load factor percentage as energy-related might not affect the allocation among classes, it could significantly affect the apportionment of costs within rate classes. Such a classification could also affect the allocation of production plant costs to interruptible service, if the utility or the regulatory authority allocated energy-related production plant costs but not demand-related production plant costs to the interruptible class. Table 4-10C presents the allocation factors and production plant revenue requirement allocations for an average and excess cost of service study with the system load factor percentage classified as energy-related.

TABLE 4-10C

CLASS ALLOCATION FACTORS AND ALLOCATED PRODUCTION PLANT REVENUE REQUIREMENT USING THE AVERAGE AND EXCESS METHOD

(AVERAGE DEMAND PROPORTION ALLOCATED ON ENERGY)

Rate Class	Energy Allocation Factor - Average MW	Energy Allocatn. Factor (%)	Energy-Related Production Plant Revenue Requirement	Excess Demand Allocation Factor (NCP MW - Avg. MW)	Excess Demand Alloctn. Factor (Percent)	Demand-Related Production Plant Revenue Requirement	Class Production Plant Revenue Requiremnt
DOM	2,440	30.96	190,387,863	2,917	44.05	196,294,822	386,682,685
LSMP	2,669	33.87	208,256,232	2,393	36.14	161,033,085	369,289,317
LP	2,459	31.21	191,870,391	926	13.98	62,313,680	254,184,071
AG&P	254	3.22	19,819,064	318	4.80	21,399,298	41,218,363
SL	58	0.74	4,525,613	68	1.03	4,575,951	9,101,564
TOTAL	7,880	100.00	614,859,163	6,622	100.00	445,616,837	1,060,476,000

Notes: The system load factor is 57.98 percent (7,880 MW/13,591 MW). Thus, 57.98 percent of total production plant revenue requirement is classified as energy-related and allocated to all classes on the basis of their proportions of average system demand. The remaining 42.02 percent is classified as demand-related and allocated to the classes according to their proportions of excess (NCP - average) demand, and allocated to the firm service classes according to their proportions of excess (NCP - average) demand.

Some columns may not add to indicated totals due to rounding.

2. Equivalent Peaker Methods

Objective: Equivalent peaker methods are based on generation expansion planning practices, which consider peak demand loads and energy loads separately in determining the <u>need</u> for additional generating capacity and the most cost-effective <u>type</u> of capacity to be added. They generally result in significant percentages (40 to 75 percent) of total production plant costs being classified as energy-related, with the results that energy unit costs are relatively high and the revenue responsibility of high load factor classes and customers is significantly greater than indicated by pure peak demand responsibility methods.

The premises of this and other peaker methods are: (1) that increases in peak demand require the addition of peaking capacity only; and (2) that utilities incur the costs of more expensive intermediate and baseload units because of the additional energy loads they must serve. Thus, the cost of peaking capacity can properly be regarded as peak demand-related and classified as demand-related in the cost of service study. The difference between the utility's total cost for production plant and the cost of peaking capacity is caused by the energy loads to be served by the utility and is classified as energy-related in the cost of service study.

Data Requirements: This energy weighting method takes a different tack toward production plant cost allocation, relying more heavily on system planning data in addition to load research data. The cost of service analyst must become familiar with system expansion criteria and justify his cost classification on system planning grounds.

A Digression on System Planning with Reference to Plant Cost Allocation:

Generally speaking, electric utilities conduct generation system planning by evaluating the need for additional capacity, then, having determined a need, choosing among the generation options available to it. These include purchases from a neighboring utility, the construction of its own peaking, intermediate or baseload capacity, load management, enhanced plant availability, and repowering among others.

The utility can choose to construct one of a variety of plant-types: combustion turbines (CT), which are the least costly per KW of installed capacity, combined cycle (CC) units costing two to three times as much per KW as the CT, and baseloaded units with a cost of four or more times as much as the CT per KW of installed capacity. The choice of unit depends on the energy load to be served. A peak load of relatively brief duration, for example, less than 1,500 hours per year, may be served most economically by a CT unit. A peak load of intermediate duration, of 1,500 to 4,000 hours per year, may be served most economically by a CC unit. A peak load of long annual duration may be served most economically by a baseload unit.

Classification of Generation:

In the equivalent peaker type of cost study, all costs of actual peakers are classified as demand-related, and other generating units must be analyzed carefully to determine their proportionate classifications between demand and energy. If the plant types are significantly different, then individual analysis and treatment may be necessary. The ideal analysis is a "date of service" analysis. The analyst calculates the installed cost of all units in the dollars of the install date and classifies the peaker cost as demand-related. The remaining costs are classified as energy-related.

A variant of the above approach is to do the equivalent peaker cost evaluations based only on the viable generation alternatives available to the utility at any point in time. For example, combined cycle technology might be so much more cost-effective than the next best option that it would be the preferred choice for demand lasting as little as 50 to 100 hours. If so, then using a combustion turbine as the equivalent peaker "benchmark" might be inappropriate. Such choices would require careful analysis of alternate generation expansion paths on a case by case basis.

Consider the example shown in Table 4-11. The example utility has three 100 MW combustion turbines of varying ages. All investment in these units is classified as demand-related. The utility also has three unscrubbed coal-fired units of varying ages. The production plant costs of these units are classified as follows: first, the ratio of the cost of a new CT ($300/KW) to the cost of a new unscrubbed coal unit ($1000/KW) is calculated and found to be 30 percent. Then, this factor is multiplied by the rate base for each plant, and the result is classified as demand-related, with the remainder classified as energy-related. The cost of the utility's new, scrubbed coal unit is classified by the same method. Since the unit cost is $1200/KW, only 25 percent of it ($300/KW)/($1200/KW) is classified as demand-related, with the remaining three-fourths classified as energy-related. Treating the utility's nuclear unit similarly, only 15 percent of its cost ($300/KW)/($2000/KW) is classified as demand-related.

TABLE 4-11

ILLUSTRATION OF DEMAND AND ENERGY AND ENERGY CLASSIFICATION OF GENERATING UNITS USING THE EQUIVALENT PEAKER METHOD

Unit	Unit Type	Capacity (MW)	Rate Base	Percent Class Demand-Related	Demand-Related Rate Base	Energy-Related Rate Base
A	CT	100	10,000,000	100	10,000,000	0
B	CT	100	20,000,000	100	20,000,000	0
C	CT	100	30,000,000	100	30,000,000	0
D	Coal	200	80,000,000	30	24,000,000	56,000,000
E	Coal	250	100,000,000	30	30,000,000	70,000,000
F	Coal	450	270,000,000	30	81,000,000	189,000,000
G	Coal W/FDG	600	720,000,000	25	180,000,000	540,000,000
H	Nuclear	900	1,800,000,000	15	270,000,000	1,530,000,000
TOTAL		2,700	$ 3,030,000,000	21	$ 645,000,000	$ 2,385,000,000

The equivalent peaker classification method applied in the example above ignores the fuel savings that accrue from running a base unit rather than a peaker. Discussions with planners can help incorporate the effects of fuel savings into the classification.

Table 4-12 shows the revenue responsibility for the rate classes using the equivalent peaker cost method applied to the example utility's data. In this example, a summer and winter peak demand allocator was used to allocate the demand-related costs. Observe that the total revenue requirement allocation among the rate classes is significantly different from that resulting from any of the pure peak demand responsibility methods.

TABLE 4-12

CLASS ALLOCATION FACTORS AND ALLOCATED PRODUCTION PLANT REVENUE REQUIREMENT USING THE EQUIVALENT PEAKER COST METHOD

Rate Class	Demand Allocation Factor - 3 Summer & 3 Winter Peaks (%)	Demand-Related Production Plant Revenue Requirement	Energy Allocation Factor (Total MWH)	Energy-Related Production Plant Revenue Requirement	Total Class Production Plant Revenue Requiremnt
DOM	36.67	78,980,827	30.96	261,678,643	340,659,471
LSMP	35.50	76,460,850	33.87	286,237,828	362,698,678
LP	25.14	54,147,205	31.21	263,716,305	317,863,510
AG&P	2.22	4,781,495	3.22	27,240,318	32,021,813
SL	0.47	1,012,299	0.74	6,220,230	7,232,529
TOTAL	100.00	215,382,676	100.00	845,093,324	$1,060,476,000

Note: Some columns may not add to indicated totals due to rounding.

3. Base and Peak Method

Objective: The objective of the base and peak method is to reflect in cost allocation the argument that an on-peak kilowatt-hour costs more than an off-peak kilowatt-hour and that the extra cost should be borne by the customers imposing it. This approach first identifies the same production plant cost components as the equivalent peaker cost method, and allocates demand-related production plant costs in the same way. The difference is that, using the base and peak method, the energy-related excess capital costs are allocated on the basis of the classes' proportions of on-peak energy use instead of being allocated according to the classes' shares of total system energy use. The logic of this approach is that the extra capital costs would be incurred once the system was expected to run for a certain minimum number of hours; i.e., once the break-even point in unit run time between a peaker and a baseload (or intermediate) unit was reached. However, system planners generally recognize no difference between on-peak hours and off-peak energy loads on the decision to build a baseload power plant, instead, the belief is that system planners consider the total annual energy loads that determine the type of plant to build. To allocate energy-related production plant costs on the basis of only on-peak energy use implies a differential impact of on-peak KWH as compared to off-peak KWH that may or may not exist.

Table 4-13 shows the results of a base and peak cost of service method for the example utility.

TABLE 4-13

CLASS ALLOCATION FACTORS AND ALLOCATED PRODUCTION PLANT REVENUE REQUIREMENT USING THE BASE AND PEAK METHOD

Rate Class	Demand Allocation Factor - 3 Summer & 3 Winter Peaks (%)	Demand-Related Production Plant Revenue Requirement	Energy Allocation Factor On-Peak MWH	Energy-Related Production Plant Revenue Requirement	Total Class Production Plant Revenue Requirement
DOM	36.67	78,980,827	32.13	271,541,532	350,522,360
LSMP	35.50	76,460,850	36.21	306,044,166	382,505,016
LP	25.14	54,147,205	28.26	238,860,669	293,007,874
AG&P	2.22	4,781,495	2.73	23,086,785	27,868,280
SL	0.47	1,012,299	0.66	5,560,171	6,572,470
TOTAL	100.00	215,382,676	100.00	845,093,324	$1,060,476,000

Note: Some columns may not add to indicated totals due to rounding.

4. Judgmental Energy Weightings

Some regulatory commissions, recognizing that energy loads are an important determinant of production plant costs, require the incorporation of judgmentally-established energy weighting into cost studies. One example is the "peak and average demand" allocator derived by adding together each class's contribution to the system peak demand (or to a specified group of system peak demands; e.g., the 12 monthly CPs) and its average demand. The allocator is effectively the average of the two numbers: class CP (however measured) and class average demand. Two variants of this allocation method are shown in Tables 4-14 and 4-15.

TABLE 4-14

CLASS ALLOCATION FACTORS AND ALLOCATED PRODUCTION PLANT REVENUE REQUIREMENT USING THE 1 CP AND AVERAGE DEMAND METHOD

Rate Class	Demand Allocation Factor - 1 CP MW (Percent)	Demand-Related Production Plant Revenue Requirement	Avg. Demand (Total MWH) Allocation Factor	Energy-Related Production Plant Revenue Requirement	Total Class Production Plant Revenue Requirement
DOM	34.84	233,869,251	30.96	120,512,062	354,381,313
LSMP	37.25	250,020,306	33.87	131,822,415	381,842,722
LP	24.63	165,313,703	31.21	121,450,476	286,764,179
AG&P	3.29	22,078,048	3.22	12,545,108	34,623,156
SL	0.00	0	0.74	2,864,631	2,864,631
TOTAL	100.00	671,281,308	100.00	389,194,692	$1,060,476,000

Notes: The portion of the production plant classified as demand-related is calculated by dividing the annual system peak demand by the sum of (a) the annual system peak demand, Table 4-3, column 2, plus (b) the average system demand for the test year, Table 4-10A, column 3. Thus, the percentage classified as demand-related is equal to 13591/(13591+7880), or 63.30 percent. The percentage classified as energy-related is calculated similarly by dividing the average demand by the sum of the system peak demand and the average system demand. For the example, this percentage is 36.70 percent.

Some columns may not add to indicated totals due to rounding.

TABLE 4-15

CLASS ALLOCATION FACTORS AND ALLOCATED PRODUCTION PLANT REVENUE REQUIREMENT USING THE 12 CP AND AVERAGE DEMAND METHOD

Rate Class	Demand Allocation Factor - 12 CP MW (Percent)	Demand-Related Production Plant Revenue	Average Demand (Total MWH) Allocation Factor	Energy-Related Production Plant Revenue Requirement	Total Class Production Plant Revenue Requirement
DOM	32.09	198,081,400	30.96	137,226,133	335,307,533
LSMP	38.43	237,225,254	33.87	150,105,143	387,330,397
LP	26.71	164,899,110	31.21	138,294,697	303,193,807
AG&P	2.42	14,960,151	3.22	14,285,015	29,245,167
SL	0.35	2,137,164	0.74	3,261,933	5,399,097
TOTAL	100.00	617,303,080	100.00	443,172,920	$1,060,476,000

Notes: The portion of production plant classified as demand-related is calculated by dividing the annual system peak demand by the sum of the 12 monthly system coincident peaks (Table 4-3, column 4) by the sum of that value plus the system average demand (Table 4-10A, column 3). Thus, for example, the percentage classified as demand-related is equal to 10976/(10976+7880), or 58.21 percent. The percentage classified as energy-related is calculated similarly by dividing the average demand by the sum of the average demand and the average of the twelve monthly peak demands. For the example, 41.79 percent of production plant revenue requirements are classified as energy-related.

Another variant of the peak and average demand method bases the production plant cost allocators on the 12 monthly CPs and average demand, with 1/13th of production plant classified as energy-related and allocated on the basis of the classes' KWH use or average demand, and the remaining 12/13ths classified as demand-related. The resulting allocation factors and allocations of revenue responsibility are shown in Table 4-16 for the example data.

TABLE 4-16

CLASS ALLOCATION FACTORS AND ALLOCATED PRODUCTION PLANT REVENUE REQUIREMENT USING THE 12 CP AND 1/13TH WEIGHTED AVERAGE DEMAND METHOD

Rate	Demand Allocation Factor - 12 CP MW (Percent)	Demand-Related Production Plant Revenue Requirement	Average Demand (Total MWH) Allocation Factor	Energy-Related Production Plant Revenue Requirement	Total Class Production Plant Revenue Requirement
DOM	32.09	314,111,612	30.96	25,259,288	339,370,900
LSMP	38.43	376,184,775	33.87	27,629,934	403,814,709
LP	26.71	261,492,120	31.21	25,455,979	286,948,099
AG&P	2.42	23,723,364	3.22	2,629,450	26,352,815
SL	0.35	3,389,052	0.74	600,426	3,989,478
TOTAL	100.00	978,900,923	100.00	81,575,077	$1,060,476,000

Notes: Using this method, 12/13ths (92.31 percent) of production plant revenue requirement is classified as demand-related and allocated using the 12 CP allocation factor, and 1/13th (7.69 percent) is classified as energy-related and allocated on the basis of total energy consumption or average demand.

Some columns may not add to indicated totals due to rounding.

C. Time-Differentiated Embedded Cost of Service Methods

Time-differentiated cost of service methods allocate production plant costs to baseload and peak hours, and perhaps to intermediate hours. These cost of service methods can also be easily used to allocate production plant costs to classes without specifically identifying allocation to time periods. Methods discussed briefly here include production stacking methods, system planning approaches, the base-intermediate-peak method, the LOLP production cost method, and the probability of dispatch method.

1. Production Stacking Methods

Objective: The cost of service analyst can use production stacking methods to determine the amount of production plant costs to classify as energy-related and to determine appropriate cost allocations to on-peak and off-peak periods. The basic principle of such methods is to identify the configuration of generating plants that would be used to serve some specified base level of load to classify the costs associated with those units as energy-related. The choice of the base level of load is crucial because it determines the amount of production plant cost to classify as energy-related. Various base load level options are available: average annual load, minimum annual load, average off-peak load, and maximum off-peak load.

Implementation: In performing a cost of service study using this approach, the first step is to determine what load level the "production stack" of baseload generating units is to serve. Next, identify the revenue requirements associated with these units. These are classified as energy-related and allocated according to the classes' energy use. If the cost of service study is being used to develop time-differentiated costs and rates, it will be necessary to allocate the production plant costs of the baseload units first to time periods and then to classes based on their energy consumption in the respective time periods. The remaining production plant costs are classified as demand-related and allocated to the classes using a factor appropriate for the given utility.

An example of a production stack cost of service study is presented in Table 4-17. This particular method simply identified the utility's nuclear, coal-fired and hydroelectric generating units as the production stack to be classified as energy-related. The rationale for this approach is that these are truly baseload units. Additionally, the combined capacity of these units (4,920.7 MW) is significantly less than either the utility's average demand (7,880 MW) or its average off-peak demand (7,525.5 MW); thus, to get up to the utility's average off-peak demand would have required adding oil and gas-fired units, which generally are not regarded as baseload units. This method results in 89.72 percent of production plant being classified as energy-related and 10.28 percent as demand-related. The allocation factor and the classes' revenue responsibility are shown in Table 4-17.

2. Base-Intermediate-Peak (BIP) Method

The BIP method is a time-differentiated method that assigns production plant costs to three rating periods: (1) peak hours, (2) secondary peak (intermediate, or shoulder hours) and (3) base loading hours. This method is based on the concept that specific utility system generation resources can be assigned in the cost of service analysis as serving different components of load; i.e., the base, intermediate and peak load components. In the analysis, units are ranked from lowest to highest operating costs. Those with the lower operating costs are assigned to all three periods, those with intermediate running costs are assigned to the intermediate and peak periods, and those with the highest operating costs are assigned to the peak rating period only.

TABLE 4-17

CLASS ALLOCATION FACTORS AND ALLOCATED PRODUCTION PLANT REVENUE REQUIREMENT USING A PRODUCTION STACKING METHOD

Rate Class	Demand Allocation Factor - 3 Summer & 3 Winter Peaks (%)	Demand-Related Production Plant Revenue Requirement	Energy Allocation Factor (Total MWH)	Energy-Related Production Plant Revenue Requirement	Total Class Production Plant Revenue Requirement
DOM	36.67	39,976,509	30.96	294,614,229	334,590,738
LSMP	35.50	38,701,011	33.87	322,264,499	360,965,510
LP	25.14	27,406,857	31.21	296,908,356	324,315,213
AG&P	2.22	2,420,176	3.22	30,668,858	33,089,034
SL	0.47	512,380	0.74	7,003,125	7,515,505
TOTAL	100.00	109,016,933	100.00	951,459,067	$1,060,476,000

Note: This allocation method uses the same allocation factors as the equivalent peaker cost method illustrated in Table 4-12. The difference between the two studies is in the proportions of production plant classified as demand- and energy-related. In the method illustrated here, the utility's identified baseload generating units -- its nuclear, coal-fired and hydroelectric generating units -- were classified as energy-related, and the remaining units -- the utility's oil- and gas-fired steam units, its combined cycle units and its combustion turbines -- were classified as demand-related. The result was that 89.72 percent of the utility's production plant revenue requirement was classified as energy-related and allocated on the basis of the classes' energy consumption, and 10.28 percent was classified as demand-related and allocated on the basis of the classes' contributions to the 3 summer and 3 winter peaks.

Some columns may not add to indicated totals due to rounding

There are several methods that may be used for allocating these categorized costs to customer classes. One common allocation method is as follows: (1) peak production plant costs are allocated using an appropriate coincident peak allocation factor; (2) intermediate production plant costs are allocated using an allocator based on the classes' contributions to demand in the intermediate or shoulder period; and (3) base load production plant costs are allocated using the classes' average demands for the base or off-peak rating period.

In a BIP study, production plant costs may be classified as energy-related or demand-related. If the analyst believes that the classes' energy loads or off-peak average demands are the primary determinants of baseload production plant costs, as indicated by the inter-class allocation of these costs, then they should also be classified as energy-related and recovered via an energy charge. Failure to do so -- i.e., classifying production plant costs as demand-related and recovering them through a $/KW demand charge -- will result in a disproportionate assignment of costs to low load factor customers within classes, inconsistent with the basic premise of the method.

3. LOLP Production Cost Method

LOLP is the acronym for loss of load probability, a measure of the expected value of the frequency with which a loss of load due to insufficient generating capacity will occur. Using the LOLP production cost method, hourly LOLP's are calculated and the hours are grouped into on-peak, off-peak and shoulder periods based on the similarity of the LOLP values. Production plant costs are allocated to rating periods according to the relative proportions of LOLP's occurring in each. Production plant costs are then allocated to classes using appropriate allocation factors for each of the three rating periods; i.e., such factors as might be used in a BIP study as discussed above. This method requires detailed analysis of hourly LOLP values and a significant data manipulation effort.

4. Probability of Dispatch Method

The probability of dispatch (POD) method is primarily a tool for analyzing cost of service by time periods. The method requires analyzing an actual or estimated hourly load curve for the utility and identifying the generating units that would normally be used to serve each hourly load. The annual revenue requirement of each generating unit is divided by the number of hours in the year that it operates, and that "per hour cost" is assigned to each hour that it runs. In allocating production plant costs to classes, the total cost for all units for each hour is allocated to the classes according to the KWH use in each hour. The total production plant cost allocated to each class is then obtained by summing the hourly cost over all hours of the year. These costs may then be recovered via an appropriate combination of demand and energy charges. It must be noted that this method has substantial input data and analysis requirements that may make it prohibitively expensive for utilities that do not develop and maintain the required data.

TABLE 4-18

SUMMARY OF PRODUCTION PLANT
COST ALLOCATIONS USING DIFFERENT COST OF SERVICE METHODS

	1 CP METHOD		12 CP METHOD		3 SUMMER & 3 WINTER PEAK METHOD		ALL PEAK HOURS APPROACH		AVERAGE AND EXCESS METHOD	
	Revenue Req't. ($)	Percent of Total	Revenue Req't. ($)	Percent of Total	Revenue Req't. ($)	Percent of Total	Revenue Req't. ($)	Percent of Total	Revenue Req't. ($)	Percent of Total
DOM	$ 369,461,692	34.84	$ 340,287,579	32.09	$ 388,925,712	36.67	$ 340,747,311	32.13	$ 386,682,685	36,46
LSMP	394,976,787	37.25	407,533,507	38.43	376,433,254	35.50	384,043,376	36.21	369,289,317	34.82
LP	261,159,089	24.63	283,283,130	26.71	266,582,600	25.14	299,737,319	28.26	254,184,071	23.97
AG&P	34,878,432	3.29	25,700,311	2.42	23,555,089	2.22	28,970,743	2.73	41,218,363	3.89
SL	0	0.00	3,671,473	0.35	4,978,544	0.47	6,977,251	0.66	9,101,564	0.86
Total	$1,060,476,000	100.00	$1,060,476,000	100.0	$1,060,476,000	100.00	$1,060,476,000	100.0	$1,060,476,000	100.0

	EQUIVALENT PEAKER COST METHOD		BASE AND PEAK METHOD		1 CP AND AVERAGE DEMAND METHOD		12 CP AND 1/13th AVERAGE DEMAND METHOD		PRODUCTION STACKING METHOD	
Rate Class	Revenue Req't. ($)	Percent of Total	Revenue Req't. ($)	Percent of Total	Revenue Req't. ($)	Percent of Total	Revenue Req't. ($)	Percent of Total	Revenue Req't. ($)	Percent of Total
DOM	$ 340,657,471	32.12	$ 3350,522,360	33.05	$ 354,381,313	33.42	$ 339,370,900	32.00	$ 334,590,738	31.55
LSMP	362,698,678	34.20	382,505,016	36.07	381,842,722	36.01	403,814,709	38.08	360,965,510	34.04
LP	317,863,510	29.97	293,007,874	27.63	286,764,179	27.04	286,948,099	27.06	324,315,213	30.58
AG&P	32,021,813	3.02	27,868,280	2.63	34,623,156	3.36	26,352,815	2.48	33,089,034	3.12
SL	7,232,529	0.68	6,572,470	0.62	2,864,631	0.27	3,989,478	0.38	7,515,505	0.71
Total	$1,060,476,000	100.00	$1,060,476,000	100.00	$1,060,476,000	100.00	$1,060,476,000	100.00	$1,060,476,000	100.00

5. Summary

Table 4-18 summarizes the percentage allocation factors and revenue allocations for the cost of service methodologies presented in this chapter. Important observations are: (1) that the proportions of production plant costs classified as demand-related and energy-related can have dramatic effects on the revenue allocation; and (2) the greater the proportion classified as energy-related, the greater is the revenue responsibility of high load factor classes and the less is the revenue responsibility of low-load factor classes.

V. FUEL EXPENSE DATA

Fuel expense data can be obtained from the FERC Form 1. Aggregate fuel expense data by generation type is found in Accounts 501, 518, and 547. Annual fuel expense by fuel type for specified generating stations can be found on pages 402 and 411 of Form 1.

Fuel expense is almost always classified as energy-related. It is allocated using appropriate time-differentiated allocators; e.g., on-peak KWH and off-peak KWH, or non-time-differentiated energy allocators (total KWH) calculated by incorporating adjustments to reflect different line and transformation losses at different levels of the utility's transmission and distribution system. Depending on the cost of service method used, it may be necessary to directly assign fuel expense to classes that are directly assigned the cost responsibility for specific generating units. Table 4-19 shows the allocation of fuel expense, other operation and maintenance expenses and purchased power expenses for the example utility. Fuel and purchased power expenses were allocated according to the classes' energy use at the generator level. Other operation and maintenance expenses were allocated using demand and energy allocators and ratio methods.

VI. OTHER OPERATIONS AND MAINTENANCE EXPENSES FOR PRODUCTION

Other production O&M costs may also be classified as demand-related or energy-related. Typically, any costs that vary directly with the amount of energy produced, such as purchased steam, variable water cost and water treatment chemical costs, are classified as energy-related and allocated using appropriate energy allocation factors. Such cost items would typically be booked in Accounts 502 through 505 for fossil power steam generation, Accounts 519 and 520 for nuclear power generation, and Accounts 548 and 550.1 for other generation (excluding hydroelectric).

TABLE 4-19
ALLOCATED GENERATION FUEL, OPERATION, AND MAINTENANCE EXPENSES
(Thousands of Dollars)

EXPENSE CATEGORY	TOTAL COMPANY RETAIL	DOMESTIC	LIGHTING, SMALL AND MEDIUM POWER	LARGE POWER	AGRICULTURAL AND PUMPING	STREET LIGHTING
Total Fuel	$ 871,598	$269,887	$295,147	$272,028	$28,068	$ 6,467
Steam Generation Expenses						
Operation Expenses	53,740	17,246	20,652	14,355	1,301	186
Maintenance Expenses	176,117	54,632	60,037	54,574	5,601	1,272
Total Steam Excl. Fuel	229,857	71,879	80,688	68,929	6,902	1,459
Nuclear Generation Expenses						
Operation Expenses	106,851	34,291	41,061	28,541	2,587	371
Maintenance Expenses	88,787	27,552	30,305	27,475	2,817	638
Total Nuclear Excl. Fuel	195,638	61,842	71,366	56,017	5,404	1,009
Hydraulic Generation Expenses						
Operation Expenses	9,730	3,054	3,462	2,872	284	58
Maintenance Expenses	13,135	4,123	4,674	3,877	383	78
Total Hydraulic Expenses	22,865	7,177	8,136	6,749	667	136
Other Generation Expenses						
Operation Expenses	20,461	6,563	7,953	5,358	516	70
Maintenance Expenses	10,371	3,327	4,020	2,729	259	36
Total Other Excl. Fuel	30,832	9,890	11,973	8,087	775	106
Purchased Power	1,275,663	395,005	431,975	398,138	41,080	9,466
System Control & Dispatch	0	0	0	0	0	0
Other	0	0	0	0	0	0
Total	$2,626,453	$815,680	$899,285	$809,948	$82,896	$18,643

Note: Some values may not add to indicated totals or sub-totals due to rounding.

Operations and maintenance costs that do not vary directly with energy output may be classified and allocated by different methods. If certain costs are specifically related to serving particular rate classes, they are directly assigned. Some accounts may be easily identified as being all demand-related or all energy-related; these may then be allocated using appropriate demand andenergy allocators. Other accounts contain both demand-related and energy-related components. One common method for handling such accounts is to separate the labor expenses from the materials expenses: labor costs are then considered fixed and therefore demand-related, and materials costs are considered variable and thus energy-related. Another common method is to classify each account according to its "predominant" -- i.e., demand-related or energy-related -- character. Certain supervision and engineering expenses can be classified on the basis of the prior classification of O&M accounts to which these overhead accounts are related. Although not standard practice, O&M expenses may also be classified and allocated as the generating plants at which they are incurred are allocated.

VII. SUMMARY AND CONCLUSION

A. Choosing a Production Cost Allocation Method

As we have seen in the catalog of cost allocation methods above, the analyst chooses a method after considering many complex factors: (1) the utility's generation system planning and operation; (2) the cost of serving load with new generation or purchased power; (3) the incidence of new load on an annual, monthly and hourly basis; (4) the availability of load and operations data; and (5) the rate design objectives.

B. Data Needs and Sources

Most of the cost of service methods reviewed above require: (1) rate base data; (2) operations and maintenance expense data, depreciation expense data, and tax data; and (3) peak demand and energy consumption data for all rate classes. Some methods also require information from the utility's system planners regarding the operation of specific generating units and more general data such as generation mix, types of plants and the plant loading; for example, how often the units are operated, and whether they are run as baseload, intermediate or peaking units. Rate base, O&M, depreciation, tax and revenue data are generally available from the FERC Form 1 reports that follow the uniform system of accounts prescribed by FERC for utilities (18 CFR Chapter 1, Subchapter C, Part 101). See Chapter 3 for a complete discussion of revenue requirements. Load data may be gathered by the utility or borrowed from similar neighboring utilities if necessary. Data or information relating to specific generating units must be obtained from the utility's system planners and power-system operators.

C. Class Load Data

Any cost of service method that allocates part or all of production plant costs using a peak demand allocator requires at least estimates of the classes' peak demands. These may be estimates of the classes' coincident peak (CP) or non-coincident class peak (NCP) demands.

For larger utilities, class load data is generally developed from statistical samples of customers with time-recording demand and energy meters. Utilities without a load research program can sometimes borrow load data from others. See Appendix A for a thorough discussion of development of data through load research studies.

Different cost of service methods have different data requirements. The requirements may be as simple as: (1) total energy usage, adjusted for different line and transformation losses to be comparable at the generation level; (2) the class coincident peak demands in the peak hour of the year; and (3) the class non-coincident peak demands for the year. Some methods require much more complex data, ranging from class CP demands in each of the 12 monthly peak hours to estimated class demands in each hour of the year. Thus, load data development and analysis for cost of service studies entail substantial effort and cost.

D. System and Unit Dispatch Data

Some methods, such as the base-intermediate-peak methods, require classification of units according to their primary operating function. This may involve judgmental classification by system planners or power system operators. Other methods, such as the probability of dispatch methods, require either actual or modeled data regarding specific units' operation on an hour-by-hour basis, as well as hourly load data. Production stacking methods require data on the dispatch configuration of units, including reserves, required to serve a given load level. Such data must be developed and maintained by the utility.

E. Conclusion

This review of production cost allocation methods may not contain every method, but it is hoped that the reader will agree that the broad outlines of all methods are here. The possibilities for varying the methods are numerous and should suit the analysts' assessment of allocation objectives. Keep in mind that no method is prescribed by regulators to be followed exactly; an agreed upon method can be revised to reflect new technology, new rate design objectives, new information or a new analyst with new ideas. These methods are laid out here to reveal their flexibility; they can be seen as maps and the road you take is the one that best suits you.

CHAPTER 5

FUNCTIONALIZATION AND ALLOCATION OF TRANSMISSION PLANT

The transmission system may be defined for ratemaking purposes as a group of highly integrated bulk power supply facilities, con-sisting of high voltage power lines and substations. They are designed and operated by a utility to transport electric power reliably and economically from points of origin on its system to distribution loads or load centers located within its franchise area, or to other points of delivery on its system[1]. The points of origin of power so transported may be from the utility's own production resources, or may be that of another utility which is then delivered by that utility to the other's system through various transmission interconnections. The transmission function is generally concluded at the high-voltage side of a distribution substation owned by the utility, or at points where the ownership of bulk power supply facilities change.

The two principal characteristics that distinguish one transmission system from another are the voltages at which the bulk power supply facilities are designed and operated, and the way in which those facilities are configured.

The voltages of transmission facilities can and do vary widely from one electric system to another. For example, where one system's predominant backbone transmission facilities may consist of 345KV or higher voltage facilities, another's may consist of 115KV facilities, while still another's may have a combination of facilities which operate at various transmission voltages.

[1]The Federal Energy Regulatory Commission defines a transmission system to include: (1) all land, conversion structures, and equipment employed at a primary source of supply (i.e., generating station, or point of receipt in the case of purchase power) to change the voltage or frequency of electricity for the purpose of its more efficient or convenient transmission; (2) all land, structures, high tension apparatus, and their control and protective equipment between a generating or receiving point and the entrance to a distribution center or wholesale point; and (3) all lines and equipment whose primary pupose is to augment, integrate or tie together the sources of power supply. (1 FERC Para, 15,064).

The way in which transmission facilities are configured also varies widely from system to system. For example, some systems may be highly integrated, where facilities of the same or different voltages are configured to form networks that provide a number of alternative paths through which power may flow from one point to another. Other systems may be essentially radial, where few or no alternative paths exist to transport power from one point to another.

In general, the transmission system may be considered to be comprised of a number of subsystems, or component parts, which operate together to deliver bulk power supply to various points or load centers. The most commonly used terms to differentiate the various subsystems from each other are: (1) the backbone and inter-tie facilities; (2) generation step-up facilities; (3) subtransmission plant; and (4) radial facilities.

In addition, there are other plant components that may perform a function not perceived as being predominately related to transmission, but nonetheless contributing to the economic and reliable operation of the transmission system. In a cost of service format, these particular plant facilities, which are represented as investment costs recorded in a utility's production or distribution plant accounts, are often referred to as "plant reclassifications."

The use of transmission subsystems is both a useful means of generally explaining the different aspects of transmission system design and operation, and is particularly applicable to the ratemaking process. For example, where certain classes of electric utility customers require service from the transmission system as a whole, other classes may not require the use of all components of the system. Thus, the use of subsystems or plant groupings provides the basis upon which cost responsibilities among customer groups may be differentiated.

This chapter first discusses two methods of transmission system functionalization; with more detailed attention paid to subfunctionalization methods. Next, several methods used to allocate transmission plant costs are presented. The careful reader will see similarities with Chapter 4. Finally, the treatment of wheeling costs is discussed.

I. FUNCTIONALIZATION OF THE TRANSMISSION SYSTEM

Functionalization may be defined as the process of grouping costs associated with a facility that performs a certain function with the costs of other facilities that perform similar functions. The extent to which transmission plant is functionalized in a cost of service analysis will usually depend upon the design and operating characteristics of classes of facilities, their different cost characteristics, and the type and nature of electric services being provided by the utility.

The process of transmission plant functionalization usually begins with the identification and grouping of those higher-order customers, and concludes with those groups of facilities of a lesser order that are required to serve only particular customers or groups of customers.

The number of transmission plant cost groups can range from one to several. Where only one transmission cost group is recognized, the functionalization method is referred to as the "rolled-in method." Where more than one group of transmission facilities is recognized, the functionalization method is usually called the "subfunctionalization method."

A. The Rolled-in Transmission Plant Method

Under the rolled-in transmission method of functionalization, the transmission system is comprised of highly integrated facilities which are designed and operated collectively to deliver bulk power supply from point to point on the system. Thus, where facilities of various operating voltages form integrated transmission networks, each element within those networks is considered to be contributing to the economic and reliable operation of the overall system.

While the concept of a fully integrated transmission system is the principal reason for treating it as a single system for ratemaking purposes, there are certain transmission facilities that are not integrated. These facilities, principally radial transmission lines, are used exclusively to serve specific customer loads at transmission voltages. The philosophy for rolling-in these radial lines is that they represent a short-term strategy in which a utility is able to maximize long-term system efficiency, without sacrificing reliability, by phasing-in transmission system expansions. In effect, radial transmission lines are perceived as the initial phase of transmission expansion from which network or looped facilities will ultimately emerge as system loads begin to grow. Therefore, since all customers are generally expected to benefit from the strategy of overall transmission cost minimization, all should be expected to share the costs of the system.

B. The Subfunctionalized Transmission Plant Method

The main alternative method to the rolled-in approach is the subfunctionalization of the transmission system. Under this approach, transmission subsystems may be distinguished from one another by the utility's use of them, or, on the basis of line configuration, geographic circumstances and voltage level, among other considerations.

The data requirements imposed by subfunctionalization are substantially more demanding than those imposed by the rolled-in method. Not only are detailed plant account records and schematic diagrams required to evaluate the function or role performed by each transmission element, but a high degree of subjective judgment is required to categorize these elements when their function is less than clear, or where an element performs multiple functions. For example, substation structures may house integrated transmission plant components that require the use of micro-allocation methods to apportion investment costs among all the subfunctionalized plant categories. In order to perform such micro-allocations, detailed plant cost accounting data as well as facility demand data must be available.

In addition, subfunctionalization gives rise to questions concerning the manner in which facilities of different vintages should be accounted for in the cost of service analysis. For example, subtransmission investment of early vintage is more depreciated than other subsystems within the transmission system. In order to recognize any vintage difference in the functionalization of depreciation reserve, a detailed review of a utility's historic plant accounting records will need to be undertaken.

Because of these substantial requirements, the extent to which transmission plant is to be functionalized should be limited to the number of plant categories that adequately recognize the different cost consequences that may exist among customers or groups of customers.

Under subfunctionalization, the main distinction is usually between those facilities that interconnect all the major power sources with each other -- the backbone transmission facilities -- and everything else. Utilities have identified subsystems such as generation step-up facilities, system interconnection and subtransmission, among others. These transmission system components and other non-backbone facilities may often be considered as a separate network of facilities that are either not used to support the backbone system, or represent facilities that require special recognition in the ratemaking process.

1. Backbone and Inter-tie Transmission Facilities

Backbone and inter-tie transmission facilities are generally considered to be the network of high-voltage facilities through which a utility's major production sources, both on and off its system, are integrated. As power systems have expanded to meet increased demands for electric energy, lower voltage networks have been overlaid with higher voltage transmission facilities to improve transmission system reliability and to capture economy benefits. Today, 115KV to 765KV (and even higher) voltage facilities constitute the backbone of most large transmission systems or power pools. Where a utility is a member of a formal power pool, through which reliability and economy gains may be realized from coordinated utility operations, it is not unusual that segments of an area-wide EHV backbone transmission network will be owned by several different utilities consistent with their pool obligations. The points at which ownership changes between utilities are often referred to as the pool inter-ties or interconnection points. Power flows in either direction over these inter-ties as a result of the coordinated operations of the interconnected utility members. This classification of transmission plant investment becomes significant in utility cost allocation studies where loads are served exclusively from the high voltage transmission network without appreciable support from the lower voltage networks. These facilities are generally allocated to all classes of firm power customers.

2. Generation Step-Up Facilities

Generation step-up facilities generally refer to the substations through which power is transformed from a utility's generation output voltages to its various transmission voltages. This classification is based on the concept that such facilities are an extension of production plant and should be treated accordingly, particularly where wheeling services are directly or indirectly involved in the cost allocations. Under this theory, all classes of firm load are generally allocated generation step-up costs except wheeling customers.

3. Subtransmission Plant

Subtransmission plant refers to those lower voltage facilities on some utilities' systems whose function, over time, has changed to a quasi-transmission role in the delivery of electric power supply. As generation station sites become further removed from the utility's loads, the character of the transmission system has significantly changed. Today, facilities operating at voltages of 115 KV or higher are considered to be transmission, while facilities operating at voltages below 25 KV are generally considered to be distribution. Those facilities operating at voltages between 25 KV and 115 volts are now commonly referred to as subtransmission facilities. Accordingly, subtransmission may be defined to represent that portion of utility plant used for the purpose of transferring electric energy from convenient points on a utility's backbone transmission system to its distribution system, or to other utility systems, such as points of interconnection with wholesale customers' facilities. Cost responsibility for subtransmission plant is usually assigned to only those loads served directly at the subtransmission voltages and those distribution loads fed through subtransmission facilities. Customers served at voltages higher than subtransmission are not allocated these costs on the theory that the subtransmission facilities are not required or used to provide the higher voltage services.

4. Radial Facilities

Radial transmission facilities represent those facilities that are not networked with other transmission facilities, but are used to serve specific loads directly. For cost of service purposes, these facilities may be directly assigned to specific customers on the theory that these facilities are not used or useful in providing service to customers not directly connected to them.

5. Plant Reclassifications

In some instances, distribution line and substation investments recorded in the distribution plant accounts may be reassigned to transmission because of their functional characteristics. An example of this is when a power generator is not directly interconnected with the transmission system but feeds directly into the distribution system. This could occur when a combustion turbine generator is located within a distribution load center. In this case, distribution facilities which provide the shortest path from the generator to the transmission system may be considered for reassignment to the transmission function on the theory that these facilities represent an integral part of the power supply network. The advent of cogeneration has added significantly to the importance of this reclassification because, in many cases, a cogenerator is connected to a utility's electrical system at a distribution voltage.

In other instances, large capacitor banks and synchronous condensers located within the distribution system may also be considered part of the transmission system. Synchronous condensers and capacitor banks generate volt-amperes reactives (VAR's) which feed into the transmission system and help stabilize transmission voltages and improve system power factor. The installation of large capacitor banks on the transmission system can cost as much as three times more per VAR than if they were installed at the distribution level. Thus, even though large capacitor banks and synchronous condensers have a significant influence in the operation of the transmission system, they are often installed at the distribution level to save in installation costs. In some cases where synchronous condensers are installed at the distribution level and are assigned to the transmission function, the shortest distribution path from these facilities to the transmission system as well as the condensers themselves may also be assigned to the transmission function.

II. METHODS OF ALLOCATING TRANSMISSION PLANT

A utility keeps track of its transmission plant costs in a manner suitable for ratemaking purposes in order to charge customers a cost-based rate for providing them with transmission services. These costs may be rolled-in or subfunctionalized to effect the appropriate assignment of costs based on the contribution of each customer group to the applicable plant cost category.

Costs are assigned using one of two general principles: (1) allocation; or (2) direct assignment. Allocation is an indirect method of cost assignment under which customer cost responsibilities are usually measured in terms of usages, e.g., KW, KWH or KVA. The premise of cost allocation is that the cost of providing transmission service to a customer is proportional to the demand that customer imposes on the system or its components. There are several methods discussed below to calculate these relationships. Direct assignment, as its name implies, rests on the premise that, insofar as facilities are used exclusively by a customer, the costs of those facilities can be imposed directly on that customer.

After transmission costs are separated into appropriate demand or energy allocation categories, it is necessary to then select a method of assigning cost allocation responsibility to various customers. In general, customers are allocated a portion of the fully distributed (embedded) cost of the transmission system on a basis similar to the way production costs are allocated. The reason for this is that the transmission system is essentially considered to be an extension of the production system, where the planning and operation of one is inexorably linked to the other. Thus, the major factors that drive production costs, it is argued, tend to drive transmission costs as well.

On the other hand, the transmission system is designed to reliably and economically deliver bulk power supply throughout the system, even under adverse operating conditions. In transmission contingency planning, the keystone to reliability is redundancy which translates, in effect, to capacity being built in excess of that which is minimally required to deliver load. The redundant character of the transmission system then gives rise to the theory that its capacity is separable into two functional components: (1) an energy-delivery system component, allocable on an energy basis; and (2) a reliability component, allocable on the basis of some demand or capacity measurement. This particular approach, however, is not in common usage.

Customer transmission cost responsibility in the cost of service is expressed in terms of allocation ratios. These ratios are usually developed on the basis of customer demands to the sum of all demands deemed to be imposed on the total system or subsystem. Thus, the demand of the customer is included in both the numerator and denominator of the allocation factor and the customer is accordingly allocated a portion of the total costs. Since firm power loads are the highest order of electric service, all fixed costs are deemed incurred to provide such service. Conversely, non-firm service may either be opportunity-type sales without availability assurances, or sales from surplus capacity with limited assurances of availability. Thus, revenues derived from these sales, usually based on negotiated rates, may recover costs anywhere in the range of zero to the amount of the fully distributed costs. With value of service negotiated prices, revenues may even exceed fully distributed costs. In recognition of this cost or price flexibility, the demands for non-firm customers are usually excluded from the allocation factor determinations and, concomitantly, the revenues collected from non-firm customers are treated as credits in the cost of service.

Numerical examples for several allocation methods are provided with data contained in Table 5-1.

TABLE 5-1

1988 SYSTEM AND CUSTOMER DATA - TRANSMISSION LEVEL

	SYSTEM			CUSTOMER GROUP		
Month	KWH (millions)[1]	CP Demand (MW)[1]	NCP Demand (MW)[2]	CP Demand (MW)[1]	NCP Demand (MW)[1]	KWH (millions)[3]
Jan	5610	10520	11074	337	319	166
Feb	5130	10570	11126	344	315	153
Mar	5590	10180	10716	354	344	179
Apr	5400	10620	11178	361	358	180
May	5670	11190	11779	410	403	210
Jun	5860	12090	12726	431	427	215
Jul	6580	13730	14453	524	515	268
Aug	6910	14610	15379	524	520	271
Sep	6410	15050	15842	491	489	246
Oct	6110	12380	13032	405	405	211
Nov	5500	10770	11337	364	336	169
Dec	5700	11120	11705	355	347	181
Total	70470	142830	150347	4900	4778	2449

[1] Basic data supplied by Southern California Edison Company.

[2] Assuming .95 coincidence factor.

[3] Assuming 70% monthly load factor.

A. Allocation Methods

1. The Single System Coincident Peak (1CP) Demand Allocation Method

The single highest peak demand is the overriding consideration that drives power supply cost decisions. Customer contribution to this single annual system peak is used to measure customer responsibility. The result is that those customers which most heavily contribute to the single monthly peak will pay a proportionally larger amount of the cost of maintaining the transmission system.

The calculation of the 1CP demand allocation requires a knowledge of the company's single transmission system peak demand (exclusive of non-firm demands) and the demand of the customer group at the same hour and day of that month. The 1CP demand allocation ratio is computed by dividing the customer group's 1CP demand by the utility's transmission demand at the time of the system peak, as follows:

$$\text{1CP Customer Group Demand Ratio} = \frac{\text{Customer Group 1CP Metered Demand + Demand Losses}}{\text{Firm Transmission Peak Demand}}$$

In order to determine the transmission system peak demands, the company must be able to monitor the utility's demands on its production facilities and the power flows entering its system. To determine the customer group's actual demand at the time of the transmission system's peak demand, the utility must have either time-demand meters, or employ statistical techniques to determine the relationship between the individual customer's billing demand and its actual incurrence. See Table 5-2 for illustrative example of 1CP allocation methodology.

TABLE 5-2

EXAMPLE OF SINGLE SYSTEM PEAK DEMAND ALLOCATION

Customer group CP demand at system CP (Sep)	491
System CP(MW)	15050
1 CP customer group demand ratio	.03262

2. The Average Seasonal System Coincident Peak Method

Because of heating and air conditioning loads, a utility may experience peak demands of comparable magnitude during different seasons of the year. The peak demands during those seasons may be considerably higher than those for the remaining months of the year, and the actual peak month may rotate from year to year between the seasons. In addition, the high level of usages may be sustained longer in one season than the other.

The calculation of the average seasonal CP demand allocation requires data for the company's transmission peak demands for the allocation periods selected and the demands of the customer groups at the same hours and days for each of those periods. The problem of implementation is the same as for the 1CP demand allocation method, except that data for more than one period is needed.

The average seasonal CP demand allocation ratio is computed by dividing the sum of the customer group's demands at the peak periods by the sum of the utility's transmission demands during those same periods. The demand ratios are computed as follows:

$$\text{Seasonal CP Demand Ratio} = \frac{\text{Sum of Customer Seasonal CP Demands \& Demand Losses}}{\text{Sum of Seasonal Transmission System Peaks}}$$

Implementation of the average seasonal CP demand allocation method will involve the same type of data and the same difficulties, except that data for more than one allocation period are required. See Table 5-3 for sample application of seasonal CP allocation methodology.

TABLE 5-3

EXAMPLE OF AVERAGE SEASONAL SYSTEM COINCIDENT PEAK ALLOCATION

Customer group CP total for months of July, August and September*	1539
System CP total for the same month(MW)	43390
Customer group average seasonal demand ratio	.03547

* Selection of July-September period is based on criterion of using months with system CP demand of at least 90% of system annual CP demand. Actual selection may consider historical occurrence of CP demand in additional months.

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

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

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

Customer responsibility under this allocation method is computed as follows:

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

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

TABLE 5-4

EXAMPLE OF 12 MONTHLY SYSTEM COINCIDENT PEAK ALLOCATION

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

4. The Single Non-Coincident Peak (NCP) Demand Allocation Method

The NCP method attempts to give recognition to the maximum demand placed upon a system during the year by all customers. This method is based on the theory that facilities are sized to meet these maximum demands. Therefore, the costs of the facilities are allocated in accordance with each customer's contribution to the sum of the maximum demands of all customers' imposed on the facilities.

Customer responsibility under this method is computed as follows:

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

Data for individual customers such as municipal or cooperative systems is usually readily available by delivery point. The maximum peak demands of individual or groups of retail customers are not available since many retail loads are not demand metered. Thus, large groups of retail customers will benefit from the diversity among their loads in the allocation process. See Table 5-5 for a sample application of the single NCP allocation methodology.

TABLE 5-5

EXAMPLE OF SINGLE NON-COINCIDENT PEAK DEMAND ALLOCATION

Customer group NCP demand (MW)	520
System NCP demand*	15842
Customer group NCP demand ratio	.03282

* Assuming a coincidence factor of .95 for the system, NCP for CP demand of 15050 MW would equal 15842 MW.

5. The Monthly Average NCP Demand Allocation Method

The monthly average NCP demand allocation method attempts to give recognition to the variation or diversity among monthly NCP demands placed on a system during the year by all customers. This in effect recognizes the fact that facilities are installed to provide reliable service throughout the year including periods of scheduled maintenance. Costs of the facilities are allocated in accordance with each customer's average monthly contribution to the sum of the average monthly maximum demands of all customers.

As with the NCP method, data for individual customers such as municipal or co-operative systems is usually readily available by delivery point. The maximum peak demands of individual or groups of retail customers are not available since many retail loads are not demand metered. See Table 5-6 for sample application of monthly average NCP allocation methodology.

TABLE 5-6

EXAMPLE OF MONTHLY AVERAGE NCP DEMAND ALLOCATION

Customer group NCP demand total(MW)	4778
System NCP demand total*	150347
Customer group monthly average NCP demand ratio	.03178

* Assuming a coincidence factor of .95 for the system, NCP for system CP monthly demands as shown in Table 5-1 would total 150347 MW.

6. Average and Excess Allocation Method

In contrast to the various peak demand allocation methods which assign costs based entirely on peak demand responsibility, under the average and excess demand allocation method (A&E) transmission costs are divided into two parts for allocation purposes on both demand and energy based on the system load factor (the ratio of the average load over a designated period to the peak demand occurring in that period). As such, the A&E method emphasizes or recognizes the extent of the use of capacity resulting in allocation of an increasing proportion of capacity costs to a customer group as its load factor increases. This theory implies that a utility's capacity serves a dual function -- while system peak demands establish the level of capacity, providing continuous service creates additional incentive for such capacity costs. Use of the A&E method for allocating transmission costs is typically employed for consistency when production costs are allocated on the same basis.

Because the A&E method does not recognize the coincident peak contribution of a customer group's load, the data necessary to perform the calculation is limited to the energy consumption and maximum (non-coincident) demand for a given period.

The first half of the formula, the "average" component representing the customer group's average energy consumption, allocates transmission costs on an energy use or average demand basis. The second half of the formula, the "excess" component is derived from the difference between the customer group's maximum non-coincident peak demand and the "average" demand component. The A&E method is expressed algebraically as follows:

$$D = L \times \frac{A}{B} + (1-L) \times \frac{C}{E}$$

Where: D = customer group's demand responsibility ratio
L = system's annual load factor
A = customer group's energy requirements
B = total system energy requirements
C = customer group's "excess" demand responsibility
E = sum of all customer groups' "excess" demand responsibility

Implementation problems associated with the A&E method are inherent in the complexity of the computation. Additional complications may arise in an attempt to recognize that demand meter readings are not taken on a consistent basis, e.g., a large bulk power customer may reflect a greater degree of diversity as compared to a smaller low voltage distribution customer with little or no diversity. See Table 5-7 for sample application of average and excess allocation methodology.

TABLE 5-7

EXAMPLE OF AVERAGE AND EXCESS DEMAND ALLOCATION

$$D = L \times \frac{A}{B} + (1-L) \times \frac{C}{E}$$

Where: D = customer group's demand responsibility ratio
L = system's annual load factor = $\frac{\text{average load for year}}{\text{peak load for year}}$

$$= \frac{\dfrac{\text{70470 million KWH (Table 5-1)}}{\text{8784 hrs/yr}}}{\text{15,050,000 KW (Table 5-1)}} = 53.3\%$$

A = customer group's energy requirements = 2449 million KWH assuming monthly load factor of 70%
B = total system energy requirements = 70,470 million KWH
(1-L) = 46.5%
C = customer group's "excess" demand responsibility
= 520 MW (Table 5-1) - $\frac{\text{2449 million KWH}}{\text{8784 hrs in 1988}}$ = 241 MW
E = 15842 MW (Table 5-1 CP demand for system at .95 coincidence factor) - $\frac{\text{70470 million KWH}}{\text{8784 hrs in 1988}}$
= 7819 MW

Therefore: $D = (53.3\%) \ \frac{2449 \times 10^6}{70{,}470 \times 10^6} + (46.7\%) \ \frac{241 \text{ MW}}{7819 \text{ MW}} = .032917$

7. Combination of Other Methods

The preceding discussions have addressed situations involving allocation of various firm transmission investments to firm power loads. Depending on the factual situation present on a utility's system, it may be appropriate to employ a combination of methods to properly allocate cost responsibility to customers. Thus, an NCP allocation is sometimes used to allocate subtransmission costs, while a peak responsibility method based on coincident demands is used for the higher order transmission facilities. In addition, where certain customers may exhibit load patterns that are not adequately represented in their coincident load data, other factors not normally employed in a peak responsibility method may need to be introduced to assure proper cost allocation.

With regard to non-firm transmission services, while it may or may not be true that such services should not be held responsible for any demand costs, it should also be recognized that non-firm services require very close analysis of service contract provisions to determine utility obligations in order to establish the correct basis for allocation.

B. <u>Direct Assignment</u>

The costs of specific transmission facilities, such as long radial transmission lines and substations, may be directly assigned to particular customers. Direct assignments of such costs implies that the facilities can be considered entirely apart from the integrated system. In fact, the case for the independence of the facilities must be unequivocal since the customer must be willing to bear all the costs of service that, due to the unintegrated character of the facilities, may be just as high for service that is less reliable than service on the integrated system.

Costs assigned directly to customers are often collected via a special facilities charge. The charge can reflect: (1) the installed costs of the facilities; or (2) the average system cost of such facilities.

The plant costs that are directly assigned to a customer group must be excluded from the utility's total transmission plant costs for allocation. Alternatively, the revenue can be treated for costing as a revenue credit.

III. WHEELING

Wheeling is a transfer of power over transmission facilities owned by a utility that does not produce or sell the transferred power. The transfer may either be on a simultaneous or non-simultaneous basis. On either basis, the actual source of the power delivered to the purchasing system is not necessarily from the contracted for power source. Instead, power from other sources may flow over the integrated transmission system to satisfy the loads of the owner who has contracted for the specific source of power that is to be wheeled. Power from the specific source will in turn be used to meet other loads on the integrated system. This process is often referred to as service by displacement. When the power to be wheeled is from a hydroelectric facility, the wheeling system will often assume scheduling responsibilities by entering into "energy banking" arrangements to maximize fuel cost economies on its own system. The energy banking arrangements are often used in the wheeling of preference power from a power marketing agency to small distribution systems dispersed within a larger system which performs the necessary wheeling services.

The simultaneous or non-simultaneous wheeling of power may be conducted on either a firm or non-firm basis. In either case, a continuous contract path is generally required between the power source and load of the system which is receiving wheeling service. Firm transmission services are intended to be available at all times during the contract and are essentially the unbundled transmission portion of requirements rates. The functionalization and allocation methods applied to requirements service are applicable to firm transmission service as well.

Non-firm wheeling service is usually available under arrangements which do not provide assurances of continuous availability to the customer. Intuitively, it would appear that the costs to be recovered for non-firm wheeling should be less than costs recovered for firm wheeling, provided that the costing basis for both is identical. However, since non-firm wheeling service is often associated with opportunity or interchange transactions among power systems -- where such transactions usually reflect incremental cost pricing or other non-embedded cost measurements -- the benefits of the interchange transactions may also be considered in the development of non-firm wheeling rates. Such consideration may be expressed in terms of the costs of foregone opportunities to the utility providing non-firm wheeling service. Thus, the methods of allocation used in costing firm transmission service may or may not represent a cost ceiling for non-firm transmission service rates.

The advance in computer technology is providing additional capability for allocating costs to more accurately determine revenue from providing transmission service. One of the new methods for allocating and pricing transmission service is based on the positive difference, MW-mile methodology. The development and application of the positive difference, MW-mile method for each party is a multi-step process. The first step is to compute the MW-mile rating of the wheeling utility's transmission system by multiplying the length of each transmission line by a percentage of the thermal rating of the line. The products are summed to provide the aggregate MW-mile and are determined at least annually. The aggregate MW-miles are summed and divided into the functionalized transmission cost of service of the wheeling utility to yield a dollar per MW-mile billing charge. The next step is to determine the wheeling utility's MW-mile billing units. Billing units are determined by the use of computer models. The utility arranges for two simulations of power flows on its system, one simulation with wheeling for the wheeling recipient and one without. The simulations are compared to determine the effects on the system of the wheeling utility's wheeling. Negative changes (i.e., line unloadings) are sometimes ignored. Each positive MW change on a line is multiplied by the line length and the products are summed to yield the wheeling utility's positive MW-mile billing units. The billing units are multiplied by the utility's MW-mile charge to develop the bill.

CHAPTER 6

CLASSIFICATION AND ALLOCATION OF DISTRIBUTION PLANT

Distribution plant equipment reduces high-voltage energy from the transmission system to lower voltages, delivers it to the customer and monitors the amounts of energy used by the customer.

Distribution facilities provide service at two voltage levels: primary and secondary. Primary voltages exist between the substation power transformer and smaller line transformers at the customer's points of service. These voltages vary from system to system and usually range between 480 volts to 35 KV. In the last few years, advances in equipment and cable technology have permitted the use of higher primary distribution voltages. Primary voltages are reduced to more usable secondary voltages by smaller line transformers installed at customer locations along the primary distribution circuit. However, some large industrial customers may choose to install their own line transformers and take service at primary voltages because of their large electrical requirements.

In some cases, the utility may choose to install a transformer for the exclusive use of a single commercial or industrial customer. On the other hand, in service areas with high customer density, such as housing tracts, a line transformer will be installed to serve many customers. In this case, secondary voltage lines run from pole-to-pole or from handhole-to-handhole, and each customer is served by a drop tapped off the secondary line leading directly to the customer's premise.

I. COST ACCOUNTING FOR DISTRIBUTION PLANT AND EXPENSES

The Federal Energy Regulatory Commission (FERC) Uniform System of Accounts requires separate accounts for distribution investment and expenses. Distribution plant accounts are summarized and classified in Table 6-1. Distribution expense accounts are summarized and classified in Table 6-2. Some utilities may choose to establish subaccounts for more detailed cost reporting.

TABLE 6-1

CLASSIFICATION OF DISTRIBUTION PLANT[1]

FERC Uniform System of Accounts No.	Description	Demand Related	Customer Related
	Distribution Plant [2]		
360	Land & Land Rights	X	X
361	Structures & Improvements	X	X
362	Station Equipment	X	-
363	Storage Battery Equipment	X	-
364	Poles, Towers, & Fixtures	X	X
365	Overhead Conductors & Devices	X	X
366	Underground Conduit	X	X
367	Underground Conductors & Devices	X	X
368	Line Transformers	X	X
369	Services	-	X
370	Meters	-	X
371	Installations on Customer Premises	-	X
372	Leased Property on Customer Premises	-	X
373	Street Lighting & Signal Systems [1]	-	-

[1]Assignment or "exclusive use" costs are assigned directly to the customer class or group which exclusively uses such facilities. The remaining costs are then classified to the respective cost components.

[2]The amounts between classification may vary considerably. A study of the minimum intercept method or other appropriate methods should be made to determine the relationships between the demand and customer components.

TABLE 6-2

CLASSIFICATION OF DISTRIBUTION EXPENSES[1]

FERC Uniform System of Accounts No.	Description	Demand Related	Customer Related
	Operation [2]		
580	Operation Supervision & Engineering	X	X
581	Load Dispatching	X	-
582	Station Expenses	X	-
583	Overhead Line Expenses	X	X
584	Underground Line Expenses	X	X
585	Street Lighting & Signal System Expenses [1]	-	-
586	Meter Expenses	-	X
587	Customer Installation Expenses	-	X
588	Miscellaneous Distribution Expenses	X	X
589	Rents	X	X
	Maintenance [2]		
590	Maintenance Supervision & Engineering	X	X
591	Maintenance of Structures	X	X
592	Maintenance of Station Equipment	X	-
593	Maintenance of Overhead Lines	X	X
594	Maintenance of Underground Lines	X	X
595	Maintenance of Line Transformers	X	X
596	Maint. of Street Lighting & Signal Systems [1]	-	-
597	Maintenance of Meters	-	X
598	Maint. of Miscellaneous Distribution Plants	X	X

[1]Direct assignment or "exclusive use" costs are assigned directly to the customer class or group which exclusively uses such facilities. The remaining costs are then classified to the respective cost components.

[2]The amounts between classifications may vary considerably. A study of the minimum intercept method or other appropriate methods should be made to determine the relationships between the demand and customer components.

To ensure that costs are properly allocated, the analyst must first classify each account as demand-related, customer-related, or a combination of both. The classification depends upon the analyst's evaluation of how the costs in these accounts were incurred. In making this determination, supporting data may be more important than theoretical considerations.

Allocating costs to the appropriate groups in a cost study requires a special analysis of the nature of distribution plant and expenses. This will ensure that costs are assigned to the correct functional groups for classification and allocation. As indicated in Chapter 4, all costs of service can be identified as energy-related, demand-related, or customer-related. Because there is no energy component of distribution-related costs, we need consider only the demand and customer components.

To recognize voltage level and use of facilities in the functionalization of distribution costs, distribution line costs must be separated into overhead and underground, and primary and secondary voltage classifications. A typical functionalization and classification of distribution plant would appear as follows:

Substations:	Demand
Distribution:	Overhead Primary
	Demand
	Customer
	Overhead Secondary
	Demand
	Customer
	Underground Primary
	Demand
	Customer
	Underground Secondary
	Demand
	Customer
	Line Transformers
	Demand
	Customer
Services:	Overhead
	Demand
	Customer
	Underground
	Demand
	Customer
Meters:	Customer
Street Lighting:	Customer
Customer Accounting:	Customer
Sales:	Customer

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

II. DEMAND AND CUSTOMER CLASSIFICATIONS 0F DISTRIBUTION PLANT ACCOUNTS

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

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

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

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

A. The Minimum-Size Method

Classifying distribution plant with the minimum-size method assumes that a minimum size distribution system can be built to serve the minimum loading requirements of the customer. The minimum-size method involves determining the minimum size pole, conductor, cable, transformer, and service that is currently installed by the utility. Normally, the average book cost for each piece of equipment determines the price of all installed units. Once determined for each primary plant account, the minimum size distribution system is classified as customer-related costs. The demand-related costs for each account are the difference between the total investment in the account and customer-related costs. Comparative studies between the minimum-size and other methods show that it generally produces a larger customer component than the zero-intercept method (to be discussed). The following describes the methodologies for determining the minimum size for distribution plant Accounts 364, 365, 366, 367, 368, and 369.

1. **Account 364 - Poles, Towers, and Fixtures**

   - Determine the average installed book cost of the minimum height pole currently being installed.

   - Multiply the average book cost by the number of poles to find the customer component. Balance of plant account is the demand component.

2. **Account 365 - Overhead Conductors and Devices**

   - Determine minimum size conductor currently being installed.

   - Multiply average installed book cost per mile of minimum size conductor by the number of circuit miles to determine the customer component. Balance of plant account is demand component. (Note: two conductors in minimum system.)

3. **Accounts 366 and 367 - Underground Conduits, Conductors, and Devices**

   - Determine minimum size cable currently being installed.

   - Multiply average installed book cost per mile of minimum size cable by the circuit miles to determine the customer component. Balance of plant Account 367 is demand component. (Note: one cable with ground sheath is minimum system.) Account 366 conduit is assigned, basedon ratio of cable account.

   - Multiply average installed book cost of minimum size transformer by number of transformers in plant account to determine the customer component. Balance of plant account is demand component.

4. **Account 368 - Line Transformers**

   - Determine minimum size transformer currently being installed.

- Multiply average installed book cost of minimum size transformer by number of transformers in plant account to determine the customer component.

5. Account 369 - Services

- Determine minimum size and average length of services currently being installed.

- Estimate cost of minimum size service and multiply by number of services to get customer component.

- If overhead and underground services are booked separately, they should be handled separately. Most companies do not book service by size. This requires an engineering estimate of the cost of the minimum size, average length service. The resultant estimate is usually higher than the average book cost. In addition, the estimate should be adjusted for the average age of service, using a trend factor.

B. The Minimum-Intercept Method

The minimum-intercept method seeks to identify that portion of plant related to a hypothetical no-load or zero-intercept situation. This requires considerably more data and calculation than the minimum-size method. In most instances, it is more accurate, although the differences may be relatively small. The technique is to relate installed cost to current carrying capacity or demand rating, create a curve for various sizes of the equipment involved, using regression techniques, and extend the curve to a no-load intercept. The cost related to the zero-intercept is the customer component. The following describes the methodologies for determining the minimum intercept for distribution-plant Accounts 364, 365, 366, 367, and 368.

1. Account 364 - Poles, Towers, and Fixtures

- Determine the number, investment, and average installed book cost of distribution poles by height and class of pole. (Exclude stubs for guying.)

- Determine minimum intercept of pole cost by creating a regression equation, relating classes and heights of poles, and using the Class 7 cost intercept for each pole of equal height weighted by the number of poles in each height category.

- Multiply minimum intercept cost by total number of distribution poles to get customer component.

- Balance of pole investment is assigned to demand component.

- Total account dollars are assigned based on ratio of pole investment. (Transformer platforms in Account 364 are all demand-related. They should be removed before determining the account ratio of customer- and demand-related costs, and then they should be added to the demand portion of Account 364.)

2. Account 365 - Overhead Conductors and Devices

- If accounts are divided between primary and secondary voltages, develop a customer component separately for each. The total investment is assigned to primary and secondary; then the customer component is developed for each. Since conductors generally are of many types and sizes, select those sizes and types which represent the bulk of the investment in this account, if appropriate.

- When developing the customer component, consider only the investment in conductors, and not such devices as circuit breakers, insulators, switches, etc. The investment in these devices will be assigned later between the customer and demand component, based on the conductor assignment.

  - Determine the feet, investment, and average installed book cost per foot for distribution conductors by size and type.

  - Determine minimum intercept of conductor cost per foot using cost per foot by size and type of conductor weighted by feet or investment in each category, and developing a cost for the utility's minimum size conductor.

  - Multiply minimum intercept cost by the total number of circuit feet times 2. (Note that circuit feet, not conductor feet, are used to get customer component.)

  - Balance of conductor investment is assigned to demand.

  - Total primary or secondary dollars in the account, including devices, are assigned to customer and demand components based on conductor investment ratio.

3. Accounts 366 and 367 - Underground Conduits, Conductors, and Devices

- The customer demand component ratio is developed for conductors and applied to conduits. Underground conductors are generally booked by type and size of conductor for both one-conductor (I/c) cable and three-conductor (3/c) cables. If conductors are booked by voltage, as between primary and secondary, a customer component is developed for each. If network and URD investments are segregated, a customer component must be developed for each.

- The conductor sizes and types for the customer component derivation are restricted to I/c cable. Since there are generally many types and sizes of I/c cable, select those sizes and types which represent the bulk of the investment, when appropriate.

  - Determine the feet, investment, and average installed book cost per foot for I/c cables by size and type of cable.

  - Determine minimum intercept of cable cost per foot using cost per foot by size and type of cable weighted by feet of investment in each category.

  - Multiply minimum intercept cost by the total number of circuit feet (I/c cable with sheath is considered a circuit) to get customer component.

  - Balance of cable investment is assigned to demand.

  - Total dollars in Accounts 366 and 367 are assigned to customer and demand components based on conductor investment ratio.

4. Account 368 - Line Transformers

- The line transformer account covers all sizes and voltages for single- and three-phase transformers. Only single-phase sizes up to and including 50 KVA should be used in developing the customer components. Where more than one primary distribution voltage is used, it may be appropriate to use the transformer price from one or two predominant, selected voltages.

  - Determine the number, investment, and average installed book cost per transformer by size and type (voltage).

  - Determine zero intercept of transformer cost using cost per transformer by type, weighted by number for each category.

  - Multiply zero intercept cost by total number of line transformers to get customer component.

  - Balance of transformer investment is assigned to demand component.

  - Total dollars in the account are assigned to customer and demand components based on transformer investment ratio from customer and demand components.

C. The Minimum-System vs. Minimum-Intercept Approach

When selecting a method to classify distribution costs into demand and customer costs, the analyst must consider several factors. The minimum-intercept method can sometimes produce statistically unreliable results. The extension of the regression equation beyond the boundaries of the data normally will intercept the Y axis at a positive value. In some cases, because of incorrect accounting data or some other abnormality in the data, the regression equation will intercept the Y axis at a negative value. When this happens, a review of the accounting data must be made, and suspect data deleted.

The results of the minimum-size method can be influenced by several factors. The analyst must determine the minimum size for each piece of equipment: "Should the minimum size be based upon the minimum size equipment currently installed, historically installed, or the minimum size necessary to meet safety requirements?" The manner in which the minimum size equipment is selected will directly affect the percentage of costs that are classified as demand and customer costs.

Cost analysts disagree on how much of the demand costs should be allocated to customers when the minimum-size distribution method is used to classify distribution plant. When using this distribution method, the analyst must be aware that the minimum-size distribution equipment has a certain load-carrying capability, which can be viewed as a demand-related cost.

When allocating distribution costs determined by the minimum-size method, some cost analysts will argue that some customer classes can receive a disproportionate share of demand costs. Their rationale is that customers are allocated a share of distribution costs classified as demand-related. Then those customers receive a second layer of demand costs that have been mislabeled customer costs because the minimum-size method was used to classify those costs.

Advocates of the minimum-intercept method contend that this problem does not exist when using their method. The reason is that the customer cost derived from the minimum-intercept method is based upon the zero-load intercept of the cost curve. Thus, the customer cost of a particular piece of equipment has no demand cost in it whatsoever.

D. Other Accounts

The preceding discussion of the merits of minimum-system versus the zero-intercept classification schemes will affect the major distribution-plant accounts for FERC Accounts 364 through 368. Several other plant accounts remain to be classified. While the classification of the following distribution-plant accounts is an important step, it is not as controversial as the classification of substations, poles, transformers, and conductors.

1. Account 369 - Services

This account is generally classified as customer-related. Classification of services may also include a demand component to reflect the fact that larger customers will require more costly service drops.

2. Account 370 - Meters

Meters are generally classified on a customer basis. However, they may also be classified using a demand component to show that larger-usage customers require more expensive metering equipment.

3. Account 371 - Installations on Customer Premises

This account is generally classified as customer-related and is often directly assigned. The kind of equipment in this account often influences how this account is treated. The equipment in this account is owned by the utility, but is located on the customer's side of the meter. A utility will often include area lighting equipment in this account and assign the investment directly to the lighting customer class.

4. Account 373 - Street Lighting and Signal Systems

This account is generally customer-related and is directly assigned to the street customer class.

III. ALLOCATION OF THE DEMAND AND CUSTOMER COMPONENTS OF DISTRIBUTION PLANT

After completing the classification of distribution plant accounts, the next major step in the cost of service process is to allocate the classified costs. Generally, determining the distribution-demand allocator will require more data and analysis than determining the customer allocators. Following are procedures used to calculate the demand and customer allocation factors.

A. Development of the Distribution Demand Allocators

There are several factors to consider when allocating the demand components of distribution plant. Distribution facilities, from a design and operational perspective, are installed primarily to meet localized area loads. Distribution substations are designed to meet the maximum load from the distribution feeders emanating from the substation.

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 projection 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, The Economics of Regulation: Principles and Institutions, 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.

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[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

[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. <u>Allocation of Costs to Customer Group</u>

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 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.

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.

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]

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

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

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

[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.

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.

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.

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.

- 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 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.

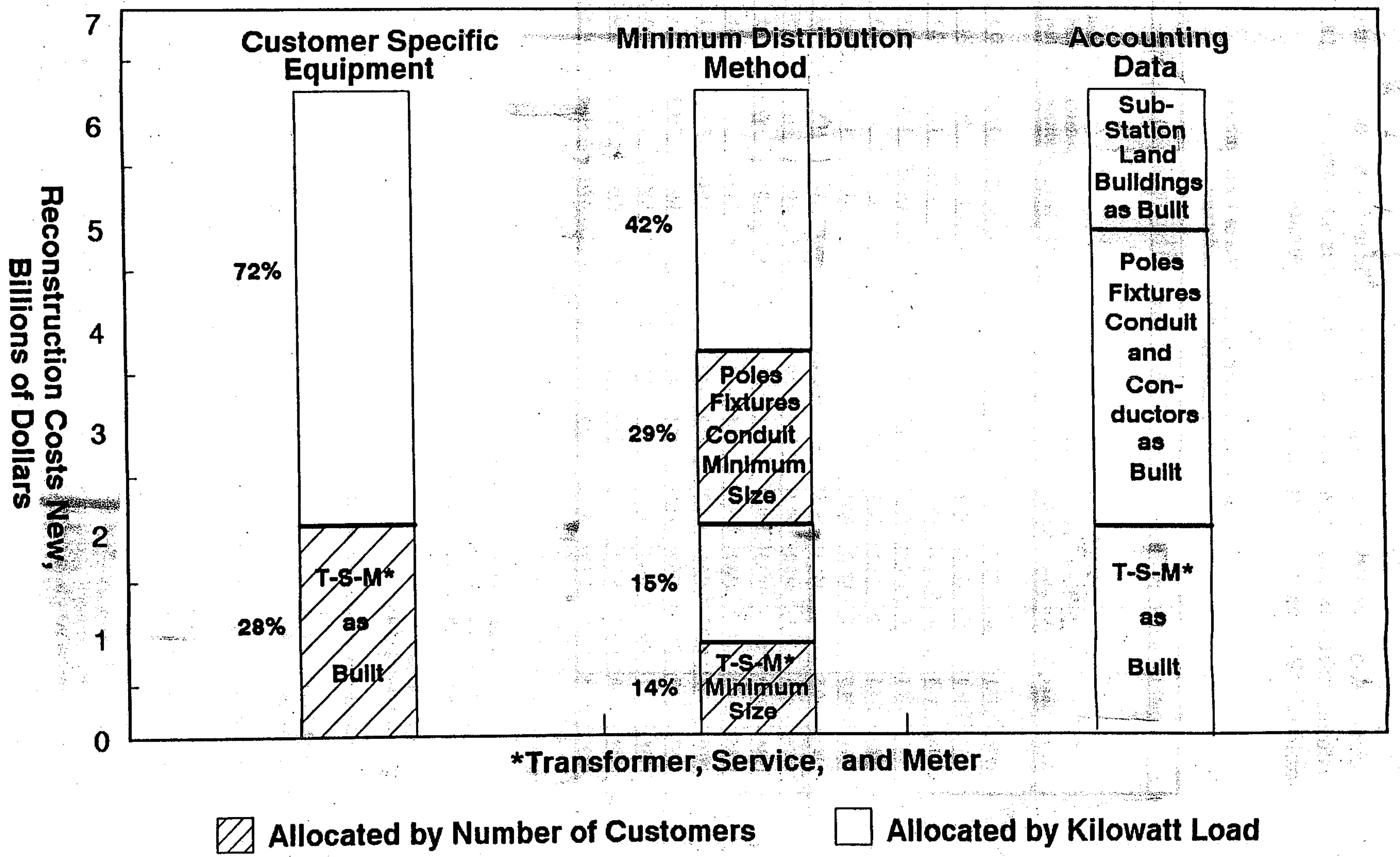
Figure 10-1 illustrates the results of the minimum grid approach for the marginal customer-related cost for a typical residential customer of the sample utility. In column 1 (Customer Specific Equipment) only line transformers, service and meters are functionalized to the customer category while all 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

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

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 distribution 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 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

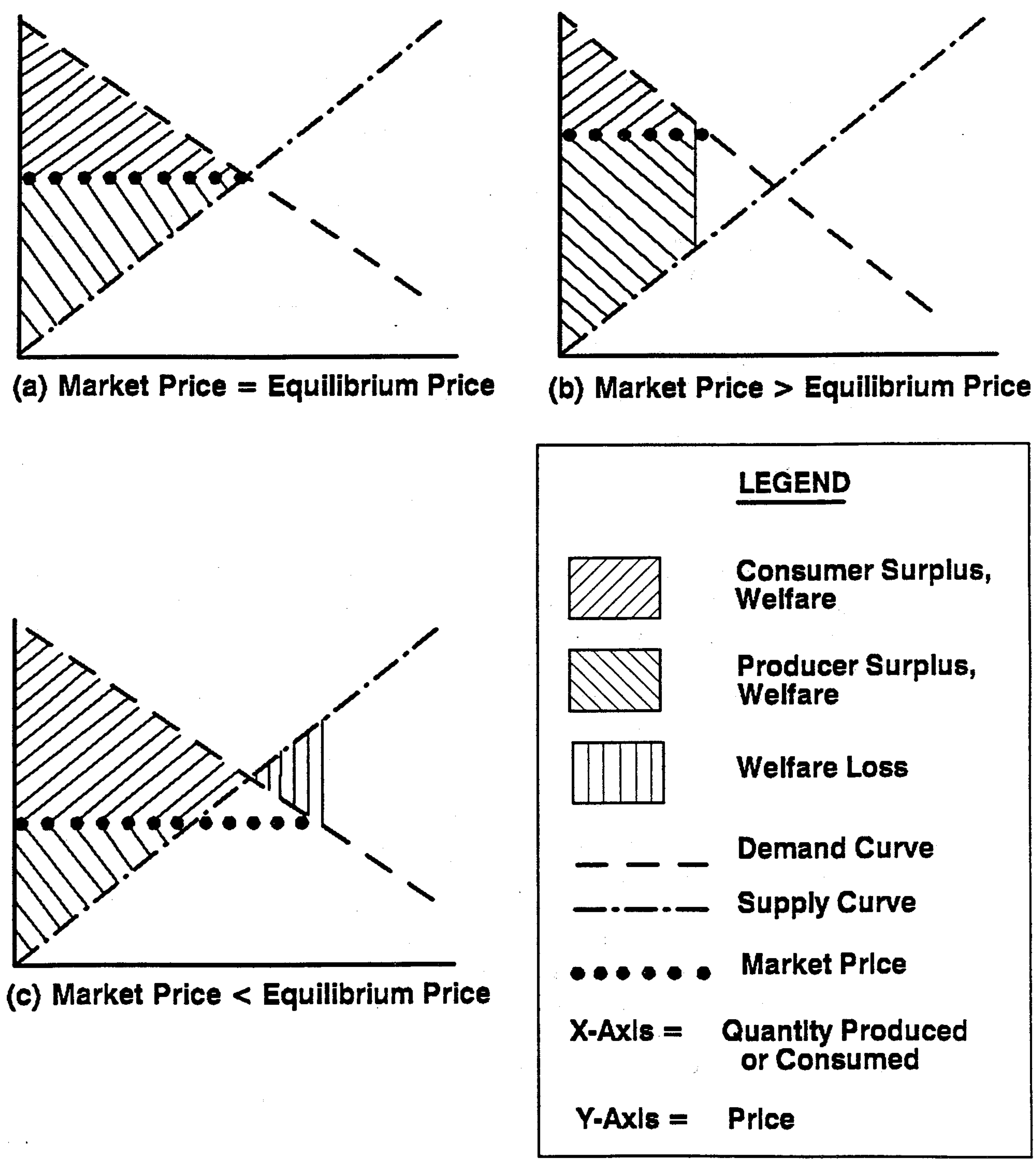
MARGINAL COST REVENUE RECONCILIATION PROCEDURES

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

Figure 11-1
SOCIETAL WELFARE



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

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, $(P_i\text{-}MC_i)/P_i = Ka/E_i$, 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;

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

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:

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

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)

Class	Sales (GWH)	Marginal Cost Revenues: Energy ($1000)	Marginal Cost Revenues: Demand ($1000)	Marginal Cost Revenues: 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.

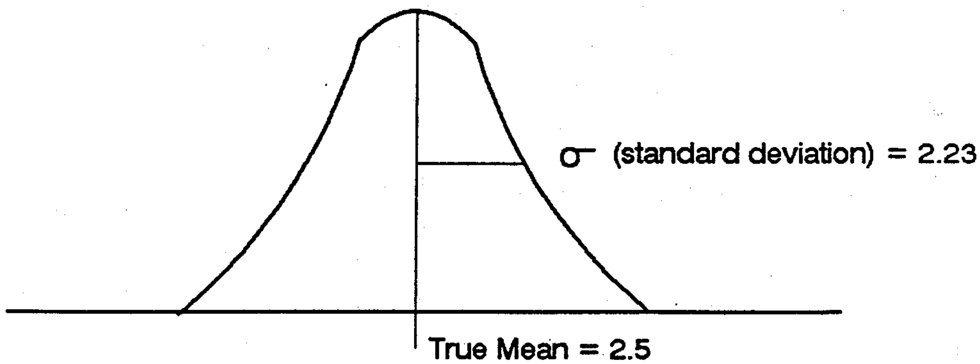
A confidence interval around an estimate is an interval which is designed to contain the class measured demand a specified percentage of the time. For example, an interval of two standard errors on each side of the estimated demand is approximately a 95% confidence interval. This means that if we hypothetically 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 ± 100 x (.26 ÷ 2) or ± 13%; in the latter case 100 (.26 ÷ 1) or ± 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.

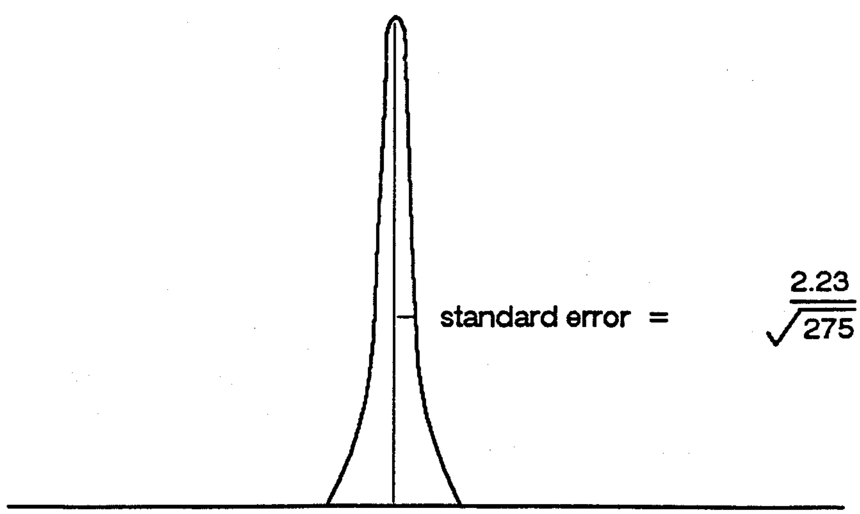
FIGURE A-1

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 <u>demand</u> 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 <u>precision</u> due to a reduced sample size but does not address the <u>bias</u> 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 Neyman 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.

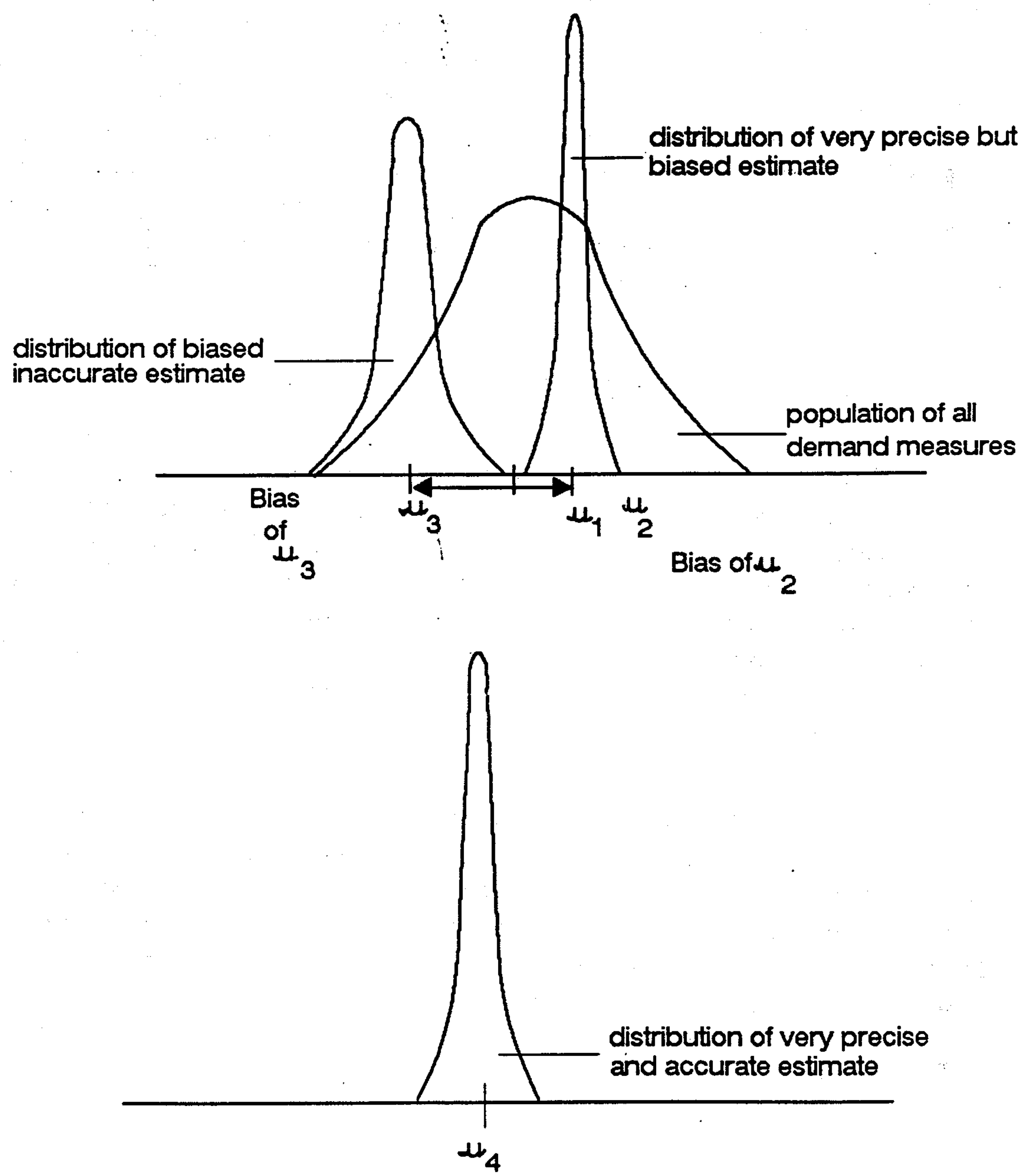
D. Form of Estimator

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

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