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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.

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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.
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. 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.

1In 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.