Electric Utility Cost of Service Analysis

This package was prepared in 1992 for the Arizona Public Service Commission. Due to importation from now-obsolete software, some formatting has been lost, and no attempt to restore it has been made.

Part 1 deals with the fundamentals of cost of service analysis, and the presentation of study results.

Part 2 addresses the classification and allocation of production plant and expenses.

Part 3 addresses the classification and allocation of transmission and distribution plant and expenses.

I strongly recommend that any reader first review a more up-to-date overview of the rate making process. The Regulatory Assistance Project publication Electricity Regulation in the US: A Guide has a discussion at pages 47 – 54 which provide a quick overview of these topics. It is available for download at:
http://www.raponline.org/document/download/id/645

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Cost Elements and Study Organization For Embedded Cost of Service Analysis

Applicable to the Tucson Electric Power Company

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COST ELEMENTS AND STUDY ORGANIZATION

WHAT IS AN EMBEDDED COST OF SERVICE STUDY?

An embedded cost of service study is an analysis which divides the costs included in a utility's revenue requirement among the various classes of customers. There are three primary steps to the process. **Functionalization** consists of identifying whether costs are related to production, transmission, distribution, or other cost areas. **Classification** of costs is the determination of whether particular costs are related to the number of kilowatts of peak demand, the number of kilowatt-hours of energy consumption, or to the number of customers served. **Allocation** is the process of dividing the costs between the classes based on usage characteristics for each class.

The end result of an embedded cost of service study is a measure of revenue, expenses, and rate base by class. These results permit calculation of a rate of return for each class, a profit margin for each class, and some indices of return, such as a return index (class rate of return divided by system rate of return) and a revenue to cost ratio (revenue divided by revenue requirement). It is often assumed, but not necessarily required, that all classes should provide the same rate of return. A differential rate of return, recognizing differences in class risk, class growth rates, or other factors can significantly affect the results of a study.

Tucson Electric has presented the results of its study in two ways. First, it shows, for each class, a rate of return at present rates, and a return index. Second, it calculates the revenues needed from each class to produce a uniform rate of return among classes. As indicated, there is no unanimity on the notion that all classes should produce a uniform rate of return.

Embedded cost studies are imprecise in nature. While the number of customers served and kilowatt-hours sold to each class is known, many of the other assumptions needed to prepare a study are only estimated. The most critical estimates are those for peak demand by class. These estimates are prepared using load research studies which typically measure the actual contribution to peak demand for fewer than 100 customers in each class; the expected behavior of the entire class is statistically extrapolated from this sample. Typically the samples are prepared once every five to ten years, and the samples are generally large enough only to provide an estimate expected to be accurate within 10% of the class demand at the time the study is performed. Thus, the demand data used in cost of service studies is only an estimate, and is usually somewhat out of date. In addition, the joint costs on a utility system -- the distribution infrastructure, plus the administrative and general costs -- cannot be precisely apportioned according to any formula.

Embedded cost studies do not generally examine the causes of cost on a system. Marginal cost of service studies look at cost causation. Embedded cost studies look at facility utilization. First, the total of allocated costs by class always equals the total system costs input into the study. Important regulatory issues such as excess capacity (where a utility may be allowed only a partial return on certain plant) are not normally recognized in embedded cost of service analysis. Second, only test year usage is considered; if a particular class has grown rapidly or declined, this is generally not recognized, even though the change in usage may have caused many of the cost changes being addressed in rates. Third, except in a few of the many methodologies available, embedded cost studies do not consider the incremental costs of meeting increasing loads, but rather evaluate only the average costs associated with meeting existing loads. These are often major issues in rate proceedings, but embedded cost studies are neither designed nor equipped to assist in evaluating them.

The end results of an embedded cost study provide a snapshot at a point in time of costs and facility utilization on a utility system. Few commissions ever rely strictly or exclusively on the results of the cost studies prepared in rate cases. Other factors, including conservation goals, gradualism, fairness and equity, value of service, and effectiveness at producing the required revenue are often considered.

WHAT COSTS ARE INCLUDED IN A COST OF SERVICE ANALYSIS?

Typically an embedded cost study uses the same costs being proposed in the revenue requirement analysis for a given rate proceeding. Since some state commissions utilize historic test years and other use future test years, the studies are normally prepared using whichever is being utilized for revenue requirement purposes.

Plant in service, accumulated depreciation, and depreciation expense for each account are typically taken directly from the revenue requirement workpapers. It is important to adjust the distribution plant accounts to recognize the customer advances and contributions in aid of construction; as discussed in the Transmission and

Distribution Cost Allocation briefing paper, the manner in which these adjustments are made can affect the study results.

In a FERC-account structured study, these costs are used directly; in a functionalized group study, the common costs, such as administrative and general expenses and general plant, are subjected to substantial separate analysis to divide them among the production, transmission, and distribution functions.

A. Historic Test Year Costs

Historic test-year based embedded cost of service studies normally use proforma results of operation. Where the results are audited and approved by the Commission, there should be little question regarding any of the individual cost items. This is normally not the case, however, and many of the cost items are subject to adjustments during the ratemaking process. It is exceedingly difficult for the cost of service analyst to have access to the final results of staff (or other party) adjustments to company-filed results of operation.

This problem is further compounded when utility rate proceedings are settled, rather than resolved by commission deliberation. If agreement is reached in a proceeding on the level of rates without any resolution on the exact components of rate base, expense, and taxes which justify that level of rates, the basic information upon which a study can be based is not available.

It is always possible to use unadjusted book results, but these may be misleading. For example, if rates are settled at a level which does not provide for full recovery on all or a portion of a generating plant, but the utility is not directed to write down the investment, the book production plant in service may be different from the amount which is allowable for ratemaking purposes. This may presently be the case for Tucson Electric (TEP) as a result of the regulatory treatment of its generating plant. In addition, where major changes are anticipated in utility investment or expenses, such as the expected conversion by Tucson Electric of a purchased power contract to ownership of the generating facility, the use of historic book information may not provide accurate data. For these reasons, use of unadjusted book cost data is often not desirable.

For all of the above reasons, analysts for parties subject to filing deadlines have a difficult time preparing cost of service studies at the same proposed revenue, expense, and rate base levels as their revenue requirement area colleagues unless the rate proceedings are "staged" with revenue requirement testimony due at a date well before the cost allocation and rate design testimony are due. In this manner, the cost of service analyst can work with fully adjusted rate base, expense, and revenue data. This is discussed below in Section VII.

A. Future Test Year Costs

The issues identified above with respect to data for historic test year studies are made even more complex in jurisdictions which use future test periods. A future test period is totally estimated. Not only are rate base and expense items imprecise, but even revenue is subject to the results of analysis of the sales forecast. Over the course of lengthy rate proceedings, an economic forecast which provides the underpinning for a future test year can change dramatically. Thus, cost studies based on future test years are even more difficult to prepare and the case for staged proceeding is even stronger.

I. HOW CAN THE COSTS BE ORGANIZED

There are two general approaches used to structure embedded cost of service studies. The first is to organize the study along the lines of the FERC uniform system of accounts. An example of one of these, for the Kauai Electric Division of Citizens Utilities, is included as Appendix A to this briefing paper. The second approach is to functionalize all of the administrative and general costs and plant as production, transmission, or distribution related, and then allocate the functionalized costs. An example, prepared on the Arizona Public Service Company, is included as Appendix B to this briefing paper.

Tucson Electric has prepared a single computer model which begins with all costs on a FERC account basis, then functionalizes the A&G costs and ultimately allocates costs within the functionalized groups.

A. FERC Account Based Studies

A study prepared directly following the FERC uniform system of accounts breaks out all plant and expenses by individual account number. For example, there are some 26 production plant accounts, nine transmission plant accounts, fourteen distribution plant accounts, and similar numbers for general plant and O&M expense. Each of these records the costs associated with a particular type of cost.

A FERC account-based study first allocates the production plant on the basis of allocation factors derived from the demand and energy usage by class. Baseload and peaking plants may be allocated in different manners. The study often then computes a subtotal of production plant, which may be used to allocate transmission plant; alternatively, transmission plant may be allocated on specific allocation factors based on demand and energy usage. In Exhibit A, the initial allocation factors are computed from the load data at page 14, lines 644 - 657; these are then used directly to derive other factors on pages 14-17.

In Exhibit A, production, transmission, and distribution plant are allocated on page 5-6. In this example, all transmission plant is allocated on the same factor as all production plant, while 13 different factors are used to allocate distribution plant. Distribution plant investment is allocated on the basis of specific allocation factors based on demand, energy, and customer count by class. Different factors may be applied to different types of distribution plant; one factor for substations, a different one for distribution lines, one for transformers, meters, services and so forth. A subtotal factor for all production, transmission, and distribution plant is then computed [Page 6, line 279], and is commonly applied to general plant. [P. 7, Lines 284-295] That completes the plant allocation portion of the study.

Accumulated provision for depreciation and depreciation expense are then allocated on the same basis as the plant accounts to which they apply. Sometimes subtotals of all production, transmission, or distribution plant are used to allocate aggregate amounts of depreciation reserve or depreciation expense. In Appendix A, the plant balances for each account had already been computed with accumulated depreciation, customer advances, and contributions in aid of construction netted out, so the treatment of accumulated provision for depreciation is not evident; the depreciation expense allocation appears on page 13.

Allocation of expenses generally follows that of the plant accounts. For example, the fixed O&M costs of steam production are allocated on the same basis as the fixed investment in steam production; the maintenance costs for meters are allocated on the same basis as meters. This occurs in Appendix A at pages 8-11.

Under the uniform system of accounts, salaries and wages are recorded by functional areas -- power plant operators in production, line crews in distribution, and so forth. This is reported at page 354 of the FERC Form 1. Therefore it is possible to develop a factor for salary and wage allocation by class, based on the subtotals for production, transmission, distribution, and other functions computed within the model. This appears in Appendix A at page 12, lines 515-525.

A&G expenses can be allocated on any of several internally derived factors. This appears at page 12, lines 529 - 540 of Appendix A. The most commonly used are:

1) Total production, transmission, and distribution expense [Often used for A&G salaries and outside services employed]
2) Total expense less purchased power and fuel [Sometimes used for A&G salaries and outside services employed]
3) Salary and wage expense [Often used for employee pensions and benefits]
4) Total production, transmission, and distribution Plant [often used for property insurance and maintenance of general plant]

This completes the allocation of O&M expenses other than taxes. At this point, the methodology for both FERC-account studies and functionalized-group studies comes together for the allocation of taxes and computation of return by class. This is presented on pages 1-4 of Appendix A.

Taxes are allocated on several distinct bases. Property taxes are typically allocated between classes on the same basis as total plant. Revenue-related taxes are normally allocated on the basis of revenue. These are shown on page 4 of Appendix A, lines 145-164. The primary taxes remaining are income taxes, which are treated in three different ways.

The first is to subtract expenses (O&M plus taxes other than income) from revenue by class, compute a before-tax return for each class, and then allocate income tax on the basis of net income by class. This method assigns a larger share of income taxes to classes producing a higher rate of return than it does to classes providing a lower than average return. The rationale for this practice is that income taxes are based on income, and that the classes providing that income should pay the associated taxes. This is clearly appropriate where different classes are expected to produce different rates of return. This approach is shown in Appendix A, line 170.

The second method is to allocate all income taxes on the basis of utility plant previously allocated. This method assigns to each class a share of taxes equal to its allocated share of production, transmission, distribution, and general plant. The rationale for this is that since income is allowed to a utility as a fair rate of return on plant, income produced by each class should be a function of plant allocated to that class. This method has as an underlying premise that all classes should produce the same rate of return. If shown in Appendix A, this would show the "PTDRB" factor applied to line 175 on page 4.

The third method used to allocate income taxes is on the basis of profit margin by class. Profit margin is computed by subtracting expenses from revenues for each class, and dividing the remainder by the revenue for that class. The rationale for this practice is that profit is not solely a function of plant, an approach which is becoming more appropriate as utility commissions move to isolate profit from investment levels through incentive regulation and decoupling mechanisms. This method is less frequently used than the other two; when it is applied, the profit margin (return on revenue) by class is normally the "bottom line" of the study. If shown in Appendix A, this method would compute taxes for each class based on the "pre-tax operating income" shown on line 29 of Page 1.

The end result is a calculation of a net operating income and/or pre-tax operating income for each class. This is then divided by the allocated rate base for each class to compute the rate of return by class, or by the class revenue to determine the profit margin. This is shown in Appendix A on lines 26 and 33 of Page 1.

A. Functionalized Groups

The second general approach to presentation of cost of service studies is to distribute the administrative and general costs, taxes, and other cost items between cost categories, and then allocate the categories based on usage. This approach is shown in Appendix B, a study prepared on the Arizona Public Service Company.

In a functionalized group study, all allocation decisions are made strictly on production, transmission, distribution, customer accounts, and sales categories. No direct allocation of administrative and general costs or general plant is performed. By some method, the percentage of general plant, A&G expenses, and other utility costs are assigned to the categories which are then allocated.

For working capital, this division of costs appears in Appendix B on page 6, for materials and supplies, it appears on page 7, and so forth for O&M expenses, A&G expenses, property taxes, etc. In contrast, O&M expenses are allocated account by account in Appendix A, pages 8-12, while working capital and materials and supplies are allocated in single line items based on subtotals of other costs in Appendix A, at page 7, lines 313 and 316.

Once the functionalization of these costs are completed, the process is very similar to FERC-account based studies, except that internally derived factors are not normally used for allocating the functionalized costs. The allocation factors permit calculation of totals for all plant and expense items, which in Appendix B appear on the bottom of pages 2-18.

As indicated in the preceding section, once the plant and expenses are allocated, the two approaches become very similar. At page 19 of Appendix B, an income tax calculation very similar to that on Page 4 is performed, first computing income by subtracting expenses from revenues, then assuming that income tax should be in proportion to that income.

The results of this study are summarized on page 1 of Appendix B. In this particular study, no calculation of return on revenue (profit margin) is carried out, but the data is all present -- adding lines 13 and 14 to line 16 would produce this figure. A return index -- the ratio between the class rate of return and the system rate of return --

is computed on line 30, and a revenue to cost ratio is computed on line 35, just as it is on line 52 of page 1 in Appendix A.

A. Advantages and Disadvantages of Each Approach

The FERC account-based methodology is the more common approach, primarily because it requires far less work than a functionalized group study, and because it is a more flexible study approach, allowing the analyst the ability to use any information derived in any completed portion of the study to allocate any subsequent cost item. For example, transmission rate base can be allocated on the subtotal of production rate base very simply, since a "PRRB" factor is created <u>above</u> the point where transmission cost allocation occurs in the study. [Appendix A, Page 1, lines 204; 209]. This is not typically possible in a functionalized study.

Additionally, it is easy to change the factor used to allocate any cost in a FERC account-based study. For example, on page 7, line 313, Materials and Supplies are allocated on the same basis as Production Rate Base (PRRB); with a few keystrokes, the method can be changed to the subtotal of Production, Transmission, and Distribution rate base (PTDRB). This is not possible in a functionalized study.

This flexibility is often particularly desirable when dealing with Administrative and General Costs. In a functionalized study, in order to change the method used to divide these costs between production, transmission, distribution, and so forth, from a salary and wage basis to a total expense basis, it is necessary to first compute the total expenses for each category, then manually change the apportionment of A&G costs on page 11 of Appendix B to reflect the change. In the FERC account study, simply designating the "S&W" or "PTDRB" factor will allocate these costs on the basis of salaries and wages [Appendix A, Page 12, lines 534, 535].

Within functionalized groups, it is possible to achieve greater levels of precision in the allocation of certain utility costs than is normally achievable in a FERC account- based study. For example, it is widely recognized that administrative and general salaries (corporate officers) spend more time dealing with production and regulatory issues, which affect all classes, than deciding what brand of meter to purchase or what type of conductor to use, which generally affects only distribution voltage customers. Within a functionalized study, it is possible to assign the administrative and general salaries directly to the function which they support. In a FERC-account study, it is only possible to allocate these on broad measures of cost responsibility -- subtotals of plant, expense, or salaries and wages.

This added precision comes at the cost of greater complexity and a loss of flexibility to study the effect of alternative allocation decisions. Changing the method of A&G cost allocation in a functionalized study can take hours; in a FERC-account study it takes seconds.

Perhaps the strongest argument in favor of one over the other is that rate case adjustments are always changes to specific accounts of rate base or expense. These adjustments can be much more easily integrated into a FERC-account study than into a functionalized study. Thus it is possible to recompute a cost of service study at a changed revenue requirement much more quickly in a FERC-account study than in a functionalized study. The only exception is when future test years are used, and adjustments are made to salaries and wages; in this situation the analyst would have to spread the adjustment between the individual accounts where labor costs are recorded in a FERC-account study, or between the functionalized groups in a functionalized study.

I. CAPABILITY TO SUPPORT SENSITIVITY ANALYSES

Often in rate proceedings, the parties disagree over whether production plant should be allocated on a demand basis, a demand and energy basis, a time-differentiated basis, or some other method. The ability of a cost study to be able to quickly produce consistent results under different allocation assumptions adds to the value of the study. Ideally, a study model should respond to simple commands which allow the allocation factors to be changed. Studies in which the allocation formulae are "hard-wired" by specifying that certain cells are to be multiplied by certain factors are the least flexible.

An efficient model can be used to produce many sensitivity runs on the same data in a very short period of time. The model in Appendix A was used to prepare four completely different cost of service studies in less than two hours. This allows the analyst to test any desired allocation method for specified costs.

I. DEMAND/ENERGY/CUSTOMER COST BREAKDOWN

Some cost of service studies break all costs down into demand costs, energy costs, and customer costs, and then compute "unit costs" for each of the three types of costs which are included in rate design. The goal of this approach is usually to tie the retail rate design to the cost allocation methodology. Under this approach, costs which are allocated between classes on the basis of their peak demand are to be recovered in rates through the demand charge. The rationale for this approach is that the "demand" costs are associated with meeting peak demand, and should be recovered through the charges applied to individual customers based on their own peak demand.

This approach is extremely controversial among analysts. It is generally preferred by advocates for high load factor industrial customers, and generally opposed by advocates of residential and small business consumers. There are several conceptual flaws with the link between cost allocation and rate design.

First, retail demand charges apply to individual customer noncoincident demands, not to their demands at the time of a system or class peak demand. This may be an appropriate way to recover the costs for line transformers, which are sized to meet individual customer demands, and cannot normally be used by other customers at times when any given customer is not fully utilizing them. It is not appropriate for production plant, which can serve commercial air conditioning loads in the summer, and residential space heating loads in the winter. Even transformers can sometimes be shared by several customers. If a breakfast joint is in the same building as a night club, and they have identical demands but opposite daily load patterns, the peak demand of both can be met with a single transformer (plus production, transmission, and distribution plant) sized to meet the load of one of them. If the "demand" costs of production, transmission, and distribution plant are recovered in the demand charge, the two individual businesses will be charged twice as much as a single 24-hour restaurant, even though their combined demands and the costs to serve them are identical.

Second, many commissions have agreed to use embedded cost of service studies to divide utility costs <u>between</u> classes, but to use marginal or cost-causal methods for designing rates <u>within</u> classes. For example, it may be agreed that the costs of a distribution system are 50% customer-related, but that does not mean that the costs for poles, conductors, and transformers are increased every time a customer is added to the system. Several commissions base the customer charges in rate designs on only those costs which go up or down directly with changes in numbers of customers -- meters, services, meter reading and billing -- rather than include any costs treated as customer-related in cost studies in the customer charge.

Third, some methodologies mix the definition of "demand" and "energy" related plant. For example, the Peak and Average method normally classifies a large percentage (equal to the load factor, perhaps 60%) of production plant as energy-related, and the balance as demand-related. This should then lead to 60% of these costs becoming "energy" costs when the unit costs are calculated. However, it is also possible to apply the Peak and Average method by first <u>classifying</u> all of the production plant as "demand" related, and then <u>allocating</u> those costs based on a factor which weights class energy use by 60%, and class peak demand by 40%. If this were done, the allocation of costs <u>between</u> classes would be identical, but the "demand-related" costs would be two and one half times as great. Similar situations exist for other methodologies, including the Average and Excess, Probability of Dispatch, and Base-Intermediate-Peak method.

Tucson Electric's cost of service workpapers show that it has followed the second path -- defining 100% of its production plant costs as demand-related. Accepting this classification, and relying on the unit costs developed by the study for rate design purposes, would produce results directly at odds with these energy-weighted and time-differentiated cost allocation methodologies.

I. PRESENTATION OF RESULTS

The ultimate results of any cost of service study must somehow be made intelligible to decision makers. This is usually done by converting the results into a simple number for each class, which can be compared with that computed for other classes and for the system as a whole. There are four indices frequently used.

A. Rate of Return on Rate Base

The rate of return on rate base is the most commonly used result of embedded cost studies. It is derived by dividing the after-tax income for each class by the allocated rate base for each class. Since under rate base regulation, utilities are normally allowed a defined rate of return on their total rate base, the return on rate base for each class can be quickly compared with the system average.

In Appendix A, the rate of return for the system and for each class appears on Page 1, line 26; in Appendix B it appears on Page 1, line 29. This shows that some classes are providing a higher than average return, and some a lower than average return.

A. Return on Revenue (Profit Margin)

A commonly used index of earnings from providing services to customers outside of the regulated utility area is the return on revenue, or profit margin. This is obtained by dividing the pre-tax operating income (revenue minus O&M and depreciation expense) from each class by the revenue received from that class. Electric cooperatives frequently use this measure of return, because they are required to "revolve" their capital credits, returning net income from sales in one year to the same customers in a future year. This has the effect of providing an interest-free loan of capital to the utility. Since the revolvement is done on the basis of revenue (each customer gets back in a future a percentage of the revenue they paid to the utility in a previous year), it is appropriate that the studies attempt to identify the relative return on revenue each class provides.

The return on revenue, or profit margin, is shown in Appendix A at Page 1, line 33.

A. Return Index

A return index is computed by dividing the class return (on rate base or on revenue) by the system average return. It provides a single number which can be used to quickly identify which classes are providing a higher or lower than average return, and to what degree.

A return index is computed and shown in Appendix B, Page 1, at line 30.

A. Revenue to Cost Ratio

The revenue to cost (or revenue to revenue requirement) ratio is computed by dividing the class revenues by the class revenue requirement. Most often this is done by computing the revenue requirement based simply on the system average allowed rate of return, but there is no reason it cannot not be computed at different rates of return for different classes, recognizing different risk levels or other return determinants for each class. The revenue requirement for each class is derived by multiplying the rate base by the rate of return to identify the operating income requirement, subtracting the return being generated at the revenue levels in the study, and determining a net operating income surplus or deficiency. That result is then adjusted to account for taxes, and either added or subtracted from the class revenues in the study to produce a revenue requirement for the class.

Like the return index, the revenue to cost ratio is a single number which can be used to identify classes which are providing more or less than their share of revenues. Since it is ultimately revenues which are allocated in a rate case, this is often a more useful measure. This calculation can also help the analyst consider a different rate of return requirement for each class, which the return index does not.

The revenue to cost ratio is displayed in Appendix A at Page 1, line 52, and in Appendix B at page 1, line 35. Both of these were computed at the same rate of return for each class, which is only one way to compute this result.

I. STAGED VERSUS SIMULTANEOUS PROCEEDINGS

Most utility rate proceedings are scheduled so that all witnesses for a party file testimony on the same day. Since there are generally several revenue requirement witnesses addressing complex topics, and their combined analyses must be integrated to compute the bottom line on revenue requirement, the last few days before filing are generally fairly harried. The witnesses asked to prepare cost of service studies generally do not have the raw data needed to produce the cost study until the revenue requirement witnesses have completed their work. As a result, it is nearly impossible for cost of service studies to fully reflect all adjustments to rate base and expenses (and, in the case of future test year studies, sales volumes and revenues) which appear in the revenue requirement portion of the proceeding.

One way to solve this problem is through "staged" rate proceedings. In Docket No. U-1345-90-007, the Arizona Corporation Commission established a schedule in which revenue requirement testimony would be filed a month before cost allocation and rate design testimony. This allowed the cost of service analysts to fully integrate the adjustments proposed by the revenue requirement witnesses into the cost of service and rate design proposals. Since the hearings were expected to go on for many weeks, it was expected that this procedure would not delay final resolution of the proceeding.

Where FERC-account based cost studies are utilized, it is normally possible for a cost analyst to fully integrate adjustments into the cost of service study in a few days of analysis. Allowing time to draft testimony incorporating these results would mean that testimony could normally be filed about ten days after the revenue requirement testimony. In a major proceeding, the rate design witnesses usually come about ten days after the first revenue requirement witnesses. Therefore, a delay of ten days between filing of revenue requirement testimony and filing of cost allocation testimony would allow the same amount of time to all parties to evaluate the different portions of the testimony.

Where functionalized cost studies are utilized, it normally requires accounting expertise as well as cost of service analysis capability to integrate adjustments into the cost of service study. In Docket No. U-1345-90-007, the full month allowed was needed to perform this task.

Staged proceedings can provide a more accurate and useful cost of service result, because the cost allocation studies are based on the same accounting data as the proposed revenue requirements. This is particularly important where the adjustments are focused in a particular area. For example, if excess capacity is at issue, it is important to prepare the study in a manner which fully reflects the proposed treatment of excess capacity, since changed production costs affect some classes (such as high voltage industrial customers) much more than others (such as residential customers, for whom much of the revenue requirement is distribution-related).

I. SUMMARY AND CONCLUSIONS

Embedded cost studies are useful tools in determining how a revenue adjustment should be divided between classes. It is important that the studies present costs in a manner consistent with the revenue requirement being addressed in the proceeding. Better cost of service models are capable of quickly performing sensitivity analyses using alternative cost allocation methods.

While some embedded cost studies are used to compute unit costs for demand, energy, and customer costs for each class, these results are subject to a variety of criticism. These results should be viewed in the context of other rate design goals; conservation, efficiency, and equity should all play a role in rate design.

The usefulness of the results depends on many factors, including the quality of the load research used to determine allocation factors, the methodology for cost allocation selected, and the degree to which the cost study is adapted to the proposed changes in rate base, revenues, and expenses. All of this can be enhanced through the use of staged rate proceedings in which cost of service testimony is completed after revenue requirement analyses are complete.

APPENDICES

APPENDIX A: Cost of Service Study by FERC Account
Kauai Electric Division

APPENDIX B: Cost of Service Study by Functionalized Groups
Arizona Public Service Company

PRODUCTION COST ALLOCATION

I. INTRODUCTION TO PRODUCTION COST ALLOCATION

The process of cost allocation, or "cost of service" consists of taking the production, transmission, distribution, customer service, and administrative and general expenses of a utility and apportioning them among the customer classes based upon various measures of usage, including maximum coincident and noncoincident peak demand, kilowatt-hour usage, seasonal and time of day characteristics.

Production costs consist of investments in generating plant and energy conservation measures, fixed and variable production O&M costs, energy conservation expenses, and purchased power costs. In addition, revenues from off-system sales are often considered "negative" production costs in the context of cost allocation. A cost allocation study must divide these fixed and variable production costs between "demand-related" costs and "energy-related" costs. Generally speaking, demand-related costs are those incurred to meet peak demands, and energy-related costs are those which must be incurred to provide power at any time.

Some production costs are associated with baseload generating resources, while some are associated with peaking resources. Baseload generating resources generally include coal and nuclear plants, run of river hydroelectric plants, geothermal resources, and other units with relatively low variable operating costs. Peaking resources generally include oil and gas fired generating plants which, while expensive to operate, are relatively inexpensive to construct and maintain. In addition, peak demands may be met with resources which do not generate "new" electricity, such as pumped storage hydroelectric plants or load management systems. While baseload resources are generally operated during peak load periods, peaking resources are generally idle during off-peak periods.

In addition, some resources, such as solar, wind, and non-firm power purchase arrangements may provide the utility with energy during the year, but may not be dependable resources at any given moment in time. While potentially very valuable, such resources do not provide benefits equal to a more dependable generating plant.

Even generally dependable resources, however, are less than 100% reliable. For example, a baseload coal or nuclear power plant is subject to outages, which may occur during peak periods. They are not "100% reliable" on-peak. Oil and gas fired generating plants are generally more mechanically dependable (in part because they run less frequently than baseload plants), but are still subject to mechanical breakdown; in addition, where firm fuel contracts do not exist, oil and gas fired resources are also subject to fuel cost uncertainty. It is particularly important to consider reliability when a utility has unpredictable peak loads or is not adequately interconnected to other utilities to provide emergency backup capacity.

There is generally a trade-off made between the capital cost of generating resources and the expected operating costs. Oil and gas fired generating plants are generally cheap to construct, but have relatively high variable operating costs. At the opposite end of the spectrum, geothermal and nuclear plants may have extremely high construction costs and extremely low variable operating costs. The cost allocation study should consider the cost characteristics of the generating units serving a utility.

Finally, utilities frequently purchase power from outside their system or sell surplus power to other utilities. Contracts may be structured to provide peaking capacity only, to provide peaking capacity plus associated energy, or provide off-peak energy only. The prices paid for such contracts may range from a mostly fixed rate to a 100% variable rate. The cost allocation study must consider the type of purchased power resources and the cost characteristics of those resources.

The methods used for cost allocation range widely. At one extreme, some analysts use a "fixed-variable" method, which treats all costs other than fuel as demand-related and then allocate those demand-related costs on the basis of contribution to the single highest peak hour on the system, while treating only variable fuel expense as an energy-related cost. These type of studies produce results which are generally most favorable to industrial customers with high load factors. Conversely, some analysts treat all production costs as energy-related and allocate these based on annual usage. This approach tends to produce results which are most favorable to small commercial customers who tend to have the poorest load factors.

In between lie methods of classification which categorize a larger or smaller fraction of fixed production costs as demand-related, and numerous methods of allocating these demand-related costs ranging from the use of single peak, multiple peak, energy-weighted, seasonal, and time-differentiated approaches.

A. Why does the methodology used matter?

Different customer classes have different usage characteristics. Residential and small business customers tend to have usage more heavily concentrated around the periods of peak demand than do industrial customers. Irrigation customers tend to use significant amounts of power in the summer months, but little or none during the non-growing seasons.

Different cost allocation methodologies assign different proportions of cost based on peak demand and season of usage. One method may favor the residential class, while another may favor the industrial customers. A method appropriate in one area of the country, where oil and gas fired plants provide much of the energy may be inapplicable in an area where coal plants are the primary resource. A method appropriate in a region where summer users such as agriculture are balanced by winter users such as electric heat residential customers may be inapplicable in an area where all classes reach their maximum peak demands at the same time of the year.

The goal of efficient and equitable cost allocation is to identify the methodology which best reflects the cost and load characteristics of the utility to which it is applied.

B. Cost Allocation for Other Costs

This briefing paper discusses classification and allocation of production plant and expenses only. This contract with the Arizona Corporation Commission also calls for discussion papers on transmission and distribution cost allocation. Other issues remain with respect to administrative and general costs and taxes. To keep production costs in perspective, they amount to less than half of the total costs on the TEP system. The appropriate treatment of the remaining costs is at least as important. A paragraph on each other area is appropriate at this time.

1. Transmission Costs

Transmission costs consist of long lines used to connect baseload plants to the utility load centers, network lines used to ensure reliability within the load centers, and long lines built primarily to facilitate interchange of power between utilities. Most cost analysts treat transmission in the same manner as generating plant. If a peak demand method is used for generation, the same is applied to transmission; similarly, if an energy-weighting or time-differentiated method is used for production plant, a similar approach is used for transmission.

2. Distribution Costs

Distribution costs fall into demand, energy, and customer components. It is generally agreed that substation investment is demand-related, and that meters and service drops are customer-related. The most durable controversy in cost allocation is over the appropriate means to allocate the distribution infrastructure -- poles, conductors, and transformers, which make up nearly one-fourth of the total investment of a typical utility. The most common method is to treat these costs as demand-related; other analysts consider only a portion of these costs to be demand-related, and treat the balance as either energy or customer related.

3. Administrative and General Costs

A&G costs are a significant portion of the total operating expense for a utility. A portion of these, such as property insurance and maintenance of general plant, and employee benefits are clearly related to total plant investment and total salaries, respectively. Other items, such as officer salaries and director fees, outside services employed, and advertising expenses are more controversial.

4. Taxes

Taxes fall into several categories. It is generally agreed by analysts that property taxes should be allocated on the same basis as plant in service, and that income taxes should follow net income by class. Revenue taxes generally can be allocated on the same basis as revenue. Generating taxes, possible future taxes such as a carbon dioxide emissions tax, or pollution law violation fines are attributable to energy production. The largest tax items are non-controversial.

C. Tucson Electric issues.

The Tucson Electric system is characterized by primarily coal-fired baseload generating plants, with a lesser investment in peaking resources and older generating plants relegated to cycling operation. Tucson sells significant amounts of power off-system to other utilities, and utilizes purchased power and exchange energy from other utilities. The loads on the TEP system are highly seasonal in nature, and peak demands can be quite extreme, but the majority of the Company's generating plant investment is utilized throughout the year. These characteristics suggest that a peak demand based cost allocation method would be inappropriate for cost allocation on this system. A wide variety of appropriate methods, however, are available and should be considered. This briefing paper identifies several other methods which would be appropriate and should be considered, including the Peak Credit, Base and Peak, Base-Intermediate-Peak, Peak and Average, and Probability of Dispatch methods.

II. TYPES OF PRODUCTION COSTS

Production costs fall into several categories, each of which is assigned separate account numbers under the FERC Uniform System of Accounts. The general categories include production plant, conservation plant, production O&M expenses, purchased power expenses, conservation expenses, and off-system sales revenues.

A. Capital Costs

Capital costs are typically those included in "rate base" in a utility rate proceeding. The primary capital costs are included in FERC accounts 310 - 346. The areas of production plant treated separately in the FERC Uniform System of Accounts are as follows:

Account	Resource
310-316	Steam Plant [generally coal, oil, and gas]
320-325	Nuclear Plant
330-336	Hydroelectric Plant
340-346	Other Production Plant [primarily combustion turbines]

Conservation investments have not yet been assigned an account number by the FERC. These investments may be included in rate base and earn a return, or they may be currently expensed. Where they are included in rate base, most utilities utilize "suspense" accounts such as Account 124 to record their investment in conservation measures. These costs are then amortized over their accounting lifetime to Account 908 [Customer Assistance Expense]; where conservation expenditures are expensed, rather than capitalized, they are often recorded in account 908 as well. While many commissions now recognize conservation expenditures as production-related, some still treat these costs as customer service costs, and do not count them as production costs at all. The cost analyst must be aware of the appropriate accounting for conservation costs, so as not to confuse $20 million in conservation measure acquisition expenses recorded in Account 908 with the other types of consumer education expenses often recorded in that account.

In addition, however, certain "intangible" plant costs may be included in FERC Accounts 301-303. These might include capitalized expenses associated with a purchased power contract, a fixed payment made for a limited term right to use falling water, or certain other types of investments in power production. These are typically minor in nature, but with evolving power markets, may become more important to consider.

The important common characteristic of capital costs is that they are made by the utility for plant expected to last more than one year, and they are included in the rate base to which a rate of return is applied and upon which revenue requirements are based.

1. Baseload resources

Capital costs of baseload generating resources generally dominate utility production plant in service. These costs include nuclear, coal, hydro, and geothermal generating plants, and are spread throughout the FERC accounts for production plant in service.

2. Intermediate resources

Intermediate (or cycling) resources are those which are operated at times other than peak periods, but which typically are left idle during shoulder seasons or in the middle of the night. Two different types of intermediate resources are common. First, there are relatively recent plants designed and built specifically to be used as cycling plants, such as combined cycle natural gas plants. These have significant capital costs, but also fairly significant operating costs. The other category may include older generating plants, which may have originally served as baseload units, but due to aging, rising operating costs, or increased efficiency of newer technologies, are no longer used in that capacity. Many utilities which have acquired new coal or nuclear baseload generating plants have relegated their former oil and gas fired plants to intermediate duty. Older units are typically almost fully depreciated; in this situation, the operating cost is the most significant portion of total cost.

Intermediate resources are generally steam-power at least in part. Older units are typically steam units which may have previously served as baseload plants and have now been relegated to intermittent service; combined cycle plants may have the steam generation portion of the plant included in Steam Plant accounts 310-316, and the gas turbine portion included in Other Production Plant accounts 340-346.

3. Peaking resources

Certain types of resources are used exclusively to meet peak demand. Most commonly recognized in this capacity are combustion turbines, but many other types of peaking plants exist. Internal combustion (diesel) units are common, and many utilities keep older steam-power units available solely to provide reliability during peak periods.

In addition, a hydroelectric dam may be constructed with more generating units installed than are necessary to fully utilize the water available. This allows the utility to use all of the available water during high-demand periods, and to slow or stop flows during off-peak periods. This creates a potentially interesting problem for the cost analyst. If the dam were built with only one or two generating units, it could operate 24 hours a day, 365 days per year on the available water, and would be characterized as a baseload resource. By the addition of the (relatively inexpensive) additional generating turbines, the dam may be used to produce the same amount of power over a year, since the amount of water available does not change, but the power may be produced solely during on-peak periods, since the rate at which water can be utilized increases with the additional turbines installed.

4. Off-peak or nonfirm resources

Some resources provide only sporadic power, or cannot be depended upon on a planning basis to meet peak demands. These may include wind energy, solar-electric energy, excess power from self-generating industries, or other resources. Hydroelectric resources may be nearly 100% reliable, but the supply of water may be subject to the vagaries of the weather. The analyst should carefully evaluate the characteristics of such resources in preparing a cost allocation study.

5. Conservation resources

Energy conservation investments and expenses may be associated with any type of utility load. Conservation investments may occur for 100% peak-oriented resources such as load management interruption systems, or with 100% off-peak resources such as more efficient street lighting systems on a utility with a summer afternoon peak. In addition, unlike generating plant, conservation measures are installed at the point of end-use, and do not directly serve multiple customers or customer classes. Some cost studies treat conservation investments exactly like other production plant and allocate these costs to all classes based on measures of demand and energy usage; this is based upon an assumption that the conservation measures are a cost-effective means to augment the utility system, and should be treated in the same manner as other resources. Other studies directly assign these costs to the customers or customer classes which are the direct beneficiaries of the expenditures.

B. O&M Expenses

Production O&M expenses primarily consist of generating plant operating costs plus conservation program operating costs. Purchased Power expenses will be treated elsewhere. Generating plant expenses consist of fuel expenses, which for most utilities are the largest portion of production O&M, plus non-fuel expenses. Generally in a cost study these two portions of generating plant expenses are treated separately.

1. Non-fuel expenses

Non-fuel expenses include plant operation and maintenance expenses included in FERC accounts 500 through 557, with the exception of the following:

Type of Expense	Account #	Description

Fuel accounts:	501	Steam fuel
	518	Nuclear fuel
	536	Water for power
	547	Other fuel
Purchased Power	555	Purchased Power

In general, the non-fuel expenses for power generating plants are allocated in the same manner as the associated generating plant. For example, if the Average and Excess Demand method is used for allocating the investment costs of a coal plant, the same method will typically be used for allocating the non-fuel O&M expenses associated with that plant. Similarly, if a combustion turbine peaking plant investment is allocated solely on the basis of peak demand, the non-fuel O&M expenses for that plant will typically also be allocated on the basis of peak demand. For this reason, the primary controversy in production plant cost allocation is generally directed at the method used for the plant accounts, with the resolution generally carrying forward to the O&M accounts.

Sometimes, particularly when a "fixed-variable" approach to cost allocation is used, it is necessary to ascertain what portions of some of these accounts are actually "variable." For example, Account 506, Miscellaneous Steam Power Expenses, includes the cost of water treatment chemicals and sulphur dioxide scrubbing agents used in coal plants; the amount of these products used may vary directly with the number of kilowatt-hours produced, and therefore are "variable" costs.

Accounts 556 and 557, System Control and Load Dispatching, and Other Expenses, generally apply to all types of production plant equally. If different methods are used for classifying and allocating the different types of production plant (for example, baseload plant on an energy-weighted basis, and peaking plant on a peak demand basis) these accounts may appropriately be allocated on the basis of a subtotal of all of the other production accounts. If a single method is used for all production plant, the same method should apply to these accounts.

2. Fuel and other kwh-variable expenses

Fuel is the primary variable cost item which is a function of the number of kilowatt-hours produced. In nearly all cases, fuel costs are allocated on the basis of total kilowatt-hour use by each class. This may not be entirely appropriate. For example, the fuel used by peaking plants (e.g., natural gas burned at relatively high heat rates) is generally far more expensive per kilowatt-hour than the coal which may be used by the same utility in it's baseload units. If time-differentiated approaches are not used, it may be more fair to treat a portion of these fuel expenses as peak-related so that they are allocated to the classes using power during the time when these expenses are incurred.

As indicated above, certain non-fuel expenses, such as water treatment and air pollution abatement materials are used in more or less direct proportion to kilowatt-hour production, and should be treated in the same manner as fuel costs.

C. Purchased Power Expenses

Utilities frequently incur large expenses for purchased power. These take many form, including long-term firm capacity and energy purchases, long-term firm capacity-only purchases, short term firm purchases of energy and/or capacity, as-available economy energy purchases, and maintenance or operational interchange energy. Each has different cost characteristics and should be evaluated separately.

1. Capacity and Energy contracts

Capacity and energy contracts can be short or long term. In a typical long-term contract, a utility agrees to pay the seller an annual fixed charge, sometimes called a "capacity charge" or an "energy reservation charge" in order to secure access to the generating capability, and a per-kilowatt hour energy charge. The portion of the plant fixed costs (interest, return, amortization, taxes, maintenance) which are included in the fixed portion of the payment can range from zero to 100%. Generally all of the variable portion of plant operating cost, plus the residual portion of fixed costs, are included in the energy charge.

Contract payment schedules are often structured to provide the power seller with some reasonable assurance of recovering their fixed costs, and to provide the buyer with some reasonable assurance of having a reliable resource available. These economic considerations may result in a contract with fixed and variable payment provisions which bear little resemblance to the fixed and variable cost characteristics of the generating resource. For example, a contract may provide that 100% of the debt interest costs are included in the fixed payments, to protect the seller from insolvency, but 100% of the equity return and associated taxes in the variable portion, to assure the buyer that the project will be maintained to a high level of reliability.

In cases where the fixed payment for capacity or energy reservation exceeds the amount which a utility would incur to secure access to a peaking plant, the additional fixed payments may be treated differently in cost allocation studies. For example, assume that a utility could secure a combustion turbine at a monthly lease rate of $6/kw/month [$72/kw/year] plus 5 cents/kwh for fuel and variable operating costs, or could instead enter into a long term contract with a seller having a geothermal project by paying $15/kw/month [$180/kw/year], plus 2 cents/kwh for operating costs. In this situation, the only justification for choosing the geothermal option is to reduce annual energy costs assuming a high number of hours of operation. Under the example, the geothermal plant would need to operate about 3500 hours per year to be cost-effective compared with the combustion turbine; if the utility needed only peaking capacity, the geothermal project would not be an economical option. In this situation, it may be appropriate to classify the $180/kw/year fixed capacity payment in a manner consistent with the treatment of other baseload production costs.

This logic should follow from the approach used for company-owned baseload generating plant. If all generating plant investment is classified as demand-related, the same approach should be used for the fixed payments to independent power producers. If a portion is classified as energy-related, using the Peak and Average or Peak Credit methods, for example, the same should apply to the fixed portion of the purchased power contract.

For example, under the Peak Credit method, the first $72/kw/year of fixed payment [an amount equal to the fixed costs of a combustion turbine] would be classified as demand-related, and the balance would be classified as energy-related.

The portion of purchased power contracts which varies directly with the number of kilowatt-hours provided is often considered to be an energy-related cost. This may not be the case, however, if a baseload generating plant is contracted for on a cents/kwh only basis. For example, a purchased power contract may be contracted for on an energy-only basis due to either a seller preference or a relatively high level of uncertainty over the number of hours per year the underlying resource will produce energy. However, if there is a statistical correlation between periods of high availability and periods of high demand, the plant may be expected to provide a high probability of providing useful peaking capacity. In this situation, it may be appropriate to recognize a portion of the variable payment made as a demand-related cost. While less common than contracts with fixed capacity payments, the Washington Water Power Company has historically structured all of its firm purchases from independent power producers in this manner in order to insulate shareholders and ratepayers from potential poor performance of generating units.

Some capacity and energy contracts are for specific seasons only. For example, contracts between utilities in the Pacific Northwest and those in the Desert Southwest typically provide capacity to the Northwest only in winter, and capacity to the Southwest only in summer, consistent with the peak needs of both areas. In situations where the resource is available seasonally, the costs should be treated in a manner consistent with that availability.

The point is that capacity and energy contracts take many forms, and that the payment provisions may be affected by many things other than utility economics. Classification and allocation of these costs should not necessarily follow a simple formula.

2. Capacity-only contracts

Utilities enter into capacity-only contracts with other utilities which may have surplus generating capacity or hydroelectric capability. Some contracts may be for annual capacity used for load factoring, while others may be for emergency capacity. The annual fee for such capacity may depend on the length of the contract, the transmission access available with the capacity, the operating costs associated with utilizing the capacity, and other factors. In a typical capacity-only contract, the utility receiving power during high-demand periods pays an annual or monthly fee for the availability of the capacity, and then must return that energy during a specified period after receiving it.

The fixed payments associated with capacity-only contracts are generally considered to be 100% demand-related. However, if a utility pays a significant premium above the cost of a peaking-only resource in order to obtain load factoring services, and uses that capacity frequently, it may be necessary to utilize demand allocation factors which recognize the frequent utilization of the capacity, or even to classify a portion of the fixed payments as energy-related.

3. Economy energy contracts

Utilities enter into economy energy purchase and sale agreements frequently. These allow the utility to dispose of power temporarily surplus to their needs to utilities having need for energy or having higher cost plants which can be shut down, or to purchase power from other utilities when it is available at costs lower than the variable operating costs of company-controlled resources.

Most economy energy transactions are short-term agreements, even hour-to-hour, which provide no planning certainty or defined capacity benefits. Consequently, nearly all of these purchased power costs and the alternative, revenues to the utility from sales of economy energy discussed in section II (E), are treated as energy-related costs.

The exception to this general rule is where the economy energy is available for a sufficient duration that it allows some capacity savings or reductions in the use of any resource where a portion of the avoided cost is considered a capacity cost. Some seasonal transactions between regions may meet this requirement.

D. Abandoned Project Costs

Utilities across the country have abandoned generating projects on which money was spent. In some cases, only preconstruction and licensing costs were incurred; in others, hundreds of millions of dollars were expended on partially completed units. The issue of whether or not to allow these costs into rates is a major revenue requirement issue dealt with by regulatory commissions. The only issue of interest to the cost of service analyst is the treatment of those costs which are ultimately determined to be allowable in rates.

Typically, abandoned project costs allowed in rates are included in the cost of service analysis using the same methodology as would have applied had the project been completed. If a 4CP, Peak

Responsibility approach is found applicable to baseload generating plant, then the same approach is applied to abandoned baseload generating plant; if a Peak Credit methodology is applied to operating baseload plant, this method would be applied to abandoned baseload plant.

Some controversy may arise in a situation where the utility has no completed generating plant of the same type as the abandoned plant. For example, if a utility has only oil, gas, and coal generating plant, but has an investment in an abandoned nuclear plant, it may be necessary to address how nuclear plant would have been treated if the plant had been completed. For example, in a Peak Credit, Probability of Dispatch, or Peak and Average study, typically a higher percentage of investment in nuclear plant will be treated as energy-related than would be the case for oil, gas, or coal plants. Since the amounts involved in abandoned plant recovery are typically small relative to the total costs being allocated, differing treatment for abandoned plant will typically make little difference in the results of a study.

E. Off-system Sales Revenues

Utilities make sales of power to other utilities in addition to retail sales to ultimate consumers. In many cases, the revenues from off-system sales can be 10% or more of total revenues. These revenues are treated as offsets to revenue requirements in the result of operations phase of a rate proceeding; they must be accounted for in the cost of service study as well. The general approach is that off-system sales revenues should be accounted for in the same manner as the generating plants which make such sales possible. Unfortunately, it is not often possible to attribute a specific off-system sale to a specific generating plant. For that reason, off-system sales revenues are sometimes allocated between classes on the same basis as the subtotal of total production costs. Specific treatment is sometimes possible, and will add to the precision of a study.

1. Capacity and Energy contracts

Where a utility makes a sale of capacity and energy, and the payment received clearly reflects the firm capacity being provided, it is appropriate to attribute at least a portion of the revenue as an offset to capacity costs in the cost of service study. The classification of the revenues between capacity and energy in the cost study can follow the characteristics of the contract, the characteristics of the generating plant supporting the contract, or the general allocation of generating plant.

At times, utilities make sales of "unit capacity" contracts, in which the buyer receives the right to control and dispatch the installed capacity of a specified generating unit. While it may seem logical to classify the revenue from such a contract in the same manner as the costs of the unit associated with it, the revenues may be greater than or less than cost.

For example, Arizona Public Service sold the capacity of it's Cholla 4 unit to Southern California Edison at a price which was between the fully allocated cost of Cholla 4 and the (higher) cost of the newer Palo Verde generating plant; in that case, it was arguable that what APS was really reselling was the (new) excess capacity from Palo Verde plant, but that the buyer desired the greater predictability of the coal unit.

At a minimum, the variable costs of production which the cost study treats as energy costs should be offset by the revenues under the contract. For example, if a contract provides capacity and energy at a price of $5.00/kw/month, and $.02/kwh, and the utility incurs variable production costs of $.015/kwh to provide the energy, <u>at least</u> the $.015 should be treated as an energy-related. cost. Controversy may develop over the treatment of the remaining energy revenues and all of the capacity revenues. In general, however, these revenues should be classified in the same manner as the plant which makes the revenues possible.

2. Capacity-only contracts

Where a utility sells strictly peaking capacity to another utility, generally 100% of the revenues should be treated as an offset to demand-related costs within a cost study. The logical exception to this, however, is where 100% of off-system sales revenues are classified on the basis of the subtotal of total production costs. In this type of situation, the capacity-only revenues would be included in the overall classification scheme.

3. Economy energy contracts

The most common transactions in the utility industry are simple economy energy sales, where one utility has a baseload plant available and another has a plant with higher running costs (usually gas-fired) currently operating. In this situation, the sale will typically be made at a price above the variable operating cost of the baseload plant, and below the decremental operating cost of the gas-fired plant. These are generically known as "shared-savings" rates. It is a transaction which benefits both utilities.

Clearly the revenues from such sales should first be applied to offset variable running costs of the baseload plant, i.e., be classified as energy-related. The residual, however, is effectively a return on the investment in the baseload plant, and should be classified and allocated in the same manner as the investment in the plant. Thus, even though the total sales price may be expressed on an energy basis, the revenues should be classified as partly demand-related.

III. USAGE MEASURES USED FOR COST ALLOCATION

All costs within a cost of service study are ultimately allocated based on indices of usage. For production plant, the appropriate indices are peak demand usage and energy usage. Many different measures of each are possible. Several of these are discussed below.

In the classification step, described in Section II, production costs are categorized as either "demand" related or "energy" related. In selecting an allocation methodology, discussed later in Section IV, some combination of demand measures and energy usage are used to allocate those costs; in many cases, energy usage is used to allocate the costs which are classified as demand-related.

This section discusses the different measures of "demand" and "energy" which are used in the allocation step of the cost study.

A. Demand Measures

Demand measures the rate of use of electricity at a particular point in time. Usually individual consumer meters which register demand measure it over a 15 minute interval; for class cost allocation purposes, however, hourly demand is generally utilized. The differences are minor.

1. Coincident Peak

Coincident peak demand is the demand of an individual customer or customer class at the time of the system coincident peak. This may occur at a time when none of the individual customers or customer classes are at their individual peak level.

Coincident peak is normally measured on an annual peak (1 CP), seasonal peak (4CP or 6CP), or monthly peak (12CP) basis. Generally, narrower definitions of peak (1CP) are more favorable to high load factor customer classes than broader definitions of peak such as 12CP.

The 1CP measure looks at the highest single hour of system demand. Variations may look at the highest 12, 50, 200, or even 1500 hours of system demand, or several individual hours of system demand spread through the day of the system peak.

2. Monthly Coincident Peak

For many years, the Federal Energy Regulatory Commission has expressed a preference for 12CP studies for allocating the cost of generating plant. A 12CP study measures each class' contribution to the peak hour of each of the 12 months of the year. These are then either added or averaged to determine a single peak allocation factor. For example, assume that irrigators may make no contribution whatsoever to the winter peak, but use 50% of the system demand during the summer. A 1CP study would either assign them no demand cost responsibility at all (if the system peak were during the winter) or 50% of the demand responsibility (if the system peak were in the summer). A 12CP approach would assign this class a demand responsibility reflecting their monthly contribution to demand - zero in some months, 50% in others, and averaging something like 25%; under this approach, the irrigators would be assigned 25% of the demand-related costs on the system.

3. Non-coincident Peak

Non-coincident demand is the demand placed on the system by each customer or customer class at the point in time when that customer or customer class reaches it's individual peak demand. This can be measured on an annual or monthly basis. For example, if residential customers demand is caused primarily by air conditioning the residential class peak may be after work at 6:00 P.M. If the commercial class reaches it's peak at the hottest hour of the day, it may reach it's class peak at 3:00 P.M. The system peak may occur at 5:00, when the commercial class is falling off a bit from it's noncoincident peak and the residential class is rising to it's noncoincident peak. The sum of the class non-coincident demand is normally higher than the system coincident peak demand. Only when all classes reach their noncoincident peak at the same time are the two equal.

B. Energy Measures

Fuel costs and, in many cost of service methodologies, a portion of fixed investment and O&M expense, are classified as energy-related. These are allocated between classes based on energy usage. Normally metered energy usage for each class is adjusted to reflect losses from the point of generation to the point where the energy is metered. Losses are usually computed on an annual average basis, but it would be more accurate to do so on a seasonal and/or time-differentiated basis, since losses from baseload plants are typically higher (due to greater travel distances) while losses during peak periods are typically higher (due to transmission system loading).

In any case, however, the energy-related costs can be spread between classes in several different ways.

1. Annual Energy

The most common method of spreading energy-related costs is on the basis of annual kilowatt-hour usage adjusted for average losses in each class. This has the advantage of simplicity; for systems where the production costs vary significantly by season, however, the imprecision may be undesirable.

2. Seasonal Energy

For systems with distinct seasonal load characteristics, production costs may vary in distinct seasons. This is common in both summer and winter peaking systems. It is relatively straightforward to compute loss-adjusted energy usage by season, and this adds precision to an embedded cost study.

Tucson Electric is a summer peaking system, and it would probably be beneficial to at least compute energy costs on a seasonal basis. Rate design can follow a seasonal format as well, so that the seasonalized costs are collected in seasonalized rates.

3. Time of Day

Some systems have significant variations in cost by time of day, and time of day rates are feasible. The data requirements for computing production costs by time of day are considerable, and accurate usage data by time of day typically only exists for certain classes or subclasses. If there is reason to estimate energy costs by time of day, the load research programs should be carefully geared to provide the desired information. It makes little sense to compute cost responsibility using time of day data unless the metering and rate design are expected to be in place to ensure that individual consumers can benefit from shifting of their loads.

IV. FIXED PRODUCTION COST ALLOCATION APPROACHES

There are many different methods used to allocate production fixed costs. As described earlier, these include peak demand methods, energy-weighted methods, and time-differentiated methods. The 1992 NARUC Cost Allocation Manual (pages 39-68) provides numerical examples of how many of these different methods operate. That data will not be reproduced here. Only a brief description of the various methods is presented; examples of state or federal regulatory agencies using a particular method are given, although no systematic search of the literature has been made to identify the approaches used in the various jurisdictions. With fifty-two regulatory agencies and more than two hundred regulated utilities, many different methodologies and variations thereof are in use.

A. Fixed/Variable Peak Demand Methods

Peak demand methods allocate all production fixed costs on the basis of a measure of peak demand for each class. In these approaches, 100% of the investment and fixed O&M is classified as demand-related, and is allocated on the basis of class contribution to peak demand.

1. Single Coincident Peak (1CP)

A single coincident peak method uses the highest single hour or hours of system demand as the basis for cost allocation. Each class' contribution to system demand during that hour or hours forms the basis for their allocated share of fixed production costs. It is known as a "single" coincident peak method because only the highest points on the load duration curve are considered. Even where the highest 200 hours of system demand are considered, this would be considered a 1CP methodology. At some point, the number of hours considered increases to the point where it begins to resemble the All Peak Hours method identified below.

Industrial customers often advocate the use of a single coincident peak methodology; while the author is unaware of any state commissions using this approach for electric cost allocation, FERC Order 636 has approved this approach for interstate natural gas pipeline cost allocation.

2. Multiple Coincident Peak (4CP, 12CP)

Multiple coincident peak approaches use the highest hour of system demand during each month of the season or year. A seasonal approach, such as 4CP or 6CP (using the peak hour in each of the four or six highest months of system demand) may be appropriate for systems with strongly seasonal demand characteristics which, even after economic scheduling of maintenance and off-system sale and purchase transactions, have excess capacity during particular seasons.

The Federal Energy Regulatory Commission (although in some cases it has accepted other approaches) and the Indiana Commission utilize the 12CP methodology. The Arizona Commission has expressed dissatisfaction with the 4CP methodology in several Arizona Public Service proceedings.

3. Non-coincident Peak (1NCP; 12NCP)

Non-coincident peak methods use the highest demand for each class during the measurement period, even though these do not occur at the same time of day. For example, if residential loads peak in the morning and commercial loads in the afternoon, a non-coincident peak load method would base the allocation factor on the morning peak of the residential class and the afternoon peak of the commercial class. In this manner, a class which places a significant demand on the system and uses significant amounts of capacity at times other than the system peak shares in the cost of making that capacity available.

Noncoincident peak demand studies may consider each class' peak demand during the single month of maximum system peak demand (1NCP), or may look at multiple months (4NCP, 6NCP, 12NCP) of system load.

4. Loss of Load Probability

Loss of load probability (LOLP) studies identify the probability of the utility being unable to meet it's demand at any given point in time. If a study determines that 50% of the hours per year when the utility is at risk of not being able to serve its loads occur during summer days, 25% during summer nights, and 25% during winter days, the fixed costs would be allocated proportionally on the basis of class load during those periods.

LOLP studies can produce counterintuitive results. The studies take into account planned maintenance, which may make the amount of capacity available during off-peak periods smaller, and the probability of outages at major generating plants occurring at any time of the year. For example, Pacific Northwest is heavily dependent on hydropower and therefore faces much higher power supply costs in dry years. The region has a severe winter peak load shape and incurs significant extra costs to prepare for those peaks. Nonetheless, the highest probability of a loss of load occurs in the early spring of years with high snowpack (at a time when power supply costs are extremely low) because flood control standards require that reservoirs be drained in anticipation of a large runoff; with little water in the reservoirs, a sudden cool or cold snap can quickly exceed the available capacity of the system.

5. All Peak Hours

An All Peak Hours approach divides the utility's loads into all hours when the system capacity utilization is near the available capacity. This may well include some hours during months which are considered off-peak if plant maintenance causes some generating plants to be unavailable, and the remaining plants are being fully utilized. Just because loads may be lower by a considerable margin that the absolute system peak hours does not necessarily mean that the utility has excess capacity.

In order to prepare an All Peak Hours study, it is necessary to collect accurate data on hourly usage of each class. This requires a fairly extensive load research program.

It is possible to mix and match methodologies for different types of production plant. For example, it may be appropriate to use an All Peak Hours approach to allocate the costs of peaking plants, but to use an energy-weighted or time differentiated approach to classify the costs associated with baseload plants. Similarly, whenever an energy-weighted methodology is used for baseload plant classification, some definition of "peak" must be selected to allocate the portion of costs which is classified as "demand" related.

B. Energy-Weighted Methods

Energy-weighted methods treat a portion of fixed production plant costs as energy-related, and allocate these based on a measure of energy usage, and a portion of fixed production plant costs as demand-related, and allocate these on a measure of demand. When using these methods, it remains necessary to decide whether to use single or multiple peaks, coincident or noncoincident peaks, and annual or seasonal energy usage.

1. Peak Credit or Equivalent Peaker

The Peak Credit method, used in several states, classifies baseload generating plant fixed costs between demand and energy based on the ratio of cost of peaking plant to baseload plant. For example, if new peaking plants cost $300/kw, and new baseload coal plants cost $1000/kw, 30% of the cost of a baseload plant would be treated as demand-related, and 70% energy-related. The demand-related costs would then be allocated on one of the various measures of demand -- either coincident, non-coincident, or all peak hours.

More recently, this method has been revised to accurately account for purchased power contracts from non-utility generators. In this approach, the <u>annualized</u> costs of a peaking unit used for peaking purposes (including fuel costs for the peaking usage) is divided by the annualized costs of a baseload usage (including fuel costs for the baseload generation). In this manner, the pricing provisions of many independent power producer contracts (which may be designed to accommodate the financing requirements of the developer) are not allowed to bias the cost allocation study.

The Washington, Idaho, and Maryland Commissions utilize the Peak Credit methodology for cost allocation.

2. Peak and Average

Like the Peak Credit method, the Peak and Average method treats a portion of the fixed production costs as demand-related, and a portion as energy related. Historically, the method treated a proportion equal to the system load factor as energy-related, and the balance as demand related; the logic was that the system load factor defined the level of usage of generating plant which was independent of any class peak demands.

More recently, analysts have been treating a cost-based proportion of baseload generating plant costs as energy-related. When this is done, the differences between this method and the Peak Credit method become merely semantic.

In any event, after fixed production costs are classified using the Peak and Average approach, the demand-related portion is then allocated among classes using one of the peak demand methods discussed in Section IV(A) of this paper; generally a coincident peak demand method is used.

The Peak and Average method is used by the North Carolina Utilities Commission [Re. Carolina Power and Light, 87 PUR 4th, 64]

3. Average and Excess

The Average and Excess Demand method computes a single allocation factor for allocating fixed production costs which incorporates both average demand (energy usage) and class noncoincident peak demand in excess of class average demand. First, a proportion of production fixed costs equal to the system load factor is allocated between classes based on their average demand. Second, the <u>noncoincident</u> peaks (typically 1NCP) of the individual classes are determined; the class average demand is subtracted from this noncoincident peak demand to determine a class "excess" demand -- that is, a class noncoincident demand in excess of the class average demand.

A situation where this method would be applicable would be a utility with little or no baseload generating capacity which serves customer classes which each have their noncoincident peak at a time other than the system coincident peak.

The Average and Excess Demand method is used by the Hawaii Public Utilities Commission for production cost allocation [Docket 6531; 6532].

4. Base and Peak

The Base and Peak method simply treats baseload plants as energy-related, and peaking plants as peak-related. It is the simplest energy-weighted method available. If a system consists solely of baseload units and peaking units, it may be an appropriate approach; where intermediate plant is a part of the resource mix, the imprecision of this approach may be undesirable.

5. System Planning

The System Planning method uses the prospective investment of a utility in baseload and peaking plants to ascertain the proportion of total power supply costs which are demand-related versus energy-related. The change in power supply costs expected over a finite planning horizon is evaluated with respect to both increased capacity and increased energy supply.

If a hypothetical utility is not expected to make any expenditures to expand peaking capacity, but will make expenditures to increase energy production, 100% are power supply costs are treated as energy-related. Similarly, if the utility is not expected to make any expenditures to produce additional energy except for adding capability at the time of the system peak, essentially 100% of it's power supply costs would be treated as demand-related. The method can produce erratic results, particularly where a utility is far from an optimal configuration of generating capacity. It is often considered a melding of marginal and embedded cost principles.

The Oregon Commission, which formerly used the Peak Credit methodology, is now using the System Planning approach in marginal cost of service studies.

The System Planning approach is of limited value where a utility is not expected to make imminent expenditures for new generating resources, since it looks at the prospective investment in peaking and baseload resources as the source data for cost classification. Given the resource situation of Tucson Electric, this approach is probably inappropriate.

C. Time-Differentiated Methods

Time differentiated methods generally share a philosophy that the costs of power plants should be recovered from the customers using power at the time that different plants are in use. Baseload plant costs should be used during all hours, and the costs recovered ratably from all usage. Peaking plants are used only at times of the system peak, and the costs should be assigned to customers in proportion to their contribution to those peak loads. Time differentiated methods are characterized by treating 100% of plant investment, fixed operating cost, and variable operating cost in the same manner -- essentially computing a total cost/kwh for power produced in different rating periods, and assigning it to classes based on their usage during those periods.

1. Production Stacking

The Production Stacking method identifies the configuration of baseload generating plants that would be used to serve some specified base level of load, and classifies these unit costs as energy-related. Peaking plants are classified as demand-related. It is similar to the Peak Credit methodology, except that no separate recognition is given to the peaking capacity value of baseload plants.

2. Base-Intermediate-Peak (BIP)

A refinement of the Production Stacking method, the BIP method assigns costs to three rating periods. The cost of baseload plants is treated as energy-related, and recovered from all classes based on annual energy use. Intermediate plant, used seasonally or diurnally, is recovered from class usage over base levels during the period when this plant is used. Peaking plant costs are assigned to classes based on their incremental demand above intermediate levels.

While data requirements are not small, the methodology is relatively simple to compute and apply.

3. Probability of Dispatch (POD)

The Maine Commission has taken the BIP method to a more refined stage by using an hourly dispatch model to identify when, on a planning basis, each generating plant will be used. The total costs of ownership and operation of each generating unit are divided by the number of hours each unit operates. These unit costs are then assigned to the hours during which the plant operates, and to the classes using power during those hours. The methodology does not directly lead to any distinction between "demand" and "energy" related costs, but rather to time-differentiated energy costs. Rate design may follow that model, or be converted to a more conventional demand/energy split.

V. SELECTING A COST ALLOCATION METHOD

The production cost allocation methodology selected for an individual utility should recognize the historical development of the utility generation system, the load characteristics of the utility, the resource characteristics of the utility, the nature of the utility's interchange of power with neighboring utilities. Non-cost considerations, such as gradualism, equity, fairness, conservation, political pragmatism, and regulatory history may be important in determining how to use the results of a cost study in designing rates among and within classes, but generally should not affect the choice of methodologies.

There are multiple steps to implementing a cost allocation methodology. First, the resource characteristics of the utility, including the nature of it's interactions with other utilities, should be primary determinants of the <u>classification</u> of the utility costs. Second, the load characteristics of the utility should be primary determinants of the <u>allocation</u> of these costs between and within customer classes. Generally, the <u>resource</u> characteristics of the utility should guide the <u>classification</u> of production plant, while the <u>load</u> characteristics of the utility should influence whether a seasonal, annual, or other approach should be used to <u>allocate</u> demand-related costs.

A. Resource Characteristics of Utility

Generally speaking, there has been a tradeoff in utility planning between capital-intensive and fuel-intensive resources, and this should be taken into account in selecting a cost allocation method. Some utilities, like Tucson Electric Power, meet much of the peak and energy load they serve with baseload generating plants having low operating costs. The systems should be subject to different cost classification techniques than that applied to a utility which relies heavily on low-investment oil and gas-fired plants with relatively high operating costs, such as Hawaii Electric Company.

1. Type of resources owned

Baseload resources are generally characterized by high capital and fixed O&M costs, and relatively low variable operating costs. If these form the bulk of a utility's annual generation and dominate the utility's costs, it would be clearly inappropriate to allocate 100% of the costs of such projects based on a short-term definition of peak demand, particularly if the increased requirements at peak are met with relatively low-capital cost peaking units.

Until recently, utilities tended to select between oil and gas-fired combustion turbines, costing $200-$300/kw for capacity, coal plants costing $1000 - $1500/kw for capacity, and nuclear plants costing $2000 and up per kw of capacity. The expected operating costs were inversely proportional to the capital costs -- oil and gas units were expected to cost 5 cents/kwh or more to operate, while nuclear plants were expected to have very low operating costs. A utility would be expected to choose that combination of resources which would minimize total cost for serving a given load.

If the utility had sufficient baseload generation to meet load during all but the highest hours of peak demand, it would logically choose a peaking unit, knowing that the high operating costs would only be incurred for short periods, and the low capital costs would keep the total costs low. On the other hand, a utility forecasting rapid growth in on-peak and off-peak demand might choose a baseload unit, knowing that otherwise it would have to operate a peaking unit for thousands of hours per year, with attendant extremely high fuel costs.

Most utilities, following such an approach, have a mix of different types of generating units. On such typical hybrid systems, it is appropriate that the costing methodology recognize the cost differences of different types of generating plant. Methods such as the Peak Credit, Base and Peak, Peak and Average, Base-Intermediate-Peak, and Probability of Dispatch methods all take these differences into account. For those methods which first classify the fixed plant costs into a demand and energy component, it is typical to use a single or seasonal coincident or noncoincident peak method to allocate the portion of costs classified as demand-related, although on some utility systems with broad peaks and high class diversity, it may still be appropriate to use a method which recognizes the extent to which each class uses production plant, such as the Average and Excess method to allocate the demand-related costs.

Some systems, however, meet all or essentially all of their needs with either baseload units. In this situation, the fixed costs tend to be relatively high and variable operating costs low. Using a Probability of Dispatch method would result in essentially the same costs being assigned to every kilowatt-hour, while using a 1CP Fixed/Variable method would result in extremely high on-peak charges and extremely low off-peak charges. The analyst should clearly look at the <u>reason</u> why the system was configured as it was in choosing a methodology.

On a system with essentially all baseload plants and sharp seasonal load characteristics, however, it is possible that scheduling maintenance during the off-peak months can leave the utility with relatively equal reserve margins throughout the year; it may also be possible to achieve this through inter-utility exchanges or system sales, as described below.

2. Operating costs

A system characterized by primarily baseload generating plants may have very low operating costs. In this situation, where the vast majority of total power supply costs are capital costs, tradeoffs may have been employed to reduce operating costs. Such tradeoffs include construction of mine-mouth generating plants and long transmission lines, to avoid fuel transportation costs; selection of coal, geothermal, hydro, solar, or nuclear capacity to minimize expected fuel costs; or even the selection of combined-cycle gas-fired generation rather than simple-cycle generation. In any situation where a trade-off of capital for fuel costs has occurred, the cost allocation methodology should recognize this, either by directly classifying some of the fixed costs as energy-related (as in the Peak Credit, Base and Peak, or Peak and Average methods), or by allocating the higher fixed costs over a larger number of hours using a time-differentiated method such as the B-I-P or Probability of Dispatch method.

At the opposite extreme, if all of the generation on a system is oil or gas fired simple cycle units, and all classes have a coincident peak at the same time of day and year, then the utility arguably must incur the capital cost of each unit in order to meet peak demand, and a 1CP, fixed/variable approach may be equitable and cost-based. Alternatively, if these resource cost characteristics occur, but different classes have peaks at different times, an Average and Excess or Noncoincident Peak method may be appropriate.

B. Nature of off-system sales market

Utility transactions in the wholesale power market affect the appropriate allocation of costs. Utilities in the Pacific Northwest aggressively seek markets for surplus capacity during the spring, summer, and fall months. Utilities in the Desert Southwest similarly seek markets in the winter months. By carefully integrating maintenance schedules, and planning transmission interconnections well in advance, it has been possible to reduce the costs of systems in both areas with interregional exchanges. It is not necessarily the seasonal load characteristics of native load (usage by retail customers) which should guide the selection of a seasonal or coincident peak methodology in these circumstances.

For example, the merger of Pacific Power (a winter-peaking system centered in Oregon) with Utah Power (a summer-peaking system) resulted in a combined system with relatively balanced loads throughout the year. Both systems are dominated by baseload generating plants and relatively low operating costs. The merger led to a change in the cost allocation methodology relied on by both systems. Pacific Power previously utilized a Peak Credit method for classifying production plant between demand and energy, with the demand-related portion allocated on the basis of a single coincident peak day. Utah Power previously utilized a 12CP Fixed/Variable methodology. After the merger, the combined utility appears to be moving in favor of an energy-weighted classification methodology, with the demand-related portion allocated on a 12CP basis.

It is not necessary to formally merge companies in order to obtain the diversity benefits which multiple systems enjoy. Market transactions -- selling excess energy and capacity in winter, purchasing needed energy and capacity in summer -- can help a summer-peaking utility lower costs and avoid the need to acquire or construct generating units used solely for peaking. Such transactions are now a regional priority for the Pacific Northwest, where a large surplus of summer capacity and energy exists, and failure to market that power is impairing the region's ability to provide the summer flows needed to protect, mitigate, and enhance the Columbia River salmon fishery.

In any case, the allocation of revenues from off-system sales should be used to offset the costs of the generating units which make these possible. If the total costs of production from a unit are classified as 50% demand-related and 50% energy-related, it is appropriate to classify the revenues received in the same fashion. Another approach is to first apply the revenues received to offset the variable operating costs, and then to classify the remainder (small or large) in the same manner as the fixed costs of the plant are classified.

In many cost studies, the revenues from off-system sales are classified and allocated on the basis of the subtotal of all generating costs, on the theory that the entire system makes off-system sales possible. In others, specific units are dedicated to off-system sales, and the resulting revenues are classified and allocated on the same basis as the plants making these sales possible.

It is important to note that off-system sales contracts, like purchases from independent power producers, may be structured with explicit "demand" or "capacity" costs. These rate design conventions may be designed to be attractive in the market or to meet the cost or revenue stability needs of one party to the transaction. They should not necessarily be including in the cost study on the same basis, so-called "as-billed pass-through" treatment.

C. Load Characteristics of Utility

The character of a utility's load should clearly affect the choice of production cost allocation methodology. If a utility has an extreme seasonal peak demand, then a seasonal methodology of allocating demand-related costs (however defined) should probably be used. The 1CP, 4CP, and 6CP methods are examples of seasonal approaches; if an energy-weighted method is used to classify the fixed costs between demand and energy, the demand-related costs should be allocated based on the seasonal peak load.

A utility with multiple classes which have individual peaks which occur at very different times of the day or the year is a logical candidate for a non-coincident peak demand allocation approach. For example, if a mountainous portion of a service territory has a winter peak for space heating, while the lowlands have a summer peak for air conditioning, both distinct loads should bear a portion of the demand-related costs, again, however, defined.

D. Treatment of Excess Capacity

Utility systems may experience excess capacity. In some cases, a utility may complete a long lead time baseload plant and not have the expected load to need this type of unit. If this situation is evident, the utility may defer peaking plant additions, or accelerate retirement of older units in order to have a match of peak capacity and peak demand. Under such circumstances, however, it may then have an excess of baseload capacity -- using baseload plants for fewer hours than is necessary to economically justify the capital investment.

There are several different ways to view this situation. First, some commissions allocate all or a portion of the cost of the excess capacity to the shareholders. If this is done, cost allocation should proceed as though there is no excess capacity, and the selection of methodology should clearly match the load and resource characteristics of the utility under conditions of load-resource balance.

Where all or a portion of the excess capacity costs are assigned to the ratepayers, two opposite approaches are defensible. One is to prepare the cost study assuming load/resource balance, classifying costs on the basis of long-run resource costs; the other is to incorporate short-run considerations of excess energy producing capability.

First, it is reasonable to continue to design a cost allocation methodology assuming that the utility is in load/resource balance and has the ideal combination of baseload, intermediate, and peaking resources. This approach is justified on the basis that no individual customer class should be adversely affected by a mismatch of loads and resources. The underlying logic of this approach is reinforced if the utility has recently retired older production plant in order to achieve some sort of load/resource balance (as Arizona Public Service Company did with the West Phoenix station), or has made an off-system sale of capacity and.or energy at less than the fully allocated cost of the resources providing the power in order to achieve load/resource balance. In this approach, the baseload generating plants (which may be used more like a peaking unit, or have energy sold off-system at a relatively low rate) would still be classified between demand and energy using a method such as the Peak Credit, Base and Peak, or Base-Intermediate-Peak method.

The second approach where the costs of excess capacity are assigned to ratepayers is to recognize the short-term plant dispatch situation faced by the utility, which as a practical matter has achieved load/resource balance to meet peak demand, but can produce additional energy at off-peak times simply by running more fuel through an available baseload plant -- at quite a low cost. Under this situation, it may be possible to defend a coincident peak cost allocation methodology, since an increased peak demand would cause a need for increased generating capacity, but an increased off-peak demand would cause only an increase in variable costs. In this alternative, a much higher proportion of fixed costs would be assigned to the peak period. One logical flaw with this approach, of course, is that if the utility had a need for increased peaking capacity, it could more economically meet that need with a new peaking unit or reactivation of a older unit than by construction of a new baseload unit.

E. Stand-Alone Studies - A Test of Methodologies

One test of the equity and efficiency of any cost allocation methodology is to compare the results it produces for each class with a "stand alone" cost study. A stand-alone study looks at the costs which would be incurred to build an entire system to serve one major customer class. Since a major benefit of having regulated utilities is assumed to be the "natural monopoly" of having a single company, rather than multiple companies, providing service, it follows logically that the result of any cost allocation study should be to make all customer classes better off than if they "went it alone."

For example, a 100% fixed/variable 1CP methodology applied to a system consisting largely of expensive new baseload generating plants and older, mostly depreciated units used for peaking, would assign all of the fixed costs on the basis of peak demand.

If the residential and small commercial class were the primary contributors to the peak demand, they would bear most of the fixed costs; the allocated costs could well be higher than if an ideal configuration of generating plants were built to serve only the needs of these classes -- they might be worse off than under a stand-alone system approach.

Conversely, if an industrial class used power throughout the day and year, they would benefit from the calculation of capacity costs including the older, fully depreciated units, but would also benefit from the fact that the system excess of baseload generating capacity meant that their power needs were produced at baseload plants with low operating costs. This class would bear neither the full high fixed costs of the baseload units, not the high operating costs of the older peaking units, and would have a total assigned cost lower than under a stand-alone approach.

Since one class is worse off than under a stand-alone approach, and another is better off, an analyst could conclusively determine that a fixed/variable method was inappropriate, and could look at an energy-weighted or time-differentiated method.

Of course, where excess capacity costs are assigned to ratepayers, it is possible that <u>both</u> classes might be worse off than under two stand-alone systems. Whenever excess capacity results in fully allocated costs included in rates exceeding the replacement costs of a system (i.e., long-run incremental costs), there is a possibility of this situation. Still, the selected cost allocation methodology should never make one class better off than under a stand-alone methodology and another worse off.

VI. APPROPRIATE APPROACHES FOR TUCSON ELECTRIC

Selection of a production cost allocation scheme for Tucson Electric should consider each of the criteria identified above. In each case, the situation at TEP is special, and should be carefully noted.

A. Resource Characteristics of Utility

TEP is characterized by an abundance of baseload generating plant, and a limited amount of substantially depreciated peaking units. In this configuration, the production rate base and fixed O&M is dominated by baseload generation.

1. Type of resources owned

TEP owns portions of five coal generating plants, totalling approximately 1100 MW, plus gas and oil-fired generators totalling approximately 750 MW. With a maximum peak demand in 1991 of some 1319 MW, the utility has what can only be termed an abundance of baseload and intermediate generating capacity. A plan was developed to convert the Irvington station to coal as well, but this has been cancelled. The utility meets nearly all of it's load with coal-fired generation, plus it produces a substantial surplus for off-system sale. In 1991, the Company's coal plants produced approximately 5,665 gwh, while it's oil and gas fired units produced only 168 gwh; 97% of the energy produced was at coal-fired plants.

The heavy reliance on baseload coal generation by TEP is such that an appropriate cost allocation methodology would be either an energy-weighted method which classifies a substantial portion of the fixed investment and operating cost as energy-related, or a time-differentiated method which bypasses the classification step and allocates a substantial portion of the fixed investment and operating cost on the basis of year-round energy production. Appropriate methods include the Peak Credit, Base and Peak, Peak and Average, Base-Intermediate-Peak, and Probability of Dispatch methods. The Commission has previously rejected methods of cost allocation which are based solely on measures of peak use; this would include all fixed/variable methods discussed above.

2. Operating costs

TEP's reliance on baseload plants means that its operating costs are smaller than if the system were more economically balanced or were heavily comprised of peaking units. However, the operating costs for its coal plants are not particularly low, and its production operating costs far exceed its production capital costs at the revenue requirement level. Much of this, however, is due to the relatively heavy reliance on purchased power, much of which came from its former affiliates.

The San Juan and Springerville coal plants, in particular, have operating costs in excess of three cents per kilowatt-hour; these costs will typically exceed the price which can be obtained under current market conditions in the surplus energy market during off-peak periods.

3. Purchased Power

TEP's heavy reliance on purchased power means that the terms of the power contracts should be examined. It appears that these contracts provide for access to baseload generation, and have a relatively high reliance on fixed charges to compensate the seller for the fixed costs of production plant, and energy charges which recover only variable production costs. This type of contract is common, and provides a high degree of revenue certainty to the seller. However, these costs should be examined for causality in the context of cost of service analysis. The fixed charges, in general, should be subjected to the same methodology used for classification and allocation of company-owned baseload generating plant. Again, appropriate methods include the Peak Credit, Base and Peak, Peak and Average, Base-Intermediate-Peak, and Probability of Dispatch approaches.

The Arizona Commission has determined that only a portion of the fixed charges under the Century contract are recoverable in rates. The remaining portion should still be subject to classification between demand and energy for cost allocation purposes; only those portions reasonably associated with securing a peaking resource should be considered demand-related if an energy-weighted methodology is selected. If a time-differentiated method is utilized, the total cost of power per kwh under the contract should be allocated to appropriate rating periods.

B. Nature of off-system sales market

TEP is an active participant in the bulk power market in the western states. The western states, in turn, is the most highly integrated market in North America, with over 7000 MW of transmission capacity interconnecting California and the desert southwest summer-peaking markets with the Pacific Northwest, and with nearly 10,000 mw of transmission capacity interconnecting the Arizona/Nevada area with California. This allows for relatively frequent economy sales and purchases, and also for reliance on out-of-region utilities for peaking capacity as needed. While TEP is not currently a purchaser of capacity, due to its excess capacity situation, it is able to obtain summer peaking capacity from capacity-rich utilities in the Pacific Northwest at reasonable cost, and should be able to dispose of surplus winter capacity at fully compensatory rates.

In spite of large and well developed markets, TEP does not seem to have been able to fully market its firm capability during the non-peak season. Assuming that this is determined to be the result of market conditions, and not a management shortcoming, it is probably not yet appropriate to consider an annual allocation methodology for demand-related costs. In the future, with targeted DSM programs aimed at summer peak loads, increased intertie capacity development, increased incentives for out of region utilities to seek winter and early spring capacity, and better integration of maintenance schedules throughout the west, it may be appropriate to do so in the future.

C. Load Characteristics of Utility

TEP's load is characterized by having a substantial base load and a significant summer increase in both peak and energy demand. The months of June, July, August, and September are the consistently the highest months of system demand.

There is a relatively unusual characteristic to the residential load, caused by an influx of customers in the winter period (known in the vernacular as "snowbirds") which causes the residential load to be higher than if only permanent residents stayed on the system through the year. Residential loads are higher in December, January, and February than in other the months immediately before and after, reflecting both the use of electric space heat and the influx of customers. While this increases the winter residential load above the level it would be without the influx of temporary residents, the reduction in air conditioning loads in winter more than offsets the growth in residential customers, and TEP remains a summer-peaking system.

TEP's industrial customers are largely year-round process operations but do have significant summer-peaking seasonal characteristics. Commercial load is the most severely seasonal in nature of the major classes. The system has seen a decline in irrigation usage, which is a result of irrigation water being redirected to domestic and urban uses.

TEP's load characteristics have been in flux. The residential load factor has increased dramatically over the past decade, while the commercial load factor has deteriorated. This is consistent with trends in other parts of the country, where improved efficiency of residential structures and appliances have reduced space conditioning requirements, while explosive growth in retail space has greatly increased space cooling requirements. Aggressive DSM programs can reverse the trend within the commercial sector, but TEP has not yet been very active in this area. Reductions in mining activity, rather than changes within individual industrial processes, has contributed to an overall drop in the industrial load factor over the decade.

TEP's load characteristics suggest that a cost allocation methodology should allocate demand-related costs based on the summer peak demand period, rather than an annual approach. The appropriate options would include 1CP, 4CP, All Peak Hours, or similar criteria. The selection of an appropriate method, however, should also consider the off-system sales and purchase capabilities of the system discussed below; if the utility is able to balance its loads and resources through a combination of scheduled maintenance and interutility transactions, an annual approach to allocation of peak demand (similar to that discussed above for the combined Pacific Power / Utah Power systems) may be appropriate.

D. Treatment of Excess Capacity

TEP is faced with generating capacity in excess of its current needs, particularly during off-peak hours of the year. It is able to market only a portion of that surplus, and at rates which do not fully recover the cost of new generating capacity. Both a regional glut of capacity and severely depressed prices for natural gas contribute to this situation.

As discussed, excess capacity may be dealt with in the revenue requirement, cost allocation, or rate design phases of ratemaking. To some extent, the Arizona Corporation Commission has done so by disallowing some production costs from revenue requirement. The remaining issue for cost allocation is whether to classify the allowed costs as though the system is in load/resource balance (thereby sharing the costs of excess capacity among all classes in proportion to what each class would pay for an optimally sized system) or to classify the allowed costs in a manner recognizing the current surplus of (particularly) off-peak generating capacity.

This is only an issue for the energy-weighted methods; time-differentiated methods would simply allocate all costs to appropriate weighting periods without consideration of excess capacity.

This is strictly a policy issue, rather than an analytical issue. If the regulatory goal is to share the burden of excess capacity among all classes, the costs should be classified as though the system is in load/resource balance. If the regulatory goal is to price service to classes such that those which utilize more of what is temporarily in surplus (off-peak supply) are rewarded, and those which utilize more of what is more closely aligned with current needs (on-peak capacity) are encouraged to limit usage, it may be appropriate to classify these costs on the basis of current conditions.

VII. SUMMARY AND CONCLUSIONS

Cost allocation methodologies for production plant should reflect the load and resource characteristics of the system to which they are applied. The summer-peaking load characteristics of the TEP system support the use of a seasonal peak allocation method. The baseload coal generating plant resource dominance of the TEP system justify the use of an energy-weighted or time differentiated cost allocation methodology. The reliance on purchased power acquired under contracts with relatively high fixed costs and relatively low variable costs means that the purchased power costs should be considered in the same manner as the baseload generating plants. TEP's access to the western states bulk power markets means that it can augment its power supply during peak periods at moderate cost, and dispose of excess capacity and energy at market-based prices. The associated costs and revenues should also be considered in an energy-weighted or time-differentiated cost allocation methodology.

Several methodologies meet the basic requirements. They vary in the effect on different customer classes dependent on the load characteristics of the classes; no analysis has been performed on any of these to ascertain the effect. The appropriate methods, and the bias or perspective they favor, are as follows:

1) **Peak Credit (Energy-Weighted)**: Baseload plants classified to demand and energy based on relative costs of peaking and baseload plants; Purchased Power contract fixed charges classified between demand and energy; off-system sales classified between demand and energy. Peaking units classified as 100% demand related. 200 hour 1CP or simple 4CP method used to allocate demand-related costs between classes.

2) **Peak and Average (Energy-Weighted):** Baseload plants classified on basis of load factor to energy; balance classified as demand-related. Same applied to purchased power contract fixed charges, off-system sales revenues net of variable production costs. Peaking units classified as

100% demand-related. 200 hour 1CP or simple 4CP method used to allocate demand-related costs between classes.

3) **Base and Peak (Energy-Weighted):** Baseload plants classified as energy-related; peaking units classified as demand-related. Purchased power contracts used over 200 hours/year classified as energy-related; peaking contracts classified as demand-related. Off-system sales revenues associated with baseload plants classified as energy-related. 200 hour 1CP used to allocate demand-related costs between classes.

4) **Base-Intermediate-Peak (Time-Differentiated):** Baseload plants classified as energy-related. Irvington plant classified as intermediate. Peaking units classified as demand-related. Purchased power contracts utilized more hours/year than Irvington classified as energy-related. Off-system sales revenues associated with baseload plants classified as energy-related. 200 hour 1CP used to allocate peak demand-related costs between classes; 1500 hours 1CP used to allocate intermediate plant costs.

5) **Probability of Dispatch (Time-Differentiated):** All plant and purchased power costs, plus off-system sales revenue assigned equally to all hours in which the plants or contracts operate.

Each of the above methods will produce results which are reflective of the cost of providing production capability to the different customer classes served by Tucson Electric. Other methods, for various reasons, will produce less satisfactory results. Similar levels of scrutiny must be applied to transmission, distribution, administrative and general, and other utility costs in preparing a comprehensive and representative cost allocation study.

Transmission and Distribution Cost Allocation In Embedded Cost of Service Analysis

Applicable to the Tucson Electric Power Company

A Briefing Paper Provided to:

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TRANSMISSION AND DISTRIBUTION COST ALLOCATION

I. INTRODUCTION TO TRANSMISSION AND DISTRIBUTION COST ALLOCATION

Transmission and distribution costs generally make up about one-half of total utility costs. Transmission facilities operate at high voltage and connect the utility's generating sources to its load centers. Distribution facilities connect the transmission lines to the individual customers. The cost allocation methods used for both vary widely. Some methods are based on engineering criteria, while others are based on economic considerations. Since there may be little connection between economic reasons for constructing facilities and the engineering criteria which go into the design and construction process, the two approaches may produce very different cost allocation results. It is therefore important to understand both approaches and their effects on cost allocation and rate design in selecting an appropriate methodology.

Production costs are typically classified only on the basis of energy usage and demand, and transmission costs generally follow the same classification scheme as production plant. Distribution costs are classified among demand and customer indices, and sometimes to energy as well.

This is the second of three briefing papers to the ACC staff on embedded cost allocation. A July 1, 1992 paper addressed only production costs. A third paper will address the elements of cost and the methods of presentation of cost of service studies.

In addition to analyzing the allocation of transmission and distribution costs, this briefing paper lists the areas of cost allocation which are not covered by separate issue papers. These include customer accounts and sales expense, administrative and general expense, and taxes. These are presented only to ensure that the two briefing papers together cover the entire realm of costs which are allocated in an embedded cost of service study. The major methods used to allocate each of these other cost areas are identified, but not analyzed.

I. ENGINEERING ISSUES

Transmission and distribution facilities are designed to meet specified engineering criteria. The systems must be capable of carrying the expected maximum peak demand under the weather conditions expected when that peak demand occurs. The facilities must be high enough off of the ground (or deep enough beneath it) that they are not a danger to the public or at risk of damage from other activities, such as traffic and landscaping. They must be able to withstand sun, wind, rain, freezing and thawing, and other environmental elements. Addressing these requirements contributes to the cost of these facilities.

The design criterion most often considered in cost allocation is the peak demand to which systems are sized. Engineers usually design transmission and distribution lines to carry the expected capacity in the relatively near term, but they sometimes design lines to accommodate growth in demand far into the future. In either case, the lines are rated for a certain level of demand.

Because transmission and distribution lines are designed to accommodate a specified peak demand, some analysts treat 100% of transmission and distribution costs as demand-related. However, as will be discussed, the reasons for building transmission and distribution lines may be energy-related. Therefore, a strict engineering-based classification scheme based on peak demand may not be appropriate in a regulatory environment designed to encourage conservation, efficiency, and equity.

I. ECONOMIC ISSUES

There are several reasons why transmission lines are constructed. The different purposes for which lines are built may justify different methods of cost allocation. There are significant economies of scale in transmission development; since the incremental cost of capacity may be far below the average cost, transmission allocation methods may appropriately consider peak demand and average demand differently. While the transmission line is sized for a certain capacity, the reason it is built may be to move baseload energy, and the extra costs to add peaking capacity may be very small.

Similar situations exist in decisions to construct distribution facilities. Distribution lines are designed along engineering criteria to perform certain functions and to meet safety standards. These engineering criteria are generally best evaluated by the number of customers to be served and the peak demand of those customers. However, the decision of whether, when, and where to build distribution lines is driven by economic criteria, not engineering criteria. For example, utility line extension policies are generally tied to expected revenue levels from customers, which in turn are largely determined by kilowatt-hour sales. Thus, the decision to make the investment may be related to energy usage, rather than peak demand or the number of customers served.

The economic criteria supporting development of T&D facilities are just as important as the engineering criteria, and both should be considered in the ratemaking process.

I. TYPES OF DEMAND

There are many different measures of peak demand. At one end of the distribution system is the non-coincident customer demand (NCCD), which is the maximum demand of each customer on the system at their individual point of use, regardless of when it occurs. This is a very large number, but it only affects the size of line transformers and service connections which the utility must install. At the other extreme is the system coincident demand, which is the maximum demand on the total system at any point in time during the year. This affects the level of peak generating capacity which the utility must have available. In between are several other measures of demand.

The demand imposed by individual customers is subject to "diversity" on the system. One customer's refrigerator, water heater, toaster, or hair dryer is not on at exactly the same moment as everyone else's. Therefore, the peak demand of a system of 1000 identical customers who each use power at various times during the day and year is much less than 1000 times the peak demand of any of the individual customers. Large industrial customers with high load factors (load factor is the ratio between average usage and peak usage) are subject to less diversity than smaller customers because they use power continuously. Certain end-uses, such as air conditioning for summer-peaking utilities or space heating for winter-peaking utilities, generally occur simultaneously, and are therefore subject to much less diversity than lights, appliances, and water heating loads.

On large complex utilities, load research studies are conducted to identify the peak demand of each class according to several different measures. The measures usually computed are:

a) Coincident Peak Demand (CP): Aggregate load for each class at each hour of the year, measured as a fraction of the total system load at each hour;

b) Class Non-coincident Peak Demand (NCP): The highest load imposed by each class, independent of what loads are being experienced at the same time from other classes; this is usually measured at the substation or distribution circuit level;

c) Non-Coincident Customer Demand (NCCD): The sum of the peak demands for each individual customer in a class.

Each of these measures of peak demand may be used for different purposes in allocating costs between classes. The coincident peak demand is often used to allocate the demand-related production and transmission costs. Class noncoincident peak is used in some production cost allocation methods, such as the Average and Excess method, but is also used to allocate some distribution costs, such as substations, because the areas where these are located tend to serve select classes of customers. The non-coincident customer demand measures demand at the very end of the distribution system, and is often used to allocate the demand-related costs of service connections and line transformers. Often a mid-point estimate between NCP and NCCD is used to allocate the demand-related costs of the distribution infrastructure.

In addition, the non-coincident demand calculations are often computed at both primary and secondary voltage. This is because some facilities, such as line transformers, are only needed to serve customers who receive power at lower voltages, and special allocation factors are appropriate to ensure that primary voltage customers are not assigned these costs.

I. TRANSMISSION COSTS

Transmission costs are almost always fixed in the short run. Transmission lines are designed and built to serve a particular peak demand. Some analysts therefore assume that the costs are demand-related, and should be allocated among classes based on measures of peak demand. This type of allocation method, where fixed costs are all determined to be demand costs, requires no further elaboration. If a commission adopts a fixed/variable peak-responsibility method for production costs, that methodology may be applied to transmission costs as well. Consideration of the underlying criteria supporting the decision to build the transmission facilities may lead to different cost allocation approaches, however.

Some transmission facilities' primary function is connecting remote baseload coal and nuclear generating plants to the utility load centers. These are called *generation-related* transmission. Some facilities are built primarily to connect together localized areas in a utility's service territory for reliability purposes. These are known as *network* transmission. Finally, *Inter-utility* transmission links, such as the Southwest Powerlink, were constructed to connect one utility to another, so that they could enjoy the economies of joint resource development and operation. Each of these functions is driven by different economic criteria, and each may justify different consideration in cost allocation.

Once a decision is made to build certain types of facilities, of course, the utility system evolves and may put the facilities to uses different from the expected use. For example, a line built to move bulk power from a generating plant to a load center may make it possible to build a large industrial project at a location which otherwise would have been uneconomical. Thus it is important to consider both historical intended purpose and current use in determining an appropriate method for transmission cost allocation.

A. Economies of Scale in Transmission

Transmission development is subject to considerable economies of scale. These economies of scale are important for cost allocation purposes. If a utility needed to move only 100 megawatts of capacity at a 100% load factor, it could do so by building a lower-voltage [115 kv] line. In order to upgrade this to serve a 400 megawatt peak load, it could build four 115 kv lines or a single 230 kv line. The cost of the higher voltage line is typically much lower than four times the cost of a lower capacity line. Part of this is due to right-of-way requirements, and part to simple economies of scale in construction.

For cost allocation purposes, it is important to recognize that a 100 megawatt peak load served at a 25% load factor typically does not cost four times as much to provide transmission for as a 25 megawatt peak load which has a 100% load factor. Therefore, there is little economic justification for treating 100% of the costs of transmission as demand-related, and allocating these costs based solely on peak demand, in spite of the fact that the transmission facilities are designed to meet a particular peak demand.

Many traditional cost allocation methodologies recognize this. All of the energy-weighted methods do so. Some of the time-differentiated methods do as well. It is possible to apply different methods to production plant and transmission plant, recognizing the unique engineering and economic considerations of both.

A. Generation-Related Transmission Costs

Generation-related transmission is constructed for the primary purpose of connecting remote generating plants to the load centers served by the utility. Examples of these are the lines connecting the Four Corners, San Juan, and Springerville sites to the Tucson area. These lines are subject to the greatest economies of scale. Generally, generation-related transmission is built at 230 kilovolts and above.

While the lines are built to be capable of carrying certain peak demands, they do not generally connect peaking resources to the load centers. For cost allocation purposes, it is reasonable to consider the cost of these transmission lines in the context of the generating plants they connect to the system.

An alternative to building remote generating plants and long transmission lines would be to build generating plants in urban areas, and incur additional costs for fuel transportation and pollution control. Since extra fuel transportation and pollution control are costs associated directly with the quantity of electricity produced, the effect of such a change would be to increase energy costs on a system. Thus, the costs saved by these transmission lines are energy costs, and a justification can be given to treat the costs as 100% energy-related.

Under certain energy-weighted or time-differentiated production cost allocation methods, such as the Peak and Average, Base and Peak, Base-Intermediate-Peak, System Planning, or Probability of Dispatch methods, the costs assigned to "demand" are based on the costs of constructing and operating peaking resources; the balance of costs are treated as intermediate-related, energy-related, or average demand-related. Since peaking resources can typically be built close to the utility load center, there is no need to build generation-integration transmission lines to meet increased peak demand. Arguably 100% of generation-related transmission costs are energy-related.

A. Network Transmission Costs

A typical urban/suburban utility has a network of transmission lines which interconnect its substations so that power can be fed from multiple sources to each. This improves the reliability of electric service in light of uncertainties regarding power plant performance, weather, and other factors which can cause one transmission line or another to be out of service.

These lines are designed and built to serve particular peak demands. The economies of scale are generally smaller than for large generation-related lines, simply because the network lines are smaller. Therefore, since they do not serve to reduce fuel or other energy-related costs, and do not have very significant economies of scale, these facilities can reasonably be allocated on the basis of some measure of peak demand. It would not necessarily be inappropriate to recognize the existence of some limited economies of scale and attribute an energy component to network transmission.

A. Inter-Utility Transmission Costs

Inter-utility transmission lines serve multiple purposes. They permit utilities to exchange energy with other utilities when it is surplus to their own needs. This is generally thought of as a purely energy-related function. They permit emergency capacity sharing at times of extreme peak demand, which is generally thought of as a purely capacity-related function. They permit long-term firm capacity and energy contracts between utilities, which effectively permit a utility to receive or dispose of the output of baseload resources, which is a capacity-and-energy function.

There are several ways to approach these facilities in cost allocation. First, one can identify the primary actual historical (or planned) uses of lines, and construct a cost allocation scheme appropriately recognizing each use. Second, one can identify the primary purpose for which the lines were built, and attribute all costs to that purpose. For example, the Southwest Powerlink was built ostensibly to permit the sale of baseload energy from Arizona to San Diego, and could logically be considered an energy-related facility. While this was not empirically verified, the author believes that the lines to the Saguaro facility may now be used primarily for peak load sharing between Arizona Public Service (APS) and Tucson Electric Power (TEP), and therefore considered demand-related.

A. Composite Approaches

Identifying the purpose and segregating the cost of each segment of a transmission system for cost allocation purposes may be a precise approach, but it is time consuming. Several composite approaches are often used. These include simply using a subtotal of production plant allocation results, applying the same method used for baseload generation to all transmission, or dividing transmission into two or three major categories, and treating all units within a single category in the same manner.

Tucson Electric has utilized a composite approach in its studies prepared to date, applying the same method to all transmission plant as it applies to production plant. In each study where the method used to allocate production plant changes, the same change is applied to transmission.

A. Transmission Operation and Maintenance Costs

Transmission O&M costs are generally relatively small, few of them vary as the amount of electricity carried changes. In an engineering sense, these are fixed costs. In an accounting sense, since they are operating expenses, rather than capital costs, they are variable costs. In a fixed/variable cost allocation system, where fixed costs are considered demand-related, and variable costs are considered energy-related, these are treated as either demand-related or energy-related, depending on whether the studies are prepared by engineers or accountants.

In nearly all other approaches, transmission O&M is allocated based on the same cost allocation approach applied to transmission plant. While it is theoretically possible to disaggregate transmission O&M down to the same levels of detail as plant -- for example, allocating O&M associated with inter-utility transmission on one basis, and O&M associated with network transmission on another -- this is seldom done. Because the costs are small, the choice of method generally makes little difference in study results.

Tucson Electric applies a subtotal approach, allocating all transmission expenses except those which are directly assigned on the basis of the subtotal of transmission plant allocation.

I. DISTRIBUTION COSTS

Distribution costs begin at the substation where transmission voltage power [generally above 34 kilovolts] is converted to lower voltages and dispersed into distribution circuits which pass near individual customers. The distribution system consists of an infrastructure of distribution circuits (poles, underground conduit, conductors, and transformers) and customer-specific equipment (service drops and meters). In addition, utilities often own and maintain street lights, and these are accounted for within the distribution accounts.

Different logic is generally applied to the allocation of the infrastructure and the customer-specific plant. There is generally little controversy regarding the allocation of services and meters as customer-related costs. Extreme controversy arises over the allocation of the distribution infrastructure, with industrial consumers advocating a customer-based allocation, and representatives of residential and small commercial customers advocating a demand and/or energy-based allocation approach.

A. Substations

At distribution substations, transmission lines deliver power at high voltage (above 34 kilovolts), which is transformed down to lower voltages (usually 13 kilovolts; sometimes lower or higher) for distribution. These facilities and the expenses associated with them are virtually 100% fixed cost in nature, not varying with the number of kilowatt-hours delivered.

In most cost allocation studies, these costs are allocated on the basis of peak demand, measured at either the coincident peak level (the load of each class at the time of the system peak) or the non-coincident peak level (each class' load at whatever time it reaches a class maximum, regardless of the loads of other classes.)

Substations are generally not allocated to customer classes served at transmission voltage, since they do not normally use these facilities. Occasionally, however, a transmission substation must be constructed to serve such a customer; for example, where the adjacent transmission facilities operate at 230 kv or more, some transformation is required to provide service even to a large industrial customer.

Tucson Electric has classified most substation costs as demand-related, and divides those costs between primary and secondary voltages. Some facilities are directly assigned to specific customers. It is unclear why the Company applies a primary/secondary voltage split to these costs, since substations by definition do not operate at secondary voltage.

A. Distribution Circuits

Distribution circuits consist of poles, underground conduit, and conductors. These costs generally represent the largest part of distribution plant, and may total 25% or more of total utility plant, particularly for utilities which rely on purchased power for much of their energy supply. These costs are subject to the greatest degree of controversy in distribution cost allocation.

Distribution circuits are designed to carry a specified level of peak demand. Particularly in network transmission, where distribution circuits connect two substations, the incremental cost of additional peaking capacity on the distribution circuit may be very small.

Regardless of what method is used to determine what costs are demand-related, the demand-related costs are normally allocated between classes on the basis of some measure of class noncoincident peak demand. This is because distribution circuits are local in nature, and it is assumed that all of the customers on a distribution circuit are likely to have their individual peak demands at about the same time of day and year.

1. Minimum System and Zero Intercept Methods

At one extreme is the so-called "minimum system" method of cost allocation. This approach divides these costs between "customer-related" and "demand-related" by computing the costs of building a theoretical distribution system using the smallest size components typically used by the utility. These costs are defined as "customer-related", and the extra costs associated with expanding that theoretical minimum size system to meet expected demands are considered demand-related. This approach typically results in 50-75% of distribution circuit costs being allocated on a customer basis, and thus assigns the bulk of the costs to the residential class.

The theoretical basis for this approach is that a utility would incur a certain amount of cost simply to connect all of the customers to the grid, even if each used only one light bulb. The cost of erecting poles or trenching for underground systems, for example, is almost entirely independent of the size of conductor to be carried. Since the costs are independent of any measure of usage, and every customer receives the same access to the system, this method assigns these infrastructure costs on a per-customer basis.

This approach has been criticized for as long as cost studies have been prepared. First, utilities do not build such minimum systems, and do not use any real "minimum-size" components in their systems. Thus, the base system of the model is artificial and unreliable.

Second, the minimum-sized components assumed generally are capable of carrying much or all of the demand of a typical residential customer, and so there should be no additional assignment on the basis of demand. In spite of this, the demand-related costs are typically allocated to all classes as though the minimum size components had zero capacity. [A variation on the minimum system method, known as the "zero intercept" method attempts to address this criticism.]

Third, utilities have line extension policies which generally preclude the extension of distribution lines into areas where the expected sales volumes will be small, but the minimum system method does not consider sales volumes anywhere in the equation. When using this method, it is crucial to carefully assess what portions of the theoretical minimum system are paid by customer advances and contributions in aid of construction. These amounts should be subtracted from the customer-related portion of the distribution plant. Since utilities normally report their distribution plant investment <u>after</u> subtracting the advances and CIAC, the information needed to perform this analysis is often not readily available to the cost analyst.

1. Basic Customer Demand Allocation Method

The most commonly used method for allocating distribution infrastructure costs is to treat services and meters as 100% customer-related, and the poles, conduit, and conductors as 100% demand related. In this approach, 100% of the costs in the accounts applying to poles, conduit, and conductors are treated as demand-related, and normally allocated on the basis of class non-coincident peak demand, while the services and meters are allocated on a customer basis.

The theoretical basis for this approach is that the distribution system is sized to a certain capacity, that capacity is available to the total population of customers served by a system, and any capacity used by one customer is generally not available to another.

1. Demand and Energy Allocation Method

At the opposite extreme from the minimum system method are approaches which consider annual energy use in the formula used to allocate distribution plant. In this approach, the portion of costs of distribution system extension which are paid by the utility under its line extension policy are allocated to each class on the same basis as line extension policy allowances are provided to that class.

For example, if a line extension policy provides that the Company will expend up to two times the annual expected revenue from a particular customer, the analyst should determine what elements of revenue justify the expenditure. For example, if a customer is expected to use 10,000 kwh/year, and the applicable rate is $5/month plus $.08/kwh, two years' revenues will equal $1720, and that is the most the utility will expend on distribution system expansions to serve the customer. Of this amount, $120, or 7%, is related to the customer charge, and $1600, or 93% is related to the energy charge. Thus, the distribution lines would be treated as 7% demand-related, and 93% energy-related.

The theoretical basis for this approach is that the utility will not normally extend lines except in areas where it expects substantial amounts of business. Since the "business" consists of selling kilowatt-hours, kilowatts, and collecting customer charges, all three rate elements should be considered in the cost allocation of the distribution infrastructure.

1. Tucson Electric Considerations

Tucson Electric's line extension policy, Article 8, provides a fixed 500 feet of overhead line extension per residential customer regardless of expected usage, but requires customers to pay for underground system costs. For large light and power customers, the policy provides for a free line extension costing up to two years total revenue. Thus the analyst may reasonably treat a portion of overhead, but not underground, service as customer-related for the residential class, and may reasonably treat a portion of the distribution lines serving non-residential customers as energy-related.

Tucson Electric's cost of service studies have treated 100% of the costs of the distribution infrastructure as demand-related. As indicated, this is the most commonly used method. The Company splits all of these accounts between primary and secondary voltage, even though all of these facilities upstream of line transformers are operated at primary voltage.

A. Line Transformers

Transformers are located throughout the distribution system to convert distribution voltage power (usually 13 kilovolts) down to the voltages used by homes and businesses (usually 110 - 440 volts).

Line transformers are sized for the expected peak demand of the individual customers served by the transformers, but the fixed cost per transformer (i.e., the costs independent of size), including the labor to install it, often amounts to 50% or more of the total cost.

Line transformers are sometimes allocated on a noncoincident demand basis, sometimes on a demand and customer basis, and sometimes on a weighted customer basis.

When a customer or weighted customer basis is used, normally an estimate is made of the number of customers in each class served by each transformer. Except in rural areas, 3 to 20 residential customers can be served by a single transformer, while most general service customers require a dedicated transformer.

Tucson Electric has treated the cost of transformers as 100% demand-related. The workpapers indicate that these costs are allocated based on a primary/secondary split; in the last general rate case, they were all treated as exclusively secondary voltage, which is more accurate.

A. Service Connections

Service connections link customer meters with line transformers. Some utilities install the same (usually oversized) service connection for all residential customers, regardless of expected usage. Others size the service drop to the expected load. Service connections for general service customers are normally sized to the expected demand.

Because larger service connections are used for larger customers, they should normally be assigned more cost per customer than smaller customers. This is usually accomplished by computing "weighting factors" for different customer types. These weighting factors can take into account both the number of customers per service connection (multifamily residential, for example) and the size of the typical connections installed.

Tucson Electric allocates these costs on a weighted customer basis.

A. Meters

Each customer needs one meter. Residential meters typically measure energy only, while meters for larger customers are more sophisticated, with demand, time of day and kilovolt-ampere (kvar) recording capabilities, and larger capacities. For this reason, meters are generally allocated based on a weighted customer count, with the weighting factor selected to reflect the relative cost of the meters serving each class.

Tucson Electric uses a weighted customer method.

Street and Area Lighting

Utilities often directly own street lighting facilities, and lease them to municipalities. Even where the municipalities own the facilities, they often pay the utility to maintain them, simply because the utilities usually own the poles they are mounted on, have appropriate equipment, and are familiar with maintenance of electric plant. For this reason, utility costs associated with street lights are unique -- the utility accounting system includes not only the costs of serving the electric load, but also part or all of the cost of the facilities which cause that load.

Utility costs associated with street and area lighting are normally directly assigned. Tucson Electric uses this approach.

I. GENERAL PLANT

General Plant consists of office buildings, computers, vehicles, communication equipment, and the like. These plant costs and associated expenses are normally allocated on the basis of the subtotal of all production, transmission, and distribution plant. This approach is based on the logic that the general plant supports all other activities of the Company.

Some analysts allocate these on the basis of salaries and wages within production, transmission, and distribution divisions of the company; this method excludes primarily fuel and purchased power costs. Such an approach is based on the logic that little or none of the general plant is used to facilitate the very large expenses in these two categories. Excluding fuel and purchased power tends to shift costs to smaller users, because the salaries and wages are dominated by line maintenance, meter reading, and billing costs, all of which are assigned primarily to smaller users.

Tucson Electric allocates general plant based on salaries and wages.

I. CUSTOMER ACCOUNTS EXPENSE

Customer accounts expense consists of meter reading and billing costs. These costs are normally allocated on a weighted customer basis. This ensures that the extra time it takes to read meters of larger customers, which are further apart and more complex and time consuming to read, are taken into account.

Tucson Electric allocates these costs on a weighted customer basis.

I. CUSTOMER SERVICE AND SALES EXPENSE

Customer service and sales expenses include conservation and safety information, merchandizing expenses, and advertising. Unless large conservation costs are booked to account 908 (customer assistance), these costs are generally fairly small. These costs are sometimes allocated on a customer basis, sometimes on the subtotal of other O&M expense, and sometimes on a revenue basis. The first is most favorable to large customers, the last most favorable to small users.

Tucson Electric has allocated customer service and sales expenses on a revenue basis.

I. ADMINISTRATIVE AND GENERAL EXPENSE

Administrative and general expenses include administrative salaries, outside services employed, employee benefits, insurance, and regulatory commission expenses. Several of these are major costs.

The methods used to allocate these costs vary widely. Some analysts allocate them on the basis of total expense by class including fuel and purchased power. Others exclude fuel and purchased power. Some allocate the costs based on salaries and wages. Others apply different methods to different costs. For example, administrative and general salaries may be viewed as supporting the entire enterprise and are allocated on the basis of total expense, while property insurance is viewed as plant-related and allocated on the same basis as total plant in service. Employee benefits are clearly labor-related, and are almost always allocated on a salary and wages basis.

A total expense-based factor is most favorable to small users. A labor expense-based factor is more favorable to large customers for the reason discussed in the General Plant section.

Tucson Electric has allocated these costs on the basis of labor expense.

I. TAX EXPENSE

Tax expense consists primarily of state property tax, revenue related taxes, payroll taxes, and state and federal income tax.

The allocation methods used are fairly direct. Property tax is normally allocated on the same basis as total plant. Revenue related taxes are allocated on the basis of revenue by class. Payroll taxes are allocated on the same basis as salaries and wages. State and federal income tax are allocated either on the basis of total plant, or on the basis of income before taxes by class. If all classes are providing the same rate of return, the two are equal.

I. SUMMARY

In most areas, TEP is using a cost allocation methodology which is neither the most favorable method from the perspective of small customers or from the perspective of large customers. A few items clearly merit additional study.

First, the decision to apply a single allocation factor to transmission may be inappropriate, given the large amount of transmission which TEP provides to other utilities. Separating out the types of transmission may permit more precise allocation. TEP's study allows for this, by breaking out transmission by voltage category, which roughly separates the generation-related and inter-utility transmission from network transmission.

Second, TEP classifies all of the distribution infrastructure as both primary and secondary voltage related. All facilities upstream of line transformers, however, are operated at primary voltage only. The choice of a demand allocation method for this plant, while most common, is only one of several ways to treat this plant.

Third, TEP allocates all general plant and administrative and general expenses on the basis of salaries and wages in production, transmission, and distribution previously allocated to each class. These in turn are dominated by distribution maintenance and customer accounts expenses, which depend relatively little on the Company's general plant. Alternative methods may be more appropriate.