

COSTING AND RATE DESIGN
METHODOLOGIES FOR ELECTRIC UTILITIES
IN RHODE ISLAND

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for the
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PREFACE

This report was prepared by J.W. Wilson & Associates, Inc. as an account of work sponsored by the National Regulatory Research Institute (NRRI). The report contains the findings and reflects the views of the consultant. The distribution of this document does not necessarily imply an endorsement by NRRI, or any of the agencies of the State of Rhode Island for which this report is prepared.

In February of 1978, the National Regulatory Research Institute established a Regulatory Assistance Program designed to offer technical assistance to state regulatory authorities and their staffs in areas where expertise was lacking. The State of Rhode Island applied for assistance under this program to investigate electric rate design issues of importance to the State. In response to this report, NRRI provided funds for this project and selected J.W. Wilson & Associates, Inc. (JWWA) to perform this analysis.

The three specific objectives included in the work plan have guided the activities of J.W. Wilson & Associates, Inc. under this project:

1. To develop a cost-of-service methodology to apportion revenue requirements among customer classes;
2. To determine how cost-of-service methods can be used in designing rates; and
3. To evaluate lifeline proposals now before the Rhode Island PUC.

To achieve these objectives, three substantive tasks were included in the JWWA work plan; and, at the request of Rhode Island DPU staff, an additional task was accepted under the original terms of the contract. The first task required the development and evaluation of standard methodologies for conducting cost-of-service studies. Two types of costing methodologies were considered as part of this task. Appendix A to this report provides the development and evaluation of standard fully allocated cost-of-service methodologies; and Appendix B is a procedural manual for developing costs of service on the basis of marginal cost, and for translating these costs into time-varying rates. In each appendix the methodologies are illustrated by a case study drawing on the experience of the Newport Electric Company.

The second substantive task called for the determination and evaluation of the types of rate designs that are feasible on the basis of both fully allocated and marginal cost-of-service studies. As part of this task JWWA was also specifically to address the question of how best to design rates to permit suboptimization of cost responsibility within constraints imposed by variations of lifeline rate structures. All of these issues are addressed in the main body of the report.

The third substantive task required the evaluation of the proposed lifeline rates and the proposed lifeline experiment now being considered by the Rhode Island Commission for implementation on the Newport Electric Corporation system. This

evaluation is provided in Appendix C. Finally, Appendix D provides, in response to a specific request from the Rhode Island DPU staff, a discussion of the costing and pricing of streetlighting service. That is a rate design matter of immediate concern to the Commission and the people of Rhode Island.

Portions of the text in the main body of this report and in Appendix B are drawn with modifications and by permission from a report prepared by J.W. Wilson & Associates, Inc. for the Experimental Technology Incentives Program (ETIP) of the U.S. Department of Commerce and the National Bureau of Standards.* We wish to thank ETIP for this privilege. We also wish to thank the Newport Electric Corporation for its help and cooperation in providing the data and information that allowed us to develop a case study of each of the costing and rate design methods presented.

*Innovative Approaches to Electric Utility Rate Structure: Marginal Costs and Time-Varying Rates, Volumes I and II, June 1978.

I. Introduction

Regulatory commissions across the country, including the Rhode Island Public Utilities Commission, are presently facing a number of controversial issues dealing with the design of electric utility rate structures. Rate design issues have emerged as crucial considerations due to a number of different factors, most of which trace their origins to the dramatic rise in the costs of electric power that began toward the end of the 1960s. Prior to that time electricity rates were relatively low, and consequently there was less concern over how the costs of electric service should be allocated among customers; nor was much attention paid to the impact that rate structure design had on allocative efficiency or conservation. In the aftermath of the "energy crisis" of 1974, the emphasis of federal energy policy on the conservation of fossil fuels, along with the continued increase in both capital and operating costs in the electric utility industry, have combined to focus attention on electric utility rate design. Federal policy has provided incentives to the states to implement rate design innovations that will encourage conservation. Further, as revenue requirements have increased dramatically, each customer class has taken an increasingly active part in the ratemaking proceeding; and rate design considerations have been made a frequent, if not regular, issue in these proceedings, as each party attempts to minimize its portion of whatever increase in

revenue requirements the utility succeeds in obtaining from the commission.

In operational terms, the present interest in rate design is focused on two broad issues. First, should rate structures be designed to reflect the structure of costs; or should rate structures be designed to achieve some specific set of social objectives--such as conservation or desired income redistribution--regardless of the costs of providing different types of service to different customers? Secondly, there are alternative concepts of costs. Thus if, or to the extent that, rate structures should reflect costs, what cost concept is appropriate? How specifically should these costs be measured? And how should rate structures be designed to reflect these costs and still recover the specific amount of revenue ordered by the regulatory authority?

The purpose of this report is to provide the Rhode Island Public Utilities Commission and its staff with a fuller understanding of these issues so that they can better evaluate the relative merits of alternative rate design proposals and the underlying rationales that are presented for consideration. The main body of this report is separated into four sections. In Part II, we discuss what are traditionally viewed as the twin objectives of rate design--efficiency and equity. Understanding more fully what is meant by these objectives, provides a general frame of reference from which to evaluate rate design alternatives. In Part III, we deal with the question

of whether rate structures should be based on the structure of costs, and whether marginal or average costs provide the better basis for cost-based ratemaking. In Part IV, we demonstrate that several different types of rate structures can be devised on the basis of either average or marginal costs, including traditional declining-block rates, flat rates, inverted rates or "time-of-use" rates. Attention is then paid to possible reasons for necessary or desired deviations from costs within a cost-based rate structure. As part of this discussion, we have given attention to the issue of lifeline rates, and particularly how they can be incorporated within a cost-based rate structure to do minimal damage to the efficiency and equity effects that provide the major rationale for basing rates on cost of service to begin with. Finally, in Part V, we summarize the advantages and disadvantages of time-varying rates based on marginal costs in comparison with other rate forms.

Several appendices are also provided as supporting material to the general discussion in the main body of the report. Appendix A is a report on alternative methodologies that can be used in the preparation of a fully allocated class cost-of-service study, a crucial ingredient in the preparation of any cost-based rate design. Appendix B is a procedural manual for the development of a marginal cost-of-service study and time-of-use rates. In both Appendices A and B we provide an illustrative example of these cost-of-service methodologies

for the Newport Electric Corporation, and we design a specific set of tentative time-of-use rates for this utility in Appendix B, based on our development of the marginal cost of bulk power production in New England. Finally, in Appendices C and D, respectively, we evaluate the inverted rates for the Newport Electric Corporation that have been proposed for the Commission's consideration; and we evaluate several issues involved in the question of the proper design of streetlighting rates, which is a rate design matter of immediate concern to the Commission and the people of Rhode Island.

II. The Goals of Rate Structure Design

Electric utility rate structure design has attracted intense interest, because it has been viewed as one of the most important steps in an ambitious program for increasing the economic efficiency of resource use in the electric utility industry, and for increasing the equity with which the costs of these resources are borne by the ratepayers. To understand more fully these two reasons for the intense interest in electric utility rate structure design, it is convenient to begin with a more detailed look at these concepts of economic efficiency and equity in the electric utility industry.

Economic Efficiency

Economists generally believe that prices in a free market economy are an effective mechanism for promoting efficient use of economic resources, provided these prices properly reflect costs of production. If prices do reflect production costs properly, they correctly signal to consumers the true resource requirements for producing the different goods among which each consumer must choose, and consumer choices in the marketplace thus direct the economy's resources into the employments in which they add the most to consumer satisfaction. Also, in developing these principles, economists have shown that economic efficiency in the use of resources is promoted most effectively when prices reflect marginal costs.

The application of these principles to the electric utility industry has been concerned primarily with the variation in electric utility costs among different hours of the day, days of the week and seasons of the year. The reason why electricity costs vary with the time of use is that the demand for electricity varies by the hour, day and season. Since electric energy cannot easily be stored on a large scale, the generation of electric energy must vary in accord with the time pattern of demand, and utilities must have sufficient generating capacity to meet the highest demands imposed on them. But since these peak demands are imposed only during a relatively few hours of the day, week, or year, much of a utility's generating capacity sits idle most of the time.

Since the full generating capacity of electric utilities is required only to be able to meet the peak loads, and since excess capacity is idle at other times, a proper application of marginal cost principles to the electric utility industry ascribes capacity costs only to the so-called peak periods. This is the first way in which electricity costs vary with the time of use.

A second reason for time variation in electricity costs is that the fuel or energy cost is also higher in peak periods than when demand is slack. These variations in energy cost occur because utilities use a mix of several different types of generating capacity, and the fuel or energy cost of running the different types of generators is different. Some kinds

of capacity, such as nuclear and coal-fired steam generating plants, have high initial (or capital) costs, but low energy (or running) costs, because coal and nuclear fuel are less expensive and relatively more plentiful than other fuels. Other kinds of capacity, such as plants that burn petroleum fuels, have lower initial (or capital) costs, but higher fuel costs, because of the scarcity of oil and gas.

Owing to their high initial cost, nuclear and coal-fired plants are not economical unless they can be run a sufficient number of hours in the year for the savings in their fuel cost, as compared to the cost of the oil or gas required for less expensive generators, to more than offset their higher initial (or capital) cost. Utilities therefore build nuclear and coal plants only to meet the loads that persist around the clock and throughout the year, even in slack times. These load levels that persist at all times of use are called base loads, and the fuel-efficient generators built to serve them are called base-load generating units.

In selecting generating units to meet peak loads, which (in contrast to base loads) may occur only in a few hundred hours during the year, electric utilities have found it most economical to rely on units with low initial (or capital) costs, even though these units burn the more expensive petroleum fuels. The reason is that the penalty of higher fuel cost is incurred only for the few hundred hours each year that these so-called peaking plants are actually operated, and the fuel cost penalty

for such a relatively small number of hours of operation is not great enough to overcome the annual capital cost savings of a peaking unit with much lower initial cost than a baseload generating unit. A consequence of this decision is that peaking units are only run during peak periods, after all the available baseload units are already loaded to capacity; and thus the higher fuel costs of peaking units are incurred only during the peak periods of electricity demand.

The widespread recognition that marginal costs of electricity supply are higher in peak periods than in off-peak periods has led to a strong interest in programs intended to shift some of the demand for electricity from the peak to the off-peak periods, so as to reduce the total cost of electricity supply. Actions intended to achieve this shift in electricity demand patterns have come to be known as load management.

An important special aspect of load management, in addition to savings in the total cost of electricity supply, is the opportunity to reduce the nation's dependence upon scarce petroleum fuels, and to shift instead to greater use of coal and nuclear fuel. This opportunity exists because the most economic kinds of peak generating units happen to use petroleum fuels, as explained above, whereas coal and nuclear fuel are most economical in baseload generating units. To the extent that load management activities are successful in shifting load from the peak to the off-peak periods, they are thus decreasing the need for peaking units, and they are increasing

the opportunity to generate electricity from baseload units fired by coal or nuclear fuel.

Time-of-use rates are one of the policies intended to promote electric utility load management. They do so by signaling the time variations in electricity costs to the users of electricity, and thus they provide an economic incentive for them to shift some of their demand from the peak periods to the off-peak periods.

Time-of-use rates are only one of several ways to promote load management. Other methods include the use of time clocks on such appliances as water heaters and air conditioners, and the use of direct ripple or radio control of appliances by the electric utility.* However, time-of-use rates do have one advantage over other approaches to load management, and that is the fact that they signal to consumers the cost savings in electricity supply that result from changing the time patterns of electricity use. These price signals permit users of electricity to shift their load patterns to the extent that the savings in electricity cost justify the inconveniences or other

*Time clocks on appliances such as electric water heaters could prevent the appliances from being switched on during predetermined and fixed peak periods, such as 5:00 - 7:00 p.m. Time clocks on air conditioners could be set to turn the compressors off for a fixed fraction of each half hour, say, so that the appliances could not run continuously. Ripple and radio control are signals sent directly by the utility to receivers mounted on the appliances, which provide the utility with direct and continuous control of when the appliances can be switched on or must be switched off.

costs of making the shift; and they permit the users to refrain from making further shifts in their load patterns that are not worth to them the costs of shifting. This signaling and incentive feature of time-varying rates is the basis for the proposition that time-of-use electric rates promote economic efficiency. A further advantage is that this increased efficiency is achieved without destroying the consumer's freedom to choose the time and amount of electricity used.

Equity

Time-varying electric rates can contribute to economic efficiency only if they actually affect the time pattern of electricity consumption, causing it to be different from the time pattern realized under the existing system of conventional rates.* Even if there are no gains to be made in economic efficiency, because electricity users prefer to maintain their present electricity consumption patterns in the face of higher prices for peak-period usage, there is a second reason for initiating time-varying prices. That second reason is the equity with which the total costs of supplying electricity are divided among the users thereof. Some customers have their electricity

*It should be noted that conventional rates to large industrial customers, and also to some commercial customers, do already have some time-varying elements in them. However, these time variations are not comprehensive, and they have not generally been designed to bear a close relationship to the current structure of electric utility costs.

use concentrated in the peak hours, when marginal costs are high; while other users have loads that are level throughout the day and year, or that may even be concentrated in the off-peak hours. Absent time variation in the rates, two customers with the same total usage would pay the same total price for electric service, even though these time patterns of their use were very different and imposed different costs on the utility. In contrast, a time-of-use rate design, if it properly reflected the time variation of costs, would make each user pay the true costs of the electricity he used in his own particular time pattern of consumption. This principle of giving each customer what he pays for, and making each customer pay for what he gets, is generally recognized as one aspect of economic equity.

Other aspects of economic equity, such as the ability-to-pay principle, have also received attention in connection with electric utility rate structure within the past few years. The concern with so-called lifeline rates is one important example of this attention. Some of this other interest in equity has been unrelated to the structure of electric utility costs, but some has been prompted by a belief that pursuit of these other aspects of equity will also contribute to economic efficiency. Thus, the lifeline or inverted rate approach to rate design is sometimes viewed as a good way to combine marginal-cost pricing, which appears to require rates higher than the present average costs, with the requirement that total revenues cover only the actual total costs of the regulated utilities.

The appropriateness of an inverted rate structure with a lifeline feature is the subject of Appendix C to this report. In Section IV, we also consider lifeline rates within the context of a general discussion regarding how best to integrate into a cost-based rate structure features unrelated to costs, should such a constraint be imposed by order of the regulatory authority.

III. The Relationship of Costs to Rate Structure

The current interest in innovative rate designs is based in large part upon the proposition that the structure of electric rates ought to reflect the structure of electricity supply costs. In this section we examine two aspects of this general proposition. First is a brief consideration of the question whether rate structure ought to be based at all on costs. Second is the question of what type of cost measure is the most appropriate basis for rate structure, with consideration given especially to the advantages and disadvantages of marginal cost concepts in relation to the alternatives.

Should Rate Structure Be Based on Cost Structure?

Before turning to the question of marginal cost as compared to other cost concepts, it is important to note briefly the arguments for and against using any cost concepts at all in establishing electric utility rate structures. In general, the basing of rate structures on the structure of costs is desirable for the contribution it makes both to economic efficiency and to equity. The notion of economic efficiency in relation to electric utility rate structure has already been discussed in the second section of this report, and aspects of it will be explored in more detail in connection with the comparison between marginal costs and other concepts of

costs. To illustrate the point about economic efficiency, it is sufficient here to consider two examples of rate structures that are not based on cost structure.

One such example is a fixed price per customer, independent of the quantity of service actually used. This arrangement would be like an "all-you-can-eat" meal at a restaurant. There is no pecuniary incentive to economize on the use of electric energy under this arrangement, but there is instead an incentive for users to combine their electric facilities, so as to become one customer and thus pay only one bill instead of several.

Another example is an arrangement where the cost of furnishing electricity service is covered by taxation based on the income or revenues of each customer, not the usage of electricity. This arrangement resembles the provision of public schooling. The cost of the public school system does depend upon the number of children in it, just as the cost of electricity supply depends upon the quantity used. The difference is that the use of electricity is an economic choice likely to be influenced by the price, whereas the number of children in public school is less of an economic decision.

These two examples also illustrate the equity considerations of basing rates on costs. A fixed price, independent of the quantity used would, in effect, force the small users to subsidize the large users; and the disparities would be especially great among businesses, where a large industrial plant may use thousands of times as much energy as a small store.

With an all-you-can-eat restaurant, those who are not especially hungry can at least dine elsewhere, but that is not possible for electricity service. The taxation approach does involve less of an equity problem, but the analogy to the public schools shows that this approach also would not be devoid of controversy.

If these examples seem to be a bit strained, it is because ours is a market society, and the pricing of economic goods with some reasonable relation to their cost is taken for granted. However, it is worth noting that another approach does exist in a part of the electric utility industry. That is the pricing of electricity service to master-metered apartment and commercial buildings, where the electric utility charges the landlord for all the electricity used in the building, without metering the individual tenants. Sometimes the landlord may submeter the tenants, but the common practice is for the landlord to recover his utility costs through his rental fees, without relating each tenant's rent in any direct way to the electricity actually used by the tenant.

These examples of possible electricity pricing schemes unrelated to costs are also extreme in that cost plays essentially no role in the rate structure in them. A more practical question is the extent to which departures of the price structure from the underlying cost structure may be acceptable. Thus, considerations of equity are sometimes advanced as a reason for departing, at least to some extent, from a rate structure based on the structure of costs. For example, the

ability-to-pay principle is sometimes used as an argument in favor of lifeline rates, even where such rates are (and are recognized as) a departure from the structure of costs. Ability to pay may also be used to argue against strict reliance on cost considerations in establishing the relationship between residential and business rates. Further, strict reliance on cost considerations will restrict the scope for using utility rates to help reach other goals of economic policy. For example, regulatory authorities in some jurisdictions may wish to implement rate structures that subsidize business customers in order to attract jobs to their states and communities. Such subsidies, of course, are a departure from the basing of rate structure on the structure of electric utility costs.

Marginal Costs v. Average Costs

In working with the structure of electric utility costs, it is important to note that there are several different concepts of cost applicable to this subject. The principal ones are marginal cost and average cost.

Marginal cost is the cost, in current dollars, of expanding electricity supply by one unit. This unit may be a kilowatt-hour of energy at a particular hour of the day, a kilowatt of peak demand, an additional customer, or any other measure (or combination of measures) of the service provided by the utility. Average cost, in contrast, is the total cost divided by the total number of units of service provided. Average cost may be greater than, equal to, or less than marginal cost.

In the electric utility industry, there is also a distinction between embedded average cost and average cost based on current prices. This distinction arises because electric utility ratemaking is based in many jurisdictions on the original cost of plant, and the total costs used in ratemaking reflect these embedded plant costs. Since marginal costs are by definition based upon current costs, a comparison between marginal and embedded average costs is in part a comparison between current prices and the actual historical prices embedded in a utility's plant. To avoid the intrusion of this additional element of time, and to focus only on the difference between marginal and average costs (rather than on the difference between current and past prices), average costs based on current plant prices are sometimes considered.

The principal argument for using marginal costs rather than average costs as the basis for electricity rate structure is the argument of economic efficiency. In a free market economy, prices are viewed by the purchasers of any product as signals of the value of the resources used to make that product. Purchasers can properly guide resource use in the economy only if prices correctly signal to them the additional quantity of one product that can be made from the resources released when less is required of another product. However, since these changes in supply occur at the margin, it is the marginal costs that determine the quantities in which one product can be replaced by another through the shifting of economic resources.

Hence, prices based on marginal costs are the ones that correctly signal the terms on which the economy can transform one product into another; and thus, they are the prices most conducive to economic efficiency.

These cost concepts, and the efficiency argument related to them, can be illustrated with reference to the generation of electricity. If one looks only at the fuel cost of running the generators, the average fuel cost is the total fuel bill (for an hour or for an entire month) divided by the quantity of electricity generated in that time. The marginal fuel cost at any hour is, in contrast, the cost of the additional fuel that would be required to increase generation by an additional kilowatt-hour at that time. This marginal cost is virtually always greater than the average fuel cost at that hour. The reason is that generating units with relatively low fuel costs are used to the maximum extent possible, even when demand is relatively low; and higher loads are served by running units with successively higher fuel costs. Hence, the marginal increment to load requires a fuel cost increase sufficient to obtain additional energy from one of the generators with a relatively high fuel cost.

Consider, for example, a utility with a run-of-the-river hydroelectric plant serving a small part of its total load. This plant is always run at capacity (except when down for maintenance), and differences in the load level are accommodated by changing the output of other plants that do burn fuel. The

marginal fuel cost of generating energy therefore reflects the cost only at the fuel-burning plants, whereas the average cost is pulled down by the zero fuel cost of the hydroelectric plant. Thus, the marginal running cost exceeds the average running cost.

This marginal cost is also the proper basis for the efficient pricing of electricity, because it correctly reflects the fuel that can be saved if demand is reduced, or the additional fuel required if demand increases. The average fuel cost is irrelevant, because the hydroelectric plant is (by assumption in the example) so small that it will always be run at capacity even if the demand does change. Moreover, it is misleading the users of electricity to signal to them that the generation of energy can be increased in part with more hydroelectric power at zero fuel cost when, in fact, the run-of-the-river plant is already fully utilized.

The difference between marginal and average costs is especially important with respect to the relative costs of capacity for meeting peak demands and the generation of energy. Analysis using average cost concepts often associates the entire cost of all generating plants with the meeting of demands, and it assigns only the fuel plus a part of the other expense of operating these plants to the cost of energy. This approach flies in the face of marginal cost principles. Baseload plants are built because they have low fuel costs, not because they are required to meet peak demands. Peak demands can be met using turbines, at a current investment cost of less than

\$250 per kilowatt; whereas baseload units cost \$500 to \$800 per kilowatt, or more, at current prices. This differential is certainly not a proper part of the marginal cost of meeting peak demand.* Thus, the marginal cost of meeting peak demand is currently less than the average cost of new generating capacity. This is exactly the reverse of the situation with respect to energy, where marginal cost exceeds average cost.

However, if one looks instead at the embedded average cost of capacity rather than at the average cost based on current prices, the relationship between marginal and average costs may change. Owing to the recent and rapid inflation in the U.S., current prices for new generating units are much higher than the historical costs of plant. Therefore, the embedded average cost is less than the average cost based on current prices, because the embedded cost reflects older plants built at lower prices. Thus, the embedded average cost of capacity is nearer to the marginal cost of meeting demand (or it may even be below the marginal cost).

An important advantage of marginal-cost pricing for capacity is that it conveys the proper price signal to those users who are in a position to reduce their peak demands on the utility system by generating some of their own power, or by purchasing from a third party. If the price charged per kilowatt of peak demand is substantially above the cost of

*It is not a part of the marginal cost of energy either, as explained below.

additional peaking capacity, as it may be if it is based on average capacity costs, then large users may find it economical to shave their peak demands by installing their own peaking units, and thus avoid paying the higher price per kilowatt being charged by the utility. Since the utility can almost certainly expand its own peaking capacity at a lower cost than the customer can, owing to economies of large scale, this failure to charge a price properly reflective of marginal costs can cause economic inefficiency. This is exactly what happened some years ago, when Britain's Central Electricity Board first began charging the regional boards a demand price based on average rather than on peaking capacity costs. Thus, the lessons of marginal-cost pricing were learned in Europe some time ago.

IV. Alternative Rate Structures Based on Average and Marginal Costing Approaches

In the previous section, we have demonstrated that rate structures should reflect cost structures; and we have further argued that marginal costs are the proper basis for rate structure design. Time-varying rates are usually linked with marginal cost concepts but, in fact, this link is not necessarily as close as it is sometimes made to appear. On the one hand, time-varying rates need not be based on marginal costs. They can instead be based on average costs, or they can even be constructed arbitrarily and without reference to any specific aspect of electric utility cost structure. On the other hand, marginal cost concepts can be used in developing a rate structure, even where the rates themselves are of conventional form rather than time varying.

In short, to the extent that rate structures are based upon cost structures, the cost concept underlying the rate design can be either marginal or average cost. In this section, we shall briefly outline the usual approaches to traditional rate designs and to time-varying rate designs based on marginal costs, and then consider how either costing approach can be used in both types of rate designs. In our discussions, we shall also consider the basis for and implications of inverted and declining block variations when based on either costing methodology. In particular, we shall pay special attention to the effect on time-of-use rate designs when constrained by a lifeline component.

The Traditional Approach to Rate Structure Determination

To understand more fully the way that marginal-cost-based, time-varying rates are constructed, it is useful to discuss briefly the way that electric utility rate schedules have traditionally been determined. Each electric rate schedule, or tariff, is a price list for electricity service. In general, the customers (who are called ratepayers) are grouped into several classes, and each class purchases its electricity service under a different rate schedule. On most utility systems, the two largest customer classes are residential service, for individual households, and so-called general service, for most nonresidential customers. On many electric utility systems, the general service category is replaced by two or three major business service categories, divided either between commercial and industrial customers, or according to the size of the load. In addition, there are often smaller classes for services such as street and highway lighting, and water pumping (for irrigation).

Customer classes. Customers are grouped into different classes so that they may be charged different rates. These rate differences are alleged to reflect differences in the character of the service provided or in the cost of furnishing service, but differences in the former (even where the character of the service is not related to cost) are often as important as differences in the latter.

Residential rates are almost everywhere based only upon the total quantity of electricity (measured in kilowatt-hours or Kwh) used by the customer, with perhaps an additional customer charge or minimum bill of a few dollars per month. However, the price per Kwh may depend upon the quantity used, with a higher price for the first 50 Kwh used in any month, a lower price for the next 150 Kwh, and so on. This is a so-called declining block rate. There may also be seasonal differences in the prices per Kwh; but otherwise there is, in general, no attempt to measure the time pattern of residential electricity use or to price residential service on a time-varying basis.

Many nonresidential rates, especially those for classes of larger customers, differ from residential rates in that they also include a demand charge. A demand charge is a charge based upon the greatest amount of electricity used by the customer in any particular time interval (usually one hour) during the billing month (measured in kilowatts or Kw) rather than only upon the total amount of energy (Kwh) used by the customer. The imposition of a demand charge does make the price of electricity depend upon this one further dimension of peak usage in the time pattern of electricity consumption, but the demand charge typically does not depend upon when during the month the customer's peak occurs, nor does a typical two-part rate (i.e., one with a separate demand and energy charge) depend upon other aspects of the time pattern of consumption besides the peak demand itself.

Separate rates are required for street and highway lighting service primarily because this service is not metered.* It is also recognized that streetlighting has a known and unusual time pattern for electricity usage, with much of the energy consumption concentrated in the off-peak hours in the middle of the night.

Special rates for water pumping and other special classes may be based in part upon the characteristics of the customer; but there may also be some differences in the nature of the service, and these differences may be related to cost. For example, service for the pumping of water for irrigation may be interruptible, because this is an activity for which minor interruptions of service are of relatively little import or cost to the customer; but the right to interrupt the service may help the electric utility reduce its capacity costs.

Steps in the traditional process. The traditional process for establishing a set of electric utility rates involves five steps:

1. Establishment of the total revenue requirement, or rate level, required by the utility.
2. Grouping of the customers into classes upon which different rates will be imposed.
3. Division of the total revenue requirement into the revenue responsibilities for each class.

*The question of how to design streetlighting rates so as to reflect costs properly is considered in Appendix D.

4. Design of the general rate form to be used to collect the appropriate revenue from each class.
5. Specification of the detailed elements of each rate, in accord with the overall rate design, the class revenue responsibilities, and the test-year quantities of service actually furnished by the utility.

These five steps are discussed in turn.

The revenue requirement or rate level is the issue that is most hotly contested in electric utility rate proceedings, but it has little or no direct bearing upon rate structure issues. The utility and its management are understandably concerned with the allowed revenue requirement, because it is a primary determinant of the profitability of the company; but they are much less concerned with how the responsibility for this revenue is divided among the customer classes, because most utilities have sufficient monopoly power to succeed in collecting the allowed revenues, no matter how they are divided among the classes. The customers have an equally obvious interest in the disallowance of excess revenues, and their interest in rate structure is limited by their view of rate design as essentially a zero-sum game, once the total system revenue requirement has been determined. Each class may seek to have its own share of the total revenue requirement reduced at the expense of other classes, but these maneuvers

do not directly change the total burden of the rates upon all the customers together.*

The grouping of customers into rate classes is done largely by tradition, and the only test that is ordinarily imposed is that of continuity. The traditional customer classes are so well accepted that their continuation is not even perceived as an issue in most rate proceedings, and the classification of customers is generally noticed only when some relatively minor change is proposed.**

With the customer classes fixed, the task of apportioning the total revenue requirement among them is performed using a so-called class cost-of-service study.*** In its most advanced form, a traditional class cost-of-service study allocates the total cost of service, which is all of the costs comprised by the revenue requirement, among the several customer classes. The costs are grouped into functions, such as demand and energy, and each cost element is allocated among the classes in proportion to the use made by the several classes of the function of

*One of the goals of rate structure innovation is to transform utility rate structure work from a zero-sum game into one with a positive sum, as all the participants (both the company and the several customer classes) recognize that rate structure innovations can help improve the economic efficiency of resource use in the electric utility industry and thus reduce the total cost of furnishing service.

**For example, a previously separate category for farm service may be combined with the rest of the residential class.

***A detailed discussion of fully allocated class cost-of-service studies is provided in Appendix A.

which that cost element is a part. For example, fuel costs are generally allocated among the classes in proportion to their energy use (Kwh); while capacity costs are generally allocated in accord with class demands (Kw). An important characteristic of the traditional class cost-of-service study is that it is based upon actual total or average costs, as they are recorded and used in the ratemaking process for establishing the revenue requirement, rather than upon other possible measures of economic cost, such as marginal cost.

It should also be noted that the complete class cost-of-service study is the most advanced of the traditional techniques for developing an electric utility rate structure, and it is not used in all rate cases. If it is omitted, the process of establishing a rate structure proceeds directly to the questions of rate design or, more likely, to the adjustment of the specific rate elements themselves.

Rate design is the establishment of the general principles according to which a specific rate is constructed. For example, the choice between a one-part rate, which has only an energy (Kwh) charge, and a two-part rate, which has both demand (Kw) and energy charges, is an issue in rate design. So is the choice between a declining block rate and a flat rate, and so forth. Rate design questions are sometimes addressed with specific reference to the cost structure as developed in the class cost-of-service study, if one were performed, but the judgment and experience of the rate analysts are also very

important ingredients. In most cases, the existing rate design is simply carried forward with only minor modifications, and rate design (like the grouping of customers into classes) is often perceived as not an important issue.

The final step in the development of a rate structure is the selection of the numerical values for the specific rate elements. These rate elements must be chosen in such a way that the rates recover the authorized total revenue requirement or, if class revenue responsibilities have been determined, the authorized responsibilities for each class. This is accomplished by reference to the billing determinants for the so-called test year. The billing determinants are the quantities of each kind of service provided and billed by the utility, such as kilowatt-hours of usage in each rate block, kilowatts of demand, and number of customers. The test year is the twelve-month period to which the revenue requirements determination is applicable, and the billing determinants for the test year are the quantities of service against which the authorized revenue is to be recovered. The new rates must therefore be calculated so that, when applied to the test-year billing determinants, they provide precisely the authorized revenue for that test year. Selection of the specific rate elements that meet this requirement, and that are constructed in accord with the accepted rate design principles, completes the process of constructing authorized rates.

As indicated above, this complete process of rate structure determination is not followed in every electric utility rate case. The grouping of customers into classes and the principles of rate design are generally addressed only when they become important issues. This happens if the company or some other party proposes a change in the existing class structure or rate design; but even then, the attention tends to be focused only on the proposed changes and not on the unchanging parts of these aspects of rate structure determination.

The class cost-of-service study has also been omitted in many rate cases. In this event, utilities and regulatory agencies have used their judgment and experience to apportion the total increase in the revenue requirement among the customer classes. This may be done, for example, by applying the same percentage increase in revenue responsibility to each class, or by increasing all rates by the same flat amount in cents per Kwh. Other approaches, including variations away from equalizing the increase, have also been used. Recently, however, it is becoming increasingly clear to regulatory agencies and to the parties involved that the failure to fix class revenue responsibilities through an explicit class cost-of-service study leaves an important gap in the procedure for setting rates.

Rate Structures Embodying Time-Varying Rates

Based on Marginal Costs

The rate structure innovations encompassing time-varying rates based on marginal costs do not touch upon the traditional revenue requirements determination, but they do impinge upon all the other steps in the process for setting rates. The important ways in which these innovations add to or change the traditional process of determining rates are as follows:

1. The structure of electric utility costs is analyzed with much greater reference to the time of electricity use than is found in a traditional class cost-of-service study.
2. The structure of electric utility costs is analyzed, at least in large part, using marginal cost concepts rather than the embedded total or average cost concepts used in a traditional class cost of service study.
3. The elements in the rate design correspond directly to the service functions used in developing the analysis of the utility's cost structure.
4. The numerical value assigned to each rate element equals the cost found to be associated with that element in the cost-of-service study, except to the extent that deviations are required to meet the total revenue requirements constraint.
5. The need for customer classes is questioned. Instead, the innovative approaches lead to the imposition of essentially the same rate schedule on all customers in all of the what have traditionally been different classes.
6. To the extent that metering costs or other institutional restraints prevent the imposition of a single set of cost-based rates for all customers on the system, and instead force the grouping of customers into classes, the class revenue responsibilities are determined in accord with the marginal cost principles of the innovative approach rather than the embedded total or average cost principles in a traditional class cost-of-service study.

Each of these changes is discussed in turn and is incorporated in the case study rate design for the Newport Electric Corporation, that is developed in Appendix B.

Traditional ratemaking techniques reflect only some of the variations in electricity costs by time of use. Specifically, they recognize that the costs of capacity, especially generation and transmission capacity, are determined by peak demands rather than by total energy use. However, they do not reflect differences in energy or running cost by time of use, and they do not generally reflect the known differences in energy loss factors between peak and off-peak periods. These additional time-varying cost elements are treated explicitly in the innovative analytical techniques underlying the time-of-use rate design methodology presented in Appendix B.

The second important departure in the innovative analytical techniques is the use of marginal cost concepts rather than embedded average cost concepts for determining the structure of electric utility costs. This departure is especially important to the separation of bulk power supply costs into its demand and energy components. The marginal cost of energy is higher than the average cost of energy at any hour of the day or year, because the marginal cost at any hour is essentially the cost per Kwh of running the highest cost generator actually carrying load in that hour; and this highest running cost is obviously greater than the average energy or running cost of all the generators serving the load at that hour. In contrast, the

marginal cost of meeting additional demand is far less than the average fixed cost of new generating capacity, and it may well be less than the average embedded cost of all capacity. The reason is that the total or average cost of baseload generating capacity includes a large investment made not for the purpose of meeting demand, but rather to save on fuel when these baseload generating units are run many hours of the year. The marginal cost of meeting additional peak demand is at most the capacity cost of a peaking unit, which is much less expensive than baseload generating capacity; and the use of marginal cost concepts properly attributes the excess of the capital cost of a baseload unit over a peaking unit to the energy function rather than to the capacity function. Since different customers make different relative use of energy and capacity, the allocation of costs between the energy and demand functions is very important to rate structure.

The third important innovation is to design rates so that the charges for electricity service are based on the same service characteristics and quantities thereof as are used in the cost structure analysis. This principle is based upon the proposition that ratepayers should be charged for using services that cause the utility to incur costs. The cost-of-service study is an attempt to find out what those services are, and how much it costs the utility to provide each of them. Once

this has been determined, it is appropriate to make the use of these services the basis for charges to the ratepayers.*

A corollary of this proposition is that the price charged for each of these services should be the per unit cost incurred by the utility to provide it. This is the fourth innovation embodied in the analytical techniques presented in Appendix B. However, to the extent that the per unit costs are marginal costs rather than embedded average costs, the total revenue that results from applying these costs to the services furnished by the utility may be different from the allowed total revenue requirement. When this happens, some adjustments are necessary to meet the revenue requirements constraint, and these adjustments are also part of the innovative analytical procedures presented here.

With rate structures based properly on charges for the services that cause electric utilities to incur costs, the need for grouping customers into classes disappears. Customer classes have been required in the past primarily because bills were based in part on service characteristics that were not closely

*Perhaps surprisingly, there are some areas in which rate design is ahead of cost analysis. In particular, many industrial rates include a charge for a low power factor. (The power factor is the relationship between the phase of the voltage and the current flow in an alternating current system. Low power factors may result from loads that are predominantly electric motors.) Low power factors do impose costs upon electric utilities, and thus it is proper that there be a charge for them in the rates; but neither traditional cost-of-service studies nor the innovative approaches presented here relate cost to power factors or to the equipment required to compensate for loads with low power factors.

related to the structure of electricity costs. This was an especially great problem with residential rates, where energy charges were based on total kilowatt-hours used, and failed to reflect time patterns of electricity use. The problem was solved in part by grouping together customers who were expected to have similar time patterns in their electricity use so that the utility could establish class rates that compensated for these expected differences in time patterns. This compensation was achieved by imposing different charges per Kwh on the different classes, as a substitute for metering the actual differences in their patterns of electricity use. For example, homeowners using electric space heating or electric water heating are believed to have more favorable time patterns of electricity use than homeowners using electricity only for other purposes, and thus there is a cost basis for offering lower rates per Kwh to electric space heating and electric water heating customers. Similarly, class distinctions were obviously necessary to permit nonresidential customers with demand meters to be billed differently from residential customers having kilowatt-hour energy meters only.

The imposition of time-of-use rates changes this picture entirely. Since time patterns of electricity use are metered, each customer can be billed in accord with his own actual usage pattern; and thus there is no longer any need to group customers on the basis of the probable or assumed time patterns of their usage, so as to confer on them the benefits or charge

them for the costs of usage patterns that are not being metered individually.

The problem with comprehensive time-of-use rates is that the cost of metering the time pattern of electricity consumption for each ratepayer may exceed the benefits resulting from the implementation of time-of-use rates. This problem must be recognized, and provision must be made for the continued existence of customer classes where comprehensive time-of-use metering is institutionally unacceptable or not worth the costs. However, in these instances the innovative analytical procedures are directed toward measuring the class revenue responsibility that would exist if time-of-use rates were feasible; and class revenue responsibilities are therefore determined using the innovative approaches to cost structure analysis rather than the traditional approaches. This means specifically that the apportionment of revenue responsibility to customer classes is based upon marginal cost approaches rather than upon embedded average costs for capacity and energy, and that attention is paid to the complete time pattern of class use, where such information is available, even though individual members of the class cannot be billed on that basis.

Optional Rate Designs under Either Costing Approach

As stated in the beginning of this section, time-varying prices are not tied to marginal costing techniques, nor are more traditional rate structures tied to average costing

methodologies. To the extent that the rate structure is tied to the structure of costs, either costing concept can provide the basis for the rate design. Of course, rate designs that deviate from cost responsibilities are in no way constrained by the concept of costs employed, be it average or marginal.

Time-varying rates can be designed to reflect average costs. It is possible to split the total costs of power production into capacity costs and energy costs; and it is also possible to observe how much of the total energy cost is being incurred in peak periods and how much in off-peak periods. If one then makes the further assumptions that capacity costs can be associated with peak-period demands only, and that energy costs can be associated with the services provided at the time these costs are being incurred; one can split the total costs into two parts: one, consisting of all capacity costs plus energy costs incurred during peak periods, is associated with peak-period usage; and the other, consisting only of energy costs incurred during off-peak periods, is associated with off-peak usage. One can then divide each portion of the total cost by the usage associated with it to obtain an average cost for peak-period usage and a different average cost for off-peak usage. These average costs can then be made the basis for time-varying rates.

It is also possible to devise time-varying rates in ways that are devoid even of the average cost concepts that have just been discussed. One can begin, for example, with a

desire to promote load management, and one can then devise rates that one hopes will achieve the objective of radical change in the time pattern of electricity use. Some early rate structure experiments did, in fact, use large time differentials, primarily to determine what the customer response would be. Such rates need not bear any relationship to cost structure at all, but they do vary with time of use.

The problem with time-varying rates that exaggerate the time variations in the cost structure is that they may go too far in promoting load management. One experiment in Connecticut used a peak/off-peak rate differential of 16-to-1, and one customer on this rate found that it made electric storage heating very economical. The problem was that the off-peak rate of 1¢ Kwh was substantially below the marginal cost of generating energy in New England, even at night, and thus all the other customers were subsidizing the nighttime charges for this one user's electric storage heating system. This is another example of the reason why prices reflecting marginal costs are most conducive to economic efficiency.

On the other hand, the response of the one customer described in the preceding paragraph was most unusual. Indeed, the typical load management response is probably slow and small, even with very large rate differentials; and it can be argued that large time differentials--larger even than are justified by the time structure of electricity costs--are needed to get load management off the ground.

Just as time-varying rates can be constructed without regard to cost structure, so marginal costs can be used in the development of conventional rates. Even in a conventional rate structure, it is necessary to divide the total system revenue responsibility among several customer classes. As explained in the preceding section, this division has traditionally been made by apportioning the total or average costs of the utility among the customer classes in accord with the use made by these classes of the various functional services provided by the utility. Among these functional services are demand and energy. It is possible to use the marginal costs of providing these functional services instead of their average costs, yet proceed in all other respects with the conventional approach to rate structure design. The result is a conventional rate, but one in which the balance between energy and demand charges reflects marginal costs of demand and energy, rather than embedded average costs of capacity and energy.

This change in the balance of the rate structure between demand and energy can have as important an impact on the use of electricity as load management. If it turns out that marginal energy costs are higher--at all times--than average energy costs, then energy conservation may be a more important objective than load management; and marginal cost considerations will be important in their own right, even without time-varying rates.

Deviations from cost-based rates. It was pointed out above that rate structures can be designed that have no direct basis in the structure of costs. Too, deviations of some parts of the rate structure (e.g., rates for specific classes of customers) may occur, while an attempt is made to have the remaining parts reflect costs of service to the extent possible, given the deviations from costs of some interrelated components of the structure. These deviations may be incorporated to achieve goals other than those of economic efficiency and the concept of economic equity already defined. Load management and ability-to-pay concepts of equity are examples of other objectives that may provide a basis for such cost deviations.

Two particular rate structures that are frequently discussed are the traditional declining block rates and inverted rates, often incorporating a beginning lifeline block. Neither of these rate designs is based directly on the structure of costs, either average or marginal, although arguments have been made for each that they represent a crude approximation of marginal costs in the respective worlds of decreasing or increasing electric utility industry costs. In the absence of adequate estimates of the marginal costs of service, it was argued during the 1950s and 1960s that declining block rates were justified because the costs of serving larger customers were lower and because increasing total output on a system characterized by decreasing costs would lower the average cost per Kwh for all customers, including those consuming in the

intramarginal blocks. A similar argument is made for inverted rate structures, except that, given the altered assumption of an increasing cost industry, it is considered cost justified to discourage additional consumption. Thus, rates per Kwh rise as the typical customer increases his monthly rate of consumption.

In fact, neither of these cost structures has solid theoretical or common sense groundings. To provide the "proper" price signal for marginal usage, each of these cost structures must assume that the marginal customers for the system are those customers who fall into the tail blocks, and thus are charged the marginal cost of production. In theory, and in fact, all customers consume at the margin. That is, any customer who decides to increase his consumption by a kilowatt hour will impose the marginal cost on the system if it is consumed at the same point in time. Consequently, all customers should face the same rates based on marginal cost.

Declining block rates were recommended historically, just as inverted rates are sometimes recommended today, as devices for adjusting a cost-based rate structure to meet a revenue constraint, while minimizing the distortions that result in the allocation of resources. If marginal costs are used in any way as the basis for pricing, it is unlikely that revenues collected under such rates will, without some adjustment, exactly equal the revenues allowed by the regulatory authority. Since marginal cost pricing leads to an optimal use of re-

sources, it is desirable to adjust the prices to meet the revenue constraint in a manner that minimizes the movements away from these optimal usage levels.

One version of this procedure is the so-called inverse elasticity rule. According to this concept, deviations of rates from marginal costs should be greatest for those customers who have the lowest elasticity of demand for electric power and, therefore, will change their consumption least in response to price signals that deviate from marginal cost. When this rule has been employed as a rationale for either declining block or inverted rate structures, the implicit assumption has been that larger users of electricity will have more elastic demands than smaller users. Thus, if high marginal prices are warranted, but would lead to excess revenues (and profits), the inverse elasticity rule directs that rates in beginning blocks be reduced to adjust total revenue downward. This approach is often coupled with the assumption that large users are the marginal users on the system, and so should face the true marginal costs for additional consumption to promote conservation. Further, this approach is frequently coupled with an ability-to-pay concept of equity, which provides proponents of inverted rates with an additional basis for lowering rates in early blocks, on the assumption that customers with low usage rates have the lowest ability to pay for electricity. Thus, inverted rates are often tied to a proposal for a life-line block.

In fact, there is no clear-cut theoretical or empirical support for any of these assumptions. We have already noted that all customers on the system consume at the margin, and there is no basis for concluding that only customers in the tail blocks are marginal customers for the system. Similarly, there is no empirical support for the proposition that customers in early blocks have elasticities of demand that differ in either direction from those of customers who consume in the tail blocks. Nor is there a clear-cut theoretical basis for the assumption.

First, not all small users of electricity have less income than larger users. More importantly, it is not clear that the price elasticity of demand for electricity rises as income rises. Behavior patterns can be identified that would both lower and raise the price elasticity of demand as income rises. The net effect of these opposing influences remains an empirical question, and the work simply has not been done.

On the other hand, there is a different argument for adjusting rates for lower levels of use (i.e., the early blocks) to achieve a given revenue target in order to minimize the allocative distortion that results from rates deviating from marginal costs. All customers consume in the first block, and only a relatively small number of these view the first block rate as marginal. Thus, any rate adjustment in the first block will affect all customers, but only intramarginal consumption for a large number of them. Since a large

quantity of energy is consumed in the first block, the required revenue adjustment can often be achieved with relatively modest rate adjustments covering a relatively small range of consumption, and so affecting fewer consumption decisions at the margin. To make the revenue adjustment in the tail blocks would either require a larger deviation of price from marginal cost over a similar range of consumption, or a similarly sized deviation over a much broader range of consumption. In either case the effect would be to seriously distort allocative efficiency more than if the adjustment is made by altering the rates at low levels of consumption.

Carrying this logic to the limit, it would imply that the least distortion would result from the adjustment being applied to the zero block of consumption--i.e., adjustments in the customer charge. This result is consistent with the usual conclusion of economic theory that any tax (or subsidy) should be applied in a manner that will not affect consumption levels at the margin. Adjustments in the customer charge will have little impact on rates of usage for customers already on the system; and it is unlikely that the number of customers is responsive to even large adjustments in the level of the customer charge.

For reasons other than allocative efficiency, however, an across-the-board prorated adjustment (to each rate component) is likely to be superior in practice to an "inverse elasticity" type of adjustment, including adjusting only the

customer charge. To begin, if the revenue excess or deficiency is large, the resulting adjustment in the customer charge is likely to be sizable. Since the customer charge comprises significantly different portions of the total bills of different types of customers, this adjustment mechanism is likely to be highly discriminatory. This is most clearly seen in the case of an upward adjustment, which might increase smaller residential customers' monthly bills by a sizable percentage, while the increase for large industrial customers would be minuscule in percentage terms. Too, in this case the impact on residential consumers (and especially smaller customers) would be so substantial as probably to lead to aggressive intervention on their behalf, making it very difficult for the regulatory authority to implement the rate design despite its other merits. Large downward adjustments in only the customer charge would be similarly discriminatory, but in this case large customers would receive only minuscule benefits from the rate adjustment, while small residential customers would benefit greatly.

In addition to the discriminatory nature of restricting the adjustment to the customer charge, this type of adjustment process could result in the instability of rates, generally something that all parties--the company, the ratepayer, and the regulatory authority--wish to avoid. Any significant change in the level of consumption or the required revenue target, if made up for solely by adjustments in the customer

charge, could result in significant swings in the level of this rate component and, thus, significant swings in the bills of small customers. Since revenues are spread over so many billing units of energy and demand, on the other hand, even significant swings in consumption levels or costs would result in only minor rate adjustments if prorated over all components of the rate design.

Lifelines and Time-of-Use Rates

The argument for adjusting rates only at low levels (blocks) of usage does not provide an allocative efficiency argument for the incorporation of a lifeline block in a cost-based rate structure. If lifeline blocks are to be incorporated in cost-based rate structures, they must be rationalized on the basis of an ability-to-pay concept of equity.

With the rapid rise in electric utility rates that has occurred in the past few years as a result of rapidly rising capital costs and fuel and other operating expenses, regulators have experienced increasing pressure from consumer groups and their elected representatives to provide relief of some sort to those ratepayers least able to afford these increases--usually the poor and the elderly. The only tool available to regulators to deal with this issue is their authority to set rates for utility service. Thus, commissions are under increasing social and political pressure to implement some form of lifeline rates that would provide service to qualifying customers at

rates below the cost of service. Often, proposed lifeline rate subsidies contain provisions that freeze these rates for some period of time, say three or five years.

Regulatory authorities thus find themselves facing two conflicting objectives. On the one hand, they are being pressed to implement rate structures that reflect costs in order to provide the proper consumption incentives which will lead to greater efficiency in production and conservation of scarce fossil fuels. On the other hand, they are being pressed to implement rate structures, part of which (e.g., the lifeline component) deviate significantly from the cost of service in order to provide rate relief to those customers who are especially burdened by the rising price of electric power. The trade-off involved in this choice is apparent, yet regulatory authorities are frequently forced to make their decision on the basis of an incomplete understanding of the potential benefits to accrue from lifeline rates. Moreover, such a policy places regulatory bodies squarely in the arena of income redistribution, generally without benefit of an understanding of the principles upon which alternative redistribution policies should be evaluated.

In considering the merit of imposing a lifeline block in an otherwise cost-based rate structure, regulatory authorities must deal with each of the following questions:

1. Who is intended to benefit from the lifeline, and what criteria should be used for qualification?
2. Are alternative subsidy programs preferable to lifeline on the basis of their effects on allo-

cative efficiency and the administrative efficiency of the programs?

3. If a lifeline is to be implemented, how should the subsidy be paid to minimize allocative distortions?
4. If a lifeline is to be implemented, how should remaining customers pay for this subsidy, and how should the costs of the subsidy be allocated among those bearing the costs?

In this section, we shall address each of these questions within the context of a time-of-use rate design based on marginal costs of service. Before turning to these specific questions, however, it is useful to review the basic principles that should be considered when evaluating welfare policy alternatives. If regulatory authorities are to enter into the business of income redistribution, it behooves them and the people they represent to gain an understanding of these principles.

Some principles of welfare policy. Public policy in this and other western countries is frequently designed to alter the distribution of income that results from the operation of the market system. The general objective of these policies is to render the income distribution more equitable (equity being defined in the voting booth) while not seriously blunting the market incentives to work, save and produce. Two general types of redistributive mechanisms are used for this purpose. The first is referred to as direct income (or cash) subsidies designed to augment directly the incomes of those considered by the body politic to be beneath some minimum standard of living. Examples of these programs include the earned income tax credit

and aid to families with dependent children. Other "welfare" programs provide income assistance in kind or by reducing the prices of specified necessities below the level determined in the marketplace and reflecting the cost of production. Examples of this type of "welfare" program include Medicaid, the food stamp program and housing subsidies. Lifeline rate structures would also fall into this category of income assistance.

Both cash assistance and income-in-kind subsidies are designed to improve the standard of living of those in need, but they are fundamentally different approaches. The cash assistance approach attempts directly to raise families' standards of living to some preconceived minimum level. Under these subsidy programs, how any family uses the extra income is at its discretion. The subsidizing public agency imposes no requirements on the use of the funds.

In-kind assistance programs, on the other hand, deal with the problem of poverty in terms of the inability (and perhaps lack of desire) to acquire adequate quantities of specific and essential classes of goods--food, housing, medical care, and now, perhaps, electricity. Behind these programs lies the assumption that, at a minimum, public policy should insure that these necessities be available to all at an affordable price. In-kind assistance programs, therefore, are designed not only to augment the incomes of the poor but also to influence their consumption patterns.

It is likely that most policy makers favor the use of both approaches: increasing the incomes of the poor through direct assistance, while tying some programs to the provision of certain essential goods and services. Yet the two approaches are also alternatives. For example, the funding for the food stamp program could be redirected into direct cash assistance for the same families who are presently purchasing food stamps. Therefore, when considering additional assistance to any specific group of individuals, the policy maker should evaluate the relative merits of these two forms of subsidy programs--direct cash assistance or in-kind subsidies. Certainly, considerations of this sort should be made when evaluating the merit of any lifeline rate proposal.

A case can be made for either form of assistance. Direct cash assistance programs are often thought to be administratively simpler, and they leave intact consumers' freedom of choice. Importantly, cash assistance programs have minimal effects on the allocation of resources because the subsidized consumer continues to face the correct (i.e., cost related) price signals. By way of contrast, in-kind (or price-subsidizing) assistance programs distort decision making by confronting consumers with prices that do not reflect costs. Thus, from a social viewpoint, the subsidized consumer buys too much of the subsidized good or service and too little of all other unsubsidized items. From a static efficiency point of view, cash assistance programs are clearly superior.

However, other advantages are claimed for in-kind or price-subsidizing assistance programs. Whereas, under cash assistance programs the recipient is permitted to dispose of the income supplement in any way he chooses, in-kind or price-subsidizing programs provide some guarantees that public funds will be spent on goods and services that society deems necessary or socially useful. Too, it is sometimes argued that a direct income subsidy or "dole" carries with it a social stigma, whereas reduced prices to the less affluent do not. This may be due partly to the fact that such subsidies are largely hidden from both the recipient and from the rest of society.

Price subsidies may also be a more effective method of maintaining a given level of assistance during periods of rapidly changing prices. The plight of the less affluent may well be linked rather closely to sudden and significant changes in the prices of a few essential goods and services. Under direct cash assistance programs, adjustments in the level of cash subsidies would be required as changes occur in the prices of these key commodities (or services), in order to maintain a minimum standard of living for the recipient. Thus, it might be argued that a more convenient way of accomplishing the same thing would be to provide price relief (i.e., a lifeline on the key good or service).

The fact that subsidies in kind provide assistance only if, and to the extent that, qualified families consume the subsidized commodity or service is at the heart of the philosophical

differences underlying the two types of redistributive mechanisms. In-kind (or price-reducing) subsidies represent a denial of the principle of relying upon consumer choice to maximize social welfare. Rather, the underlying principle is that social welfare will be maximized if society insures that the subsidy is used for goods and services that are deemed useful or essential rather than for goods or services deemed either nonessential or harmful to society's interests.

Two types of arguments are used to support this approach to redistribution. The first recognizes that consumption of some goods and services has significant externalities, either positive or negative. That is, private consumption of these goods and services generates either additional benefits or costs that accrue to the rest of society. Education is a classic example of a service that yields substantial external benefits to the remainder of society, and so education is often subsidized to encourage additional private consumption. Private consumption of addictive drugs, on the other hand, generates significant costs (or negative externalities), in the form of higher crime rates or other forms of antisocial behavior, that must be borne by the rest of society. Thus, the costs of these goods are increased above the market level (by making the consumption and sale of these commodities illegal) to discourage their use.*

*The difficulty of eliminating the adverse social effects of the consumption of some goods and services by significantly [Footnote continued on following page]

Subsidies in kind are also based on another and more philosophical argument, which is that since society is providing the subsidy, it is society's consumption preferences that should govern the use of these funds rather than the preferences of the recipient of the subsidy. Often these preferences are different, and so in-kind assistance programs guarantee that the subsidy will be used for goods and services that society deems either essential or beneficial.

In-kind subsidies for electricity consumption cannot be rationalized directly on the basis that the consumption of more electricity generates significant positive social externalities. On the other hand, the second type of argument can be and is used to support lifeline rates. Tying the subsidy directly to the use of some minimal amount of electric power guarantees that the subsidy will be used for what today is generally considered to be an essential commodity. Further, the first type of argument can be used to bolster the case for providing a subsidy in kind to account for the burden of high electric power rates on low-income families. Providing direct

[Footnote continued from previous page]

raising their effective prices is aptly demonstrated by U.S. policy toward addictive drugs. The high incidence of criminal activity associated with drug use is, in large part, the result of the artificially high market prices of narcotics, which stem from the fact that production and sale of these commodities have been made illegal, and producers are subject to severe penalties upon apprehension and conviction. Often being unable to secure employment that provides a large enough income to support their habits, addicts tend to turn to criminal activity.

cash assistance to alleviate this burden offers no guarantee that the recipient will not use the additional income to consume goods and services that generate additional social costs, rather than for goods and services that society deems essential or beneficial.

Who should receive the lifeline? If lifeline rates are to be implemented, the regulatory authorities must first determine in conceptual terms which customers the subsidy is intended to benefit. Then this conceptual definition of the group of recipients must be translated into a set of operational qualification standards that is both administratively practical and achieves the objective, in terms of providing the subsidy to those for whom it was intended. Lifeline proposals usually tie the subsidy to a specific monthly usage level. That is, consumption up to the first 300 Kwh or 500 Kwh per month will be at the subsidized rate per Kwh. This means that all customers who consume less than the ceiling amount pay subsidized rates for all of their usage. All other customers who use above this quantity receive a subsidy on all consumption in the lifeline block, but pay a rate above actual cost (i.e., pay for the lifeline subsidy) for all consumption in excess of the maximum lifeline quantity. Thus, the amount of subsidy received and the amount of subsidy paid by each customer is directly related to the level of usage.

The usual conceptual criterion for subsidy eligibility is that of need, and income is generally considered a partial

determinant for the need of any given family. Usual lifeline proposals are grounded on the assumption that usage levels are closely correlated with income and, therefore, providing the subsidy for usage in the first block of consumption results in lower income families receiving the subsidy. However, the same logic creates inequities in the distribution of the subsidy. Because the subsidy is provided in terms of a lower price per Kwh (below costs), the amount of subsidy received by any customer depends upon the amount of energy consumed. To the extent that usage is correlated with income, this means that among all customers consuming within the lifeline block, higher income customers (with higher usage) receive greater assistance than lower income customers. This result violates the usual equity standard for a welfare assistance program -- that those in greatest need receive the greatest benefit.

In fact, the distribution of the benefits of usual lifeline proposals is even more perverse than just indicated. Because all customers usually receive the subsidy for any consumption in the first block and are "taxed" to pay for the subsidy on the basis of consumption in subsequent blocks, many customers who consume well in excess of the lifeline ceiling will be receiving a net subsidy; and, depending upon the specific rate design, subsidies for these relatively large customers may exceed those extended to very small customers in the beginning stages of the lifeline block.

Both aspects of these perverse distributional effects are exemplified in Table 1, which presents a simplified lifeline rate design for a hypothetical electric utility system and the magnitude of the lifeline subsidies provided to customers at various levels of consumption both within and well beyond the lifeline ceiling. For illustrative purposes an extremely simplified rate structure is assumed. There are no customer demand charges; and it is assumed that all customers, in the absence of a lifeline, would pay the same average total cost per Kwh (20 mills) to yield total allowed revenues of \$200 million from total sales of 10 billion Kwh. It is further assumed that the lifeline block will extend to the first 500 Kwh per month and that consumption in this block amounts to 3.75 billion Kwh. The proposed lifeline rate is 10 mills per Kwh or a total subsidy of \$37.5 million, and it is proposed that the company be made whole by imposing a surcharge of 6 mills per Kwh on all other consumption--i.e., residential consumption above 500 Kwh per month and all non-residential consumption.

On close inspection of the bottom panel of Table 1, one can see the perverse distributional effects of the lifeline proposal. First, as we suggested above, customers within the lifeline block who have the highest usage levels receive the greatest subsidy; a customer using 100 Kwh per month receives \$1.00 a month, while a customer using 500 Kwh receives a \$5.00 monthly subsidy. Further, customers who consume well beyond

Table 1

A Simplified Lifeline Rate for a
Hypothetical Utility System

<u>Total Sales:</u>	<u>Revenues (thousands)</u>
10 billion Kwh @ 20 mills/Kwh	\$200,000
Revenues from sales to residential class (1/2 of total)	100,000
Revenues from residential sales on first 500 Kwh (3/4 of total resi- dential sales at cost-based rate of 20 mills)	75,000
10 mill subsidy for residential consumption of first 500 Kwh	37,500
Additional charge for all remaining consumption to recoup \$37,500,000 subsidy ($\$37,500,000 \div 6.25$ billion Kwh)	6.0 mills/Kwh

Rate Design

10 mills/Kwh for 1st 500 Kwh of residential consumption
26 mills/Kwh for all other consumption

Residential Subsidies

<u>Kwh/month</u>	<u>Subsidy</u>	<u>Payment</u>	<u>Net Subsidy</u>
100	\$1.00	-0-	\$1.00
250	2.50	-0-	2.50
500	5.00	-0-	5.00
750	5.00	1.50	3.50
900	5.00	2.40	2.60
1200	5.00	4.20	.80
1333	5.00	5.00	-0-
2000	5.00	9.00	(4.00)
3000	5.00	15.00	(10.00)

the 500 Kwh per month lifeline ceiling also receive net subsidies. Not until a customer exceeds 1,333 Kwh per month will he become a net "taxpayer" rather than a net subsidy recipient. This results, of course, from the fact that all residential customers receive a subsidy of \$5.00 per month on the first 500 Kwh consumed and, at a 6 mill per Kwh surcharge for the remaining consumption, a customer must consume at least 833 Kwh beyond the lifeline block to incur a total surcharge payment of \$5.00. Not only do larger customers receive net subsidies, but under the lifeline scheme in Table 1, some rather large customers consuming beyond the lifeline block receive net subsidies greater than small customers consuming within the lifeline block. For example, a customer using 900 Kwh per month receives a greater net subsidy (\$2.60) than does any customer using up to 250 Kwh (\$2.50); and a customer using 1,200 Kwh per month receives nearly as great a net subsidy as does an extremely small (and poor?) customer using only 100 Kwh per month.

The fact that consumption is subsidized well beyond the lifeline block (up to 1,333 Kwh per month in our example) points out an item of concern that should be, but often is not, addressed in lifeline proposals. It is the net subsidy received that is of importance, and the lifeline should be designed so as to extend subsidy benefits at those levels of consumption that are deemed to qualify for assistance, and not to any consumption beyond that ceiling. In short, the "break-even"

level of consumption (where the net subsidy becomes zero) is a critical ingredient in the design of a lifeline intended to provide benefits to some group of customers, using usage levels as a proxy for need.

Once it is decided at what level net subsidies should fall to zero (the break-even point), there are several rate designs that will produce this result. Given that the amount of the subsidy will be tied to the rate of usage (up to the break-even point), perhaps the best way to achieve a desired "break-even" point is to adjust the length of the lifeline block accordingly. Of course, this will require the simultaneous determination of the "tax" to be imposed on higher levels of consumption, since the total subsidy cost to be recovered (and so the "tax" rate) will depend, in part, on the length of, and the amount of energy sold in, the lifeline block.

Alternatively, the subsidy could be provided by applying to total consumption within the lifeline block a decreasing subsidy per Kwh that falls to zero at the desired break-even point. An example of this type of scheme is presented in Table 2. In addition to the ease with which this lifeline can be designed to achieve a specified break-even point, an additional advantage of this approach is that the subsidy per Kwh declines as the rate of use rises. To the extent that usage levels reflect abilities to pay, this design can be judged as superior to usual lifeline rates on the basis of vertical

Table 2

A Hypothetical Sliding Scale Lifeline Design

<u>If Total Monthly Consumption Is Between</u>	<u>The Subsidy per Kwh for All Consumption up to 500 Kwh Is (mills)</u>	<u>The Rate per Kwh for All Consumption up to 500 Kwh Is (mills)</u>
0 and 100 Kwh	1.8	.2
101 and 200 Kwh	1.4	.6
201 and 300 Kwh	1.0	1.0
301 and 400 Kwh	.6	1.4
401 and 500 Kwh	.2	1.8
500 and up	-0-	depends on how subsidy costs are allocated

Monthly Bills and Total Subsidies at Various Levels of Use within the Lifeline Block

<u>Kwh per Month</u>	<u>Rate per Kwh</u>	<u>Monthly Bill</u>	<u>Monthly Subsidy</u>
50	.2 mills	\$.10	\$.90
150	.6	.90	2.10
250	1.0	2.50	2.50
350	1.4	4.90	2.10
450	1.8	8.10	.90

equity. The trade-off, however, is in terms of the adverse effects this technique may have on allocative efficiency. Because the average rate for all Kwh rises as the rate of consumption rises, the marginal price the customer faces greatly exceeds both the average price he pays, and (in our example) even the true average cost of service. For example, the marginal price of the 101st kilowatt-hour is 41 mills and, for the 401st Kwh the marginal price is 162 mills. These great discrepancies between marginal and average prices may lead to serious distortions in the use of electric power within the lifeline block. Clearly, most consumers do not have sufficient control over their usage to allow them to consume 400 Kwh per month, but to avoid using the 401st. Still, recognition of the rapidly rising marginal price of energy would likely lead to some reduction in usage below what otherwise might be considered optimal levels.

In the example on Table 1, there is also a substantial interclass subsidy of \$30 million that is being provided by nonresidential customers to the residential class. Another way of looking at this cost allocation of the subsidy is to note that nonresidential customers are responsible for \$30 million of the total \$37.5 million subsidy cost, while the remainder is paid by residential customers in proportion to their consumption above 1,333 Kwh per month. If none of the subsidy costs were imposed on nonresidential customers (i.e., they continued to pay 20 mills per Kwh), the residential

rate beyond 500 Kwh per month would rise to 50 mills per Kwh hour.

The assumptions incorporated in the example presented in Table 1 are extremely simplified, but they are in keeping with both the spirit and the general design of many lifeline rate proposals. Though the magnitude of the perverse distributional effects of this type of proposal will differ from the example, the direction of the effects will be the same if the benefits and costs of the lifeline are tied directly to usage, and if usage is directly related to family income levels.

There is an additional factor that influences each family's "need" for assistance. This factor tends to mollify to some degree the perversity of the usual usage-based lifeline proposal but, at the same time, points up another drawback of the usage criterion for subsidy eligibility. The level of electricity consumption is probably highly correlated with household size which may not be so highly correlated with income. To that extent, higher subsidies to customers with higher usage levels may have the acceptable result of providing larger subsidies to large families with low incomes but high electricity usage rates. On the other hand, large subsidies are also likely to be paid to small families with high income and with moderate total but very high per capita monthly usage rates. The extreme case of this perverse distributional effect would be when a single and high-income individual has a high rate of consumption per capita of nearly 500 Kwh. This would place him in the

tail end of the lifeline block, and he would receive close to the maximum subsidy provided when, in fact, he is least deserving on the basis of any usual "needs" criteria. Similarly, moderate-income families with very large households may be well beyond the point at which they receive any net subsidy. Thus, a substantial portion of the tax to be paid for the lifeline subsidy may be imposed on these families when, in fact, their consumption per capita is relatively low.

Another extreme case of perverse distributional effects of lifeline rates tied to usage is the subsidy that owners of second homes are likely to receive. Second homes that are frequently used only for weekend or holiday recreational purposes are likely to be covered by the lifeline, since monthly usage in these homes would tend to be low. In these cases the subsidy is clearly misdirected, for the owners of second homes tend not to be numbered among the less affluent.

In short, if the purpose of the lifeline is to assist those families who are most in need, then usage levels represent a very poor criterion for subsidy eligibility. Information on customers' incomes, family sizes and ages are the ingredients required to establish appropriate eligibility criteria. However, obtaining, verifying and incorporating these data into the utility's billing procedures is an extremely costly, time-consuming and potentially politically controversial process. It is doubtful that either electric utilities or the commissions that regulate them will be willing

to engage in the kind of screening process necessary to insure that price subsidies will be extended to those truly in need of assistance.

How should lifeline benefits be provided? If it is decided that a price-reducing subsidy is to be provided to a specified group of recipients, it must then be decided how such a subsidy is to be paid. In a cost-based rate structure, the subsidy is the amount by which any given customer pays less than the cost of providing him with service. As we discussed earlier in this report, cost-based price signals play an extremely important role in the allocation of resources by providing customers with the proper consumption incentives. Thus when incorporating price subsidies into a cost-based rate design the goal should be to minimize the disturbance to the cost/price relationships. In the case of time-of-use rates based on marginal costs, the price subsidy should be provided in a manner to minimize the disturbances in two kinds of price related consumption responses: the level of consumption in response to the average price of electricity, and the time pattern of consumption in response to the peak/off-peak price differential. Lifeline subsidies incorporated in energy charges and tied to usage levels will seriously distort both of these responses.

Experts in public finance have generally maintained that the least distorting tax (or subsidy) is a head tax (or subsidy) since these transfer payments do not have direct effects on marginal decisions to work, save or consume. Following this principle in designing a lifeline subsidy, the optimal way to avoid pricing distortions and yet achieve the desired redistribution of income is to provide the assistance to each recipient customer in the form of a per customer lump-sum subsidy. This would appear as a credit on each recipient's monthly bill and would have the effect of reducing the recipient's monthly customer charge. In some instances the net "customer charge" (inclusive of the subsidy) could be negative.*

To achieve an equitable subsidy program the magnitude of this credit should be tied to those customer attributes that determine ability to pay: income, household size, and, perhaps, age. Thus, the size of the subsidy (credit) would represent the difference between costs of service and a lifeline rate for some minimal amount of monthly usage that is considered essential for each age, income, and family size cohort. The amount of the subsidy could be increased as incomes fall and as family sizes increase. And higher credits at given income

*But the payment of the subsidy would still be tied to the consumption of electricity in the sense that a customer would never receive a negative total bill. That is, the amount of the subsidy would never be greater than the total bill computed at true costs of service, so the utility company would never pay cash to the customer. Thus, if the customer wished to take maximum advantage of the subsidy offered, he would have to consume the product being subsidized.

and family size levels could be extended to all individuals over 65, if that were deemed desirable.*

In a time-of-use rate structure based on marginal costs, this approach would leave intact the marginal price signals that partly determine the customer's decision of how much and when to consume electric power. Most important, each subsidized customer would still face cost-based, time-varying rates and would still have the incentive to transfer consumption from the peak to the off-peak period in order further to reduce (beyond the subsidy) his monthly electric bill. This behavior would be in keeping with the fundamental objective of time-of-use rates.

By whom and how should the subsidy be financed? A major difference between lifeline electric rates and other income assistance programs is that the latter are generally funded from general tax revenues, whereas lifeline rates are designed so that the subsidy is paid by other consumers of electric power. In most lifeline proposals, the amount that any one customer is forced to contribute to the subsidized customer is directly related to his rate of electricity consumption. As we have already noted in conjunction with our discussion of eligibility criteria, the problem is that usage levels may be very poorly related to the ability to pay. Consequently, serious questions

*Wealth (assets) as well as current income should probably be considered in determining eligibility, because income is not always a good indicator of purchasing power. This is especially true for the elderly whose assets and purchasing power may be substantial even if earned income is zero.

arise over the vertical equity of these usage-related taxing procedures.

Even if usage levels were determined to be a fair measure of customers' abilities to pay, allocation of the costs of the subsidy on this basis could lead to serious allocational distortions since the marginal price of electricity would be directly affected by each customer's rate of consumption. Thus, proper cost-based price signals would be disturbed as would be the consumption responses to these signals. As with the payment of the subsidy, the tax to be imposed on all other customers ideally should be a per customer "head tax" that in no way affects the average price of electricity or the marginal peak/off-peak price differential. The problem remains, however, of determining the magnitude of this additional customer charge for customers with different abilities to pay; and the magnitude of this tax should be, to the extent possible, independent of usage levels.

Establishing appropriate ability-to-pay criteria is difficult enough when considering only residential customers, but the problem is increased significantly when criteria are sought for nonresidential customers. If imposition of the costs is based solely on usage levels, without regard to historical customer classifications, a disproportionately high share of the total subsidy costs will be borne by nonresidential customers. This may or may not be appropriate; and, in large part, the allocation of subsidy costs between residential and

nonresidential customers will be a social judgment that is made within the context of local political pressures. In some instances, these pressures will urge that nonresidential customers bear most of the burden of the subsidy costs, and regulatory authorities may find it politically expedient and even justifiable to succumb to these pressures. However, in deciding what portion of the subsidy costs should be borne by nonresidential customers, the regulatory authorities should consider, at least, the following issues:

1. Will imposition of the costs on nonresidential customers contribute significantly to inflationary pressures in the state because of the ability of these customers to pass on increased costs in the form of higher prices for their goods and services?
2. Will imposition of the costs on industrial customers make local firms less competitive with their out-of-state rivals?
3. What is the risk that imposing these additional costs on industrial customers might induce them to move away or discourage new firms from entering the state?

These possible undesirable impacts on the state economy will place limits on the degree to which regulatory authorities may want to impose the costs of the lifeline subsidy on nonresidential customers. Failure to recognize these potential adverse effects may have the result of worsening the economic plight of the very individuals the lifeline rate structure was designed to assist.

In assigning lifeline cost responsibility among different customers with differing abilities to pay, or among residential

and various groups of nonresidential customers on the basis of some other acceptable criterion, it will probably be necessary to retain the existing or some substitute customer classification scheme. This will be required because the informational costs entailed in assigning each customer its "appropriate" share of the costs of the subsidy would be prohibitive. For practical purposes, customers will have to be grouped into relatively homogeneous classes.

Once these class subsidy cost responsibilities are determined, other criteria may yet be required to assign cost responsibilities among customers in each class in order to achieve the maximum possible degree of vertical equity in the distribution of the subsidy costs. As we have noted earlier, flat fees assigned to all customers are preferable in terms of minimizing the distortions to the efficient allocation of resources that result from cost-based prices. However, this approach will not necessarily meet generally acceptable ability-to-pay criteria. On the other hand, if the size of the tax is related directly to a customer's usage level, then price signals and the resulting allocation of resources may be significantly distorted. The best solution for residential customers would be to obtain the same information regarding income and family size for those customers paying, as well as for those receiving, subsidies; and to link the size of the customer "head tax" to some sliding scale based on these family characteristics, and one that reflects each family's ability to pay. Once again,

however, the informational costs of the approach are likely to be excessive; and the regulatory authorities may have to choose between the allocative inefficiencies resulting from a usage-based tax, and the vertical inequities that will result from a flat charge for all residential customers.

The same trade-off will have to be faced when allocating the subsidy costs among customers in each of the nonresidential classes; except as noted above, it is even more difficult to settle on appropriate criteria for a business firm's ability to pay. Consider what is usually referred to as the class of general service customers. Vast differences may exist in the size of firms served under this tariff, and allocating the subsidy cost among these customers on the basis of an equal customer surcharge would be clearly inappropriate on the basis of generally accepted ability-to-pay standards. These standards suggest that larger business firms should bear a larger portion of the costs of the subsidy. The administratively convenient method to accomplish this is to tie the tax to usage levels, again resulting in distortions in the price/cost relationship. Too, this approach tends to penalize those business firms that, on the basis of production efficiency, have correctly chosen relatively more electricity intensive technologies. Again, the preferred approach would be to levy a customer surcharge that varies in response to a firm's size, when size is not measured in terms of electricity consumption. Value-added or employment are examples of such measures, but here again

the costs of maintaining these data and integrating them into a utility's billing procedure are likely to be greater than the resulting benefits.

An alternative would be to finance the cost of the subsidy from general state tax revenues. This approach would be preferable because it would not alter electricity price signals based on marginal costs, and the regulatory authority would not face the problem of determining which nonsubsidized ratepayers should bear the burden of the subsidy and in what amounts. A state-financed program could be set up in several different ways. For example, the utility could be made whole by the state paying directly to the company from general tax revenues the amount of the subsidy, which would be the difference between the total cost of service provided to qualified customers and the revenues collected by the utility from those customers. Alternatively, the state might waive the collection of all state taxes (sales, gross receipts and income taxes) on all sales made to qualified customers, with the provision that all of these tax benefits be flowed through to those customers who qualify for the subsidy. The problem with this approach, of course, is that it cannot be initiated by the regulatory commission. Therefore, such a program offers no acceptable response to those parties who are urging the commission to take some direct action to provide relief in the absence of legislative programs to solve the problem.

Lifeline rates compared to alternative assistance programs.

The general objective of lifeline rate structures is to provide assistance to those low-income families whose standards of living are seriously affected by the rising price of electric power. Lifeline rates for qualifying customers provide this assistance in the form of electricity prices that are below the costs of service, and the costs of these subsidies are borne in some manner by some or all of the remaining customers on the system by paying rates that exceed the cost of providing them with service. If properly designed, a lifeline subsidy program could meet vertical equity standards by providing subsidies on the basis of need and allocating costs on the basis of ability to pay. These equity criteria could also be met while doing minimal damage to the allocative efficiency resulting from rates based on marginal cost, if the subsidies were paid and the costs of the subsidies imposed in the form of a customer credit or surcharge. Unfortunately, the informational and administrative costs of implementing this type of lifeline program will probably be prohibitive. Moreover, it is unlikely that either utility companies or the authorities that regulate them will be willing to engage in the kind of screening process that will be required to determine subsidy eligibility and to assess subsidy costs on the basis of customers' abilities to pay. Nor is it clear that either a utility or a regulatory commission should involve itself with such issues even if it were willing to undertake the task.

Because equitable and allocatively neutral lifeline programs are likely to be administratively difficult and expensive, it is probable that, if lifelines are ordered, they will be of a variety that is administratively convenient and inexpensive. Present lifeline proposals that tie subsidies and payment for the costs of these subsidies directly to the level of electricity usage have merit on this basis. However, as we have demonstrated above, these programs are perverse in terms of the inequities that result from the distribution of both benefits and costs, and in terms of the allocative distortions that result from their implementation. If this is the trade-off that must, or at least will, be made--i.e., lifeline programs that are administratively practical but perverse in their effects on equity and efficiency; or programs that have acceptable impacts on equity and efficiency but are administratively impractical--then, before implementing lifeline rates, regulatory authorities are well advised to consider seriously whether alternative assistance programs that can accomplish the same objective are preferable.

In considering the relative merits of alternative programs, regulatory authorities should keep in mind the following points. In all states there exists governmental machinery designed to implement and administer a wide variety of public assistance programs. These agencies have both the expertise and the necessary funding to obtain the information required to identify those families in need of assistance. These agencies could be

utilized to provide additional assistance through established programs to offset the detrimental impact on living standards that results specifically from rapidly rising electricity rates. The funding of such additional assistance would tend to come from general tax revenues and, therefore, the allocation of the costs of the additional subsidy is likely to have significantly fewer detrimental impacts on allocative efficiency and more acceptable distributional effects than any lifeline scheme that is administratively feasible. Moreover, by utilizing existing welfare programs, the determination of whether and how much additional subsidy would be paid to offset rising electricity prices would be a social judgment that would ultimately be made in the voting booth rather than in a quasi-judicial forum. And a strong case can be made that that is where such a decision should be made in a democratic society.

Summary. After considering all the arguments and the alternatives available for providing aid to those customers with legitimate need for assistance, we feel compelled to recommend against implementing lifeline rates. In large part, this negative recommendation is based on our conviction that rate design should be based on cost both for reasons of efficiency and equity. Customers should be caused to pay their fair share of system costs. If society concludes that paying their fair share will excessively burden some customers, and wishes to provide assistance to them to reduce that burden, all well and good. But the efficiency distortions and

the perverse distributional effects of easily administered lifeline programs more than offset any social gains that might result. And this trade-off is largely unnecessary when one considers that alternative and more efficient means are already available to accomplish the same social welfare objective.

V. Advantages and Disadvantages of Time-Varying Rates
in Comparison with Other Rate Forms

Time-of-use rates are rates in which the price for each kilowatt-hour of electric energy depends upon when it is used. There may be two or three (or conceivably more) different rate periods during each day, with different prices charged for the kilowatt-hours used in the different periods. The rate periods and prices on weekends may also be different from those on weekdays, and the entire structure may change from season to season.

Conventional electric rates do not have prices per kilowatt-hour that vary with the time of day, but they may incorporate some other time-varying features. The simplest form of conventional rate has charges that depend only upon the total kilowatt-hours of electricity used during a billing period, which is typically one month. This is a so-called "one-part" rate, and it is the rate form used almost everywhere for residential electric service. Another conventional rate form is the two-part rate, in which there is also a separately stated charge for each kilowatt (not kilowatt-hour) in the maximum demand imposed by the customer during any one hour in the billing period. Two-part rates are used generally for industrial and some commercial customers, where the quantity of service justifies the higher cost of metering the maximum demand. Finally, conventional rates often include a so-called customer charge, which is a fixed dollar

amount per month for each customer, independent of electricity usage. The customer charge is often counted as an additional part of the rate, so that a kilowatt-hour rate with a customer charge becomes a two-part rate; whereas a rate with energy (Kilowatt-hour), demand (Kilowatt), and customer charges becomes a three-part rate.

Another dimension of conventional electric utility rate structures, aside from the number of parts, is the way that the price per unit varies with the quantity of service taken by the customer. The most common rate form has been the declining block rate. With declining blocks, the price per Kwh of the first 200 Kilowatt-hours (or some other quantity) used in any one month is higher than the price per Kwh of the next 300 Kilowatt-hours, and so on down for still larger quantities of electricity usage. For two-part rates, which also include a separately stated demand charge, the price per Kw may also have declining blocks.

Other rate forms, which have received attention as alternatives to declining block rates, are flat rates and inverted rates. Flat rates are those in which the price per Kwh (or per Kw) is the same for all quantities of electricity usage. Inverted rates are rates in which the price per unit becomes higher, rather than lower, at higher levels of usage. Lifeline rates, in which there is a low price per Kwh for a basic quantity (perhaps 350 or 500 kilowatt-hours per month) of electricity viewed as an economic necessity, generally take

the form of inverted rates; but the inversion due to the low price for the lifeline quantity can also be combined with declining block prices for high levels of usage.

The classic argument for conventional declining block rates is that the additional cost of generating more energy to serve a customer with a higher load is less per Kwh than the average cost of running the entire system. Where this is the case, it is necessary for the utility to charge a price higher than the marginal additional cost for at least some of the service it provides, so as to recover its total costs. In these circumstances, it has generally been deemed desirable to charge a higher price for the first blocks, so as to be able to keep the prices in the succeeding blocks, at larger quantities of usage, as close as possible to the marginal cost of supplying electricity. The reason for this is the belief that a divergence between marginal costs and prices in the first blocks will have less of a distorting impact upon the consumption decisions of electricity consumers than a similar divergence in the blocks for higher usage, because most consumers will purchase small quantities of electricity as an economic necessity, even if the prices are high.

Another view of this argument is that conventional declining block rates were intended to promote additional electricity use. The promotional effect was achieved by setting the rates for the tail blocks, which apply to expanded usage, as low as possible, and by setting the rates in the first blocks sufficiently

high to recover the needed total revenue. This kind of promotional effect was deemed desirable for two reasons. First, it was believed that marginal costs were less than embedded average costs (and they were, in most of the 1950s and 1960s), so expanded use of electricity would bring the average cost down for all users. Second, it was also believed that higher usage levels were generally associated, at least among residential customers, with better load factors; and low tail block rates were thus viewed as a device to promote what is now called load management.*

The principal argument against declining block rates, especially in comparison with flat or inverted rates, is based upon the supposition of factual circumstances exactly the opposite of those in the preceding paragraphs, namely that the marginal cost of electricity exceeds the average cost. In this event, the same analytical reasoning would suggest that the price of electricity be kept as high as the marginal cost of supplying more of it, at least for consumption in the tail blocks, where users are believed likely to be most sensitive to prices in deciding how much electricity to buy. With marginal

*A customer's load factor is the ratio of that customer's average load to its maximum load. For example, a customer using 1,080 kilowatt-hours in a 30-day month has an average load of 1.5 kilowatts for each of the 720 hours in the month. If that customer's maximum load during any one hour of the month is 5,000 watts (or 5 kilowatts), the load factor is 1.5/5, or 30 percent. If low load factor loads are concentrated in the peak hours, as has generally been assumed in the past, then increases in the load factor are the result of increased off-peak usage, and thus they are improvements in the overall load pattern.

costs exceeding the embedded average cost, this is possible only if prices are reduced for the first blocks of the rate schedule, so that the utility recovers no more in total revenues than its embedded total cost of service.

This argument against declining block rates is used also by proponents of lifeline rates. They argue that conservation, not sales promotion, is the proper policy with regard to electricity use in the current economic situation of the United States, and that conservation can be achieved in part through inverted rates.

The preceding analysis indicates that the advantages and disadvantages of the three conventional rate forms--namely, declining block, flat, and inverted rates--relative to one another are dependent, to a great extent, upon the economic conditions in the electric utility industry, and specifically upon the relationship between the marginal cost and the embedded average cost of electricity supply. If the current marginal cost is less than the current average embedded cost, as it was in most of the 1950s and 1960s, then declining block rates are more conducive to economically efficient use of resources in electricity supply than are inverted rates. Conversely, if the marginal cost of electricity exceeds the embedded average cost, as it apparently does at present, then inverted rates are likely to be more conducive to efficient use of resources than are declining block rates. However, this entire analysis fails to express the variations in electricity supply costs

with time of use, and it ignores the possibility of time-varying rates. When these possibilities are considered, it becomes clear that time-varying rates possess some important advantages over all three of the conventional rate forms.

Consider, for example, the present economic situation. The goal of energy conservation applies to electricity along with other kinds of energy, and therefore it is desirable that electric rates be designed to promote conservation. At the same time, however, it is also desirable (as explained earlier in this report) to shift some electricity use from peak to off-peak periods, and this requires some promotion of off-peak use. Indeed, it may be desirable to expand off-peak electricity use even without any reduction in peak-period usage, if this expansion is due to the substitution of off-peak electricity use for direct burning of petroleum fuels, rather than to an expansion of total energy use. Thus, it is not so simple to conclude that electricity-pricing policy should be directed either toward conservation or toward sales promotion--instead a mixture of the two may be required.

Time-varying rates have the flexibility to be used in support of these multiple objectives. The overall rate level, and especially that for peak-period usage, can be set high enough to promote conservation while, at the same time, a suitable differential between peak and off-peak rates can be used to promote load management and even the off-peak use of electricity in place of petroleum fuels.

These advantages of time-varying electric rates are also related closely to the structure of electric utility costs. Since the marginal cost of expanding the supply of electricity is different at different times of the day and the year, it is actually loose usage to refer to "the" marginal cost of electricity. Instead, one may note that at present the marginal cost of increased off-peak usage is less than the embedded average cost of peak and off-peak usage combined, whereas the marginal cost of additional peak-period usage is probably greater than the embedded average cost of all present electricity supply. These cost relationships are one reason why it may be economically efficient to promote increased off-peak use of electricity at the same time that conservation is encouraged during peak periods.

Before proceeding to the disadvantages of time-of-use rates, it is important to note briefly that the preceding comparison between time-varying and conventional rates has implicitly referred only to one-part conventional rates, with energy (Kwh) charges only. If one considers two-part conventional rates, with demand charges as well as energy charges, one finds greater possibilities for time variation than with one-part rates, but still not the flexibility of time-of-use rate designs.

The introduction of a separately stated demand charge does incorporate some time differentiation into the rates for electricity service, because the customer is charged partly

on the basis of the largest quantity of power taken in any one hour, as well as for the total energy used in the entire billing period. This does make the total bill depend upon the load factor of the customer, and the customer obtains a lower rate--namely, the energy charge only--for increases in electricity use in any hour other than the one in which he makes his maximum demand for power. Two-part conventional rates thus do promote load management in the sense of encouraging each customer to increase his own load factor.

Despite these advantages in comparison to one-part conventional rates, with energy charges only, there are two respects in which two-part rates remain less adapted than time-of-use rates to the promotion of economic efficiency. First, the demand charge is based on the power used by the customer when the customer's own demand is highest, and this may not necessarily occur in the peak period for the electric utility supplying the power. The conventional two-part rate thus discourages customers from concentrating their demands in the off-peak hours, and instead it provides an incentive merely to level the demand throughout the day. Second, the energy charge is the same at all hours of the day, and thus it fails to reflect the time differences in energy costs. It therefore provides no incentive for a customer to manage his pattern of energy consumption, or to encourage off-peak use, except in the very restricted sense of minimizing the customer's own maximum one-hour demand.

Disadvantages and Uncertainties of Time-Varying Rates

Although the application of economic theory to the facts of the electric utility industry provides strong support for the principle of time-varying electric utility rates, there are also several extremely important disadvantages and uncertainties associated with them. The first and foremost of the disadvantages of time-of-use rates is that the metering costs of implementing them are very high. This is especially true for residential customers, where the metering costs may add several dollars to the monthly bill. Since this increase is a substantial fraction of the total cost of electricity supply, it may more than offset any improvements in economic efficiency that might result from the imposition of time-varying rates. For most nonresidential customers, metering costs are less of a drawback, because they are much smaller in relation to total cost; and many utilities already have installed time-recording meters on their largest customers on conventional rates. However, even for nonresidential customers, there remains some uncertainty whether the efficiency gains are worth the implementation costs on all systems.

This uncertainty about the magnitude of the effect of time-of-use rates on resource use in the electric utility industry is the crucial and as yet unresolved question concerning this innovation. The question is in two parts. First, it is not known how electricity users will respond to time-of-use rates. If the time patterns of electricity use do not change

substantially in response to time-of-use rates, then these price signals will have added little or nothing to economic efficiency.*

At present, the experience with time-varying rates is far too limited to support any firm assessment of their likely effect on the time pattern of electricity usage. The immediate problem is, ironically, one of time: until time-varying rates have been in effect long enough for electricity users to adjust their stock of electric appliances and other electricity using equipment to these rates, it will be possible only to guess what their long-term impact will be. More generally, the adjustment to time-varying rates involves changes in the capital goods industries, perhaps including the development of new products such as storage heating and storage cooling devices. The occurrence of all these changes will require not only a period of years, but also widespread experimentation with time-varying rates, so as to create a market for the new products required for further gains in electricity load management. Thus, it may turn out that we cannot determine whether it is worthwhile to implement time-varying rates until after implementation has already occurred, because that will be the only way

*It may be, for example, that promotional activities in the past, combined with other load management programs of the present, have already achieved essentially all the likely improvements in time patterns of electricity use; and that the inconveniences or other implementation costs of further shifts are sufficiently great to overcome the further economic incentive of time-varying rates.

to determine their actual long-term effect on the time patterns of electricity use.

The second part of the unresolved question about the impact of time-varying rates on resource use concerns the response of the electric utility industry to whatever changes may occur in the time patterns of electricity use. Although it is clear as a matter of theoretical principle that expansion of the off-peak supply of electricity must be less costly than expansion of the peak-period supply, the magnitude of the prospective savings is very uncertain. Indeed, when one takes into account all the uncertainties about future fuel prices and other unknowns, it is even conceivable that supply expansion intended for baseload use to meet growing off-peak demands may turn out to be more expensive than electricity from plants that would be built if load management were unsuccessful.

However, even if electricity supply planners are correct that plants fired by coal and nuclear fuel will turn out to be the least expensive way to generate electric energy, it is still uncertain how much of a savings will be derived from successful load management, such as would result if time-varying rates do affect the time patterns of electricity use. The reason is that supply expansion is already being directed toward baseload coal and nuclear plants, and the pace of this shift in the way electricity is generated may be determined more by restraints on the supply side--such as environmental problems with coal, or that and other obstacles to nuclear energy--than by the time

patterns of the demand for electricity. For example, some utilities in the northeastern part of the U.S. believe that the construction of nuclear plants can be justified economically merely by the savings in fuel cost that result from substituting nuclear fuel for oil, and without any consideration of the additional capacity that these new plants will provide. Similarly, some utilities in Texas find coal-fired plants economical merely for the natural gas they displace, and again without consideration of whether the additional capacity is needed. In these circumstances, changes in the time pattern of electricity use may not be needed as an impulse to changes in the supply pattern, since the supply is changing anyway, and as rapidly as is feasible.

Time-varying rates also have some possible disadvantages with respect to equity. Time variations in the rates make no sense unless they are related to the time variations in the costs of electricity supply, and thus tend to require each ratepayer to pay for the service he receives and to receive only what he pays for. However, not everyone agrees with this notion of economic equity. Other notions of equity are that electricity rate structures should be used to help obtain social goals, such as income redistribution; and the imposition of different equity objectives upon the rate structure design problem can lead to different results, as was demonstrated in the case of the lifeline rate proposals discussed in the preceding section.

Finally, time-varying rates suffer from the disadvantage of being novel. There is a streak of conservatism in many of us, including electric utility systems, regulatory agencies, and the consuming public that uses electricity. Some persons and organizations are frightened by any change that appears on its face to be a radical departure from the present pricing system, and that is how some persons and institutions view time-of-use pricing for electric utility service.

APPENDIX A

FULLY ALLOCATED COST-
OF-SERVICE STUDIES

A Report on Standard Methodology

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I. Executive Summary

Electric rates are established, in general, on a customer class cost-of-service basis. Most interested parties--utility representatives, intervenors, customers, and commissions--agree that cost-based rates are nondiscriminatory and fair. The controversy centers upon cost causation. Some costs are directly assignable; that is, they are easily attributable to a particular customer or group of customers. Other costs, called common or joint costs, cannot be directly assigned because causation is shared among more than one customer or group of customers. Costs that cannot be directly assigned must be allocated. Because cost allocations are intended to reflect cost causation, allocations are made on the basis of customer behaviors that are perceived to cause costs to be incurred by a utility. The problem of allocating joint costs is peculiar to all capital intensive industries. However, because regulated utilities are prohibited from charging discriminatory rates, cost allocations for electric and other utilities have long been a subject in regulatory proceedings.

The importance of selection among cost allocation methods is best illustrated by two points:

1. Since rates are determined by costs, costing methodologies are a form of income redistribution (as is any pricing methodology). In other words, the output of cost studies determines who shall pay. As utility

costs have increased faster than costs or prices in total, apportionment of cost responsibility has become increasingly important in regulatory proceedings.

2. In most electric utility rate proceedings, nearly all of the total cost to serve is allocated for the purpose of making rates. Only a small portion of the revenue requirement can be directly assigned. Because so much of the revenue requirement must be allocated, customer cost-of-service and rate discrimination considerations are frequently a major issue in rate proceedings.

Costing methods can be characterized in several ways. This appendix addresses what is referred to as fully allocated costing or fully distributed costing. Marginal costing is addressed in Appendix B. Fully allocated costing focuses on embedded or historical costs, and it is implicitly assumed that, although new (and currently more expensive) facilities may be built for a particular set of customers, all customers share equally an average cost per unit of service (kilowatts or kilowatt-hours).

Cost allocations are a pricing tool; their purpose is to match particular costs of serving customers with the behavior that causes those costs to be incurred in order that pricing is reflective of costs. Such an objective requires that several questions be answered. The primary question relates to determination of behaviors or variables believed to cause costs. The

most typical taxonomy is the customer/energy/demand system of classifying cost-causing variables. Customer costs are those which vary with the number of customers; they include the costs of metering and billing, as well as some distribution costs. Energy costs are fuel and fuel-related costs; these are the costs that vary with the number of kilowatt-hours produced or sold. Demand or capacity costs vary with kilowatt demand and consist of plant related costs such as depreciation, return and property taxes. Demand costs vary with the size of plant required to meet instantaneous demand requirements. Other critical questions include customer class membership criteria, measurement and data quality, and review of the implicit assumptions about customer use and demand behavior made in the course of performing customer class cost studies.

This appendix consists of a description and discussion of the component parts of performing a fully allocated customer class cost-of-service study; an analysis of the alternative methods typically used; and a case study illustrating the flow of activities and details of the computations. Data, workpapers and other details have been included as attachments. A flowchart of the sequence of activities performed in an allocated cost study is shown in Attachment A-1. In addition, definitions of commonly used terms are provided in Attachment A-2. Newport Electric Corporation data for 1976 were used in the case study. Inasmuch as the Company has never conducted a class cost-of-service study, estimated billing determinants for calendar 1976 were used.

II. Customer Classification

The ideal way to price electricity is to charge each customer according to the cost of serving that particular customer. This is almost possible if all customers are metered for both energy use and time-of-day demand, and if component prices are determined according to marginal costs. Traditionally, the approach to setting rates has been to spread historical costs among customers by allocating the costs according to characteristic use and demand behavior of particular customers or classes of customers. As a result, the probability of rate discrimination depends upon the manner by which customers are sorted into classes. Inasmuch as allocations are approximate (because of the lack of sophisticated metering devices), and because of the complexity and cost of treating each customer individually, customers usually are grouped for costing purposes. Cost allocations are then made according to the total or average of the group characteristics, so that customers who are quite different from other members of their class are not likely to be matched with their specific cost of service. The trade-off is between the cost of increased accuracy and the benefits of increased accuracy. Increasing homogeneity within the customer classes increases costs of conducting the study because a larger number of groups and more detailed data are required; but greater homogeneity within the classes also improves the accuracy of the results. On the other hand, decreasing the number of customer classes and reducing

data requirements simplifies and reduces the expense of the costing process, but the result is to increase within-class heterogeneity. Since heterogeneity means that more members of the class are quite different from the average, some rate discrimination is unavoidable.

Another critical aspect of customer classification is selection of the criteria by which customers are grouped. Since the different costs of service can be characterized as varying with energy consumption, instantaneous demand for power, and the number of customers, customer grouping should be done in a manner that maximizes, at a reasonable expense, intraclass homogeneity with respect to these variables. Cost, complexity and data availability should be weighed in determining the optimal customer classification strategy.

The easiest way to classify customers is according to their end use of electricity. The usual approach to classifying customers depends on who they are (residents, commercial operations, etc.). The implicit assumption is that the way customers use electricity affects the costs of providing electricity. This assumption may not be valid. For example, consider the following customer characteristics:

	<u>Load Factor 0 to .30</u>	<u>Load Factor .31 to .65</u>	<u>Load Factor .66 to 1.00</u>	<u>Total</u>
Residential	20%	44%	16%	80%
Commercial	6	3	1	10
Industrial	2	1	2	5
Other	2	2	1	5
Total	<u>30%</u>	<u>50%</u>	<u>20%</u>	<u>100%</u>

Usually, customer classification for purposes of cost-of-service analysis and rate determination tends to follow the "who are they" grouping shown in the first column (residential, etc.), rather than the "how do they use plant capacity and output" grouping shown in the load factor classification across the top. If the two groupings produce different results and costs vary by use of capacity and output rather than by end use, the cost allocations established on the basis of end use will be incorrect. Consequently, any one customer (or subgroup of customers) may be subsidizing or be subsidized as the result of a very precise cost study based on an inappropriate customer taxonomy. Although most practitioners recognize this problem, it is a difficulty more often mentioned than solved. Of course, end use may well approximate customer cost causation, and improvements may be more costly than they are worth.

Another difficulty with classifying customers is the scarcity of accurate data about their use and demand characteristics. The measurement problems that appear at the beginning stages of a customer class allocation study are present at all stages. As a result, the conclusions reached by the study will always be an approximation of customer cost responsibility. This flaw tends to be overlooked, and a high degree of precision may be imputed to results flowing from judgmentally established data, which may or may not reflect actual conditions. For example, many costs vary with Kw demand, yet the majority of customers (most or all residential, many commercial, etc.) are not metered for

demand. Demand data measurements for customers whose demands are not metered are judgmentally determined, generally through a combination of deduction (e.g., metered customers account for 47 percent of peak demand, therefore nonmetered customers must account for 53 percent), and often improperly used statistical inference techniques (e.g., 10 percent of residential customers were found to have 31 percent load factors during August of 1972; therefore, all residential customers have 31 percent load factors today). The primary reason for poor or absent data is the high cost of measurement. However, two trends--increasing electric utility plant costs and rates, and cheaper metering technologies--have affected the historical cost/benefit relationship associated with demand measurement.

In general terms, more accurate measurement is warranted if the benefits of reduced uncertainty exceed the costs of obtaining the data. There are statistical methods available that, if properly applied, can produce significantly greater accuracy at relatively moderate increases in costs. But the key is proper use of statistical tools rather than the use of statistics in general. The improper use of statistics or the use of the wrong statistics merely complicates the situation, inasmuch as the presence of complicated quantitative manipulation gives an unwarranted appearance of precision.

III. Cost Classification

A fully distributed cost study generally follows three procedural steps:

1. Identification and segregation of costs and rate base items directly attributable to any particular class of service;
2. Classification of the remaining costs and rate base items so that they can be allocated to the various groups of customers jointly responsible for the cost incurrence; and
3. Allocation of the joint costs consistent with measurable attributes (demand, energy consumption, and the number of customers) of the class of service.

The third step is discussed in Section IV. This section addresses the first two steps. The first step is one of direct assignment and consists of matching the cost of dedicated facilities with the class served by the facilities. The second step is one of classifying or arranging costs into groups that can be traced to measurable characteristics which cause costs to be incurred by the utility (demand usage, energy consumption, and number of customers). In other words, classification refers to categorizing costs as demand, energy or customer related.

All costs included in the revenue requirement as well as rate base items can be classified, either directly or indirectly, according to these four categories (direct, demand, energy,

customer). The classification is done according to a causality standard: the category to which each cost is assigned is determined by the service associated with the cost.

Directly assignable costs are those that are identified with providing service to a single customer or customer group. For example, a transmission line might be built to serve a single large customer. In that event, the rate base amount of the line and the expenses directly attributable to operating, maintaining and meeting capital costs associated with the rate base investment are assigned directly to the customer or group served by the line. Other costs are not assigned to particular groups for the same reasons. For example, customers taking power at high voltage require no distribution facilities and thus are not assigned any of the distribution system costs.

Demand-related costs are those costs and rate base items associated with providing the capacity to supply kilowatts. Most capacity costs, which are generally fixed in the short run, are demand-related costs. Exceptions include plant intended to supply energy rather than peak demand requirements, such as run-of-river hydro plant or excess capacity resulting from fuel conversion construction programs. All costs associated with meeting peak demand requirements are demand-related costs. These include annual peak requirements as well as other peaks that affect maintenance scheduling.

Energy-related costs are those costs that vary with the number of kilowatt-hours generated or sold. The largest energy related cost is fuel expense.

Customer-related costs are those that vary with the number of customers served. Examples include costs associated with meters and service drops, billing and uncollectible accounts. Distribution and services accounts contain costs that are both customer and demand related. The usual practice for separating these components is to identify the customer component and allocate the remainder according to demand characteristics. There are two commonly used methods for identifying the customer component of the accounts: minimum intercept and minimum size. The minimum-intercept method is less dependent upon judgment, but requires more data and calculations than does the minimum-size method. Minimum-intercept methods attempt to define the plant and expenses by extrapolating the pole, service, etc., sizes that would exist at zero load. Minimum-size approaches rely upon determinations of the minimum size pole, service, etc., currently being installed. In both cases, the minimum size facility is costed at the average embedded cost (installed) of that size pole or service (or conductor, cable, line transformer), and that cost is multiplied by the total number of units (including all sizes) currently in service.

Since different voltage level lines are likely to have different minimum requirements, distribution line costs are usually separated into primary and secondary. In addition, distribution lines and services are generally separated according to whether they are overhead or underground because of the cost difference.

For some accounts, the entire amount can be classified according to demand, energy, or customer. For example, rate base account #310 (steam production) is a demand-related cost. Account #501 (steam power--fuel) is an energy-related cost, and account #586 (meter expenses) is a customer-related cost. Other accounts may contain expenses or investment common to two or all three of the categories. For example, account #502 (steam expenses) contains expenses that are related both to demand and energy. The criterion used to apportion the account balance between the two classifications is the extent to which the costs are independent of Kwh output. If the costs are incurred whether kilowatt-hours are produced or not, they are demand related. The portion of costs that vary with the number of Kwh produced are considered energy related.

Other accounts are classified indirectly by prorating them according to payroll or other expenses. For example, some portion of most operation and maintenance accounts are wage and salary costs. Supervision and engineering is split between demand and energy in the same ratio as are total payroll costs within the steam power generation operation group (accounts #500-507).

Another approach to prorating costs depends upon the split between labor and material expenses. For example, account #502 (steam power generation operation--steam expenses) is usually prorated by this criterion. Labor costs are classified as demand related whereas materials are considered energy related. Other prorations are done on the basis of billing. Purchased power

costs are billed typically according to their demand and energy components and are classified according to the billings received by the utility.

A list of the rate base and expense accounts are shown in Attachment A-3 according to the usual allocation to demand, energy, customer components or the typical prorated allocation basis.

IV. Cost Allocation Methods

For each of the cost classifications--demand related, energy related and customer related--costs are spread among customer classes according to the historical characteristics (Kw demand, Kwh consumption and number of customers) of each class.

Energy-related costs are allocated on the basis of kilowatt-hours generated or sold, depending on which best fits the cost. For example, account #153 (steam power generation operation maintenance--electric plant) consists of energy-related costs at the point of generation and thus is most appropriately allocated to customer classes on the basis of Kwh generated. Since kilowatt-hours are typically measured at the point of delivery, line loss must be factored in according to voltage and distance. The allocation factors for energy related costs, including adjustments for line losses, are calculated as follows:

	<u>Kwh Sales at Meter</u>	<u>Line Loss</u>	<u>Kwh Generated</u>	<u>Allocation Factor</u>
Class A	100 Kwh	.05	105 Kwh	16.25%
Class B	400	.01	404	62.54%
Class C	<u>125</u>	<u>.09</u>	<u>137</u>	<u>21.21%</u>
Total	625 Kwh	.03	646 Kwh	100.00%

As shown by the computations, the allocation factor is the proportional contribution to the total kilowatt-hours generated.

Demand related costs are allocated according to the relative demands customer classes make upon available capacity at critical points in time. There are three general philosophies about cost responsibility for plant capacity and demand-related expenses:

1. The level and composition of capacity are designed to meet peak requirements, and thus contribution to system peak is the appropriate cost allocation method.
2. The plant is designed to meet the peak requirements of each class, and thus costs should be allocated according to maximum noncoincident class demands (diversity benefits are allocated without regard to class coincident load factor, as discussed below).
3. A high class coincident load factor indicates a high probability of a class being on line at the time of the system peak, and thus generating a smaller amount of diversity benefits; so diversity benefits should be credited to low load factor customers.

The contribution to system peak method is appealing at first glance. However, it is based upon a single observation and may not provide an accurate model of future demand behavior. Using the average of 12 monthly peaks improves the likelihood that the model accurately apportions costs, and averaging reflects the dependence of maintenance planning and power supply system operations upon monthly peak levels.

Maximum noncoincident class peak demand allocation ignores demand at the system peak and thus apportions the diversity benefits without regard to class contributions to the system peak load. In other words, noncoincident methods credit all customers with a share of diversity benefits, without recognizing the unit cost reduction to the system as a result of off-peak use.

A third approach to demand-related cost allocation is separation of maximum and average demand elements, also called the load factor excess demand method. Allocation by average demand is equivalent to energy allocation (since average demand is Kwh consumption divided by the number of hours in the period measured). One commonly used version is the average and excess method, which works as follows:

1. Total demand-related costs are multiplied by the system load factor;
2. The portion obtained is allocated according to average demand; and
3. The remaining demand-related costs are allocated according to group excess demands (the difference between group maximum and group average demand).

Often, system excess demand for each group will be used instead of group excess demand.

As was true of the energy allocations, line losses must be considered if metered data are used.

On the basis of data provided by Newport Electric Corporation, the results of the different demand cost allocation methods are as follows:

	<u>Coincident Peak</u>	<u>Noncoincident Peak</u>	<u>Average and Excess</u>
Residential	45.44%	45.46%	44.71%
Commercial	21.44	21.81	21.66
Industrial	30.74	30.75	31.73
Streetlighting	2.38	1.98	1.90
Total Demand Costs	<u>100.00%</u>	<u>100.00%</u>	<u>100.00%</u>

System load factor = 59.08%

The computations behind these results are described in Section VI below. In addition, more detailed computations are shown in Attachment A-5.

Customer-related costs are allocated according to the number of customers in each customer class. For some customer costs, it is necessary to weight the customer proportions in order to take into account the known differences in costs per customer. The investment in metering equipment is likely to vary by type of customer; high-voltage customers require more sophisticated and more costly metering equipment and thus should bear a greater share of the cost than their proportional contribution to total customers would indicate. Another appropriate situation for using customer weights is in the case that there are extreme density differences between customer subgroups, and there are too many customers to permit direct assignments. For example, if the residential class consists of both urban and rural customers, and customers per square mile averages are quite different, the line cost allocation to rural customers can be increased to reflect cost differences by means of weights related to density differences.

V. Data Requirements

Although customer class cost allocation considerations are most visible during rate proceedings; data collection, load studies and pricing analyses need to be done continually. This is necessary in order to improve the accuracy of the studies under static conditions, as well as to identify changes in class energy use and demand characteristics as they occur. If the on-going research and analysis is done, better evidence can be presented in the rate proceeding context. For this reason, it is advisable to collect data regularly and continually to make certain the data that are collected are useful for determining customer class costs. Staffing constraints may preclude such on-going data collection and analysis efforts. However, requiring utilities to file usage, load and customer data at the time a rate change application is filed permits independent evaluations to be made.

A standard cost allocation data reporting form is included as Attachment A-4. Changes may be necessary to adapt to the level of data collection sophistication of the various jurisdictional utilities. The data reporting form should be a required filing accompanying any rate application request. Since some of the data elements are critical whereas others are expendable in light of cost/benefit considerations, the data elements and their interrelationships are discussed in greater detail below.

In addition to the information required on the standard form, a copy of the FERC Form 1 should be filed. Data from the Form 1 can be used to approximate the proper cost allocations in the event that more detailed data are unavailable, if the test year is a calendar year, and if the rate classes are those used in the Form 1.

VI. Case Study: Newport Electric Corporation

On the basis of data taken from Newport Electric Corporation's FERC Form 1 for the year ended December 31, 1976, and preliminary data on billing determinants provided by Newport's consultants, an illustrative fully allocated cost study was conducted. For the purpose of illustrating the different demand allocation methodologies, three demand allocations were used. The revenue requirement was set at \$15,142,000. This revenue requirement was determined by the Commission in Docket No. 1268.

In Sections III and IV of this appendix, three procedural steps for classifying costs were described. These three steps were followed in performing the allocated cost study for Newport Electric Corporation. The results are summarized on Table VI-1. The demand allocation method used for purposes of this summary is the average and excess method, and the customer classification provided by the Company's consultants was followed.

The first step was the determination of costs that were incurred in order to serve a single customer or group of customers. Pages 417 to 420 of the Form 1 list expenses for the year, by FERC account. Accounts 585 (Streetlighting and Signal System Expenses) and 596 (Maintenance of Streetlighting and Signal Systems) were assigned to the streetlighting rate class. No other direct assignments were made. The direct assignments amounted to \$52,000. A proportional allocation of the \$609,000 rate increase brought the assignment up to \$54,000.

Allocated Cost of Service Results

	<u>Demand-Related Costs</u>		<u>Energy Costs</u>	<u>Customer Costs</u>	<u>Special Assignments</u>	<u>Total</u>
	<u>Power Production and Transmission</u>	<u>Distribution</u>				
Residential	\$ 816,917	\$1,074,060	\$ 4,267,714	\$ 843,065	-	\$ 7,001,950
Commercial	395,698	515,354	2,155,391	177,734	-	3,244,177
Large power-- transmission	338,991	-0-	2,255,880	213	-	2,595,084
Large power-- distribution	240,745	307,735	1,419,154	4,039	-	1,971,673
Street & other lighting	<u>34,649</u>	<u>46,851</u>	<u>155,861</u>	<u>37,949</u>	<u>\$54,000</u>	<u>329,116</u>
Total	\$1,827,000	\$1,944,000	\$10,254,000	\$1,063,000	\$54,000	\$15,142,000

Classification or functionalization of the remaining costs and rate base items according to detailed information about the account contents would normally be done in the course of a fully allocated cost-of-service study.

As we indicated in the introduction to this appendix, Newport Electric Corporation has never conducted a class cost-of-service study. The Company is currently in the process of developing such a study, but it will not be completed until well after this report must be submitted. Consequently, a simplified example of the functionalization of total system costs for the Newport Electric Corporation is presented in Table VI-2. This schedule relates to 1976 and it is developed using only data on costs actually incurred, as reported to the Federal Energy Regulatory Commission in FERC Form No. 1. The table is in four pages. The first page is a summary of the functionalization of the Newport Electric Corporation total cost of service, and the details are presented on the three following pages. On each page, the first column shows the total cost recorded on the books of the Company for a single cost account or group of accounts. The remaining columns show the way that this total system cost is distributed among the functional activities.

Page 1 of Table VI-2 is a summary of the total cost of service and its distribution to the functional categories. Line 1 shows net electric plant in service. It is used, in lieu of rate base, as the basis for allocating operating income and most taxes among the functional categories. Details on the function-

Newport Electric Corporation

Functionalization of Total System Costs, 1976
(per Books of Account, in Thousands of Dollars)

	<u>Total, All Functions</u>	<u>Power Production Demand</u>	<u>Energy</u>	<u>Trans- mission</u>	<u>Distri- bution</u>	<u>Customer Costs</u>
1. Net electric plant in service	15,595	1,397	--	5,458	7,307	1,433
2. Electric operating revenue	14,533					
<u>Operating Expenses</u>						
3. Operation and maintenance	11,550	404	9,435	212	745	754
4. Depreciation	659	185	--	141	278	55
5. Taxes other than gross receipts tax	677	71	8	204	321	73
6. Gross receipts tax	<u>590</u>					
7. Total operating expenses	13,476					
8. Total, excluding gross receipts tax	12,886	660	9,443	557	1,344	882
9. Operating income <u>a/</u>	<u>1,057</u>	<u>94</u>	<u>--</u>	<u>370</u>	<u>496</u>	<u>97</u>
10. Cost of service, excluding gross receipts tax	13,943	754	9,443	927	1,840	979
11. Allocation of gross receipts tax <u>b/</u>	<u>590</u>	<u>32</u>	<u>399</u>	<u>40</u>	<u>78</u>	<u>41</u>
12. Total cost of service	14,533	786	9,842	967	1,918	1,020
13. Increase in total cost of service <u>c/</u>	609	33	412	41	80	43
14. Pro forma total cost of service	15,142	819	10,254	1,008	1,998 <u>d/</u>	1,063

a/ Allocated in proportion to line 1.

b/ Allocated in proportion to line 10.

c/ Allocated in proportion to line 12.

d/ Special assignments of \$54,000 were subtracted from this total.

Table VI-2
Page 1 of 4

Newport Electric Corporation
 Functionalization of Plant, 1976
 (per Books of Account, in Thousands of Dollars)

	<u>Total</u>	<u>Power Production</u>		<u>Trans-</u>	<u>Distri-</u>	<u>Customer</u>
		<u>Demand</u>	<u>Energy</u>	<u>mission</u>	<u>bution</u>	<u>Costs</u>
1. Production plant (FERC accounts 301-346)	2,732	2,732				
2. Transmission plant (FERC accounts 350-359)	5,603			5,603		
3. Distribution plant (FERC accounts 360-368, 372-373 to distribution function; accounts 369-371 to customer costs)	10,542				8,812	1,730
4. Subtotal	18,877	2,732	--	5,603	8,812	1,730
5. Other plant in service (allocated according to line 4)	<u>2,264</u>	<u>328</u>		<u>673</u>	<u>1,057</u>	<u>206</u>
6. Total electric plant in service	21,141	3,060	--	6,276	9,869	1,936
7. Accumulated provision for depreciation a/	<u>5,546</u>	<u>1,663</u>		<u>818</u>	<u>2,562</u>	<u>503</u>
8. Net electric plant in service	15,595	1,397	--	5,458	7,307	1,433

a/ Accumulated provision for depreciation of distribution plant functionalized according to distribution plant above. Depreciation of general plant distributed proportionally among other categories.

Table VI-2
Page 2 of 4

Newport Electric Corporation

Functionalization of Operation and Maintenance Expenses
and Depreciation, 1976
(per Books of Account, in Thousands of Dollars)

	<u>Total</u>	<u>Power Production</u>		<u>Trans-</u>	<u>Distri-</u>	<u>Customer</u>
		<u>Demand</u>	<u>Energy</u>	<u>mission</u>	<u>bution</u>	<u>Costs</u>
<u>Operation and Maintenance Expenses</u>						
1. Power production a/ (FERC accounts 500-557)	9,262	335	8,927			
2. Transmission (FERC accounts 560-573)	175			175		
3. Distribution (FERC accounts 580-585, 588-596, 598 to distribution function; 586, 587, 597 to customer costs)	811				554	257
4. Customer accounts (FERC accounts 901-910)	399					399
5. Employee pensions and benefits (FERC account 926, distributed in proportion to salaries and wages)	306	48	21	26	152	59
6. Subtotal	10,953	383	8,948	201	706	715
7. Other O&M expenses (allocated according to line 6)	597	21	487	11	39	39
8. Total operation and maintenance expenses	11,550	404	9,435	212	745	754
<u>Depreciation Expense</u>						
9. Depreciation b/ (Functionalizations as reported in FERC Form No. 1, p. 429)	659	185	--	141	278	55

a/ Energy component is fuel and purchased power; rest is demand component.
b/ Depreciation charged to distribution functionalized in proportion to to distribution plant.

Table VI-2
Page 3 of 4

Newport Electric Corporation

Functionalization of Taxes
and Development of Allocation Factor, 1976
(per Books of Account, in Thousands of Dollars)

	<u>Total</u>	<u>Power Production</u> <u>Demand</u>	<u>Energy</u>	<u>Trans-</u> <u>mission</u>	<u>Distri-</u> <u>bution</u>	<u>Customer</u> <u>Costs</u>
<u>Taxes</u>						
1. Employment-related <u>a/</u>	109	17	8	9	54	21
2. Property taxes <u>b/</u>	500	44	--	175	235	46
3. Gross receipts tax	590					
4. Federal income tax <u>b/c/</u>	<u>68</u>	<u>10</u>	<u>--</u>	<u>20</u>	<u>32</u>	<u>6</u>
5. Subtotal, all taxes except gross receipts	677	71	8	204	321	73
6. Gross receipts tax	<u>590</u>					
7. Total taxes	1,267					
<u>Allocation factor</u>						
8. Salaries and wages (excluding <u>d/</u> those charged to construction)	1,593	251	108	134	794	306

a/ Functional allocation in proportion to salaries and wages.

b/ Functional allocation in proportion to net electric plant in service.

c/ Including provision for deferred income taxes and investment tax credit.

d/ Salaries and wages in power production allocated 70% to demand and 30% to energy.

Source: Totals for lines 1, 2 and 3 taken from FERC Form No. 1, p. 222. Total for line 4 from Statement C of FERC Form No. 1.

Table VI-2
Page 4 of 4

alization of net electric plant in service are presented on page 2 of the table. Continuing on page 1, electric operating revenue is shown in the first column as a control total for the total cost of service, but no attempt is made to distribute it among the functional activities. The remainder of page 1 shows the cumulation of the functionalized operating expenses and operating income, to develop a functionalization of the costs (including return on invested capital) that exhaust operating revenues. The functionalization of operation and maintenance expense (line 3 on page 1) is shown in detail on page 3 of Table VI-2. The functionalization of depreciation (line 4) is also on page 3; and the functionalization of taxes (line 5) is on page 4. Line 8 is the subtotal of lines 3 through 5; and operating income distributed among functions in proportion to net electric plant in service, is added at line 9. This gives the functional distribution of the total cost of service, excluding the gross receipts tax, in line 10. Since the gross receipts tax is a tax on revenues, it is now allocated (in line 11) among the functions in accord with the total cost of service in line 10. When it has been added, the grand total for the cost of service for actual 1976 is shown in line 12. Note that except for the minuscule variation due to independent rounding, this procedure results in a functionalization of the cost of service that exactly matches the actual electric operating revenues, as reported at line 2. To adjust total cost of service to the revenue requirement allowed by the Commission for pro forma 1976, the revenue

increase is allocated in line 13 according to the cost of service shown in line 12. The pro forma total cost of service is then shown in line 14.

The assignment of electric plant in service to the various functional categories is shown on page 2 of Table VI-2. This assignment is based in a simple and straightforward way upon the plant account balances reported at pages 401-403 of FERC Form No. 1. Total power production plant (FERC accounts 301-346) is assigned entirely to the power production demand function; and total transmission plant (FERC accounts 350-359) is assigned entirely to the transmission function. Distribution plant (FERC accounts 360-373) is divided between the distribution and customer cost functions, with accounts 369-371 (representing service drops and meters) assigned to customer costs, and the rest to distribution. The FERC also requires that the balances of accumulated provision for depreciation be reported to it at page 408 of Form No. 1, and these amounts are also shown in page 2 of Table VI-2. The detail by functional category is shown in the table as reported to the FERC, except that the depreciation balance for distribution plant is distributed between distribution and customer cost categories in the same proportions that the plant balance (line 3 of page 2) is distributed. Net electric plant in service, obtained by subtracting the depreciation balance from the total (gross) electric plant in service, is then shown at the bottom of page 2 and transcribed to page 1, line 1.

The distribution of operation and maintenance expenses among the functional categories is handled much the same way as that for electric plant in service, and it is shown on page 3. Fuel and purchased power expense (accounts 501, 518, 547, and 555) are assigned to energy; and the remaining power production expenses (accounts 500-557) are assigned to power production demand. Transmission expenses (FERC accounts 460-573) are assigned to the transmission function, and distribution expenses are divided between the distribution and customer cost functions. Accounts 586, 587, and 597, which represent the operation and maintenance expenses for meters and customer installations, are assigned to customer costs; and the remainder of accounts 580-598 are assigned to the distribution function. Customer accounts expenses (FERC accounts 901-910) are assigned in their entirety to the customer cost function. Employee pensions and benefits, which are reported in FERC account 926, are distributed among the functional cost categories in proportion to total salaries and wages, for which an allocation factor is developed on page 4. All other operation and maintenance expense is distributed among the functional categories in proportion to the O&M subtotal in line 6. The total operation and maintenance expense, with detail by functional categories, is recorded in line 8 of page 3 and transcribed to line 3 of page 1 of Table VI-2.

The functionalization for depreciation expense, as recorded at line 9 of page 3 and also at line 4 of page 1 of Table VI-2, is that reported to the FERC on page 429 of Form No. 1. The

amount reported for depreciation expense on distribution plant is divided between the distribution and customer cost functions in the proportions that distribution plant (page 2, line 3 of Table VI-2) is so divided.

The distribution of taxes among the functional cost categories is shown on page 4 of Table VI-2. Electric utility taxes fall into four major categories: those related to employment, such as employer social security and unemployment insurance taxes; property taxes; income taxes; and gross receipts taxes. The first is distributed functionally in proportion to wage and salary expense, while the second and third categories are distributed in proportion to net plant in service. Plant is clearly the proper basis for distributing property taxes, and it is used in lieu of the rate base for distributing income taxes, which are related to the return requirements and thus to the rate base. Gross receipts tax revenues are segregated from the other tax items on page 4, and carried forward directly to page 1 without distribution among functional categories. This is necessary, because the gross receipts tax is properly distributed in proportion to the total revenue requirements for each function, exclusive of this tax; and these functional revenue requirements are obtained only on page 1, when the operating expenses and return requirements are combined, as has been described.

Finally, the last line on page 4 is the allocation factor for salaries and wages, as taken from pages 355-356 of Form No. 1.

After the classification was completed, all of the costs not directly assigned were allocated to the customer classes jointly responsible for causing them. Each of three demand allocations (coincident peak, noncoincident peak, and average and excess) were followed. In each case, demand allocations were made to all rate classes for the demand portion of power production and transmission expenses. The billing determinant data and computations are shown in Attachment A-5.

The first section of Attachment A-5 shows the billing determinant data that were used in allocating the joint costs to the various customer classes. Item No. 1 lists average weighted customers for 1976. In the absence of complete data on customer costs by class, weighted average customers were computed by assigning a weight of 1.0 to residential customers; 2.0 to secondary nonresidential customers; and 3.0 to large streetlighting customers and large power customers served at primary distribution.

Item 2 lists megawatt-hour sales at generation during calendar 1976. These sales have been adjusted for line loss; the Company had no data for line loss by customer class, so that each class was adjusted according to the voltage level at which power is taken. For customers who take power at transmission voltages, the energy line loss factor was assumed to be .96. For customers who take power at distribution voltage, the energy line loss factor was .91. The third item is the class contribution to system peak demand. For each of the customer classes,

the kilowatt demand shown is the kilowatt demand by that class at the time of the system peak. The Company's own use demand of 412 kilowatts is not shown in item 3; this amount is dropped for purposes of allocation, which has the effect of spreading Company demand over each of the classes in proportion to their contributions to system peak. Class noncoincident peak demands are shown in item 4. Class noncoincident peak demand is the maximum demand exerted by the class as a whole during 1976, rather than the demand at the time of system peak.

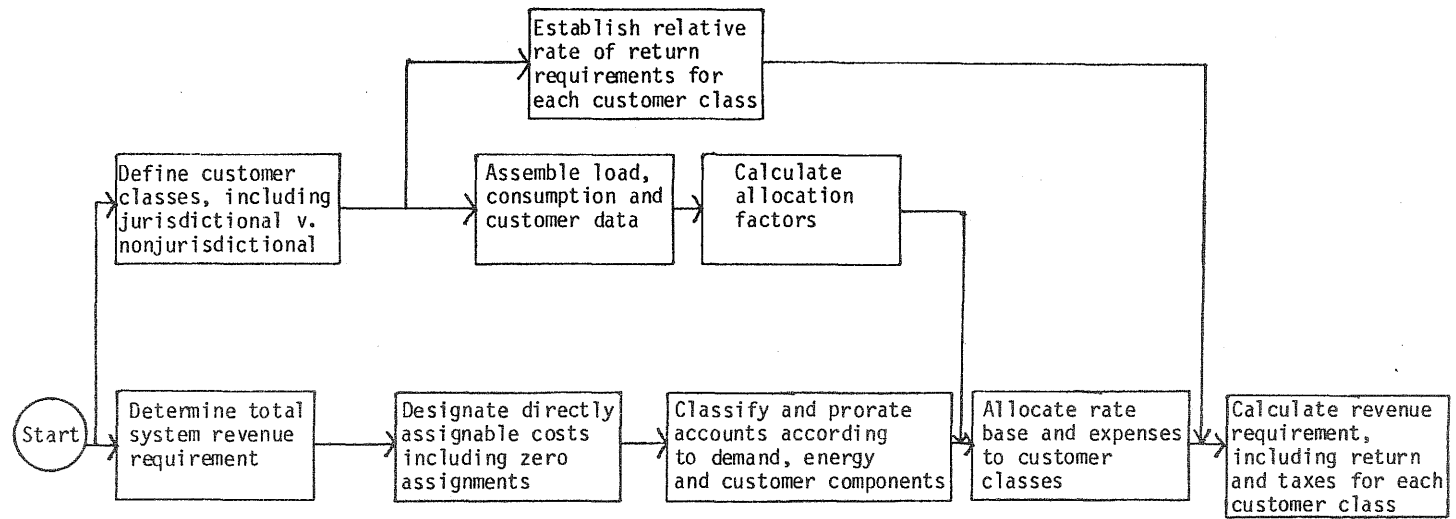
The second section of Attachment A-5 shows the allocation computations. The first item is the allocation of customer costs. In each case, weighted customers were restated in terms of their percentage contribution to total customers; for example, the 21,007 residential customers were 79.31 percent of the 26,488 total customers. The amount of cost to be allocated, \$1,063,000, was taken from line 14 of the last column on page 1 of Table VI-2. The allocation was a simple proportional one; the residential customer cost allocation of \$843,065 is 79.31 percent of the \$1,063,000 total. The second item, allocation of energy costs, was done in precisely the same way. Megawatt-hour sales were restated in terms of the contribution to total, and the allocated cost of \$10,254,000, also taken from page 1 of Table VI-2, was spread according to the percentage contribution. Item 3 shows the allocation of distribution costs. Distribution costs were allocated on the basis of noncoincident peak demand. The rationale for this approach is that distribution capacity is limited

and is used differently by different customer classes. For this reason, each customer class's own peak demand is the best statement of the maximum demand for distribution facilities. In this allocation, each class noncoincident peak was expressed as a percentage of the sum of the noncoincident peaks of all classes, and the \$1,944,000 total distribution cost was allocated according to these percentage contributions. The total distribution cost to be allocated was taken from line 14 of page 1 of Table VI-2. The difference between the figure shown on Table VI-2 and the distribution cost allocated is the \$54,000 special assignment to the streetlighting class.

The remaining costs, demand-related power production and transmission costs, were allocated according to the three demand allocation alternatives discussed previously. These are shown in items 4, 5, and 6 of the second part of Attachment A-5. Item 4 shows the allocation on the basis of contribution to system peak. Once again, a simple proportional allocation was done. The total cost to be allocated, \$1,827,000, is the sum of two figures from page 1 of Table VI-2. Line 14 of that table shows \$819,000 of demand-related power production costs and \$1,008,000 of transmission costs. These two were combined for purposes of allocation. Item 5 shows the same \$1,827,000 allocated on the basis of class noncoincident peak. The average and excess method is shown in Item 6. The total cost to be allocated, \$1,827,000, was split according to the system load factor between average and excess demand portion. The Newport Electric Corporation

system load factor for 1976 was 59.08 percent. Therefore, 59.08 percent of the total \$1,827,000, or \$1,079,392, was allocated on the basis of average demand. The remaining \$747,608 was allocated according to excess demand. For the average demand allocation, average demands for each of the classes were calculated by dividing kilowatt-hours at generation by the number of hours during the year (8,760). Average demands were then expressed in terms of contribution to total, and the \$1,079,392 portion of the demand costs was allocated on these percentage contributions. For the excess demand allocation, excess demands for each customer class were computed by taking the difference between the class noncoincident peak demand and the average demand. The excess demands were then expressed in terms of percentage contribution, and the \$747,608 portion was allocated according to these percentage contributions.

The results of the cost allocation are summarized on Table VI-1. In this summary, the average and excess allocation method was used to allocate power and transmission costs.



Attachment A-1

Summary Flowchart of Cost Allocation Activities

Attachment A-2

Definition of Terms

There are several important terms that make up the language of cost allocation and load research activities. Since expert witnesses use these terms, and since their meaning is important to the cost allocation methods discussed in this report, some of the more significant ones are included here.

Coincident Peak Demand: (Also called group coincident maximum demand.) The coincident peak is the largest Kw demand at a point in time for a group of customers together.

Noncoincident Peak Demand: (Also called group noncoincident maximum demands.) This is the sum of each customer's peak demand for all the customers in the group, during a particular time period.

To illustrate the difference between coincident and noncoincident peak, consider the following data.

Individual Maximum Demands in Kilowatts (Kw)

	<u>Week 1</u>	<u>Week 2</u>	<u>Week 3</u>	<u>Week 4</u>	<u>Peak for Month</u>
Customer A	50 Kw	80 Kw	60 Kw	45 Kw	80 Kw
Customer B	25 Kw	25 Kw	30 Kw	25 Kw	30 Kw
Customer C	70 Kw	65 Kw	60 Kw	70 Kw	70 Kw
Customer D	30 Kw	35 Kw	40 Kw	35 Kw	40 Kw
Customer E	<u>15 Kw</u>	<u>10 Kw</u>	<u>15 Kw</u>	<u>20 Kw</u>	<u>20 Kw</u>
Total*	190 Kw	210 Kw	205 Kw	195 Kw	240 Kw

*This example assumes that, for an individual week, individual customer peaks occurred at the time of coincident peaks.

The month's coincident peak for this group of customers occurred during the second week and was 210 Kw. Noncoincident peak was 240 Kw.

Coincidence Factor: The ratio of coincident peak to non-coincident peak demands. For the previous example, the coincidence factor is 87.5 percent (210 Kw ÷ 240 Kw). The lower the coincidence factor, the less likely are customer peaks to occur at the time of the system peak.

Diversity Factor: The reciprocal of the coincidence factor. For the example above, the diversity factor is 1.14. The higher the diversity factor, the more likely are customer peaks to occur at off-peak times. Diversity refers to timing differences in customer peaking behavior which lower the unit cost of Kw output produced.

Load Factor: The ratio of the average demand for a period of time to the maximum demand during the period. Annual load factor is calculated as follows:

Load Factor (annual) =

$$\frac{\text{Consumption for the year in Kwh}/8,760\text{hours}}{\text{Peak Demand (in Kw)}}$$

In this expression, 8,760 is the number of hours in the year (365 days x 24 hours per day). Dividing annual Kwh consumption by 8,760 hours gives the average hourly demand in Kw. The load factor ratio, which will always be between 0 and 100 percent, indicates the proportion of average load to peak load and thus provides information about a customer's (or group of customers') utilization of plant capacity.

Load factors vary according to both Kwh consumption and peak Kw demand. For example, consider two customers, A and B, both of whose annual peak demand is 100 Kw. Customer A's annual consumption is 438,000 Kwh whereas Customer B's consumption is 624,000 Kwh. Customer A's load factor is 50 percent ($438,000 \text{ Kwh} / 8,760 \div 100 \text{ Kw}$) whereas customer B's load factor is 71 percent ($624,000 \text{ Kwh} / 8,760 \div 100 \text{ Kw}$). A high load factor indicates significant off-peak use; a customer whose load factor is high uses much of the available capacity at off-peak times. Similarly, the high load factor customer has the highest probability of being on-line at the time of the coincident peak, and thus potentially provides few diversity benefits to the system.

Attachment A-3

Typical Demand, Energy and Customer
Classifications by FERC Primary Account

1. The following account balances are usually classified according to demand:

Rate base accounts 151, 301-303, 310-316, 320-325, 340-346, 350-369, 362-363.

Expense accounts 506-507, 511, 524-525, 529, 536-537, 539-540, 542, 546, 548-554, 556-557, 560-573, 581, 582, 592.
2. The following account balances are usually classified according to energy:

Expense accounts 501, 503-504, 512-514, 518, 521-522, 530-532, 544-545, 547.
3. The following account balances are usually classified according to customers:

Rate base accounts 369-372.

Expense accounts 586-587, 597, 901-905.
4. The following account balances are generally directly assigned:

Rate base account 373.

Expense accounts 585, 596.
5. The following account balances are generally prorated according to labor costs within the account group:

Expense accounts 500, 510, 517, 528, 535, 541.
6. The following account balances are generally prorated according to the labor/materials breakdown within the account:

Expense accounts 502, 505, 519, 520, 523, 538.
7. The following account balances are generally allocated between demand and energy, depending upon the extent to which costs are related to available Kw capacity or to Kwh output:

Rate base accounts 330-356.

Expense account 543.

8. The following account balances are generally allocated between demand and customer, depending upon the extent to which costs are related to capacity or to the number of customers:

Rate base accounts 152-174, 360-361, 364-368, 389-399.

Expense accounts 580, 583-584, 588-591, 593-595, 598, 911-916, 922-932.

Attachment A-4
Standard Data Reporting Form

1. The year to which these data apply:

Beginning date _____
 Ending date _____

2. Identify the customer classes used, and the criteria used to determine the class within which each customer is placed.
3. Customer data should be the average number of customers for the month.

	Residential	Commercial	Industrial*	Resale	Other	Total
January	_____	_____	_____	_____	_____	_____
February	_____	_____	_____	_____	_____	_____
March	_____	_____	_____	_____	_____	_____
April	_____	_____	_____	_____	_____	_____
May	_____	_____	_____	_____	_____	_____
June	_____	_____	_____	_____	_____	_____
July	_____	_____	_____	_____	_____	_____
August	_____	_____	_____	_____	_____	_____
September	_____	_____	_____	_____	_____	_____
October	_____	_____	_____	_____	_____	_____
November	_____	_____	_____	_____	_____	_____
December	_____	_____	_____	_____	_____	_____
Year	_____	_____	_____	_____	_____	_____

* If industrial customers take delivery at either transmission or distribution voltages alone, the class should be split accordingly.

4. Coincident peak (at the generator) is the Kw demand at the hour during the year (and each month) in which the maximum Kw demand is placed on the system.

	Residential	Commercial	Industrial*	Resale	Other	Total
January	_____	_____	_____	_____	_____	_____
February	_____	_____	_____	_____	_____	_____
March	_____	_____	_____	_____	_____	_____
April	_____	_____	_____	_____	_____	_____
May	_____	_____	_____	_____	_____	_____
June	_____	_____	_____	_____	_____	_____
July	_____	_____	_____	_____	_____	_____
August	_____	_____	_____	_____	_____	_____
September	_____	_____	_____	_____	_____	_____
October	_____	_____	_____	_____	_____	_____
November	_____	_____	_____	_____	_____	_____
December	_____	_____	_____	_____	_____	_____
Year	_____	_____	_____	_____	_____	_____

* If industrial customers take delivery at either transmission or distribution voltages, alone, the class should be split accordingly.

5. Explain how the data for each class were obtained, and how line loss adjustments, if any, were made.
6. Noncoincident class peak demand (at the generator) is the maximum Kw demand at the hour during the year (and each month) in which each class imposed its maximum demand. Total noncoincident demands for the system will be greater than the system peak demand.

	Residential	Commercial	Industrial*	Resale	Other	Total
January	_____	_____	_____	_____	_____	_____
February	_____	_____	_____	_____	_____	_____
March	_____	_____	_____	_____	_____	_____
April	_____	_____	_____	_____	_____	_____
May	_____	_____	_____	_____	_____	_____
June	_____	_____	_____	_____	_____	_____
July	_____	_____	_____	_____	_____	_____
August	_____	_____	_____	_____	_____	_____
September	_____	_____	_____	_____	_____	_____
October	_____	_____	_____	_____	_____	_____
November	_____	_____	_____	_____	_____	_____
December	_____	_____	_____	_____	_____	_____
Year	_____	_____	_____	_____	_____	_____

* If Industrial customers take delivery at either transmission or distribution voltages alone, the class should be split accordingly.

7. Explain how the data for each class were obtained, and how line loss adjustments, if any, were made.
8. Energy consumption (at the generator) is the total Kwh taken during the year (and each month).

	Residential	Commercial	Industrial*	Resale	Other	Total
January	_____	_____	_____	_____	_____	_____
February	_____	_____	_____	_____	_____	_____
March	_____	_____	_____	_____	_____	_____
April	_____	_____	_____	_____	_____	_____
May	_____	_____	_____	_____	_____	_____
June	_____	_____	_____	_____	_____	_____
July	_____	_____	_____	_____	_____	_____
August	_____	_____	_____	_____	_____	_____
September	_____	_____	_____	_____	_____	_____
October	_____	_____	_____	_____	_____	_____
November	_____	_____	_____	_____	_____	_____
December	_____	_____	_____	_____	_____	_____
Year	_____	_____	_____	_____	_____	_____

* If industrial customers take delivery at either transmission or distribution voltages alone, the class should be split accordingly.

9. Explain how the data for each class were obtained, and how line loss adjustments, if any, were made.
10. List any rate base or expense items which should be directly assigned, and provide the reason for doing so.
11. For all rate base and expense accounts that are split among demand, energy and customer-related property or expenses, provide the rationale supporting the split and the workpapers showing the calculation mechanics.

Attachment A-5

Newport Electric Company: Detailed Computations for Case Study
Billing Determinant Data

1. Weighted Customer: 1976

Residential	21,007
Commercial	4,430
Large power - transmission	6
Large power - distribution	100
Street and other lighting	<u>945</u>
Total	26,488

2. Mwh Sales, at Generation: 1976

Residential	154,846
Commercial	78,200
Large power - transmission	81,863
Large power - distribution	51,488
Street and other lighting	<u>5,643</u>
Total	372,040

3. Class Contribution to System Peak Demand: 1976

Residential	32,665 Kw
Commercial	15,416
Large power - transmission	12,740
Large power - distribution	9,357
Street and other lighting	<u>1,710</u>
Total	72,300 Kw

4. Class Noncoincident Peak Demand: 1976

Residential	39,198 Kw
Commercial	18,808
Large power - transmission	15,288
Large power - distribution	11,228
Street and other lighting	1,710
Company use	420

Allocation Computations

1. Allocation of Customer Costs

<u>Customer Class</u>	<u>Customers (Weighted)</u>	<u>Percent of Total</u>	<u>Allocated Cost</u>
Residential	21,007	70.31%	\$ 843,065
Commercial	4,430	16.72	177,734
Large power - transmission	6	.02	213
Large power - distribution	100	.38	4,039
Street and other lighting	<u>945</u>	<u>3.57</u>	<u>37,949</u>
Total	26,488	100.00%	\$1,063,000

2. Allocation of Energy Costs

<u>Customer Class</u>	<u>Mwh Sales At Generation</u>	<u>Percent of Total</u>	<u>Allocated Cost</u>
Residential	154,846	41.62%	\$ 4,267,714
Commercial	78,200	21.02	2,155,391
Large power - transmission	81,863	22.00	2,255,880
Large power - distribution	51,488	13.84	1,419,154
Street and other lighting	<u>5,643</u>	<u>1.52</u>	<u>155,861</u>
Total	372,040	100.00%	\$10,254,000

3. Allocation of Distribution Costs

<u>Customer Class</u>	<u>Noncoincident Peak</u>	<u>Percent of Total</u>	<u>Allocated Cost</u>
Residential	39,198	55.25%	\$1,074,060
Commercial	18,808	26.51	515,354
Large power - distribution	11,228	15.83	307,735
Street and other lighting	<u>1,710</u>	<u>2.41</u>	<u>46,851</u>
Total	70,944	100.00%	\$1,944,000

4. Allocation of Power and Transmission Costs: Contribution to System Peak Method

<u>Customer Class</u>	<u>Contribution to System Peak</u>	<u>Percent of Total</u>	<u>Allocated Cost</u>
Residential	32,665	45.44%	\$ 830,189
Commercial	15,416	21.44	391,709
Large power - transmission	12,740	17.72	323,744
Large power - distribution	9,357	13.02	237,875
Street and other lighting	<u>1,710</u>	<u>2.38</u>	<u>43,483</u>
Total	71,888	100.00%	\$1,827,000

5. Allocation of Power and Transmission Costs: Class Noncoincident Peak Method

<u>Customer Class</u>	<u>Noncoincident Peak</u>	<u>Percent of Total</u>	<u>Allocated Cost</u>
Residential	39,198	45.46%	\$ 830,554
Commercial	18,808	21.81	398,469
Large power - transmission	15,288	17.73	323,927
Large power - distribution	11,228	13.02	237,875
Street and other lighting	<u>1,710</u>	<u>1.98</u>	<u>36,175</u>
Total	86,232	100.00%	\$1,827,000

6. Allocation of Power and Transmission Costs: Average and Excess Method

Total cost to be allocated	\$1,827,000
System load factor	<u>X .5908</u>
Cost allocated on average demand	\$1,079,392
Total cost to be allocated	\$1,827,000
Allocated on average demand	<u>-1,079,392</u>
Allocated on excess demand	\$ 747,608

Average Demand Allocation:

<u>Customer Class</u>	<u>Average Demand */</u>	<u>Percent of Total</u>	<u>Allocated Cost</u>
Residential	17,676	41.62%	\$ 449,243
Commercial	8,927	21.02	226,888
Large power - transmission	9,345	22.00	237,466
Large power - distribution	5,878	13.84	149,388
Street and other lighting	<u>644</u>	<u>1.52</u>	<u>16,407</u>
Total	42,470	100.00%	\$1,079,392

Excess Demand Allocation:

<u>Customer Class</u>	<u>Noncoincident Peak</u>	<u>Average Demand</u>	<u>Excess Demand **/</u>	<u>Percent of Total</u>	<u>Allocated Cost</u>
Residential	39,198	17,676	21,522	49.18%	\$367,674
Commercial	18,808	8,927	9,881	22.58	168,810
Large power - transmission	15,288	9,345	5,943	13.58	101,525
Large power - distribution	11,228	5,878	5,350	12.22	91,358
Street and other lighting	1,710	644	<u>1,066</u>	<u>2.44</u>	<u>18,241</u>
Total			43,762	100.00%	\$747,608

*/ Kwh at generation, divided by 8,760 hours.

**/ Noncoincident peak demand less average demand.



APPENDIX B

PROCEDURES FOR DETERMINING MARGINAL
COSTS AND TIME-VARYING RATES

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APPENDIX B
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Introduction

This appendix explains in practical terms how marginal costs can be calculated and how time-varying rates can be constructed. Its purpose is to assist the staff of the regulatory authority and other persons in applying these techniques. The discussion also contains some more detailed observations about the procedures for developing and applying time-varying rates, including some suggestions for work going beyond that developed here.

The procedures for calculating marginal costs and for constructing time-varying rates are explained in this appendix in nine steps. Briefly, these nine steps are as follows:

1. Choose the rate periods among which the time-varying rates will be different.
2. Determine the marginal cost of the demand and energy components of bulk power supply.
3. Calculate the costs related to other functions and functional services provided by electric utilities.
4. Construct the billing determinants needed to establish time-varying rates.
5. Bring the foregoing data together to construct a preliminary set of time-varying rates.
6. Adjust the preliminary time-varying rates to meet a revenue requirement established independently by the regulatory authority.
7. Determine what markups are needed for energy losses between the generators and the customers.
8. Compare typical bills that would result from time-varying rates based on marginal costs with typical bills for the same service under traditional rates.

9. If time-varying rates are not being constructed, determine class revenue responsibilities by distributing the functional components of the total cost of service among the customer classes in accord with the use by those classes of the different functions.

Each of these nine steps is illustrated by the development of a marginal cost study and time-of-day rate design for the Newport Electric Corporation. As we shall indicate in the discussion of each of these steps, the Newport case study has been completed partly on the basis of estimated data and, therefore, the marginal costs and time-of-day rates that are developed should be viewed as illustrative rather than as definitive costs and rates that should be implemented without adjustment. Newport is presently in the process of conducting a fully allocated cost-of-service study and a loss study, the combination of which will go part way toward providing the updated and additional information required to "fine-tune" the cost and rate measurements, utilizing the same procedures to be developed in this appendix. As we shall note in our discussion, a regular load survey program will be required to permit accurate estimates of billing determinants and the precise revenue impacts of time-of-day rates.

Step 1: Choosing Rate Periods

A. General Considerations

If time-of-use rates are to be instituted, then the first step is division of the year into two or more rate periods, among which the rates will be different. The rate periods must be chosen so that consumers can comprehend them easily. This means no more than two or three rate periods in any one day or week, and not more than four seasons, preferably fewer, when the rates or rate periods are different.

The most important aspect of the choice of rate periods is the selection of the hours against which capacity charges shall be levied. The principle of peak responsibility pricing requires that the marginal cost of system generation and transmission be charged against the electricity use or users responsible for the system's peak, because it is demand in the peak period that determines how much capacity the system must have.

The peak hours should ideally be determined with reference to hourly loss-of-load probability (LOLP) curves, because they show best when the demands are taxing a system's generating capacity. In practice, reference to daily load curves is a feasible approach. Reference to load curves is practical, because the general pattern of the load curves is likely to be reflected in the LOLP curves. Also, the need for comprehension by users

restricts the choice of rate periods to simply defined time blocks, and the regularity of load curves facilitates simplicity.

One important consideration in choosing the peak rate period is the seasonal pattern of peak loads, and the way maintenance schedules relate to this seasonal diversity. If seasonal diversity is so limited that optimized maintenance scheduling equalizes LOLPs across seasons, then all seasons should have peak hours. But wide seasonal diversity may indicate that the off-peak seasons may not have any peak-period hours or (more likely) that these hours may not share fully in capacity charges levied in the peak season.

A second consideration in selecting rate periods is difference in marginal running cost (system lambda). Where these differences are large, as between oil-burning peaking units and baseload coal, it is proper that they be reflected in rates. And the rate periods ideally should be chosen so that system lambda is homogeneous within each period but different between periods. In practice, this principle is again compromised by the requirement that rate periods be easily comprehended by the ratepayers.

A related point is that the peak hours for allocation of generating capacity charges are defined by LOLPs, which are different in concept from the marginal running cost differential required to operate peaking plants. For example, it may be economical on some systems to serve the region between 85 and 90 percent on the load-duration curve from peaking capacity rather than to install enough baseload capacity to meet 90 percent of the

load, but this need not mean that demand in these hours is responsible for the system capacity requirement.

The procedure for selecting rate periods is illustrated and explained in more detail by the example that follows. It pertains to all of the New England region and to the Newport Electric Corporation in particular.

B. New England (NEPEX)

The example for the selection of rate periods is the New England Power Exchange (NEPEX), using data for 1975 and 1976. The daily load curves for four days in each of three seasons are shown in Schedule 1--average loads for workdays, weekends and holidays, and the actual daily load curve for the peak day. The three periods are January through May, June through August, and September through December. The first and third periods are combined for purposes of rate design and are separated in Schedule 1 merely to simplify the computer analysis.

There is important and systematic variation in the electricity demand for NEPEX by the hour of the day, the day of the week, and the season of the year. The seasonal fluctuations are due primarily to changes in the normal seasonal weather conditions, including the number of daylight hours. But, in addition, the weather within one season also varies from day to day, and these less predictable daily weather changes also have a major impact upon electricity demand.

The variations in electricity demand by time of day are illustrated by the 12 daily load curves in Schedule 1. These curves show that the aggregate demand in New England remains stable at a high level from early in the morning until well into the evening on weekdays. There is a deep valley in the nighttime hours of approximately midnight through 7 a.m., and a very rapid change in the demand level in the brief time between the valley and the plateau.

The daily load levels in Schedule 1 also illustrate some of the effects of weather. December 13, 1976, when NEPEX reached its annual peak, and January 22, 1976 were cold days, with low temperatures close to 0°F. Average temperature for the remaining workdays of the nine nonsummer months were considerably higher, and so the load curves for the average weekdays are below that for the two peak days. The same relationship is observed in the summer. On June 24, the summer peak day, the temperature reached into the high 90's and never fell below the mid-70's. Average temperatures for the remaining summer weekdays were significantly lower, and so the load curve for the average summer weekday is significantly below that of the summer peak day.

Loads also vary systematically by the day of the week. Loads on Saturdays, Sundays, and also holidays are generally far below the plateaus established on working days. Specifically, the peaks on Saturdays, Sundays and holidays are almost invariably less than 90 percent of the typical peak for a workday in the same

month, as can be seen by comparing the average weekend and average holiday load curves with the average weekday load curves shown in Schedule 1. Further, it can be seen that loads on weekends and holidays are very similar.

When the hours of the year are grouped into rate periods that have relatively homogeneous demand levels, the following periods result:

Peak Hours

Winter months (September-May),
8 a.m. to 9 p.m. on workdays

Summer months (June-August),
9 a.m. to 6 p.m. on workdays

Summer Evenings

6 p.m. to 10 p.m. on workday evenings,
June - August

Off-Peak Hours: all other times

Winter months, 9 p.m. to 8 a.m.

Summer months, 10 p.m. to 9 a.m.

All day Saturday, Sunday, and holidays throughout the year.

On page 4 of Schedule 1 are shown some statistics describing these periods and the loads in these periods for the Newport Electric Corporation.

The peak period includes those hours of the day in which the demand is generally above 90 percent of the daily peak. These are the hours within which the daily peak is likely to occur, or into which the peak might be shifted if the hour were excluded from the peak period for ratemaking purposes. Summer evenings are identified as a separate period because the average

loads are far above those experienced in the other off-peak hours; but marginal running costs were also an important consideration in this decision.

Some typical values of system lambda for NEPEX are shown in Schedule 2. These ranges are an impressionistic reading of data supplied by NEPEX. The ranges shown in this schedule are not the absolute lower and upper bounds for system lambda during the period shown, but rather they are boundaries for the range likely to be encountered on most days, excluding extreme situations. As expected, marginal running costs are substantially higher during the peak period than during the off-peak periods. But the summer evenings deviate from this general pattern for marginal running costs, and that is a principal reason why they are identified as a separate rate period. Marginal running costs are higher on summer evenings than during almost all other off-peak hours, and indeed they approach the level typically found only during the peak period. To capture this variation in marginal running costs, the summer evenings must be separated from the other off-peak hours in a different rate period. However, it is also improper to include the summer evenings in the peak period, because the demand levels are so far below the daily peaks that usage during these evening hours should not properly be required to bear the costs of generating capacity itself.

It is important to note that the peak period is defined by reference to the relationship of the hourly load to the daily peak rather than to the monthly or annual peak. Variations in

the height of the load curve from day to day within a single week or month are due primarily to variations in weather conditions around the normal for the seasons. The precise timing of weather events obviously cannot be determined in a ratemaking proceeding and, therefore, the only practical way to define the rate period far in advance is to assume normal weather conditions on each day. However, the size of the impact of the weather conditions upon the demand indicates that it would be desirable to establish rates that vary in accord with the weather, if that is found to be feasible.

Another important and distinct feature of the peak-period definition is its length: 13 hours in the winter months and nine hours in the summer. The length of this period (as, say, compared to a four hour period) makes it much more difficult for electricity users to shift the loads out of the peak period into hours when the cost of electricity is lower. But load shifting is desirable only to the extent that it smooths the load curve by chopping off the peaks and filling in the valleys. If, instead, demand is shifted from the old peak hour of the day into an hour when demand generally exceeds 90 percent of the daily peak (and may sometimes be well up into 90 percent range), the effect is to move the peak from one hour of the day to another, not to reduce the peak demand. And if the peak demand is merely shifted but not reduced, there is no cost saving for the system as a whole.

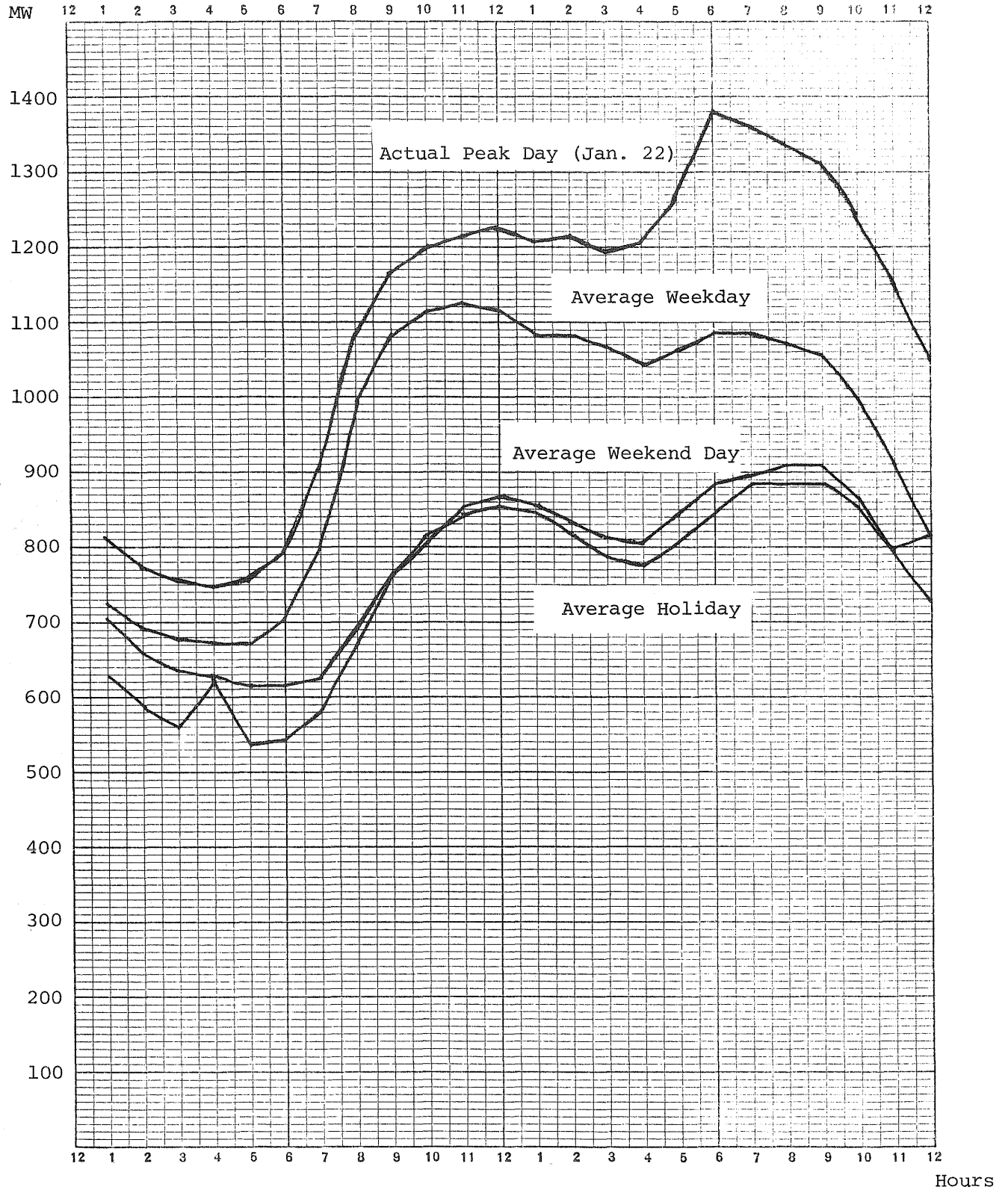
Viewed from the perspective of the New England region as a whole, there are only two ways to make major improvements in the utilization of electric generating capacity through changes in loads. One of these is to fill in the nighttime and weekend valleys, and this is the objective that will be promoted directly by the adoption of time-varying prices as suggested here. The other way is to reduce the day-to-day load variations attendant upon fluctuations in weather conditions. Here, again, the solution is not merely to turn the air conditioners off for a few hours in the middle of the day, because that would only shift the peak to late in the afternoon when all the air conditioners were turned on again. More far-reaching measures are required, and the adoption of a broad peak period for ratemaking purposes is one way to indicate to electricity users that only through such measures can they reduce their electricity bills significantly.

An especially important aspect of the rate design procedure is that the experience of NEPEX, rather than of an individual utility (in this case, Newport Electric Corporation), is used to evaluate the impact of demand variations upon bulk power production costs. The reason for this is that the New England Power Pool (NEPOOL) is highly integrated, and more so than other power pools. The planning of generating capacity is done jointly by the members of the pool, and there are very good arrangements for sharing the cost and use of individual generating units through several types of purchase, sale, and joint ownership agreements. In addition, the scheduling of maintenance and the economic dispatch

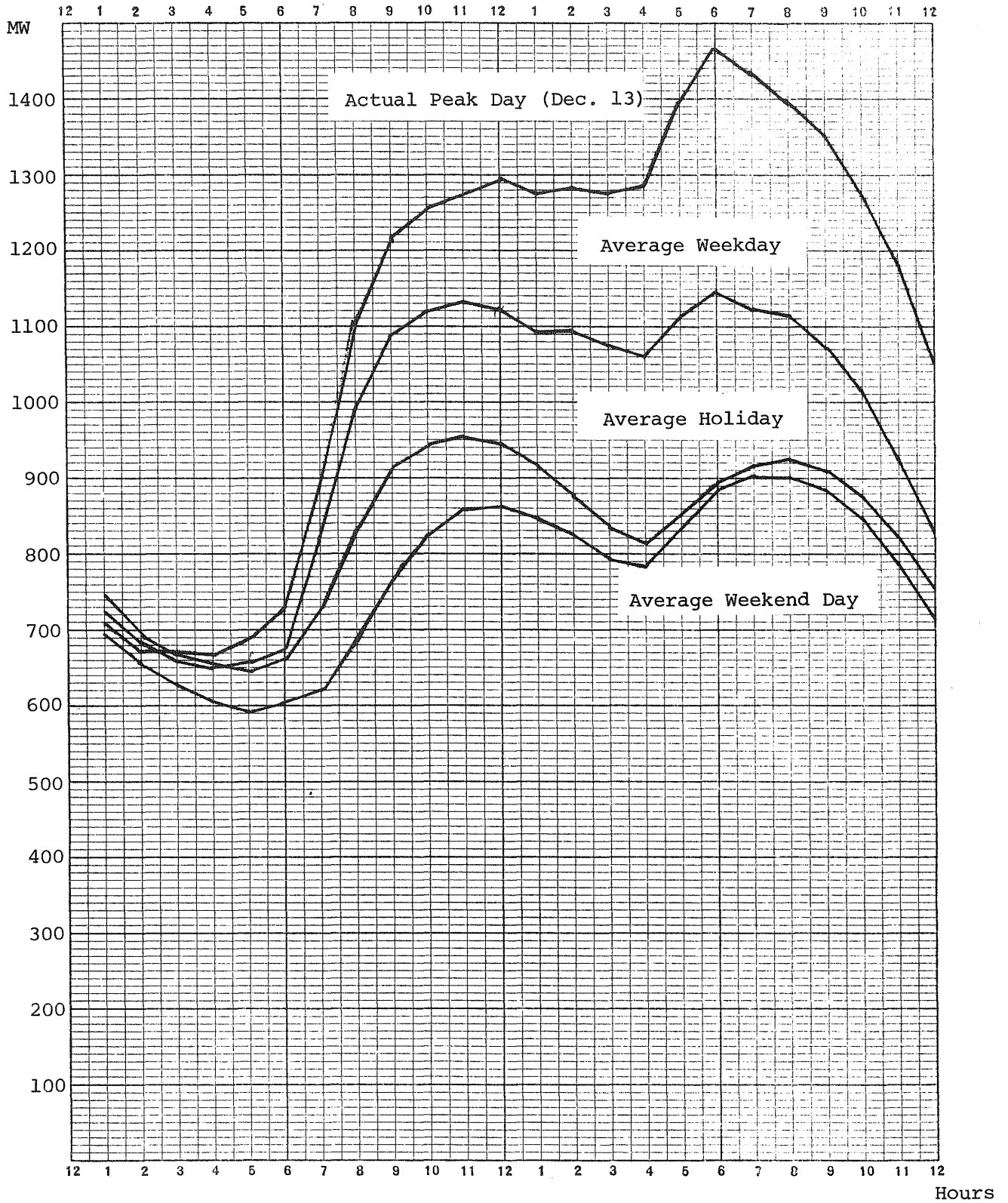
of all the members' generating units (including those of Newport) is done by NEPEX. All of this indicates that the costs of bulk power production in New England are more appropriately viewed as joint costs incurred on a region-wide basis, rather than as separate costs of individual utilities incurred in response to the time patterns of demand on their own systems.

The region-wide determination of bulk power production costs also bears on the decision to include the months of April and October in the peak periods, despite the fact that demands during these months are typically lower than in either the winter or the summer. The reason has to do with the region-wide scheduling of plant maintenance. Each electric generating unit requires scheduled maintenance, and it is therefore likely to be out of service for a few weeks during each year. Electric utilities try to schedule this maintenance at times when the load is likely to be less than at the peak seasons of the year. But in New England, the seasonal fluctuations in demand are not sufficiently great to accommodate all of the scheduled maintenance in months when demand is low. It would, therefore, be of no value to shift demands from the winter and summer months, when demands are slightly higher, to April and October, because that would only force NEPEX to reschedule maintenance otherwise planned for April and October into the winter or summer months; and the net effect would be no savings in the total requirement for installed generating capacity.

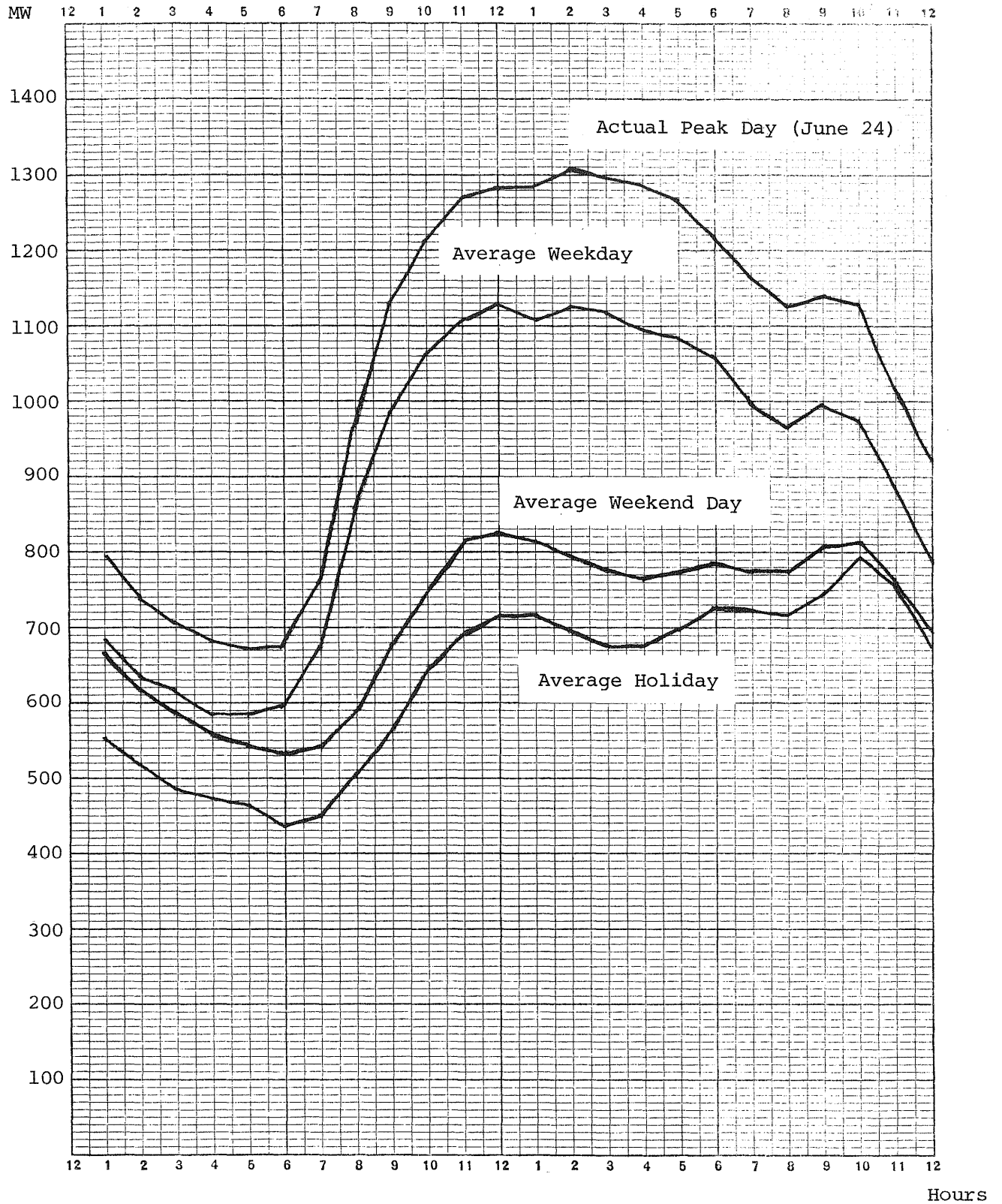
NEPEX Daily Load Curves
January 1 - May 31, 1976



NEPEX Daily Load Curves
September 1 - December 31, 1976



NEPEX Daily Load Curves
June 1 - August 31, 1976



Newport Electric Corporation

Analysis of Net Loads by Proposed Rate Period, 1976

<u>Period</u>	<u>Clock Hours</u>		<u>Net Energy Available at Generation Level</u>		<u>Average Hourly Load (Kw)</u>
	<u>Number</u>	<u>Percent</u>	<u>Quantity a/ (Mwh)</u>	<u>Percent of Total</u>	
<u>Peak Period</u>					
8 a.m. - 9 p.m. in winter (Sept. - May)	2,444	27.8%			
9 a.m. - 6 p.m. in summer (June - Aug.)	585	6.7			
	<u>3,029</u>	<u>34.5%</u>	157,184	42.4%	51,893
<u>Summer evenings</u>					
6 p.m. - 10 p.m. workdays (June - Aug.)	260	3.0	13,224	3.6	50,862
<u>Off-peak Period</u>					
All other hours (nights, Saturdays, Sundays, and Holidays)	<u>5,495</u>	<u>62.6</u>	<u>200,035</u>	<u>54.0</u>	<u>36,403</u>
<u>Total, All Periods</u>	<u>8,784</u>	<u>100.1%</u>	<u>370,443</u>	<u>100.0%</u>	<u>42,172</u>

Peak load:

72,300

Average annual load factor $(370,433 \text{ Mwh} \div 8,784 \times 72.3 \text{ Mw})$: 58.3%
 Average load factor during peak period: $(157,184 \text{ MWh} \div 3,029 \times 72.3 \text{ Mw})$: 71.8%
 Peak-period kilowatt-hours per kilowatt
 of annual peak demand (157,184 Mwh
 divided by 72.3 Mw) 2,174 hours

a/ Estimated by summing up the hourly net loads for 12 monthly peak days, 12 typical days and 12 weekend days, and expanding these loads for peak and off-peak hours to an annual basis.

Marginal Running Costs (System Lambdas)
for NEPEX, 1975-1976

Rate Period	Approximate Range of System Lambda				1976 <u>c/</u> Average
	Peak Day	Typical Weekday	Saturday	Sunday	
Peak	28-38	25-35	NA	NA	26.8
Summer evenings					
1975	30-36	23-30	NA	NA	
1976	18-34	19-25	NA	NA	21.9
Off-peak	17-22 <u>a/</u>	17-22	16-25 <u>b/</u>	16-25 <u>b/</u>	18.5

- a/ The one hour following the end of either the peak period or the summer evenings is often higher (up to about 30 mills).
- b/ Lambdas as high as 30 are found for a few afternoon or evening hours in some months of the year.
- c/ Average of system lambdas in each subperiod weighted by number of hours in each subperiod.

Step 2: Marginal Costs of Bulk Power Supply

After the rate periods have been chosen, the next task is to determine the costs of providing electric service in each of these several rate periods. The determination of these costs should be made first at the system generation level, and this determination requires two steps in the total procedure. The first of these two steps is the determination of the marginal costs of bulk power supply in each of the rate periods. Then, in Step 3, the appropriate cost rates for the other functional components of the provision of electric service will be considered.

The costs of bulk power supply are in two parts: the cost of having sufficient generating capacity available to meet the loads, and the cost of running that capacity to generate sufficient energy. The costs appropriate for time-of-use rates are marginal costs, rather than the embedded cost levels used to establish a revenue requirement for cost-of-service purposes. However, except for this difference, the marginal capacity and running costs are essentially the same as the demand and energy components of the total power production costs in a conventional cost-of-service study.

A. Marginal Running Costs

Marginal running costs are the simpler of the two components of total bulk power supply cost, and it is more convenient to begin with them. Marginal running costs can generally be associated

with system lambda. Where data on system lambda are not explicitly available as such, one may rely instead upon the individual plant and generating unit estimates of running cost per kilowatt-hour that are used in the dispatching algorithm for scheduling generation. In this event, the marginal running cost at any time is the dispatching cost of the least expensive unit not fully loaded at that time.

The marginal running cost for any rate period should generally be taken as the average of the marginal running costs during all of the different hours in that rate period. If the rate periods have been chosen to minimize the within-period variation in system lambda (as the discussion in Step 1 explains they should be chosen), then the use of a single average value for system lambda throughout an entire rate period is consistent with the proposition that the rates charged to the users should reflect, at each hour, the marginal costs of that particular hour.

The data on marginal running costs of New England have already been presented in Schedule 2, which was discussed in Step 1. The weighted average of the marginal running costs for the many different hours of the peak period is 26.8 mills; and 21.9 mills is the weighted average of the marginal running costs during the different hours of the summer evenings. For the off-peak rate period, the weighted average of the marginal running costs is 18.5 mills per kilowatt-hour.

Where automatic fuel adjustment clauses are in effect, it will generally be appropriate and sufficient to incorporate the

marginal running cost differentials among the rate periods into the base rates, and then to add a fuel adjustment charge that is a uniform amount for all rate periods. However, if the fuels used in the marginal generating units in the several rate periods are subject to sharply differing price trends, then it may be desirable instead to make separate fuel cost adjustment calculations for the several rate periods. Also, the imposition of a differential in the marginal running costs between rate periods is possible only if some fuel cost is included in the base rates. With a zero-base fuel adjustment procedure, the marginal running cost differentials may have to be imposed in the fuel adjustment calculations rather than in the base rates.

B. Marginal Cost of Meeting Demand

The second part of the bulk power supply cost analysis is the calculation of the marginal cost of generating capacity required to meet an additional kilowatt of demand. It is now generally accepted that the marginal cost of meeting a kilowatt of demand in the peak period is properly based on the cost of a peaking unit. An alternative calculation--the so-called Turvey computation--is the cost of a baseload generating unit less the fuel savings realized when that unit is run instead of a peaking plant during the peak hours. However, it has been demonstrated that this calculation yields the same result as the cost of a peaking unit, provided that the length of the peak period is defined for this purpose as the number of hours that peaking

plants would be in use on a system with an optimally designed mix of peaking and other plants.*

A sample calculation of the marginal cost for meeting an additional kilowatt of demand during the peak period is shown on page 1 of Schedule 3. This calculation is made with reference to the NEPEX system in general and the Newport Electric Corporation in particular.

The original cost per kilowatt of capacity is the \$229 incurred by Newport Electric to construct its 2,750 Kw Eldred No. 3 diesel unit in 1978. This unit is one of the most recent and more expensive peaking units in New England, and its cost per Kw falls in the range of costs generally being experienced by other companies in the country.

The annual capital carrying cost rate of 14.1548 percent is developed on page 2 and 3 of Schedule 3. The return requirement is based upon the current cost of new long-term debt, preferred stock and the most recent allowed rate of return on equity, so that it reflects the marginal cost of capital. Income taxes are included at the full nominal rates of taxation, with appropriate reduction for the benefit from income tax deferrals due to rapid

* The reason for this equality is that baseload capacity should ideally be built exactly to that point on the load-duration curve where the fuel savings precisely offset the higher capital cost of the baseload plant compared to peaking capacity. If the baseload plant cannot be run enough hours for these fuel savings to offset its extra capital cost, there is too much baseload plant. And if all baseload plants--even the marginal baseload plant -- can be run more than enough hours to offset the extra capital cost, there is not enough baseload plant.

depreciation and for the effect of the investment tax credit. The return requirement is translated into a levelized annual payment for recovery of the initial cost of the plant plus a return on the unrecovered balance. This approach, which is akin to the calculation of a mortgage payment for principal and interest, is a slower means of revenue recovery than straight-line depreciation plus a return on the undepreciated balance of plant. This means that the levelized annual payment is less than the revenue that would be required in the first year of the life of a new plant, although it is, of course, higher than the traditionally calculated revenue requirement late in the life of the plant.

The annual carrying cost per kilowatt of capacity is \$32.41, obtained by multiplying the 14.1548 percent carrying cost rate times the \$229 original cost per kilowatt of generating capacity. The annual maintenance cost of \$1.55 per kilowatt of capacity represents the excess of the total operating and maintenance cost for the unit over and above the portion related to the operation of the unit. The sum of the annual carrying cost per kilowatt of capacity, and the annual operation and maintenance cost, is the total marginal cost per kilowatt of generating capacity.

The final element in the calculation of the marginal cost of meeting a kilowatt of demand is the addition of a margin for the reserve requirement. The reserve requirement of 22.5 percent represents the margin of installed capacity required above expected peak demand. If this margin is to be maintained, then an increase

of one kilowatt of expected peak demand requires an increase of 1.225 kilowatts of generating capacity, and the cost per unit of capacity must therefore be increased by this factor to reflect fully the capacity costs of meeting additional demand. The choice of a 22.5 percent reserve margin is intended to approximate the NEPOOL target planning level, not the actual reserve margins that may currently be available in New England or elsewhere.

When the marginal cost of \$33.96 per kilowatt of generating capacity is multiplied by 1.225, to allow for the required reserve, the result is a total annual marginal cost of \$41.60 for meeting a kilowatt of demand.

To replicate for another system the calculation of the marginal cost of meeting an additional kilowatt of peak demand, the estimate of the original plant cost should be brought up to current price and construction cost levels at that time, as should the calculation of the annual operation and maintenance cost. The annual carrying cost rate for capital should be based upon the current costs of money, revised from those in Schedule 3 if necessary, and on a property tax rate appropriate for the system under study. Finally, the reserve requirement should also be that appropriate for the system for which the costs are being determined.

Newport Electric Corporation

Marginal Cost for Meeting Demand
during Peak Periods

1. Original cost per kilowatt of capacity <u>a/</u>	\$229.00
2. Annual carrying cost rate for capital, including depreciation and taxes (see pages 2 and 3.)	<u>14.1548%</u>
3. Annual carrying cost per kilowatt of capacity	\$ 32.41
4. Annual maintenance cost per kilowatt of capacity <u>b/</u>	<u>1.55</u>
5. Total marginal cost per kilowatt of generating capacity	\$ 33.96
6. Reserve requirement <u>c/</u>	<u>22.5%</u>
7. Annual marginal cost per kilowatt of demand	\$ 41.60

a/ Cost per Kw of new 2750 Kw diesel Edred Unit No. 3 installed during 1978.

b/ Estimated as 50% of 1976 maintenance cost per Kw of installed capacity for six diesel units. Newport Electric Company 1976 FPC Form No. 1, p. 434.

c/ The mean of NEPLAN's target reserve margin of 20% - 25%. The New England Power Pool: Description, Analysis, Implications (March 1976), pp. 4-33. NEPLAN is the planning arm of NEPOOL.

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Newport Electric Corporation
 CALCULATION OF REVENUE REQUIREMENTS RELATED TO
 INCREMENTAL CAPITAL INVESTMENT

YEAR	MEAN ANNUAL SURVIVORS (1)	BOOK DEPRECIATION (2)	RETIREMENTS (3)	BOOK DEPRECIATION RESERVE (4)	MEAN NET INVESTMENT (5)	ADR DDB DEPRECIATION (6)	DEFERRED INCOME TAX (7)	DEFERRED TAX RESERVE (8)	INVESTMENT TAX CREDIT		
									CREDIT (9)	AMORTIZATION RESERVE (10) (11)	
							.5009* (6)-(2)				
1	1000.	40.00	0.	0.00	1000.00	125.00	42.57	0.00	100.	4.00	100.00
2	1000.	40.00	0.	40.00	960.00	109.38	34.75	42.57	0.	4.00	96.00
3	1000.	40.00	0.	80.00	920.00	95.70	27.89	77.31	0.	4.00	92.00
4	1000.	40.00	0.	120.00	880.00	83.74	21.90	105.21	0.	4.00	88.00
5	1000.	40.00	0.	160.00	840.00	73.27	16.66	127.11	0.	4.00	84.00
6	1000.	40.00	0.	200.00	800.00	64.11	12.07	143.77	0.	4.00	80.00
7	1000.	40.00	0.	240.00	760.00	56.10	8.04	155.85	0.	4.00	76.00
8	1000.	40.00	0.	280.00	720.00	49.09	4.55	163.91	0.	4.00	72.00
9	1000.	40.00	0.	320.00	680.00	42.95	1.48	168.46	0.	4.00	68.00
10	1000.	40.00	0.	360.00	640.00	42.95	1.48	169.94	0.	4.00	64.00
11	1000.	40.00	0.	400.00	600.00	42.95	1.48	171.42	0.	4.00	60.00
12	1000.	40.00	0.	440.00	560.00	42.95	1.48	172.90	0.	4.00	56.00
13	1000.	40.00	0.	480.00	520.00	42.95	1.48	174.37	0.	4.00	52.00
14	1000.	40.00	0.	520.00	480.00	42.95	1.48	175.85	0.	4.00	48.00
15	1000.	40.00	0.	560.00	440.00	42.95	1.48	177.33	0.	4.00	44.00
16	1000.	40.00	0.	600.00	400.00	42.95	1.48	178.81	0.	4.00	40.00
17	1000.	40.00	0.	640.00	360.00	0.00	-20.03	180.28	0.	4.00	36.00
18	1000.	40.00	0.	680.00	320.00	0.00	-20.03	160.25	0.	4.00	32.00
19	1000.	40.00	0.	720.00	280.00	0.00	-20.03	140.22	0.	4.00	28.00
20	1000.	40.00	0.	760.00	240.00	0.00	-20.03	120.19	0.	4.00	24.00
21	1000.	40.00	0.	800.00	200.00	0.00	-20.03	100.15	0.	4.00	20.00
22	1000.	40.00	0.	840.00	160.00	0.00	-20.03	80.12	0.	4.00	16.00
23	1000.	40.00	0.	880.00	120.00	0.00	-20.03	60.09	0.	4.00	12.00
24	1000.	40.00	0.	920.00	80.00	0.00	-20.03	40.06	0.	4.00	8.00
25	1000.	40.00	0.	960.00	40.00	0.00	-20.03	20.03	0.	4.00	4.00

READY.

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	MEAN NET INVESTMENT	EQUITY RETURN	INTEREST	TAXABLE INCOME	INVESTMENT TAX CREDIT	INCOME TAX	PRO-PERTY TAX	REVENUE REQUIREMENT	\$1 AT .10776	MEAN ANNUAL SURVIVORS	REVENUE REQUIREMENTS
	(1)-(4)-(8)	4.189% (12)	6.587% (12)	[(2)-(6)+(7)-(10)+(13)] / (1-.5008)	(16)	50.08% (15)	2.00% (1)	(2)+(7)-(10) + (13)+(14) + (16)+(17)+(18)	(1) AT .10776	(1)*(20)	(19)*(20)
YEAR	(12)	(13)	(14)	(15)	(16)	(17)	(18)	(19)	(20)	(21)	(22)
						-104.62					
1	1000.00	41.89	65.87	-9.10	100.	*****	20.00	201.77	.90272	902.72	182.14
2	917.43	38.43	60.43	-.41	0.	-.20	20.00	189.40	.81491	814.91	154.35
3	842.69	35.30	55.51	7.00	0.	3.51	20.00	178.21	.73564	735.64	131.10
4	774.79	32.46	51.04	13.26	0.	6.64	20.00	168.04	.66408	664.08	111.59
5	712.89	29.86	46.96	18.54	0.	9.28	20.00	158.76	.59948	599.48	95.18
6	656.23	27.49	43.23	22.94	0.	11.49	20.00	150.28	.54116	541.16	81.32
7	604.15	25.31	39.80	26.59	0.	13.31	20.00	142.48	.48852	488.52	69.60
8	554.09	23.29	36.63	29.56	0.	14.80	20.00	135.28	.44100	441.00	59.66
9	511.54	21.43	33.69	31.96	0.	16.01	20.00	128.61	.39810	398.10	51.20
10	470.06	19.69	30.96	29.48	0.	14.26	20.00	122.39	.35937	359.37	43.99
11	428.58	17.95	28.23	25.00	0.	12.52	20.00	116.18	.32442	324.42	37.69
12	387.10	16.22	25.50	21.52	0.	10.78	20.00	109.97	.29286	292.86	32.21
13	345.63	14.48	22.77	18.04	0.	9.03	20.00	103.76	.26437	264.37	27.43
14	304.15	12.74	20.03	14.56	0.	7.29	20.00	97.54	.23865	238.65	23.28
15	262.67	11.00	17.30	11.00	0.	5.55	20.00	91.33	.21544	215.44	19.68
16	221.19	9.27	14.57	7.60	0.	3.81	20.00	85.12	.19448	194.48	16.55
17	179.72	7.53	11.84	47.07	0.	23.57	20.00	78.91	.17554	175.56	13.85
18	159.75	6.69	10.52	45.39	0.	22.73	20.00	75.91	.15848	158.48	12.03
19	139.78	5.86	9.21	43.72	0.	21.89	20.00	72.92	.14307	143.07	10.43
20	119.81	5.02	7.89	42.04	0.	21.05	20.00	69.93	.12915	129.15	9.03
21	99.85	4.19	6.58	40.37	0.	20.21	20.00	66.94	.11659	116.59	7.80
22	79.88	3.35	5.26	38.69	0.	19.38	20.00	63.95	.10525	105.25	6.73
23	59.91	2.51	3.95	37.01	0.	18.54	20.00	60.96	.09501	95.01	5.79
24	39.94	1.67	2.63	35.34	0.	17.70	20.00	57.97	.08577	85.77	4.97
25	19.97	.84	1.32	33.66	0.	16.86	20.00	54.98	.07742	77.42	4.26
										8561.49	1211.86

14.1548%

READY.

Step 3: Other Functional Cost Components

Power production is only one (or two, if capacity and energy are counted separately) of the many functional services provided by electric utilities; and the marginal costs of power production, whose determination was discussed in the preceding Step 2, reflect only a part of the total cost picture of electricity supply. Since time-varying rates are intended to reflect the entire spectrum of electric utility costs, the analysis of the marginal costs of power production must be supplemented by an accounting for the other costs of electricity supply.

These other costs fall into four major categories:

- transmission
- distribution
- customer costs
- administrative and general.

In conventional ratemaking, the analysis of these functional cost categories enters into the determination of the rate structure through a class cost-of-service study, the object of which is the establishment of separate class revenue responsibilities for the different customer classes.* The individual cost elements of each functional service are distributed

* Appendix A to this report discusses at length the development of a fully allocated class cost-of-service study.

among the customer classes in accord with the classes' use of the service, and thus the class revenue responsibilities do reflect class usage characteristics. But the functional cost totals are submerged into the class revenue responsibilities, and the rate structure within each class is generally constructed without specific regard to the functional cost structure.

In developing time-of-use rates, it is important that the total costs for each function be accumulated and preserved, so that a single price per unit of the functional service can be calculated and applied to all users (in all customer classes) on the utility system. Preservation of totals for the functional cost categories rather than for class revenue responsibilities is also a necessary first step toward the design of rates that recover these costs from the specific times of use (peak, off-peak, shoulder) and part of the rate schedule (demand, energy, customer charge) to which each cost properly applies.

Development of the functional costs for functions other than power supply can be done either on a marginal cost basis or with reference to embedded average costs as traditionally calculated. As a matter of economic theory, marginal costs for these other functional services are the proper basis for pricing, just as marginal costs are the proper basis for the pricing of power supply demand and energy. But the determination of marginal costs for these functions, and especially distribution and customer costs, is much more difficult and less precise than for power supply, and it is not clear that the benefits are

sufficient to justify the effort. This is especially true where the object is to refine the time structure of electric rates in support of load management objectives, which relate primarily to power production costs and fuel use rather than to the other functional activities of electric utilities.

In contrast to marginal costs, the determination of the embedded total or average costs for the other functional services is familiar to those who have worked in or with traditional electric utility ratemaking. Use of embedded average costs for these other functional activities can also be justified as probably a reasonable approximation to the theoretically preferable marginal costs, and it is the approach adopted in the Newport Electric Corporation cost study.

A. Newport Electric Corporation

As we indicated in the introduction to this appendix, Newport Electric Corporation has never conducted a class cost-of-service study. It is currently in the process of developing such a study, but it will not be completed until well after this report must be submitted. Consequently, a simplified example of the functionalization of total system costs for the Newport Electric Corporation is presented in Schedule 4. This schedule relates to 1976 and it is developed using only data on costs actually incurred, as reported to the Federal Energy Regulatory Commission in FERC Form No. 1. The schedule is in four pages. The first page is a summary of the functionalization

of Newport's total cost of service, and the details are presented on the three following pages. On each page, the first column shows the total cost recorded on the books of the Company for a single cost account or group of accounts. The remaining columns show the way that this total system cost is distributed among the functionalized activities.

Page 1 is a summary of the total cost of service and its distribution to the functional categories. Line 1 shows net electric plant in service. It is used, in lieu of rate base, as the basis for allocating operating income and most taxes among the functional categories. Details on the functionalization of net electric plant in service are presented on page 2. Continuing on page 1, electric operating revenue is shown in the first column as a control total for the total cost of service, but no attempt is made to distribute it among the functional activities. The remainder of page 1 shows the cumulation of the functionalized operating expenses and operating income to develop a functionalization of the costs (including return on invested capital) that exhaust operating revenues. The functionalization of operation and maintenance expense (line 3 on page 1) is shown in detail on page 3 of Schedule 4. The functionalization of depreciation (line 4) is also on page 3; and the functionalization of taxes (line 5) is on page 4. Line 8 is the subtotal of lines 3 through 5; and operating income, distributed among functions in proportion to net electric plant in service, is added at line 9. This gives

the functional distribution of the total cost of service, excluding the gross receipts tax, on line 10. Since the gross receipts tax is a tax on revenues, it is now allocated (on line 11) among the functions in accord with the total cost of service on line 10. When it has been added, the grand total for the cost of service for actual 1976 is shown on line 12. Note that except for the minuscule variation due to independent rounding, this procedure results in a functionalization of the cost of service that exactly matches the actual electric operating revenues, as reported on line 2. To adjust total cost of service to the revenue requirement allowed by the Commission for pro forma 1976, the revenue increase is allocated on line 13 according to the cost of service shown on line 12. The pro forma total cost of service is then shown on line 14.

The assignment of electric plant in service to the various functional categories is shown on page 2 of Schedule 4. This assignment is based in a simple and straightforward way upon the plant account balances reported on pages 401-403 of FERC Form No. 1. Total power production plant (FERC accounts 301-346) is assigned entirely to the power production demand function; and total transmission plant (FERC accounts 350-359) is assigned entirely to the transmission function. Distribution plant (FERC accounts 360-373) is divided between the distribution and customer cost functions, with accounts 369-371 (representing service drops and meters) assigned to customer costs and the rest to distribution. The FERC also requires that the balances

of accumulated provision for depreciation be reported to it on page 408 of Form No. 1, and these amounts are also shown on page 2 of schedule 4. The detail by functional category is shown in the schedule as reported to the FERC, except that the depreciation balance for distribution plant is distributed between distribution and customer cost categories in the same proportions that the plant balance (line 3 of page 2) is distributed. Net electric plant in service, obtained by subtracting the depreciation balance from the total (gross) electric plant in service, is then shown at the bottom of page 2 and transcribed to page 1, line 1.

The distribution of operation and maintenance expenses among the functional categories is handled much the same way as that for electric plant in service, and it is shown on page 3. Fuel and purchased power expense (accounts 501, 518, 547, and 555) are assigned to energy; and the remaining power production expenses (accounts 500-557) are assigned to power production demand. Transmission expenses (FERC accounts 560-573) are assigned to the transmission function, and distribution expenses are divided between the distribution and customer cost functions. Accounts 586, 587, and 597, which represent the operation and maintenance expenses for meters and customer installations, are assigned to customer costs; and the remainder of accounts 580-598 are assigned to the distribution function. Customer accounts expenses (FERC accounts 901-910) are assigned in their entirety to the customer cost function. Employee pensions and benefits,

which are reported in FERC account 926, are distributed among the functional cost categories in proportion to total salaries and wages, for which an allocation factor is developed on page 4. All other operation and maintenance expense is distributed among the functional categories in proportion to the O&M subtotal in line 6. The total operation and maintenance expense, with detail by functional categories, is recorded on line 8 of page 3 and transcribed to line 3 of page 1 of Schedule 4.

The functionalization for depreciation expense, as recorded on line 9 of page 3 and also on line 4 of page 1 of Schedule 4, is that reported to the FERC on page 429 of Form No. 1. The amount reported for depreciation expense on distribution plant is divided between the distribution and customer cost functions in the proportions that distribution plant (page 2, line 3 of Schedule 4) is so divided.

The distribution of taxes among the functional cost categories is shown on page 4 of Schedule 4. Electric utility taxes fall into four major categories: those related to employment, such as employer social security and unemployment insurance taxes; property taxes; income taxes; and gross receipts taxes. The first is distributed functionally in proportion to wage and salary expense, while the second and third categories are distributed in proportion to net plant in service. Plant is clearly the proper basis for distributing property taxes, and it is used in lieu of the rate base for distributing income taxes, which are related to the return requirements and thus to

the rate base. Gross receipts tax revenues are segregated from the other tax items on page 4 and carried forward directly to page 1 without distribution among functional categories. This is necessary, because the gross receipts tax is properly distributed in proportion to the total revenue requirements for each function, exclusive of this tax; and these functional revenue requirements are obtained only on page 1, when the operating expenses and return requirements are combined, as has been described.

Finally, the last line on page 4 is the allocation factor for salaries and wages, as taken from pages 355-356 of Form No. 1.

B. Refinements To The Functionalization Of Total Cost

The procedures that have been described for functionalizing the total system costs of service for an electric utility have been developed with the intention that they be kept simple. As a result, it is possible that these procedures may either underestimate or overestimate the costs of one or another of the functional services; and it is even possible that they may underestimate or overestimate the cost of all of the relevant functional categories, namely transmission, distribution, and customer cost. (The power production costs are not relevant for time-of-use rates, because the marginal costs of bulk power supply are used in place of them.) Underestimates or overestimates of the functional cost components are not as serious a

problem as they might seem, because they do not affect the revenue level to which the time-of-use rates developed from this cost analysis are designed. Instead, the system revenue requirement is established independently of the rate structure, and the rates developed in this procedure are then adjusted (in Step 5) to the extent necessary to have them recover the revenue requirement established by the regulatory authority. The only question, then, is whether the simplifications in procedure for calculating cost components are so distorting that they lead to rates that reflect electric utility cost structures less well than present rate designs. That is most unlikely, given the importance of time variation in electricity costs and the general failure of conventional rates to reflect this time variation, but it is nevertheless proper for each analyst to bear in mind the standards against which the development of time-varying rate structures should be judged.

For those who may wish to improve upon the cost allocation procedures suggested in this appendix, the following refinements may deserve consideration:

More functional cost categories. It is implicit in the use of a single cost category for all distribution costs that all customers must fall in one of two categories: those who do pay a distribution charge to help cover distribution cost, and those who do not. No distinction is possible on the basis of this functionalization between customers taking service at primary distribution voltage (but not off the transmission

grid) and those served at secondary voltages. Similarly, there is no basis in this cost record for distinguishing between customers who do and do not receive underground service. If one wanted to charge different prices for these different service characteristics, then one way to determine the appropriate rate differentials would be to make a functional separation of the cost, adding columns to the cost study in Schedule 4. Cost of the primary distribution system could then be recovered from all customers taking service at either primary or secondary voltages, while costs of the secondary distribution system would be recovered only from customers taking service at secondary voltages. In fact, for the Newport Electric Corporation, which serves some customers at transmission voltages, it would be desirable to segregate plant into three or more voltage levels for transmission and distribution service, with different customer groups taking service in each voltage range.

General and common plant. In the Newport cost study, all general plant is assigned to the various functional categories in proportion to plant that is directly assignable. A more refined study would permit the direct assignment of some types of general and common plant, especially communications and transportation equipment, to one or another of the functional cost categories. This procedure is especially important in determining the net plant associated with providing special types of service such as streetlighting. For combination

utilities, special attention must also be given to common plant, because it may not appear at all on the books as electric utility plant in service, even though most of it may, in fact, be devoted to electricity service.

Rate base. Net electric plant in service is used in lieu of rate base as a proxy for the functional distribution of operating income. In a more refined study, it would be possible to determine the other components of the total rate base and assign them to functional categories also. To the extent that this functional assignment of the other elements of rate base differed from that for net plant, it would slightly change the functional allocation of operating income. (Since cash working capital is related to revenues, the return on it should be held out of the cost study until the end, and then distributed in proportion to the sum of all the other cost components, in the same way that gross receipts taxes are distributed.)

Other operation and maintenance expenses. Of the administrative and general operating expenses (900 series of accounts), only the customer accounting expenses and pension and benefits are directly assigned to functional categories. The remaining expenses are allocated in proportion to the directly assignable component. These expenses are relatively small, but they too could be directly assigned to specific functional cost categories with a more detailed study.

Income taxes. Since the purpose of the cost development exercise is to build cost from the bottom, income taxes must be

assigned with reference to a cost category rather than in accord with functional detail of income before taxes, which could only be obtained if revenues for the several functional categories had already been determined. For ordinary income taxes, the functional distribution of rate base (as approximated by net electric plant in service) is clearly the appropriate basis for distribution. But investment tax credit adjustments could perhaps be traced directly to specific functional categories of plant, rather than distributed proportionally across all plant in service; and rate base deductions such as accumulated deferred income taxes could also be assigned directly to functional cost categories in refining the net plant vector used as a basis for distributing income tax charges.

Functionalization of a test-year cost of service. All of the preceding assignments point in the direction of functionalizing a complete test-year cost of service. If time-varying rates are being developed in the context of a complete rate investigation, then the functionalization of total costs can be developed instead of, or as a by-product of, a complete class cost-of-service study. These studies are now required to be filed with all rate increase applications in some jurisdictions, and they are increasingly being used in other jurisdictions even where not required in all instances. Virtually all the information needed for a complete functionalization of total system costs is contained in a typical class cost-of-service study, and there is, in fact, less work required to complete the functionalization and all the other aspects of a time-varying rate design than to complete a class cost-of-service study.

NEWPORT ELECTRIC COMPANY

Functionalization of Total System Costs, 1976
(per Books of Account, in Thousands of Dollars)

	<u>Total, All Functions</u>	<u>Power Production Demand</u>	<u>Energy</u>	<u>Trans- mission</u>	<u>Distri- bution</u>	<u>Customer Costs</u>
1. Net Electric Plant in Service	15,595	1,397	--	5,458	7,307	1,433
2. Electric Operating Revenue	14,533					
<u>Operating Expenses</u>						
3. Operation and Maintenance	11,550	404	9,435	212	745	754
4. Depreciation	659	185	--	141	278	55
5. Taxes other than gross receipts tax	677	71	8	204	321	73
6. Gross receipts tax	590					
7. Total Operating Expenses	13,476					
8. Total, excluding gross receipts tax	12,886	660	9,443	557	1,344	882
9. Operating income <u>a/</u>	1,057	94	--	370	496	97
10. Cost of service, excluding gross receipts tax	13,943	754	9,443	927	1,840	979
11. Allocation of gross receipts tax <u>b/</u>	590	32	399	40	78	41
12. Total cost of service	14,533	786	9,842	967	1,918	1,020
13. Increase in Total Cost of Service <u>c/</u>	609	33	412	41	80	43
14. Pro Forma Total Cost of Service	15,142	819	10,254	1,008	1,998	1,063

a/ Allocated in proportion to line 1.
b/ Allocated in proportion to line 10.
c/ Allocated in proportion to line 12.

NEWPORT ELECTRIC COMPANY

Functionalization of Plant, 1976
(per Books of Account, in Thousands of Dollars)

	<u>Total</u>	<u>Power Production</u> <u>Demand</u>	<u>Energy</u>	<u>Trans-</u> <u>mission</u>	<u>Distri-</u> <u>bution</u>	<u>Customer</u> <u>Costs</u>
1. Production Plant (FERC accounts 301-346)	2,732	2,732				
2. Transmission plant (FERC accounts 350-359)	5,603			5,603		
3. Distribution plant (FERC accounts 360-368, 372-373 to distribution function; accounts 369-371 to customer costs)	10,542				8,812	1,730
4. Subtotal	18,877	2,732	--	5,603	8,812	1,730
5. Other plant in service (allocated according to line 4)	<u>2,264</u>	<u>328</u>		<u>673</u>	<u>1,057</u>	<u>206</u>
6. Total electric plant in service	21,141	3,060	--	6,276	9,869	1,936
7. Accumulated provision for depreciation <u>a/</u>	<u>5,546</u>	<u>1,663</u>		<u>818</u>	<u>2,562</u>	<u>503</u>
8. Net electric plant in service	15,595	1,397	--	5,458	7,307	1,433

a/ Accumulated provision for depreciation of distribution plant functionalized according to distribution plant above. Depreciation of general plant distributed proportionally among other categories.

NEWPORT ELECTRIC COMPANY

Functionalization of Operation and Maintenance Expenses
and Depreciation, 1976
(per Books of Account, in Thousands of Dollars)

	<u>Total</u>	<u>Power Production</u>		<u>Trans-</u>	<u>Distri-</u>	<u>Customer</u>
		<u>Demand</u>	<u>Energy</u>	<u>mission</u>	<u>bution</u>	<u>Costs</u>
<u>Operation and Maintenance Expenses</u>						
1. Power production a/ (FERC accounts 500-557)	9,262	335	8,927			
2. Transmission (FERC accounts 560-573)	175			175		
3. Distribution (FERC accounts 580-585, 588-596, 598 to distribution function; 586, 587, 597 to customer costs)	811				554	257
4. Customer accounts (FERC accounts 901-910)	399					399
5. Employee pensions and benefits (FERC account 926, distributed in proportion to salaries and wages)	306	48	21	26	152	59
6. Subtotal	10,953	383	8,948	201	706	715
7. Other O&M expenses (allocated according to line 6)	597	21	487	11	39	39
8. Total operation and maintenance expenses	11,550	404	9,435	212	745	754
<u>Depreciation Expense</u>						
9. Depreciation b/ (Functionalizations as reported in FERC Form No. 1, p. 429)	659	185	--	141	278	55

a/ Energy component is fuel and purchased power; rest is demand component.

b/ Depreciation charged to distribution functionalized in proportion to to distribution plant.

NEWPORT ELECTRIC COMPANY

Functionalization of Taxes
and Development of Allocation Factor, 1976
(per Books of Account, in Thousands of Dollars)

	<u>Total</u>	<u>Power Demand</u>	<u>Production Energy</u>	<u>Trans- mission</u>	<u>Distri- bution</u>	<u>Customer Costs</u>
<u>Taxes</u>						
1. Employment-related <u>a/</u>	109	17	8	9	54	21
2. Property taxes <u>b/</u>	500	44	--	175	235	46
3. Gross receipts tax	590					
4. Federal income tax <u>b/c/</u>	<u>68</u>	<u>10</u>	<u>--</u>	<u>20</u>	<u>32</u>	<u>6</u>
5. Subtotal, all taxes except gross receipts	677	71	8	204	321	73
6. Gross receipts tax	<u>590</u>					
7. Total taxes	1,267					
<u>Allocation factor</u>						
8. Salaries and wages (excluding <u>d/</u> those charged to construction)	1,593	251	108	134	794	306

- a/ Functional allocation in proportion to salaries and wages.
b/ Functional allocation in proportion to net electric plant in service.
c/ Including provision for deferred income taxes and investment tax credit.
d/ Salaries and wages in power production allocated 70% to demand and 30% to energy.

Source: Totals for lines 1, 2 and 3 taken from FERC Form No. 1, p. 222. Total for line 4 from Statement C of FERC Form No. 1

Step 4: Billing Determinants for Time-Varying Rates

To construct a set of utility rates, one needs information about billing determinants as well as about costs. For costs that are developed initially on a per unit basis, such as the marginal costs of power supply, in Step 2, the number of billing units to which these prices are applied is the determinant of revenue, and thus it is needed for comparison of the revenue from the time-varying rates with the system revenue requirement. For other functional activities for which costs are developed on a total system basis, as in Step 3, it is necessary to know how many units of service were provided by the utility incurring those total costs, so that an average cost per unit can be obtained by division and applied as the unit price for the relevant service.

For three-part time-varying rates, with demand, energy, and customer charges, the billing determinants are billing demands, energy used in each rate period, and the number of customers.

In general, data on energy usage in each rate period (at system level) and on the number of customers can be obtained directly from the records of the company. Hour-by-hour data on energy usage at the system level are generally available from the system dispatch logs, and indeed they are likely to have been developed as a by-product of the selection of rate periods in Step 1. Data on the number of customer bills to which a

minimum charge or customer charge is applicable should also be readily available.

Data on billing demands are likely to be much more of a problem, because demands are routinely metered only for some customer classes and not for others. Estimates of billing demands can be derived from load study data, preferably from the system for which time-varying rates are being determined, but if necessary by use of detailed load study data from other comparable systems. Estimates of billing demands are often made for use as allocation factors in class cost-of-service studies, and these data and estimating procedures are therefore not unknown to electric utility rate analysts.

A. Newport Electric Corporation

Billing determinants at the generation level for the Newport Electric Corporation for 1976 are derived in Schedule 5. The generating capacity requirement is determined by the highest demand in the year, which for Newport Electric Corporation was 72.3 megawatts. Power supply demand costs are recovered by billing against the sum of the monthly billing demands through the year. These demands are estimated at 1,777 megawatts. The ratio of weighted billing demands to the annual peak demand exceeds a factor of 12, because the billing demands are the sum of the noncoincident maximum demands of all the customers in each month, and the sum of the noncoincident maximum demands of the individual customers is substantially greater than the

maximum coincident demand during the month. Owing to this diversity, the price to each customer for each kilowatt of his own maximum demand in any one month need be only approximately 1/25 of the annual cost to Newport of meeting one kilowatt of demand, rather than the 1/12 that each customer would have to pay if there were no diversity.

In addition to power supply demands, the demands upon the distribution system must also be measured, because they are the basis against which some of the distribution costs are recovered. Since the necessary size and capacity of the distribution network are determined at each point on that network by the maximum localized loads there, an appropriate basis for recovering the distribution costs is the sum of the noncoincident maximum demands of each customer for service taken from the distribution system. For Newport, the distribution system is defined as the system for providing service at voltages below 23 kilovolts (Kv), and the demand on this system must be calculated excluding the billing demands of all customers taking service at 23 Kv or above. The sum of the noncoincident maximum demands of all customers taking service from the distribution system is estimated to be 1,617 megawatts for the 12 months of 1976.

Energy usage at generation level, before losses, is obtained directly from the Newport system dispatch logs. These logs record actual loads for each hour of the year, and the hourly loads are summed for all the hours in each rate period for 12 typical weekdays, 12 typical weekend days, and all 12 monthly peak

days. These average loads for each period for each type of day are then multiplied by the number of each type of day within each season and for the year as a whole. The results are provided on page 4 of Schedule 1. By this procedure, annual energy is estimated at 370,443 Mwh or, less than .5 percent below actual 1977 energy of 372,040 Mwh. The distribution by rate period resulting from the estimates in Schedule 1, is then applied to the actual 1976 net generation figure to provide use at generation level by rate period, which is shown on page 5 of Schedule 5.

The weighted number of customers is simply the number of residential customers plus twice the number of commercial customers, and three times the number of all other customers. The weights assigned are chosen arbitrarily to reflect the differences in costs involved in serving different types of customers. A detailed class cost-of-service study, if thoroughly and carefully conducted, would permit more precise estimates of the customer cost weights for different classes. Development of the weighted number of customers is shown on page 6 of Schedule 5.

Newport Electric Corporation

Estimated 1976 Annual Billing Demands

	Estimated January 1978 Noncoincident Billing Demands a/ (Kw)	Adjustment Factor b/	Estimated 1976 Annual Noncoincident Billing Demand (Kw)	Energy at Generation Level (Mwh)
Total residential	65,833	10.5098	691,892	154,846
Total commercial	73,811	10.5098	775,739	78,200
<u>Total Large Power</u>				
Transmission voltage	15,202	10.5098	159,770	81,863
Distribution voltage	12,675	10.5098	133,212	51,488
Total street and other lighting	1,526	10.5098	16,038	5,643
Total company, excluding company use	160,047	10.5098	1,776,651	372,040

a/ From page 3.
b/ From page 2.

Newport Electric Corporation

Development of Estimated 1976 Annual Billing Demands

1. Estimated January 1978 peak less company use <u>a/</u>	64,124 Kw
2. Estimated January 1976 peak less company use <u>b/</u>	66,200 Kw
3. (2) - (1)	1.0324
4. Sum of 12 monthly 1976 system peaks <u>c/</u>	735,800
5. 1976 annual system peak <u>c/</u>	72,300
6. (5) - (6)	10.18
7. Total adjustment factor to raise January 1978 billing demands to annual 1976 billing demands [(3) x (7)]	10.5098

a/ Based on assumptions by Newport's consultants in preliminary development of demand allocation vectors.

b/ .9940 x system peak to adjust for same company use percentage as shown on page 3. System peak reported in 1976 FPC Form No. 1 Report.

c/ 1976 FPC Form No. 1 Report.

Newport Electric Corporation

Estimated Class Demands for the January 1978 Peak Day
(at Generation Level)

	Contribution to System Peak <u>a/</u> (Kw)	Assumed Interclass Diversity Factors <u>a/</u>	Contribution to Class Peak (Kw)	Assumed Intraclass Diversity Factors <u>b/</u>	Estimated Sum of Customer Noncoincident Demands (Kw)
<u>Residential</u>					
101 Residential service	23,303	1.00	23,303	1.94	45,208
120 Controlled water heating	-0-	--	4,932	1.94	9,568
103 Residential w/space heating					
o water on separate meter	975	1.19	1,162	1.59	1,848
o w/water heating	4,821	1.19	5,745	1.59	9,135
104 Residential--Prudence Island	<u>38</u>	<u>1.00</u>	<u>38</u>	1.94	<u>74</u>
Total Residential	29,137	1.21	35,180		65,833
<u>Commercial</u>					
201 General service					
o primary	548	1.07	579	2.11	1,222
o secondary	9,100	1.31	11,877	5.43	64,492
o secondary w/space heating	1,007	1.17	1,178	2.00	2,356
202 Cooking & refrigeration	27	1.81	49	5.43	266
204 G.S.--Prudence Island	6	2.33	14	5.43	76
205 Total electric living	<u>3,063</u>	<u>1.02</u>	<u>3,121</u>	1.73	<u>5,399</u>
Total Commercial	13,751	1.22	16,818		73,811

a/ Based on assumptions utilized by Newport's consultants in preliminary development of demand allocation vectors.

b/ Based on measured diversity factors of similar classes in January 1978 for the Northern States Power Company.

Newport Electric Corporation

Estimated Class Demands for the January 1978 Peak Day
(at Generation Level)

	Contribution System Peak <u>a/</u> (Kw)	Assumed Interclass Diversity Factors <u>a/</u>	Contribution to Class Peak (Kw)	Assumed Intraclass Diversity Factors <u>b/</u>	Estimated Sum of Customer Noncoincident Demands (Kw)
<u>Large Power</u>					
301 General service					
o primary	4,951	1.18 <u>b/</u>	5,826	1.24	7,224
o secondary	2,846	1.18 <u>b/</u>	3,851	1.25	4,189
302 U.S. Navy (23 Kv)	9,191	1.32	12,128	1.03	12,491
303 Kaiser (23 Kv)	2,173	1.01	2,186	1.24	2,711
304 Municipal pumping					
o primary	386	1.04	400	1.34	536
o secondary	106	1.08	114	5.63	642
-- Weyerhouser	57	1.19	68	1.24	84
Total Large Power	19,710	1.22	24,073		27,877
<u>Street & Other Lighting</u>					
501 Street and highway lighting	985	1.00	985	1.00	985
502 Area (security) lighting	348	1.00	348	1.00	348
503 Flood lighting	193	1.00	193	1.00	193
Total Lighting	1,526	1.00	1,526		1,526
Total Company Exclusive of Company Use	64,124	--	--	--	169,047
Company Use	369	1.02	375	1.00	375
Total Company	64,493	--	--	--	169,422

a/ Based on assumptions utilized by Newport's consultants in preliminary development of demand allocation vectors.

b/ Based on measured diversity factors for similar classes in January 1978 for the Northern States Power Company.

Newport Electric Corporation

Energy by Rate Period, 1976
at Generation Level

	Distribution of Energy by Rate Period <u>a/</u> (%)	Energy by Rate Period (Mwh)
Peak	42.4%	157,745
Summer energy	3.6	13,393
Off-peak	<u>54.0</u>	<u>200,902</u>
Total	100.%	372,040 <u>b/</u>

a/ Schedule 1, page 4

b/ Total from 1976 Form No. 1, p. 432.

Newport Electric Corporation
Development of Weighted Customer
Billing Units

	<u>Assumed Weight</u>	<u>1976 Average Monthly Customers a/</u>	<u>Weighted Customers</u>
Residential	1	21,157	21,157
Commercial and large power - Secondary	2	2,652	5,304
Large power - primary	3	2	6
Street & highway lighting & other public authorities	3	<u>7</u>	<u>21</u>
Total		23,818	26,488

a/ 1976 FERC Form No. 1 Report, p. 409.

Step 5: Time-Varying Rates at System Generation Level

The first three steps in the development of time-varying rates concern the separation of the total costs of electricity service into components associated with the several different functional aspects of that service: power supply demand; energy furnished at different times of the day, week, and year; demands upon the distribution system; and customer-related costs. Step 4 explains how the quantities of service furnished in each of these functional areas can be measured. The purpose of Step 5 is to bring together these data calculated in the four preceding steps, to determine a rate per unit of service for each of the functional services provided by electric utilities.

In general, the energy charges in each rate period are simply the marginal running costs developed in Step 2, which are already expressed on a per Kwh basis. The demand-related costs of power production can be met either by charges against the noncoincident monthly billing demands measured during the peak rate period, which are a proxy for the individual customer contributions to the coincident system peak, or by charges against the energy used in the peak rate period. A combination is also possible, with some of the demand-related costs recovered by charges against billing demands and some of the cost recovered by charges against energy usage in the peak period. The power supply demand charge is levied only against billing demands and/or energy usage in the peak rate period, because high

rates of energy use in off-peak periods, when generating capacity is idle, do not affect the demand-related costs incurred by the utility furnishing service. Without metered demand data, however, it is necessary to make the simplifying assumption that all customers attain their maximum monthly demands during the peak period.

Transmission costs should generally be recovered in the same way that the demand-related costs of power production are recovered, because transmission serves the functional purpose of integrating the power supply centers and connecting them to the major load centers. Since the size and cost of the transmission network are governed by the maximum demands placed upon the network, these costs are related to capacity rather than to energy.*

The size and cost of the distribution system are also related to demand rather than to energy, but--like power supply demand costs--they may be recovered either from demand charges or from energy charges, or from a combination of the two. If distribution cost is recovered from demand charges, these charges should be applied to the maximum noncoincident demands for service from the distribution system, without regard to the rate period in which the maximum occurs for any individual customer. The power supply demand charge is limited to the peak period, because customers should not be charged additionally

* But see below for a qualification of this proposition.

for high rates of energy used during the off-peak period. However, the required capacity of the distribution system is governed by the maximum local (neighborhood) demands that will be placed on it, regardless of when that maximum occurs. The best proxy for this local maximum is the sum of individual customer maximum billing demands, regardless of when they occur.

The costs per unit of the several functional components of service rendered by the Newport Electric Corporation in 1976 are developed in Schedule 6. Total capacity costs at the margin are the product of the marginal cost of peaking capacity and the 1976 Newport system peak, or \$3,007,680. This is billed against the estimated sum of monthly noncoincident demands, resulting in a cost per Kw per month of \$1.6929. Total transmission costs, taken from Schedule 4, are also billed against the sum of monthly noncoincident demands, resulting in a cost per Kw per month of \$.5674. Distribution costs from Schedule 4 are spread over all billing demands of customers receiving service below 23 Kv transmission voltage. The resulting monthly cost per Kw is \$1.2357. If cost data were available to permit separating secondary and primary distribution costs, then separate monthly unit costs for these two dimensions of service would be calculated to be billed only to those customers who impose such costs on the system. Total customer costs from Schedule 4 are billed against the total of weighted customers, resulting in a cost per month per weighted customer of \$3.3443.

Two further comments are required regarding the unitized costs of capacity and transmission. First, it is preferable to separate transmission costs into three components if data are available. EHV transmission capacity costs (say, 235 Kv and larger) are not properly charged against demand because these lines are really constructed to serve energy requirements at lower costs per Kwh. Specifically, these large transmission lines are installed to transmit to load centers energy from very large baseload plants that are usually located at great distance from some (or all) load centers. The alternative would be to serve these energy requirements with peaking or cycling capacity located near the load center. The larger capital costs of the baseload plant and required EHV transmission will be incurred only when the fuel savings are great enough to offset them. Thus, the EHV capital costs are appropriately assigned to energy.

The portion of transmission costs properly assignable to demand is made up by the marginal costs involved in tying the new peaking plant into the existing transmission system, plus the costs of the transmission network below EHV levels (that properly can be viewed as similar in function to the distribution system, the capacity of which is directly dependent upon the maximum noncoincident demands placed on the system.)

The final point relates to the benefits that accrue to the system from the diversity of customers' demands, and who ought to receive these diversity benefits. For each metered Kw of

demand, the average customer will contribute considerably less than a Kw to the system peak, which governs the amount of generation capacity that must be maintained. Thus, if average customer diversity relative to the monthly system peak is 3.0, for each Kw of billing demands the Company would have to maintain 1/3 of a Kw of capacity. Since total capacity cost is determined by the annual coincident peak demands placed on the system, the cost of this capacity is properly assigned to each customer's contribution to the system peak, rather than to his own maximum demand. However, the cost of metering demands on this basis would be prohibitive.

Two options are available. One is to treat all customers alike on the basis that a Kw is the same regardless of how it is used or who uses it. This approach distributes the benefits of diversity to all customers on the system, regardless of whether they have little or substantial diversity themselves. Alternatively, customers can be grouped into homogeneous classes; the diversity of these classes measured; and total capacity costs allocated among these classes by taking account of their relative diversity factors. With this approach, customers within each class gain the benefits of the diversity of their own class. Customers within classes that have little diversity relative to the system peak would pay relatively greater capacity charges, while customers in those classes with relatively great diversity would pay relatively smaller demand charges.

It should be recalled that noncoincident billing demands are simply used as proxy for a customer's contribution to the system peak. Accounting for diversity between billing demands and system coincident peak demands when allocating capacity cost responsibility is therefore consistent with the principle of designing rates to reflect costs of service. While some customers in classes with relatively great diversity will actually peak at the time of the system peak and therefore pay less than their actual contribution to system capacity costs, the probability is highest that diversity benefits will be returned to those who created them if the benefits are retained within homogeneous customer classes than if distributed to all customers on the system.

There are at least two methods by which to retain diversity benefits within classes. One approach is to adjust (weight) class billing demands by each class's relative diversity factor. Alternatively, the total marginal costs of capacity can be allocated among customer classes according to each class's contribution to system peak. The resulting capacity cost responsibility is then billed against the total noncoincident billing demands of each class. This latter procedure is used to determine capacity costs and the resulting retail rates by class for the Newport Electric Corporation. For the sake of continuity, the calculations are deferred until Step 7.

Newport Electric Corporation

Cost per Unit of Functionalized Service at Generation Level

<u>Function</u>		
<u>Capacity</u>		
Cost: \$41.60 per Kw	a/ x 72,300 Kw	b/
Monthly billing Kw	c/	\$3,007,680
Cost per Kw per month		1,776,651
		\$1.6929
<u>Transmission</u>		
Cost	d/	\$1,008,000
Monthly billing Kw	c/	1,776,651
Cost per Kw per month		\$.5674
<u>Distribution</u>		
Cost	d/	\$1,998,000
Monthly billing Kw	e/	1,616,881
Cost per Kw per month		\$1.2357
<u>Customer</u>		
Cost	d/	\$1,063,000
Monthly weighted billing units	f/	26,488
Cost per month per weighted customer		\$3.3443
<u>Energy g/</u>		
Peak period		26.8 mills
Summer evenings		21.9 mills
Off-peak peirod		18.5 mills

a/ Schedule 3, page 1.

b/ 1976 System Peak from FERC Form No. 1.

c/ Schedule 5, page 1.

d/ Schedule 4, page 1.

e/ 1,776,651 less estimated annual billing demands of Navy and Kaiser, which are served at 23 Kv. (15,202 Kw x 10.5098 = 159,770 Kw.)

f/ Schedule 5, page 6.

g/ Schedule 2.

Step 6: Adjusting Time-Varying Rates
to Meet the Established Revenue Requirement

If the time-varying rates determined in Step 5 are applied to the billing determinants at system generation level, as developed in Step 4, the result is a definite amount of revenue. This revenue amount may, by chance, equal the revenue requirement established by other means for the electric utility in question, but it is possible (indeed, likely) that it will not. In the procedures used in this manual, some parts of the time-varying rates are indeed developed from an analysis of the embedded total system costs, as these costs would be viewed in determining a revenue requirement. But only the transmission, distribution, and customer costs are so treated in this presentation; whereas the prices for both the demand and the energy components of power supply are based upon marginal rather than upon embedded average costs. The initially determined time-varying rates will, therefore, produce revenues equal to the total embedded costs only if the higher marginal costs of energy exceed the average costs of energy by exactly the amount by which the average costs of all capacity exceed the marginal costs of peaking capacity. Finally, the embedded costs used in developing the time-varying rate structure may not themselves equal the revenue requirement. This would occur, for example, if the costs were based upon a calendar-year during which a rate increase was placed in effect, so that the current revenue

requirement exceeds the revenues actually collected during the year of the cost study.

The purpose of Step 6 is to explain how the rates determined in Step 5 can be adjusted to meet an established revenue requirement. To make adjustments, it is first necessary to know what the revenue requirement is. This is not likely to be a problem in a complete rate investigation, where the rate structure can be established for the same test year that is used in the determination of the revenue requirement by the regulatory authority. In other circumstances, it will be necessary to calculate the revenues that would have been obtained if the currently approved rates had been in effect for the entire year used in developing the billing determinants for setting the time-varying rates. If the currently approved rates were actually in effect during this entire year, then this calculation simply involves adding up the actual revenues; but if a rate change has occurred since the beginning of this base year, the revenues actually collected during the year must be adjusted to reflect the new rate levels most recently approved.

A. General Considerations

There are several different ways that time-varying rates can be adjusted to meet an established revenue requirement. Following are brief discussions of six different approaches to the adjustment problem.

1. Uncertainty in the marginal cost calculations. The estimation of marginal energy and capacity costs is invariably subject to some uncertainty. Marginal running costs differ from hour to hour, even within a single rate period, and this variation defines a plausible range for the kilowatt-hour charge. Similarly, the marginal cost per kilowatt of capacity depends upon which generation plant is chosen as the standard for measurement, and this again defines a range in the demand components that will be recovered through the rates in one way or another. Rates can be adjusted upward or downward to one extreme or the other of this range, where that is necessary to meet a preestablished revenue requirement.

In the case of Newport Electric Corporation this rationale could be used as a basis to adjust revenues by reducing the off-peak energy charge by the amount needed. This approach might be considered appropriate in view of the fact that most generating capacity under construction for New England uses nuclear fuel and has running costs far below even 17 mills, with the expected result that the dispatching procedures might shift to slightly more efficient fossil-fired units at the margin in the off-peak periods in the future. More important, it was also noted that the marginal running costs for turbines and other peaking units exceed 30 mills per kilowatt-hour; and that the only way to have a time-weighted average marginal running cost during the peak rate period below 30 mills is through the inclusion therein of many hours when none of the

turbines is being used. Since it is expected that the current excess reserves of generating capacity in New England will be reduced, as demand grows more rapidly during the next few years than capacity, it can be expected that the use of peaking plants will increase, and this would raise the time-weighted average of marginal running costs in the peak period. Thus, an additional adjustment can be supported that would raise the peak period running charge sufficiently to more than offset the decrease in the off-peak running charge. Such an approach may not, of course, solve the excess revenue problem.

In principle, economic advice is likely to suggest that the best point estimate be chosen from a range of uncertainty, and that there is great peril in using the admitted imperfections in one's methods and techniques as an excuse for reaching a result that one may, for other reasons, want to achieve. On the other hand, there is considerable debate over the correct way to establish prices based on marginal costs in the first place, and it would be difficult to object in practice to the use of external constraints as a device for helping to resolve some of this controversy.

2. Aberrations in the data for a single utility. The determination of costs for a particular utility may involve the use of data that are atypical of representative cost conditions. For instance, if a given system is far out of balance with regard to its plant program, its actual marginal running costs during the off-peak period may not reflect these costs in the

future as new construction optimizes the plant program. Since one of the objectives of marginal cost pricing is to give consumers stable signals as to the real cost of producing energy as it is consumed (or foregone) at the margin, the use of a more long-term equilibrium cost, rather than a more short-term cost aberration, may be justified on a rational basis, as well as aiding in the achievement of a given revenue requirement. An example of this approach would be the increasing of the peak-period running charge for Newport Electric Corporation, to reflect expected future cost conditions in New England as the gap between capacity and demand is narrowed.

3. Redefinition of rate periods. A third approach is to shift hours from high-price to low-price rate periods, to reduce the revenue obtained from given rates, or in the opposite direction with the opposite effect. In other words, the boundaries of the peak and the off-peak periods will generally be selected with reference to the load curves and the dispatching system, but where these two do not mesh perfectly, there is a need to apply judgment and practical considerations. One such practical consideration can be the amount of revenue that is required, and this can be used to decide whether a particular borderline hour belongs in a high-priced or a low-priced rate period. The same practical considerations apply to this approach as to adjustments made within the range of uncertainty about what the marginal costs themselves are.

4. Flat percentage adjustment to some or all components of a multipart rate structure. A flat percentage adjustment to all parts of the multi-part rate structure is another practical way to remove any difference between the revenue requirements and the revenue that would be generated from rates set at marginal costs. Alternatively, this adjustment can be performed only on those functional components that are estimated on a marginal cost basis, since those rate components estimated on the basis of average cost lead to revenues that match the costs of service based on average embedded cost. If the adjustment is small, this approach has much to recommend it. (And if the adjustment is a large one, then no approach is likely to be very good.) This approach has the appeal of apparent fairness, and its results are likely to be very much like those that are obtained when the first approach is applied. As far as economic merit is concerned, the question is how this approach compares with the more finely tuned ones to be discussed in the following two points.

5. Adjustment only to customer charges. Adjustment only to the customer charges is likely to be appropriate and practical only if the adjustment is downward. The principal argument in favor of adjusting customer charges is that they are the one part of the rate structure to which the demand response is likely to be least elastic. In other words, modest reductions in the customer charge are not likely to have any impact on the

number of customers, whereas adjustments in any other part of the rate structure are likely to affect electricity usage to some extent. This argument also applies to upward adjustments of customer charges if they should become necessary, but it is likely that any such action would be interpreted as a regressive shift of revenue responsibility onto customers with lower incomes or lesser abilities to pay.

6. The inverse elasticity rule. The inverse elasticity rule for making revenue adjustments can be applied in either of two very different ways. One approach is to use elasticity estimates as a criterion in deciding what parts of a multipart rate structure should be changed. For example, this is the principle on which the customer charge is best defended as the most appropriate candidate for revenue adjustment when that becomes necessary.

A very different use of the inverse elasticity rule is its application to adjust differently the prices paid by different classes of customers. This approach is defended only on the grounds of economic efficiency, and even economic principles recognize that questions of equity must also be considered in public policy decisions such as electricity pricing. Since it is extremely difficult in practice to determine the elasticity of demand for any one customer or customer class, there are extreme difficulties likely to be encountered in attempting to implement the principle of inverse elasticity for choosing among customers and deciding how much to adjust the rates of each customer or customer class.

B. Newport Electric Corporation

Two different adjustments are developed in the Newport case study: an adjustment of the customer charge only, and proportional adjustment of both power production components (capacity and energy charges). Utilization of the marginal unit costs of capacity and energy leads to a small revenue excess of \$172,240, or 1.6 percent of total power production costs under an average costing approach. The calculation of this revenue excess is shown in Schedule 7.

In Schedule 8 is provided the calculation of the adjusted customer charge if the entire adjustment is made on this functional component. The result is a reduction of the weighted customer charge from \$3.3443 to \$2.8024, or a reduction of 16 percent. Page 2 of Schedule 8 shows that the adjusted (Variant A) rates at generation level produce the pro forma revenue requirement of \$15.142 million.

A proportional adjustment of the capacity and energy charges is shown on page 1 of Schedule 9. The reduction of each power production component rate is 1.6 percent, the amount by which power production revenues at marginal costs exceed the costs of these services estimated at average embedded costs. On page 2 of Schedule 9 it is demonstrated that the adjusted (Variant B) rates produce the pro forma revenues ordered by the Commission, except for a minor deviation due to rounding.

Newport Electric Corporation: 1976

Calculation of the Excess of Power Production Revenues
at Marginal Cost Determination over
Proposed Revenues at Average Cost Determination

Power production at marginal costs	\$11,245,240
Cost of power production from average cost study	\$11,073,000
Excess of functionalized power production revenues determined on a marginal cost basis over power production costs determined on an average cost basis	\$172,240

Newport Electric Corporation

Revenues from Application of
Marginal Costs of Power Supply

<u>Function</u>	<u>Marginal Cost</u>	<u>Billing Determinant at Generation</u>	<u>Revenue at Marginal Costs</u>
Capacity <u>a/</u>	\$41.60	72,300 Kw	\$3,007,680
Energy <u>a/</u>		<u>MWH</u>	
Peak	26.8 mills	157,745	\$4,227,566
Shoulder	21.9 mills	13,393	293,307
Off-peak	18.5 mills	<u>200,902</u>	<u>3,716,687</u>
Total Energy		372,040	\$8,237,560
Total power supply revenues at marginal costs			\$11,245,240

a/ Schedule 6.

Newport Electric Corporation
Rate Adjustment to Calibrate to
1976 Pro Forma Revenue Requirement
(Variant A: Customer Charge Only)

Revenue excess at marginal costs	\$172,240
Weighted customers	26,488
Decrease in weighted customer cost per month	\$.5419
Adjusted monthly weighted customer charge	\$2.8024

Newport Electric Corporation

Revenue Verification with Variant A Adjusted Rates
(at Generation Level)

<u>Function</u>	<u>Unit Cost</u>	<u>Billing Units</u>	<u>Revenue</u>
Capacity	\$1.6929/Kw	1,776,651 Kw	\$3,007,692
Transmission	.5674/Kw	1,776,651 Kw	1,008,072
Distribution	1.2357/Kw	1,616,881 Kw	1,997,980
Customer	2.8024/customer month	26,488/ weighted customer months	890,760
<u>Energy</u>			
Peak	26.8 mills	157,745 Mwh	4,227,566
Summer evenings	21.9 mills	13,393 Mwh	293,307
Off-peak	18.5 mills	<u>200,040 Mwh</u>	<u>3,716,687</u>
Total Energy		372,040 Mwh	8,237,560
Total All Functions			<u>\$15,142,064</u>
Total Pro Forma Revenue Requirement			<u>\$15,142,000</u>

Newport Electric Corporation

Rate Adjustment to Calibrate to
1976 Pro Forma Revenue Requirement

(Variant B: Proportional Adjustment of Marginal Components)

- | | |
|---|--------------|
| 1. Power production revenues at average costs | \$11,073,000 |
| 2. Power production revenue at marginal costs | \$11,245,240 |
| 3. Proportional adjustment factor [(1) - (2)] | .98468 |
| 4. <u>Adjusted Cost per Unit of Functionalized Service at Generation Level:</u> | |

<u>Function</u>	<u>Before Adjustment</u>	<u>Adjustment Factor</u>	<u>Adjusted Cost</u>
Capacity	\$1.6929	.98468	\$1.6670
<u>Energy</u>			
Peak	26.8 mills	.98468	26.4 mills
Summer evening	21.9 mills	.98468	21.6 mills
Off-peak	18.5 mills	.98468	18.2 mills

Newport Electric Corporation

Revenue Verification with Variant B Adjusted Rates
(at Generation Level)

<u>Function</u>	<u>Unit Cost</u>	<u>Billing Units</u>	<u>Revenue</u>
Capacity	\$1.6670/Kw	1,776,651 Kw	\$2,961,677
Transmission	.5674/Kw	1,776,651 Kw	1,008,072
Distribution	1.2357/Kw	1,616,881 Kw	1,997,980
Customer	3.3443/customer month	26,488/weighted customer months	1,063,006
<u>Energy</u>			
Peak	26.4 mills	157,745 Mwh	4,164,468
Summer evenings	21.6 mills	13,393 Mwh	289,289
Off-peak	18.2 mills	200,902 Mwh	3,656,416
Total Energy		372,040 Mwh	\$8,119,173
Total Revenues at Marginal Costs			\$15,140,908
Total Pro Forma Revenue Requirement			\$15,142,000
Revenue Discrepancy Under Adjusted Marginal Cost Rates (due to rounding)			\$1,092

Step 7: Time-Varying Rates at Customer Level,
Marked Up for Loss Factors

After rates have been determined at system generation level consistent with a revenue requirement, one further step is necessary in the derivation of retail rates. The rates at system generation level must be marked up to reflect both demand and energy losses that occur between the generation level and the delivery of electricity to ultimate consumers. Since losses vary with the delivery voltage level and rate period during which service is taken, loss estimates should vary accordingly.

The adjustment of rates from system generation level to customer level, to reflect transmission and distribution losses, is illustrated for the Newport Electric Corporation system in Schedules 10 through 12. The actual computation is extremely simple and straightforward, as illustrated in Schedule 10. This schedule shows the development of retail rates for customers taking service at transmission and distribution voltages for both the Variant A and Variant B rate designs. The rates at generation level are shown in the first row of the schedule, and are taken directly from Schedule 6 and either Schedule 8 or 9. The assumed loss factors are also shown in Schedule 10, with different factors applicable to customers served at distribution and transmission voltages. Lower loss factors should apply to off-peak than to on-peak energy for each class, but there was no basis upon which to estimate these loss differentials.

Once the loss factors have been determined, all that remains is division of the rates at generation level by the loss factors to obtain the actual rates applicable at the customer level. This is done for Variant A rates on page 1 of Schedule 10 and for Variant B rates on page 2 of the same schedule.

Determination of the appropriate loss factors for each customer class requires the combination of engineering judgment with available statistical information. Average loss factors for total system energy for all classes can be determined by comparing total energy recorded at the system level in the system dispatch logs. Loss factors at peak periods would generally be higher, owing to Ohm's Law. Loss factors also differ by delivery voltage level, and engineering judgment is likely to be required to establish the appropriate differentials in the loss factors. Such a study is presently being conducted for the Newport Electric Corporation. When these improved loss factor estimates are completed, they should be used to mark up each of the generation level rate components to the retail level.

One final caution about the loss factors is that they must indeed be consistent with the true relationship between energy sales recorded at meters and energy at the system level. The reason is that no further check is being made at this point to insure that the actual rates at the customer level provide revenue equal to the established revenue requirement. As time-recording meters come into wider use, and actual billing

determinants are recorded for the customer classes that will be subject to time-varying rates, it will become possible to test actual rates at the customer level against the established revenue requirement, and to make the necessary adjustments at this level rather than at the system generation level. But under present conditions of data unavailability, the best that can be done is to caution the users about the need for estimating as accurately as possible the relationship between billing determinants at customer level, after losses, and billing determinants actually recorded at the system generation level.

Two additional sets of rates are also calculated at this juncture for the Newport Electric Corporation. It was pointed out in the discussion accompanying Step 5 that demand-related cost responsibilities could be calculated to permit each customer class to retain the benefits of its own diversity. This step is taken in Schedule 11 for both Variants A and B rates. In each case, the total costs of capacity and transmission (after adjustments) are allocated among the four customer classes in proportion to their contributions to the annual system peak. Each class's cost responsibility is then divided by the number of noncoincident billing demands for each class to arrive at monthly capacity and transmission charges per Kw for each class. These rates are then taken to the retail level in Schedule 12 by dividing each component by the appropriate loss factor.

Ordinarily the procedure results in lower costs per Kw for the residential and small commercial classes owing to their

greater relative diversity of demands. In the case of the Newport Electric Corporation, however, the residential class has relatively low diversity due primarily to the assumption that the residential class peaks at the time of the system peak. The assumption rests heavily on the two observations that Newport is an evening-peaking system in the winter, and that the residential class comprises a disproportionately large share of total peak demand relative to other systems. As a result, residential customers gain only the benefit of their intraclass diversity; it is assumed that there is no inter-class diversity. When the adjustments for diversity are made, residential customers' capacity charges (at Variant A generation level) increase by about 26 cents; their transmission charge rises by about nine cents.

The only class to receive a reduction in demand charges when diversity is accounted for is the commercial class. Large power and lighting customers' rates both rise substantially. Whether these adjustments are appropriate depends directly upon the accuracy of the diversity factors that have been assumed in building the estimate of class contributions to system peak and class noncoincident billing demands. The importance of these assumptions underscores the importance of initiating and maintaining ongoing load survey programs to support the development of accurate time-of-use rate designs.

Newport Electric Corporation

Retail Rates with Variant A Adjustment
(Adjusted Customer Charge Only)

	<u>Capacity</u>	<u>Transmission</u>	<u>Distribution</u>	<u>Customer</u>	<u>Energy (mills)</u>		
					<u>Peak</u>	<u>Shoulder</u>	<u>Off-Peak</u>
<u>Costs at Generation</u>	\$1.6929	\$.5674	\$1.2357	\$2.8024	26.8	21.9	18.5
<u>Rates at Transmission Voltage</u>							
Assumed loss factors	.94	.94	--	--	.96	.96	.96
Rates at retail	1.8010	.6036	--	2.8024	27.9	22.8	19.3
<u>Rates at Distribution Voltage</u>							
Assumed loss factors	.89	.89	.89	--	.91	.91	.91
Rates at retail	1.9021	.6375	1.3884	2.8024	29.5	24.1	20.3

Newport Electric Corporation

Retail Rates with Variant B Adjustment
(Proportional Power Supply Cost Adjustment)

	<u>Capacity</u>	<u>Transmission</u>	<u>Distribution</u>	<u>Customer</u>	<u>Energy (mills)</u>		
					<u>Peak</u>	<u>Shoulder</u>	<u>Off-Peak</u>
<u>Costs at Generation</u>	\$1.6670	\$.5674	\$1.2357	\$3.3443	26.4	21.6	18.2
<u>Rates at Transmission Voltage</u>							
Assumed loss factors	.94	.94	--	--	.96	.96	.96
Rates at retail	1.7734	.6036	--	3.3443	27.5	22.5	19.0
<u>Rates at Distribution Voltage</u>							
Assumed loss factors	.89	.89	.89	--	.91	.91	.91
Rates at retail	1.8730	.6375	1.3884	3.3443	29.0	23.7	20.0

Newport Electric Corporation

Class Allocation of Capacity and Transmission Costs
to Retain Diversity Benefits within Classes

	Estimated Contribution to January 1978 System Peak		Capacity Costs		Transmission Costs	Estimated 1976 Billing Demands (Kw)	Unit Costs at Generation Capacity		
	Kw	%	Variant	Variant			Variant	Variant	Transmission
			A	B					
Residential	29,137	45.44%	\$1,366,689	\$1,345,786	\$458,035	691,892	\$1.9753	\$1.9451	\$.6620
Commercial	13,751	21.44	644,847	634,984	216,115	775,739	.8313	.8186	.2786
Large power	19,710	30.74	924,560	910,420	309,859	292,982	3.1557	3.1074	1.0576
Street & other lighting	1,526	2.38	71,584	70,487	23,991	16,038	4.4634	4.3950	1.4959
Total system, excluding company use	64,124	100.00%	\$3,007,680	\$2,961,677	\$1,008,000	1,776,651	\$1.6929	\$1.6670	\$.5674

Newport Electric Corporation

Retail Rates with Retention of Class Diversity Benefits
Residential Class

	<u>Capacity</u>	<u>Transmission</u>	<u>Distribution</u>	<u>Customer</u>	<u>Energy (mills)</u>		
					<u>Peak</u>	<u>Shoulder</u>	<u>Off-Peak</u>
<u>Costs at Generation</u>							
Variant A	\$1.9753	\$.6620	\$1.2357	\$2.8024	26.8	21.9	18.5
Variant B	1.9451	.6620	1.2357	3.3443	26.4	21.6	18.2
<u>Rates at Retail</u>							
Assumed loss factors	.89	.89	.89	--	.91	.91	.91
Variant A retail rates	2.2194	.7438	1.3884	2.8024	29.5	24.1	20.3
Variant B retail rates	2.1855	.7438	1.3884	3.3443	29.0	23.7	20.0

Newport Electric Corporation

Retail Rates with Retention of Class Diversity Benefits
Commercial Class

	<u>Capacity</u>	<u>Transmission</u>	<u>Distribution</u>	<u>Customer</u>	<u>Energy (mills)</u>		
					<u>Peak</u>	<u>Shoulder</u>	<u>Off-Peak</u>
<u>Costs at Generation</u>							
Variant A	\$.8313	\$.2786	\$1.2357	\$2.8024	26.8	21.9	18.5
Variant B	.8186	.2786	1.2357	3.3443	26.4	21.6	18.2
<u>Rates at Retail</u>							
Assumed loss factors	.89	.89	.89	--	.91	.91	.91
Variant A retail rates	.9340	.3130	1.3884	5.6048	29.5	24.1	20.3
Variant B retail rates	.9198	.3130	1.3884	6.6886	29.0	23.7	20.0

Newport Electric Corporation

Retail Rates with Retention of Class Diversity Benefits
Large Power Class

	<u>Capacity</u>	<u>Transmission</u>	<u>Distribution</u>	<u>Customer</u>	<u>Energy (mills)</u>		
					<u>Peak</u>	<u>Shoulder</u>	<u>Off-Peak</u>
<u>Costs at Generation</u>							
Variant A	\$3.1557	\$1.0576	\$1.2357	\$2.8024	26.8	21.9	18.5
Variant B	3.1074	1.0576	1.2357	3.3443	26.4	21.6	18.2
<u>Rates at Transmission Voltage</u>							
Assumed loss factors	.94	.94	--	--	.96	.96	.96
Variant A retail rates	3.3571	1.1251	--	8.4072	27.9	22.8	19.3
Variant B retail rates	3.3057	1.1251	--	10.0329	27.5	22.5	19.0
<u>Rates at Distribution Voltage</u>							
Assumed loss factors	.89	.89	.89	--	.91	.91	.91
Variant A retail rates	3.5457	1.8883	1.3884	5.6048	29.5	24.1	20.3
Variant B retail rates	3.4915	1.8883	1.3884	6.6886	29.0	23.7	20.0

Newport Electric Corporation

Retail Rates with Retention of Class Diversity Benefits
Street & Other Lighting

	<u>Capacity</u>	<u>Transmission</u>	<u>Distribution</u>	<u>Customer</u>	<u>Energy (mills)</u>		
					<u>Peak</u>	<u>Shoulder</u>	<u>Off-Peak</u>
<u>Costs at Generation</u>							
Variant A	\$4.4634	\$1.4959	\$1.2357	\$2.8024	26.8	21.9	18.5
Variant B	4.3950	1.4959	1.2357	3.3443	26.4	21.6	18.2
<u>Rates at Retail</u>							
Assumed loss factors	.89	.89	.89	--	.91	.91	.91
Variant A retail rates							
o for public authorities	5.0151	1.6808	1.3884	8.4072	29.5	24.1	20.3
o for residential lighting	5.0151	1.6808	1.3884	2.8024	29.5	24.1	20.3
Variant B retail rates							
o for public authorities	4.9382	1.6808	1.3884	10.0329	29.0	23.7	20.0
o for residential lighting	4.9382	1.6808	1.3884	3.3443	29.0	23.7	20.0

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Step 8: Typical Bill Comparisons

The schedule of rates developed by the procedure presented in the previous sections are intended to reflect the costs of furnishing the several components of electricity service to the various classes of customers, and to recover the revenue requirement approved by the regulatory authority. Before implementing these rates, however, it is important also to consider the effects that the time-varying rates will have on typical customer bills. Parties to the rate hearings will be particularly interested in comparing typical bills computed under existing rates and against the proposed time-varying rate design. Second, these comparisons will provide some indication of any changes in customer class revenue responsibility that may occur with implementation of the time-varying rates. This question of class revenue responsibilities cannot be answered definitely until after the rates are implemented and/or more detailed information is gathered on class billing determinants by rate period, but it is so important that even rough indications are useful. Finally, a comparison of bills at given monthly Kwh usage levels, but with different time patterns, will indicate the potential savings that customers can realize by adjusting their patterns of consumption to the incentives incorporated in the rate design.

Comparisons of class revenue responsibilities under two versions of Variant A time-of-use rates and existing declining

block rates are presented in Schedule 13. On page 3 of Schedule 13, energy revenues by class are calculated under Variants A and B rates. The distribution of energy use for each class is assigned by assumption, lacking the detailed information to make these assignments directly. The lighting class energy use by rate period is developed by assuming no diversity for the class and certain hours of operation for winter and summer seasons. The remaining classes are assumed to use energy within each period in direct proportion to the system as a whole, less the lighting class. Thus, the energy cost responsibility for each class assumes that the hourly distribution of the class loads are similar to the system as a whole.

The energy revenues under Variant A rates are brought forward to page 1 of Schedule 13, which shows the costs of each functional component of service by customer class under Variant A rates when diversity benefits are retained by class. Page 2 of Schedule 13 shows Variant A class revenue responsibilities when diversity benefits are shared by all customers regardless of class. These revenue comparisons suggest several points that will be of obvious interest to all parties to the ratemaking proceeding.

Residential revenue responsibility is slightly higher under marginal costs than under average costs, and this class is assigned greater responsibility when class diversity is accounted for. The responsibility of the commercial class is approximately the same under average costs and Variant A marginal-

cost-based rates; but when diversity is shared by all customers, its class revenue responsibility rises by about a million dollars. This indicates the importance of deciding who will receive the diversity benefits. The costs allocated to large power transmission customers are significantly higher under existing rates, especially when diversity benefits are shared by all customers. The same is true for the class of lighting customers. Large-power customers taking service at distribution voltages are allocated similar revenue responsibilities under existing rates and Variant A time-of-use rates when diversity levels are retained; but their allocated share is considerably lower when diversity is shared regardless of customer class.

In general terms, when the effects of class diversity are accounted for, only the large-power customers taking service at transmission voltage appear to be paying rates based on average costs that significantly exceed the revenue responsibility assigned to them under Variant A marginal-cost-based rates. In short, considering that Newport Electric Corporation has never undertaken a full class cost-of-service study, it is to the Company's credit that its assigned class revenue responsibilities track costs as closely as they do. Of course, it must be recalled that these comparisons are based upon roughly estimated class billing demands and upon the assumption that each class (except lighting customers) use energy by rate period in the same proportion as the system as a whole. If these assumptions and estimates miss the mark by a wide margin, then revenue

responsibilities under either version of Variant A rates will change significantly.

Typical bill comparisons are presented in Schedule 14 for the rate 101 general residential customers on the Newport Electric Corporation system. Bills under the existing rates (101) and Variant A rates (with diversity retained) were computed for customers with typical load factors and average systemwide distribution of energy among the three rate periods (42 percent, 4 percent, 54 percent). Bills for several combinations of different load factors and different distributions of energy among the rate periods were also computed for each monthly usage level to demonstrate the effect of different load characteristics. The number of clock-hours falling in each rate period was used as a bound indicating the most favorable distribution of energy use among rate periods that is likely to occur.

The Newport bill comparisons provide a good indication of the impact that the time-varying rates will have on customers in the residential class. Small residential customers, for example, could pay substantially more or less under the time-varying rates, depending upon the load factor and the distribution of energy use by rate period. Larger residential customers, who benefit from the declining blocks in the existing rate structure, would pay approximately the same monthly bill under the time-varying rate design if they have a relatively desirable

load pattern, but substantially more with either a typical or an undesirable load pattern.

These bill comparisons also illustrate the savings that customers can realize by adjusting their usage patterns to the incentives incorporated in the rate design, as well as to the penalties they will incur by maintaining load patterns that result in higher costs of providing electric power.

Newport Electric Corporation

Class Revenue Responsibilities under
Variant A Time-of-Use Rates
(Diversity Benefits Retained by Class)

	<u>Residential</u>	<u>Commercial</u>	<u>Large Power</u>		<u>Lighting</u>	<u>Total</u>
			<u>Trans- mission Voltage</u>	<u>Distri- bution Voltage</u>		
Demand charge/Kw	\$3.8730	\$2.3456	\$4.2133	\$5.4490	\$7.1950	
Billing demands	691,892	775,739	159,770	133,212	16,038	
Demand revenues	<u>\$2,679,698</u>	<u>\$1,819,573</u>	<u>\$637,159</u>	<u>\$725,872</u>	<u>\$115,393</u>	\$6,013,695
Customer charge	\$2.8024	\$2.8024	\$2.8024	\$2.8024	\$2.8024	
Weighted customers	21,007	4,430	6	100	945	
Customer revenues	<u>\$706,440</u>	<u>\$148,976</u>	<u>\$202</u>	<u>\$3,363</u>	<u>\$31,780</u>	\$890,761
Energy revenues	\$3,433,679	\$1,734,069	\$1,815,296	\$1,141,736	\$113,221	\$8,238,001
Total T-0-U Revenues	\$6,819,817	\$3,702,618	\$2,488,657	\$1,870,971	\$260,394	\$15,142,457
Pro Forma Revenues at Average Costs <u>a/</u>	\$6,636,466	\$3,563,701	\$2,754,213	\$1,782,212	\$393,114	\$15,129,706

a/ RI PUC Docket 1268, Revised Exhibit D, Schedule 1.

Newport Electric Corporation

Class Revenue Responsibilities under
Variant A Time-of-Use Rates
(Diversity Benefits Shared)

	<u>Residential</u>	<u>Commercial</u>	<u>Large Power</u>		<u>Lighting</u>	<u>Total</u>
			<u>Trans- mission Voltage</u>	<u>Distri- bution Voltage</u>		
Demand charge/Kw	\$3.4960	\$3.4960	\$2.2603	\$3.4960	\$3.4960	
Billing demands	691,892	775,639	159,770	133,212	16,038	
Demand revenues	<u>\$2,418,854</u>	<u>\$2,711,984</u>	<u>\$361,128</u>	<u>\$465,709</u>	<u>\$56,069</u>	\$6,013,744
Customer charge	\$2.8024	\$2.8024	\$2.8024	\$2.8024	\$2.8024	
Weighted customers	21,007	4,430	6	100	945	
Customer revenues	<u>\$706,440</u>	<u>\$148,976</u>	<u>\$202</u>	<u>\$3,363</u>	<u>\$31,780</u>	\$890,761
Energy revenues	\$3,433,679	\$1,734,069	\$1,815,296	\$1,141,736	\$113,221	\$8,238,001
Total T-0-U Revenues	\$6,558,973	\$4,595,029	\$2,176,626	\$1,610,808	\$201,070	\$15,142,506
Pro Forma Revenues at Average Costs <u>a/</u>	\$6,636,466	\$3,563,701	\$2,754,213	\$1,782,212	\$393,114	\$15,129,706

a/ RI PUC Docket 1268, Revised Exhibit D, Schedule 1.

Newport Electric Corporation

Energy Revenues by Class under Variants A & B Rates
(at Generation Level)

	Energy by Rate Period ^{a/}					Energy Revenues	
	1976 Sales	Sales at Generation ^{b/}	Peak	Shoulder	Off-Peak	Variant A	Variant B
Residential	140,785	154,846	66,275	5,574	82,997	\$3,433,679	\$3,380,598
Commercial	71,099	78,200	33,470	2,815	41,915	1,734,069	1,707,262
<u>Large Power</u>							
Transmission voltage	78,588	81,863	35,037	2,947	43,879	1,815,296	1,787,233
Distribution voltage	46,813	51,488	22,038	1,854	27,597	1,141,736	1,124,086
Lighting	5,129	5,643	1,010	130	4,503	113,221	111,427
Total All Classes	342,415	372,040	157,829	13,320	200,891	\$8,238,001	\$8,110,606

a/ Lighting class period distribution based on the assumption that there is no diversity for the class, and that lights operate on average from 8:30 a.m. to 6:30 p.m. during the three summer months, and from 7:00 p.m. to 7:00 a.m. during all other months. All other classes are assumed to use energy by rate periods in the same proportion as the entire system less the lighting class: 42.8% in peak hours, 3.6% in shoulder hours, and 53.6% in off-peak hours.

b/ Transmission voltage sales at meter increased with .96 assumed loss factor. All distribution voltage sales at meter increased to generation level by loss factor of .909193.

Schedule 14

Newport Electric Corporation

Bill Comparisons between Existing Rate 101
and Variant A Time-of-Use Rates, with Diversity Retained

	Monthly Kwh	Load Factor	Energy Use By Rate Period			Bills	
			Peak	S.E.	O.P.	Rate 101 a/	Time-of-Use Rates b/
1.	200	20%	42%	4%	54%	\$12.27	\$13.71
2.	200	27	35	4	61	12.27	12.02
3.	200	27	55	5	40	12.27	12.39
4.	200	35	35	4	61	12.27	10.97
5.	500	20	42	4	54	26.40	30.06
6.	500	27	35	4	61	26.40	25.82
7.	500	27	55	5	40	26.40	26.76
8.	500	35	35	4	61	26.40	23.25
9.	2,000	20	42	4	54	83.50	111.88
10.	2,000	27	35	4	61	83.50	94.92
11.	2,000	27	55	5	40	83.50	98.68
12.	2,000	35	35	4	61	83.50	84.70
13.	3,000	30	42	4	54	118.30	136.19
14.	3,000	30	30	3	67	118.30	132.77

a/ Source: RI PUC Docket 1268, Revised Exhibit D, Schedule 6.

b/ Source: Schedule 12, page 1.

Note: It is assumed that the maximum noncoincident demand is reached in the peak period.

Step 9: Deriving Class Revenue Requirements and
Conventional Rates from Marginal Costs

The implementation of time-varying rates, as described in the preceding steps, can only be accomplished where time-recording meters are (or already have been) installed. Since metering costs are very high, even for a relatively simple time-varying rate with only two rate periods for kilowatt-hour charges and a single demand charge, the introduction of time-varying rates must necessarily proceed very slowly; and, for some types of customers, time-varying rates may never be worth the cost. Conventional kilowatt-hour rates and two-part demand and energy rates will, therefore, continue to be used.

However, this continuing use of conventional rate forms is not a bar to the reliance on marginal costs in establishing some aspects of the rate structure. In particular, it is possible to use marginal costs rather than embedded average costs to derive the class revenue responsibilities that underlie conventional rates.

If the complete time pattern of loads for each customer class is known for the test year, then it is possible to apply the time-varying rates derived in Step 7 to each class as a whole, to determine its class revenue responsibility on the basis of time-varying marginal cost principles. The class load patterns may be known from load studies on a sample of customers in each class, or they may be partly estimated using load study data from comparable utilities.

If the time pattern of the class loads is not known, then it is necessary to rely on some data from a conventional class cost-of-service study to allocate revenue responsibility to the customer classes. However, it is still possible to apply these conventionally determined class allocation factors to a functionalization of total system costs based on marginal rather than on embedded average costs. Since a functionalization based on marginal cost principles is likely to assign greater cost to the energy function than an embedded cost approach, but less of the total system cost to peak demand and perhaps some other functions, the use of these marginal cost principles tends to assign greater revenue responsibility to those customers that use relatively more energy than capacity or other functional services. Specifically, marginal costing methods are likely to assign greater revenue responsibility to classes with high load factors than these classes are assigned under fully distributed average cost approaches.

Schedule 15 is an example of the use of conventionally determined class allocation factors to distribute costs functionalized in accord with marginal cost principles. It applies to the service by Newport Electric Corporation, and the functionalization of total jurisdictional cost, which was derived using Variant A marginal costs, is shown on the first line of the schedule. The class allocation factors appear in the bottom panel of the schedule, and they are similar to those derived in a conventional class-cost-of service study. When

these allocation vectors are applied to the costs functionalized on a marginal cost basis, they result in the class cost and revenue responsibilities shown on the second through the sixth lines of the schedule.

The allocation vectors used in Schedule 15 are of a type that are generally available in class cost-of-service studies. The factors for power production demand and for transmission are based on peak responsibility. Power production energy is allocated in accord with class energy use, and without any registration of differences in the time pattern of class loads. Distribution and customer-related costs are based on demands at the distribution level and on the weighted number of customers.

Once class revenue responsibilities have been determined, the process of designing conventional rates to recover these revenues proceeds along the conventional path. However, classes with two-part rates may have a lower demand charge and higher energy charge than under a conventional fully distributed, embedded cost-of-service approach, because the functional components of revenue responsibility for each class will be more heavily weighted toward energy when marginal costing concepts have been used. This is the most important practical effect of applying marginal cost principles to rate structure.

Newport Electric Corporation

Conventional Class Revenue Allocation
of Functional Components of Service at Marginal Costs

Costs By Function

	<u>Capacity</u> ^{a/}	<u>Transmission</u> ^{b/}	<u>Distribution</u> ^{b/}	<u>Customer</u> ^{c/}	<u>Energy</u> ^{d/}	<u>Total</u> ^{*/}
1. Jurisdiction	\$3,007,680	\$1,008,000	\$1,998,000	\$890,760	8,237,560	\$15,142,000
2. Residential	1,366,645	458,020	854,980	706,440	3,428,538	6,814,623
3. Commercial	644,980	216,159	958,590	148,976	1,731,473	3,700,178
<u>Large Power</u>						
4. Transmission	533,018	178,637	--	202	1,812,578	2,524,435
5. Distribution	391,462	131,195	164,612	3,363	1,140,027	1,830,659
6. Lighting	71,576	23,988	19,818	31,779	124,945	272,106

Allocation Vectors

	<u>Contribution to System Peak</u> ^{f/} (Kw)	<u>Sum of Non-Coincident Demands</u> ^{g/} (Kw)	<u>Weighted Customers</u> ^{h/} (No.)	<u>Energy Sales</u> ^{g/} (Mwh)
Residential	29,137	691,892	21,007	154,846
Commercial	13,751	775,739	4,430	78,200
<u>Large Power</u>				
Transmission	11,364	--	6	81,863
Distribution	8,346	133,212	100	51,488
Lighting	<u>1,526</u>	<u>16,038</u>	<u>945</u>	<u>5,643</u>
Total	64,124	1,616,881	26,488	372,040

- a/ Allocated according to contribution to system peak.
b/ Allocated according to sum of noncoincident demands.
c/ Allocated according to number of weighted customers.
d/ Allocated according to energy sales.
e/ Jurisdictional customer and energy costs are from Schedule 8, page 2; other functional costs are from Schedule 6.
f/ From Schedule 5, pages 3, and 4. These are contributions to the January 1978 peak that are assumed to be proportional to each class's contribution to the 1976 annual system peak.
g/ From Schedule 5, page 1.
h/ From Schedule 13, page 1.
*/ Class Totals may not sum to jurisdictional total due to rounding.



APPENDIX C

THE PROPOSED INVERTED-LIFELINE
RATES FOR THE NEWPORT ELECTRIC CORPORATION

An Evaluation of the Costing Methodology,
Rate Design and Experimental Approach

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APPENDIX C
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I. Introduction

Newport Electric Corporation's electric power rates tend to conform to the traditional rate design structure found elsewhere throughout the electric utility industry. Both in Rhode Island and throughout the U.S. in general, electric power rates have historically been structured so that large power users pay less per kilowatt-hour than small users, and virtually all customers are able to obtain marginal units at prices below their average rate per Kwh. The following reasons have generally been given for this common pattern of rate design: (1) economies of scale result in lower average unit costs for serving large-volume customers; (2) large consumers often tend to have better load factors because of more varied electricity uses, regularly scheduled industrial operations, or off-peak loads such as light, water and space heating, which helps to reduce the average cost of serving them; and (3) large consumers generally have the most price elastic demands, so that low tail block rates may attract desirable loads (at prices below average cost but above marginal cost) that would otherwise be lost to the utility--and losing these desirable loads would force the remaining customers to pay even higher rates to permit the company to cover its fixed costs.

Four lines of argument have been used to support the contention that declining block rates should be modified and

even inverted. First, some critics of declining prices have urged rate structure inversion to curtail alleged uneconomic growth of electricity consumption. This line of argument contends that actual cost conditions no longer conform to the conventional economies of scale thesis noted above. Second, inversion has been advocated by some as a convenient means of reducing environmental degradation stemming from electricity generation. Third, it has been argued that declining block rates are unfair to low income consumers. These families often use relatively small amounts of electric power and consequently pay higher average prices than more affluent, large volume consumers. Fourth, energy supply shortages, natural gas curtailments, and electricity brownouts have prompted others to advocate an inverted rate structure simply to slow the electric power industry's growth until on-line generating capacity catches up with demand. Advocates of rate structure inversion generally build their case on two or more of these lines of argument.

II. The Sterzinger-Coyle Approach

The purpose of this appendix is to assess the proposed lifeline rate experiment recommended by witnesses George Sterzinger and Eugene Coyle, who presented testimony on behalf of the Coalition for Consumer Justice in January 1978 before the Rhode Island Public Utilities Commission in the Newport Electric Corporation electric rate case, Docket No. 1311. The Sterzinger-Coyle recommendations are essentially for an inverted electric rate structure design with a comparatively low rate in the first block and progressively higher rates in subsequent blocks. Thus, their proposal differs in concept from the conventional declining block approach in that it reverses the blocks so that small users pay lower average costs while large users' average costs are higher.

Mr. Sterzinger and Dr. Coyle do not explicitly commend inverted rates on their own merits. Instead, they "back in" to that end result through a two-step process. That is, first, Newport's system incremental costs are estimated at a very high level; and second, a balance with the Company's revenue requirements is achieved by reducing the early rate blocks to levels below the incremental cost estimate. As is discussed in more detail below, careful examination of this approach reveals that the procedure is faulty in that incremental costs are substantially overestimated in the first place, and it is only through this overestimation that the

inverted rate design is rationalized. Other issues with respect to the Sterzinger-Coyle approach are also discussed below. These include their concept of incremental costs, the presumed historical motivation for traditional declining block rate designs, and the question of social and economic impact. The discussion is broken into four sections:

1. The presumed motivation for conventional rate structure designs;
2. The social and economic impact of electric utility rate structure reform;
3. Consumer price signals and economic efficiency; and
4. Computational procedures underlying the proposed inverted rates.

Before moving to these four major areas of assessment, a preliminary comment is appropriate concerning the "experimental" nature of the Sterzinger-Coyle proposal. From Newport's view, it would appear that the proposal does not constitute an "experiment" at all, but, rather, is a recommendation for systemwide implementation of inverted block rates for the general residential class throughout the Newport service area. It might, however, be contended that while the proposal is thus not "experimental" for Newport, it is nevertheless experimental on a broader basis in that what is learned on the Newport system may have general applicability in devising rates for other electric utilities in the State. If that is the intended experimental nature of the proposal, it is then important to identify carefully the experimental objectives and the hypotheses that the experiment is intended to test.

On these matters there is not much enlightenment offered in the Sterzinger-Coyle presentation. On the subject of experimental benefits, Dr. Coyle states that the benefit will be to "eliminate most of the burden of running experiments" (Coyle testimony, Docket No. 1311, page 46). On the subject of "experimental data" to be gathered as a result of the proposed rate program, he states:

The "experimental" data that will emerge from the rate reform will be the detailed Bill Frequency data by months and twelve month periods.

But bill frequency data are already available from virtually every electric utility's regular billing records. Indeed, bill frequency data have traditionally been used in electric rate cases in order to verify that the rates ultimately implemented can be expected to produce test-year revenue requirements. Consequently, the only new intelligence apparently contemplated from this proposed "experiment" would be the comparison of bill frequency data under a system of inverted rates in contrast to bill frequency data at other times or on other systems under alternative rate designs. Why one should be interested in such comparisons (and thus the purpose of the experiment) is not made clear. That different rate structures are likely to produce different bill frequencies is, of course, quite probable. That is both logical and, presumably, verifiable from the "substantial experience around the country" referred to by Dr. Coyle on page 45 of his testimony. The

benefits of reconfirming this known fact through further "experimentation" in Rhode Island are unspecified. Nor is there any explanation as to how the results of such an "experiment" will aid the Commission or the Company in broader efforts to design rate reforms. In fact, Dr. Coyle does not specify unanswered questions nor does he specify the experimental criteria that must be satisfied before moving from experimentation to full statewide implementation of inverted rates. Indeed, as he states on page 49 of his prepared testimony, a "problem" with the proposed experiment is that "the Commission will want to eliminate the declining block rate on the other utilities as fast as practicable, thereby ending the comparison." If that is a foregoing conclusion, the Commission should logically move directly to implementation, and no further "experimentation" is needed or justified.

As is discussed in more detail below, our assessment of the Sterzinger-Coyle proposal does not indicate that there is a persuasive case for systemwide implementation, of inverted electric utility rate designs.

Motivation

An apparent foundation of the Sterzinger-Coyle thesis is that self-serving financial motivations are the primary explanation of declining block rates in the electric utility industry. Specifically, it is argued that utilities favor declining block rates and oppose inverted rate designs because the declining

block approach promotes growth, and growth is in the financial interest of utility companies and their equity owners.

A higher rate of growth will result in a higher price for shares on the market. (Coyle testimony, page 5.)

* * *

Growth is translated correctly into higher share prices on the stock exchange. (Coyle testimony, page 25.)

* * *

The utility can earn only the number of dollars in profits that results from the rate base and rate of return that the regulatory commission allows. But if it can get these dollars from a variety of rate schedules, then it will choose that rate schedule that will promote growth. (Coyle testimony, page 29.)

But, while thus arguing that electric companies favor declining block rate structures because of their inherent financial attractiveness, it is, nevertheless, subsequently argued in apparent contradiction, that inverted rates would minimize earnings attrition and that declining blocks should therefore be removed because failure to do so "would penalize the company financially." (Coyle testimony, page 45.)

It cannot be both ways--at least, not at the same time. Either declining block rates are financially attractive or they are not. Indeed, in recent years, many electric utilities have complained that the need to finance new capacity expansion in inflationary construction markets and high-cost capital markets has been financially detrimental rather than beneficial.

Utilities have argued repeatedly in rate cases in Rhode Island and throughout the nation that regulatory lag, coverage problems associated with the need to finance large construction programs, and higher incremental fuel costs associated with rising demands have cut into profit margins and necessitated rate increases. The internal dichotomy in the Sterzinger-Coyle thesis, generated by arguing, on one hand, that electric utilities find it in their financial interest to promote growth through declining block rate structures and, on the other hand, that inverted rates will be of financial benefit to the utility industry may, of course, be reflective of nothing more than an overly aggressive effort to muster every conceivable argument in favor of one's advocacy position. At any rate, this is one apparent conceptual inconsistency in the authors' analytical approach.

A more subtle criticism of the Sterzinger-Coyle growth motivation thesis concerns the type of growth that, in the past, utilities have frequently been characterized as favoring. Particularly in the 1960s, it was frequently theorized that, because under conditions of declining costs regulatory lag resulted in earned rates of return exceeding the cost of capital, utilities had a financial incentive to favor capital-intensive production techniques, rather than more economical alternatives that would have been less capital intensive. This theory was widely referred to in academic literature as the Averch-Johnson thesis. Although it is no longer as frequently contended that regulatory lag leads to rate-of-return levels in excess of the

cost of capital, Dr. Coyle's arguments concerning utility rate design motivation bear some resemblance to Averch-Johnson type arguments.

The fact that times have changed, however, is not the only difficulty here. In addition, Dr. Coyle's arguments suggest that utilities maximize profits through growth, *per se*, and not merely through capital-intensive growth. Thus, even in terms of conventional theory, Dr. Coyle's argument does not appear to be well documented. That is, the Averch-Johnson theory would argue that under specified economic circumstances (which are not necessarily prevalent today), utilities would maximize profits by maximizing net plant investment. That is not technically the same as Dr. Coyle's argument that profit maximization is pursued merely by maximizing demand. Indeed, depending upon relative demand elasticities, a regulated utility may best pursue an investment maximization objective through the implementation of well-designed rates that properly reflect peak/off-peak cost differentials rather than through less efficient block rates that fail to reflect time differentiated cost conditions. This is so because the former may expand the need for capital-intensive baseload plants whereas the latter could favor the construction of peaking capacity with low capital but high operating costs. Thus, it is not clear that there is any necessary conceptual connection between the theory of profit maximization under a rate-of-return constraint and conventional declining block rate structure design.

This theoretical difficulty aside, it must be noted that the academic authorities cited by Dr. Coyle, when read in full context, do not appear to share fully his motivational thesis-- nor do they support the concept of inverted rates. For example, Dr. Coyle's quote from Troxel's The Economics of Public Utilities, which is set forth on pages 27 and 28 of his prepared testimony in Docket No. 1311, when read within its full context, does not support the implication that declining block rate structures were deviously contrived by utility companies interested only in higher profits to the detriment of the overall public welfare. Indeed, in the paragraph immediately preceding the one quoted by Dr. Coyle, it is clearly shown that Troxel believes that regulatory authorities, as well as utility companies, had reasons for favoring declining block rates in the past:

Both the companies and the commissions like promotional price schedules. Commissioners believe that inducements for more service consumption are necessary characteristics of "scientific" pricing. They want to increase the consumption of old buyers, and to develop new uses of service. Commissions prescribe the reasonable earnings for a company; then they ask for price schedules that give the consumers the largest possible amount of service for their money. Utility companies are interested in promotional price schedules for another reason; they like this kind of pricing because they get additional earnings with it. They offer price reductions to buyers because the revenue increment is expected to exceed the cost increment. (Troxel, page 597.)

In other words, utility companies, according to Troxel, adopted block rates to some extent because they were forced or

encouraged to do so by their regulatory commissions. Moreover, the utility companies found appeal in such rate structures because they believed that the incremental revenues exceeded the incremental costs. Not only does this passage indicate that the development of declining block rates took place in a less devious environment than may be inferred from Dr. Coyle's discussion, it also suggests that the approach was viewed to be consistent with the concept of efficient incremental pricing.

Further reading of Troxel reinforces the conclusion that utility rate managers, rather than being antisocial, were convinced that "promotional rates" were perfectly consistent with society's broader interests in cost-based ratemaking.

Imputation of the readiness to serve cost to individual buyers is the crux of the price scheduling problem....Company managers usually assume that all buyers, except the strictly off-peak consumers, have a responsibility for the utility plant investments. They assume, furthermore, that the company holds itself ready to serve one buyer quite as much as any other buyer. Accepting this holding out rule, they believe that the readiness to serve cost ought to be covered out of the revenue that each buyer pays for his first units of service. This reasoning, which the electric and gas firms actually try to follow as they fix prices, makes the readiness to serve charge as high or almost as high for the small buyer as for the large consumer. (Troxel, page 596.)

* * *

Gas and electric firms usually try to recover the customer costs and some "demand" costs (the readiness to serve costs) from the first block price or first two block prices of the schedule. The inferred cost behavior of service production is used to explain the descending scale of block prices: unit cost of service decreases as the customer's purchases increase....According to

their reasoning, the plant is available to both large and small buyers in a service classification. Consequently, the readiness to serve charge should not be proportionate to purchases; and the small consumers should pay a larger readiness to serve charge, relative to their consumption, than the large buyers pay. That is the cost rationale for a descending scale of block prices. But the several kinds of cost--customer, readiness to serve, and energy costs--are not identified by separate parts of an ordinary block schedule. Since these costs are not specifically identified, the ordinary block schedule is a compromise between uniform pricing and the more complex two-part and three-part rates. (Troxel, pages 600-601.)

This reading of Troxel, of course, should be viewed in its proper time perspective. Troxel's work was completed in the mid-1940's and is out of date as a guide for modern ratemaking today.* The point is, that within that time frame, Troxel recognized that utility rates were structured both with a

*To illustrate the "out-of-date" nature of some of Troxel's thinking, consider the following passage, which would hardly be descriptive of today's more enlightened regulatory authorities:

Being administrators who like to get jobs done quickly, utility commissioners often want a simple, expedient method of earnings control. But the marginal-cost method is so complex that many regulators cannot quickly understand it or easily use it. Being practical, political-minded men, the commissioners wish a method that is tested by experience rather than general reasoning....Trusting their common sense, regulators are certain to call the marginal-cost proposal an unrealistic plan of control. To the public officials it is a strange idea, based on peculiar reasoning and expressed in an unfamiliar language. Since these men are rarely interested in what they consider odd thinking, nothing short of a general upheaval in utility regulation can drive them to study the idea. (Troxel, page 463.)

view toward cost and in concert with public objectives and the desires of regulatory commissions. In short, it would not be fair to characterize Troxel as a supporter of the thesis that utilities have explicitly "twisted their rate structures" so as to abuse the necessitous nature of utility service for low-income consumers to the private benefit of their own interests.

Another authority cited by Dr. Coyle is Ralph Kirby Davidson's book, Price Discrimination in Selling Gas and Electricity. However, like Troxel, Davidson recognized that promotional block rates were not merely a private benefit device conjured up by electric utilities. Rather, they were a reflection of what regulators and utilities alike believed to be the optimal pricing device in their time. Moreover, while arguing that declining block rates were inadequately reflective of costs, it is not proper to suggest that Davidson identified "the small household users" as the singular victim of such rate designs, and it is surely misleading to imply that Davidson's work in any way supports the concept of inverted block rates such as those advocated by Dr. Coyle. The facts are that Davidson identified the failure to differentiate between peak and off-peak usage and demand as the principal shortcoming of declining block rates, and his proposals for rate reform track very closely with modern time-of-use pricing concepts--not inverted block rates.

Both regulatory commissions and utility companies have pushed promotional rates, usually of a block rate type, as desirable pricing methods. As a result of the use of this type of rate, energy consumed during peak hours is sold below cost and energy consumed during off-peak hours is sold above cost. This unduly restricts the use of existing facilities in off-peak hours and promotes over investment in gas and electric utilities. (Davidson, page 97.)

The theoretically most efficient type rate schedule for gas and electric utility rates is a time-of-day rate schedule with a fixed charge to cover customer costs and one rate for peak consumption and another, lower rate for off-peak consumption. The arguments for this type of rate are strongest for the electric utility companies; for these companies a time-of-day rate schedule is practical....

The proposed time-of-day rate schedule for electric utility companies and a seasonal rate schedule for gas utility companies are practical and would be far superior to present rate structures with respect to the economic allocation of productive resources. Increased use of existing facilities would be promoted, while investment in new plant would not be induced unless consumers were willing to pay long-run marginal or incremental cost. Consumption during peak periods would not be subsidized at the expense of off-peak consumption. (Davidson, page 204.)

Finally, the likelihood that "politics" may be one of the motivating explanatory factors behind customer class cost allocations should not be ignored. Intelligent utility executives (of whom there are many), like public officials, are not insensitive to their public image or to public opinion, and they are likewise frequently responsive to the perceived political preferences of regulatory authorities. That is to say, utility companies have not been unmindful of the "public

acceptance" considerations referred to by Dr. Coyle on page 34 of his analysis. Consequently, it is not surprising that, more so today than in the past, rates of return by customer class for many utilities tend to be lower for residential service than for industrial service and, not infrequently, returns are highest of all for relatively small commercial users. Where this pattern exists, it tends to be more reflective of political priorities than either cost responsibility or profit maximization objectives.

Impact

The Sterzinger-Coyle critique of conventional electric utility rate structure designs frequently tends to be couched in terms of the relative cost burdens imposed on large versus small customers (e.g., Coyle testimony, page 19). As suggested above, this approach may be politically appealing but it is likely to miss the mark with respect to sound rate design reform. Whereas it may be a viable political posture to critique rates from the point of view of whether they are burdensome to large or small customers, from an economic perspective it is more appropriate to approach the problem from the viewpoint of cost responsibility. And, from a cost-causative perspective it is the peak/off-peak dichotomy that is crucial rather than issues of big versus small.

It is somewhat ironic that, although Mr. Sterzinger's analysis of incremental cost levels and Dr. Coyle's discussion of "price

signals" suggest the need to price service on a marginal cost basis, the peak/off-peak distinction, which is the essence of marginal cost price differentials in the electric utility industry, is nowhere evident in Dr. Coyle's proposed rate structure design. In fact, in a recent proceeding in Maine (Docket No. F.C. 2332), Mr. Sterzinger testified that he was "opposed to time of use rates." This, of course, may not be particularly surprising in that an income distribution objective rather than a cost-causation objective is, virtually by definition, at the heart of the lifeline rate concept recommended by these advocates. Unfortunately, the difficulty encountered in objectively analyzing the merits of the Sterzinger-Coyle recommendation is compounded specifically because of the authors' sometimes strained attempts to justify, or at least rationalize their proposals in terms of an ill-fitting cost-of-service cloak, rather than more straightforwardly on the basis of income distribution.

Although Dr. Coyle does suggest on page 11 of his testimony that income distribution is a function of utility rates, that statement can be interpreted to mean that the proper regulatory function is to assure that rates properly reflect costs so that noncost-related income redistribution is not an undue ancillary side effect of rate design. That is to say, in accordance with traditional economic principles, rates that are equal to costs will serve to achieve a number of socially meritorious objectives including: (1) fairness or equity, in

that each consumer pays a price equal to the burdens that his consumption places on society; (2) optimal allocation of productive factors, in that demands will not proceed beyond the point where the benefits derived by consumers are less than the value of the resources committed to providing the commodity or service in question; and (3) resource conservation, in that society's scarce productive factors (including energy) are used effectively so as to provide the greatest overall public benefit. Since prices equal to costs achieve these ends through the automatic functioning of the market system, it can be concluded that cost-reflective ratemaking philosophies in regulated industries will not serve to distort income distribution.

Candidly, however, the central objective of lifeline rates is to redistribute society's income, and this has never been an accepted principle in the economics of regulation. The specific lifeline form proposed by Sterzinger and Coyle would specifically redistribute income from large residential users to smaller residential users. Particularly in communities with substantial recreational or seasonal populations, such redistribution can be something quite different than transfers from the rich to the poor. The problem of matching the income redistributive benefits of inverted rate structure designs with those consumers (i.e., the poor) who are, presumably, intended as the ultimate beneficiaries, is even more speculative and uncertain than is generally the case with other lifeline

approaches. This difficulty has been discussed at greater length in other contexts and will not be belabored here. But it should be emphasized that mere rate structure inversion is at best a scatter-gun approach that could be even less income related in Newport than elsewhere.

Industrial attraction to a utility company's service area is a further rate structure impact emphasized by Dr. Coyle. As he correctly notes on page 24 of his testimony, a contributing factor in industrial location is the cheapness of utility service. It is also true that relatively low-cost electricity will help to deter the relocation of industrial customers to other competitive service territories. The relatively high cost of energy in New England during the past half century, in comparison with lower cost power in the southeast and east-south central regions of the country surrounding the Tennessee Valley area, has not been an insubstantial factor influencing the migration of certain industrial activity and related economic benefits. While this observation should not be interpreted as support for "lifeline industrial rates" to attract and hold industry in New England, it does suggest that where utility companies have been concerned about attracting and holding the types of industrial loads that sustain local economies, it should not be presumed that such concerns were mutually inconsistent with their region's overall public interest and, especially, the interest of many small consumers whose jobs and livelihoods are dependent upon a healthy regional economy.

Dr. Coyle's suggestion that industrial rates may be intentionally set below the costs of serving such customers as a sales inducement, is much less likely today than it may have been in other regions of the country in the more distant past. Of course, to the extent that industrial tariffs fail to reflect peak/off-peak cost differentials, it is true that peak consumption is subsidized and off-peak usage is subjected to excessive burdens. Thus, either block rates or flat rates can serve to subsidize peak usage in all classes, including the industrial class, to the detriment of off-peak usage. The solution to this problem, of course, is more cost-reflective, time-differentiated rate design concepts rather than an inverted block rate structure. To the extent that industrial consumers have higher load factors and relatively more off-peak demand in relation to peak demand than other types of customers, rates that are not time differentiated, in fact, tend to overcharge these users. This is consistent with the observation above, that for political reasons or otherwise, rates of return by customer class in recent years have frequently tended to be higher for industrial users than for those in the residential category.

Focusing specifically on the residential class, the Sterzinger-Coyle rate inversion recommendations would serve to reduce bills for small customers while increasing them for large ones. There is an apparent suggestion on page 39 of the Coyle study that large residential users should not be

unduly concerned by the proposal because their service requirements might be obtained through Newport's special tariffs for electric water heating and electric space heating, rather than through the inverted residential tariff. However, upon further reading, it is clear that little comfort can be taken from this suggestion as Dr. Coyle subsequently expresses reservations about maintaining these water- and space-heating tariffs in the future (see pages 40-44 of the Coyle analysis).

In addition to the impact of rate structure inversion, the Sterzinger-Coyle proposal would relieve the relatively small residential customers on the Newport system of significant cost responsibility due to the virtual omission of any customer cost charge.

Finally, the proposed elimination of special water-heating and space-heating rates appears to be premised on an invalid impression. That is, Dr. Coyle seems to question the meritoriousness of these rates because a substantial portion of the energy consumption under them takes place during the winter months when the system peak also occurs. In assessing this contention, it must first be noted that the summer peak on the NEPEX system is equal to nearly 95 percent of the winter peak. Thus, the seasonal differential is very small. The seasonal swings that do exist are required for scheduled maintenance purposes. Consequently, seasonal rate differentials are unjustified. Second, the real peak/off-peak problem for Newport and throughout New England concerns the differential between

daytime and nighttime loads, and this requires time-of-use rate design reforms--not seasonal ratemaking considerations. Third, a substantial portion of residential water- and space-heating requirements typically occurs during off-peak (night-time and weekend) hours, and therefore rates that embody a proper recognition of off-peak costs are appropriate.

Ultimately, of course, nothing short of time-of-use pricing will fully remove the potential for intraclass and interclass cross-subsidization. In the meantime, however, there is little evidence in the Sterzinger-Coyle analysis that warrants the abandonment of admittedly crude approximations toward cost-reflective ratemaking in favor of an inverted block rate design.

Signals

A particularly troublesome aspect of the Sterzinger-Coyle analysis is that, although their ultimate lifeline rate proposal is, rather obviously, essentially an income redistribution program that is quite unrelated to utility service costs, there is a strained effort to attempt to link the proposal to a cost justification and rationale--perhaps because such a strategy is perceived to make the proposal more salable. As is discussed in more detail in the following section, the attempted cost justification is clearly contrived and, in our view, conceptually unsound. Thus, the authors' frequent verbal homage to "price signals," while perhaps forensically appealing, is a most unlikely traveling companion for inverted rates.

But even ignoring the obvious contradiction between concept and proposal, a number of the conceptual arguments, in themselves, are unsound. For example, Dr. Coyle's discussion on page 10 of his study suggests that it is particularly critical that marginal costs be reflected in the tail block of the residential rate schedule rather than in the other blocks. With respect to the blocks proposed by Dr. Coyle on page 37, this reasoning is clearly wrong. What is critically important is that the rates paid for marginal service reflect marginal cost. However, marginal service for most customers on the Newport system is at consumption levels well below 700 Kwh per month. Therefore, to equate prices and marginal costs only in the tail block (i.e., above 700 Kwh per month) would result in marginal-cost pricing for only a very small minority of Newport's residential class. Most of Newport's customers take their marginal service within Dr. Coyle's middle block, and it is there, rather than the tail block, that rates equal to marginal cost are therefore most critical. Of course, the elimination of a block rate structure entirely, and movement, instead, toward time-differentiated rates equal to marginal cost during peak and off-peak periods for all customers would be a far superior solution.

In a further effort to rationalize inverted block rates in terms of price signals reflective of marginal cost, the inverted rate advocates appear to conclude that since incremental cost concepts were the foundation of declining block

rate structures in the past when costs were falling, it is reasonable to conclude that inverted block rate structures during the current period of rising costs are incrementally justified. There are both conceptual and factual fallacies to this line of reasoning. First, as a factual matter, declining block rates were historically justified largely in terms of the inclusion of customer and system access costs in the initial blocks rather than as a fixed charge independent of energy consumption. In addition, declining blocks were rationalized as a rough reflection of the cost implications of large customer load factors, which were frequently associated with relatively large levels of service. While marginal-cost pricing may have been less inconsistent with declining block rates than with inverted block rates, the relationship was remote, and the suggested parallel does not stand up as a meaningful justification of the Sterzinger-Coyle lifeline proposal.

On a conceptual basis, it is technically incorrect to associate the slope of the marginal cost curve with the direction of cost trends over time. Consider, for example, that after several decades of decline, the average cost of producing electric energy has increased annually since the late 1960s. This is illustrated in Figure 1 by the fact that power supply cost functions (the lines that slope downward from left to right) have shifted upward in each year. Consequently, due to inflationary factors, it has cost more to supply any given

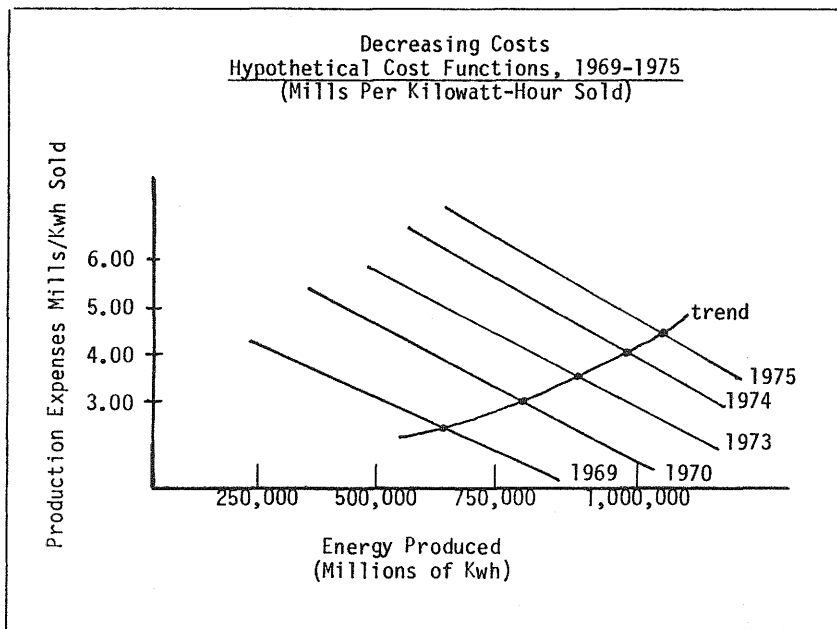


Figure 1

amount of power in later years. It cannot, however, be concluded from this that the electricity cost function itself is now upward sloping. As illustrated in Figure 1, although the cost trend over time has been up one year to the next, the functions themselves have still been downward sloping in any individual year. The correct explanation of recent trends is that higher average electric power costs over time reflect a dynamic shift in the cost function, resulting in higher costs at all levels of consumption from one year to the next.

By connecting the dots on each of the annual cost functions shown in Figure 1, we derive an upward sloping cost trend over time. But the fact that costs may be trending in either an upward or downward direction tells us virtually nothing about whether marginal costs are above or below average costs. In fact, peak costs are likely to be above average costs and off-peak costs below average costs regardless of the cost trend. Similarly, because peak service at the margin is likely to be provided from oil-fired turbines with relatively low capital costs but high operating costs, marginal energy costs are likely to be well above average energy costs; but marginal capacity costs will be below the average--again regardless of the direction of the trend. This confusion of marginal cost concepts with cost trends, in an apparent effort to justify rate design inversion, is a most unfortunate conceptual error in that it has led to unwarranted claims (and fears) concerning the income distributional effects of marginal-

cost pricing. In short, the apparent income redistributive objectives and effects of lifeline rates may be unrelated to properly conceived rate designs based on marginal cost. Attempts to rationalize one in terms of the other tend to be misleading, and generally constitute an intellectual disservice to a proper understanding of both sound economic principles and social income policy.

Inverted Rates

Perhaps the most unsatisfactory aspect of the Sterzinger-Coyle presentation involves the rather superficially contrived attempt to rationalize an inverted rate design by first grossly overstating NEPEX's marginal cost and then conforming these overstated costs to Newport's revenue requirement by proposing substantial and arbitrary discounts to the initial blocks of service. It is only through the process of first contriving a revenue excess and then adjusting rates so as to conform with the revenue requirement that Dr. Coyle and Mr. Sterzinger are able to develop their inverted rate design in the first place. Without first constructing costs that would generate a substantial revenue excess if directly converted into rates, Sterzinger and Coyle would lose their asserted conceptual basis for an inverted rate structure.

There are several important areas in which Mr. Sterzinger's cost computations improperly inflate NEPEX's cost data so as to develop excessively high incremental cost estimates. First,

the development of weighted NEPEX capacity costs fails to discount future cost levels back to present dollars. As stated in Table II of Mr. Sterzinger's exhibit in Docket No. 1311, the cost figures used are expressed in 1980-1988 dollars. This fact is confirmed by the New England baseload generation study which shows that the costs, as reported, are inflated through this period at an assumed escalation rate of 6.2 percent per year. The problem with Mr. Sterzinger's approach is that it is totally spurious to attempt to base today's rates on the projected inflated costs of future generation plants without at least discounting those future costs back to present value. Thus, for example, if the \$1,141 per Kw cost shown on Table II of Mr. Sterzinger's exhibit for new nuclear generation capacity expected to go on line in 1986 is discounted back to a 1978 present value at NEPOOL's presumed 6.2 percent inflation rate, the result is only \$705--not the \$1,141 used in Mr. Sterzinger's computations.

Second, Mr. Sterzinger begins his operating cost computations in Table IV of his exhibit with 1980 cost estimates, and then, instead of discounting these 1980 estimates back to a 1978 present value, he actually compounds them forward to 1988 at a 6.2 percent annual escalation rate. This procedure would establish 1978 rates on the basis of inflated 1988 dollar costs.

Third, Mr. Sterzinger's computations are based on a 20 percent fixed charge rate that is substantially higher than

Newport's actual carrying cost of 14.1548 percent as developed and shown on Schedule 3, page 2, of Appendix B of this report.

Correcting only for these most obvious errors and recomputing Newport's average historical transmission and distribution costs in terms of the Company's 1977 operating experience, it is shown in Schedule 1 attached to this appendix that the Sterzinger computational method produces a 1978 yearly cost of new generation of 3.51¢ per Kwh as opposed to Mr. Sterzinger's own inflated estimate of 6.68¢ per Kwh. This corrected result, in turn, would produce inadequate revenues for Newport if applied to all sales; it would not produce a revenue excess. Thus, the underlying revenue requirements basis for an inverted rate structure design literally evaporates. Under these circumstances, if we were to accept the Sterzinger computation as corrected and apply the same ratemaking principles as suggested by Dr. Coyle, the corrected result would serve as a basis for deeply declining block rates. This is so because, in order to be intellectually consistent, Dr. Coyle would now have to propose much higher rates than 3.51¢ in his initial blocks in order to achieve revenue adequacy. The only obvious alternative would be to maintain a flat rate of 3.51¢ per Kwh and to institute a fixed customer charge in excess of \$7.00 per month. Thus, deprived of cost overstatement, the Sterzinger-Coyle methodological approach produces precisely the opposite result of what is implied by the lifeline concept in the first place. However, due to the conceptual problems embodied in

the Sterzinger-Coyle methodology, it is not suggested here that the Commission follow a course of action that logically tracks the corrected Sterzinger computations.

In addition to the conceptual difficulties noted in the preceding sections above, a fundamental remaining problem is that Mr. Sterzinger computes the marginal cost of capacity largely in terms of the cost of baseload nuclear and coal-fired generating units. This is inappropriate in that the marginal cost of capacity is only the cost of peak generating units. Capacity costs beyond the level of a peak generating unit are justified only to the extent that more capital-intensive generation is also required to meet off-peak demand. In other words, capacity costs in excess of peak generator costs should be and are incurred only to the extent that, because of extended hours of usage, they produce greater energy cost savings because the higher capacity costs of baseload generators are more than offset by reductions in the operating costs of peakers. Viewed in that manner, it is clear that the capacity costs in excess of peak generator costs are incurred as a cheaper substitute for the cost of operating less capital-intensive equipment. Thus, the amount by which the capital costs of baseload generating units exceed the capital costs of peakers is properly reflected as an energy cost component and should not be treated as the marginal cost of capacity as is done in Mr. Sterzinger's computations.

A further error in Mr. Sterzinger's analysis pertains to his discussion of AFDC* earnings, as set forth on page 5 of his prepared testimony in Docket No. 1311. First, an estimated AFDC cost is already included in the NEPOOL cost estimates. Therefore, any additional increment, in accordance with Mr. Sterzinger's suggestion, would be double counting. Additionally, Mr. Sterzinger's impression of the relative impact of AFDC is grossly exaggerated. That is, AFDC requirements must be computed only from the date at which a particular construction investment is made. A substantial portion of construction expenditures are made during the latter stages of the overall construction schedule. Therefore, to compute AFDC requirements by capitalizing the carrying cost associated with the completed plant over the full construction period, as is done in the Sterzinger analysis, is a very large overstatement of these costs.

It should be noted that the extension of the Sterzinger-Coyle inverted rate structure design methodology from the residential sector to commercial and industrial classes would prove to be an even more unworkable situation. For example, the application of an inverted rate design in the industrial class would create an unwarranted and inefficient incentive toward the establishment of small producing units even though, for real economic reasons, large producing units may be more

*Allowance for funds used during construction.

efficient in certain industries. Also, to the extent that rate deviations from costs vary between competitive firms within a given industry, the resulting price discrimination would raise the possibility of serious antitrust problems. Furthermore, as suggested above, deviations from cost are likely to encourage industrial location and expansion decisions that are not particularly conducive to the economic health of regions implementing discriminatory rate structure designs.

Moreover, to the extent that inverted rates reduce the revenues available from off-peak industrial demands that would otherwise be applicable to fixed costs, small residential customers whose lighting and appliance demands are comparatively inelastic would then be burdened with a larger share of the capital costs, including fixed charges for periods when generating facilities were underutilized. Also, to the extent that inverted rate structure proposals raise industrial and commercial costs, there can be little doubt that the bulk of these higher production costs would be translated into higher prices for products and services. Thus, to the extent that low income groups spend a relatively larger percentage of their income on immediate consumption needs, the ultimate impact would be similar to that of a regressive sales tax. Ironically, the burden of inversion could fall more heavily on those consumers who are supposed to benefit from the rate design change in the first place.

A final criticism of the Sterzinger-Coyle inverted rate proposal as a means of improving income distribution depends on a broader view of American social policy. Income maintenance programs such as social security, unemployment compensation, progressive income taxes, and direct welfare payments are generally accepted as necessary exceptions to a pure market economy. The design of each of these programs focused on the primary intended effect: income redistribution. Not ignoring the shortcomings of specific programs, these measures are explicit means designed to improve the lives of those citizens who require such assistance. It is a similar but, in our view, misdirected intention which leads to the suggestion that electric utility rate design is a proper and effective means of accomplishing the same income redistribution objectives.

To argue, as Dr. Coyle does, that electricity consumption by poor people is a critical need is a tautology that misses the central economic fact that precisely the same can be said for virtually every other (rational) expenditure made by the poor. The benefit/cost principles of consumer economics prove (unexceptionably) that marginal electricity consumption has no greater value to the poor than does marginal clothing, shelter, nutritional, medical, educational or other expenditures. Obviously, if the incremental value derived from any of these other expenditures were less than the incremental value of electricity consumption, the consumer would restructure his spending priorities so as to get the most out of his limited

disposable income. In short, poverty is a critical social and economic issue which is not in any way unique to electricity consumption. The problem is a general one that pertains equally (and precisely so at the margin) to all goods and services consumed by the poor. It is a problem that should be dealt with directly and not through distorted contrivances that would serve further to undermine the attainment of efficiency and overall well-being within an economic system where cost-reflective prices are the central and indispensable motivational and disciplinary force. The alternative, to discard the market mechanism in favor of an imposed discretionary discipline and centrally directed operationally economic framework, is a path that electric utilities and their regulators in most states are not yet well equipped to travel.

The disadvantages of the Sterzinger-Coyle approach are important and obvious. The problems of regulation would be greatly compounded. Under current regulatory requirements, rate design must not be unduly nor unjustly discriminatory nor detached from the cost of service. Rate inversion, however, as embodied in the Sterzinger-Coyle approach, would diverge from cost-of-service principles. More important, the income transfers and subsidies of such an approach would not be explicit; and it would be difficult, if not impossible, to bring responsible economic and political judgment to bear on the resulting impacts. Such an approach would conceal incomes policy from scrutiny and would greatly hinder electric

utility prices from accomplishing their resource allocation function.

III. The Newport Experimental Design

As we have demonstrated in the previous sections in this appendix, the Sterzinger-Coyle proposed inverted rate design suffers from several theoretical and empirical errors. The long-run incremental cost estimate, upon which the rates are based, is replete with errors of calculation and is conceptually inappropriate as the basis for ratemaking to begin with. Further, the procedure Dr. Coyle utilizes to adjust his rates to meet the Commission-approved revenue target results in inappropriate price signals, which in turn would lead to an inefficient allocation of resources.

In addition to these problems, there is considerable uncertainty regarding the design and conduct of the Newport experiment. There are at least two major questions to be addressed in an inverted rate/lifeline experiment: (1) what alterations in consumption patterns will result solely from the implementation of the proposed rate design; and (2) will the subsidies that result from rates set below the cost of service be provided to those most in need and paid for on the basis of some reasonable "ability-to-pay" criteria. In this section, we demonstrate that the experimental design proposed by Dr. Coyle is woefully inadequate both in terms of specifying the objectives of the "experiment," and in terms of specifying how the evaluation of the impact of his proposed rate structure is to be assessed. We further suggest an experimental design that will permit a

limited and crude approximation of conservation effects of the Sterzinger-Coyle rate proposal, and provide an approximate minimal estimate of the cost that such a controlled experiment will involve. The costs of such an experiment, the probable tenuous nature of the results, and the conceptual shortcomings of the Sterzinger-Coyle rate design combine to cast serious doubt on the merit of implementing the proposed Newport inverted/lifeline rates on either a partial experimental or on a system-wide basis.

Dr. Coyle's Experimental Approach

It is very difficult to determine with any specificity what Dr. Coyle intends to find out from the Newport "experiment," or precisely how Dr. Coyle believes the experiment should be carried out. It is proposed that the Commission implement inverted rates on a systemwide basis for the general residential class; all other classes would apparently continue to face the Company's existing declining block rates. Two reasons are presented for not implementing the rate design on an experimental basis for only a portion of the general residential class. First, Dr. Coyle states that systemwide implementation will obviate the questions of sample design and selection. That is not true if the Commission wishes to conduct any rigorous analysis to determine the effects of the rate design. As we shall demonstrate below, to assess the impact of the new rates properly, all other important factors must be accounted for.

To obtain information on these other factors for the class of general residential customers will require a significant survey effort; and unless it is proposed to survey all general residential customers (an extremely expensive approach), it will be necessary to design a sample and a selection procedure. Dr. Coyle is also concerned with avoiding legal challenges by customers because they either would or would not be included in the group facing inverted rates. But systemwide implementation for only the general residential class does not completely avoid this problem because other residential customers will be excluded. Moreover, numerous rate design experiments have been conducted on samples of customers throughout the country (including Rhode Island), and these experiments have not regularly resulted in legal challenges.

Despite the fact that Dr. Coyle believes there has occurred substantial nationwide experience with inverted rates, he still seems to feel it necessary to use the Newport "experiment" to determine what will be the effects on consumption of the new rate design. He comes closest to specifying the objective of this proposed analytical effort when he states that the bill frequency data of Rhode Island utilities (including those for Newport under inverted rates) can be used to "...measure the various rates of change between companies, to quantify the effect of the rate design change in slowing growth in consumption." (Coyle testimony, page 48.) Other than stating that bill frequency data will be used and that,

"...non-rate influences will constitute 'statistical noise' in the experiment and must be contended with (Coyle testimony, p. 48)," Dr. Coyle provides no indication of how this analysis will proceed; whether the results are likely to be reliable; and whether the costs of the analysis will be prohibitive.

To determine the conservation effects of Dr. Coyle's inverted rate structure, it is necessary to obtain estimates of the price elasticities of demand by usage levels (for at least two or three blocks). Dr. Coyle has assumed that residential customers at low usage levels have significantly lower price elasticities of demand than do customers at higher usage levels. Thus, any given proportional price increase for large customers will lead to a greater reduction in usage than the increases in usage resulting from an equal proportional decrease in price for small customers. Given these assumptions, the result of implementing inverted rates would be a net reduction in energy consumption for the class as a whole, assuming that other factors influencing consumption levels do not change.

Dr. Coyle has implied that this effect somehow can be measured by comparing the growth of usage of Newport's general residential customers (facing inverted rates) with the growth in usage of general residential customers of other Rhode Island utilities (facing declining block rates). Apparently, in conducting this analysis, Dr. Coyle believes that the effects of nonrate influences, merely constituting "statistical noise," can easily be dealt with. In fact, that is a most

difficult task. The price of electric power is only one of several crucial factors affecting consumption levels, among which are included income levels, family size, appliance stocks, weather conditions and the availability of alternative fuels. To determine the partial effect that the Newport inverted rate design would have on the growth of consumption, as compared with the growth experienced by the other Rhode Island utilities, would require a determination of the effects of all of the other factors by usage levels, and a determination of how these other variables (or their rates of change) differ among utility service territories for the customers in question. This would require extensive survey work for each company included in the analysis to obtain necessary data on income levels, appliance stocks, family size, and substitute fuel availability for customers by usage level. Even then, there would probably not be enough price variation to estimate econometrically price elasticities by usage level. It might be possible to infer the magnitudes of these price elasticities as a residual effect by conducting a before and after survey to determine how other factors have changed and have affected changes in consumption patterns. But, as we shall indicate below, this approach can be conducted on the Newport system alone, obviating the need to conduct surveys of customers on other systems.

In short, what Dr. Coyle seems to assume is that one can ascribe all the changes (compared to other companies) in Newport's bill frequency curve to the implementation of inverted

rates. That approach is dangerously simplistic. By the same logic, one would be forced to conclude that the increased use of electric power over the past several years when electricity rates have risen, means that the demand for electric energy increases as the price rises. Both conclusions are equally incorrect.

Dr. Coyle does not address at all the other major question associated with the implementation of his inverted rate design--that is, how to assess the distributional effects of his proposed rate structure. Other than differences in costs associated with differences in delivery voltage levels, a kilowatt-hour consumed at the same point in time by all customers imposes the same cost on the system. Thus, if customers pay different rates for this kilowatt-hour (beyond those associated with differences in delivery voltage), then some customers are being subsidized by others. The major purpose of most lifeline proposals is to provide this type of subsidy to those families most in need of assistance. Need is usually defined in terms of family income, though family size and age characteristics of the customer sometimes are (and probably should be) taken into account. Dr. Coyle's proposed inverted rate/lifeline design involves such subsidies, the magnitudes of which are tied directly to the customer's level of usage rather than to some objectively defined "needs" criteria. The level of usage may be a good proxy for need, but it is unlikely. As we have discussed at length in Section IV of

the text of this report, basing subsidies (or surcharges to pay for them) on usage as a convenient way to provide (or pay for) assistance to those actually in need is, at best, a very blunt sword with which to attack the problem. This is especially the case in an area such as that served by Newport Electric Corporation. Monthly usage levels per customer depend in part on the size of the family. One-member households (e.g., unmarried, affluent individuals) are almost certain to receive larger subsidies than less affluent large families. Too, individuals with vacation homes in the Newport area are likely to have relatively low average monthly usage and so would receive large subsidies. It is improbable that any individual owning a second (vacation) home in the Newport service territory is deserving of a subsidy on the basis of any generally accepted "needs" criteria.

If the Commission were to consider imposing higher rates (above costs) on some customers in order to provide lower rates (below costs) to others who are in need of some sort of assistance, then it is clearly incumbent upon the Commission to insure that customers undeserving of subsidy assistance do not receive it. At a very minimum, it should be determined what type of customers (in terms of income, age and family size) predominate in those consumption blocks covered by the proposed length of the lifeline; and the length of the lifeline should be adjusted accordingly to match, to the degree possible, provision of subsidies with the need for subsidies.

An Outline for an Experimental Design

If, despite all of the conceptual and practical problems associated with the Sterzinger-Coyle inverted/lifeline rate design, the Commission still wishes to consider implementation of this proposed rate structure (or some similar alternative) in order to assess its conservation and equity impacts; it needs to be apprised of how this assessment can be conducted, how reliable the results will be, and what will be the approximate costs of collecting and analyzing the necessary data.

As we pointed out above, to determine the conservation effects of an inverted rate structure, it is necessary to obtain reliable estimates of the price elasticities of customers in varying usage blocks. Since the Sterzinger-Coyle rate design proposes three consumption blocks, at a minimum, separate price elasticity values must be estimated for customers falling in each of these blocks: i.e., customers using between 0 and 200 Kwh per month, between 201 and 700 Kwh per month, and for those using over 700 Kwh per month. Once these price elasticity estimates are obtained, the conservation effect of implementing the inverted rate structure can be estimated by applying the elasticity coefficients to the change in price for each rate block that results when substituting the proposed inverted rates for the present declining block rates, and weighting these consumption changes by the

number of customers in each block. The problem, of course, is to obtain reliable estimates of these price elasticities.

One method that would permit an approximation of these price elasticity values would be to estimate the effects of all other major determinants, and to calculate the impact of the rate structure change as a residual. The following steps outline a procedure for conducting this kind of analytical effort on the Newport system:

1. Conduct a survey among a sample of general residential customers to obtain data on income, family size, appliance stocks and other factors that may affect usage levels. The sample must be stratified by usage level and drawn randomly within strata.
2. Collect monthly usage data for this sample of customers for at least one year prior to implementation of the inverted rate design.
3. Implement the proposed inverted/lifeline rate design after the initial survey.
4. Econometrically estimate demand functions by usage levels (at least the three proposed usage blocks), utilizing the initial survey data and the historical usage data. Usage variation within usage blocks will be explained by nonprice variables (e.g., income, appliance stocks). It is of crucial importance that the estimated demand functions be fully and correctly specified--that is, that all important nonprice influences be accounted for.
5. Collect usage data (under the proposed rates) for the sample customers for a minimum period of one year.
6. At the end of the "experimental" period, conduct a follow-up survey to determine what changes have occurred in the nonprice "causal" variables determined to be statistically significant in Step 4.

7. Calculate for each usage group the consumption that would have occurred due only to actual changes in the nonprice variables. This would be done by using the updated values of these variables (from the follow-up survey) in the equations estimated in Step 4. These estimated consumption levels are those that would have occurred in the absence of any rate change.
8. Estimate the consumption response to the new rates as the difference between estimated consumption in Step 7 and actual consumption from data collected in Step 5.
9. Estimate the short-run price elasticity of demand for each usage category as the percentage change in quantity consumed (based on projected consumption in Step 7) over the percentage change in price.

Although this approach has the potential of providing estimates of price elasticities by usage blocks, it has several serious limitations. First, the procedure just outlined will only provide estimates of short-run elasticities, whereas the determination of the long-run conservation effects of implementing any new rate design must be made on the basis of the long-run price elasticities of demand. Typically, long-run elasticities exceed short-run elasticities by a significant amount since, with the passage of time, customers are afforded the opportunity to adjust appliance stocks and living patterns to changes in price. For purposes of evaluating the conservation effects of inverted rates, it is especially important to determine the differences in long-run price elasticities by usage levels; and the methodology just described will not permit estimates of these long-run responses.

Another major problem with the suggested methodology results from the fact that the consumption response must be estimated as the residual change--i.e., that part of the total change in consumption not accounted for by changes in other variables. To obtain fairly reasonable price elasticity estimates in this manner requires that the estimating equations (accounting for the effects of nonprice variables) be fully and properly specified. That is, each relationship must be properly captured by the estimating equation, and all significant nonprice determinants must be included in the equation. Even when this is done, the resulting residual price elasticity estimates will be imprecise, for they will include all of the influences, in addition to omitting price from the equation, that cause actual consumption to vary from the level of explained consumption.

The cost of conducting this type of analytical effort, although perhaps not prohibitive, is clearly substantial. At a minimum, the effort would probably cost in the neighborhood of \$65 to \$70 thousand if undertaken by a consulting firm. This estimate is arrived at by assuming a sample size of 300 customers, interviewing costs of \$20 per interview, and \$5,000 for computer costs. The labor time is estimated as that required to obtain all nonsurvey data; to supervise the survey; to develop the analytical design, the sample design and the survey instrument; to conduct the econometric analysis; and to prepare the final report.

In summary, the experimental procedure we have outlined is one that could be used to test the consumption impacts of inverted rates within a reasonable cost constraint. The question remains, however, whether these costs are justified by the probable outcome of the experiment. We suggest that they are not. There remain too many questions regarding the conceptual basis for inverted rates in general and the calculation of the Sterzinger-Coyle rate design in particular. Further, the results of the experiment will be tenuous at best. Even if there exist significant differences in price elasticities among usage levels, there is no guarantee that those differences will be captured by the analytical procedure described above. Finally, the procedure will not provide estimates of long-run elasticities, which are necessary to construct an estimate of the alleged long-run conservation benefits to be derived from the inverted rate structure.

In addition to determining the potential conservation effects of implementing inverted rates on the Newport system, it is also important, as mentioned above, to determine the redistributive effects of the proposed rate structure. Most important in this regard is to determine whether (or how many) customers receiving subsidies have legitimate need for assistance by the usual "needs" criteria; and whether those customers paying higher rates to provide the subsidies are indeed customers with greater ability to pay.

Much of the information required to provide partial answers to these questions can be obtained in the initial survey described above in Step 1. Since the sample would be randomly drawn within designated usage strata, it would be possible to use these sample data to estimate the income, family size and age characteristics of all general residential customers within each usage block recommended by Dr. Coyle. It is then straightforward to determine what share of customers receiving subsidies meet alternative "needs" criteria; and whether the allocation of the costs of the subsidies is in any way related to alternative definitions of ability to pay.

There is an alternative (or supplemental) way to determine whether subsidies are being provided only, or primarily, to individuals who have legitimate need of such assistance. It may be possible to obtain a listing of families in the Newport service territory presently receiving some form of welfare assistance. These individuals could then be surveyed to determine their average monthly electricity usage levels. With this information, it would be possible to provide partial answers to two relevant questions. First, how many of the families who meet the needs tests of existing welfare assistance programs would fail to receive any subsidy (or only a very small subsidy) because their usage levels are too high? Second, what proportion of customers receiving substantial subsidies do not meet the needs criteria for existing welfare programs? If it were found that many of those qualifying for

other welfare programs do not receive any, or only small, electricity subsidies; or that the bulk of those receiving most of the electricity price subsidies do not qualify for existing welfare assistance programs; then these findings would cast serious doubt on the appropriateness of tying the size of the subsidy to usage levels. In that event, a strong case could be presented for basing the provision of lifeline rates on a more direct assessment of the customer's need for such assistance, if such a rate design were to be implemented.

Summary

To determine the conservation and redistributive effects of implementing the Sterzinger-Coyle inverted/lifeline rate structure in the Newport service area would be a fairly expensive proposition. The reliability of the estimated conservation effects stemming from the analytical effort would be uncertain, and these results would not have general applicability. They would only indicate the short-run conservation effects (if any) resulting from a movement from Newport's present declining block rates to the Sterzinger-Coyle recommended inverted rates. They would not provide a basis for evaluating the conservation effects of the Coyle rate design vis-à-vis other types of innovative rate structures, such as time-of-use rates. Further, the results of the analysis would not necessarily indicate what the conservation effects would be if similar rates were implemented on other Rhode

Island systems. Nor would the results of the analysis of the redistributive effects of inverted rates for Newport necessarily indicate what those effects would be on other systems. The geographic, economic and demographic characteristics of the Newport service territory are likely too dissimilar to expect that similar conservation and redistributive effects would occur, were similar rates to be implemented for utilities in other areas in Rhode Island, and particularly for utilities providing service in and around the City of Providence.

In short, the dubious merit of the Sterzinger-Coyle costing methodology and rate design; the cost and probable tenuous nature of the results of the analysis of the conservation effects of that rate design; and the lack of general applicability of those analytical results to other utilities in Rhode Island--all of these drawbacks indicate that the Commission will not be acting in the best interests of either the utility companies or the ratepayers of Rhode Island by ordering the implementation of Dr. Coyle's proposed rate design on either a partial experimental or on a systemwide basis.

Yearly Cost of New Generation Capacity
at 1978 Dollars

Fixed Plant

$$\text{Yearly charge} = \$6,412,454^{\text{a/}} \times 0.141548^{\text{b/}} = \$907,670$$

$$\text{Charge per kwh} = \frac{\$907,670,000}{52,871,984,000^{\text{c/}}} = \$0.0172$$

O&M Costs (including fuel)

$$.011^{\text{d/}} / (1.062)^2 = \$0.0098$$

$$\text{Transmission \& distribution} = \$0.0081^{\text{e/}}$$

$$\text{Total} = \$0.0351^{\text{f/}}$$

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- a/ See page 2 of this schedule.
 - b/ See pages 2 and 3, Schedule 3, Appendix B.
 - c/ See Sterzinger Exhibit, Table IV, Docket No. 1311.
 - d/ See Sterzinger Exhibit, Table VI, page 2, Docket No. 1311.
 - e/ See page 3 of this schedule.
 - f/ Mr. Sterzinger's estimate of 6.68¢ per kwh exceeds this total by 90.31 percent.

Total Cost of Additional Capacity
 at 1978 Dollars

		<u>\$000</u>
Gas turbines:	170,000 kw x $\frac{\$203}{(1.062)^4}$ =	27,130
Combined cycle:	340,000 kw x $\frac{\$451}{(1.062)^3}$ =	128,021
Oil Baseload:	600,000 kw x \$638 =	382,800
Coal Baseload:	568,000 kw x $\frac{\$1,141}{(1.062)^8}$ =	400,533
Nuclear Baseload:	1,150,000 kw x $\frac{\$1,015}{(1.062)^4}$ =	917,626
	1,150,000 kw x $\frac{\$1,145}{(1.062)^6}$ =	917,817
	1,180,000 kw x $\frac{\$1,216}{(1.062)^7}$ =	941,768
	2,230,000 kw x $\frac{\$1,291}{(1.062)^8}$ =	1,779,242
	1,150,000 kw x $\frac{\$1,456}{(1.062)^{10}}$ =	917,517
Total		\$6,412,454

Average Historical Transmission
and Distribution Cost: 1977

Net transmission & distribution plant	\$13,349,995
Carrying cost	<u>0.141548</u>
Yearly cost	\$ 1,889,665
Operating & maintenance	<u>934,357</u>
	2,824,022
Kwh sales	349,800,277
Cost per Kwh	.0081



APPENDIX D

THE DESIGN OF STREETLIGHTING RATES

A Report on Alternative Methodologies

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APPENDIX D

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I. Introduction

Over the past years the rising costs of electric power supply have focused attention on numerous rate design issues, perhaps chief among which is the desirability of basing rate structures on the structure of costs. This interest in basing rates on cost responsibility has caused consternation among municipal streetlighting customers; for although streetlighting revenues (and costs) comprise a very small proportion of an electric utility's total revenues (and costs), a move to cost-based streetlighting rates would result in dramatic increases in the lighting costs of many municipalities. The major reason for this dramatic change is that for a very long time some municipal streetlights have been priced significantly below the cost of service, reckoned on either an average or marginal cost basis.

Partly underlying the movement toward cost-based streetlighting rates is a concern with improving the equity of the allocation of revenue responsibilities, in the sense that customers should pay rates that reflect the costs of serving them. Additionally, there is growing concern that the existing level and structure of streetlighting rates has and continues to encourage the use of inefficient streetlighting equipment. Specifically, rates for relatively inefficient incandescent units usually remain significantly below the average embedded cost of these units, and dramatically below the marginal cost

of providing this service. Because more efficient (in terms of lumens per watt) mercury and sodium vapor units are considerably newer, even the average embedded cost of these units exceeds that for incandescent lights, and this relative cost difference is reflected in relative rates. Consequently, some municipalities have resisted switching to mercury or sodium units. It is argued that this resistance would be reduced significantly if incandescent lights were priced to reflect more nearly their costs.

The gap between streetlighting rates and costs, and especially for incandescent lights, has persisted in Rhode Island for several decades in some cases. In fact, it is not uncommon that no increases in streetlighting rates have occurred over this time span, while costs (especially on a marginal basis) have increased considerably. Thus, if streetlighting rates were suddenly to be implemented on a cost basis (and especially on the basis of marginal costs), the result would be exceptionally large increases in the streetlighting costs of some, if not most, municipalities. It is argued by some that such an abrupt change in rates (especially for incandescent units) would impose a gross inequity upon the municipalities. The basis for this argument is that the cities have planned for both the level and composition of streetlights on the basis of past price signals, and with the reasonable expectation that no abrupt change in either the level or structure of streetlighting rates would occur.

Some Objectives of Streetlighting Rate Design

Many diverse interests are involved in any change in the level and structure of streetlighting rates that might be implemented. Put another way, several often competing objectives have been suggested to guide the design of streetlighting rate alterations in Rhode Island. Before proceeding to an examination of some alternative rate designs, it will be instructive to enumerate more specifically what are several of the more important objectives that have been suggested to guide the design of streetlighting rates.

Designs to improve equity. Two different notions of equity are used when recommending a preferred structure of streetlighting rates. The first is the classical economic notion that equates equity in rate design with charging each customer according to the cost of serving it. From this perspective, each municipality would be considered as an individual customer, and equity would be achieved by imposing on each municipal customer the marginal cost of providing it with service. The costs of streetlighting, under this approach, would be borne by the municipal taxpayers on the basis of whatever tax system the municipality agrees to use. The level and quality of streetlighting that each municipality purchases would be determined, under this approach, by the municipality's elected officials, and so ultimately in the voting booth.

Under the other view of equity, streetlighting is properly viewed as a public good, but one that proponents of this view

feel should be subsidized by the utility's private ratepayers, rather than directly by the municipality's taxpayers. Under this approach, streetlighting rates would be set below costs of service, and the revenue deficiency would be made up by other classes of customers. As a result, customers not living within the municipalities, and thus receiving significantly fewer benefits from streetlighting, would be caused to pay a portion of these costs. Cross-subsidization among municipalities also occurs if different types of streetlights are subsidized in varying amounts. Both of these types of cross-subsidization occur under most of Rhode Island's current electricity rate structures.

Continuity in rate design. This objective also is concerned with equity, though from a slightly different perspective. As noted above, many streetlighting rates have been kept well below the cost of service for a number of years. In this sense, municipal customers have been subsidized for a long period of time, and some argue that an abrupt withdrawal of this subsidy would be unfair to the municipalities. It is pointed out that municipal customers have planned their streetlighting systems on the basis of past price signals, and the further implication is made that they are partly "locked in" to a particular level and composition of streetlighting service. An abrupt increase in rates to levels reflecting the cost of service would therefore impose a severe and unfair financial burden on municipal budgets. Proponents of this position

maintain that, at a minimum, the move to cost-based rates ought to be phased in over a period of several years to permit municipals to plan necessary adjustments in their streetlighting systems and the concomitant changes in municipal budgets.

Improved efficiency. Dramatic changes have occurred over the past few years in streetlight efficiency (in terms of lumens per watt). However, because older incandescent units are priced so far below their costs (relative to more efficient mercury and sodium vapor units), existing rate structures have retarded the substitution of the more efficient fixtures. It is therefore argued that if all rates properly reflected costs (and particularly marginal costs), this substitution would be speeded up and significant energy conservation would result.

Revenue constraints. Because the current costs of all types of streetlights greatly exceed the average costs, pricing at the margin would result in streetlighting revenues greatly exceeding the utility's cost of this service as determined by the regulatory authority in the ratemaking process. Thus, the total rate design for all classes of service must result in revenues that reflect total embedded costs. With regard to streetlighting, the question is whether this revenue constraint should be imposed on each customer class and, if so, who should receive the benefits of the capital gains realized by the utilities on streetlighting equipment. Thus, we may consider the equitable distribution of these capital gains as another streetlighting rate design objective.

In summary, it is clear that several of these objectives and the rate designs to achieve them are conflicting. The classical economic concept of equity and the efficiency objective both demand cost-based rates and, preferably, rates based on marginal costs. The argument that streetlighting is a public good that should be subsidized by private ratepayers, if accepted, calls for rates that are below the cost of service; while the continuity objective, at a minimum, calls for a lengthy phase-in period during which rates would gradually move to levels that reflect costs of service. If revenues from the class of streetlighting customers may not exceed the total cost of service to this class, then the average rate for all types of lights may not exceed the average embedded cost for all units; although, as demonstrated below, the relative prices of different types of installations may reflect differences in marginal costs. In short, no one rate design will satisfy all objectives. Trade-offs will be required, and these trade-offs will involve redistributive effects among several classes of customers and the utility providing the service.

II. The Economics of Pricing Streetlights

There are two component costing and pricing problems involved in designing streetlighting rates. The first involves the proper costing and pricing of those services provided to all classes of customers: energy, demand and attendant customer services; and the proper approach to develop the costs and rates for these services is relatively straightforward. The second problem concerns the proper way to determine the costs and the appropriate rental values for the streetlighting equipment, owned by the utility company. Most (though not all) of the controversy surrounding the design of streetlighting rates centers on the solution to this second problem. We shall deal first and rather quickly with the easier of these two rate design issues.

Charges for Regular Operation and Maintenance Expenses

Energy charges. As a general proposition, the prices for streetlighting energy faced by municipalities should be the same as prices faced by all other customers for energy consumed at the same voltage and at the same times. Though most streetlights are not metered, the energy used for streetlighting purposes can be quite accurately estimated for each light on the basis of the wattage for each unit and the number of burning hours per year.

If time-varying rates are implemented, it will be necessary to determine the kilowatt-hour usage during each rating period against which to apply the appropriate peak, off-peak or shoulder-period rate. This allocation should be done individually for those municipalities that install special timing devices to insure that lights do not operate during some or all of the designated peak-period or shoulder-period hours.

The advantages of implementing time-varying rates based on marginal costs have been thoroughly discussed in Section V of the main body of this report; but this issue relates to systemwide rate design and not to the specific problem of determining streetlighting rates. However, an additional question should be faced if nontime-varying rates are in force. One of the major objections to systemwide implementation of time-varying rates is that the metering costs required to determine individual customers' time patterns of usage will not warrant this type of rate structure. But the time pattern of usage for streetlights can be readily ascertained; and since much of streetlighting energy usage is during off-peak hours, thereby conferring benefits on the utility, it may be appropriate to extend an energy rate discount to streetlighting customers for this off-peak usage even though time-varying rates are not implemented on a systemwide basis.

A related question is whether streetlighting customers should be given the benefits of tail-block rates in a declining block rate structure. Since one of the original purposes of

declining block rate structures was to extend to larger customers the benefits resulting from the lower costs of off-peak usage, it is clearly appropriate to extend this same benefit to streetlighting customers. In fact, because it is known with certainty that on some systems streetlighting energy usage is primarily off-peak usage, it may be appropriate to price all streetlighting energy at the tail-block rate.

Whatever fuel adjustment charge is appropriate for a given month should be applied to the energy component of the streetlighting rate. As is discussed in detail in Appendix B, if there are significantly different trends in the price changes of fuels used for peak-period and off-peak-period generation, then separate fuel adjustments should be calculated for energy consumed by rate period if time-varying rates are implemented. Even in the absence of systemwide time-varying rates, the regulatory authority may wish to account for the off-peak nature of streetlighting energy consumption with a lower (or higher) than average fuel adjustment charge if the price changes for off-peak-period fuel are persistently and significantly different than changes in prices for fuels used primarily for peak-period generation.

Demand charges. The demand charge component of streetlighting rates should also be the same as for all other customers on the system for kilowatts used at the same voltage and at the same times. That is, as a class, streetlighting customers should be assessed their appropriate share of system costs for

generation, transmission and distribution capacity. The determination of these capacity costs may be on a marginal cost basis as described in Appendix B. In that event, the marginal cost of generation and transmission capacity would be applied to the maximum demand per unit (the wattage of the fixture) during the designated peak period. Thus, for any billing period during which the unit is not operating in the peak period, no demand charge to cover generation and transmission capacity costs would be imposed. On the other hand, since distribution costs in a time-varying rate structure are properly assigned on the basis of maximum noncoincident demands, the distribution component of the demand charge would be applied to the wattage of each unit regardless of whether the light operated only during off-peak hours.

If systemwide capacity costs are determined and imposed on the basis of average embedded costs, several methods may be used to allocate these joint costs among the various customers. These alternative allocation methods are discussed at length in Appendix A to this report. Whichever of these allocation methods is utilized to assign capacity costs to other customer classes should also be used to assign costs to the class of streetlighting customers; and this class revenue responsibility should then be translated into the appropriate unit charges on the basis of the wattage of each fixture.

Customer-related costs. Billing, customer service (other than lamp repair or replacement), and other customer-related

costs should be imposed on streetlighting customers in the same manner as for all other classes of customers.

Other operation and maintenance expenses. Some operation and maintenance expenses are unique to the provision of streetlighting services, and these costs are properly assigned directly to the class of streetlighting customers. Of major significance in this category are bulb replacement costs, which vary significantly by the type of fixture, and may also vary significantly among municipalities. This variability presents some problems when it comes to equitably assigning bulb replacement costs among types of fixtures and especially among customers using any specific type and size of bulb.

The frequency of bulb replacement is determined by the average length of life of a bulb and the average breakage rate. The average life of a bulb is determined by the number of burning hours per year and the bulb's rated life in hours. A major advantage of mercury and sodium vapor units is their significantly longer lives, resulting in lower replacement rates than incandescent bulbs. For this reason alone, it is necessary to determine annual replacement costs for each type and size of installation, rather than on the basis of the average for all types and sizes of units, in order to insure that replacement costs are allocated to those customers that impose them on the system.

Breakage rates also depend upon both the type of unit and their location. An additional advantage of mercury and sodium

vapor lights is that they are more resistant to damage from being struck by objects thrown at them. This is further reason to differentiate replacement costs by type of fixture. Further, breakage rates will be higher in those areas where rates of vandalism are higher; and since vandalism rates are probably associated with the amount of police protection afforded, the attitude of local courts to the treatment of vandals, and the socioeconomic characteristics of the community, breakage rates for a given type of fixture may vary significantly among municipal customers. It is therefore inappropriate to base replacement costs per unit partly on the average breakage rate for all such units in all municipalities served. A more equitable approach would be to include no allowance for breakage in the base rate, but to charge separately, to each municipal customer, the incremental cost for each light replaced due to breakage in its area. Alternatively, the base rate might include the costs for a fixed number of breakage replacements (perhaps based on the lowest rate for any one municipal customer), while breakage replacements above this number would be imposed as an additional monthly charge. Either of these approaches, and especially the first, would provide incentive to the municipalities to reduce the costs of breakage. Further, either approach, and especially the first, has the advantage of allocating costs directly to those customers that cause them.

The calculation of the annual replacement rate per unit, based on average annual lamp life and breakage rates (if included), is shown as equation 1 in Figure D-1. This replacement rate is multiplied by the replacement bulb cost for each unit, adjusted by the utility's inventory markup to obtain the annual cost of materials per unit, as shown in equation 2 in Figure D-1. Although this step appears straightforward, some problems are, or may be, confronted at this point. First, the utility may face a problem in selecting appropriate values for bulb replacement costs. It has been noted that the major supplier of incandescent bulbs may not continue to provide replacement parts, in which case there may be no current market values for these units to use in the calculation. Of course, this is

Figure D-1

Calculation of Average Annual Replacement Cost Per Unit

1. Annual replacement = Burning hours per hour ÷ Lamp life in hours + Average annual breakage rate
2. Annual materials replacement cost = Annual replacement × Replacement bulb cost × Inventory markup
3. Annual labor replacement cost = Annual replacement × Labor cost per replacement
4. Total annual replacement cost = Materials replacement cost + labor replacement cost

not really a problem since, once replacement parts become unavailable, incandescent units will have to be replaced by either mercury or sodium vapor lights, for which replacement values will be available.

Some important questions may be raised about the utility's inventory accounting practices in regard to replacement costs. If inventory markups are simply made in proportion to the purchase price of the unit, a disproportionate share of total inventory costs may be allocated to more capital-intensive units. Other than the carrying cost of capital, there may be no basis for assuming that the inventory cost per unit (for shipping, ordering, storing, and handling) is related to the value of that unit. This procedure would further exaggerate the cost differentials between incandescent and mercury or sodium vapor lights, and would therefore tend to reduce the incentive to substitute the more energy-efficient units for incandescent lights. An additional aspect of the utility's inventory accounting practices concerns the carrying charge applied to the inventory investment. The value of this carrying charge may differ from the appropriate carrying charge on fixed plant because property taxes may be computed differently on inventory and because inventory should not be depreciated. The regulatory authority should ascertain that the appropriate inventory carrying charge is used in calculating the materials replacement component of streetlighting rates.

To the annual materials replacement cost is added the annual replacement labor cost to arrive at total annual replacement cost per unit, as shown in equations 3 and 4 in Figure D-1. Annual replacement labor costs are the product of the average annual replacements per type of unit and the average labor cost per replacement, which is a function of the productivity of the replacement crews and the hourly labor costs for these workers.

The sum of the annual energy charges (including fuel adjustment charges), annual demand charges, total annual replacement costs, and ordinary average annual maintenance costs that are directly assignable to streetlights*, comprise the total of annual operation and maintenance costs per unit. It is this total annual cost that would provide the basis upon which to base the rate for each type of streetlight if each municipal customer owned its streetlighting plant, and the utility provided to the municipalities only electrical power and replacement and maintenance services. However, in most instances, the streetlighting plant is owned by the utility company, and thus the rate for each type of unit must reflect a rental value for the use of this equipment. It is when one turns to the determination of this rental value that many of

*Ordinary maintenance involves regular cleaning of fixtures and probably inspection of the unit. If utilities schedule this type of maintenance during regular replacement visits, then the labor costs involved would be included in the annual replacement labor costs.

the problems and the controversy surrounding the design of streetlighting rates begin to emerge.

The Determination of Annual Rental Values

In this section, we shall explore some alternative methods to establish annual rental values for the utility's streetlighting plant. In our discussion we shall largely take as given the proposition that streetlighting rates, and the rental value component of those rates, should reflect actual costs of service to the extent possible. In the following section, we explore some of the practical, political and equity considerations that further complicate the design of streetlighting rates in Rhode Island. These considerations may well cause the Commission to wish to implement streetlighting rates that differ to varying degrees from any or all of the cost-based rate designs suggested in this section.

The basic input data. The total investment cost of a streetlight unit is generally the sum of the following components:

1. luminaire
2. bracket
3. photo cell
4. pole (if appropriate)
5. special circuit
6. other hardware
7. stores markup
8. indirect costs (engineering, planning, etc.)
9. installation costs

The appropriate rental value can then be viewed as equal to the annual levelized payment over the length of life of the

investment that results when applying the company's carrying cost rate to this total investment per unit. Some controversy may surround the calculation of this carrying cost rate, but we shall not examine these issues in this appendix. We shall simply note at this point that the carrying cost rate, and thus the rental value, will be sensitive to the depreciation schedule and the rate of return used in the calculation. It is also important to insure that the true tax effects of accelerated depreciation and the investment tax credit are accounted for in the determination of the carrying cost. The appropriate method by which to calculate the carrying cost rate is explained in detail in Step 2 of Appendix B on pages B-19 and B-20.

It is a simple task to enumerate the physical components of streetlighting plant, the values of which will be summed to provide the value of the investment. The difficulty for pricing purposes lies in selecting the appropriate values for these component parts, and thus for the total investment. There are at least two possible valuation alternatives: average embedded cost, and marginal costs as represented by the current cost of the investment or prospective costs if equipment prices are rising rapidly. As we shall demonstrate directly, it is primarily the wide discrepancy between marginal and average embedded costs (especially of incandescent fixtures) that presents the major problem in the design of streetlighting rates. Substantial capital gains have been realized on older

installations, and part of the pricing problem concerns who should get the benefits of these capital gains.

Average embedded cost. Traditionally, electric utilities have determined costs of service on the basis of average embedded costs. A major attraction of basing rates on average embedded costs is that revenue requirements are also (and properly) based on this concept, and so there results an automatic matching of revenues and costs. However, as the discussion in Section II of the text of this report explains, basing rate structures on this cost concept leads to an inefficient allocation of resources. This is clearly seen in the case of present streetlighting rates. The average embedded cost of incandescent fixtures is very low primarily because a large portion of this capital stock was acquired in the past when price levels were significantly lower. The much newer stocks of mercury and sodium vapor units have much higher average embedded costs, not only in relation to incandescent units but also relative to their own marginal costs. This asset/price differential, if reflected in differential rates, provides an artificial incentive to retain incandescent fixtures despite the substantial superiority of the other types of units in terms of energy efficiency and replacement and breakage rates. From society's standpoint, this amounts to a misallocation of resources in terms of the excessive use of energy in place of capital to meet a specific social need.

Marginal cost. It is also explained in Section II of the text that prices based on marginal costs will lead to the most efficient use of society's resources. This is primarily because the social value of any product is the value of other goods and services that could be produced by the resources that would be released if one less unit of the product in question were produced. This value is measured by marginal cost. Pricing at marginal cost also achieves one aspect of equity. That is the notion that each consumer ought to pay a cost equal to the social cost of providing it with service. This notion of equity and the way it is achieved through marginal-cost pricing is also explained more fully in Section II of the text.

To establish annual rental values for streetlighting equipment on the basis of marginal costs, each of the components of the unit investment enumerated above should be valued at current (or prospective) costs, and the annual carrying charge for this investment should be determined using a carrying cost rate that incorporates the company's marginal cost of capital. (See Step 2 in Appendix B.) Two practical problems are confronted when calculating the rental value component of the rate in this manner. First, there may be no current definition of the marginal cost of the investment if the fixture is no longer available on the market. Second, and more important, the revenues generated by this pricing approach will exceed the Commission-approved cost of service of providing the use

of this capital (as measured by average embedded costs). This discrepancy is the amount of the capital gain that has been realized, and the issue is to whom (and how) these benefits should be given, without greatly distorting the marginal cost pricing signals.

It has been suggested by some that replacement parts for incandescent units may not be available in the near future; or if they are, it would be only on the basis of special orders and at significantly higher costs. In the latter case, the higher cost resulting from reduced rates of production would be the appropriate measure of the true social cost of the unit and so should be used as the value of the marginal investment cost. In the event that no current price is available, the price of the most recent installation will provide an appropriate proxy for the value of the marginal investment. In either event, the result will ultimately be the phasing out of the less efficient incandescent units. This process will take longer than is optimal, however, if the units continue to be priced at average embedded costs because no current market quotations are available.

A more serious problem that must be dealt with when using marginal cost to define rates is the dispersal of the excess revenue that will be collected under these rates. Several options are available. For efficiency purposes, it is preferable to disperse the revenue excess in such a way as to cause minimal disturbance to the marginal-cost-pricing signals.

One obvious and simple way to accomplish this is to allow the utility to retain the excess revenues, thereby avoiding the alternation of any part of the rate structure, including street-lighting rates. The revenues involved would comprise a very small fraction of the utility's total revenues, and the effect on the company's realized rate of return probably would be de minimus. Despite this, the approach is probably not politically feasible, and thus the Commission will have to choose among alternative ways to disperse these capital gains to the utility's ratepayers.

To minimize the disturbance to the streetlighting rates, the revenue excess, resulting from the capital gains, could be distributed to all ratepayers in proportion to class revenue responsibilities. Since the relative amount of the revenue excess is so small, the disturbance to any of the cost-based rates in the overall rate design would be minimal. Here again, because implementation of rates based on marginal costs will lead to substantial increases in the streetlighting bills of many municipalities, distributing the capital gains to any other customer class would likely generate bitter opposition from streetlighting customers. Too, there is intuitive appeal to the argument that since the capital gains were realized in the process of providing service to streetlighting customers, it is somehow proper that these customers receive those benefits. Justifiable or not, it is likely that the Commission will have to respond to this argument.

Two options are available if the capital gains are to be distributed to customers in the streetlighting class. If revenue requirements are set equal to the total embedded costs of each size and type of unit, and the rate per unit reduced to the level necessary to yield these revenues, one arrives at rates set equal to average embedded cost, with all the attendant problems discussed earlier. Alternatively, the capital gains (the revenue excess) can be determined for the streetlighting class as a whole and the marginal price for each unit reduced proportionally to arrive at a set of adjusted rates that will yield the allowed revenues. The advantage of this approach is that the price differentials that will be retained among the different sizes and types of fixtures are the relative differentials based on marginal costs. Of special importance is the fact that the price differentials between incandescent and the more efficient types of fixtures are much smaller on the basis of marginal costs than on the basis of average embedded costs. Consequently, implementation of these rates will provide municipalities with significantly greater incentive to replace less efficient incandescent lights with mercury or sodium vapor installations.

It is fairly clear that, from an economic standpoint, the optimal streetlighting rate structure would incorporate these adjusted rates that retain differentials reflecting the relative marginal cost of each unit. This rate structure will provide the price incentive to substitute more energy-

efficient mercury and sodium vapor units; it will improve one aspect of equity, in that it will impose costs upon those customers that incur them; and it will yield revenues that are allowed by the regulatory authority on the basis of average embedded costs. On the other hand, implementation of this type of rate structure will result in substantial increases in the streetlighting costs of many municipalities primarily because the rates for many streetlighting units have been maintained well below the costs of service for a number of years. This, and other practical and political considerations, may provide sufficient reason for the regulatory authority to implement rates that deviate from the cost-based rates here recommended, at least during a phase-in period.

III. Some Political and Practical Considerations

Because of the historical and political contexts within which streetlighting rates must be designed, numerous non-economic considerations must be entertained by the regulatory authority in determining what the future of streetlighting rate structures will be in Rhode Island. In particular, the Commission must consider what alternative rate design plans would ameliorate some of these noneconomic problems without doing serious damage to the pricing signals of a properly cost-based rate design, and the efficiency benefits stemming therefrom. In this section, we examine somewhat more closely some of the more important noneconomic considerations and suggest some of the types of practical phase-in plans that would make a move to cost-based streetlighting rates less difficult for streetlighting customers.

Should Private Ratepayers Subsidize Municipal Streetlights?

We have already indicated in Section I of this appendix that present electricity rate structures in Rhode Island result in significant subsidization by private ratepayers of some municipalities' streetlights. Further, there occurs crosssubsidization from ratepayers in municipalities with mercury or sodium vapor lights to municipalities relying heavily on incandescent lighting. This cross-subsidization is touted by some as the proper way to go about pricing

municipal streetlighting services because it is a public good.

This approach to streetlighting rate design may be politically appealing, but it is incorrect for a number of reasons. First, under present rate structures, this pricing approach has and will continue to lead to continued reliance on inefficient lighting systems. Second, it is appropriate that those individuals who benefit from the consumption of a public good be caused collectively to bear the burden of its cost. The benefits of municipal streetlights accrue primarily to residents of that particular municipality, and they should bear the burden of the costs of this municipal service. This match does not occur if a significant portion of the costs of a municipality's streetlights are borne by all ratepayers on the utility system, whether they reside in or near the municipality or not. Finally, under this approach, the quantity and quality of streetlighting service will be made on the basis of artificially low rates that do not reflect the social costs of this service. It is true that the nature of a public good requires that the cost for individual marginal consumption be subsidized (or reduced to zero) in order to result in the optimum level of consumption. But it is not true that public goods should be priced below the level of social costs when the public collectively (i.e., the municipality) determines the level of consumption. The result of this approach in the case of streetlighting is a misallocation of resources, both because the public good is

underpriced and because private consumption of electricity must be overpriced in order to make the company whole.

Continuity of Rates

One of the practical and politically difficult implications of implementing cost-based streetlighting rates is the abrupt increases in municipal streetlighting costs that will occur. As we indicated in Section I of this appendix, the municipal customers view such an abrupt change as inequitable because lighting systems have been planned with the reasonable expectation of no such abrupt changes, and because already overburdened municipal budgets will be further strained as a result of the increase. To reduce the impact on municipalities, the Commission may wish to consider alternative phase-in plans.

Several plans have been suggested that are designed to encourage the switch to more efficient mercury and/or sodium vapor installations. These plans have provided discounted prices for the more efficient units to encourage substitution. The phase-in period frequently used is five years. A similar type of phase-in plan could be implemented that would have the dual purpose of encouraging the substitution of more efficient units and gradually raising the revenues paid by municipal customers to levels sufficient to cover the marginal cost of service--that is, marginal prices adjusted to meet the class revenue constraint.

Under this phase-in plan, all operation and maintenance costs would be fully reflected in the annual rates for all streetlights. Additionally, the rental value component of mercury and sodium vapor units would reflect the marginal cost of this capital. The rental value of incandescent units, on the other hand, would be priced at either existing levels or at average embedded costs for all municipal customers presently using these lights, as long as these customers signed an agreement to substitute mercury or sodium vapor units for all their incandescent lights within a given period of time, say five to seven years. Those municipal customers who refuse to make this substitution commitment would pay the full marginal rate for existing incandescent lights.

A plan such as this has several advantages. Lower incandescent rates would be available for the phase-in period only if the customer agreed to replace these units with mercury or sodium vapor units. Thus, there would be a strong incentive to shift to more efficient installations. However, this incentive would not impose immediate and abrupt cost increases on those customers who presently rely heavily on incandescent lighting, and who would suffer most from an abrupt move to cost-based rates for all lights. Streetlighting revenue responsibility for these municipalities will increase gradually toward full cost responsibility as each year a portion of their low-priced (subsidized) incandescent units are replaced by higher priced (unsubsidized) mercury or sodium vapor units. Finally,

implementation of such a plan would almost immediately move total streetlighting revenues closer to the total costs of service for the class of streetlighting customers; and after the phase-in period, revenues from streetlighting customers would fully cover the costs of providing them with service.

Some problems are posed by a phase-in plan such as this, but most can be handled with a little ingenuity. A general problem that would remain throughout the phase-in period is that many incandescent lights would be priced below the cost of service, and it must be decided from whom and how the additional revenues are to be collected in order to make the company whole. Another revenue problem will result from the early retirement of incandescent fixtures as customers substitute mercury and sodium vapor fixtures. To provide the proper incentive to make the shift to more efficient lighting systems, it is imperative that customers not be penalized for the early retirement of fixtures. Rather, the unamortized portion of these fixtures (plus, perhaps, the revenue undercollection during the phase-in period) could be capitalized, and these amortized costs imposed on the entire class of streetlighting customers for an appropriate period beginning with the end of the phase-in period.

Minor administrative problems would also have to be worked out. For example, the annual rate of replacement of incandescent units must be established prior to the phase-in period. If the period is five years, then it would be required of the

customer to agree to the replacement of, say, one-fifth of its incandescent units each year of the phase-in period. If the company is able and willing to replace this number, but the customer prevents it, then the customer's incandescent rates should revert to the fully costed levels. On the other hand, the utility may find that it is unable to complete replacement at the agreed upon rate. In such cases, the customer should not be forced to pay higher rates for remaining incandescent units (even after the end of the phase-in period) if, through no fault of its own, replacements do not proceed as planned.

Aesthetic and Safety Considerations

There is an additional advantage that results from the type of phase-in plan described in the previous section. By gradually moving streetlighting rates to cost-based levels, and by giving municipal customers the choice of participating in the phase-in plan or immediately paying cost-based rates for incandescent units, the decision of what type and what quantity of streetlighting to purchase remains at the local municipal level; and these choices will be made on the basis of comparing local evaluations of the benefits to be derived from alternative lighting systems with the true social costs of providing these systems.

Retaining this kind of local autonomy seems preferable to imposing on municipalities wider area lighting requirements (e.g., state standards) because there are a number of different

criteria for selecting a lighting system; and the relative importance assigned to these criteria may vary significantly from community to community. More specifically, different sizes and types of streetlights are not directly interchangeable for either safety or aesthetic purposes. The proper design of a streetlighting system for purposes of driving safety requires consideration of the level of illumination and the spacing and mounting heights of lights. Aesthetic considerations may specify a given level of illumination as the objective (perhaps below that available from mercury or sodium units); or the quality (e.g., the color) of the light or the appearance of the fixture may be important considerations for some communities. In short, the evaluation of alternative sizes and types of lights is not based solely on the single criterion of maximum lumens per watt. Other economic, safety and aesthetic criteria must also be considered, and this consideration is best conducted at the local municipal level given that municipality's streetlighting objectives. It may well be that some municipalities place high values on the aesthetic or other attributes of incandescent lights and may wish to retain them despite their energy inefficiency. It should be the Commission's responsibility to permit that municipality to implement its own decision in this regard, as long as it is willing to pay the full costs of providing that service. In short, the Commission's primary responsibility is to insure that each streetlighting rate reflects the true social cost of service.