

An Outline Discussion

of

THE PURPA RATEMAKING STANDARDS

prepared by

The National Regulatory Research Institute

for the Staff of the

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## PREFACE

As part of a cooperative agreement between the West Virginia Public Service Commission (PSC) and The National Regulatory Research Institute (NRRI), the NRRI agreed to assist the Staff of the PSC in developing Staff positions on the ratemaking standards in the Public Utility Regulatory Policies Act of 1978 (PURPA). Section 111 of PURPA requires state regulatory agencies to consider adoption of six standards for use in setting rates for certain large electric utilities. As part of the Commission's consideration process, it is necessary for the Staff to develop a position on each standard for recommendation to the Commission.

The first step agreed upon for so assisting the Staff is for NRRI to develop a "white paper" describing in summary form the generic advantages and disadvantages of adopting each standard. Later steps consider company-specific data.

This document contains six summary "white papers" for the six standards. It was written by Kevin Kelly, Robert E. Burns, Roger McElroy and Robert Redmond, Jr. of the NRRI and Professor Patrick Mann of West Virginia University, and was edited by Kevin Kelly of the NRRI. The views expressed in this document are those of the authors and not necessarily the views of the NRRI.

The first white paper, covering the cost-of-service standard, goes into more detail than the others because this first paper defines terms used in the later papers and because many of the issues discussed in later papers relate to cost-of-service topics discussed at length only in the first paper.

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## BACKGROUND

### Three PURPA Purposes

The Public Utility Regulatory Policies Act of 1978 (PURPA) supplements otherwise applicable state law to establish three federally mandated purposes of state utility regulation that must be taken into account in consideration of PURPA standards. These purposes are the conservation of electric energy, optimally efficient use of electric utility facilities and resources, and equitable rates to electric consumers.

Conservation of electricity refers to the wise use of electricity in order to conserve capital and human resources as well as fuel. Efficient use of facilities refers to high productivity so that a maximum amount of electricity is generated from a fixed amount of plant investment. Efficient use of resources is achieved by satisfying all justified demand for electricity while eliminating wasteful demand. The concept of optimization is intended to exclude mere limited efficiency improvements. The notion of equitable rates to electric consumers is to avoid unwarranted cross-subsidization among customer classes and usage periods.

### Consideration and Determination of PURPA Standards

PURPA requires each state regulatory authority to consider the federal ratemaking standards addressing cost of service, declining block rates, time-of-day rates, seasonal rates, interruptible rates, and load management techniques and to determine the appropriateness of each standard.

The state regulatory authority may, to the extent consistent with state law, implement any standard determined to be appropriate to carry out the purposes of PURPA or determine that a standard is inappropriate to carry out the purposes of PURPA.

If the state regulatory authority determines that a standard is appropriate to carry out the purposes of PURPA and otherwise consistent with applicable state law, the state regulatory authority would be authorized by PURPA to implement the standard. However, a failure to implement a standard determined appropriate to carry out the purposes of

PURPA would not violate federal law. Nonetheless, such a failure to implement the standard could violate state law.

If the state regulatory authority determined that a standard is inappropriate to carry out the purposes of PURPA, PURPA would not require implementation of the standard. Finally, if a standard is determined appropriate to carry out the purposes of PURPA but inconsistent with otherwise applicable state law, the state law governs and prevents implementation of the standard.

When implementing standards, the state regulatory authority may fully implement the standard or partially implement the standard by phasing in implementation of the standard, by providing for temporary exemptions from the standard, or by any other means determined appropriate to mitigate hardships due to implementation of a standard.

States may also implement standards under their own authority even if a standard is determined to be inappropriate to carry out the purposes of PURPA.

#### The PURPA Ratemaking Standards

A simplified statement of the six PURPA ratemaking standards follows. An exact statement of each standard may be important for fine interpretation of standard consideration. The exact statements are to be found at the beginning of the white paper on each standard. Some of these statements refer to section 115 of PURPA, the appropriate subsections of which are in the appendix.

Cost of Service -- Electric utilities must charge each customer class a rate based on the cost of providing service to that customer class.

Declining Block Rates -- The energy portion of an electric rate may not decrease as kilowatt-hour consumption increases for any customer class unless it can be demonstrated by the utility that the energy costs decrease as that customer class increases consumption.

Time-of-Day Rates -- An electric utility must charge rates for each customer class on a time-of-day basis, i.e., reflecting the costs of serving customers at different times of the day, excepting when these rates are not cost-effective. Time-of-day rates are not cost-effective if the metering and other administrative costs of implementation outweigh the long-term savings that can be realized by time-of-day rates.

Seasonal Rates -- An electric utility must charge rates reflecting the cost of serving each customer class on a seasonal basis to the extent that costs vary seasonally.

Interruptible Rates -- Industrial and commercial customers must be offered an interruptible rate by electric utilities which reflects the cost of providing interruptible service.

Load Management Technique -- The utilities must offer customers load management techniques which the state regulatory authority finds to be practicable, cost-effective, reliable, and to provide useful energy or capacity management advantages.

## COST OF SERVICE

The standard established in PURPA is the following:

Rates charged by any electric utility for providing electric service to each class of electric consumers shall be designed, to the maximum extent practicable, to reflect the costs by providing electric service to such class, as determined under section 115(a).

### Discussion

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. There are two aspects to this general proposition. The first is the consideration of the question of whether rate structure ought to be based on costs at all. The second is the question of what type of cost measure is the most appropriate basis for rate structure, with consideration nowadays given especially to the advantages and disadvantages of marginal cost concepts in relation to the alternatives.

Before turning to the question of marginal cost as compared to other cost concepts, it is important to note the arguments for and against using any cost concepts at all in establishing electric utility rate structures. In general, economists argue that 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 first basis - efficiency - is fairly easily demonstrated and less susceptible to debate than the second. 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. It is also recognized that strict reliance on cost considerations will restrict the scope for using utility rates to help reach other goals of economic policy. 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.

Even when it is agreed that basing rates on costs is proper policy, determining whether a rate structure is or is not cost based is very difficult for several reasons. The cost of serving customers varies at least minutely for each individual customer. Cost differences arise from many different patterns of customer usage at many different locations. The problem becomes even more complex when attempting to incorporate these cost differentials into a single tariff applicable to a large group of customers.

Grouping customers into classes has traditionally been on the basis of the end-use of electricity: residential use, commercial use, industrial use, streetlighting, and other uses. Historically, this made sense in that most customers in a class had similar time-varying usage patterns. Residential use and streetlighting were at night for indoor and outdoor lighting, respectively; commercial use was predominantly during the day, and many large industrial users had a somewhat steady 24-hour load.

It can be argued that traditional classifications are less valid today. Daytime residential air conditioning use is growing and evening commercial use is often substantial. An important question is whether the diversity of usage patterns within a traditional class is greater than the diversity among classes. If so, the class may be poorly defined. Individual customers with "low-cost" characteristics -- such as an exclusively off-peak demand -- may feel unduly discriminated against when they are charged high rates because they belong to a class with a large peak period demand.

Some time-of-day pricing advocates believe that traditional customer classes should be eliminated if cost-based rates are to be achieved. Instead, they contend that customers should be classified on the basis of the extent to which the cost of the primary and secondary distribution systems are incurred to serve them. Then, all customers would face the same peak and off-peak rates, with appropriate price differentials for high, medium, and low voltage service.

Among those who agree that rates should be cost-based, besides disagreement on how to classify customers, there is a lack of agreement on



how costs should be calculated. Adding up the incremental costs of providing service to individual customers will not yield a result equal to the revenue requirement of the utility. This is because the only costs which can be attributed to a specific customer or a group of customers are the incremental costs of providing energy service to those customers. These incremental costs do not include the "sunk" or fixed costs which the utility incurs before providing any customer or group of customers with energy service. In the economists' terminology this is equivalent to differentiating between marginal costs (incremental costs) and average costs (which include the fixed components). Thus, adding up all the costs attributable to groups of customers or to individual customers would not necessarily yield sufficient revenues for the utilities to meet all their costs and earn a "reasonable" rate of return on their investments. Beyond this, there is disagreement over whether the original, historic cost of equipment in use or the current replacement cost is a proper basis for rate design.

Furthermore, even among those who can agree on the solution of the difficulties listed above, there is wide disagreement on how the joint costs of facilities for producing, transmitting and distributing energy should be allocated among the various classes of users.

The net result of these difficulties in determining costs for ratemaking is that there are widely varying rate designs and price levels which are purported by various advocates to be cost-based. In short, a wide range of rate structures have at least some claim to being cost-based. Outside of this range are rate structures universally recognized as intentional subsidies.

The following is a summary of the steps to be followed in determining the cost of service. Steps 1 and 3 are included only if time-of-use costs are to be determined. The steps are:

- 1) Selection of the rating periods which may be daily, seasonal, or both.
- 2) Division of costs, first, among the functions of production, transmission, and distribution; and second, among the customer, demand and energy categories.
- 3) Allocation of costs to the various rating periods.

- 4) Allocation of costs within the rating periods to the various customer classes.

The result of the costing process is the identification of demand-related, energy-related, and customer-related costs for each customer class in each rating period. Once the costing process is completed, a rate form can be designed to recover the cost components. A commentary on each step in the costing process follows.

**Selection of Rating Periods:** In theory, utility costs change from hour to hour. In practice, it is necessary to divide the year or the day into a few "rating periods" for ratemaking purposes. Rating periods should be selected so that they are broad enough to avoid the problem of "chasing the peak." If the system peak is defined too narrowly, some consumer demand may tend to move in time so that a new system peak appears in the off-peak or shoulder peak rate period. Thus, seasonal rates and time-of-day rates should not be set with extremely narrow rate periods, e.g., two or three hours for time-of-day rates, or one month for seasonal rates. However, rating periods should not be overly broad so as to give ineffective pricing signals to on-peak or shoulder peak customers. For example, if the peak and off-peak prices in time-of-day pricing are each twelve hours in length, then a utility with a late afternoon summer peak may not be giving its on-peak customers effective pricing signals to shift to periods other than the late afternoon.

**Division of Costs:** Division of costs is an elaborate process with a simple goal: to place (or force) all utility investments and expenses into three cost categories: customer, demand, and energy costs. An excellent review of this process and the degree of arbitrariness in it is contained within the NARUC Cost Allocation Manual. The manual gives detailed guidance as to which costs can be considered demand-related, energy-related, and customer-related costs.

**Allocation of Costs to Rating Periods:** The amount of costs allocated to rating periods depends on the probability that demand will exceed supply for the period. If seasonal rates are adopted, then the periods included in each season should accurately reflect the loss-of-load probability (LOLP) during the season, i.e., if the LOLP is highest during the months of June, July, August and September because the utility is a summer peaking

system, then the highest rates should also be in those months. A similar argument can be made for time-of-day rates.

Allocation of Costs to Customer Classes: The allocation of costs (perhaps within a rating period) to customer classes is often the most controversial step in the costing process. To reflect the cost of service to customers as closely as possible, the allocation of costs should be according to the customer class's time-varying pattern of use. Without time-of-use rates, this is accomplished by class load studies which provide data for assessing the degree of peak responsibility. With time-of-use rates allocation could be according to voltage level. Transmission and distribution system losses can be taken into account according to voltage level to reflect the costs of energy line losses as higher voltage electricity from the transmission system is transformed to lower voltage electricity. To the extent that traditional customer class definitions reflect the voltage level for serving members of the customer class, traditional customer definitions could reflect the cost of service. However, if a traditional customer class uses electricity at diverse voltage levels, the customer class may not reflect the cost of service.

### Issues

Consideration of this standard requires the consideration of two issues:

- (1) whether or not rates should be based on the cost of service; and if so,
- (2) whether rates based on cost of service are more appropriately based upon accounting costs or marginal costs.

### Arguments That Rates Should Be Based on the Cost of Service

Cost of Service and the PURPA Purposes -- The Congress presumably believed that cost-based rates are the principal means by which the PURPA purposes of conservation of electric energy, optimally efficient use of electric utility facilities and resources, and equitable rates to electric consumers can be achieved. Cost-based rates reflect the cost of service for each customer class and may form a justification for four other PURPA

ratemaking standards: declining block rates, time-of-day rates, seasonal rates, and interruptible rates.

Conservation -- Cost-of-service based rates would tend to encourage conservation of electricity by reflecting the increasing costs of fuel and capital. Cost-of-service based rates would allocate the costs of fuel and capital to the appropriate consumers, who are causing fuel and capital to be used; such a proper allocation should have a conservation effect. However, the magnitude of the effect will depend on the particular rate design which is judged to be cost-based.

Efficient Use of Utility Facilities -- Cost-of-service based prices would tend to encourage optimally efficient use of electric utility facilities by charging the demand, energy, and customer costs to the proper customers -- so as to discourage the use of electricity on the system peak as well as encouraging off-peak electric consumer to purchase more electricity. This effect would, of course, be greatest with time-of-day pricing but would occur to a lesser extent without it but with proper allocation of demand and energy costs among customer classes.

Equity -- One criterion of equity is "fairness." It is a clear notion of equity that fairness demands that each consumer should pay to the utility company the cost of serving him.

#### Arguments That Rates Should Not Be Based on the Cost of Service

Value of Service -- One argument against cost-of-service based rates is that rates should sometimes be based upon the value of service, i.e., the consumer should be charged a price based upon what the service is worth to him. In this view, a customer who places a high value on electricity, such as a commercial refrigeration customer, may be charged more than the cost of serving him in order to provide discount rates to other customers who would be unwilling or unable to pay a cost-based rate. For example, for an electric system where the running cost is considerably below the average cost of service, a rate somewhere between these two costs may be offered to an industrial customer who would turn to an alternate fuel if he faced a higher rate. As long as his rate is above the running cost, it is argued, the industrial customer makes a partial contribution to covering the fixed costs of the utility system. Other customers being charged a

rate based on average cost (or more) benefit from the partial subsidization of the industrial customer.

Equity and Ability to Pay -- The argument has been made that equity requires that rates, especially for residential customers, be set according to the customer's ability to pay, even if the rate does not reflect the cost of service. (Such an argument might favor lifeline rates.) The same argument can be applied to financially troubled industries, especially where state economic development policy is aimed at preventing loss of jobs or erosion of the tax base.

Societal Policy -- An argument can be made that cost-of-service rates are inappropriate when societal policy is to encourage a particular end-use of electricity, for example, rates lower than costs for back-up service to users of new technologies. Such rates may promote wind power systems or passive solar homes. As another example, industrial rates lower than the cost of service may be part of a state policy to promote industrial growth.

Conservation -- Rates reflecting the cost of service might also be abandoned if the state has a policy of promoting conservation of fuel by discouraging electricity consumption. Such a policy would suggest the use of lifeline or inverted rates (to the extent these are believed not to be cost-based) in order to tax large users and subsidize small users.

Flat Rates -- An argument might be made that flat rates for customer classes should be instituted even if these are found not to be cost-based. Flat rates meet the test of simplicity and understandability and so would have a greater degree of acceptance among residential and other customers than any other rate form.

#### Discussion of Accounting Costs

PURPA does not specify any particular costing methodology. Rather, PURPA states that the selection of the appropriate costing methodology rests within the discretion of the state regulatory authority. PURPA's section 115 definition of cost of service allows a general costing method which, to the maximum extent practicable, permits identification of differences in cost incurrence attributable to daily and seasonal time of use of service for each class of electric customers, and permits identification of differences in cost-incurrence attributable to differences in

customer, demand, and energy components of cost, while taking into account the extent to which total costs to an electric utility are likely to change if additional capacity is added to meet peak demand relative to base demand, or additional kilowatt-hours of electric energy are delivered to electric customers.

There are two fundamentally different categories of methods for determining the cost of service: the accounting cost approach and the marginal cost approach. The accounting cost approach is also referred to as the use of embedded costs, the allocation of historic average costs, or the fully distributed cost approach.

The basic difference between the two approaches is as follows. The accounting cost approach assigns to customers the responsibility for the total of all costs actively on the company's books. The marginal cost approach assigns to customers the responsibility for increases or decreases in the total current cost of service. Marginal cost advocates usually advocate time-of-use pricing, but marginal costing without time variance is possible, even if not preferable.

Accounting cost rates require each customer class to pay a rate covering the current energy costs plus allocated booked customer and demand costs. These rates are determined by studying the original costs of plant and equipment as well as the historic expenses of the utility during a historic test year to determine the revenue requirement, and designing rates by dividing up the revenue requirement by some allocative method that reflects the cost of service in terms of the original plant costs. Rates are usually based on a historic test year; however, fully distributed costs can also be found for a future test period. Forecasting future utility expenses can be difficult, and no single method of forecasting is generally accepted. Clearly, the "cost-based" rates in effect will differ according to the test period selected.

Time-of-use pricing can be based upon average as well as marginal costs. Time-of-use pricing based upon average costs divides up the revenue requirement by time periods as well as by customer classes. Rates are set primarily to gather in the required revenues. When such rates are first implemented, if the peak consumers do not respond to the higher price while the demand of the off-peak customers grows because of lower rates, then the

utility is likely to collect revenues greater than its revenue requirement. On the other hand, the utility will tend to under-collect revenue if peak consumers tend to be responsive while the off-peak consumers tend to be unresponsive. This difficulty is less severe with time-of-use rates based on marginal costs.

#### Arguments in Favor of Accounting Cost Pricing

Familiarity -- Accounting cost based methodologies are already familiar to the West Virginia Public Service Commission and the Appalachian Power Company. The Appalachian Power Company presently presents its rate increase request, which the West Virginia Public Service Commission analyzes, using accounting cost based methodologies, i.e., a historic test year and original costs.

Clarity of Issues -- Proponents of accounting costs claim that issues related to accounting cost based methodologies are easier to understand. The use of a historic test year in an accounting cost based methodology negates any need for complex issues concerning forecasting methodologies to determine costs in a projected test year.

The use of original historic costs in an accounting cost based methodology avoids the issues relating to the determination of system expansion costs for calculating marginal costs. Also, use of an accounting cost based methodology avoids the problems of adjusting rates to meet the revenue requirement. Accounting cost based methodologies precisely track revenue requirements and therefore require no adjustment in order to hold revenues at the allowed level.

Because accounting cost issues are clearer and more easily understood, these issues will be more easily and expeditiously resolved.

Cost-of-Service Studies -- Cost-of-service studies based upon accounting cost based methodologies could provide reasonable estimates of the responsibility of each customer class for the utility's past and current capital, operating and maintenance costs. The estimates could be the result of an allocation of known joint fuel, capacity, transmission and distribution costs to known historical load patterns of various customer groups. Thus, accounting cost based methodologies could accurately reflect utility operating characteristics and customer load factors as they are known to exist.

Test Year -- Accounting cost based methodologies are usually compatible with a historic test year, i.e., the period of time upon which the revenue requirement is determined. Moreover, the time period upon which accounting costs are determined is well detailed thereby preventing the estimation and guesswork that may be necessary to determine marginal costs.

Adaptability -- Accounting cost based methodologies are very adaptable and can be utilized to recognize other regulatory concerns. For example, the use of average costs inherently recognizes the heavy influence imposed by existing capacity upon the overall revenue requirement. Moreover, the use of accounting costs allows recognition that off-peak loads have a significant demand-related cost responsibility and that equity might require off-peak users to share a portion of the base load costs.

#### Arguments Against Accounting Cost Pricing

Economic Efficiency -- The principal arguments against accounting costs based methodologies are that they fail to promote fully economic efficiency. The argument is that only marginal cost based pricing can optimize social benefits while minimizing society costs. Accounting cost based methodologies fail to give the proper price signals to the consumer. If proper price signals are given, economic efficiency is enhanced.

Apportioning Costs is Arbitrary -- While accounting cost ratemaking procedures pretend to have great precision, the various versions of how to allocate accounting costs are arbitrary, having no underlying rationale. There is no theoretically correct way to allocate joint costs of service. Accounting cost methods depend, not on sound theory, but on tradition and precedent.

#### Discussion of Marginal Costs

Marginal cost is the additional cost of producing and selling a single incremental unit; for electricity, the unit is the kilowatt-hour (kWh). That is, the marginal cost of electricity is the increase in total cost for providing an additional kWh of electricity. An intermediate step in determining this marginal cost may be the calculation of the cost of one extra unit (a kW) of generating capacity. Two versions of marginal cost



are important: short-run marginal cost (SRMC) which is essentially the change in operating costs by changing the utilization rate of existing capacity, and long-run marginal cost (LRMC) which is essentially the unit cost of capacity expansion plus the unit operating cost associated with the expanded system. In sum, the marginal cost of electricity is simply the cost (or savings) incurred in providing more (or less) electricity.

The marginal cost of electricity is affected by multiple factors including voltage levels, time of usage, volume of service, consumer location, and consumer density in the service area. In contrast to average cost which focuses on sunk, embedded, or historical accounting costs, the calculation of marginal cost involves the projection of future operating and capacity costs for a specified time frame, focusing on cost changes over time with capacity expansion and demand increments. Incremental cost, short-run incremental cost (SRIC), and long-run incremental cost (LRIC) are concepts very similar to marginal cost (and SRMC and LRMC), i.e., marginal cost refers to one-unit changes in kWh or kW while incremental cost generally refers to multi-unit output changes. For practical purposes, the incremental and marginal concepts are interchangeable.

Marginal cost pricing is therefore the pricing of electricity at the cost of producing kWh or kW increments. Time-differentiated pricing logically flows from marginal cost pricing; however, time-of-day or seasonal pricing can be based on average cost as well as marginal cost.

In analyzing marginal cost pricing (as well as time-differentiated or peak load pricing), it is essential to distinguish between kW and kWh increments. Demand for electric power measures the kW demand imposed on the electric utility; it is a measure of peak power demand. In contrast, demand for electric energy measures kWh usage or energy consumption.

#### Arguments In Favor of Marginal Cost Pricing

Economic Efficiency -- Prices for electricity equal to marginal costs generate allocative efficiency (an efficient allocation of resources). The reason is that consumers are being induced to use electricity efficiently since the value placed by consumers on additional units is equal to the value placed on additional units of alternative or sacrificed goods. If electricity rates are unequal to marginal costs, consumers are receiving

incorrect signals regarding the value of resources used in the production of electricity; therefore, they will tend to consume either too little or too much electricity. Electricity rates based on marginal costs provide the foundation for both attaining an efficient utilization of system capacity (in the short-run) and attaining efficiency in capacity investment (providing long-run investment signals).

Correct Price Signals -- Marginal cost prices signal consumers the resource cost consequences of their consumption decisions and, conversely, reflect the cost savings if users forego additional units of electricity. In brief, marginal cost pricing generates efficient usage levels since it gives consumers the most accurate price signal regarding the cost of providing additional units of electricity. By doing so, it tends to discourage wasteful consumption, e.g., where prices are less than the cost of providing additional electricity service. Average cost rates convey price signals reflecting the average historical cost of producing electricity increments; marginal cost rates convey more effective price signals of the actual cost of the kW or kWh increment (i.e., the future operating and capacity costs). In sum, marginal cost pricing incorporates the causal responsibility concept that revenues generated by electricity users should match the costs imposed on the system by user demand. It should be stressed that the primary purpose of marginal cost pricing (and time-differentiated rates based on marginal costs) is not to shift usage, but instead to provide the most correct price signal. Although some shifting is anticipated, it is not the primary objective of marginal cost pricing to shift electricity loads.

Technical Efficiency -- In addition to allocative efficiency (which focuses on the consumption of electricity), another efficiency concept relevant to electricity pricing is technical efficiency. Technical or cost efficiency in an electric utility system involves the attainment of economies of scale, the adoption of the best available production techniques, and the achievement of maximum labor-management productivity. For the electric utility, technical efficiency means cost minimization in system size, in technology employed, and in labor-management performance. Rate structure design has a stronger link with allocative than with technical efficiency. For example, the choice between marginal and average

cost pricing has little impact on whether the electric utility adopts the most efficient technology or whether organizational slack is minimized. However, marginal cost pricing can minimize wasteful consumption and thus eliminate unnecessary capital expansion. Furthermore, peak load pricing can affect cost minimization by improving system load factors.

#### Arguments Against Marginal Cost Pricing

The Distribution of Income Problem -- Marginal cost pricing, in its attempt to achieve allocative efficiency, will affect the distribution of income. In essence, the efficiency issue cannot be completely divorced from the equity issue. Marginal cost pricing implicitly presumes that the unavoidable distributive outcome is reasonable, acceptable, or equitable. In contrast, if there is substantial evidence that the imposition of marginal cost pricing will adversely affect the distribution of income, then the question emerges of whether electricity rates are the appropriate and most efficient vehicle for improving the distribution of income.

The Minimal Efficiency Problem -- There are several arguments why the anticipated economic efficiency gains from marginal cost pricing may not materialize. One, allocative efficiency cannot be achieved without the simultaneous attainment of technical efficiency. That is, if the electric utility is not achieving cost minimization (the prerequisite for allocative efficiency), the economic efficiency gains from electricity rates based on marginal cost may be illusory. Two, marginal cost pricing does not incorporate future consumer values on resources, e.g., the prices of some exhaustible resources should be higher than present marginal cost in order to conserve a portion for future consumers who may be willing to pay higher prices. Given minimal efficiency gains, the economic costs of determining and implementing marginal cost rates, in some cases, can significantly exceed the efficiency advantages that such rates can achieve.

The Industrial Flight Problem -- The proposition here is that large commercial and industrial users are confronted by significant uncertainty with the implementation of marginal cost pricing; as a result, these large users of electricity may relocate. The rate continuity problem is one that can be remedied by gradual implementation of marginal cost pricing and simultaneous public education programs. The industrial flight problem may

be more applicable to time-differentiated rate structures than to marginal cost pricing per se. For example, some large users may be unable to change usage patterns due to production processes and therefore may have some inducement to avoid peak load pricing. However, many commercial and industrial users are likely to design, implement, and finance load management techniques to reduce electricity bills; furthermore, if a firm has a continuous production process and is virtually unable to adjust to time-differentiated rates, high peak prices will be offset by low off-peak prices.

The Cost Forecasting Problem -- The cost forecasting that is necessary in marginal cost estimation is not precise. For example, estimates of LRMC generally involve uncertain estimates of future costs. Given technical problems, the actual computation of marginal cost is somewhat ambiguous with marginal cost having multiple definitions, e.g., the estimation techniques vary as to their handling of capacity costs. The end result is marginal cost calculations that are only rough approximations of theoretical marginal cost. In sum, the numerous pragmatic problems of applying marginal cost pricing to electricity service permit significant variation in both the definition and estimation of marginal cost. The necessity of resorting to subjective judgment in adopting actual data to the theoretical model does not generate accuracy and preciseness in the marginal cost pricing of electricity.

The Cost Allocation Problem -- One can argue that the process of cost allocation to different user classes is much more difficult under marginal cost pricing than under average cost pricing. However, the latter generally involves arbitrary allocations, i.e., with the existence of joint or common capacity, it is equally difficult to apportion electricity costs under either marginal cost or average cost pricing. A related problem is the potential conflict between SRMC and LRMC. Setting price equal to SRMC will result in the efficient utilization in capacity investment. The primary problem with SRMC is its extreme volatility; the primary problem with LRMC is the estimation of future costs and output. The selection of LRMC over SRMC, and vice versa, involves judgments regarding the importance of near-term efficiency versus long-term efficiency. Time-differentiated rates by incorporating SRMC as the basis for off-peak prices and LRMC as

the basis for peak prices, avoids the conflict inherent in selecting the basis for non-time-differentiated (annual) marginal cost rates.

The Acceptance Problem -- One can argue that the marginal cost methodologies (estimation techniques) lack simplicity and are unfamiliar to utility companies as well as regulators and electric consumers. As a result, the concept of marginal cost is subject to multiple interpretations. Although the estimation techniques all incorporate future costs and output, they vary as to time horizon and as to the averaging process regarding capacity costs. In addition, the existence of various marginal cost estimating methods (with widely divergent results) confuses rate designers and elevates the degree of skepticism held by the electric utility industry regarding the applicability of marginal cost pricing.

The Second Best Problem -- An important application issue is that marginal cost pricing is not necessarily efficient for electricity given substantial deviations from optimal pricing and resource allocation in related sectors of the economy. In brief, marginal cost pricing in one sector may increase allocative inefficiency if the remaining sectors, because of monopoly, regulation, and taxation, have prices exceeding marginal costs. For example, in the energy sector, petroleum and natural gas prices are regulated and may not reflect marginal cost. Therefore, efficiency in electricity pricing may require prices unequal to marginal cost to counter distortions elsewhere, i.e., to avoid increasing the degree of allocative inefficiency caused by prices unequal to marginal cost elsewhere.

In sum, the argument is that in order to achieve allocative efficiency via the marginal cost pricing of electricity, prices of substitutes (natural gas, petroleum), prices of complements (electric appliances), prices of inputs (coal), and even prices of products whose production employs electricity as an input must also be based on marginal cost. In theory, this "second best" problem does exist and with prices unequal to marginal costs in various parts of the energy sector, marginal cost pricing of electricity could tend to distort further the allocation of resources. However, it has not been empirically demonstrated that the employment of marginal cost rates, even in a second best situation, distorts resource allocation more than the use of average cost or embedded cost rates.

The Revenue Problem -- A problem of incorporating marginal cost into rate design in periods of rising prices is its excess revenue potential, i.e., electricity rates set equal to long-run marginal costs have a high probability of generating revenues in excess of revenue requirements. This leads to arbitrary methods of shedding excess revenues to meet the revenue requirement constraint. The excess revenue problem flows from marginal cost calculations being based on projected costs while revenue requirements in the traditional cost of service approach are determined from total accounting costs. Therefore, the total revenues generated by marginal cost rates tend to exceed total revenue requirements as determined in the traditional regulatory framework. The opposite would be true when prices are falling.

The excess revenue problem must be reconciled with the permissible earnings constraint of traditional regulation. The solutions to this problem include modifying marginal cost rates to yield revenue requirements. This constraining process can produce rates providing inefficient signals not reflecting user costs. In addition, the methods used to shed excess revenues are highly arbitrary, lack a strong theoretical base, and produce ambiguous prices not equal to marginal cost but instead "based" on marginal cost.

In brief, since accounting costs have been (and will continue to be) the dominant consideration in determining revenue requirements for electric utilities and since marginal cost tends to deviate significantly from historical accounting costs, the regulatory process may tend to minimize the difference between electricity rates based on marginal cost and electricity rates based on average cost. The end result may be marginal cost rates converging toward average cost rates, marginal cost pricing in practice deviating significantly from marginal cost pricing in theory, and marginal cost rates that diverge significantly from the actual marginal cost of providing electricity service.

## DECLINING BLOCK RATES

The standard established in PURPA is the following:

The energy component of a rate, or the amount attributable to the energy component in a rate, charged by any electric utility for providing electric service during any period to any class of electric consumers may not decrease as kilowatt-hour consumption by such class increases during such period except to the extent that such utility demonstrates that the costs to such utility of providing electric service to such class which costs are attributable to such energy component decrease as such consumption increases during such period.

### Discussion

Declining block rates are the electric rate design form most commonly used from early in the twentieth century through the 1970's. Various reasons are put forth for the use of this rate form. Utilities often assert that it is used to spread customer costs and other fixed costs over the initial sales. Others assert that it is a form of promotional pricing appropriate for a period of declining costs. Historically, the rate form appears to have evolved, at least in some jurisdictions, from prior rates that took account of end use. For example, the first few hundred kilowatt-hours were assumed to be for electric lighting that occurred during the evening peak. Additional electricity was used for another purpose, such as water heating, that tended to occur somewhat off-peak (say, in the early morning hours) and that deserved a lower rate. A third block may have been added for additional off-peak usage.

### Issues

Consideration of this standard requires the consideration of two issues:

- (1) whether declining block rates reflect declining service costs; and if not,
- (2) whether such rates should be eliminated.

### Arguments That Declining Block Rates Reflect Declining Service Costs

Customer - Related Costs -- It can be argued that declining block rates do reflect declining service costs. A utility incurs the customer cost component of the declining block rate regardless of the customer energy usage level. Hence, to ensure that most of the customers pay rates which allow the utility to recover these costs, the customer cost component is allocated to the first rate blocks.

Load Factor -- In order to allocate the demand component of the customer's bill proportionally to the demand imposed by the customer, a relationship must be found between demand imposed and energy usage since only the latter is metered. It is asserted that load research data show that energy is utilized more evenly over time as energy usage increases. Hence, as energy usage increases, demand imposed by the customer increases at a decreasing rate. The above relationship suggests that as energy usage increases, the customer's per-unit demand charge should decrease, illustrating that a decreasing per-unit charge accurately reflects the demand costs imposed on the electric system.

Economies of Scale -- An argument has been made that there are still economies of scale to be realized by building larger plants, and therefore demand at the tail block should be encouraged for efficiency reasons. While it is true, in a strict engineering sense, that there are economies of scale yet to be exploited, the cost of increased maintenance time and unplanned shutdown time of larger plants vis-a-vis smaller plants and the cost of increased reserve margin required due to larger plants more than offset the engineering advantages to be gained by larger plants.

### Arguments That Declining Block Rates Do Not Reflect Declining Service Costs

Accounting Costs -- Under a pure declining block rate structure, a customer's bill is based solely on the amount of energy used. All of the component costs of providing electricity - energy, customer, and demand - are recovered through an energy usage rate. But the customer cost component is not related to usage and the demand cost component is not directly related to usage but to plant investment necessary to supply energy. The energy cost component is the same for all kilowatt-hours and



does not decrease with increasing usage. The customer component is the same for all similar customers; since it does not depend on the number of kilowatt-hours consumed, it ought to be recovered through a fixed customer charge. There is no good way to recover the demand component unless a separate demand charge or a time-of-use rate is in effect. Arguments that the demand component included in the kWh energy charge should decline, remain constant, or increase with increasing kWh usage are not convincing. One could argue, for example, that large residential usage occurs mainly in summer months for air conditioning which creates a summer peak. From this, it could be argued that a greater proportion of the demand component should be allocated to tail blocks for residential customers. At any rate, equal allocation of this component to all kWh's seems a good compromise among competing claims for increasing and decreasing demand components in the energy charge.

Marginal Costs -- Declining block rates do not reflect declining marginal costs and therefore do not provide the customer with a proper price signal. If a customer is purchasing electricity in the tail block region, he is paying rates which are below the long-run marginal cost of supplying his demand. This produces excess consumption because the true cost of producing that last kWh is greater than the customer's willingness to pay. Conversely, if a customer's final purchase of electricity is in the initial blocks of the declining block rate structure, he is paying rates which are above the marginal cost of supplying his demand. A customer whose final purchases are in the initial blocks has been discouraged from further consumption by an artificially high price. More electricity would be justifiably consumed by this customer under a flat rate structure. Both cases of excess and discouraged consumption represent "societal losses" that would be eliminated by proper pricing.

#### Arguments That Declining Block Rates Should Be Eliminated, If They Do Not Reflect Declining Service Costs

Benefits of Eliminating Declining Block Rates -- If declining block rates do not reflect declining service costs, they should be eliminated in order to (1) provide rates that meet the cost-of-service standard, (2) eliminate social losses at both the initial blocks and the tail blocks, (3) better conserve our energy resources due to a probable decline in overall

electricity sales, and (4) reduce the frequency of rate cases. With regard to item (1), the decision to eliminate declining block rates may be affected by prior adoption of the cost-of-service standard.

Societal Losses -- Providing the customer with a proper price signal is the first benefit of eliminating declining block rates in favor of properly set flat rates. A related benefit is the elimination of societal losses. Total societal loss incurred with the usage of declining block rates is determined by summing the initial block losses with the tail block losses. A flat rate structure will eliminate both sources of societal loss.

Energy Conservation -- Conservation of energy resources may occur with declining block elimination because the tail block rate is raised to a higher level, resulting in less electricity consumption. Increased consumption by those small-use customers in the initial blocks will offset to some degree, however, the decrease in usage by those large-use customers in the tail blocks.

Lightened Caseload -- Eliminating the declining block rate structure in favor of a flatter rate structure may reduce the number of rate cases. Electric utilities have been making more frequent requests to the public service commission for rate increases during the 1970's. The cause of these expensive hearings is at least twofold: (1) recent high rates of inflation, and (2) the existing rate structure. Fuel adjustment clauses are designed to provide utilities with some assistance through automatic rate increases during periods of high inflation. Hence, inflation is not the sole cause of the increase in rate hearings. Part of the blame must be borne by the existing rate structure. Electricity demand grows partly as a result of current customers increasing their consumption. These customers are charged less than the cost of new supplies for their additional consumption as they consume in the tail block portion of their rate structure. The tail block rates may be below the long-run marginal cost of producing the customer's additional demand, thereby providing the utility with revenues that are below the cost of producing the additional demand. A flat or marginal cost rate structure provides a closer correspondence between revenues and costs and thus potentially eliminates one cause of the frequent rate hearings.

Arguments That Declining Block Rates Should Not Be Eliminated, Even If They Do Not Reflect Declining Service Costs

Stability of Revenues -- One disadvantage of eliminating the declining block rate structure, even when it does not reflect declining service rates, is the following. A utility's annual revenue will be less stable. Due to weather fluctuations and changes in the mix of customer types, annual consumption of electricity is somewhat random. Consequently, revenue is also somewhat random. This revenue instability is minimized under declining block rates since most of the fluctuations in electricity sales occur at the low tail block rates. Under a flattened rate structure, the tail block price would be higher resulting in greater revenue uncertainty. The possible effect of increased revenue uncertainty might be that investors would require a higher rate of return to compensate for the additional risk of revenue uncertainty.

Excess Capacity Problem -- Support for declining block rates can be presented by electric utilities which employ baseload coal burning facilities and have excess capacity. Increased demand, achieved through a declining block rate structure, allows the utilities to utilize excess capacity thereby increasing economic efficiencies. (The above is the only situation provided for under PURPA statute where declining block rates are acceptable.)

## TIME-OF-DAY RATES

The standard established in PURPA is the following:

The rates charged by any electric utility for providing electric service to each class of electric consumers shall be on a time-of-day basis which reflects the costs of providing electric service to such class of electric consumers at different times of the day unless such rates are not cost-effective with respect to such class, as determined under section 115(b).

### Discussion

Time-of-day (TOD) pricing is one form of time-differentiated electricity rates, i.e., electricity rates varying with the time of kW demand or kWh usage over a daily demand cycle. TOD rates involve different prices for electricity service at different hours of the day; more specifically, they involve higher electricity prices during the electric utility's daily peak and lower prices during the off-peak period.

TOD rates reflect the fact that the unit operating cost of providing electrical energy varies significantly between peak and off-peak hours; they also reflect the fact that electric utility capacity requirements are essentially determined by peak demands; and they also reflect the fact that peak users are responsible for the capacity required to serve the peak demands while the off-peak users bear little responsibility for the capacity requirement. Therefore, TOD rate design involves the assignment of higher costs to peak usage periods and the assignment of lower costs to consumption at off-peak hours when the electric utility is experiencing excess capacity. In brief, TOD pricing has rates varying over hours of the day based on variances in the cost of providing electricity service during various times of the day.

TOD pricing can be based on average or embedded cost as well as on marginal cost. TOD rates based on average costs can be viewed as a practical technique which reduces the potential problem of excess revenue generation associated with marginal cost pricing. TOD pricing is not synonymous with marginal cost pricing.

Electricity rate structures that promoted increased consumption in the past were not necessarily inefficient. However, at present, added capacity

may involve higher costs due to increasing costs of generating plants, an increasing number of environmental standards, and the possible exhaustion of economies of scale in generation-transmission. Increased usage may improve load factors only if the consumption occurs at off-peak so as to avoid increased capacity costs. If the electric utility promotes conservation, average consumption may decrease but peak demands may not, thus creating deteriorating load factors with no effect on capacity requirements. A possible solution to this increasing cost problem is time-differentiated or peak load pricing incorporating differential rates for peak and off-peak consumption. The dual objectives are to penalize peak consumption in the short-run and alter consumption patterns in the long-run.

### Issues

Consideration of this standard requires the consideration of two issues:

- (1) whether time-of-day rates are cost-effective; and if so,
- (2) whether such rates should be adopted.

### Arguments for the Cost-Effectiveness of TOD Rates

The Conditions for Benefits -- A technology is cost-effective if the benefits outweigh the costs. The potential benefits (savings) from TOD pricing are essentially enhanced by general system (supply) characteristics such as: a broad range of fuel costs per kWh, low capacity utilization rates on generating capacity having relatively low fuel costs, the wholesaling of off-peak energy at low rates, and generating expansion plans that incorporate high fuel cost units. In addition, the potential benefits from TOD pricing are enhanced by load characteristics such as: low daily load factors particularly on peak days and a high proportion of loads composed of demands that are relatively price elastic. In brief, the savings from TOD rates are presumed to be influenced by both supply conditions (e.g., existing capacity) and demand conditions (e.g., load served) confronting each electric utility.

Reduction in Capacity Requirements -- Another benefit is that TOD pricing provides recognition that peak demands inflate capacity requirements. TOD pricing has the potential for decreasing future capacity requirements (and some associated operating costs) by deferring generation, transmission, and distribution capacity investment. That is, capacity and operating cost reductions can be anticipated with lower peak capacity requirements. Slower peak demand growth should reduce capital expenditures and possibly enhance the financial condition of the electric utility. In brief, unless peak price elasticity is zero, TOD pricing will mean less capacity needed to meet peak demands than under uniform rates over time.

Reduction in Operating Cost -- TOD rates provide recognition that peak demands force into service expensive peaking units which incur higher operating costs than base generating plants. Improved load factors (load shifts from peak to off-peak) mean a shift of load from relatively inefficient peaking units to relatively more efficient base units. There are cost reductions due to reduced use of peaking units and costly fossil fuel; with improved load factors, there is a substitution of cheaper electricity for more costly electricity. However, it should be stressed that the load shift from peak to off-peak is not energy conservation but instead a combination of off-peak sales promotion and on-peak sales reduction for capital conservation.

The relative capacity cost and fuel cost savings will vary with plant mixes across electric utilities. For example, a typical power system consists of a specific mix of plants to serve different load types: peak, intermediate, and base loads. Each type of load or demand involves a different capital-fuel cost ratio, e.g., peak loads are generally met with generating plants having relatively low capital costs and high fuel costs while base load plants tend to have low fuel costs but involve relatively high capital costs.

Metering Justification -- An important cost associated with TOD rates is the cost of relatively sophisticated metering. The relatively expensive demand meters can easily be cost justified for large commercial and industrial users. Many large commercial and industrial users already have demand meters suitable for measuring usage by TOD; for these large users, the additional cost of implementing TOD rates would be minimal. For the

remainder of large volume users, the implementation-metering cost for TOD rates generally would be a small percentage of their total cost of electricity service. In brief, for the majority of large commercial-industrial users, metering costs are not an impediment to the implementation of TOD rates. In addition, less costly TOD kWh meters may be warranted for residential consumers. The optimal procedure is to initiate TOD pricing where implementation costs are lowest and anticipated benefits greatest, and then proceed to other user classes as technology and experience justify and as the cost of mass-produced meters declines.

#### Arguments Against the Cost-Effectiveness of TOD Rates

The Metering Problem -- TOD rates may not be cost-effective because of high metering and other administrative costs. Particularly for small commercial and all residential users, TOD meters are relatively expensive. In addition to TOD kWh meters, TOD kW (demand) meters may be required for larger customers. For small users, additional metering costs with TOD pricing would result in a significant increment to monthly electricity bills and would represent a relatively large percentage of their total cost of electricity. In addition, there would also be the additional cost of informing and educating small users about TOD rates. Thus, the cost-effectiveness of TOD pricing depends on the cost and availability of metering equipment and TOD implementation costs. In some cases, TOD pricing may not be cost beneficial to residential users. For example, the magnitude of load shifting from TOD rates may be too insignificant to justify metering and implementation costs. That is, the incremental costs of billing and metering can offset the advantages of TOD pricing. In addition, TOD meters installed now may rapidly become obsolete due to changing metering and load control technology. Finally, there could be significant costs incurred by the public service commission, e.g., the monitoring of the effects of TOD rates is an expected complement to their implementation.

The No Effect Problem -- TOD rates may not be cost-effective because little or no capacity savings may occur. It is possible that TOD rates in some cases may have little effect on usage patterns, even over a reasonable period of time. The end result may be minimal load factor improvement and

minimal deferred capacity. Critics of this argument contend that it still must be recognized that electricity consumers will have expressed acceptance of the TOD rate differentials. That is, even if consumers do not alter consumption patterns with TOD rates, payment of peak prices indicates the acceptance of peak and off-peak cost differentials and the general equity in TOD rates. Furthermore, to the economist, it is just as important that the most appropriate prices be charged for electricity service as the attainment of potential benefits such as load factor improvements and reduced capacity requirements.

Shifting Peak Demands -- Expected capacity savings may not occur if TOD rates cause a new peak period. The implementation of TOD pricing can create the problem of moving or "wandering" peaks. That is, TOD rates may merely shift the time of peak with no change in its level. This necessitates rate adjustments and shows the need for the monitoring of TOD rate effects. Peak changing, however, may be a relatively minor problem since consumer reaction to TOD rates should be relatively slow. In practice, consumer reaction can be relatively slow since the regulatory process can ensure slow price adjustments, and since new prices can take a long time period to have an effect since electricity demand is linked to appliance and equipment stocks. Therefore, the adjustment or feedback effects from the adoption of TOD rates can be sufficiently lagged that rate-setters can make relatively slow rate adjustments. In addition, the gradual implementation of TOD pricing can provide data on consumer adjustments and allow further time for rate adjustments.

The Needle Peak Problem -- TOD pricing can create a needle peak problem. The number of peak hours may decrease but not the magnitude of the peak hour leaving capacity requirements virtually unaffected. The result is the emergence of a needle peaks with declining daily load factors. More specifically, consumers may curtail use of air conditioning during peak hours on moderate days but not on extremely hot days. In addition, a daily needle peak may occur immediately following the peak period, i.e., given the incentive to shift loads, the shift may occur immediately following the on-peak period. The resulting peak may be higher than the original peak. This problem, however, can be minimized by careful



selection of peak and off-peak hours. The needle peak problem can be partly offset by certain loads (e.g., industrial processes) that will be very sensitive to TOD rates.

The Lack of Reliable Price Elasticity Data -- Cost-effectiveness is uncertain at best because there is a lack of information regarding the alteration of load curves from TOD rates. It is reasonable to anticipate some shifting; but available price elasticity data, although a good basis for predicting total consumption after price changes, cannot be relied upon to determine if electricity users will alter usage patterns, to determine the nature of usage shifts, or to determine the time period necessary for usage changes.

Unreliable peak price elasticity data create two problems. One, the effect of TOD rates on electric utility revenues and cash flow is uncertain. Potential problems are uncertain revenue stability, revenue erosion, or revenue over-recovery. For example, revenue erosion or shortfalls can occur if user response to TOD rates is greater than anticipated, or if average usage declines more than peak demand thus creating a deterioration in load factors and an increase in unit costs. Revenue over-recovery can occur if peak consumption is relatively insensitive to TOD rates while off-peak usage increases significantly. Two, the effect of TOD rates on electric utility load factors, operating costs, and capacity requirements is also uncertain. Therefore, reductions in operating costs, capacity requirements, and other potential benefits from TOD pricing are virtually impossible to predict with any accuracy. As data and experience with TOD rates in the U.S. are accumulated, the effects (benefits) will become easier to estimate.

#### Arguments that TOD Rates Should Be Adopted, If Cost-effective

Realizing the Benefits -- If they are cost-effective, time-of-day rates should be adopted to allow consumers to enjoy the excess of benefits over costs, as discussed above.

Fewer Rate Cases -- With peak prices reflecting incremental capacity costs, demand growth becomes self-financing thus reducing the number of future rate cases. That is, TOD pricing can produce a slowing in the rate of increase of electricity prices thus simplifying the rate design process

and reducing its administrative costs. The deferring or postponing of capacity expansion lessens the need for electric utilities to petition for rate increases to attract new capital. In addition, unlike declining block rates, time-differentiated rates are compensatory at every level of demand. However, rate increases will still be necessary to compensate for the effects of inflation.

Potentially Reduced Electricity Bills -- For users who alter demand patterns, TOD pricing can result in significantly decreased electricity bills. That is, electricity users who are willing and can modify usage patterns can experience cost savings in electricity expenditures. Energy conservation will be enhanced; in addition, consumer choice is enhanced since users have a means of avoiding increasing bills.

Prices Track Costs -- TOD rates result in an approximate match of actual costs of service and electricity prices by making peak users responsible for peak capacity costs. TOD rates incorporate the concept of causal responsibility (i.e., revenues provided by different user classes equal the costs caused by each user class). The result is a more accurate match of prices with cost responsibility. Incorporating the premise that the cost of providing electricity varies over the daily demand cycle, and the premise that rates are to track costs, TOD rates provide price signals based on the time-varying cost of providing electricity.

In contrast to TOD rates, uniform rates over time (with their averaging of peak and off-peak costs) tend to encourage too much consumption at peak and too little at off-peak. That is, peak period usage is encouraged with its inaccurately low price; off-peak usage is discouraged with its inaccurately high price. In brief, uniform rates over time exceed the cost of providing off-peak demands but are less than the cost of providing peak demands. The results of this internal cross-subsidization is the encouragement of capacity expansion to meet peak demands and an involuntary subsidy to peak users by off-peak users.

Stimulation of Technological Advance -- TOD rates can stimulate technological advances in both research and development, including the use of energy storage devices and related load management techniques. By providing incentives to store electricity during off-peak periods, this will stimulate peak users to develop energy storage devices, develop

alternative energy sources, and develop improved load management techniques. For example, large commercial and industrial users have the incentive and will likely design, implement, and finance load management techniques.

Improved Public Image of Electric Utility -- TOD rates avoid a problem associated with voluntary conservation in which average consumption declines but not peak consumption. The result of a declining load factor induces pressure for a rate hike to "reward" electricity consumers for their conservation efforts. By better matching costs and prices and by forcing users who cause costs to pay for them, the electric utility enhances its image by having more equitable electricity rates that truly reward peak period conservation with reduced electric bills.

#### Arguments That TOD Rates Should Not Be Adopted, Even If Cost-effective

The Industry Location Problem -- TOD pricing may be undesirable if it conflicts with the pricing policies of adjacent regulatory jurisdictions. For example, if TOD rates do not exist in adjacent states, some industrial location decisions can be affected at the margin. Loss of significant industrial baseload to neighboring states could adversely affect the financial health of an electric utility as well as the state. The PSC can minimize such a problem by gradual implementation of TOD rates along with TOD implementation (and other pricing reforms) occurring simultaneously in other states. However, large industrial users are not necessarily being penalized under TOD rates. That is, those users unable or unwilling to change usage patterns pay costs they are responsible for rather than being subsidized by off-peak users.

Adverse Consumer Reception -- Many consumers have a preference for the status quo and prefer to avoid a radical change in electricity rate structure. TOD pricing tends to reject some traditional standards of fairness (i.e., users responsible for certain historical costs of providing electricity should pay for these costs). In addition, it surely conflicts with levelized billing practices. For certain users, TOD pricing may result in a significant increase in electricity bills.

Other Load Management Techniques Superior -- Electricity consumers may not relate to rates per se, but instead to total monthly bills. That is, users do not associate increases in their monthly bill to actual usage; if

this is the case, TOD rates which do not significantly change monthly bills may not affect timing of usage. This may suggest that load control devices such as ripple control or interruptible contracts may be more cost beneficial than TOD rates. However, it should be noted that TOD rates and load management techniques are not mutually exclusive; one does not preclude the employment of the other.

Price Discrimination With Selected Application -- It may be considered discriminatory to implement TOD rates for commercial and industrial users and not for residential consumers. Obviously, some price discrimination would exist in the sense that some residential users are not paying for their contribution to peak demands while some residential users are probably paying more than the capacity costs they are responsible for. However, it is impossible to avoid some price discrimination in TOD rates given the determination of sufficiently broad peak and off-peak periods and the averaging of capacity costs. Yet, even selective implementation of TOD rates reduces the level of price discrimination from that associated with uniform rates over time for all user classes. This is particularly true if implementation of TOD rates does not change the aggregate costs allocated to commercial-industrial users.

Capacity Cost Responsibility -- It is argued that TOD rates force peak users to bear the entire burden of capacity costs for an electric utility even though some capacity is used in common with off-peak users. Some TOD ratemaking methods assign all capacity costs to be borne by the causers of the peak demand. A possible solution to this question of equity is the development of a graduated responsibility scheme for peak capacity based on varying probabilities of peak demand occurring in the particular hour of the day. Under the graduated responsibility scheme, off-peak users could bear some of the electric system's capacity costs.

Conflicting Notions of Equity -- TOD pricing may conflict with certain notions of equity. To some analysts, equity means electricity rates should vary with income levels. In the context of TOD pricing, some low-income users may be unwilling or incapable, for various reasons, to shift usage from peak to off-peak periods. TOD rates that result in higher electricity bills for the poor are opposed on equity grounds.

## SEASONAL RATES

The standard established in PURPA is the following:

The rates charged by an electric utility for providing electric service to each class of electric consumers shall be on a seasonal basis which reflects the cost of providing service to such class of consumers at different seasons of the year to the extent that such costs vary seasonally for such utility.

### Discussion

Seasonal or time-of-year pricing is one form of time-differentiated electricity rates, i.e., electricity prices varying with the time of kW demand or kWh usage over an annual demand cycle. Seasonal rates involve different prices for electricity service for different days or seasons of the year; more specifically, they involve high electricity prices during the electric utility's annual peak and lower prices during the off-peak period.

Seasonal rates reflect the fact that the unit operating cost of providing electrical energy can vary significantly between peak and off-peak seasons; they also reflect the fact that electric utility capacity requirements are essentially determined by peak demands; and they further reflect the fact that peak users are responsible for the capacity required to serve the peak demands while the off-peak users bear little responsibility for the capacity requirements. Seasonal rate design involves the assignment of higher costs to peak consumption periods and the assignment of lower costs to usage on off-peak days when the electric utility is experiencing under-utilized capacity. In brief, seasonal pricing involves rates varying over days of the year based on variances in cost of providing electricity service at various times of the year.

Seasonal pricing can be based on an average of embedded costs as well as on marginal cost. Seasonal rates based on average embedded costs can be viewed as a practical compromise which reduces the potential problem of excess revenue generation linked with marginal cost pricing. Seasonal pricing is not synonymous with marginal cost pricing.

The prerequisites for effective seasonal pricing are several. One, summer peak demand for the electric utility must be substantially greater than winter peak demand, or vice versa. Two, installed capacity requirements and planned capacity additions must be primarily determined by peak demand in a specific system. Three, the electric utility must have a peak demand occurring consistently during the same season. Finally, the electric utility must be able to estimate the cost differences between meeting peak and off-peak demands.

Electricity rate structures that promoted increased consumption are not necessarily inefficient. However, at present, added system capacity may involve higher costs due to increasing costs of generating plant increased environmental standards, and the possible exhaustion of economies of scale in generation-transmission. Increased usage may improve load factors only if the consumption occurs during the off-peak season, and can trigger increased capacity costs. If the electric utility promotes conservation, average consumption may decrease but peak demands may not, thus creating deteriorating load factors with no effect on required capacity. One solution to this increasing cost problem is time-differentiated pricing incorporating differential rates for peak and off-peak consumption. The dual objectives are to penalize peak consumption in the short-run and alter consumption patterns in the long-run. The anticipated end result is decreasing demand and energy consumption in the peak season, with improvements in the electric utility's annual load factor via the inducement of load growth in the off-peak season.

### Issues

Consideration of this standard requires the consideration of two issues:

- (1) whether costs vary significantly by season; and if so,
- (2) whether seasonal rates should be adopted.

### Arguments That Costs Vary Significantly by Season

Significant Variations-- Although the greatest variance in demand is over the daily demand cycle, most electric utilities experience distinct seasonal peaks, either summer or winter, due to weather sensitive loads.

That is, electric utilities are likely to be operating close to capacity in summer or winter due either to air conditioning or space heating loads. The seasonal load pattern may mean that costs will vary over the annual demand cycle. More specifically, if incremental costs vary substantially with the seasonal time variation in demand, seasonal rate differentials are justified. The key element of seasonal pricing is recognition that the unit cost of providing electricity varies between the peak and off-peak seasons of the year.

#### Arguments That Costs Do Not Vary Significantly by Season

Insignificant Seasonal Cost Variation -- For some electric utilities, summer and winter peaks are approximately the same. For other electric utilities, peak demand does not occur consistently over the annual demand cycle. Therefore, unit costs may not vary substantially over the annual demand cycle or the electric utilities cannot estimate, with any accuracy, cost variances between peak and off-peak demand periods.

Provision for Planned Outages -- It can be argued that costs do not vary significantly by season, even though the system load varies, because of scheduled outages. During seasons of reduced load, utilities schedule maintenance and, for nuclear units, refueling. Sometimes, it is possible to match the planned outages with the seasonal load variation so that the loss-of-load probability (or roughly, the margin between available and required capacity) remains approximately the same throughout the year. It is argued that the loss-of-load probability at any point in time tracks the costs. If this probability does not vary, then neither does the cost.

#### Arguments That Seasonal Rates Should Be Adopted, If Costs Vary Significantly by Season

Cost and Revenue Match -- Given the premise that electricity rates are to track costs, and given electricity costs varying over the annual demand cycle, electricity rates should vary accordingly. Seasonal rates provide proper price signals to consumers as to the cost savings which result from changing their time pattern of usage.

The Benefits -- Seasonal peak load pricing can reduce energy and power consumption during the peak season by inducing load growth and energy

consumption during the off-peak season. The specific benefits include increased production efficiency (via annual load factor improvement) and reduced future capacity requirements (via reduced peak demand).

Easy Implementation -- Seasonal pricing involves negligible implementation costs since it does not require expensive demand metering. Unlike time-of-day pricing, consumers have an easier adjustment to seasonal pricing; in addition, the usage shifts from one time period to another will tend to be substantially less than in TOD pricing. In brief, some of the implementation problems with TOD rates are not applicable to seasonal rates. For the electric utility, the probability that seasonal capacity will be exceeded can be easily calculated so capacity costs can be distributed based on the seasonal probability of excess seasonal demand.

#### Arguments That Seasonal Rates Should Not Be Adopted, Even If Costs Vary Significantly by Season

The Needle Peak Problem -- A summer peaking electric utility generally has a substantial air conditioning load. Seasonal pricing provides customers with incentives to reduce air conditioning use. However, such incentives may result in a decreased air conditioning load on moderately warm days but not on the hottest days. Therefore, average consumption declines in the peak season but not maximum or peak day demand. The end result is the emergence of sharp "needle" peaks (on the hot days) with no decrease in capacity requirements, a decrease in the annual load factors, and possible revenue shortfalls. In sum, for a summer peaking electric utility with a substantial air conditioning load, system peak demand may not be substantially reduced by seasonal pricing, and the system's annual load factor may deteriorate. The needle peak problem is essentially a seasonal peak load pricing problem, although it can occur in a slightly different form with TOD pricing.

The Load Factor Improvement Problem -- Seasonal pricing can generate an annual load factor improvement which may result in decreasing system reliability. That is, the annual load factor improvement may necessitate larger reserve margins of generating capacity in order to facilitate required maintenance. Load factors above a certain threshold level can interfere with planned maintenance and thus with power system reliability.



The Uncertain Effects Problem -- Overall price elasticity data form a reliable basis for forecasting total consumption with price changes, but such data cannot be relied upon to determine whether or not electricity consumers will alter usage patterns with seasonal pricing, or to determine the exact nature of shifts in consumption or load patterns, or to determine the time period necessary for the usage shift to occur. In brief, the lack of reliable estimates of peak demand price elasticities makes it difficult to estimate the seasonal pricing effects on capacity requirements, load factors, operating costs, and electric utility revenues. Peak price elasticity data are difficult to acquire and the quantification of consumption sensitivity to prices at peak periods is a difficult analytical task. One can anticipate that some load shifting and usage reduction will occur under seasonal pricing, but the actual shift is highly conjectural. For example, in some cases, little load shifting may occur since users do not use air conditioning in the winter. With the degree and nature of change uncertain, the effects on load factors, capacity requirements, operating costs, cash flow, and electric utility revenues are also uncertain.

What is certain is that the potential savings from seasonal pricing are enhanced by electric utility system (supply) characteristics such as: a wide range of fuel costs per kWh, low capacity utilization rates on generating units having low fuel costs, the purchase of off-peak energy at relatively low kWh rates, and generation expansion plans that involve high fuel cost units. In addition, the potential savings from seasonal rates are enhanced by load (demand) characteristics such as: low annual load factors, highly seasonal peak demand patterns, and a high proportion of loads composed of demands that are relatively price elastic. In sum, cost savings from seasonal rates are presumed to be influenced by both supply conditions (e.g., generation system characteristics) and demand conditions (e.g., peaking conditions) confronting each electric utility.

The No Effect Problem -- If electricity consumers, subsequent to the implementation of seasonal rates, maintain prior usage patterns, obviously many of the anticipated benefits of time-differentiated pricing will not materialize. (However, correct price signals are being provided and equity is being achieved in electricity pricing, i.e., the prices being charged match cost responsibility.)

## INTERRUPTIBLE RATES

The standard established in PURPA is the following:

Each electric utility shall offer each industrial and commercial electric consumer an interruptible rate which reflects the cost of providing interruptible service to the class of which such consumer is a member.

### Discussion

Interruptible rates for electric service are not new to electric utilities. Interruptible customers are those who have agreed to allow the utility, in return for a lower rate, to cut off their electricity when the utility is unable to meet total system demand.

While the existence of interruptible tariffs is common to many utilities, the practice of interrupting interruptible customers varies widely from one company to another. The interruptible customers of some utilities have never been interrupted; other companies interrupt service to these customers daily. Obviously, some companies create interruptible rates (for certain industrial customers, for example) but proceed to plan and construct capacity as though they were regular, assured service customers. This practice, of course, violates the rationale for creating an interruptible class in the first place: to conserve capacity and energy costs on-peak.

However, interruptible service should not be confused with curtailed service. Curtailments of power service are those which would occur for extended periods (days and perhaps even months) during times of national or regional fuel shortage or system-wide emergencies. Interruptions of service associated with interruptible rates, on the other hand, are normally short in duration (minutes or hours) and correspond to times of system "extreme-peak" demand.

### Issues

Consideration of this standard requires the consideration of two issues:

- (1) whether a utility should be required to offer each commercial and industrial customer an interruptible rate; and if so,
- (2) whether the interruptible rate should be based on the cost of service.

Arguments That a Utility Should Be Required to Offer Each Commercial and Industrial Customer an Interruptible Rate

Conservation and Efficiency -- Interruptible service offers excellent opportunities for utilities to contribute to the realization of two of PURPA's goals, efficiency and conservation in utility operations. Providing an interruptible service is one method of utility load management which can result in postponement of expensive capacity additions and in conservation of scarce and expensive peaker fuel. Offering a reduced rate for this service to the utility customer also provides an incentive to shift unnecessary peak loads to off-peak hours, thus promoting utility efficiency.

Arguments That a Utility Should Not Be Required to Offer Each Commercial and Industrial Customer an Interruptible Rate

Capacity Planning -- While ideally having an interruptible rate can result in the above favorable developments in utility operation, past experience with interruptible rate customers indicates that often the ideal is not realized. Despite being classified as "interruptible," the fact is that many customers never have had their electricity cut off because the utility has always planned capacity to meet interruptible service customer needs. This utility practice, of course, furthers neither efficiency, conservation, nor equity.

One solution may be not to approve for inclusion in the utility's construction plans those capacity additions associated with meeting "interruptible" customers load. Not permitting such raising of capital would in a way solve the problems of equity and efficiency. Planning no capacity for interruptible service, however, creates another problem: the threat of highly unstable reliability levels for interruptible service customers.

One method for resolving the instability problem is creating two classes of interruptible service, one for which no capacity additions are planned and a second for which some capacity is allocated. In the first class, no minimum reliability would be specified and the frequency of interruption could be rather high depending on the number of customers selecting the option. In the second, a minimum reliability level would be specified and generating capacity built to meet the minimum. The two classes would, of course, face different rates.

#### Arguments That Interruptible Rates Should Be Based on Cost-of-Service

Cost-of-Service Standard -- If the cost-of-service standard is otherwise adopted, it should apply equally to interruptible rates. The reasons for adopting cost-of-service rates have already been discussed under that standard. They apply no less to setting rates for interruptible customers than to rates for regular service customers. The rationale for offering interruptible service, in fact, may make a cost-based rate even more important. In order to attract sufficient numbers of customers to the interruptible option, the public service commission may want to make certain that interruptible rates are not set higher than the cost of providing the service.

#### Arguments That Interruptible Rates Should Not Be Based on Cost-of-Service

Subsidization of Interruptible Customers -- Since an interruptible rate is designed in part to promote conservation of peak load generating capacity and can result in system cost savings benefitting all the utility's consumers, some would argue that a portion of the cost of serving this customer class should be allocated to all ratepayers. The most commonly mentioned cost is that of the load control device installed on the interruptible customer's premises. The argument here is similar to the perhaps-familiar argument that the cost of home weatherization materials supplied by utilities should be included in the utilities' rate base. This argument is not so much for a cross-subsidy as it is for a special cost allocation in determining the cost of service.

Value-of-Service Pricing -- Historically, interruptible rates have often been based on the value of electricity to the industrial user rather than the fully allocated cost of electricity. That value has been

determined by the price of competitive energy sources, such as natural gas or oil. Low interruptible rates, based on the value of the alternate fuel, were offered to keep such large users on the system and so to help lower unit costs. It may be that a violation of the accounting cost-of-service standard is in order to preserve this advantage. However, the interruptible rate should still not be less than the running cost (short-run marginal cost).

## LOAD MANAGEMENT TECHNIQUES

The standard established in PURPA is the following:

Each electric utility shall offer to its electric consumers such load management techniques as the State regulatory authority (or the nonregulated electric utility) has determined will--

- (A) be practicable and cost-effective, as determined under section 115 (c),
- (B) be reliable, and
- (C) provide useful energy or capacity management advantages to the electric utility.

### Discussion

There is not universal agreement within the regulatory community as to exactly what constitutes a load management technique. In general it is agreed that load management refers to a process whereby a utility may use a wide variety of techniques to alter the pattern of demand reflected on the utility's load curve. The purpose of load management is to reduce system load during extreme peak periods in order to avoid expensive capacity expansions, peak fuel expenditures, and/or purchased power costs. Disagreement can arise, however, over exactly what is to be considered a load management technique. Such diverse practices as pumped storage, radio-control of water heaters and air conditioners, ripple-control of primary loads, time-of-use rates, and interruptible rates all have potential load management benefits for a utility and its customers.

The primary distinction among types of load management techniques is between the direct and indirect. Direct load management techniques allow the utility to control by electro-mechanical means some portion of the system load. Indirect load management techniques, on the other hand, offer consumers incentives to regulate voluntarily the demands they put on the system. Radio-control of water heaters and interruptible rates are examples of direct load management. Time-of-use rates are probably the best known example of an indirect approach to load management, but are specifically excluded from the definition of load management techniques in PURPA.

Separate PURPA standards address interruptible and time-of-use rates, and this discussion of load management techniques will refer to all techniques except these two.

An important question is whether the PSC must make the determinations (A), (B), and (C), as specified in the standard, for specific load management techniques at the time the standard is considered. The judgment here is that such determination is not required for consideration of the standard. Instead, the PSC could adopt the standard and later make such determinations with respect to various load management techniques brought before it for consideration.

Nevertheless, some recognition of the three required determinations is appropriate for the consideration process. This recognition is explicit in the issues below.

#### Issues

Consideration of this standard requires the consideration of two issues:

- (1) whether load management techniques can be practicable, reliable, cost-effective, and can provide useful energy or capacity advantages to a utility;  
and if so,
- (2) whether the load management techniques standard should be adopted.

#### Arguments That Load Management Techniques Can Be Practicable, Reliable, Cost-Effective, and Can Provide Useful Energy or Capacity Advantages to a Utility

Practicability -- To judge that a technique is practicable, one must identify whether substantial customer loads are amenable to control by the utility or by the customer. The loads most successfully controlled by direct means currently include residential and commercial space heating, water heating, and air conditioning. Industrial loads, for the most part, are not generally amenable to direct utility control, but may be subject to customer control. Three notable exceptions are chlorine production, refinery and transmission line pumping, and cement production. Irrigation

pumping in agriculture is another activity which can be directly manipulated by the utility to contribute to a system's load management objectives. If none of these load management opportunities exists for a utility among its customers, then the adoption of a requirement to offer load management techniques would not be practical.

Reliability -- One must consider whether reliable load management devices are available to control the candidate loads. There are a number of devices currently manufactured and they can be classified generally as one of two types: radio-controlled devices mounted on the customer premises or ripple-controlled mechanisms controlled directly by the utility. These load-control devices have been shown to operate reliably. In particular circumstances (such as reducing or temporarily interrupting load on air conditioners and 50-gallon water heaters), they have proved both cost-effective and acceptable to customers as a method for controlling growth of peak demand.

Cost-Effectiveness -- Once one identifies a utility's opportunities for control of peak demand with load management techniques, the next step is to assess the cost-effectiveness of implementing each load management strategy. In order to evaluate whether the long-term savings exceed long-term costs, one compares the amortized costs of purchasing and installing the load control devices with the capacity and fuel cost savings associated with not having to supply power to meet expanding peak loads. (A convenient surrogate for fuel and capacity savings may be the cost of purchased power.)

Developing a position on the cost-effectiveness of load management techniques requires a determination of whether the program should be voluntary or mandatory for customers. A voluntary program in order to be successful will require providing some kind of incentive (usually a reduction in monthly bill) for customers electing to participate, and the benefits may depend on the number of customers who volunteer and on their usage patterns. A mandatory program would require less attention by the company to gaining customer acceptance, and calculation of benefits is easier for a mandatory program. The PURPA standard clearly calls for a voluntary program where the load management techniques are to be offered to electric consumers. An experimental period of load management



implementation may be indicated to determine cost-effectiveness.

Energy and Capacity Management -- The primary advantages of implementation of direct load management techniques are related to the predictability of their effects and their relatively low overall implementation costs. The effects of direct load control of hot water heaters or air conditioning on a company's annual revenues can be assessed fairly accurately. Direct load control devices also allow the company more flexibility in managing its load and thus an enhanced ability to avoid serious system failures.

Arguments That Load Management Techniques Are Not Practicable, Reliable, Cost-Effective, or Cannot Provide Useful Energy or Capacity Advantages to a Utility

Any arguments that a particular load management technique is not practicable, reliable, cost-effective, or cannot provide useful energy or capacity advantages to a utility are arguments which would be specific to a particular load management techniques. Because load management techniques significantly vary in their applications, each load management technique would need to be judged individually according to the above-stated criteria.

Arguments That the Load Management Techniques Standard Should Be Adopted If the Above Criteria Are Met

The load management techniques standard should be adopted because it holds the potential for reducing maximum kilowatt demand on the utility system under utility company management as well as the potential for avoiding long-term energy and capacity expenses in a cost-effective manner. Also, direct load management programs demand very little change in behavior by consumers. They require less consumer education than more indirect methods which depend on consumers' actions to reduce load.

Arguments That the Load Management Techniques Standard Should Not Be Adopted Even If the Above Criteria Are Met

Loss of Consumer Sovereignty -- The single argument that is most often offered against adoption of direct load management techniques is that, even

in voluntary programs, consumer sovereignty may be reduced by virtue of the utility being able to control the consumer's load. Voluntary participation helps to reduce the impact of this objection, but even in the voluntary programs there would have to be some limitation placed on the customer's ability to change his mind about participating. Otherwise the system's opportunity for cost savings could be greatly reduced.

Even in mandatory programs, however, utility experience suggests that customer inconvenience resulting from the utility controlling water heaters and air conditioners is minimal. Loads are reduced only slightly and for short times so that the noticeable effects of the interruption are negligible.

Lack of Need -- Some contend that if prices are set on the basis of marginal costs on a seasonal and time-of-day basis, there would be no need for load management techniques. The purpose of utility regulation, they contend, is not to achieve a level load (which is one measure of engineering efficiency) but to give correct price signals regarding the replacement cost of electricity (that is, to promote economic efficiency). Customers should choose to consume or not on the basis of the price they face -- a price which equals the cost of expanding the system's delivery capacity. If the consumer is willing to pay that price, let the system grow. If he is not, he will not consume. From this vantage point, there is no need for artificial devices for control of load, except perhaps for those devices which the customer himself may choose to install.

APPENDIX

PURPA SECTION 115(a)-(c)

SEC. 115. SPECIAL RULES FOR STANDARDS. Subsections (a)-(c)

(a) Cost of Service.--In undertaking the consideration and making the determination under section 111 with respect to the standard concerning cost of service established by section 111(d)(1), the costs of providing electric service to each class of electric consumers shall, to the maximum extent practicable, be determined in on the basis of methods prescribed by the State regulatory authority (in the case of a State regulated electric utility) or by the electric utility (in the case of a nonregulated electric utility). Such methods shall to the maximum extent practicable--

(1) permit identification of differences in cost-incurrence for each such class of electric consumers, attributable to daily and seasonal time of use of service and

(2) permit identification of differences in cost-incurrence attributable to differences in customer, demand, and energy components of cost. In prescribing such methods, such State regulatory authority or nonregulated electric utility shall take into account the extent to which total costs to an electric utility are likely to change if--

(A) additional capacity is added to meet peak demand relative to base demand; and

(B) additional kilowatt-hours of electric energy are delivered to electric consumers.

(b) Time-of-Day Rates.--In undertaking the consideration and making the determination required under section 111 with respect to the standard for time-of-day rates established by section 111(d)(3), a time-of-day rate charged by an electric utility for providing electric service to each class of electric consumers shall be determined to be cost-effective with respect to each such class if the long-run benefits of such rate to the electric utility and its electric consumers in the class concerned are likely to exceed the metering costs and other costs associated with the use of such rates.

(c) Load Management Techniques.--In undertaking the consideration and making the determination required under section 111 with respect to the standard for load management techniques established by section 111(d)(6), a load management technique shall be determined, by the State regulatory authority or nonregulated electric utility, to be cost-effective if--

(1) such technique is likely to reduce maximum kilowatt demand on the electric utility, and

(2) the long-run cost-savings to the utility of such reductions are likely to exceed the long-run costs to the utility associated with implementation of such technique.