A Report on

ELECTRICITY PRICING POLICIES FOR OHIO

VOLUME I

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Submitted to the

Public Utilities Commission of Ohio

by the

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October 1977

This report is published and distributed by the National Regulatory Research Institute (NRRI) with the permission of the Public Utilities Commission of Ohio (PUCO). The report was prepared by the Policy Development Project of the Department of Mechanical and Nuclear Engineering which was established at The Ohio State University (OSU) to assist the PUCO in the development of utility regulatory policy and to provide technical assistance in certain regulatory procedures. The Policy Development Project was the forerunner of the NRRI established at OSU in 1977.

EXECUTIVE SUMMARY

Recent interest in the structure of electric rates is the result of increasing electric bills for consumers and growing production costs for the electric companies. Since 1970, Ohio electricity consumers have seen an annual rate increase that contrasts sharply with a previous history of slowly declining prices for most customers. Similarly, the electric utilities have experienced a steady deterioration in their financial condition. These and other conditions have recently prompted an examination of electricity pricing policy.

After reviewing many possible objectives of regulation, we recommend that economic efficiency be the underlying principle of any rate reform. Economic efficiency is achieved by an arrangement of society's resources that results in the largest total production of goods and services for any given distribution of income. Significant improvements in the allocation of resources are possible within the traditional regulatory guidelines that prices should be fair and yet satisfy the revenue requirement.

Economic efficiency implies that electricity prices should be based on marginal cost; that is, the cost of providing an additional unit of electricity. It also implies that the current declining block rate structure be abandoned in favor of a flat rate and a customer charge. With a flat rate, for each kilowatt-hour (kWh) a customer pays a single price equal to the marginal cost of serving him. With a customer charge, each customer pays a fixed monthly fee based on the cost of serving him, regardless of his electricity use.

If marginal cost pricing is adopted, we recommend that long run marginal costs be used since prices based on short run marginal costs would fluctuate excessively. Long run marginal costs encompass all costs of providing additional electricity, including the cost of new construction.

Marginal costs are usually calculated from anticipated costs expressed in current dollars; as such, they may provide too much or too little revenue, depending upon whether current marginal costs are greater or smaller than historic average costs. If the revenue requirement is not met by the combination of marginal cost based rates and customer charges, we recommend that customer charges be altered.

Various criticisms of marginal cost pricing are reviewed in the report. None of these, in our opinion, outweighs the previously discussed benefits of rate structure reform. These criticisms, however, do suggest that implementation be gradual and monitored for adverse effects.

Electricity rates sometimes differ by voltage level, customer location, and season of the year. We recommend that these policies be continued and strengthened by basing these price differences on the appropriate marginal costs. If marginal cost pricing seriously disrupts existing cost sharing arrangements, such as those between urban and rural users, it might be unfair to impose an unmodified marginal cost pricing policy.

Time-of-day pricing is a logical consequence of marginal cost pricing. The marginal cost of electricity increases during high use (peak) periods and decreases during low-use (off-peak) periods. Therefore, we recommend the eventual adoption of time-of-day pricing for electricity, a pricing policy with a customer charge and a flat rate for each time period.

It is possible, however, to advocate peak load pricing on grounds other than marginal cost. There may be significant benefits to time-of-day pricing regardless of how these peak and off-peak prices are calculated. These include a reduction in capital expenditures, the possible conservation of fossil fuel use by peakers, a reduction in the frequency of rate cases, and the encouragement of useful technology. In addition, electric rates would be fairer since they would more closely correspond to costs, which is a widely accepted criterion of fairness. The potential disadvantages include shifting peaks requiring a periodic redefinition of the peak period, the creation of needle peaks (for example, peak demand on the hottest day may not be limited by peak prices that are diluted by a broad definition of the peak period), and the possibility of industrial movement from Ohio. We believe that the impact of these is not so significant as to prevent the adoption of time-of-day pricing.

We do not recommend the immediate adoption of time-of-day pricing for all customers. A comparison of costs and benefits does not show that time-of-day meters are currently cost justified for average residential users. Such meters, however, do appear to be warranted for small industrial and commercial users. Time-of-day pricing is clearly justified for large industrial customers who already have the necessary meters. We recommend that the PUCO develop a schedule for implementing time-of-day pricing for all customers. This should also include a timetable for converting residential meters as this becomes economically feasible.

The electric industry also currently levies a demand charge on industrial and commercial customers based on a customer's maximum kilowatt demand. Several prominent economists and most utility spokesmen support the use of the demand charge. Despite these endorsements, we believe that this practice has several implications that have not yet been sufficiently explored. Accordingly, we withhold judgement about such charges.

To illustrate that long run marginal costs can be calculated, a calculation of Dayton Power and Light costs for 1975 was performed. Although the data are inexact, the example shows that marginal costs can yield reasonable tariffs. Consequently, we recommend that the PUCO require all Ohio utilities to perform cost of service studies in cooperation with PUCO staff, using long-run marginal costs.

We do not recommend that generic hearings be held, as a great deal of expert testimony on these issues has already been generated by prior hearings in other states. We believe that an examination of each Ohio electric company's situation is most essential to the implementation of these recommendations.

ACKNOWLEDGEMENTS

The project staff wishes to acknowledge the helpful contributions made by many individuals during the course of this study. We are particularly grateful to William Oakland, Professor of Economics at The Ohio State University, who helped clarify some difficult economic issues and provided a number of useful insights and suggestions for further study. We would also like to thank Robert Wayland and Stefanos Enkara of the PUCO staff who guided us through a number of difficult regulatory issues pertinent to this study and who helped us on a number of occasions to sharpen our economic thinking. Several well known and respected scholars and practioners took time out of their very busy schedules to help us reflect upon our conclusions and the reasons for them. Discussions with them helped us to eliminate a number of errors. We would like to thank:

Dr. Charles Cicchetti
University of Wisconsin

Mr. Clement Loshing
Cleveland Electric Illuminating Company

Mr. J. Robert Malko
Wisconsin Public Service Commission

Mr. Parker Mathusa
New York Public Service Commission

Dr. F.T. Sparrow
University of Houston

Dr. Haskell Wald
Federal Power Commission

None of these individuals should be accountable for any remaining errors and omissions. Finally, we are grateful to Carmen Way, our secretary, who suffered with us through many drafts of this report.

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CHAPTER 1

INTRODUCTION

This study was requested by the Public Utilities Commission of Ohio (PUCO) to assist in its evaluation of current electricity pricing policy for Ohio utilities. Currently, electric ratemaking is a two-step process. The first step is the determination of the annual revenues required by the electric company; this revenue requirement depends on the value of the company's investment and the fair rate of return on that investment. The second step is the determination of electricity prices that will yield the required revenues. This report is concerned with the second step only, the structure of electric rates. A discussion of the first step is provided in Appendix A.

Some important issues related to rate structure determination are not considered. These include rate base determination, the choice of past or future test year, adequate and variable rate of return issues, optimum level of reliability, and elimination of incentives for over-capitalization. Also not considered were issues important in times of inflation, such as the problem of regulatory lag and the question of extending the automatic rate adjustment clause to cover non-fuel costs.

Most importantly, this report is not primarily concerned with solving the problem of declining electric utility load factor. The recommended pricing policy reform is not considered as an alternative to the introduction of load control technology. Therefore, our recommendations for rate structure improvement should not be taken as a substitute for continued investigation of the usefulness of energy storage and load control devices. Although our recommendations assume no load control technology, the principles upon which these recommendations are based could be extended if necessary in another study to determine the best method of setting electricity prices in a system with load control technology.

This report is concerned with the pricing of electricity. It is concerned with the principles of sound rate design and the development of rate structures that follow from these principles. It also demonstrates that these rate structures are capable of practical implementation. However, it does not identify the best means of implementing all the recommendations. Investigation of these implementation issues is continuing.

Overview of the Report

Chapter 2 demonstrates that today's economic conditions differ sharply from the conditions that gave rise to the current electric rate structure and points out the need to ascertain their appropriateness under the new circumstances. Chapter 3 reviews many criteria by which to judge the appropriateness of rate structures.

We conclude that within the constraints imposed by the revenue requirement and the requirements of simplicity and stability, economic efficiency be taken as the fundamental criterion for the evaluation of rate design.

In Chapter 4, it is asserted that the objective of economic efficiency necessarily requires a policy of marginal cost pricing. The chapter defines this and other frequently used terms, provides the rationale for this pricing policy, and discusses two methods of meeting the revenue requirement. Chapter 5 discusses and refutes various criticisms of a policy of marginal cost pricing.

The implementation of this policy requires the clarification of several issues. In Chapter 6, the arguments for and against eight such issues are discussed and specific characteristics of marginal cost based rate structures are defined. In Chapter 7 the timing of implementing these goals is discussed in terms of their benefits and costs.

The ability to calculate marginal costs and to convert them into reasonable tariffs is demonstrated in the next two chapters. Chapter 8 provides a description of the electric industry's production technology, a comparison of some methods that have been suggested for calculating marginal costs, and the results of such calculations using one of these methods. Chapter 9 discusses the conversion of marginal costs into tariffs, including the cost of administration, fair return, taxes, and other miscellaneous costs.

All our conclusions and policy recommendations are summarized in Chapter 10.

CHAPTER 2

THE CURRENT RATE PROBLEM

Electric rates are increasingly contested by two diametrically opposed groups. Faced with apparently ever more burdensome electric bills, electricity consumers advocate lower or unchanging electric rates. At the same time, electricity producers urge higher rates, citing their worsening financial position. This seemingly irreconcilable conflict is the prime symptom of today's emerging electric rate problems.

While the major symptom of this problem is highly visible, the problem itself remains hidden behind the existing process of regulating electric rates. This process has allowed the establishment and continuance of rate structure that is perhaps unjustified in terms of either the present economic conditions or the accepted objectives of rate policies. The purpose of this chapter is to trace very briefly the changing economic environment within which electric rate policies exist and to demonstrate that the conditions that gave rise to the declining block rate structure no longer exist.

The Early Development of Rate Structures

Government regulation of certain economic activities was instituted in Ohio in the mid-1890's. The announced goal of regulation at that time was to ensure that various industries produced adequate levels of service at reasonable rates. In 1913, the Public Utilities Commission of Ohio (PUCO) was established by the Ohio General Assembly to provide a regulatory authority for gas, electric, water, telephone, and railroad services. Since then the PUCO's jurisdiction has been extended to include the regulation of buses, trucks, motor carriers, public highways, sewage disposal, and railroad bridges.

During its early days, the electric power industry was largely composed of small utilities, each of which served a relatively small territory. Since electric energy was primarily used for lighting purposes, few customers had the opportunity of using it in large quantities or during daylight hours. The distinction between consumption during the peak and the off-peak periods was unimportant; a simple, flat charge per kWh was deemed to be an adequate reflection of the utility's cost structure. At the same time, it was recognized that any additional use of electricity that occurred during periods other than the lighting period could be served by plants which would otherwise be idle, solely at the cost of the additional fuel consumed. Such "off-peak" consumption of electric energy was promoted by offering large volumes at lower prices. Consequently, this resulted in an expanded consumption of electricity for non-lighting purposes by a small, homogeneous group of industrial customers.

The expansion of electricity consumption by industrial users brought about inevitable changes in the utility industry. The size of a utility's generating plant is dependent on the maximum energy production for which it is responsible at any one time. Therefore, it became important to know not only the total amount of electricity that each customer consumed, but also the time profile of that consumption. By adding up the individual's profiles, it would have been possible to derive a profile of the total production requirement placed on the utility, and, more importantly, one of the maximum amount demanded. At that time, however, metering to measure the coincidence of consumer demands was still impractical; therefore, metering of only the maximum demand was instituted.

The initially major concern for relating tariff structures to the patterns of electric utilities' costs structures was slowly eroded by other concerns associated with electricity production. Principal among these was the concern for the profitability of the electric companies in relation to all other companies competing for the same investment funds.[40] Electricity producers required certain revenues that had to be apportioned among various classes of customers. The overall level of burden to be allocated to each class became a more important issue than the design of tariffs used to raise the required revenues from within each customer class. Although the tariff structure was seldom altered, the rate level rose or fell to adjust the apportionment of revenues required by the utility.

This concern was translated by the electric companies into rate structures for each class of consumers, in which rates declined in blocks as a customer's electricity consumption increased. This type of rate structure has the virtue of recovering capital costs early in the billing period; thus, it reduces the uncertainty of obtaining the required revenues. An example of a declining block tariff is presented in Table 2-1 and is graphically illustrated in Figure 2-1.

Table 2-1 Declining Block Rate Structure

Monthly Consumption (kWh)	Price (¢/kWh)
0 - 100	5.0
100 - 300	3.0
300 - 1000	2.0
over 1000	1.0

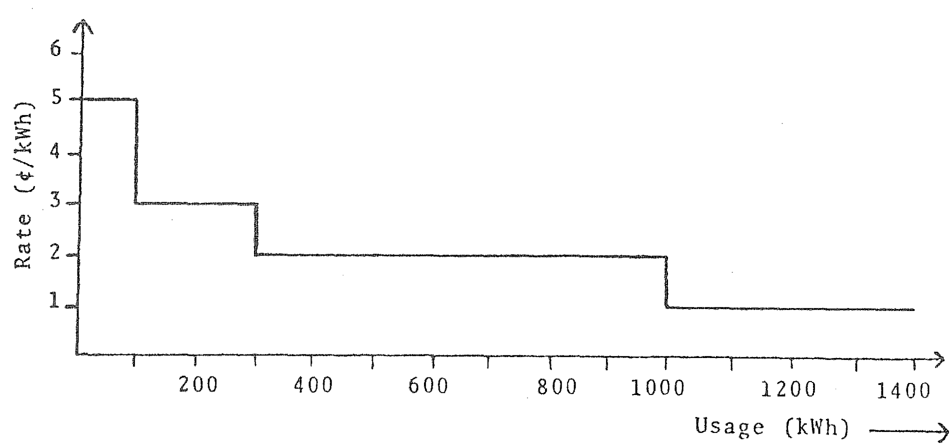

Figure 2-1 Graphical Representation of the Declining Block Rate Structure of Table 2-1

The current tariff structure corresponds to the type of tariffs advocated by Hopkinson and Wright at the turn of the century. It is comprised of three components: energy costs, customer costs, and demand (load or capacity) costs. Energy costs vary roughly with the kilowatt-hours supplied to customers and basically represent the cost of fuel. It is a cost that varies with the time of day and with the voltage at which the power is received by customers.

Customer Costs

Customer costs vary with the number of customers served, regardless of the quantity consumed. These costs include the cost of a portion of the general distribution system, local connection facilities, metering equipment, meter reading, billing, and accounting. One way of assessing customers for these costs is to levy a separate minimum charge. The major electric utilities in Ohio presently have minimum charges ranging from $1.50 to $4.00 per month for residential customers. The value of monthly customer costs has been estimated to range from $4 to $6 for residential customers of Ohio utilities. In practice, many utilities try to recover customer costs in the initial consumption blocks in order to increase the probability that sufficient revenues will be forthcoming.

Demand Costs

Demand costs vary with customer peak coincident loads; these include generating plant capital costs, depreciation, capital costs of distribution and transmission lines, capital costs of substations, and taxes. The current practice is for industries to include the demand charge in all consumption blocks.

The second major characteristic of electricity production that contributed to the erosion of interest in the relationship between production costs and tariff design was the quick pace of technological progress that kept the price of electricity low relative to the prices of other goods and services. In fact, electricity prices are somewhat unique in that they steadily declined during the 1950's and 1960's. It is not surprising, therefore, that interest in electric tariffs design was minimal.

Recent Developments

Recently the situation has changed dramatically. Electricity prices in the U.S. began to rise at a rate of 2.0 to 5.0 percent per year, beginning in 1968. Similarly, in Ohio after years of falling rates, the average charge per kWh in the residential sectors rose by roughly 3 percent in the period between 1970 and 1971. More recently, the escalation in rates has been much steeper. (See Table 2-2) For example, in September 1974, the Columbus and Southern Ohio Electric Company (C&SOE) increased its rates by 19 percent. In March, 1975, the company obtained an additional emergency rate increase of 9 percent.

Table 2-2 Average Yearly Price of Electricity
In Ohio by Sectors: 1960-1974

YEAR	RESIDENTIAL (¢/kWh)	COMMERCIAL (¢/kWh)	LARGE USERS (¢/kWh)
1960	2.562	2.558	.764
1961	2.547	2.503	.762
1962	2.569	2.517	.779
1963	2.546	2.465	.779
1964	2.501	2.420	.791
1965	2.447	2.241	.801
1966	2.397	2.196	.844
1967	2.370	2.172	.854
1968	2.322	2.129	.865
1969	2.272	2.100	.882
1970	2.269	2.072	.927
1971	2.330	2.166	1.000
1972	2.377	2.214	1.011
1973	2.425	2.262	1.051
1974	2.906	2.769	1.449

Source: Ohio Energy Emergency Commission, Ohio Energy Profiles, 1974, p. V-14.

A large portion of the recent increases in electric rates was caused by rising fuel costs. For example, a very large increase in the cost of coal in 1974, shown in Table 2-3, was accompanied by an equally large jump in electricity prices shown in Table 2.2.

Table 2-3 Average Price of Coal Per Ton for Electric Generation in Ohio

Year	Average Cost/Ton ($)
1960	5.31
1965	5.10
1966	5.17
1967	5.19
1968	5.32
1969	5.55
1970	6.50
1971	7.71
1972	8.53
1973	9.64
1974	18.27*

Source: Ohio Energy Emergency Commission, <u>Ohio Energy Profiles</u>, 1974, p. III-48.

* The figure for 1974 was calculated as the average for eight major electric generating utilities in Ohio.

The above-described changes in the cost of electricity reflect in part the financial situation of electric utilities, which started to deteriorate sharply in the early 1970's. The situation is reflected most directly in the market evaluation of utility stock prices as shown in Table 2-4. By 1974, utility stock prices had sunk to an average of 8.0 times earnings, or only 66 percent of the average industrial price-earnings ratio. By comparison, the price-earnings ratio a decade earlier was nearly 20, which was 113 percent of the comparable industrial price-earnings ratio.

Table 2-4 Selected Financial Indicators: U.S. Electric Utility Industry 1962, 1965, 1971, 1974, and 1975*

	1962	1965	1971	1974	1975
Return on Equity (%)	11.4	12.1	11.0	10.2	10.5
Return on Total Capital (%)	10.2	10.3	8.8	9.3	9.7
Total Debt as % of Total Capital	52.2	51.8	54.7	53.3	52.6
Public Utility Bond Yield (Aaa)	4.37	4.50	7.72	8.71	9.03
Public Utility Bond Yield (Aa)	4.46	4.52	8.00	9.04	9.44
Interest Coverage Ratio	5.06	5.05	2.56	2.06	2.17
Price/Earnings Ratio (P/E)	19.34	19.78	11.79	6.3	6.6
Ratio P/E Utilities to P/E Industrials	1.13	1.14	.65	.66	N.A.**

*Source: Haas, J.E., Mitchell, E.J., and Stone, B.K., (assisted by Downes, D.H.), Financing the Energy Industry, Ballinger Publishing Co., Cambridge, Mass., 1974.

1974 and 1975 figures obtained from own calculations, using the Edison Electric Institute's Statistical Year Book for 1975 and Moody's Public Utility Manual for 1975.

** N.A.: Not Available

As stock prices declined, utilities increased their debt as a percentage of their total capital investment. This, coupled with higher interest rates, resulted in a decrease in the interest coverage ratio from 5.05 in 1965 to 2.17 in 1975. These interest charges are covered by operating income on the basis of commitment to bond-holders; they must be kept above certain legal minimum levels. As a company approaches the legal minimum (usually around 2.0) it becomes limited in its ability to increase its indebtedness without first increasing its earnings.

The financial squeeze on electric utilities is due in part to a variety of other causes, such as the current rate of inflation, the length of the regulatory lag, a variety of enviromental and safety legislation, and an unexpected slowdown in the growth of demand. In a period of rapid inflation combined with technological and demand growth slowdown this regulatory lag leads to deterioration in earnings and to lower stock prices. It is these lower earnings and higher interest rates that have lead to the substantial decline in interest coverage ratios. This condition legally limits the amount of new bonds that can be issued and ultimately leads to the necessity of issuing new stock at a price below book value, all in order to meet capacity expansion needs.

Essentially, selling new shares at below book value is a way of forcing the existing stockholders (as opposed to the consumers) to bear part of the cost. Under these circumstances, it may well be in the stockholders' best interest to limit capacity expansion, rather than suffer a decrease in the value of their stock. This could lead to lower quality service (e.g., recurring brownouts) and there is even the possibility that this could eventually lead to the State buying out the utility companies.* The State would be legally obligated to pay a fair value to owners; therefore, the situation could be advantageous to stockholders who would then be able to obtain a higher price (i.e., book value) for their shares.

Summary

In summary, it is obvious that the financial condition of electric companies underwent a drastic change during the last decade. During the same time, electricity consumers experienced a traumatic reversal in the downward trend of rates. These changing economic conditions suggest that rate structures that were developed in previous decades should be reexamined to ascertain their appropriateness under the new circumstances. Whether or not such a reexamination can lead to new and improved rate structures, however, depends not only on current economic conditions, but on the current understanding of

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* New York State recently bought two generators on a lease back arrangement from Consolidated Edison.

the objectives of electricity price regulation as well. These objectives are examined in the next chapter.

CHAPTER 3

OBJECTIVES OF ELECTRIC RATE DESIGN

In the previous chapter, it was argued that recent changes in the economic environment within which rate regulation takes place are a sufficient reason for the consideration of pricing policy changes. Rate reform is appropriate if either the conditions surrounding the electric companies have changed to the point that existing rates are inadequate, or, alternatively, if the objectives of regulation are redefined and new rates are required by the new objectives. Several observers of the electric industry and several public utility commissions have recently begun to reexamine the objectives of regulation. It is the purpose of this chapter to examine the objectives of electric rate regulation and to discuss the relation of current rate structures to these objectives.

Historic Definition of Rate Objectives

The history of defining proper objectives for rate regulation obviously dates to the beginning of electric utility regulation. This history provides a rich variety of functions and attributes that have been proposed as the proper objectives of rate regulation. Some analysts have proposed as many as fifteen or seventeen rate design objectives. (A list of fifteen objectives is contained in [23], while seventeen objectives are given by [20].) An initial synthesis of similar concepts, roles, and functions led to the well-accepted list of criteria for a sound rate structure developed by T.C. Bonbright.[7] Rate structures should be characterized by:

1. The related, "practical" attributes of simplicity, understandability, public acceptability, and feasibility of application.
2. Freedom from controversies as to proper interpretation.
3. Effectiveness in yielding total revenue requirements under the fair-return standard.
4. Revenue stability from year to year.
5. Stability of the rates themselves, with a minimum of unexpected changes seriously adverse to existing customers.
6. Fairness of the specific rates in the apportionment of total costs of service among the different consumers.
7. Avoidance of "undue discrimination" in rate relationships.
8. Efficiency of the rate classes and rate blocks in discouraging wasteful use of service while promoting all justified types and amounts of use:
   (a) in the control of the total amounts of service supplied by the company, and
   (b) in the control of the relative uses of alternative types of service (peak versus off-peak electricity, Pullman travel versus coach travel, single-party telephone service versus services from a multiparty line, etc.).

Even in the case of Bonbright's list, however, there is duplication among the objectives; further, no clear distinction is made between the function of electricity rates and practical attributes of the resulting rate structure. The distinction is crucial. Rates designed on the basis of desirable attributes, abstracted from their primary function, would be as meaningless as an automobile designed to save fuel, without locomotion.

Rates As Signals

In light of this distinction, it is imperative to recognize that electric rates are prices--or signals--to consumers and producers. To the buyer, prices indicate the amount of purchasing power required to secure a given quantity of electricity; to the seller, prices indicate the revenues generated by his output.

Since electric rates are prices, they must function efficiently, as signalling mechanisms. Bonbright's attributes of simplicity (1), freedom from controversies (2), and stability (5) must hold true or by definition the ability of rates to transmit signal information would be limited. This does not imply that these objectives are insignificant. Rather, it means that all rates should fulfill them.

Furthermore, rates are a means by which the producers of electricity are compensated for their production costs. The total revenues of utilities are a function of both rates and sales according to the following simple formula:

$$\text{Revenues} = \text{Sum of } (\text{Rates} \times \text{Sales})$$

In the past, whenever a given quantity of sales did not generate sufficient revenues, rates were adjusted.

All rate structures, irrespective of their principal design criteria, can be adjusted to yield the required revenues. Since every rate structure should fulfill Bonbright's attribute of effectiveness (3), and since many rate structures could result in revenue stability, there must be some other function of electric rates to use as a guide in the initial design of proper rates.

This guide is to be found within Bonbright's objectives of fairness (6), undue discrimination (7), and efficiency (8). Like all prices, electricity rates function as rationing devices. As the price of a commodity is increased, it is reasonable to expect that consumers will curtail their consumption of it. Since consumers differ in many respects, we should not expect different consumers to purchase the same quantities of electricity when facing identical rates, nor should we expect that the burden of an identical electricity bill will affect all consumers equally. What, then, are the desirable characteristics of a rationing device? According to Bonbright, these characteristics are fairness and efficiency of electric use.

Fairness

The concept of fairness is at once both difficult and vague. Consequently, this objective has received a variety of interpretations, each of which suits a particular interest group. Bonbright delineated four standards of fairness that are often applied in practice; these are good faith or reasonable expectations, ability to pay, notional equality, and the compensation principle.* These are further described as follows:

1. Good faith or reasonable expectation standards refer to what may be called a moral obligation to live up to previous commitments. Such standards are typically held by customers who wish to maintain the low rates to which they have become accustomed. Suppose, for example, that customers were led to buy electric appliances on the basis of low electric rates. They might argue that since they made these purchases on the expectation of low rates, those rates should be maintained, even though conditions have changed. Bonbright points out, however, that, "As a matter of legal doctrine, such an argument has dubious standing in view of the generally accepted principle that public utility rates are subject to revision if and when they become 'unreasonable.'"

2. Ability-to-pay standards are based on egalitarian ideas of social justice and are used to "support whatever deviations from cost can feasibly be applied in order to minimize burdens falling on those consumers with lower incomes." Use of this standard essentially results in redistributing income and consequently represents what Bonbright refers to as a "quasi-tax." Bonbright further points out that, "The ability-to-pay principle cannot be carried beyond severe limits, since any attempt to do so would lead to a breakdown in the other functions of utility rates."

3. Notional equality standards are based on the popular impression that uniform rates for the same kind of service are fair despite differences in the costs of delivery. In the context of natural gas, for example, the temptation to apply this standard may be great because even though the costs of historic and non-historic gas are quite different, the service provided is the same. Bonbright, however, argues that, "This tendency is really a distorted reflection of an income-distributive standard," (i.e., ability to pay). "It certainly fails to accord with any of the more general theories of proper

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* The following discussion is based on Bonbright, op. cit. especially Chapter VIII and repeats a summary contained in a previous OSU report to the PUCO entitled "Alternative Policies for Pricing Non-Historic Gas," 1975, pp. 26-27.

income distribution. Instead, it accepts a specious egalitarianism.

4. The compensation standard is based on the idea that the payment of the consumer to the producer should offset or counterbalance the cost incurred by the producer in delivering the service. Under this standard, rates are not designed to reflect egalitarian principles to any degree.

Implicit in the above standards are two basic notions that are in opposition to each other. On the one hand, fairness requires that each individual compensate the producer of electricity for the cost that his consumption imposes on the producer. On the other hand, fairness also requires that certain individuals not pay the same price as others, because of the heavy financial burden that such payment would impose on them. The motivation to reduce this burden stems from the belief that price subsidies should be used to adjust an undesirable distribution of income among members of society.

Economic Efficiency

The idea that each individual should pay his own way in terms of the costs that he imposes on the producer is justifiable not only on the basis of the compensation standard of fairness, but also on the grounds that it allows us to derive the maximum possible benefits from the limited resources that are in our possession. With the limited supplies available to us of coal, oil, fossil fuels, and with the available capital and labor, there is a limited number of fuel-dependent goods and services that can be produced. It is imperative that we produce those things that we most desire before producing other things. The decision either to pay for several hundred more kWh's of electricity in the form of home heating or to buy gasoline to drive to work instead of taking the bus should be based on accurate information concerning the comparative costs of the two fuel-consuming alternatives. The consumer should know what it costs to produce the one more kWh of electric energy that he is planning to consume. If he is willing to pay that cost because the satisfaction he gains is worth the price that he pays, he is better off as is the whole society. This objective of achieving maximum satisfaction with the scarce resources in our possession is called by economists the efficient allocation of resources.

Choosing a Basis for Rate Design

To design electric rates solely on the basis of economic efficiency neglects income distribution considerations. Despite this, we recommend that economic efficiency be the fundamental function of electric rate design. There are means available that are more appropriate and effective than electricity prices for achieving income redistribution. However, rate structures are the best and only means of effecting improvements in the efficient allocation of energy resources for electricity production.

For the purpose of this report, we have not estimated the efficiency costs of alternative objectives.

Nevertheless, it is our recommendation that within the constraints imposed by the revenue requirement and the requirements of simplicity and stability, economic efficiency be taken as the fundamental objective of rate design. This is not to say that secondary objectives should be excluded from rate design; however, the decision to incorporate any other objective into rate design should be made with a knowledge of the costs involved in deviating from the most efficient rate structure.

CHAPTER 4

THE RATIONALE FOR MARGINAL COST PRICING

In the last chapter we recommended that economic efficiency be the fundamental objective of electricity pricing. In this chapter we describe how to set prices so as to achieve this objective. This pricing method is known as marginal cost pricing.

This chapter has three sections. Because there exists great variation in the way that certain key concepts are used, the first section contains definitions of terms which are used in the remainder of the report. The second section provides a brief theoretical justification of marginal cost pricing for the regulated electric industry. The third and final section discusses the implications of the revenue requirement for marginal cost pricing.

Definitions

Flat-rate is an electricity price according to which the charge for each unit of electricity is the same. For example, with a flat rate of 3¢/kWh the consumer pays $3.00 for 100 kWh, $6.00 for 200 kWh, and so on.

Marginal cost is the additional cost required to expand annual electricity production by one unit, usually a kilowatt-hour, kWh. Consequently, it is also the savings from producing one less unit of electricity. In practice, marginal cost is not a single number. For example, marginal costs vary with the voltage level at which power is received, the location of the consumer, and time of consumption. Short-run marginal costs are the costs of expanding production over a short enough time period that the stock of plant and equipment cannot be adjusted. Long-run marginal costs are those which include the cost of capacity expansion. Since plants must be built in large units, the term "long-run incremental cost" is sometimes used in lieu of "long-run marginal cost" to emphasize that large increments are involved. In this report the two terms are used interchangeably.

Marginal cost pricing is a policy whereby each unit of electricity is sold at a price equal to marginal cost. This implies that the rate structure is flat for each customer group and each time period. In practice, if flat rates are not possible, it is most important that customers purchase their final units of electricity at marginal cost. Suppose, for example, that the initial blocks of a declining block rate structure were quite short, and that relatively few customers purchased their final units in these initial high-priced blocks. Such a rate structure would provide essentially the same price signal to the electricity consumer as would a flat, marginal cost rate structure. The revenues from the latter structure, however, would be smaller. From a practical policy viewpoint, the choice between these two rate structures must be made largely on judgment. This judgment might include the utility's assessment of how the public would accept either rate structure, since both structures are in essence based on marginal cost pricing.

Customer cost is the cost to the utility company of serving a particular customer, regardless of his monthly electricity use.

Customer charge is that portion of a customer's bill that does not depend on his monthly electricity use. This tariff form is not currently used by electric companies; however, telephone bills consist of a customer charge and a separate charge for each long distance call.

Elasticity is a measure of responsiveness in one variable to changes in another variable; e.g., price elasticity of demand for electricity is a measure of the responsiveness of consumers' demand to changes in the price of electricity.

Theory of Marginal Cost Pricing

Economic theory provides strong reasons for considering marginal cost as the optimum basis for regulated prices. If an economy existed where production and consumption decisions were decentralized and there was competition in the marketplace for every good and service, then prices would be determined by the forces of supply and demand. The result would be prices equal to marginal cost for each good and service. This decentralized arrangement results in an allocation of society's scarce resources that is called efficient. Efficiency, in this situation, means that society is producing the greatest possible amount of goods and services it most desires, given its resource limitations and the existing distribution of income.

Informing the Consumer

The reason that marginal cost pricing results in an efficient allocation of resources is that consumers are receiving correct price signals. Consumers decide how to spend their income by looking at the relative prices of the commodities they purchase; thus, prices serve as signals telling each consumer what an additional unit will cost. His evaluation of the commodity is based on the price he pays. He cannot be expected to consider, explicitly, the costs of producing the commodity, if for no other reason than his lack of information.

If, however, prices were equal to marginal cost then the consumer would be implicitly evaluating the scarce resources which are used in the production process. If electricity were priced at marginal cost, a customer's decision to purchase additional kWh's would be based on the value of the scarce resources that society sacrifices to satisfy his demand. The customer's willingness to pay is an indication that the benefit he receives from the additional consumption is equal to its cost. His desires should be accommodated; society as a whole (including the consumer) benefits from the transaction. This does not hold true if the link between price and marginal cost is broken. If price were less than marginal cost, for instance, the customer continues to use electricity until the benefit he receives from the final unit is equal to the price he pays. Since the cost of producing the final unit exceeds the benefit enjoyed by the consumer, society is worse off.

Long-Run Marginal Cost

If marginal cost is adopted as an electricity pricing standard, there is an important reason why a long-run marginal cost is preferable to a short-run marginal cost. Unless long-run costs are used tariffs would have to be published frequently; this is costly and would increase the utility's revenue uncertainty.

The economic theory of marginal cost pricing is richer than this discussion suggests. Additional discussion is contained in a previous report to the PUCO on regulated pricing policy by Henderson and Kelly.[32] While justifying marginal cost pricing, economic theory does suggest several reasons for using caution in adopting such a policy. Briefly, these issues include second-best effects in other sectors of the economy besides the electric industry, income redistribution that occurs as existing cost-sharing arrangements among customer groups are changed, the increased revenue uncertainty which may accompany a marginal cost pricing policy, and the possibility of industrial relocation, if Ohio is not joined by neighboring states in reforming electricity rates. These issues are discussed in Chapter 5.

The Revenue Requirement

To attract sufficient financial capital, the electric utilities must earn an adequate return on invested funds. The revenue which the utility is allowed by the PUCO must cover all costs, including a reasonable rate of return on investment. The revenue requirement is generally determined by the test year method in which the revenues and costs are matched for a recent, past year. If electricity prices were equal to marginal costs, the revenue requirement would not necessarily be met. The revenue yielded by marginal cost pricing may be too large or too small, depending on various circumstances. Marginal cost, as defined by most observers and as used in this report, is calculated from current costs; thus, it is influenced by inflation. Accordingly, current marginal costs may be greater or smaller than historic average costs, depending in part on the inflation rate and the rate of return allowed investors under the historic method.

The revenue requirement must be imposed as a constraint on the pricing policy to ensure that the electric utility is properly financed. The only alternative is to use public taxing powers to subsidize or tax the utility in order to provide the correct rate of return to the utility's investors. This method does not appear to be a viable alternative in the U.S. at this time.

With the revenue requirement as a constraint, there are two ways to modify a marginal cost pricing policy. Assuming that marginal costs yield improper revenues, the first method is to vary the customer charge with respect to customer costs. The second method is to vary prices with respect to marginal costs.

Currently, electricity bills do not contain a customer charge; however, minimum charges for electricity serve a similar purpose. We recommend that actual customer costs be covered by customer charges as discussed in the next chapter. If the combination of customer charges and marginal cost prices yields insufficient or excessive revenues, we recommend that the customer charge be adjusted to match revenue and cost. The reason for adjusting the customer charge is that it does not vary with the customer's electricity usage; thus, it does not affect electricity price. To the greatest possible extent, it is preferable to have prices equal or close to the marginal cost of providing a kWh. First adjusting customer charges allows prices to remain nearer to marginal costs.

It would be inefficient, however, to set the customer charge so high that customers would find it profitable to disconnect from the utility, buy their own meter, and purchase electricity from their neighbor who is still connected to the utility.* In this case, electricity prices must be adjusted to meet the revenue requirement. On the other hand, in case of excess revenues, first customer charges should be reduced, and if necessary removed. Further adjustments would require price adjustments.

If such an alternative becomes necessary, economic efficiency suggests that prices for each type of electric service deviate from their respective marginal costs in inverse proportion to their respective elasticities of demand. Demand elasticity is a technical term used to describe the responsiveness of demand to price. A low elasticity means that customers are quite insensitive to price, in which case they value electricity highly. The inverse elasticity rules provide a larger deviation between price and marginal cost for those customers who value electricity the most. Empirical studies of electricity demand show that residential demand is less elastic than industrial demand. Under these circumstances, should marginal cost pricing result in insufficient revenue, residential prices would rise proportionally more than industrial prices, according to elasticity rules. Similarly, if excessive revenue was generated by marginal cost pricing, the proportional reduction in residential prices would be

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* This action is not legal, even if more efficient.

greater than that for industrial users.

Currently, information about demand elasticities for various types of electricity service is quite limited. Furthermore, it is not clear that a policy of adjusting electricity prices according to customers' willingness to pay could withstand a legal challenge on the grounds of undue discrimination. Until better data are available, we recommend that the inverse elasticity rules be replaced by the simpler rule of adjusting all prices in equal proportion.

Summary

A marginal cost pricing policy for electricity that includes customer charges can be summarized in the following way. The revenue requirement, in effect, imposes a historic average cost standard for the average of all current electricity prices. The prices for particular electric services, however, would be based on current marginal cost and would thus provide the best possible current price signals to those users. After customer charge adjustments were made, any remaining price adjustment necessary to meet the revenue requirement would be based ultimately on the inverse elasticity rules. This would then provide the most nearly correct marginal cost price signals to those customers that would most likely react to such signals. Gains in economic efficiency do not come from changing the average price for electricity, but from adjusting the relative prices among customers. While these gains are important, there are other rate structure reforms that have much greater potential benefits; these reforms are discussed in the following chapter within the context of pricing policy alternatives particularly appropriate for electric companies.

CHAPTER 5

CRITICISMS OF MARGINAL COST PRICING

The application of marginal cost pricing to the regulated electric industry has been criticized in numerous ways. This chapter contains those criticisms that are directed toward marginal cost pricing in general. Criticisms of specific rate structure recommendations are discussed in the next chapter. The discussion in this chapter divides these issues into two groups. The first section includes those criticisms that are related to the objective of economic efficiency. The second group includes all other general objections to marginal cost pricing.

Objections Related to Economic Efficiency

The criticisms of marginal cost pricing policies contained in this section are related to the objective of economic efficiency. Arguments are made that these policies are counter-productive and that they create adverse effects.

Economic Efficiency Is Not a Proper Objective

As was pointed out in Chapter 3, economic efficiency is one of the three major objectives historically recognized as proper guidelines for the design of electric rates. While there are many rate structures that can meet the revenue requirement only marginal cost pricing can achieve economic efficiency while satisfying the accepted standard of fairness.

Marginal Cost Pricing Adversely Affects the Distribution of Income

Whether or not it is intended, regulation always affects the distribution of income within society. Electricity costs are paid in varying degrees by industrial and residential customers, urban and rural customers, etc. Essentially, the objective of marginal cost pricing is to make the overall income of society as large as possible. In theory, those who gain from policy reform should have sufficient additional income to compensate those who lose; thus, everyone should be better off. Since those who lose are seldom--if ever--compensated in practice, however, the way in which cost-sharing arrangements are altered by marginal cost pricing is important.

Although we have not yet done so, it would be possible to study the cost-sharing and efficiency trade-offs associated with electricity pricing reform. Such a study would be expensive; there are potential benefits to be had from certain rate structure reforms, regardless of how costs are distributed among customers. In particular, peak-load pricing can be adopted and the declining block rate structure can be flattened while maintaining the existing cost-sharing arrangements among various groups.

Marginal Cost Pricing Might Not Achieve Economic Efficiency

It is possible that important price distortions can exist in other sectors of the economy, while improvements are being made in electricity production. As policy reform moves electricity prices towards marginal cost, these price distortions may be enlarged. Should such indirect influences exist, they must be counted as part of the policy reform cost. This is the problem of the second-best. Such inequities do not exist if prices in other sectors of the economy are equal to marginal costs. If prices elsewhere deviate from marginal cost, it is possible--although not inevitable--that further distortions may occur, if marginal cost pricing for electricity is adopted.

For example, the rationing of natural gas might increase if electricity prices are reformed. If natural gas and electricity are substitutable in the case of space heating, the demand for natural gas would decrease if nighttime electricity prices were reduced through the adoption of peak-load pricing. On the other hand, industrial demand for natural gas would probably increase during peak electricity hours, because of the higher electricity peak prices. Overall, it is not clear whether the natural gas situation will improve or deteriorate.

No substantive evidence of any adverse second-best effects has been provided by opponents of marginal cost pricing, despite a request from the New York Public Utility Commission that such evidence be submitted at its generic hearings. Even so, second-best effects may occur; it would seem reasonable for the PUCO to monitor other regulated industries for these induced distortions, if peak-load pricing is gradually adopted for electricity.

Marginal Cost Pricing May Result in Industrial Movement from Ohio

If marginal cost pricing is adopted in Ohio, while nearby states continue to use their current rate structures, there may be some incentive for industry to consider locating either existing or planned facilities outside of Ohio. This possibility certainly deserves the attention of the PUCO since the PUCO is currently considering time-of-day pricing, a preferred form of marginal cost pricing. The primary factor which would mitigate industrial migration out of Ohio is that time-of-day pricing offers firms the opportunity to reschedule their production activities so as to take advantage of off-peak prices. It is true that in the short run many firms will be unable to make such adjustments; industrial relocation, however, is by its very nature a long-run activity. The long-run choice whether to locate plants in states with transitional electricity pricing structures or to locate them in Ohio must consider the fact that in Ohio the industry could take advantage of the cheaper nighttime electricity rates implicit in rate reform. We do not know if cheap off-peak electricity is an inducement sufficient to attract business to Ohio. It seems appropriate for the PUCO to consult with other state regulatory commissions on this issue, if time-of-day pricing is adopted as a long-term goal. It is interesting that this problem was not considered to be serious by the New York Public Service Commission in their generic hearings on marginal cost pricing.

Other Criticisms

The criticisms discussed in this section deal with legal matters and the practicality of marginal cost pricing.

Marginal Cost Pricing Lacks a Legal Basis

An argument against marginal cost pricing is that it lacks a sound legal basis. It is true that, for the most part, utility commissions in the past have not proposed rate structures. Most legal precedent concerns definitions of the rate base and the regulated rate of return. Our review of the legal environment of regulation, however, has uncovered no restrictions which would prevent the PUCO from regulating the rate structure if it so wishes. The New York generic hearings on marginal cost pricing confirm our findings. The PUCO may wish, in any event, to get further legal opinions on this issue.

The Ohio Revised Code defines the objectives of regulation to include fairness, nondiscrimination, and provisions for a proper rate of return. It may be that marginal cost pricing has some legal merit on these grounds; marginal cost pricing determines rates in accordance with costs, which is a widely-accepted legal standard for fairness of compensation. Because prices and costs are more closely related under marginal cost pricing than under current rate structures, the growth in sales over time will provide revenues sufficient to cover costs, thereby providing for a proper rate of return on additional kWh sales. While we cannot offer legal advice on these matters, it may be that the Ohio Revised Code not only does not prevent marginal cost pricing, but that marginal cost pricing better fulfills the PUCO's legal requirements than do current pricing practices.

Marginal Cost Pricing May Lead to Revenue Uncertainty

As discussed in the previous chapter, there are rate structure reforms which affect the stability of the utility's revenues. In particular, reforming either the demand (kW) charge or the declining block rate structure would influence the uncertainty surrounding the company's revenues. Whether or not any increased revenue uncertainty is actually a significant burden must be judged within the context of the utility's entire production system. We have reviewed no studies of this problem, but believe that substantive research in this area is needed. Utilities in the U.S. which have already adopted rate structure reforms, including the recent (August 1976) Columbus and Southern Ohio decision to flatten its rate structures, have not apparently witnessed any significant increase in revenue uncertainty. We suggest, however, that this is an area in which future study is needed.

Marginal Costs Cannot Be Calculated

There are several methods for calculating marginal costs of electricity. Cost forecasting, especially for capital costs, is not as precise as we would want. This suggests that marginal cost calculation is not nearly as well-defined as is the marginal cost concept. Despite this, marginal costs can be estimated. The analysis of Dayton Power and Light (DP&L) reported in Chapter 8 provides, in our opinion, reasonable estimates of marginal costs. In addition, the precision with which embedded costs are calculated is not necessarily indicative of their usefulness. While there may be some computational errors, we expect marginal cost to provide more nearly correct economic signals and to track better changes in economic conditions than do embedded costs and declining block rate structures.

Elasticity of Demand Cannot be Measured

It is commonly asserted that marginal cost pricing is impractical because it requires the application of inverse elasticity rules to meet the revenue requirement; since it is not possible to measure the required elasticities marginal cost pricing cannot be applied. Because there are other means, such as variation in the customer charge, to meet the revenue requirement this objection cannot be sustained.

Only New Customers Pay Marginal Costs

It has been alleged that only new customers would pay the cost of expansion under marginal cost pricing. This is a misunderstanding of marginal cost pricing. All customers, old or new, within the same customer grouping pay the same prices under marginal cost pricing.

Apportioning of Costs Is Difficult Under Marginal Cost Pricing

It has been suggested that average embedded costs are more easily apportioned to various customer groups. If there are common facilities serving two or more customers, apportioning the common costs is equally difficult whether average cost or marginal cost pricing is used. While the accounting techniques currently used to establish cost-sharing arrangements may be precise, they are nonetheless arbitrary.

CHAPTER 6

ELECTRICITY PRICING POLICIES

The theoretical argument presented in Chapter 4 suggests that the use of marginal cost pricing for electricity in Ohio merits considerstion. The implementation of this policy requires the introduction of several features. In this chapter various such features are discussed yielding the requisite characteristics of rate structures based on marginal costs.

Declining Block Rate Structure

Currently, electricity is priced according to a declining block rate structure. We recommend the elimination of the declining block rate structure and its replacement with a schedule containing a flat rate and a customer charge, under which customers would consume all their kWh's during each time period at the same price. If necessary, because of adverse public reaction to the customer charge, a short declining block structure could be inserted at the beginning of a rate schedule,

The Benefits of Eliminating the Declining Block Structure

The most important advantage of a flat rate, which equals marginal cost, is that all consumers within a given class would base their electricity consumption decisions on the same price. Under the current rate structure there is a good possibility that the tail block price is lower than long run marginal cost, while the initial blocks are higher than marginal cost. Such a pricing policy promotes neither economic efficiency nor conservation of our scarce resources.

In the tail block region of the current rate schedules customers may be receiving their electricity at prices lower than marginal costs. They are thereby encouraged to consume more electricity than they would at marginal cost. The benefit they receive from their final kWh is equal to the tail block price and, consequently, is less than the cost of producing it. The loss to society due to the production cost exceeding the consumer's benefits could be estimated using the cost-benefit technique described in Appendix C. We have not conducted this exercise. Nevertheless, it appears that such losses may be substantial.

It is not only the tail block rate, however, that generates such social losses; the initial blocks of the declining block rate structure are also responsible. For those consumers whose final consumption is priced above marginal cost, the benefits received from the final kWh are smaller than the cost of supplying it. They would consume more electricity if price were equal to marginal cost; therefore, their demand for electricity has been discouraged by the incorrect price signal.

It is important to recognize that the societal losses which occur at both ends of a declining block rate structure do not cancel one another; rather, they must be combined to find the total loss to society. Preventing these losses is the first benefit of a flatter rate structure.

The second benefit of eliminating the declining block rate structure is better conservation of our energy resources. As the tail block is raised up to the long-run marginal cost, less electricity will be sold. This will be offset somewhat by increased sales to small users; however, the overall sales of electricity will probably decline. Moreover, this conservation of energy occurs because consumers are provided with correct price signals, as opposed to the existing promotional rates which encourage unwarranted high rates of consumption.

The third benefit of a flatter rate structure is that the frequency of rate cases would be reduced. Recently, electric companies have made frequent requests to the PUCO for additional rate increases. Such rate cases are expensive. Although inflation is a major cause of these hearings, fuel adjustment clauses provide a significant amount of automatic revenue adjustment via higher price levels. In addition to inflation, another reason for the currently high number of rate cases is the existing rate structure. As electricity demand grows over time, new sales occur chiefly as current customers extend their consumption into the lower priced blocks in the declining block rate schedule. In particular, the final blocks are likely to be priced below long-run marginal cost. Consequently, the cost of meeting new demand is greater than the revenue it generates; so the utilities ask for another rate increase. A rate structure which is essentially flat and equal to marginal cost provides a closer correspondence between costs and revenues than does the current declining block rate structure. Marginal cost pricing will provide needed revenue as electricity sales grow, thus eliminating one cause of the recent high frequency of rate hearings.

A Disadvantage

The disadvantage of our recommendation to flatten the rate structure is that the utility's annual revenue would be somewhat less stable; that is, the economic environment surrounding the utility would be slightly more uncertain. This occurs because total annual sales of electricity are somewhat random due to weather uncertainty, and changes in the composition of customers, etc. The random nature of sales implies a degree of revenue fluctuation, dependent upon price. Under declining block rate structures, most of the fluctuation in kWh sales occurs at low, tail block prices--leaving revenue quite stable. If the rate structure is flattened, however, the tail block price would be higher; this results in greater revenue uncertainty.

Conclusion

While we recognize that greater revenue uncertainty places a burden on the utility's investors, the practical effects are likely to be small. If the uncertainty surrounding the electricity industry were to increase significantly, investors would demand that a small risk premium be added to the rate of return. The currently authorized rate of return provides ample compensation to investors for any risk they bear. That risk is evaluated in the context of the total operations of the utility and includes such hazards as lightning strikes, random machine failure, and several other risks associated with any enterprise. The additional risk associated with a flatter rate structure seems to be comparatively small. In addition, we have seen no empirical evidence that the bond or stock markets do in fact respond to the degree of flatness implicit in rate schedules. While the risk associated with various rate structures should be considered by the PUCO, we believe that whatever adverse effects may result will be overshadowed by the benefits of a flatter rate structure.

Seasonal Prices

The marginal cost of supplying electricity varies seasonally through the year, because of the variation in demand. It is currently impractical to store electricity between seasons. Accordingly, charging higher prices during those seasons (winter and summer) when an electric utility is likely to be operating close to capacity and lower prices otherwise is called seasonal pricing. We recommend that Ohio electric utilities adopt a seasonal pricing policy. Currently, several utilities have small seasonal electric rate differences. From our analysis of DP&L presented in Chapter 9 and Appendix D, it appears that larger seasonal price differences can be justified than those now used.

Advantage

The benefit of seasonal pricing is that costs and revenues are nearly equal on a seasonal basis. If demand increased during the spring or autumn it is unlikely that additional capacity will be needed. The need for capacity depends on the relationship between supply and demand. The available supply of electricity depends on the maintenance schedule of the utility's plants. The probability that available capacity will be exceeded can be seasonally calculated and then used to distribute capacity costs. A simple example of such an exercise is provided in Chapter 9, the numerical results of which are intended only to illustrate this point, and should not then be construed as an actual calculation of electricity rates.

Conclusion

The cost of seasonal pricing is almost negligible. No additional meters are required; in addition, electricity customers are already accustomed to this tariff form. Accordingly, we recommend that seasonal price differences be based on marginal costs that include a different demand cost for each season, based on the seasonal probability of excess demand.

Time-of-Day Pricing

Time-of-day, a form of peak-load pricing,is a policy of charging higher prices during peak hours than are charged during off-peak hours. It is an appropriate policy if marginal cost pricing is adopted as a pricing standard because the cost of expanding electricity production at peak periods is much greater than that of meeting demand growth during off-peak periods. In particular, supplying additional electricity during those hours when the utility system is operating at full capacity requires that expanded facilities be built. Off-peak increases in demand can be satisfied by drawing heavily on the capacity already available; the increased cost of so doing is primarily for fuel. We recommend that the PUCO adopt time-of-day pricing as a long-term policy goal.

It is important to recognize that although time-of-day pricing logically follows from marginal cost pricing, it is possible to advocate it on grounds other than marginal cost principles. Many benefits related to time-of-day pricing will result with most techniques used to calculate peak and off-peak prices. These benefits, summarized below, will be greater if those prices are based on marginal costs, but they will occur nonetheless.

Advantages for Utility Companies and Consumers

One important benefit of time-of-day pricing is cost reduction. Such cost reduction may follow from a reduced need for capital facilities if a smaller peak capacity is needed. Currently, the growth in peak demand is priced far less than its marginal cost. Were peak prices closer to the true resource costs, peak demand growth would be slower, reducing capital expenditures and improving the financial health of the companies.

Reduced peak demand will also reduce the use of peakers--units used only for short periods. Peakers generally burn petroleum products which are becoming increasingly more expensive. By reducing peak demand these relatively expensive fossil fuels, oil for one, are conserved. Instead, fuels such as coal and uranium which are plentiful in the U.S., are used.

The frequency of rate cases should be reduced if time-of-day pricing is adopted. As was previously discussed in relation to declining block rate structures, demand has a tendency to grow excessively at prices which are less than marginal costs. Peak demand growth, in particular, yields lower revenue than is needed for capacity expansion. If price reflected marginal cost, demand growth would generate enough revenue to be self-financing; this would reduce the frequency of rate cases, especially during inflationary periods.

Peak load pricing meets the standard of fairness previously discussed as a fair compensation for costs principle. Peak users are responsible for peak costs; and expansion of their demand will require additional peak capacity. As mentioned earlier, demand increases by off-peak users are much less costly. Most people expect to pay the costs of being provided electric service; they understand that it is only fair for them to pay higher prices during those periods when costs are higher. It should be emphasized, however, that capacity costs are not borne by a single group in society called peak users; rather, all consumers are potentially both peak and off-peak users. The average yearly electric bill for many residential customers may change minimally under peak-load pricing.

All-electric households stand to gain; for example, those that use electricity for winter space-heating during off-peak night hours could witness cost reductions.

In addition, consumers who are willing to make an effort to switch their use to off-peak periods will be rewarded with lower bills. Currently, many energy-conserving citizens have been dismayed by the granting of a rate increase because the utility did not sell enough electricity to meet its costs. Reducing electricity use at night reduces the utilitys' revenues far more than it does their costs. The unfortunate result is that thermostat lowering campaigns have often produced seemingly perverse effects (additional rate cases) in the eyes of residential consumers. The bad image that now hinders Ohio's electric companies can be in part attributed to the mismatch of prices and costs. Time-of-day pricing will result in a more even match of prices and costs.

Finally, the real solution to the energy problem in the U.S. is technological advancement. Peak-load pricing will stimulate research and development in energy storage by providing greater incentives to store electricity during off-peak periods. If customers pay actual peak costs, research into other load management techniques and alternative energy sources also will be encouraged. While most of this knowledge will probably be developed even if peak-load pricing is not adopted in the U.S., peak-load pricing could encourage more rapid progress in these areas.

Potential Problems with Time-of-Day Pricing

Time-of-day pricing has raised the following concerns among those who have considered it.

Implementation Costs

Costs are inevitably incurred in adopting a marginal cost time-of-day pricing policy. The new customer meters required for time-of-day pricing are somewhat expensive, especially since advancing metering and load control technology may make any meters installed now obsolete in the near future. Despite this, our analysis of costs and benefits shows that even quite expensive meters can be justified for large users such as commercial and industrial customers. Less expensive meters may also be warranted for large residential users, those with all-electric homes; however, we did not have the data necessary to study this possibility. Time-of-day metering for all residential users may or may not be beneficial, depending on their response to time-of-day tariffs. Our cost-benefit analysis is discussed in greater detail in

Chapter 7 and Appendix C. It would appear that a time-of-day pricing policy would be beneficial in at least those electricity markets consisting of large users. In a few years, after the uncertainty surrounding the various metering technologies is reduced, time-of-day pricing may be beneficial for residential users as well.

Industrial Ramifications

If time-of-day pricing is adopted in Ohio but not in nearby states some industrial operations may find it profitable to relocate in those states. In addition, new industry may find Ohio less attractive and decide to locate elsewhere. If time-of-day pricing is adopted gradually, with adequate customer education, consumer expectations need not be abruptly disappointed. This will help to avoid impulsive decisions to leave Ohio. In addition, gradual policy reform would allow the PUCO to coordinate its activities with those of other states. There is presently a great deal of interest in peak-load pricing in other states; it seems likely that pricing reform will occur simultaneously in several parts of the country. If so, induced industry migration will not be significant. The possibility of industrial relocation, however, deserves the PUCO's attention, particularly if Ohio is not joined by other states in reforming electricity prices.

Peak Load Shifts

As time-of-day pricing is introduced and customers change their demand patterns, the system's peak demand period will undoubtedly shift. Some adjustment in the definition of peak hours will necessarily occur. Gradual adoption of a peak-load pricing policy would allow the utility managers to learn about the nature of such shifts without first imposing a new pricing scheme on the entire system. Under these circumstances, the PUCO can rely on the judgment and learning ability of the utility's management to adapt the general concept of peak-load pricing to its specific conditions.

It has been suggested that the uncertainty regarding the occurrence of the hottest day of the year will so dilute the peak price that there will be little incentive for people to reduce their air conditioning loads, thus creating needle peaks. This argument neglects other loads such as self-cleaning ovens, industrial processes, etc., which most likely would be shifted in response to time-of-day pricing. If needle peaks do occur, however, customers are apparently willing to pay the costs of peak expansion, at least in the short term. That implies that the direct benefit of reduced capital expenditures may be small; still, the indirect benefits of peak-load pricing will still be substantial. In particular, the benefits associated with induced technological improvements in energy storage, reduced frequency of rate cases, and a flattened rate structure are not affected by needle peaks.

Consumer Reception

It has been suggested that time-of-day pricing creates a hardship on all electricity users in general, and low income people and all-electric homes in particular. We believe that the opposite is more likely. Peak-load pricing essentially gives consumers the option of buying electricity during peak or off-peak periods. Once given an option, people are marvelously resourceful in making adjustments. Low income families will be financially rewarded with lower electricity bills, if they are willing to make an effort to change their electricity usage pattern. A public information program about the implications of peak-load pricing would be required to help people decide whether or not to make that effort. All-electric homeowners would benefit from inexpensive nighttime winter heating and could, therefore, reduce their yearly bills with only slight changes in their demand patterns.

Nighttime Winter Peak

Some utilities project that they may eventually have a shift in their winter peak from daytime to early evening, as more electric space heating is used. If so, the burden on all-electric homeowners may increase. The extent of the burden, however, is not clear. Most nighttime heating hours would still be off-peak, mitigating any burden significantly. Off-peak electricity would most likely be available during other periods of the day, such as morning or mid-day hours, thereby providing an opportunity for shifting the load of washers, dryers, and self-cleaning ovens, etc. Finally, to the extent that an early evening peak occurs, it will be appropriate that peak prices be charged. It is fair that customers bear the costs of the service being provided; otherwise, they must be subsidized by other, off-peak users. Also, it would be inefficient to charge low prices during an early evening peak, because customers would be encouraged to consume electricity excessively.

Load Control

It has been suggested that load control devices are better than peak-load prices for reducing peak demand. These two load management techniques, however, are not mutually exclusive. Both peak-load pricing and ripple control of air conditioning levels, for instance, could be used by a utility. In fact, load control development might be encouraged if peak-load pricing were adopted, because customers might be willing to subscribe to interruptable service in order to avoid high peak-period prices.

Unresponsive Customers

Most benefits of peak-load pricing depend upon positive consumer response to price signals. If they do not so respond, benefits are greatly reduced. Although we have not resolved the empirical question of how responsive customers actually are, the cost-benefit analysis in Appendix

C shows that if customers respond only slightly to peak-load pricing the benefits outweigh the costs for larger users and are only slightly less than the cost for residential users.

Fuel Adjustment Clause

Fuel adjustment clauses will require some modification if time-of-day pricing is adopted. Although some PUCO staff work would be required to establish time-of-day fuel clause differentials, there is no inherent difficulty that would prevent an appropriate fuel adjustment policy from being written.

Discrimination

There is also a legal question of whether or not time-of-day pricing is discriminatory, if only a few industrial customers are initially billed in this manner. It would be appropriate for the PUCO to obtain a legal opinion on this matter. In their answer to this argument, the New York Public Service Commission pointed out that the Commission "... has a statutory mandate to avoid undue discrimination; and there is in any event no reason to assume that it would seize the occasion of introducing economically more efficient rate designs to impose new economically unjustified burdens on particular classes of subscribers."[74]
We believe that industrial users would be more comfortable with time-of-day pricing were they to receive similiar reassurances from the PUCO.

Conclusion

The potential benefits of time-of-day pricing outweigh its potential problems. It offers the possibility of reduced electric bills for users who change their demand patterns, fewer rate cases, less capital expansion, conservation of scarce resources, a better public image for the electric companies, technological development, and overall fairness to customers. There are implementation costs incurred in adopting a peak-load pricing policy, such as metering and staff development for the utilities and PUCO. On the whole, peak-load pricing appears to be a very attractive rate policy alternative.

Prices by Voltage Level

Electricity costs also vary by the voltage level at which the customer receives service. Low voltage (240/120 volts) users are residential and small business customers. High voltage users are usually large power users, such as large industrial plants and large commercial establishments. A voltage level termed "high" may vary for different utilities, but there is usually a convenient voltage level grouping appropriate for cost analysis; i.e., voltages in excess of 12.5 kilovolts (kV). The cost of delivering a kWh to high voltage customers is significantly less than that incurred in serving low voltage users. First, the line losses involved in supplying electricity become larger as more voltage reduction is required. Second, low voltage users are usually connected to an extensive indirect distribution/transmission network. High voltage electricity, however, can usually be delivered through a small distribution system linked more directly to the transmission system.

We recommend that electricity prices be based on marginal cost by voltage level. Under this policy, costs and revenues are closely aligned. This recommendation may not result in significant price changes in Ohio, as it appears that most utilities already base their prices on voltage level considerations. Assigning customers to use categories (residential, industrial, or commercial) is partially determined by voltage levels.

Prices by Location

The cost of electricity varies by geographic region. The costs of serving rural consumers are different than those of serving high-density urban areas and therefore, rates should reflect this fact. It is alleged that it is common practice to serve rural areas with a rate structure that recovers less than marginal cost, with the resulting deficit financed by urban dwellers and other users. Some observers question whether or not this rural subsidy is an appropriate social policy as it has already successfully encouraged rural development, which was the original intention. This issue was not examined for this report; accordingly we have no recommendation. If, however, the PUCO should decide to review this issue, we believe that marginal cost estimates by geographic zone would be useful to determine the degree of cross-subsidization implicit in various policy alternatives. Thus, the concept of marginal cost can assist the PUCO in sorting the issues when considering the trade-offs between economic efficiency and economic fairness.

Customer Charges

Just as additional kilowatt-hours (kWh) involve additional costs, there are costs of adding customers to the electricity network. We recommend that customers pay for this through a customer charge which is added to their bill, regardless of their kWh usage. The utilities are best able to suggest a price for such charges. Although we calculated an example of a customer charge, which is reported in Chapter 9, it is for the purpose of illustration only. The customer charge for very large users (200 to 300 such users for DP&L) could be calculated separately for each user.

The advantage of such charges is that they result in a closer correspondence between costs and revenues. Also, since these costs are recovered regardless of kWh sales, the utility's yearly revenues would be more stable. Currently, such costs are recovered in the early blocks of the declining block rate structure; however, such a structure has some drawbacks as discussed above. The primary disadvantage of customer charges is that customers may be dissatisfied with them. If, however, electricity customers cannot tolerate such a tariff form, we would recommend that a declining block rate structure be used to enhance the utility's public image. The blocks which we would design would be much shorter than at present, so that most consumers' final monthly kWh is priced at the tail block price.

Our second recommendation regarding customer charges is that they be used to adjust the utility's total revenue to meet its total costs, including the required return on investment. The advantage of this procedure is that prices can remain equal to marginal cost, which promotes economic efficiency. There is, however, a reasonable limit to customer charge adjustments, as discussed in the previous chapter. The judgment of the PUCO and the utility managers can determine this limit.

Inverse Elasticity Rules

If customer charges are unsuccessful in meeting the revenue requirement, we recommend that the rules of inverse elasticity of demand be used to adjust prices. This will not be possible, however, until sufficient data is available to estimate these elasticities accurately. In the interim, we suggest that all prices be adjusted proportionally. The inverse elasticity rules are based on economic efficiency grounds; they are the best way to adjust prices, given the institutional character of U.S. industrial regulation, precluding tax and subsidy arrangements between the utilities and the State of Ohio.

Demand (kW) Charges

A common practice for most electric utilities is to meter some customers' use of both kilowatt-hours and kilowatts. The monthly bill for such customers includes both a kilowatt-hour charge ($/kWh) and a charge for the maximum kilowatts used during the month ($/kW), commonly called a demand charge. Noted economists such as Joskow, members of the French electric planning commission, and the U.S. utility industry as a whole are advocates of demand charges. While it is not particularly comfortable to be opposed by such an illustrious group, it does not appear that the various implications of demand charges have been sufficiently investigated to conclude that their use necessarily constitutes good pricing policy. This conclusion is based upon concerns which we believe have been inadequately considered in the literature. These are summarized below.

Load-Leveling

First, some analysts of electricity pricing have suggested that demand charges are good if they result in load-leveling. There is no question that demand charges encourage customers to reduce the variability of their own load by shifting their own peak demand into nearby off-peak periods. This probably reduces the system's peak load. Load-leveling, however, is not an end in itself. A more level load curve is not necessarily better than one that is peaked; that depends on the cost of leveling the load. Clearly, selling electricity during off-peak periods at less than marginal cost will level the load curve, but it would be an inappropriate pricing policy. Also, it might be possible to construct enormously expensive storage batteries to level the electricity production load, but the benefits would not justify the expense. It is fruitless for the utilities to take load-leveling actions which are not worthwhile. The question of whether or not demand charges are beneficial is a substantive one; it cannot be arbitrarily dismissed.

Reduced Consumer Variance

Second, demand charges encourage customers to reduce the variability of their electricity use. For some commercial or industrial users, the encouragement is sufficient to induce them to install load-control devices (such as microcomputer systems) to switch loads frequently, thereby avoiding a large kilowatt load at any instant. There is a serious question of whether or not regulated prices should encourage such activity. It is not clear that the best way for society to conserve electricity is to encourage private capital investment in customer-specific load switching devices. It seems appropriate to compare the cost of the induced private investment with the savings in the publicly-regulated electric company. Since no such comparisons exist, there are no adequate grounds for making a judgement. It is not sufficient to dismiss such comparisons with the argument that if the customer buys the devices, he and therefore the entire system benefits. If off-peak prices were zero and peak prices were ten times the marginal cost, there would be a great deal of private activity and investment in energy storage devices. These could be charged with low cost electricity at night and discharged during the day. It might well be in the self-interest of almost everyone to invest in such a device, and yet, it would cost society more to so arrange its electricity production activities than simply to adopt marginal cost pricing for both time periods. Only if prices equal marginal costs can we be certain that induced private activity is appropriate.

Customer Response

Third, there is some question about the type of customer response that demand charges allegedly encourage. Customers may reduce their average consumption during the peak period (fewer kWh's), or they may reduce their own peak kWh consumption. If peak kilowatts are reduced relative to kWh use, the customer's demand variability is reduced. The relevant issue, however, is the reduction of the system's load variance. There are no current studies of the effect of demand charge on system load variability during the peak; therefore, this cannot be evaluated as a pricing policy.

System Load Variance

Fourth, reducing individual load variance may be an inefficient way to reduce the system's load variance. The system load is the sum of many individual loads. There are natural economies of scale which occur as the number of individuals subscribing to a utility increases. Specifically, the variance of the sum of the loads does not increase as rapidly as the sum of the individual variances, due to the natural diversity among customers. It should be easier to reduce load variability by systematic load switching programs than by individual programs. No comparisons exist between system and individual load control programs; therefore, no basis exists for a judgement.

Conclusion

There are other theoretical issues regarding demand charges that are troubling. These four points convey sufficient doubts about this type of pricing policy to indicate the reason why this is a major unexplored area. Demand charges may be well justified, but the information needed to reach this conclusion is currently unavailable. Accordingly, we have no recommendation concerning the long-term desirability of demand charges.

Summary

Of the rate structure issues that we have reviewed, there is only one about which we are ambivalent: demand charges. We believe that the remaining rate structure characteristics would result in substantial benefits in the long run. If adopted, these recommendations should be implemented cautiously, possibly in conjunction with the efforts of other states. The implementation process is discussed in Chapter 7. Because numerous rate structure characteristics were discussed in this chapter, it is appropriate that we summarize our recommendations about long-run rate reform, comparing them with existing rate structures.

There are three issues for which our recommendations do not differ substantially from current practice. These are that electricity prices should vary according to voltage level, season of the year, and geographical region. Price differences should be based on marginal cost differences, except for regional pricing policy which involves income redistribution issues that we have not studied. We suspect that the amount of variation currently existing in these prices is less than that associated with marginal cost; however, our rate recommendations differ from current rates only by degree, not in any qualitative way.

Two rate structure issues which require further study are the use of demand charges and the use of inverse-elasticity rules. While we are confident that the inverse elasticity rules are appropriate in certain circumstances, better data and legal clarification are needed before they could be used. Our skepticism about the use of demand charge is more fundamental.

The three most significant recommended rate reforms are using customer charges, flattening the present declining block rate structures, and adopting time-of-day pricing. The resulting rate structure would vary by voltage level, time, season of the year, and customer location. For any specific customer group, such as primary-voltage, urban-commercial customers in the wintertime, the recommended rate structure is significantly different from the current structure. A convenient way to compare the two structures is to consider the way in which each recovers the three primary costs of producing electricity: energy, customer, and physical capital costs.

The current rate structure recovers energy costs from all kWh's sold, regardless of the customer's usage. Customer costs are recovered by initially high-priced blocks in the declining block rate structure. Capital costs are also recovered in the initial blocks, but the usual description by the utilities suggests that capital costs are loaded into more blocks of the rate schedule than are customer costs. That is, customer costs may be recovered in the first 200 kWh of residential sales, while any kWh sold recovers some capital costs.

In contrast, our recommended rate structure recovers these costs in what we believe is a more appropriate fashion. Energy costs are recovered in the flat rate structure as before so that all kWh's sold include these costs. Customer costs, however, are recovered by a customer charge. Capital costs are recovered by time-of-day pricing and, in particular, by the flat rate which is charged during the peak hours. Essentially, our recommended rate structure is based on the nature of the utility's cost structure. As the number of customers grows, additional customer costs are recovered by customer charges. As off-peak demand grows, the necessary energy costs are recovered from off-peak prices. As peak demand grows, the capital and energy costs are recovered by peak prices. It is because of the close correspondence between costs and revenues in our recommended rate structure that Ohio would enjoy the long-run benefits which have been discussed in this chapter.

CHAPTER 7

IMPLEMENTATION POLICIES

The implementation period is the time between a decision to implement policy changes and the end of the process of putting those policy changes into effect. In the context of electricity pricing policies, it is the time between the adoption of the policy goals specified in Chapter 6 and the full implementation of these policies.

Naturally, the length of this period depends on the extent to which the various proposed policies are implemented. Although a variety of criteria exists that can be used to choose the best speed for implementing these new policies, the recommendations in this report concerning proper implementation speed are based on the conservative judgment that each policy should be implemented only when its benefits exceed the costs, despite the fact that the benefits stemming from the entire policy package may exceed its costs. These ideas are illustrated with the help of a benefit-cost analysis.

Alternative Interim Policies

The package of target policies described in Chapter 6 contains several clearly desirable policies and one policy on which judgment is withheld at this time pending the acquisition of further data. Among the recommended policies are three especially significant rate reforms. These include the recommendations to use customer charges, flatten the present declining block rate structure, and adopt marginal cost-based time-of-day pricing. Furthermore, these long-term objectives clearly imply that electricity prices based on marginal cost differences should vary by voltage level, season of the year, and geographic region. A full spectrum of specific policy options exists that represents, to various extents, steps in the direction of these objectives. Not all, however, are immediately implementable or currently desirable.

A whole variety of pricing policies suggest themselves. These alternatives vary from a policy of doing nothing new at this time to a policy of changing the current rates structure immediately to prices that precisely reflect the cost of delivering electricity. Between these two alternatives are several feasible policies, all of which are based on marginal costs and all of which can be applied to some or all classes of electricity customers. These policies are single best pricing, seasonal pricing, and time-of-day pricing.

These three options are distinguished in terms of the period of time during which the ever-changing production, transmission, and distribution costs are assumed not to change. Thus, for example, the single best pricing policy is based on the assumption that a single best price can be found that is most capable of giving the consumer an indication of the cost of consuming electricity through the year, should the option of several prices be temporarily unfeasible. In addition, a policy of seasonal pricing does not necessarily exclude a time-of-day pricing policy. In fact, taken together they are a more precise representation of the utility's cost structure than is each alone.

Several other possible pricing policies, designed to remove existing obstacles to full implementation of marginal cost-based electricity tariffs could be considered at the present time. These policies include the abandonment of the existing declining block structures and the institution of customer charges. Also, there is the question of continuing kW demand charges for those customers with time-of-day rates.

Benefits and Costs of Alternative Policies

The decision to implement any one of the above policies for each class of customers must be based on a comparison of benefits and costs associated with that policy. There is a need, however, to distinguish between immediate implementation and future implementation. This need arises because certain current costs may diminish if the implementation date is postponed.

The various implementation costs can be logically divided into two distinct categories. The first major group of costs may be termed information acquisition costs.

Other costs associated with the expectations shock experienced by customers, and subsequent changes in their behavior, may be termed adjustment costs.

Information costs represent the cost of obtaining all the information necessary for the full implementation of marginal cost-based pricing policies today. Some of this information is readily available; the cost of obtaining it is merely the cost of speeding up the process of gathering the data. This type of cost represents that of obtaining information concerning consumer reaction to a change in the structure of electricity rates, measured in terms of usage patterns. This sort of information cost is small. A much larger cost figure is that associated with obtaining information that does not yet exist. An example of this is the current cost of developing a cost-effective metering technology for recording electricity consumption at a given moment of time.

Adjustment costs, on the other hand, indicate variations in the behavior of individuals and organizations, following a pricing policy change. Adjustment costs include those associated with the additional training that the utilities' staff (and that of the PUCO) may have to undertake, and the changes in daily consumption patterns, attributable to the new electric rate structures. Implementation costs can be reduced by slowing the pace at which we transform the current electricity rate structure into the proposed rate structure.

While cost reduction is possible by delaying the implementation of new pricing policies, benefits do exist that increase as these policies are implemented. These benefits stem from resource allocation adjustments caused by changing energy consumption patterns, after a pricing policy alteration. Furthermore, it is plausible that the speed at which the implementation of these policies proceeds is inversely related to the frequency of rate cases before the PUCO. A reduction in rate case frequency would certainly represent a benefit resulting directly from these policies.

Despite the existence of a well-defined list of costs and benefits associated with the alternative implementable policies, the decision concerning which policies to implement immediately is not an easy one to make. Difficulties stem mainly from a lack of clear estimate of the benefit-cost ratio. This lack of credible estimates is due in part to the inadequacy of the current data.

In the analysis of the benefits associated with the implementation of marginal cost-based pricing, an important element is the relationship between electricity prices and the quantity consumed by various customer classes. In an examination of this relationship, however, the existing econometric literature neither deals effectively with the declining block rate structure of electricity prices, nor sufficiently separates consumption during peak and off-peak periods. Perhaps the biggest obstacle to such an analysis is the current absence of data associated with such pricing practices in the U.S. Similarly, there seem to be no analyses concerning seasonal variations in the demand for electricity in existence. (For an analysis of existing studies see [59].)

Because of a lack of valid experience with marginal cost pricing in the U.S., there are very few estimates of implementation costs. Those available are partial; they do not include all the potential costs. In most cases, such cost estimates are limited to those of installing, servicing, and reading the metering devices specifically designed for time-of-day pricing.

In spite of these difficulties, we believe that the benefits exceed the costs at the present time for the following set of policy options:

1. For low and intermediate voltage electricity users:
   - (a) implement seasonal prices,
   - (b) provide the option of time-of-day pricing,
   - (c) develop an information program to assist users in making the optional time-of-day decision, and
   - (d) gather data concerning consumption patterns under the new pricing policies to aid in future policy decisions.
2. For high voltage users:
   - (a) implement seasonal prices,
   - (b) implement time-of-day pricing with a broad definition of the peak period, and
   - (c) gather data concerning consumption patterns under the new pricing policies to aid in future policy decisions.

Adoption of these options might be considered a first step toward eventual implementation of the complete policy package presented in the previous chapter. A second step could be the use of customer charges and flat rates based on long run marginal cost.

Comparison of Costs and Benefits for Time-Of-Day Pricing

To illustrate the kind of analysis needed to determine whether benefits exceed costs for any policy option, we performed an example analysis. It should be emphasized that the example does not include all costs and benefits, only the major ones, and that these costs and benefits may change in the years ahead as metering costs and the costs of capacity expansion change.

Despite the absence of reliable data for estimating benefits and costs of time-of-day pricing, it is possible to explore the feasibility of this policy option by a rough comparison of those benefits and costs for which partial data is available. These preliminary observations can potentially indicate whether or not the various pricing policies are at all worthwhile. In a test analysis, fully reported in Appendix C, only metering and billing costs were included, and only those benefits associated with change-over from a well chosen flat rate to time-of-day rates were calculated. Benefits from eliminating declining block rates, which may be substantial, were not included in order to isolate the benefits of time-of-day pricing.

These benefits result when the price increases during peak periods lead to a drop in consumption, thus providing a saving of capacity and fuel costs. Correspondingly, the potential decrease in the off-peak price of electricity leads to an increase in off-peak consumption, which is similarly considered to be beneficial. It is inevitable that customers will adjust their consumption to the point that their benefit from an additional kWh of electricity is just equal to the price of that kWh. If the cost of producing off-peak electricity is low, the price should also be low; otherwise, customers are prevented from equating their personal benefits from electricity consumption to the actual low cost of providing it and thus getting the most for their money. Accordingly, the off-peak consumption increase is deemed beneficial.

For residential customers, benefits were calculated under three alternative assumptions about the relationship between the electricity price and the quantity consumed (i.e. the price elasticity of demand). In the first case, both peak and off-peak demand elasticities were assumed to be 0.1, which is very low. These elasticities are roughly in the same order of magnitude as those that have been reported in empirical studies of electricity usage in the short run. The second case was based on a peak elasticity of 0.1, while the off-peak elasticity was at the much higher value of 1.0. Peak consumption is not greatly affected by prices, but off-peak consumption does indeed respond to price signals. The elasticities in the third case were both 1.0, which corresponds with the long-run elasticities found by empirical studies which have attempted to estimate the effects of electric appliance stock adjustment in response to price changes.

The results of the analysis for the Dayton Power and Light Company (DP&L) are shown in Table 7-1. For each of the three demand curves, this table shows the percentage change in peak and off-peak consumption that occurs as electricity prices are changed from a single price throughout the day to time-of-day pricing. Using Case 1 as an example, peak price was 6.2¢ per kWh (from Chapter 8), off-peak price was 1.2¢ per kWh (from Chapter 8), and the single price was 1.9¢ per kWh, chosen so as to yield a conservative estimate of benefits attributable to peak-load pricing.

Table 7-1 Costs and Benefits of Time-Of-Day Pricing*
(For 336,400 DP&L Residential Customers)

Case	Elasticity		Percentage Change In Consumption		Annual Benefits	Annual Costs	Annual Net Benefits
	Peak	Off-Peak	Peak	Off-Peak	($1,000,000)	($1,000,000)	($1,000,000)
1	0.1	0.1	-11.1	+ 4.7	3.11	4.15	-1.04
2	0.1	1.0	-14.6	+ 8.3	8.73	4.15	4.58
3	1.0	1.0	-77.7	+15.0	44.64	4.15	40.49

* These results are based on constant-elasticity demand curves.

In Case 1, peak consumption would be reduced by 11.1 percent, while off-peak consumption would increase by 4.7 percent. For the entire DP&L system, serving 336,400 residential customers, the benefits of this consumption change were estimated to be about 3.11 million dollars. The annualized cost of metering was about 4.15 million dollars, based upon the simplest dual-register meter costing $100 and other costs discussed fully in Appendix C. In this case, the benefits do not quite equal the costs, and the net benefits are a negative one million dollars.

These results are consistent with those in other studies, discussed in Wenders and Taylor [60], which have concluded that time-of-day metering is not quite justifiable on the basis of short-run benefits to all residential customers. It appears, however, that if the growth in residential electricity demand and relative electricity prices continues at a more rapid pace than the corresponding growth in meter costs, time-of-day metering may soon be beneficial for all residential consumers. While the appropriate data is not currently available, it seems plausible that large residential electricity users, those with all-electric homes, could currently benefit from time-of-day pricing, considering that such customers consume two and one-half to four times as much electricity as the average residential consumer. Although benefits do not increase proportionately with consumption, they would nevertheless be much higher for larger residential users.

In Case 2, the benefits were 8.73 million dollars, which yielded 4.58 million dollars of net benefits after subtracting costs. This is an annual benefit of about $12 per customer which was about 3 percent of an average annual residential electricity bill in 1975.*

* At first glance, it may appear unusual that the percentage reduction in peak usage is larger for Case 2 than Case 1. This phenomenon occurs because of technicalities in the analysis and is fully explained in Appendix C.

In Case 3, benefits are much larger than in the previous two cases, because peak demand is quite responsive to prices. The net benefits are ten times those of Case 2 and are about $120 per customer per year, which is about 33 percent of an average annual bill. While the estimates of the third case are likely to be higher than we expect in the short run, they are intended to indicate the benefits available in the long run. These appear more realistic if we recognize that consumers can make significant adjustments in their electricity usage patterns after living with time-of-day pricing for ten to fifteen years.

The second portion of the cost-benefit study concerned small industrial and commercial users. In the DP&L service area, there are about 37,000 such customers billed under a general service tariff. As bill frequency data was not available for this group, it was not possible to adjust the kWh consumption for the declining block rate structure. Additionally, it was convenient to calculate the benefits with the same method used for households to simplify the analysis.*

The average customer in the small business category consumed about ten times as much electricity in 1975 as

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* This is not strictly correct since the general service customers are billed on the basis of both kilowatts (kW) and kilowatt-hours (kWh). Fuller analysis of these complications is contained in Appendix C.

did the average household. Accordingly, the benefits associated with peak-load pricing are much larger than those for residential users, as shown in Table 7-2. The demand elasticities used in the analysis were 0.2 in both time periods. Empirical studies have consistently shown business elasticity of demand to be larger than residential elasticity and 0.2 was the most conservative estimate that we have reviewed. The percentage changes in peak and off-peak consumption in Table 7-2 are about twice those of the residential Case 1 figures, which is consistent with the elasticities being twice as large and the marginal costs remaining constant. The benefits of time-of-day pricing were $19.34 million. The costs were $2.44 million, which is quite high since it was assumed that a $650 recording tape meter would be required for these customers. The aggregate net benefits for this group were $16.90 million, or about $457 annually per customer; this is approximately 18 percent of an average annual bill for this type of customer.

Table 7-2 Costs and Benefits of Time-of-Day Pricing*
(for 37,000 DP&L General Service Customers)

Elasticity		Percentage Change In Consumption		Annual Benefits	Annual Cost	Annual Net Benefits
Peak	Off-Peak	Peak	Off-Peak	($1,000,000)	($1,000,000)	($1,000,000)
.2	.2	-21.8	+8.6	19.34	2.44	16.90

*These results are based on constant elasticity demand curves.

Policy Implications

Two specific conclusions are possible. First, time-of-day metering cannot be shown to be beneficial for residential users at this time. However, time-of-day pricing shows sufficiently positive net benefits to warrant a more detailed cost-benefit study, particularly considering that superior metering technology may be economical within two to five years, making the simple dual-register meter obsolete. If strong empirical evidence can be found that long-run elasticities are significantly higher than 0.1, the PUCO may seriously consider development of an optimum plan to phase in time-of-day pricing, including scheduling and selecting appropriate customers.

Second, time-of-day pricing would be beneficial if it were adopted for small industrial and commercial users. While additional study may be appropriate in order to improve the analysis of both benefits and costs, it is clear that the magnitude of monthly kWh consumption for this group is large enough that substantial benefits are possible, regardless of any estimation errors.

Generally, on the basis of this limited analysis of benefits and costs for one Ohio electric company, it seems clear that time-of-day pricing must be seriously considered as a policy option. It is also clear that the benefits are currently somewhat small for small users. Under these circumstances, it would be appropriate for the PUCO to consider the partial implementation of time-of-day pricing and the contingency development of a time-phased schedule of residential meter replacement. Furthermore, in a spirit of contingency planning, an analysis of alternative methods of estimating the long-run marginal costs necessary for implementing time-of-day pricing is appropriate.

Although no other empirical study of benefits and costs was conducted, several other policy conclusions can be made on the basis of a theoretical examination alone. At this time, there are no implementation costs associated with abandoning the declining block structure of electricity tariffs. On the other hand, potential benefits as outlined in Chapter 6 may be quite substantial. Similarly, there are no implementation costs associated with the institution of seasonal prices. Consequently, the PUCO could consider immediately implementing seasonal prices and substituting the corresponding marginal cost based flat rates for the declining blocks.

Flat, marginal-cost based, time-of-day prices do not reflect all the costs of producing, transmitting, and distributing electricity. Flat rates need to be accompanied by customer charges, similar to the existing monthly fixed charges for telephone services. The PUCO might immediately consider the ability of such charges to recover sufficient revenues and the potential consumer reaction to such charges. Should large customer charges prove inadmissible, there exists the option of inverse elasticity rules to permit the utilities to realize sufficient revenues. Serious questions concerning the legal problems of implementing potentially discriminatory pricing rules were mentioned in Chapter 5. Furthermore, the implementation of such a policy is feasible only when good estimates of elasticity of demand are available. We would not recommend the use of such a policy until those demand elasticity data are collected and analyzed.

CHAPTER 8

MARGINAL COST CALCULATIONS

The concept of marginal cost is well defined in economic theory. Some public utility commissions and electric company spokesmen are concerned that it may not be possible to translate the concept of marginal cost into practical rate structures. The purpose of this chapter is to show that marginal costs can be calculated, while the following chapter shows that these can be converted into reasonable electricity rates. We have analyzed the costs of Dayton Power and Light (DP&L) during 1975 in order to provide an example of our procedures. Our results are admittedly based on inadequate data and could undoubtedly be improved by incorporating the expertise of DP&L's systems engineers and cost accountants into our findings.

This chapter begins with a brief description of the production technology necessary for an understanding of the cost analysis. This is followed by a comparison of some suggested methods of calculating marginal costs. Our analysis of DP&L is based on one of these methods. The method we have chosen was developed by Charles Cicchetti and to a lesser extent, Ralph Turvey; however, there are both advantages and disadvantages to all the procedures that we reviewed. We believe that in the future additional research will improve many of these procedures. Therefore, our adoption of the Cicchetti method is not an endorsement of it; rather, it indicates that his is a convenient way to illustrate that marginal costs can be translated into practical electricity rates. This chapter concludes with a presentation of sample results based on recent data from DP&L.

Production Technology for Electricity

A typical system for producing electricity consists of power generating plants, transmission lines with substations, and an extensive distribution system of transformers, lines, and meters. The physical factors needed to produce electricity include labor, fuel, land, and durable capital goods such as poles, lines, transformers, generating plants, and buildings.

Generation Technology

There is a variety of possible generating methods currently available to electric utilities. These include internal combustion engines, gas turbines, coal-fired steam plants, various types of nuclear power plants, and hydroelectric installations. Generation facilities currently account for about 42 percent of all U.S. electric industry capital costs. During 1974, 97 percent of all electricity produced in Ohio was generated from coal. Gas and oil accounted for the remainder. Future plans for several Ohio utilities include the use of nuclear power plants. Nuclear power, however, will comprise less than half of Ohio's production within the next decade.

Each electric utility typically uses several methods of generation to meet the demand placed upon it. The mix of generating plants chosen directly reflects the nature of this demand. If a utility has a pronounced peak-period load, it is likely to use a large number of peakers.* A peaker is any low capacity generating unit which has the characteristics of low capital costs, but relatively high energy or running costs. Such units are economical if the length of time that they are used is short. By purchasing peakers, a utility can avoid the large capital costs associated with intermediate or base-load units. The optimal mix of generating plants depends not only on the shape of the load duration curve, but also on the capital and energy costs of each of the available plant types. Table 8-1 shows example capital cost per kilowatt of capacity and running costs per kilowatt-hour for three particular plant types: an oil-fired peaker, a coal-fired steam plant, and estimated costs for a base-load nuclear power facility.

Table 8-1 1976 Generating Costs for Three Plant Types†

Plant Type	Capacity (MW)	Annual Capital Cost ($/kW)	Running Cost (¢/kWh)
Gas Turbine (peaker)	50	21.59	1.70
Steam by Coal	400	27.58	0.98
Nuclear	1100	50.90	0.55

† Based on calculations,contained in Appendix D, currently being revised.

* Recently, in addition to using peakers, other arrangements have been instituted. Among these, the most commonly used is a pooling arrangement by various proximate utilities.

In general, plants with the lowest running cost are brought on line first. Other plants are added in the most economical loading order. The running costs for a given plant are not constant, as implied by Table 8-1. These costs decrease as the plant is run at an increasing load, but increase beyond the optimal plant load. Thus, the cost of generating a kilowatt-hour changes with the plant-mix and plant load.

The optimum mix of generating facilities is rarely available to a utility, however. If an electric power company could be built overnight, it might be possible to construct a set of plants which corresponds precisely to the shape of the load-duration curve. In an on-going enterprise, however, the available plants are a legacy of history. The utility may possess excellent planners and demand forecasters; however, if consumers change their behavior, or if an Arab oil embargo occurs, then the plants purchased previously may no longer provide the cheapest way of serving the customers. Despite this, it is seldom economical for a utility to rapidly adjust its stock of plants because these cannot easily be dismantled, sold and then replaced by newer units. Instead, the utility must constantly evaluate the reliability and maintenance characteristics of its plants and compare these with the construction costs of new facilities. In such a dynamic environment the calculation of marginal cost is complex.

Transmission and Distribution

The transmission and distribution system transfers energy to geographically-dispersed consumers. The annual cost of the U.S. transmission network of lines, poles, and transformers is about 20 percent of all electric utilities' capital costs, while the distribution system constitutes up to 40 percent. The feature which distinguishes the transmission and distribution networks is the voltage level.

The transmission system carries electricity at voltages too high for most individual customers. The transmission network is the most economical means of moving large amounts of electric energy to major consumption centers. The voltage is then stepped down at substations. Transmission lines are also used to interconnect utility companies. The voltage selected for particular transmission lines depends primarily on the length of that particular portion of the network. Generally, higher voltages are used for longer distances.

The distribution network is used to serve individual customers, and is much more extensive than the transmission network. The lines, poles, transformers, etc., which are familiar in almost every area of the U.S. represent a capital investment as large as that for all generating plants. Different customers receive power at different voltages. Large industrial and commercial customers buy electricity at higher voltages than do residential consumers.

Any system of transmitting electricity has a certain amount of energy losses, requiring that more than a kilowatt-hour be generated to deliver a kilowatt-hour to a customer. As the number of voltage drops increases, these line losses increase. In general, a consumer receiving electricity at the lowest voltage level requires more generated electricity per kilowatt-hour actually purchased than does a consumer receiving electricity at higher voltage levels.

A convenient measure of these line losses is a loss multiplier, which is the ratio of kilowatt-hours generated to those arriving at a customer's premises; it is accordingly larger than one. Loss multipliers appropriate to a particular voltage level can be found by successively multiplying the loss multipliers which occur across each voltage drop. In this way, the cumulative losses at each stage of voltage reduction can be found.

In addition to varying by voltage level, these loss multipliers also change depending on the amount of current in the line. As more current is transmitted, the line losses and loss multipliers increase. An implication of this is that loss multipliers are higher during periods in which electricity demand is high. This relationship is incorporated into the marginal cost analysis of DP&L and is explained more fully in Appendix B.

This report includes no analysis of the geographical nature of the transmission or distribution system of an electric company. Elaborate cost of service studies could incorporate a network analysis, thereby yielding estimates of the cost of expanding service in various portions of a utility's service area. We do not believe such an analysis is warranted in this study. The PUCO, however, may wish to consider this a possibility in the future.

The final device in the distribution system is the meter used to measure the customer's usage of electricity. Residential customers currently have meters which record only kilowatt-hours. A more elaborate version of this meter can be equipped with a clock and two dials for measuring kilowatt-hours consumed during peak and off-peak periods. Such meters are needed to implement a time-of-day tariff. A seasonal tariff does not require such special meters.

Large industrial and commercial users are typically metered in such a way as to record both maximum kilowatts and kilowatt-hours during various time periods. The simplest design is an indicating demand meter, which has a sweephand to indicate maximum kilowatts demanded between successive readings of the meter, at which time the sweephand is reset to zero. The most sophisticated recording systems produce a graphic load chart which shows the kilowatts demanded continuously throughout a billing period. Kilowatt-hours may be recorded separately, using the standard watt-hour meter, or may be determined by a fifteen-minute integrated demand meter.

Ideal Method of Calculating Marginal Costs

The technology of producing electricity determines how inputs such as labor, physical capital, and fuel are combined to deliver the industry's output, kilowatt-hours, to customers. If, in addition, the prices of inputs are known, the cost of delivering electricity can be found.

For planning purposes, the utility needs to know the resulting cost under a variety of possible circumstances.

For instance, the system planner may wish to determine the minimum cost investment plan that will meet a particular demand projection over the next fifteen years. By making such a determination for several demand projections, he can develop a relation between cost and future output. By subtracting the costs and outputs between two different such projections and forming the ratio of cost differences to output differences, he can find the additional cost required to produce an additional amount of electricity. This is the ideal way of calculating marginal cost. In essence, it consists of dividing the difference in the cost of fulfilling two demand projections by the corresponding difference in demand. The costs are found by reoptimizing the system's inputs for each demand projection.

Although this analysis of marginal cost is ideal it is, unfortunately, quite expensive to conduct. Nonetheless, it is instructive to list the elements of such an exercise, if for no other reason than to create a standard against which practical methods can be compared. In addition to responsible accounting procedures which ensure that no financial obligations are ignored, the ideal method of calculating marginal cost would incorporate relevant aspects of the following four production characteristics.

Production Dynamics

Ideally, marginal cost calculation methods would include a formulation of the production process that would take into account automatically all time-related charges. The ability to depict the utility's production capabilities over time is most important for the planning of investment, which is how the firm adjusts its capital stock. The addition, replacement and maintenance of machines and other durable goods is the firms' investment program. Finding the least expensive way to supply electricity requires detailed knowledge of the current stock of capital goods, including their expected replacement ages.

An alternative to this formulation of the electric utility is to depict the firm as existing in an unchanging world. In this world it must be assumed that the firm has reached a position in which annual investment is the same, year after year. Although this is unrealistic, such a view is often useful. In analyzing the different consequences of two possible future scenarios the unchanging-world type of marginal cost calculations can often provide insights into the essential differences between the two situations. This fundamental insight is often not as precise as that provided by the more realistic, time-sensitive, methods; nevertheless, these calculations are typically cheaper to make, easier to recalculate in answering policy questions, and more easily understood.

Uncertainty

An electric company is faced with uncertainty about future demand and uncertainty about the availability of production processes. There are two ways of incorporating uncertainty into a planning model. The most common method is to calculate uncertainty associated with any particular system configuration after the system has been designed. If, for example, the loss-of-load probability of a particular investment program is too high, then the program is successively modified until a satisfactory probability is obtained. This type of *ex post* analysis can yield a reasonably good overall system design and is inexpensive to conduct. The difficulty with this analysis strategy is that the company may have several system design goals in addition to loss-of-load probability which may conflict, and that until the costs and benefits associated with various levels of loss-of-load probability are specified, it is impossible to know whether the probability standard is too stringent or too lax.

The second, and much more costly, way to analyze uncertainty is to incorporate the costs and benefits of uncertainty directly into the marginal cost calculations. The investment plan could then be calculated by accounting for the effects of uncertainty along with all the other relevant factors.

Economies of Scale

It seems plausible that some portions of the electricity production process would become more efficient as they grow larger. For example, the average cost of producing a kilowatt-hour decreases as larger generating plants are used. Similarly, as the diameter of transmitting wire increases, its capacity increases more than its cost. Ideal marginal cost calculations would account for such large scale efficiencies as various investment programs are analyzed. No method that we are aware of adequately provides for such scale effects at the present time.

Substitution Among Production Inputs

The three primary types of inputs used to produce electricity are labor, capital, and fuel. There are numerous ways that the management could combine these inputs to produce a given number of kilowatt-hours per year. Some combinations of inputs will have more capital relative to labor. This could occur if the company purchased expensively engineered equipment which required less labor-intensive maintenance. It could also occur if the diagnostic maintenance functions were automated. In addition to the trade-offs between capital and labor, there are similar trade-offs between fuel and capital, as in the trade-off between coal and nuclear plants.

The ideal method of calculating marginal cost would consider various ways in which inputs can be substituted for one another in developing investment programs. Without exception, each electricity cost model that we have reviewed assumes that production inputs remain in fixed proportions to output, implying that one input cannot be substituted for another. This is a severe restriction. It does not allow management to investigate such policy issues as the effect of a rapid increase in uranium prices on the mix of planned capital projects. It does, however, greatly simplify the calculation of costs. In fact, the assumption that there is neither substitution nor large scale economies implies that the relationship between costs and output can be found simply by adding up input costs, as long as we remember to use the appropriate fixed input-output conversion factors.

Practical Methods of Calculating Marginal Costs

The preceding discussion outlined the basic ingredients of the ideal method of cost analysis. Such a method does not exist. In practice, the planner must choose those aspects of the firm's investment program that he wishes to emphasize. His choice depends on the policy questions he asks. Less than ideal methods can be formulated which answer particular questions quite adequately. The procedures suggested by researchers for finding marginal costs fall into one of three categories described below. These include engineering economics, statistical techniques, and accounting techniques.

Engineering Economics

The most useful methods of calculating marginal cost are based on engineering economics. These methods employ engineering formulas, physical laws, and economic data to discover the relation between cost and output. The method developed by Cicchetti, for example, uses loss multipliers which depend on the physical construction of a utility's transmission and distribution system. Another example of engineering economics is the the National Economic Research Associates (NERA) method of calculating marginal cost, described in the NERA testimony to the North Carolina Utilities Commission by Sally Streiter.[36] A simple example of the NERA approach is discussed in Appendix D, along with a method based on the optimal capacity expansion portion of the PUCO-OSU Corporate Finance Model (CFM).

Statistical Techniques

Besides engineering economics, there is a second general technique used to calculate marginal costs of electricity production. This method compares historical data from several different utility companies and develops a cost-output relationship using a statistical curve-fitting program. Marginal cost is the slope of such a curve. We have not used this method in this report, because it would be inappropriate as evidence in a rate case pertaining to a single utility.

There are advantages to this technique not possessed by current engineering methods. In particular, statistical methods permit estimation of the effects on costs of economies of scale and input substitution. A fairly complete cost analysis of this type has been conducted by Christensen and Green.[10] Although it may be possible to combine these statistical estimates of substitution and scale effects into an engineering model, we have not yet attempted such an exercise.

Accounting Techniques

A third class of techniques used to calculate marginal costs is called accounting methods. These methods are used to calculate historic average costs and are characterized by precise, but arbitrary procedures by which common costs are allocated among customer groups. The weighting procedure used by the National Association of Regulatory Utilities Commissioners (NARUC) to calculate customer costs, as discussed in Appendix F, is an accounting technique.

As previously discussed, current engineering economic methods assume that there are no scale economies in electricity generation. Under these circumstances, there may be little difference between the results obtained by an accounting method and those derived from the engineering economics approach. There is, however, a notable difference in the philosophy of the two methods. The accounting methods rely on history; an engineering economic analysis gathers historic data, but it uses this data to estimate vital parameters needed for future planning by the utility. It is this future planning orientation which distinguishes the engineering economic approch; this is a recurring theme in this report. A thorough accounting study may yield useful results, but incorporating the utility's capacity planning into the process will strengthen the analysis of marginal cost.

Cicchetti Method for Calculating Marginal Costs

Based on a methodology suggested by Ralph Turvey, Charles Cicchetti has developed a computer program to calculate the marginal cost of producing electricity. We used this program in our example calculations. Since it is well documented [11], only a brief description is provided here.

Generation Costs

To find the generation costs needed to satisfy an increased demand projection, the ideal comparison would be between two expansion plans, each of which is optimal. In lieu of reoptimizing the generation mix, Cicchetti assumes that the mix of new plants will not change. He then suggests that the marginal cost of generation is that of constructing new plants one year earlier than previously planned. The utility's existing expansion plan is simply moved forward by one year. It follows, in his view, that marginal cost is the capital cost of a new plant after it is annualized, using the appropriate interest rate and plant lifetime. The same conclusion can be reached by arguing directly that capital acquisition costs must be converted into equivalent annual costs to allow comparisons with other annual expenses.

Cicchetti's argument takes into account that power from new plants costs less than that from old ones. If construction occurs earlier, the entire generation system will have lower running costs during the interim period than it would have without the new plants. If a new plant is constructed one year early, the fuel savings will occur primarily in that year. If the savings are distributed over several years, the present value of the entire set of plants is found. The computer code supplied by Cicchetti does not provide any method of estimating these fuel savings. Our estimates for DP&L were obtained by simulating its operation for a year, with and without each planned plant. The simulations were provided by the MARC Code of the Corporate Finance Model. In the Cicchetti method the resulting savings are subtracted from the annualized capital cost of the new plants. That figure is then divided by the kW capacity of the plant, and is adjusted for a reserve margin to yield an estimate of the marginal generation cost in $/kW.

If several plants are to be constructed earlier, the same procedure is used--except that all annualized costs are summed before dividing by the aggregate kW capacity. For each of the major voltage levels of customer service, the raw cost estimate is adjusted up for line losses. For the lowest voltage level, primarily residential service, the line losses are greatest and the largest adjustment is made.

Technical progress, other than fuel efficiency, is not considered in this method. Although it could be incorporated by raising the discount rate, we have not done so in our analysis.

Transmission and Distribution Costs

Providing extra transmission and distribution capacity increases costs and raises operation and maintenance expenditures for the various types of physical facilities used for transmission and distribution to each voltage level of service. Such facilities may include, for example, additional high voltage transmission wires and the additional power capacity (expressed in kilovolt-amperes or kVA) of transmission and distribution substations and line transformers.

Transmission and distribution facilities serving each voltage level depend on the types of customers being served. High voltage users are served by high voltage transmission lines and transmission substations. Primary voltage users are served in addition by distribution lines and distribution substations, as well as line capacitors. Facilities for serving low voltage users must include additional lines and transformers.

Cicchetti assumes that the number of such facilities at a given voltage level of service varies directly with the customer kilowatt (kW) demand at that voltage level. He suggests that there are two possible ways of finding this relationship. One approach uses the future expansion plan to find the planned number of additional facilities per additional kW of peak demand. The second approach, which we have used, relies on annual historical data, and is described in Appendix E.

After finding the relation between physical facilities and kW demand (essentially the ratio of inputs to output), this is multiplied by the annualized cost of each type of facility, which yields a cost per kW. This is adjusted for line losses, as before. The cost for each voltage level is obtained by adding the costs of those facilities which serve that particular voltage level and all voltage levels which are higher. Implicitly, it is assumed that the distribution network has a hierarchical form, so that an expansion of demand at 220 volts (low voltage) also implies that demand must increase at 69.5 kilovolts (high voltage). This model of the network system is not strictly correct. For instance, portions of the high or primary voltage network which are quite expensive, but cannot be attributed to any single customer, are not in the network between the residential customer and the generating plants. Despite this, the hierarchical model seems reasonable, until more detailed network analysis is conducted.

Running Costs

Marginal running costs include fuel costs as well as variable operation and maintenance costs. These were determined by simulating the generation system using periodic customer load data, the planned maintenance schedule, the loading order of the plants, and the incremental fuel costs of each plant. The resulting running cost was adjusted for the line losses at each voltage level. These calculations depended to a minor extent upon the set of hours which were classified as peak hours, as discussed in Appendix E.

Defining the Peak Period

In devising a time-of-day pricing policy, we restricted our attention to two periods; one is called the peak period, the other is termed off-peak. More complicated schemes which include intermediate (or shoulder) periods are possible, but would add little to this illustration. In our example, all capacity costs are distributed over the kWh's sold during the peak period. Accordingly, the peak price is quite sensitive to the number of hours which are designated as peak. As the number of peak hours increases, the peak price becomes lower. The choice of how many hours to include in the peak may appear to be arbitrary; in reality, it depends on the behavior patterns of electricity customers and the probability that demand will exceed supply. Given the current inexperience that utilities have with peak-load pricing, the peak cannot be precisely defined. Consequently, we believe it would be prudent to use an initially broad definition of the peak. This can be narrowed as the utilities learn about customer reactions to time-of-day pricing.

In the discussion that follows, we have used a peak which encompasses 1352 hours, based upon an examination of DP&L's periodic load data for 1975. Specifically, the peak was defined as the hours from 10:00 a.m. to 6:00 p.m. on working days, during eight months of the year. Four of these were winter months and four were summer months. The extra month in each season reflects the uncertainty of not knowing when the hottest or coldest days would occur. A short spring and fall (two months each), and evening and weekends throughout the year are included in the off-peak period.

This peak definition is convenient because it allows several ideas to be illustrated. Specifically, it allows differential capital costs by both season and time-of-day to be incorporated into tariffs. The resulting tariffs, however, are merely examples used to illustrate our procedures. To determine the peak period properly requires that the probability of demand exceeding available capacity be determined, including the effects of planned maintenance schedules. We were unable to study the seasonal variation in probability of excess demand in the manner necessary to define the peak properly. Our choice was based on a desire to illustrate how seasonal prices can be calculated.

Under casual observation, it seems that demand is more likely to approach DP&L's capacity during summer than winter If so, this provides important pricing implications. If a peak is twice as likely during summer than winter, for example, twice the capacity cost should be allocated to each summer hour. To illustrate this, tariffs are constructed in two ways in the following chapter. First, electricity rates are calculated as if the probability of a peak were equal during both seasons. In the second case, it is considered twice as likely that a peak will occur during the summertime. The latter assumption will illustrate how seasonal tariffs can be established. If adopted in Ohio, such a tariff may capture some of the benefits of peak-load pricing, even when time-of-day pricing is not yet practical.

Marginal Costs for DP&L: An Example

To illustrate the marginal cost concepts discussed in this report, an analysis of the DP&L system was conducted. A more detailed description of the data is in Appendix E; assumptions and computer techniques are presented in Cicchetti [11]. In this section, only the final results reported in Table 8-2 are discussed. In this table the various components of the peak marginal cost are listed, as is the total, which appears in the right-hand column. These numbers should not be interpreted as exact measurements of DP&L's marginal cost. Rather, they are estimates based on available data and reasonable conjectures.

A comparison of peak marginal costs for the three voltage levels in Table 8-2 shows that the differences are due primarily to the transmission and distribution category. These are the most uncertain of all the estimates, because of the hierarchical network assumption and certain inaccuracies in the data which are discussed in Appendix E.

The energy costs vary from one time period to another because incremental running costs increase as the system load increases. The energy costs are the weighted average of the hourly incremental fuel costs during each of the six periods listed in Table 8-2.

The marginal costs as reported in Table 8-2 cannot be directly converted into tariffs because return on investment, taxes, and general plant and administrative expenses are missing. These are provided in the following chapter. The figures in Table 8-2 are, however, a good indication of the relative magnitudes

Table 8-2 Long Run Marginal Costs of Electricity Computed with the Use of Data from DP&L by the Cicchetti Method

Type of Period	Dates of Period	Voltage Level of Service	Marginal Cost (¢/kWh)			
			Generation Capacity	Transmission & Distribution Capacity	Energy	Total
Peak Period	May 15 to Sept. 14 Nov. 15 to Mar. 15 Monday thru Friday* 10 a.m. to 6 p.m.	High	1.60	0.46	1.31	3.37
		Primary	1.68	1.61	1.36	4.65
		Low	1.75	3.00	1.41	6.16
Off Peak Period	Nov. 15 to Mar. 14	High	--	--	1.14	1.14
	Monday thru Friday*	Primary			1.18	1.18
	6 p.m. to 10 a.m.	Low			1.16	1.16
	May 15 to Sept. 14	High	--	--	1.10	1.10
	Monday thru Friday*	Primary			1.13	1.13
	6 p.m. to 10 a.m.	Low			1.16	1.16
	Mar. 15 to May 14	High	--	--	1.14	1.14
	Sept. 15 to Nov. 14	Primary			1.17	1.17
	All Hrs. Mon.thru Fri.*	Low			1.20	1.20
	All Hours	High	--	--	1.02	1.02
	Weekends and	Primary			1.05	1.05
	Holidays	Low			1.08	1.08

* Excluding Holidays

of peak and off-peak prices. For residential customers, (low voltage) the peak price is about 4.5 times as large as is the off-peak price. For high-voltage industrial users, this ratio is about 2.5. Other studies have reported peak costs ten to fifteen times that of the off-peak costs. This has not occurred here because of the choice of a broad peak period.

CHAPTER 9

CONVERTING COSTS INTO TARIFFS

In Chapter 8, the Cicchetti method of calculating marginal costs was used to estimate the 1975 marginal cost of generating, transmitting, and distributing electricity for Dayton Power and Light Company (DP&L). In this chapter, these costs are used to compute electricity tariffs. In addition to the production cost calculations, other cost categories are considered in computing these tariffs. The results are examples of ways in which tariffs could be constructed. We do not recommend that our numerical findings be implemented directly.

Customer costs are discussed in the first section. Taxes and overhead expenses are examined in the second section. All are used in the third section to illustrate that a feasible tariff can be based on marginal cost principles. This tariff is found with and without a seasonal variation in the probability of peak occurrence. The fourth section indicates the revenue generated by both tariffs; the fifth section contains examples of typical bills under a similar tariff. The sixth and concluding section discusses the implications for large power users of a demand (kW) charge restricted to peak hours.

Customer Costs

The previous chapter discussed the relationship between electricity production costs and the number of kilowatt-hours produced. A second major component of electricity costs is based on the relation between costs and the number of customers. Customer costs, necessary if customer charges are to be used, can be divided into two categories.

First, each customer has some electricity facilities attached to his property. For the homeowners, these include the meter and dropline onto his property. Industrial customers may have, in addition, small transformers and various security devices. The marginal cost of these items is that which each customer would pay, were the items leased to him. The annualized cost could then appear as a customer charge, which is that portion of his bill that does not depend on his kWh consumption. If practical, this portion of the customer charge could be determined for each individual customer. Such an exercise would be useful, however, only for the largest 200-300 customers. Residential and small commercial users are sufficiently homogeneous that marginal customer costs are about the same for all individual users.

The second category of customer costs includes those portions of the transmission and distribution network which are common to several customers, but which must expand as the number of customers increase. A difficulty in estimating these costs occurs in deciding which portion of the distribution network must be built simply to serve new customers, and which portion is built to satisfy peak demand. The latter portion should be included in the marginal cost of a kWh of peak electricity; as such, it has been analyzed in the previous chapter. The former portion is called the minimum distribution system by the National Association of Regulatory Utility Commissioners (NARUC).[16]

NARUC suggests two alternative ways of finding such minimum systems, which are discussed in Appendix F. Both procedures rely on cost accounting and consequently have no provision for measuring economies of scale. Since it seems quite plausible that the cost per customer of building a distribution system would decline as larger systems are built, the NARUC methods are deficient. The NARUC work in this area, however, is probably the best that has been done to date. It should be noted that accurately estimating marginal customer cost is not as important as is correctly estimating marginal cost per kWh of electricity. This is true because economic efficiency does not depend upon such charges--except to the extent that an unreasonable customer charge might affect the decision to be a customer.

For this study, unfortunately, we did not have the data to conduct even a NARUC-type of study. Instead, we analyzed the Federal Power Commission (FPC) numbered accounts in a rather arbitrary, ad hoc manner. The details of this exercise are given in Appendix F. Essentially, we divided the accounts into those costs which could be wholly attributed to customers (e.g. meter reading) and those which could be attributed only partially to customers, which we call partial costs. A range of customer costs was obtained by attributing 0, 50, and 100 percent of the partial costs to customers. The resulting high and low cost estimates should be the upper and lower boundaries of marginal customer costs. In addition, there were certain cost categories which seemed reasonable to allot only to large power users.

Accordingly, customers were divided into two categories, large and small power users. The data did not permit more detailed customer categorization. The results of this exercise are shown in Table 9-1. For small power users, the monthly customer cost ranges from about \$2 to almost \$11. The median estimate is \$6.65. The large power customer costs are merely informed guesses and should be replaced with a more detailed accounting of the individual firms. As an average, these figures are sufficient for our purpose; they are not so far from that of actual billing.

Table 9-1 Monthly Customer Cost Estimates
(\$'s per Customer)

Customer Type	Percentage of Partial Costs Attributed to Customers		
	0%	50%	100%
Large Power User	612	648	684
Small Power User	2.39	6.65	10.96

Miscellaneous Expenses

There are four categories of costs that have not been fully considered. These are return on investment, general plant costs, taxes, and administrative costs. General plant costs include facilities such as office buildings. In a study with a truly long-run time horizon, these costs would vary as output (kWh) or number of customers varied. It appears, however, that these costs can be handled satisfactorily in an *ad hoc* manner without extensive study. The 1975 costs not included in the customer charge are given in Table 9-2. In the tax category, 3.3 million dollars were previously allotted to customer costs.

Table 9-2 1975 Miscellaneous Costs for DP&L

Type of Cost	Cost ($1,000,000)
Return on General Plant (50%)	1.5
Taxes - Federal	10.9
State and Local Property	20.9
State Gross Receipts	8.8
Credit to Customer Charge	-3.3
Administrative & General Expenses	5.5
Total	44.3

Conversion of Costs Into Tariffs

During the next several years, a time-of-day tariff for most residential and general service customers remains impractical; our analysis indicates that the necessary meters may be too expensive. During this interim period, an appropriate tariff might be an average of peak and off-peak marginal costs. In this section, tariffs are reported both with and without a seasonal variation in the probability of peak occurrence.

In these calculations, we have assumed that most low voltage and primary voltage users do not have meters capable of recording time-of-day electricity consumption. The only users for which a time-of-day tariff is constructed are the large power users, including both industrial and commercial customers. It is assumed that these customers are eligible for a high voltage rate; we have figured the corresponding peak and off-peak time-of-day tariff accordingly. If, in fact, there are some low voltage users in the DP&L service area who are billed under the general service rate schedule and who do have meters capable of time-of-day recording, the appropriate tariff can easily be computed using the procedure described in this section.

Previously, the peak period was defined as the hours from 10:00 a.m. to 6:00 p.m. on working days, during four winter and four summer months. To find an appropriate price in lieu of a time-of-day tariff, one averaging procedure would use the elasticity of demand in each period, as described in a previous report by Henderson and Kelly.[32] Information about elasticity is sparse; thus, we have instead chosen to find average prices by weighting the marginal cost for each period of the month according to the respective number of peak hours.

Equal Probability of a Peak Occurring

If the probability of a peak occurrence is the same during the winter as during the summer, capital costs should then be distributed evenly across all peak hours. The marginal costs reported in Chapter 8 were constructed in this manner. Taking an average of these marginal costs for each month, and accounting for the miscellaneous costs in Table 9-2, results in the figures shown in Table 9-3. The procedure for allocating the miscellaneous costs is described in Appendix F.

Table 9-3 Adjusted Prices for the Case Where the Probability of a Peak Occurring During Summer is the Same as During Winter

Voltage Level (Time-of-Day)	Price (¢/kWh)		
	Winter	Summer	Spring/Fall
Low Voltage - (All Day)	3.04	3.02	1.66
Primary Voltage - (All Day)	2.63	2.61	1.62
High Voltage - (Peak)	4.11	4.11	--
High Voltage - (Off-Peak)	1.55	1.52	1.59

Although Table 9-3 shows a slight variation between summer and winter prices, it is due to a small difference in energy costs and does not account for any differences in the probability of a peak occurring between summer and winter. High-voltage peak prices exceed low-voltage prices because the low-voltage tariff is an average of peak and off-peak marginal costs. The increase in the off-peak prices is due to the inclusion of some miscellaneous costs from Table 9-2.

Unequal Probability of a Peak Occurring

Marginal cost calculations can also be used to construct a tariff if a peak is more likely to occur in the summer peak demand hours than during similar winter peak hours. As an illustration we have formulated a tariff by assuming excess demand twice as likely to happen in summer as in winter. Accordingly, the capital costs of Chapter 8 ($/kW) are apportioned among the 1352 hours so that each summer hour receives twice the costs attributed to each winter hour. The peak and off-peak costs are averaged together for each season and voltage level; this yields the average prices shown in Table 9-4. The miscellaneous costs have also been included.

Table 9-4 Adjusted Prices for the Case Where the Probability of a Peak Occurring is Twice As Likely During Summer As During Winter

Voltage Level (Time-of-Day)	Price (¢/kWh)		
	Winter	Summer	Spring/Fall
Low Voltage - (All Day)	2.59	3.47	1.66
Primary Voltage - (All Day)	2.30	2.93	1.62
High Voltage - (Peak)	3.29	4.81	--
High Voltage - (Off-Peak)	1.55	1.52	1.59

The effect of assigning a different probability to a summer versus a winter peak is to make the summer prices 20 to 34 percent higher than those prevailing in the winter. A significant portion of the benefits of peak-load pricing may be captured with this type of a pricing plan. Since it is an easy plan to implement, we recommend that a seasonal pricing policy be carefully considered by the PUCO and the utility companies.

Revenue Requirement

The primary information needed to assess the revenue generated by our two tariffs is the number of kilowatt-hours sold in each pricing category. For 1975, this information is available for residential customers. Commercial and industrial customers, however, receive electricity at various levels of voltage; we do not as yet know how the total is divided among them. According to the 1975 DP&L annual report, about 80 percent of commercial users are general service subscribers, which is a low voltage service. Therefore, 80 percent of the total commercial sales was assumed to be delivered at low voltage. with the remainder delivered at primary voltage. Similarly, most industrial customers are general service subscribers; 80 percent of the total industrial sales was also deemed low voltage, with the remainder (about 7 percent of the system total) designated as high voltage. The high voltage users are the only subscribers for whom time-of-day metering may be considered practical. Having no further information, we arbitrarily assumed that 60 percent of high voltage use occurs during peak hours, with the remaining 40 percent allotted to nights and weekends. Given these assumptions, Table 9-5 shows the total kWh's sold in 1975.

When the electricity consumption shown in Table 9-5 is priced using the tariffs described in the previous section, including the median customer cost shown in Table 9-1, the resulting revenue is shown in Table 9-6. In Table 9-6,

Table 9-5 DP&L Kilowatt-Hours Sold in 1975 Classified According to Customer Class, Voltage Level, and Time-of-Day

Customer Category	Sales (1,000,000 kWh)			
	Winter	Summer	Spring/Fall	Total
Residential LV*(All Day)	1236.5	948.4	952.1	3137.0
Commercial LV (All Day)	449.3	469.8	421.8	1340.9
Commercial PV (All Day)	112.3	117.4	105.5	335.2
Industrial LV (All Day)	638.0	674.1	674.3	1986.4
Industrial HV (Peak)	95.7	101.1	---	196.8
Industrial HV (Off-Peak)	63.8	67.4	168.6	299.8
Total Sales	2595.6	2378.2	2322.3	7296.1

*LV: Low Voltage

PV: Primary Voltage

HV: High Voltage

Table 9-6 Revenues Recoverable by the Tariffs of Tables 9-3 and 9-4 ($1,000,000)

Case where peak is equally as likely to occur in Summer as in Winter				
Customer Class	from kWh Sales	from Customer Charges	Total	% of 1975 Actual Revenue
Residential	82.0	28.4	110.4	101.5
Commercial	42.6	3.2	45.8	84.2
Industrial	64.8	1.5	66.3	111.6
Totals	189.4	33.1	222.5	99.9

Case where peak is twice as likely to occur in Summer as in Winter				
Customer Class	from kWh Sales	from Customer Charges	Total	% of 1975 Actual Revenue
Residential	80.7	28.4	109.0	100.4
Commercial	42.6	3.2	45.9	84.3
Industrial	64.8	1.5	66.3	111.6
Totals	188.1	33.1	221.2	99.4

the first column shows the revenue collected from kWh sales, while the second column gives the revenue which results from the customer charge. The annual customer charge is \$77.82 for a low voltage user and \$8085.12 for a high voltage user; 171 of these are industrial customers, while 59 are commercial users.

Table 9-6 shows that the overall revenue generated by both tariffs is very close to the \$222.55 million that DP&L actually earned in 1975 from the three classes of users. Also, the revenue from residential consumers is very similar to that actually received in 1975. Industrial consumers pay somewhat more under our example tariffs than they did in 1975. This could easily occur because of the inaccuracies inherent in our assumptions about the distribution of kWh sold by voltage level and time-of-day. Commercial customers, on the other hand, have a smaller total bill under our scheme than they did in 1975. In fact, it is so much smaller, that the figure does not seem to be attributable to our arbitrary assignment of 80 percent of all kWh to the low voltage (expensive) category. Even if all kWh were priced at low voltage rates, commercial revenue would be only 87 percent of its 1975 total. Our treatment of customer costs does not distinguish among low voltage users. It is possible that by properly accounting for the cost of demand meters (needed under the general service rate schedule), a small amount of additional revenue could be generated. The most likely reason that commercial customers actually pay more than they would under our schedule, however, is probably related to the nature of the general service rate schedule. As shown in the next section, this schedule penalizes users having a low load factor (the ratio of average to peak kW), while it helps those whose load factor is high. If most commercial customers have low load factors, they would then pay more for electricity; possibly, this would be enough of a difference to explain the results of Table 9-6.

Since the revenue generated by our tariffs is quite similar to the overall revenue needs of DP&L, no further price adjustments have been made. If this were not so, revenues could be collected by adjusting the customer charge or the kWh price. As discussed previously, our first preference would be to adjust the customer charge. During the interim period when the customer charge is initially introduced, however, it may be unwise to frequently change this component of the customer's bill. Given that the flat kWh charge is the only component remaining, it could be adjusted in equal proportion for all customer classes until better information about demand elasticities is available.

Typical Bills for Residential and General Service Customers

The tariffs which were calculated in this chapter are comprised of a customer charge and a flat charge for each kWh consumed. This is sometimes called a two-part tariff. In this section, a comparison is made between the typical bills associated with one of our tariffs and those associated with the tariff structure used currently.

Although the previous section discussed a low voltage customer charge of $77.52 per year, or $6.46 per month, it does not seem prudent to institute such a charge immediately. In this section, we calculate a customer's typical bill assuming that the customer charge is set at $2 per month during some interim period.

The DP&L tariffs available to our study group were dated January 16, 1975. DP&L's revenue for 1975, however, did not entirely result from these published tariffs. The fuel adjustment clause accounted for some revenue above that available from the published base rates. To compare our tariff with those used currently, we require that both tariff structures yield similar amounts of revenue. By making some simple, plausible assumptions about the distribution of kWh used by residential and general service customers, we found that the published base rates would yield about $169.6 million, using Table 9-5. After subtracting $9.3 million generated by the annual $24 customer charge, our flat kWh charge would need to generate only $160.3 million; actually, it generates $170.8 million. To make the schedules comparable, we have chosen to reduce our kWh rates by about 6%, because we could not adjust DP&L's published declining block structure in a similar manner. Consequently, we are using a two-part tariff in this section, which is quite different from that of the previous section. The tariffs given in Table 9-7 are for low voltage users only.

Table 9-7 Tariffs which Yield Approximately The Same Revenues As DP&L's 1975 Rate Schedules for Residential and General Service Customers

Case where peak is equally as likely to occur in Summer as in Winter			
Monthly Customer Charge ($)	Added kWh Charge (¢/kWh)		
	Winter	Summer	Spring/Fall
2.00	2.90	2.88	1.60
Case where peak is twice as likely to occur in Summer as in Winter			
Monthly Customer Charge ($)	Added kWh Charge (¢/kWh)		
	Winter	Summer	Spring/Fall
2.00	2.49	3.32	1.61

Tariffs taken from Table 9-7 are used in Table 9-8 to calculate typical monthly bills for kWh usage varying from 100 to 3000 kWh per month. The average DP&L customer used about 735 kWh per month during 1975. Under the first tariff (Bill (1)), the peak is equally probable in summer and winter. Therefore, the bills that are about the same as those based on DP&L rates in the summer, for moderate use, are significantly lower in spring and fall and somewhat higher in winter. If a summer peak is twice as likely, the second tariff (Bill (2)) shows that winter bills, while reduced, still exceed current DP&L bills for large kWh users. Summer bills are higher under the second tariffs, but at

Table 9-8 Bills Based on Tariffs which Yield Approximately the Same Revenue As DP&L's 1975 Rate Schedules for Residential and General Service Customers

Usage (kWh)	Summer Bill ($) Old*	Summer New (1)	Summer New (2)	Winter Bill ($) Old	Winter New (1)	Winter New (2)	Spring/Fall ($) Old	Spring/Fall New (1)	Spring/Fall New (2)
100	4.62	4.88	5.32	4.62	4.90	4.49	4.62	3.61	3.61
200	8.12	7.75	8.64	8.12	7.80	6.98	8.12	5.22	5.22
300	11.02	10.63	11.96	10.32	10.70	9.47	10.67	6.83	6.83
400	13.92	13.50	15.28	12.52	13.60	11.96	13.22	8.44	8.44
600	19.72	19.26	21.93	16.92	19.39	16.93	18.32	11.67	11.67
800	25.12	25.01	28.57	20.87	25.19	21.91	22.00	14.89	14.89
1000	29.32	30.76	35.21	23.47	30.99	26.89	26.40	18.11	18.11
1500	39.82	45.14	51.82	29.97	45.49	39.34	34.90	26.17	26.17
2000	49.82	59.52	68.42	36.47	59.98	51.78	43.15	34.22	34.22
2500	59.82	73.90	85.63	42.97	74.48	64.23	51.40	42.28	42.28
3000	69.82	88.25	101.63	49.47	88.97	76.67	59.65	50.33	50.33

* Old Bill is based on DP&L's 1975 rate schedules for residential customers. Bill (1) is based on an equal probability of a peak occurring in the summer as in the winter, and bill (2) is based on a summer peak being twice as likely, both shown in Table 9-7.

average consumption levels the increase is only about 13 percent. This increase is reasonable for a tariff containing a high degree of seasonal variation, as compared with the small variation contained in the DP&L rates. The second tariff offers a reduction in spring and fall bills similar to that of the first.

The second tariff is attractive, except for the high bills for large users during the winter. For daily consumption occurring during the off-peak period, the kWh rate of 2.49¢ seems inappropriately higher than running costs, especially for all-electric homeowners, who consume electricity in large amounts during the night.

This rate structure flaw can be corrected by offering all-electric homeowners an optional time-of-day tariff. The peak periods would be the same as those imposed on industrial customers. If they chose such a time-of-day tariff, they might pay either for the installation of the meter immediately so that capital costs could be collected (customer purchase of the meter), or, through a specially-designed customer charge (customer rental of the meter).

Typical bills for general service customers, commercial or industrial, are more complicated; currently, they include both a demand (kW) charge and a commodity (kWh) rate. Consequently, the customer's bill depends upon his load factor, defined as the ratio of average to peak kW use. As the load factor increases, the customer's load becomes flatter. A tariff containing a kW charge encourages the user to increase his load factor by leveling his load. This encouragement occurs currently regardless of whether an individual user's peak demand occurs at 3:00 a.m. (off-peak) or 3:00 p.m. (peak). To this extent, the kW charge does not provide correct economic signals, because it provides the same incentives during off-peak periods as it does during peak periods.

In Table 9-9, examples of typical bills for the 1975 DP&L General Service Rate Scheduel (Sheet No. 32) are compared with results from our example tariffs. In the summer, the first tariff (Bill (1)) is somewhat more expensive for users with a high load factor. This is emphasized during the winter months; however, the spring

Table 9-9 Typical Monthly Bills for General Service Customers Based on Old and New Tariffs*

Usage (1000 kWh)	Old Bill ($) Load Factor (%) 30%	60%	90%	New Bill ($) (1)	New Bill ($) (2)
Summer					
5	165.61	139.02	129.94	145.80	168.05
10	325.39	275.61	258.10	289.60	334.10
15	485.14	410.49	385.61	433.40	500.15
20	644.91	545.39	512.19	577.20	666.20
25	804.64	680.22	638.75	721.00	832.25
Winter					
5	152.05	139.37	120.54	146.95	126.45
10	255.06	222.65	207.96	291.90	250.90
15	357.46	308.85	292.65	436.85	375.35
20	459.87	395.06	373.44	581.80	499.80
25	562.28	481.26	454.25	726.75	624.25
Spring/Fall					
5	158.83	134.15	125.24	82.00	82.55
10	290.23	249.13	233.03	162.00	163.10
15	421.30	359.67	339.13	242.00	243.65
20	552.39	470.23	442.82	322.00	324.20
25	683.46	580.74	546.50	402.00	404.75

* Old Bill was taken from a DP&L 1975 general service rate schedule (Sheet No. 32). Bill (1) is based on an equal probability of a peak occurring in the summer as in the winter. Bill (2) is based on a summer peak being twice as likely.

and fall bills are reduced under the first tariff. The second tariff (Bill (2)) has the desired effect of providing increased summer, but reduced winter, bills. Not surprisingly, Table 9-9 clearly shows that low load-factor users would benefit from the two-part tariff, while high load-factor customers may pay more--although the spring/fall rates makes it unclear at which point this happens. General service customers having high-load factors, e.g. grocery stores, must run machinery all night. To the extent that such customers would benefit from time-of-day pricing, the utility could provide an appropriate operational schedule in which the customer pays for the meter.

Demand Charges with Time-of-Day Tariff

More than 30,000 of DP&L's customers receive bills reflecting a demand charge, which is based on maximum kW demand, as well as a commodity (kWh) charge. We are skeptical of the economic efficiency of demand charges; nevertheless, we recognize that an abrupt abandonment of this tariff form could have an adverse effect on the frequency of rate hearings requested of the PUCO. This would occur because of the shock to consumer expectations about the permanence of such charges. If demand charges are used during an interim period, suggestions concerning tariff construction can be developed from this peak-load pricing study.

Although obvious, it must be emphasized that demand charges should be based on capital costs. Because a peak-load pricing policy allocates most capital costs to that period defined as peak, any demand charges used should be confined to the peak period. For example, if kW demand is recorded by an indicating demand meter, the kW indicating needle should be activated only during the peak period. This would include about 170 hours in each of the eight months designated as peak in our example. Also, during those 170 peak hours, a different watt-hour meter should be activated, as peak costs differ from off-peak costs. For most customers possessing demand meters, such an arrangement could not feasibly be made; therefore, we suggest that the demand charge be phased out quickly.

For those customers possessing meters capable of recording kW demand by time-of-day, the kW charge could be continued for an interim period at the discretion of the utility. If further study does not establish the economic efficiency of demand charges, we would recommend that they be abandoned. This transition period would enable most customers to prepare for the eventual flat kWh rate with a minimum of adjustment costs.

If demand charges are confined to the peak period, their character will differ from that to which industrial customers are now accustomed. Should large power users be charged for the peak demand occurring during peak system hours, the implication for their bills differs from the current situation. Currently, the demand charge is calculated using the customer's own peak demand (kW) during the month, regardless of when it occurred. The price which the utility charges ($/kW) must account for the system's coincidence factor, which is the ratio of peak system demand to the sum of individual customer demand. The coincidence factor is less than 1.0 and acts to reduce the demand (kW) charge. If it is not factored into the demand charge calculation, the utility would receive excess revenue, as the aggregate of individual peak (kW) demand is greater than the system's capacity because of the noncoincidence of individual peaks.

The relevant coincidence factor is that for the period during which the customer's (kW) demand is monitored. Since demand is currently metered all day, the coincidence factor is the ratio of his average to peak (kW) demand. As shown in Appendix F, a customer would prefer a billing method which includes a demand (kW) charge over one which has only a commodity (kWh) rate, if his own load factor is greater than the system's coincidence factor. Because the relevant coincidence factor is currently low, many customers are likely to prefer demand charges.

Should demand charges be restricted to customer demand which occurs during a more narrowly defined peak period, the relevant coincidence factor is likely to be greater. Accordingly, the opportunity in this case for customers to reduce their bills is less than with a simple commodity (kWh) rate. More importantly, a larger number of customers will find that they are paying higher bills under a demand charge tariff than they would be paying were the demand charge dropped. With the attractiveness of the demand charge diminished, the utilities may find that some of their large power users would prefer the simpler time-of-day tariff containing only commodity (kWh) rates.

CHAPTER 10

SUMMARY OF RECOMMENDATIONS

The major purpose of this electricity pricing study was to identify appropriate objectives of electric rate design, to specify rate structures that meet these objectives for eventual adoption, and to suggest guidelines that can be used to establish a timetable for implementing these rate structures.

Rate Design Objectives

We recommend that economic efficiency be the fundamental objective of electric rate design. Electricity prices, like all prices, play a crucial role in the allocation of resources. Since economic efficiency implies the best allocation of resources, electric rates must be designed so as to promote it. Furthermore, these rates should be designed within the constraint imposed by the revenue requirement.

Secondary objectives are not precluded. The decision to incorporate them should be made using as a yardstick the costs involved in deviating from the most efficient rate design.

Eventual Rate Structures

We recommend that eventually all electric rates in Ohio be equal to marginal costs, so as to achieve economic efficiency. More specifically, we recommend that long run marginal costs be the basis for rate design.

We conclude that the electric rate design which best achieves economic efficiency would have the following characteristics:

1. Customers would be classed according to the voltage level at which they receive electricity and according to their location. Differences in rates among classes would be based on differences in the marginal costs of service for the various voltage and locational classes.

2. The electricity tariff for each customer class would contain a monthly customer charge in addition to rates for electricity use. This charge would be based on the marginal cost of including another customer from that class in the utility system.

3. The electric rates would be different for the various seasons. Rate differences would be based on seasonal differences in marginal costs.

4. The electric rates would be different at various times of the day. Rate differences would be based on daily variations in marginal costs.

5. During any one time period, the rate for each customer class would be fixed. Price would not depend on the amount of electricity consumed; there would be no declining block rate structure. The price for that time period would equal the marginal cost of serving that customer class at that time.

We have not yet concluded whether it would be economically efficient to include a demand charge in these tariffs.

Tariffs based only on marginal costs would probably not meet the revenue requirement. In this case, we recommend that customer charges be adjusted up or down as necessary. In the event that customer charge adjustments are considered excessive, only then would rates be allowed to deviate from marginal costs.

Implementation Guidelines

We do not recommend that all the rate structure characteristics listed above be implemented immediately for all customer classes. We do recommend that evaluation of the benefits and costs of implementing each characteristic for each customer class be initiated. A starting point would be for the PUCO to require all Ohio electric utilities to calculate the long-run marginal cost of service for each customer class.

In our view, implementation of each rate structure characteristic for each class should take place when it is found that the benefits exceed the costs for that class. We recommend this policy of gradual implementation even though the benefits from implementing these rate structure features may be greater if they are adopted collectively rather than piecemeal.

The initial steps toward implementing the above rate structure characteristics might be the following:

1. For low and intermediate voltage electricity users:
   - (a) implement seasonal prices,
   - (b) provide the option of time-of-day pricing,
   - (c) develop an information program to assist users in making the optional time-of-day decisions, and
   - (d) gather data concerning consumption patterns under the new pricing policies to aid in future policy decisions.
2. For high voltage users:
   - (a) implement seasonal prices,
   - (b) implement time-of-day pricing with a broad definition of the peak period, and

(c) gather data concerning consumption patterns under the new pricing policies to aid in future policy decisions.

The second intermediate step toward complete adoption of a rate design with all the characteristics might be to institute, with those customer classes for whom time-of-day pricing is not yet cost-effective, a tariff with a customer charge and a flat rate based on long run marginal cost.

Partly because of the need for gradual implementation, we recommend that generic hearings on marginal cost pricing be avoided. Furthermore, a great deal of expert testimony on this issue has already been given at such hearings in other states.

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