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An Economic Analysis of the Electric Utility Sector in the Ohio River Basin Region: Phase II

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ABSTRACT

This research project had two major tasks. The first task involved a review of the literature on the demand for electricity. In the review attention was placed on the theory of electricity demand and the specification of various electricity demand models. The results of a number of national and regional studies are summarized in the report. Based upon this review two sets of estimates of various elasticities of electricity demand in the six state region centered on the Ohio River Basin were presented. The first set of estimates is based upon the "best" estimates of the various elasticities from national studies while the second set of estimates is derived from a recent Oak Ridge National Laboratory study. Both sets of estimates incorporate salient characteristics of electricity demand in the six state region.

The second task involved an examination of the implications of various regulatory pricing policies on the electricity utility sector in the Ohio River Basin Energy Study (ORBES) region. The current regulatory environment affecting electric utilities and historical patterns in electricity demand and price are reviewed in the report. Next, attention is directed toward three alternative regulatory policies regarding electricity pricing including traditional average cost pricing, marginal cost pricing and time differentiated (peak load) pricing. The potential effects of these different pricing mechanism on capacity requirements, load factors and fuel costs are examined with particular attention placed on their implications for the ORBES region.

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SECTION 1

INTRODUCTION

There are two research tasks discussed in this report. The first involved reviewing the literature on the demand for electricity; particular attention was directed at developing estimates of elasticities of electricity demand for the six states region centered on the Ohio River Basin. The second involved examining the implications of increasing electricity prices as well as the regulatory restructuring of prices; particular attention was directed at viewing the potential effects of marginal cost and peak load pricing for the electric utility sector in the ORBES region.

In Section 2 of this report, the theory of the demand for electricity is reviewed with attention to the development of models of electricity demand and the specification of variables included in such models. Attention is placed on the measurement of the elasticity of demand which is the responsiveness of the quantity demanded to changes in either prices or incomes. This is followed by a summary of the elasticities of electricity demand derived from numerous studies. Attention is devoted to both national and regional estimates of price and income elasticities for kwh demand. Finally, two sets of estimates of the elasticities of kwh demand for the six states region are presented. The investigator having primary responsibility for the research in Section 2 is Tom S. Witt.

In Section 3 of this report, the present state of electricity regulation is examined. There is a review of the historical relationship between electricity prices and the several factors theoretically associated with electricity prices. Several alternative pricing methods are examined including traditional average cost pricing (where prices are equal to the average cost of electricity production), marginal cost pricing (where prices are equal to the increment in the cost of producing additional electricity), and peak load pricing (where prices are based on the time of day when the electricity is demanded as well as either average or marginal costs of production). The potential effects of time differentiated pricing in terms of utility cost savings are also evaluated. Finally, capacity and load reduction effects from time differentiated electricity rates are estimated for both the six states region and the ORBES region. The investigator having primary responsibility for the research in Section 3 is Patrick C. Mann.

The research discussed in Section 2 and 3 can be viewed as complementary. The elasticity estimates provide valuable information for the further task of attempting to determine the growth and patterns of electricity consumption over the next several decades. Similarly, the information on regulatory reform and the empirical results from previous peak load pricing experience provide insight into future electricity consumption patterns.

SECTION 2

ESTIMATES OF THE ELASTICITIES OF DEMAND FOR ELECTRICITY IN THE SIX STATES REGION

This task of the research project involved reviewing the literature on the demand for electricity and generating estimates of various demand elasticities for a six state region centered around the Ohio River. This region, composed of the entire states of Illinois, Indiana, Ohio, Pennsylvania, Kentucky and West Virginia, is used as an approximation to the ORBES region since data for the former was more readily available.

In this section of the report we first present the various definitions and interpretations of demand elasticities utilized in the remainder of the report. This is followed by a review of the theory of electricity demand. In this review attention is not only placed on the economic theory of the demand for electricity but also the development of electricity demand models and the specification of variables included in these models.

The next part of this section summarizes the estimates of the elasticities of electricity demand from a number of national studies. Based on this review we present our "best" estimates of the national short- and long-run price and income elasticities of electricity demand. Following this is a review of regional studies of the demand for electricity. A major portion of this review emphasizes a recent Oak Ridge National Laboratory study which generates demand elasticities for each census region in the United States.

The last part of this section presents two set of estimates of demand elasticities for the six state region. The first set of estimates is based upon the "best" estimates of national elasticities while the second set of estimates is based on the census region estimates from the Oak Ridge study. Both sets incorporate salient characteristics of electricity demand in the six state region. In addition, some implications from the Oak Ridge study for growth rates in electricity demand, costs and prices are also presented for comparison with other ORBES studies.

DEFINITION AND INTERPRETATION OF DEMAND ELASTICITIES

The general theory of demand for a commodity states that the quantity demanded of the commodity during a particular time period depends on the price of the commodity, the income of the potential purchaser and the prices of all other goods, among other factors. Although there are potentially a large number of factors affecting the demand for a commodity, prices and incomes are the most important determinants of demand and, thus, are of interest to economists. Over time many of the other factors affecting demand, such as tastes and preferences, are relatively stable. In large part this interest arises due to the need to understand the responsiveness of demand to changes in prices and incomes in the market place. For example, by specifying a particular price for the commodity, a particular income for the potential purchasers and specific prices of other goods, an economist could predict the quantity of good demanded.

Economists utilize various elasticity definitions to measure the responsiveness of demand to changes in prices and income. The price elasticity of demand, η_{ij}, measures the percentage change in the quantity demand of good i with respect to a one percent change in the price of good j, all other things unchanged.

The general formula is

$$\eta_{ij} = (\Delta q_i / \Delta p_j) - (p_j / q_i)$$

when Δq_i = change in the quantity demanded of good i

Δp_j = change in the price of good j

q_i = quantity demanded of good i

p_j = price of good j

The own price elasticity refers to a situation where i and j refer to the same good; on the other hand, the cross price elasticity refers to a situation where i and j are different goods. For example, if i and j refer to gasoline, then a price elasticity of gasoline demand equal to -.2 means the quantity of gasoline demanded will fall twenty percent in response to a one hundred percent increase in the price of gasoline, all other things unchanged.[1] If i refers to gasoline and j refers to diesel, then a cross elasticity of gasoline demand with respect to diesel fuel price of +.2 means the quantity of gasoline demanded will increase 20 percent in response to a 100 percent increase in the price of diesel fuel, all other things unchanged.

The following terms are associated with specific own price elasticity of demand magnitudes: perfectly elastic, $\eta_{ij}=-\infty$; elastic, $-\infty<\eta_{ij}<-1$; unitary elastic, $\eta_{ij}=-1$; inelastic, $-1<\eta_{ij}<0$; and perfectly inelastic, $\eta_{ij}=0$. These terms can be used to related changes in total revenue to changes in price. If the own price elasticity of demand is elastic (inelastic), an increase in the price of electricity will lead to a decline

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[1]Additional examples can be found in any introductory principles of economics textbook.

(increase) in the firm's electricity sales revenues. In general economic theory leads to an expectation of own price elasticities of zero or less; in actual empirical work an own price elasticity greater than zero is an indication of either an incorrectly specified model or errors in the data utilized in the estimation of the model.

Another elasticity measure of interest is the income elasticity of demand for good i, η_{iy}, which measures the percentage change in the quantity of good i demanded with respect to a one percent change in the income y of the consuming unit, all other things unchanged.

The general formula is

$$\eta_{iy} = (\Delta q_i/\Delta y)\cdot(y/q_i)$$

where Δq_i = change in the quantity demanded of good i

Δ_y = change in income of the consuming unit

q_i = quantity demanded of good i

y = income of the consuming unit

If the income elasticity of demand is less than zero, then the good is said to be an inferior good; on the other hand, if the income elasticity of demand is greater than zero, then the good is said to be a normal good. Since all energy sources are normal goods, then their income elasticities will be positive. If the income elasticity of demand for gasoline is +0.6, then a one hundred percent increase in income would be associated with a sixty percent increase in the quantity of gasoline demanded.

In measuring the price and income elasticities of demand one must distinguish between short-run and long-run elasticities for certain types of goods and services. The degree of demand responsiveness to price or income changes varies directly with the amount of time a consuming unit has in order to make adjustments in its purchased bundle of goods and services in response to a change in price or income. For example, the price elasticity of demand for gasoline is relatively inelastic (i.e. less responsive) in the short-run since it is difficult to adjust the stock of automobiles in a short period of time in response to a change in the price of gasoline. The only adjustments available in the short-run in response to an increase in the price of gasoline is to reduce the level of usage of automobiles. In the long-run the price elasticity of demand for gasoline is more elastic since consuming units not only can alter their level of usage of automobiles in response to an increase in the price of gasoline but they can also scrap existing inefficient automobiles and purchase more efficient automobiles in response to an increase in the price of gasoline. In general, the long-run price and income elasticities of demand are more elastic (i.e. greater in absolute value) than the corresponding short-run elasticities since consuming units have more flexibility and alternative goods available in the long-run.

These concepts of price and income elasticities of demand are utilized extensively in the remainder of this study in describing the measurement and interpretation of estimates of the elasticity of demand for electricity.

THE THEORY OF DEMAND FOR ELECTRICITY

The demand for electricity is a derived demand which depends on the demand for the services provided from an electricity utilizing capital stock (such as lights, refrigerators, motors, etc.). The short-run demand for electricity assumes the stock of electricity utilizing capital stock to be fixed and focuses on the factors which cause changes in the utilization rate of this capital stock. The long-run demand for electricity focuses on the factors which cause changes in the demand for the electricity utilizing capital stock. Since the short-run demand does not allow for substitution among capital stocks utilizing different energy sources, it is more inelastic with respect to price and income than the long-run demand.

It should be noted that, in addition to the effects of the capital stock on the demand for electricity, one must also consider the role of the price of electricity, the prices of substitute energy sources, and the income of the purchasing unit, among other factors, in fully specifying the demand for electricity. In the next section the problems involved in the measurment of the appropriate quantity, prices and incomes are discussed while in subsequent sections we outline some of the explicit models of electricity demand which have been utilized in the literature. It should be noted that there have been a number of excellent reviews of this literature in recent years, and, as a consequence, we only review the major issues in this section (Taylor, 1975; National Economic Research Associates, Inc., 1977; J. W. Wilson & Associates, Inc., 1978; Edmonds, 1978).

Measurement of Electricity Quantities and Prices

One specification of the quantity of electricity demand utilizes the number of kilowatt hours (kwh) over a given time period. Although this specification is widely used, it can result in an aggregation error in the estimated models if consumers perceive kwh purchased at different time of day and seasons of the year as different commodities (Electric Utility Rate Design Study, 1977). The only instance when such aggregation error is not present occurs when the marginal prices of electricity at different points of time change in the same proportion. To the extent that such changes occur but are not proportional, the estimated price and income elasticities of kwh demand will be biased.

Models which utilize measures of kwh demand are useful in forecasting revenues when prices or income change; however, they cannot be utilized to predict either demand changes due to rate structure alterations or the optimum scale of electricity generating plant required at some future time period (J. W. Wilson & Associates, Inc., 1977).

Another specification of the quantity of electricity demanded utilizes the number of kilowatts (kw) purchased at a given point in time. For example, one could have two utilities with the same kwh demand during a given period of time but with substantially different kw demand patterns. In this case one would say that the two utilities have substantially different load factors. Models of kw demand can be used to forecast the optimum scale of electricity generating plant required during some future time period.

In many applications where the interest focuses on changing the rate structures to alter the quantity of electricity demanded, one should examine the kw demand by time of day or season of the year. Such examinations not only allow one to evaluate the demand effects of different rate structures which incorporate peak load pricing of one form or another (in which the price of electricity is higher at high kw demand than at low kw demand) but also allow forecasts of revenue effects of such rate structures and electricity generation capacity requirements (National Economic Research Associates, Inc., 1977). One way of examining this is to distinguish between the peak and off-peak demand for electricity. Unfortunately, data on peak and off-peak demands by customer class is not readily available except by conducting specialized surveys National Economic Research Associates, Inc., 1977).

In studies of the demand for electricity considerable attention has been directed toward the specification of the price variables to be utilized in the models. In theory the appropriate price should be the marginal price which is the additional amount of money a customer must spend in order to consume an additional unit of electricity. In actual practice electricity customers face a declining block schedule in which the marginal price declines as the quantity consumed increases from one block or level of consumption to another.[2] The theoretical implications of the declining block schedule on the specification of the price variable in the demand schedule has been extensively examined in the literature (Taylor, 1975; Taylor, Blattenberger, and Verleger, 1977). The conclusions of this literature is that both marginal and average price measures of electricity should be included in the demand function. In both cases the price variables should be calculated from the actual tariff schedules of the utility and not from ex post measures (as it is commonly done in the literature). It has been argued:

> The marginal price should refer to the last block consumed in, while the average price should refer to the average price per kwh of the electricity consumed up to, but not including the final block. Alternatively, the total expenditure on electricity up to the final

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[2]Residential bills typically have two components: a fixed charge which is independent of the amount of electricity consumed and a kwh change which is a declining block charge based on the level of usage. In general, non-residential customers also have a kwh charge which is based on the kw of installed capacity utilized at the time of maximum demand by customer.

block can be used in place of the average price. Whichever quantity is used, the variable will measure the income effect arising from intramarginal price changes, thus leaving the price effect to be measured by the marginal price. The omission of one of these two prices will lead to specification errors and biased estimates of the coefficients of other variables which are correlated with the omitted variable (Taylor, 1975, p. 80).

Although this is the proper specification of the price variable, few studies of the demand for electricity have utilized this specification. Those studies which utilize this specification (Taylor, Blattenberger and Verleger, 1977; Acton, Mitchell and Mowill, 1975) have confirmed the superiority of this specification of price in the demand function. Alternatively, many studies have utilized the average price as calculated ex post by dividing total expenditures by quantity of electricity consumed (Fisher and Kaysen, 1962; Baxter and Rees, 1968, Houthakker and Taylor, 1970; Mount, Chapman and Tyrrell, 1973; Lymann, 1973; Griffin, 1974; Baughman and Joskow, 1974; Uri, 1975; Chern 1976; Chern, et al., 1978; and others). As Halvorsen has shown, such a procedure leads to the introduction of simultaneity and problems in the identification of the demand schedule (Halvorsen, 1978). Given the demand schedule for electricity, the existence of the declining block tariff implies that the customer faces a downward sloping supply schedule since the average price of electricity declines as the quantity of electricity supplied increases. Consequently, without prior restrictions or additional information, one cannot disentangle the demand curve from the supply curve.

One possible solution is to include in the supply and demand schedules variables which are excluded from the other schedule. With this specification some studies estimate the parameters in a simultaneous equation model using average price and quantity of electricity as endogenous variables (Wilder and Willenborg, 1975; Chern, et al., 1978; Halvorsen, 1978).

An additional justification for the use of average price is due to the nature of the payment for electricity by customers. It can be argued that customers are rarely aware of the true marginal price of electricity since they pay at the end of some billing period and are never aware of the point in time when they switch from one consumption block to another. In addition, if one is interested in forecasting average price, the use of a marginal price variable will require forecasting the entire rate schedule which is more difficult than forecasting the average price.

One complication in this specification of the average price simultaneous equation model is that the demand schedule is not a function but is simply one point on the corresponding supply schedule. That is to say, a given rate schedule only gives one equilibrium quantity and average price per customer. A complete demand function in the usual sense, it is argued, requires a family of rate schedules which rarely exists for a given utility (Taylor, Blattenberger and Verleger, 1977).

Another approach utilizing marginal prices involves calculation them from records of the typical bills of customers for different levels of kwh demand.[3] Unfortunately, this procedure is invalid in that the kwh quantities from the typical bills blocks are not the actual quantities consumed by the customer and, thus, represent biased estimates of the true declining block marginal prices of electricity. These prices also understate the actual price to the customer since they exclude certain taxes collected by utilities which vary among utilities (J. W. Wilson & Associates, Inc., 1977). An additional complication is due to the inclusion of changes in customer fixed charges and intramarginal rates in the calculated marginal price from these bill (Taylor, Blattenberger and Verleger, 1977).

In conclusion, the theoretically superior price variable would include both the marginal price and average price while in actual practice the use of average price is justified within the context of a simultaneous equation model. Elasticity estimates for these and similar prices are presented later in this section.

Measurement of Income and Output

A less difficult problem in the specification of electricity demand models has been the measurement of income. In the case of residential customers most studies have utilized some measure of per capita or family income which is readily available for the various observational units used in the analysis. In the case of commercial customers, researchers have generally used the same per capita or family income measures used in the corresponding residential study. It should be noted that the linkage between per capita or family income and the demand for electricity by commercial customers is much more indirect than residential customers. An alternative in the case of commercial customers would be the use of a value added measure similar to that utilized for the industrial customers; however, this has not been utilized for commercial customers due to inadequate data. In the case of industrial users, the studies reviewed utilize some measure of value added so that instead of an income elasticity of demand such studies generated an output elasticity of demand. In conclusion, there are fewer conceptual and empirical problems associated with the specification of the income or output component in contrast to the price variable.

Empirical Models of Electricity Demand

The discussion thus far has focused on the specification of the major factors examined in a variety of studies on the demand for electricity. In these studies researchers have utilized four types of models of the demand for electricity.

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[3]Statistics on the typical electric bills of different customer classes for different demand levels are published yearly by the Federal Power Commission.

Underlying an autoregressive model that relates the dependent variable in time t to its value in time t-1 and a set of independent variables is a distributed lag model which relates the dependent variable at time t to the independent variables at time t and all preceeding time periods. In this distributed lag model which was popularized by Koyck (Maddala, 1977) the coefficients of the independent variables decline geometrically with the passage of time.

This type of autogressive model when applied to the estimation of the demand for electricity has the desirable property of generating both short- and long-run price and income elasticities of demand. The limitations of this specific model have been summarized by Edmonds:

> This type of model, and all of the lagged adjustment models suffer one serious weakness. None is explicitly derived from a theory of why adjustment costs exist in the first place. It has also been criticized, however, because Koyck lag structures require that the large response to any price change occurs in the first period, while each succeeding period has smaller responses (Edmonds, 1978, pp. 65-66).

In an attempt to circumvent the problems of geometrically declining coefficients in the Koyck distributed lag model, some studies have utilized the polynomial lag structure (Griffin, 1974) which allows for a more flexible albeit finite lag structure (in contrast to the Koyck infinite lag structure).

A fourth type of model utilizes a production function as a basic for examining the adjustment process for the factor inputs to the production process in response to changes in prices of all inputs, among other variables (Edmonds, 1978). This model not only makes explicit the interrelationships among all inputs used in the production process but it also allows one to examine the short- and long-run adjustment processes. Although this method is potentially promising it has only been used one (Halvorsen, 1976).

The models which we have briefly surveyed above represent some of the major types of approaches used in modeling the demand for electricity. As will be seen later in this report, some of the differences in the electricity elasticity estimates encountered in the literature are attributable to the differences in the specification of the models. In the interpretation of the elasticities presented below one should remember that each elasticity estimate assumes a different type of model and behavioral characteristics of customers.

Other Considerations in the Estimation of the Demand for Electricity

In estimating the demand for electricity, one has a wealth of information available due to federal and state electric utility reporting requirements; however, there are some other problems in the modeling of electricity demand. For example, our prior discussion above indicated the theoretical necessity of including marginal price in the demand function; in actuality, such price measures are not available in the published statistics and one must construct estimates. Problems also occur in the definition of other explanatory variables such as income and electricity utilizing capital stock. In addition, the existence of a substantial amount of data means that the individual investigators have to decide whether to utilize cities, states, nations, households, firms, or utilities as units of observations. The usage of more aggregative data raises the possibility of introducing aggregation error which could lead to biased estimates of the elasticities of interest (J. W. Wilson & Associates, Inc., 1977). In the case of state data, additional problems occur in that a number of states are served by more than one electric utility so there exists several different rate structures and prices confronting customers in each of these states. As will be seen later, a considerable amount of variation in the electricity estimates is associated with the different levels of aggregation utilized in the model estimation.

Another major question prior to estimation involves whether one should utilize time-series or cross-section data. If one is interested in obtaining estimates of the short-run elasticities of demand, it has been argued that time-series data is more appropriate since it allows for the dynamic adjustment process through time. In contrast, cross-section data has been proposed for the estimation of long-run elasticities since it reflects individual observation units in economic equilibrim. In the latter case differences among individual observation units reflect differences in long-run equilibrium positions. To the extent that one has both cross-section and time-series data, one can, it has been argued, estimate both short- and long-run elasticities through the use of various pooled econometric models. One should note, however, that there can be difficulties in the use of one type of data, cross-section or time-series, exclusively. For example, Taylor has argued that

> ...while the view that cross-sectional observations reflect steady state variation has some limited validity as a general tendency, it is not correct to say that cross-section data never reflect short-term, dynamic adjustments. For the latter will be represented to the extent that individual observation units (states, SMSA's etc.) are not all at the same point of disequilibrium arising from recent changes in income, prices, or other relevant factors. Since income and prices, in general, do not change at the same time across cities, states, and regions, differential disequilibria are almost certain to be reflected in the data. If these differential disequilibria are not allowed for explicitly-say, through the inclusion of appliance stocks or last period's consumption as a predictor-then the elasticities obtained will, in general, be downward biased estimates of long-run elasticities (Taylor, 1975, p. 103).

It also should be noted that a variety of functional forms can be used in the estimation of the models. One of the more popular functional forms is the double-log specification in which the quantity, price and income variables are expressed in terms of logarithms. In this model the estimated coefficients of price and income are the elasticities of interest. In this functional specification the elasticities are asumed constant over all ranges of prices and income; for example, a given percentage change in price will have the same percentage impact on the quantity demanded irregardless of the level of price. In contrast the linear specification of a model leads to elasticity estimates which vary with the price and income levels.

Finally, a variety of econometric methods have been used in the estimation of the demand models due to the variety of stochastic error terms, number of equations, existence of distributed lags and lagged endogenous variables, among others. Part of the variation in elasticity estimates can also be attributable to the choice of econometric method and computer program.

REVIEW OF ELASTICITY ESTIMATES: NATIONAL

Our discussion thus far indicates there are several approaches and problems in the estimation of the demand for electricity; however, the existence of several studies in this area suggests that many of these problems are surmountable. In this part we review the estimates of the price and income elasticities of kwh demand which have been generated in national studies. By national studies we simply mean studies which are not specific to a particular geographical area or utility service area. Such studies generally utilize either time series data on the United States as a whole or cross section data on states or SMSAs. The elasticity estimates are generally measured at the mean and thus refer either to the national average over a period of time or the average observational unit in the sample at a particular point in time. After reviewing these estimates for residential, commercial and industrial categories, we summarize the conclusions which have been drawn from these studies by other reviewers. Finally, we present our judgement as the "best" national estimates of kwh demand elasticities recognizing that these estimates are implicitly accompanied by a variance reflecting uncertainty. It should be noted that no estimates of kw demand elasticities are considered in this section.

Numerous studies have been made of the kwh demand in the residential, commercial, and industrial sectors and many of these are summarized in Tables 1 and 2.[4] As mentioned earlier there is a considerable amount of variation in the short- and long-run price and income elasticities estimates due to the differences in models, data, variables, and estimation methods, among other considerations. An examination of these estimates

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[4]It should be noted that the studies summarized in Tables 1 and 2 exclude some widely cited studies which are either of the United Kingdom (Houthakker, 1951; Baxter and Rees, 1968) or are of specific regions (Nelson, 1965; Levy, 1973; Lacy and Street, 1975; Acton, Mitchell and Mowill 1975; Chern, et al., 1978).

TABLE 1

PRICE AND INCOME ELASTICITIES FOR ELECTRICITY DEMAND-RESIDENTIAL SECTOR

Study	Data: Type[a]	Data: Vintage	Price Elasticity[b]: Short-Run	Price Elasticity[b]	Price Elasticity[b]: Long-Run	Income Elasticity[b]: Short-Run	Income Elasticity[b]	Income Elasticity[b]: Long-Run	Type[c] of Price
Fisher-Kaysen (1962)	CS-TS: States	1947-57			0.00	0.10		Small	A
Houthakker-Taylor (1970)	TS:USA	1947-64	-0.13		-1.89	0.13		1.94	A
Wilson (1971)	CS: SMSA's	1960,'66			-2.00			0.00	A*
Halvorsen (1972)	CS: States	1961		-1.16					M*
Anderson (1972)	CS:USA	1969		-0.84∿-0.90					
	CS:USA	1969		-0.77					A*
Halvorsen (1973)	CS-TS: USA	1947-69	-0.26		-2.11				M*
Mount-Chapman-Tyrrell (1973)	CS-TS: States	1946-70	-0.14		-1.20	0.02		0.20	A
Andersen (1973)	CS: States	1960-70			-1.12			0.80	A*
Lyman (1973)	CS-TS: Area Served by Utilities			-0.90			-0.20		A
Houthakker-Verleger-Sheehan (1974)	CS-TS: States	1959, 1965 1970	-0.90		-1.02	0.14		1.64	M
Griffin (1974)	TS:USA	1951-70	-0.06		-0.52	0.06		0.88	A

(Continued)

TABLE 1 (Continued)

	Data		Price Elasticity[b]		Income Elasticity[b]		
Study	Type[a]	Vintage	Short-Run	Long-Run	Short-Run	Long-Run	Type[c] of Price
Baughman-Joskow (1974)	CS: States	1969	-0.53∿-2.08[d]				A
Wilder-Willenborg (1975)	CS: Individuals	1973		-1.00		0.16	M*
Uri (1975)	TS: Monthly USA		-0.61	-1.66	0.44	0.12	A
Halvorsen (1975)	CS-TS States	1960-70	-1.15	-1.52	0.51	1.52	M*
Taylor-Blattenberger-Verleger (1976)	TS: States	1956-72	-0.07	-0.78	0.10	1.18	M
Chern (1976)	CS-TS: States	1971-'72	-1.44[e]			0.82[e]	A
FEA (1976)	CS-TS: Census Regions	1960-72	-0.19	-0.30		1.10	A
Halvorsen (1976)	CS: States	1969		-0.97		0.71	M*
Halvorsen (1978)	CS-TS: States	1961-69	-.58	-1.15	Negative	0.51	M*

(Continued)

TABLE 1 (Continued)

a - TS refers to time-series data; CS to cross-sectional data; and CS-TS to pooled CS and TS data.

b - Elasticities listed between short-run and long-run columns are ambiguously defined in the reference cited.

c - M refers to marginal price; M* to a theoretical model in which both average and marginal price elasticities are identical (price data was, however, either A or A*); A to an average price for electricity; and A* to an average price for a fixed amount of electricity.

d - These are "saturation" electricities and in general should be smaller than true price elasticities.

e - Combined residential and commercial sectors.

Sources: Individual Studies; Table 2 in Edmonds (1978); Electric Utility Rate Design Study (1977); Halvorsen (1978).

TABLE 2

PRICE AND INCOME/OUTPUT ELASTICITIES FOR ELECTRICITY DEMAND-COMMERCIAL AND INDUSTRAL SECTORS

	Data		Price Elasticity[b]			Income/Output Elasticity[b]			
Study	Type[a]	Vintage	Short-Run		Long-Run	Short-Run		Long-Run	Type[c] of Price
COMMERCIAL SECTOR									
Mount-Chapman-Tyrrell (1973)	CS:48 States	1946-70	-0.17		-1.36	0.11		0.86	A
Lyman (1973)	CS-TS: Area Served by Utilities	1959-68		-2.10					A
Hudson-Jorgenson (1974	TS:USA	1947-71		-0.36			1.00[d]		A
Uri (1975)	TS:Monthly aggregate USA		-0.34		-0.85	0.79		1.98	A
Tyrrell-Chern (1975)	CS:States				-1.23				A
FEA (1976)	CS-TS: Census regions yearly	1960-72	-0.24		-0.38	0.73		1.63	A
Halvorsen (1976)	CS: States 1969				-0.92			1.25	M*

(Continued)

TABLE 2 (Continued)

	Data		Price Elasticity			Income/Output Elasticity[b]			
Study	Type[a]	Vintage	Short-Run		Long-Run	Short-run		Long-Run	Type[c] of Price
INDUSTRIAL SECTOR									
Fisher-Kaysen (1962)	CS: States	1946-57			-1.25				A
Anderson (1971)	CS: States	1958,'62			-1.94				A
Mount-Chapman-Tyrrell (1973)	CS-TS: States	1947-70	-0.22		-1.82				A
Lyman (1973)	CS-TS: areas served by utilities	1959-68		-1.40					A
Griffin (1974)	TS: Aggregate U.S.	1951-71	-0.04[k]		-0.51[e]				A
Hudson-Jorgenson (1974)	TS:USA	1947-71		-0.07			1.00[d]		M A
Uri (1975)	TS: Monthly Aggregate US		-0.35		-0.69	1.32		2.63	A

(Continued)

TABLE 2 (Continued)

	Data		Price Elasticity[b]		Income/Output Elasticity[b]		
Study	Type[a]	Vintage	Short-Run	Long-Run	Short-Run	Long-Run	Type[c] of Price
Baughman-Zerhoot (1975)	CS-TS: 48 States and Wash. D.C.	1962-72	-0.11	-1.28	0.69		A
Chern (1975)	CS-TS: 16 US indus- tries	1959-71	-0.61	-1.98	0.30	0.97	A
Tyrrell-Chern	CS: States			-1.28			A
FEA (1976)	CS-TS: Census regions annual	1960-72	-0.15	-1.03	1.00[d]	1.00[d]	A
Halvorsen (1976)	CS: States	1969		-1.24		0.68	M*
	CS: States	1971		-0.92		1.00[j]	A

(Continued)

TABLE 2 (Continued)

a - TS refers to time-series data; CS to cross-sectional data; and CS and TS to pooled Cs and TS data.

b - Elasticities listed between short-run and long-run columns are ambiguously defined in the reference cited.

c - M refers to marginal price; M* to a theoretical model in which both average and marginal price elasticities are identical (price data was, however, either A or A*); A to an average price for electricity; and A* to an average price for a fixed amount of electricity.

Sources: Individual Studies; Table 2 in Edmonds (1978); Electric Utility Rate Design Study (1977).

leads to the general conclusion that the short-run price and income elasticities of kwh demand are more inelastic, on average, than the corresponding long-run elasticities. In addition, the kwh demand response to a change in the marginal price appears in general to be less than the kwh demand response to a change in the average price.

In an extensive review of some of these studies Edmonds concluded:

> These studies indicate a larger long-run price elasticity than short-run elasticity, and in fact suggest that short-run elasticities lie somewhere between zero and -.25. Long-run elasticities are larger, however, and there seems rather unanimous agreement that the long-run average price elasticity of demand for residential electricity has an absolute value larger than 1. A glance at the results for the other sectors shows that this conclusion holds for the commercial and industrial sectors as well. Income elasticities also seem to follow this general trend: inelastic in the short run while elastic in the long run (Edmonds, 1978, pp. 10-11).

A similar review by a task force of the Electric Utility Rate Design Study concluded that the long-run price elasticity for each class was -1.3 (Electric Utility Rate Design Study, 1977).

National Economic Research Associates, Inc., as part of their tasks for the Electric Utility Rate Design Study, intensively reviewed several of the studies reported in Tables 1 and 2 and concluded:

> First, absent (or holding constant) interfuel substitution effects, direct price elasticities of the demand for electricity are all roughly -0.5. Second, price elasticities pertaining to choice of electricity as against fossil fuels in a specific application are generally larger than this (in absolute terms). Thus, combining these two effects, measured total price elasticity appears to be -1.0 or slightly higher....
>
> A brief look at short-run elasticities indicates the following kinds of estimates. For the residential class, electricity price elasticity is generally around -.2. For the commercial class, it may be slightly higher. But is also seems to be around -.2 for the industrial class (National Economic Research Associates, Inc., 1977, p. xii).

These conclusions and our review of the literature lead us to the following "best" estimates of the various United States elasticities of kwh demand. The following long-run average price elasticities of kwh demand allow for interfuel substitution: residential, -1.0; commercial, -1.0; and industrail, -1.1. Industrial kwh demand is estimated as more elastic due to greater possibilities for self-generation of electricity for this customer category. The range of uncertainty regarding these estimates is larger for commercial and industrial customers since there have been fewer studies of these categories in comparison to residential customers.

The estimate of the long-run marginal price elasticity of kwh demand with allowance for interfuel substitution is -0.8 in the case of residential customers. Although there are a few studies of industrial and commercial customers using marginal price, we do not provide estimates of their corresponding marginal price elasticities of kwh demand due to the very large variance in reported results.

The following short-run average price elasticities of kwh demand do not allow for interfuel substitution effects: residential, -0.2; commercial, -0.25; and industrial, -0.2.

Although estimates of the income/output elasticity of kwh demand are presented in Tables 1 and 2, most reviewers do not establish a "best" estimate of income elasticities of kwh demand. Our review leads to an estimate of the average long-run residential income elasticity of kwh demand of +1.0 assuming the use of average price and allowing for interfuel substitution. The corresponding average short-run residential income elasticity of kwh demand is estimated as +0.1 assuming the use of average price and no interfuel substitution. The long-run commercial output elasticity of kwh demand is estimated as +1.6 assuming average price and interfuel substitution while the corresponding short-run output elasticity of kwh demand is estimated as +0.75 assuming the use of average price and no interfuel substitution. Due to relatively few studies and diversity of results, we cannot provide any "best" estimate of the output elasticities of kwh demand for the industrial sector at this time; however, we note that several studies assume this elasticity is +1.0 in both the short- and long-run.

REVIEW OF ELASTICITY ESTIMATES: REGIONAL

Several studies have developed estimates of the price and income/output elasticities of kwh demand for geographical areas such as states, SMSAs, cities and utility service areas (Nelson, 1965; Anderson, 1972; Mount, Chapman and Tyrrell, 1973; Acton, Mitchell and Mowill, 1975; Lacy and Street 1975; Chern, et al., 1978). A survey of these studies shows the same diversity in models, data, and other characteristics as was found in the previous survey of national studies. No extensive discussion of these studies is presented in this section since they are specific to a particular region; in addition, there is no table reporting all of the elasticity estimates encountered in this review. The sizable number and diversity of regional studies has led several reviewers to pessimistic conclusions regarding our knowledge of regional differences in electricity demand elasticities. For example, Edmonds has concluded:

> Having looked at these papers, which have sought to illuminate the area of regional...energy-price responsiveness, we must ask, How much do we really know about regional elasticity differences...? In the area of regional elasticities, the answer would seem to be, very little...The numerous regional papers do tell us some things; however,

because they differ with respect to their data, theoretical specifications, and econometric techniques, it is impossible to distinguish how much elasticity differences are due to differences in regional responses and how much to econometric differences (Edmonds, 1978, pp. 60-61).

We, however, are not as pessismistic as Edmonds in that there exists a recently completed regional model developed at Oak Ridge National Laboratory (Chern, et al., 1978) which was not available to Edmonds at the time of his study. In our opinion this particular regional model surmounts many of the difficulties encountered in prior modeling efforts at the regional level. Although the principal usage of the Oak Ridge model is to forecast regional demand for electricity to the year 1990, it in addition generates short- and long-run estimates of the price and income elasticities of kwh demand by major census regions which can be used to estimate the corresponding six state region elasticities. We first survey the salient features of the Oak Ridge model and its relationship to some of the other models discussed earlier in this report. We then present the estimated price and income elasticities of kwh demand by census region and the forecast growth rates of kwh demand and average electricity price to the year 1990 by customer category and state. The elasticity estimates are utilized in a later part of this section to generate corresponding estimates for the six state region while the growth rates provide a basis for comparison with other ORBES studies.

The Oak Ridge model is basically a simultaneous equation model which has submodels for the residential, commercial and industrial sectors. Within each submodel are demand and price equations which imply that kwh demand and average price per kwh are endogenous to the system. This specification eliminates the identification and estimation problems associated with the use of average price within a declining-block rate structure. Thus, this model is seen as a variant of the Halvorsen type approach to the specification of the electricity demand equation.

All of the demand equations in the three sectors have the same general dynamic structure. These equations are autoregressive with the lagged endogenous variable as a predetermined variable in each demand equation. As was noted earlier this specification is derived from a state adjustment model (Houthakker and Taylor, 1970) and has the advantage that no explicit capital stock variable needs to be used in the estimation of the model. In addition, this specification allows for the calculation of both short- and long-run price and income elasticities.

The residential demand equation was specified as

$$\ln ERS_{it} = \alpha_0 + \alpha_1 \ln ERS_{i\,t,-1} + \alpha_2 \ln(PER/CLI)_{it} + \alpha_3 \ln X_{it} + \alpha_4 D_{it} + \alpha_5 A_{it} + u_{it}$$

where i = state

t = year

ERS = residential sales of electricity measured in kwh

PER/CLI = average price of electricity in the residential sector deflated by the cost of living index

X = set of explanatory variables

D = set of state and shift dummy variables

A = set of dummy variables for reclassification of customers and other shifts in historical trends of residential sales

The set of explanatory variables used in the estimation of the residential demand equation includes the average natural gas price in the residential sector (deflated by the cost of living index), the average retail price of No. 2 fuel oil (deflated by the cost of living index), the number of residential customers, per capita personal income (deflated by the cost of living index), population, heating degree-days, cooling degree-days, and the number of natural gas customers in the residential sector. The set of dummy variables D includes state dummies as well as a dummy variable to investigate possible structural shifts between the periods of declining real electricity price and increasing real electricity prices. In addition it includes variables to measure the effects of natural gas availability on the quantity of electricity demanded. The set of dummy variables A are included to account for distortions in historical trends in electricity sales due to the reclassification of customers from one category to another. Detailed discussion of the variables' construction can be found in the original study.

The residential electricity price equation was specified as

$$PER_{it} - TOC_{it} = \beta_0 + \beta_1 (ERS_{it}/CR_{it}) + \beta_2 (ERS_{it}/CR_{it})^2 + \beta_3 CR_{it} + \beta_4 D_{it} + \beta_5 A_{it} + v_{it}$$

where TOC = average total cost of generating and distributing electricity period.

The other variables are defined in the residential demand equation.

The commercial demand equation was specified as

$$\ln ECS_{it} = \gamma_0 + \gamma_1 \ln ECS_{i,t-1} + \gamma_2 \ln(PEC/CLI)_{it} + \gamma_3 \ln M_{it} + \gamma_4 D_{it} + \gamma_5 B_{it} + u_{it}$$

where ECS = kwh of commercial sales of electricity

PER/CLI = average price of electricity in the commercial sector deflated by the cost of living index

M = set of explanatory variables

D = set of state and shift dummy variables

B = set of dummy variables for reclassification of customers

The set of explanatory variables includes population, real per capita personal income, real fuel oil price, heating degree-days, and cooling degree-days as previous defined in the residential demand equation. Furthermore, the equation includes as explanatory variables the average natural gas price in the commercial sector (deflated by the cost of living index) and the number of natural gas customers in the commercial sector. The set of dummy variables B and D are as previously defined except that B includes some additional dummies to account for the reclassification of commercial and industrial customers over the years.

The commercial electricity price equation was specified as

$$PEC_{it}-TOC_{it}=\delta_0 + \delta_1(ECS_{it}/CC_{it}) + \delta_2(ECS_{it}/CC_{it})^2 + \delta_3 CC_{it} + \delta_4 D_{it} + \delta_5 B_{it} + v_{it}$$

where CC = the number of commercial electricity customers period.

The other variables are as previously defined.

The industrial demand equation was specified as

$$\ln EIS_{it}=\theta_0 + \theta_1 \ln EIS_{i,t-1} + \theta_2 \ln(PEI/WPI)_{it} + \theta_3 \ln N_{it} + \theta_4 D_{it} + \theta_5 B_{it} + u_{it}$$

where EIS = quantity of industrial sales of electricity (kwh)

PEI/WPI = average price of electricity in the industrial sector deflated by the wholesale price index

The other variables are as previously defined. The set of explanatory variables used in the estimation of the industrial sector includes value added in manufacturing (deflated by the wholesale price index of manufacturing), average natural gas price in the industrial sector (deflated by the WPI), wholesale price of No. 6 fuel oil (deflated by the WPI), average price of coal (deflated by the WPI, and the number of natural gas customers in the industrial sector.

The industrial electricity price equation was specified as

$$PEC_{it}-TOC_{it}=\phi_1 + \phi_2(EIS_{it}/CI_{it}) + \phi_3(EIS_{it}/CI_{it})^2 + \phi_4 CI_{it} + \phi_5 D_{it} + \phi_6 B_{it} + v_{it}$$

where DI = number of industrial electricity customers.

The other variables have been defined previously.

The six structural equations have the price and quantity variables as endogenous variables whereas the remaining variables are predetermined. Although the system of equations is nonlinear, the model is estimated using two stage least squares and three stage least squares after treating the nonlinear variables as new variables. The estimation assumes no serially correlated errors. After the equations were estimated, a nonrigorous examination of the residuals from the demand equations indicated no apparent serial correlation problems in these equations. The final equations presented in the report (which are not presented here) have some of the predetermined variables excluded from individual equations due to incorrect signs of the estimated coefficients. As the report indicates, this can lead to misspecification of the model if the excluded variables actually belong in the individual equations. Since the three stage least square coefficient estimates are the most sensitive to misspecification of the individual equations, we believe attention should have focused on their two stage least squares coefficients estimates; however, we note that the authors utilize the three stage least squares coefficient estimates in estimating elasticities and deriving forecasts of the growth rate in demand and prices to the year 1990. The authors justify this procedure on the basis that the three stage least squares coefficient estimates are similar in magnitude to the two stage least squares coefficient estimates and the former are more efficient than the latter.

Tables 3-5 present the regional estimates of the short- and long-run price and income elasticities of kwh demand by customer category which were calculated in the Oak Ridge study.[5] It should be noted that, in the case of the industrial category, an industrial output elasticity of kwh demand was calculated instead of an income elasticity for reasons discussed earlier.

The following are general conclusions from the examination of these results. First, there is a considerable amount of variation among regions in the estimates of the elasticities. In part this may be attributable to differences in end use consumption, in types of appliance stocks, climatic conditions and industrial composition not reflected in the model. Second, the short- and long-run estimates are comparable to national estimates with few exceptions; the major exception are the lower short- and long-run income elasticities in the East North Central region compared to elsewhere. Third, the commercial and residential customers have more elastic average price effects than the industrial customers, particularly in the long-run estimates. Finally, the study reinforces national studies which find the average price of electricity has a very important negative effect on the quantity of electricity demanded.

The Oak Ridge simultaneous equations model is then used to forecast the kwh sales and average electricity price growth rates to 1990 for consumer sector and state. In making these forecasts the study required

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[5]These elasticities are calculated from the estimated coefficients of the various electricity demand equations. For details of this procedure see Chern, et al., 1978. Since the estimated models are double log models the elasticities are assumed to be constant over all observable ranges of quantity, price and income.

TABLE 3

RESIDENTIAL ELECTRICITY DEMAND ELASTICITIES BY REGION
OAK RIDGE MODEL

Region[a]	Electricity Price		Income	
	Short-run	Long-run	Short-run	Long-run
New England	-0.33	-1.50	0.07	0.32
Middle Atlantic	-0.22	-0.60	0.34	0.91
East North Central	-0.35	-1.22	0.06	0.19
West North Central	-0.27	-0.73	-0.01	-0.02
South Atlantic	-0.31	-1.12	0.21	0.77
East South Central	-0.47	-0.95	0.30	0.61
West South Central	-0.57	-1.07	0.27	0.51
Mountain	-0.19	-0.43	0.45	1.03
Pacific	-0.08	-0.37	0.01	0.04

[a]The states which make up the regions are as follows:

New England:	Maine, New Hampshire, Vermont, Massachusetts, Rhode Island, Connecticut
Middle Atlantic:	New York, New Jersey, Pennsylvania
East North Central:	Ohio, Indiana, Illinois, Michigan, Wisconsin
West North Central:	Minnesota, Iowa, Missouri, North Dakota, South Dakota, Nebraska, Kansas
South Atlantic:	Delaware, Maryland, Virginia, West Virginia, North Carolina, South Carolina, Georgia, Florida
East South Central:	Kentucky, Tennessee, Alabama, Mississippi
West South Central:	Arkansas, Louisiana, Oklahoma, Texas
Mountain:	Montana, Idaho, Wyoming, Colorado, New Mexico Arizona, Utah, Nevada
Pacific:	Washington, Oregon, California

Source: W. S. Chern, R. E. Just, B. D. Holcomb and H. D. Nguyen, Regional Econometric Model for Forecasting Electricity Demand by Sector and by State, Oak Ridge, Tennessee: Oak Ridge National Laboratory, (NUREG/CR-0250), October 1978, Table 5.1.

TABLE 4

COMMERCIAL ELECTRICITY DEMAND ELASTICITIES BY REGION
OAK RIDGE MODEL

Region	Electricity Price		Income	
	Short-run	Long-run	Short-run	Long-run
New England	-0.47	-1.31	0.25	0.70
Middle Atlantic	-0.33	-0.51	1.22	1.88
East North Central	-0.43	-1.60	0.20	0.76
West North Central	-0.09	-1.02	NE[a]	NE
South Atlantic	-0.39	-1.27	0.33	1.09
East South Central	-0.66	-1.29	0.33	0.65
West South Central	-0.25	-1.60	0.03	0.20
Mountain	-0.48	-0.90	NE	NE
Pacific	-0.40	-0.66	0.31	0.52

[a]NE-Not estimated

Source: Ibid, Table 5.2.

TABLE 5

INDUSTRIAL ELECTRICITY DEMAND ELASTICITIES BY REGION
OAK RIDGE MODEL

Region	Electricity Price		Industrial Output	
	Short-run	Long-run	Short-run	Long-run
New England	-0.06	-0.16	0.50	1.41
Middle Atlantic	-0.02	-0.04	1.01	1.55
East North Central	-0.32	-0.54	0.74	1.28
West North Central	-0.26	-0.87	0.25	0.83
South Atlantic	-0.15	-0.71	0.21	1.03
East South Central	-0.28	-0.55	0.48	0.96
West South Central	-0.10	-0.62	0.17	1.03
Mountain	-0.19	-0.39	0.38	0.80
Pacific	-0.03	-0.09	0.32	0.90

Source: Ibid, Table 5.3.

forecasts of all of the predetermined variables over the same time period. The assumptions used in projecting values for all of the predetermined variables except electricity generation and distribution costs are presented in detail in the study. Basically they utilized generally accepted forecasts of population, real per capita income, value added, number of customers, heating degree-days and cooling degree days and general price level changes which have been prepared and utilized by both governmental agencies as well as private consulting firms.

Three cases of assumptions were made in the Oak Ridge report regarding the electricity generation and distribution costs to 1990. Because of the importance of these in the forecasts the following are details of their procedure:

> For the base case we took the Hudson and Jorgenson projections of the price in current dollars of natural gas, refined petroleum products, and coal. The fuel prices in real terms are, of course, easily obtainable using the projected cost-of-living index and wholesale price index. To derive the estimate for the overall average of the costs of generation, transmission, and distribution is more complicated. Basically, we decomposed the overall average costs to two components: fuel costs and other costs (operation, maintenance, capital, taxes, etc.). The cost of fuels depends on the shares of various fuels used by electric utilities. This composition of fuels varies from the state to state. We took the 1974 data and derived the exact relationships between composite fuel costs and prices of fuels used by utilities for each state. The cost of fuels are then projected based on assumed prices of natural gas, petroleum products, and coal. For the operating and maintenance cost component, we assume that it will increase slightly more than the increases in the wholesale price index (6.1% for 1974-1980, 4.4% for 1980-1985, and 3.7% for 1985-1990). The projected total electricity costs are the weighted average of projected fuel costs and operating and maintenance costs. The percentage of these two cost components in 1974 were used as weighting factors.
>
> In the low-price case, we assume that all fuel prices in the residential and commercial sectors will increase at the same rate as the cost-of-living index. All prices of fuels in the industrial sector will increase at the same rate as the wholesale price index. Furthermore, the costs of fuel and operating and maintenance will increase at the same rate as the wholesale price index. In other words, it is assumed in this case that the real prices of fuels and the real costs of electricity generation, transmission, and distribution will remain at the 1974 level.
>
> In the high-price case, we assume that the growth rates of all price and cost components in the base case will be doubled in real terms (Chern, et al., 1978, pp. 7-4 through 7-5).

The projected annual growth rates of total electricity generation and distribution cost under these three cost cases from the Oak Ridge report are presented in Table 6. The associated forecast by Oak Ridge of annual growth rates in kwh demand by sector and state under these cost cases and the forecast values of the other predetermined variables are presented in Table 7.[6] An examination of kwh demand growth rates shows some variation among states during the forecast period; however, there is less variation for the ORBES states than in the remainder of the states. For the states listed in Table 7 there appears to be no definite pattern in the relative growth rates by customer category, i.e., no one category has consistently higher or lower growth rates compared to another category. These growth rates are utilized to estimate the growth rates for the six state region later in this section.

The Oak Ridge report also generated forecasts of the average electricity prices in nominal terms by customer category and state which is reported in Table 8. The forecast growth rates in average prices were consistent with the scenarios regarding the growth rates in total average electricity cost. It should be noted that the Oak Ridge model forecasts different growth rates in average electricity prices by sector among the states in the ORBES region.

PRICE AND INCOME/OUTPUT ELASTICITIES OF DEMAND FOR THE SIX STATE REGION

In this section we provide two methods of estimating the short- and long-run and income/output elasticities of kwh demand in the six states region. The first method will utilize essentially the same estimates of these elasticities as were found in the review of the national studies. The second method will generate estimates of these elasticities from the Oak Ridge report. It should be noted that both methods only provide estimates of the ORBES region elasticities. If one had access to appropriate data for the ORBES region one could develop estimates from an estimated econometric model; however, due to data, time, and budget limitations no such model was estimated.

The first set of estimates for the six state region are based on the "best" estimates of the short- and long-run price and income/output elasticities of kwh demand for the United States from studies completed during the period 1968-1975. The six state estimates are assumed to be equivalent to the United States estimates in each customer cateogry. In making this assumption one need not assume that the characteristics of the electricity customers and their tastes and preferences are the same between the six state region and the rest of the United States. In estimating the price and income/output elasticities reported in Table 1 and 2, the studies also examined simultaneously other predetermined variables including the effects of climate, appliance stocks, prices or other energy sources, trends, and

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[6]Two sets of industrial growth rates were calculated to allow in one case for projected growth in the demand for electricity by Department of Energy uranium enrichment plants.

TABLE 6

PROJECTED ANNUAL GROWTH RATES OF TOTAL AVERAGE
ELECTRICITY COST (TOC) FOR ALTERNATIVE COST SCENARIOS AND SELECTED STATES
OAK RIDGE MODEL

Scenario and Period	Projected Annual Growth Rates (Percent) of Total Average Electricity Cost (TOC)					
	Pennsylvania	Ohio	Illinois	West Virginia	Kentucky	Indiana
Base Case						
1974-80	6.49	6.66	6.43	6.76	7.12	6.50
1980-85	5.42	5.37	5.12	5.71	6.08	5.12
1985-90	4.71	4.62	4.41	4.92	5.27	4.39
Low-price Case						
1974-80	5.10	5.10	5.10	5.10	5.10	5.10
1980-85	3.40	3.40	3.40	3.40	3.40	3.40
1985-90	2.70	2.70	2.70	2.70	2.70	2.70
High-price Case						
1974-80	7.90	8.18	7.77	8.42	8.13	7.31
1980-85	7.46	7.34	6.81	8.03	7.08	6.30
1985-90	6.72	6.54	6.10	7.13	6.27	6.07

Source: Ibid, Table C-6.

TABLE 7

FORECASTS OF ANNUAL GROWTH RATES (1974-1990) OF KWH DEMAND
BY SECTOR, STATE AND COST SCENARIO
OAK RIDGE MODEL

State	Cost Scenario[a]	Forecast of Annual Growth Rates of KWH Demand by Sector (Percent)			
		Residential	Commercial	Industrial	Total
Pennsylvania	B	4.2	6.4	5.7	5.4
	L	4.6	6.4	5.5	5.4
	H	3.7	6.4	6.4	5.4
Ohio	B	4.2	3.9	4.5(4.7)[b]	4.3(4.4)[b]
	L	5.7	4.4	5.0(5.1)[b]	5.1(5.2)[b]
	H	2.7	3.3	3.9(4.2)[b]	3.5(3.7)[b]
Indiana	B	6.1	6.1	5.3	5.7
	L	7.4	6.4	5.8	6.4
	H	5.1	5.9	5.1	5.2
Illinois	B	4.6	4.1	3.4	4.0
	L	6.0	4.4	3.9	4.7
	H	3.2	3.6	3.0	3.2
West Virginia	B	4.4	4.7	3.4	3.9
	L	5.2	5.5	3.8	4.5
	H	3.4	3.7	2.9	3.2
Kentucky	B	5.6	3.5	4.9(4.9)[c]	4.8(4.8)[c]
	L	6.4	3.8	5.6(5.3)[c]	5.5(5.0)[c]
	H	5.3	3.6	4.8(4.8)[c]	4.7(4.7)[c]

(Continued)

TABLE 7 (Continued)

[a]B=base case, L=low price case and H=high case.

[b]Includes the projected consumption of the DOE uranium enrichment plant in Portsmouth, Ohio

[c]Includes the projected consumption of the DOE uranium enrichment plant in Paducah, Kentucky.

Source: Ibid, Tables 7.3, 7.4, 7.6 and 7.7.

TABLE 8

FORECASTS OF ANNUAL GROWTH RATES (1974-1990) OF AVERAGE ELECTRICITY PRICE BY SECTOR, STATE AND COST SCENARIO
OAK RIDGE MODEL

State	Cost Scenario	Forecast of Annual Growth Rates of Average Electricity Price by Sector (Percent)			
		Residential	Commercial	Industrial	Total
Pennsylvania	B	5.2	6.0	5.4	5.4
	L	4.4	4.9	3.6	4.2
	H	6.2	7.2	7.3	6.8
Ohio	B	3.3	4.3	5.7	4.5
	L	1.9	3.4	3.9	3.1
	H	4.8	5.4	7.4	6.0
Indiana	B	2.8	3.9	4.8	3.9
	L	1.5	3.1	3.1	2.6
	H	3.8	4.7	6.0	4.9
Illinois	B	3.3	4.7	6.2	4.7
	L	1.9	3.9	4.6	3.4
	H	4.6	5.7	7.8	6.0
West Virginia	B	4.1	4.2	5.8	5.0
	L	3.1	3.1	3.8	3.6
	H	5.4	5.6	7.8	6.6
Kentucky	B	4.0	7.2	5.0	5.2
	L	2.7	6.3	2.8	3.6
	H	4.6	8.0	6.0	5.9

Source: Ibid, Appendix D.

demographic characteristics, among others. As a result the reported elasticities assume the effects of other variables are held constant in the estimated models. The necessary assumption for the national "best" estimates to be good estimates of the six state region is that there be independence between the elasticity measures and the other variables in the model. Implicit here is the assumption that the econometric models are well specified and that they contain no specification errors which involve omitted variables correlated with the included variables.

Table 9 presents the estimates of the six state region average price and income/output elasticities of kwh demand by customer category using the first method. Estimates of these regional elasticities are derived by weighting the customer category elasticities by the percent of total kwh consumption in 1974 in the six state region by customer category. The short-run average price and income/output elasticity estimates are more inelastic than the corresponding long-run estimates.

The second set of estimates for the six state region are based on the regional estimates of the short- and long-run average price and income/output elasticities of kwh demand from the Oak Ridge study. For example an estimate of the six state region residential short-run price elasticity of kwh demand is derived by constructing a weighted average of the residential price elasticities in relevant census regions multiplied by the percent of six state region residential kwh consumption occuring in states within the census region. The latter consumption weights are presented in Table 10. The small divergence in percentages across customer categories is attributable to the small differences among the regions in the composition of kwh demand by customer category.

The estimates of the short- and long-run price and income elasticities of kwh demand using this second method are presented in Table 11. A comparison of the estimated six state price elasticities from the two methods shows that the average price elasticities derived from the Oak Ridge study are more elastic in the short-run than the national estimates. In contrast, the Oak Ridge derived estimates of the total long-run average price elasticity are more inelastic than the national estimates. The latter finding is attributable to the inelastic average price elasticity of kwh demand estimated for the six state industrial category from the Oak Ridge study.

A comparison of the total short- and long-run income/output elasticities of kwh demand shows a more inelastic demand in the Oak Ridge derived estimates; in contrast, there is considerable variation in the comparison of customer category estimates between the two methods. Overall we have more confidence in the Oak Ridge estimates as reflecting the types of patterns of elasticities which would be expected. For example, it is possible that type of industries located in the six state region have more inelastic demands for electricity than industries located elsewhere in the

TABLE 9

ESTIMATES OF SIX STATE REGION PRICE AND INCOME/OUTPUT ELASTICITIES OF KWH DEMAND BY CUSTOMER CATEGORY-METHOD I

	Estimate of Elasticity by Customer Category in Six State Region			
Elasticity Measure	Residential	Commercial	Industrial	Total[a]
Short-run Average Price	-.2	-.25	-.2	-.21
Long-run Average Price	-1.0	-1.0	-1.1	-1.05
Short-run Income/Output	0.1	.75	1.0[b]	.68
Long-run Income/Output	1.0	1.6	1.0[b]	1.12

[a]Derived by weighting the customer category elasticity by the following weights: residential, 30.1; commercial, 20.8; and industrial, 49.1. These weights are the percent of total kwh consumption in 1974 in the six state region by customer category.

[b]Assumed to be equal to 1; actual studies show too much diversity for actual estimate.

Source: Based on subjective review of national studies listed on Table 1 and 2.

TABLE 11

ESTIMATES OF SIX STATE REGION PRICE AND INCOME/OUTPUT ELASTICITIES OF KWH DEMAND BY CUSTOMER CATEGORY-METHOD II

	Customer Category			
Elasticity Measure	Residential (Percent)	Commercial (Percent)	Industrial (Percent)	Total (Percent)
Short-run Average Price	-0.33[a]	-0.43	-0.23	-0.33[b]
Long-run Average Price	-1.04	-1.31	-0.41	-0.79
Short-run Income/Output	0.16	0.45	0.77	0.52
Long-run Income/Output	0.43	0.96	1.31	0.97

[a] Individual customer category elasticities calculated by weighting the customer category elasticities in Table 3-5 by the corresponding weights in Table 10.

[b] Derived by weighting the customer category elasticity by the following weights: residential, 30.1; commercial, 20.8; and industrial, 49.1. These weights are the percent of total kwh consumption in 1974 in the six state region by customer category.

United States. In addition, our review of the Oak Ridge study gave us a high degree of confidence in this approach to modeling the kwh demand for electricity. Of course, one must recognize that our estimates of elasticities from both methods are implicitly accompanied by a variance reflecting our uncertainty as to the "correct" magnitude of these elasticities.

Finally we utilize the projected average price and kwh demand growth rates to 1990 from the Oak Ridge report (Tables 7 and 8) together with the consumption weights (Table 10) to generate estimates of the six state region's average price and kwh demand growth rates to 1990 by customer category. These growth rates are reported in Table 12. The estimated total kwh demand annual growth rate in the base cost scenario is 4.8 percent while the corresponding average price growth rate was 4.9 percent. The low price cost scenario results in a higher total kwh demand growth rate and a lower average price growth rate in comparison to the base case; the reverse is found in a comparison of the growth rate in the high price cost scenario compared to the base cost scenario.

SUMMARY

This task of the research project reviewed the literature on the demand for electricity and generated estimates of the short- and long-run price and income elasticities of demand for electricity in the six state region. Since there have been a considerable number of studies in this area and several economists have recently reviewed this literature, we presented a summary of the results of these studies. In addition we summarized the results from a recent study of the demand for electricity by region which generated elasticity estimates by customer category and cenus region. Our study generated two sets of elasticity estimates for the six state region using our "best" estimates of national elasticities and the regional estimates from the Oak Ridge model. Of the two sets of estimates presented we have more confidence in the derived Oak Ridge estimates. In addition,since our estimates of the elasticities will be used in simulating demand growth in the Teknekron model by the year 200, we presented independent estimates of electricity demand growth in 1990 derived from the Oak Ridge study.

TABLE 12

FORECASTS OF ANNUAL GROWTH RATES (1974-1990) OF ELECTRICITY PRICE AND DEMAND BY SECTOR IN THE SIX STATE REGION

		Growth Rates (Percent) by Customer Category			
Variable	Cost Scenario[a]	Residential	Commercial	Industrial	Total
KWH Demand	Base	4.7[b]	4.9	4.7	4.8
	Low Price	5.8	5.1	5.1	5.3
	High Price	3.7	4.5	4.5	4.3
Average Electricity	Base	3.8	5.2	5.6	4.9
	Low Price	2.8	4.2	4.5	4.1
	High Price	5.0	6.1	8.4	6.1

[a]Same as utilized in Table 6-8 as well as in the text.

[b]Derived by weighting growth rates in Table 7-8 using weights given in Table 10.

SECTION 3

THE IMPACT OF REGULATION ON ELECTRICITY PRICES AND GENERATION CAPACITY IN THE OHIO RIVER BASIN

Electric utilities in the United States are presently in the process of reevaluating planned additional generating capacity in the context of declining rates of growth in kilowatt-hour (kwh) demand. As a result, some new capacity increments have been delayed while other planned additions to generating capacity have been either postponed indefinitely or permanently cancelled (Wall Street Journal, February 7, 1979). For example, Potomac Electric Power Company has estimated it will need only 1.2 million kilowatts (kw) of additional capacity by 1982 in contrast to its original estimate of 4.4 million kw. The power firm's annual kwh growth rate has declined from 9.0 percent in 1973 to approximately 3.0 percent at present (compared to the national average of 3.5 percent). The decline in demand growth can be attributed to several factors including utility conservation programs, increased energy efficiency in production processes and appliances, and most important, increased price. The average kwh price has nearly doubled since 1973. This has induced residential consumers to conserve (e.g., reduce unnecessary use and insulate residences) and has induced commercial and industrial consumers to make capital investments necessary to conserve energy. The improvements in the efficiency of production processes and appliances are expected to continue along with increases in the price of electricity. As a result, most projections indicate that the United States annual growth rate in kwh demand will average approximately 4.0 percent through 1990, significantly less than the historical growth rate of 7.0 percent.

The purpose of this section is to examine the implications of declining growth in electricity demand as well as the implications of increasing prices and regulatory restructuring of prices for the Ohio River Basin Energy Study (ORBES) region. Several regulatory alternatives are examined as to their pricing and capacity requirements implications for the ORBES region.

One part (The Regulatory Environment) examines the present state of electricity regulation in the United States, particularly in the context of increasing pressure for regulatory reform (a function of high rates of inflation, increasing consumer militancy, and declining supplies of low cost fuel). The historical relationship between electricity prices and the several factors theoretically and empirically associated with these prices are briefly reviewed.

A second segment (The Pricing Alternatives) examines some alternative pricing situations. Three basic cases are analyzed. The first is traditional average cost pricing with no time differentiation, i.e., prices based on unit or average accounting cost. In the traditional case there is little justification for presuming any significant alteration in the load patterns faced by electric utilities. The second is marginal cost pricing with no time differentiation, i.e., prices based on incremental or marginal cost. The effect of marginal cost rates is generally higher prices of electricity than those from average cost rates, particularly since most marginal cost estimates are derived from projected future costs rather than historical or imbedded accounting costs. However, marginal cost pricing without time differentiation (i.e., without incorporation of peak and off-peak rates), similar to average cost pricing without time differentiation, has minimal effects on electric utility load patterns. The third case is some variation of time differentiated or peak load pricing, i.e., prices varying with peak and off-peak consumption. It is presumed that load patterns confronting electric utilities are significantly altered under peak load pricing schemes regardless of whether based on marginal cost or average cost. A third part examines the potential effects of time differentiated prices regarding required capacity, load factors, and fuel costs (The Potential Effects of Time Differentiated Pricing). A final segment (The Implications for the ORBES Region) examines the potential capacity reduction effects from time differentiated rates for the ORBES region.

THE REGULATORY ENVIRONMENT

Regulation per se appears to have had minimal influences on electricity rates. In their classic study, Stigler and Friedland (1962) found that average electricity rate levels were influenced primarily by market factors (market size and population density) and fuel costs rather than rate regulation itself. Jackson (1969) produced similar conclusions indicating that the cost per kwh has been a function of fuel costs, utility scale, and availability of cheap hydroelectric power, and not commission regulation. Pike (1967) provided evidence that residential electric rates were determined more by power system scale, fuel costs, and access to relatively inexpensive public power than by state regulation. Mann (1974) found that electricity rates for specific residential consumption levels were influenced by generation costs, distribution costs, and system scale; political factors impacted on rates for publicly-owned electric firms but not on rates for investor-owned electric utilities. There is a dissenting voice regarding the impact (or lack thereof) of regulation on electricity prices. Moore (1975) produced empirical results that indicated utility regulation increased electricity prices, i.e., increased regulatory effort as measured by funds expended and time consumed was associated with increased average kwh prices for residential, commercial, and industrial users.

The historical situation regarding utility regulation appears to be changing, at least in the electric power sector. Inflation coupled with surging fuel prices has changed a very passive regulatory process into an active and continuous review process (Joskow, 1974). The kwh price of electricity tended to decline through the mid-1960's; it was relatively stable in the latter part of the 1960's. The average kwh price began to rise in the early 1970's. Confronted with increased rate hike applications and rate challenges, the nature of the regulatory process in the United States has changed substantially since 1970. That is, prior to 1970, electric utilities could maintain adequate profit rates without resorting to price increases since technological change and scale economies more than offset input price increases. Shepherd (1976) has noted that 1965-1975 is the period when electric utility cost functions turned upward, i.e., some electric utilities in their entirety and other electric utilities in specific components (e.g., distribution) began to experience diseconomies of scale. In brief, electric utilities recently have been confronted with increasing unit cost due to both shifts upward in cost functions (e.g., the effect of inflation) and diseconomies of scale (Wilson and Uhler, 1976).

The rising average cost of electricity production is a function of numerous factors (Berlin, Cicchetti, and Gillen, 1974). One, inflation has meant increasing input prices (e.g., fuel and labor). Two, the technological impact which historically decreased unit costs has lessened in recent years; in addition, technological change in the areas of safety and environmental requirements has increased unit costs. Three, economies of scale appear to have been exhausted in some dimensions of electric power (e.g., generation appears to have reached the threshold of either constant or rising unit costs with increasing capacity). Four, financial, capital equipment, and construction costs have increased substantially, as well as land values for generation plant sites. In brief, the effect of inflation, increasing fuel costs, and environmental protection have tended to exceed the gains from technological change and increasing output. As a result, the declining block rate schedule for electricity, which historically has been justified by both load factor improvements and long-run economies of scale, may no longer be justified by the latter (Cicchetti, 1974).

Mann and Witt (1977) indicated that the specific effects of inflation and rapidly increasing energy prices have been several. One, rate structures for both publicly-owned and privately-owned electric utilities have become flatter, i.e., since 1967, there has been a trend toward less disparity in rates across customer classes. Two, the recent rising costs have been reflected significantly more in industrial rates than in commercial and residential electricity rates.

The traditional objectives of utility regulation have been the control of monopoly earnings, the prevention of excessive price discrimination, and the assurance of adequate service on a continuous basis to all user classes. Pressures have emerged in the 1970's for regulatory reform and broadened regulatory objectives. These external pressures include high inflation rates, increasing consumer militance, diminishing supplies of low cost fuel, increasing environmental concern, and technological change (Trebing, 1977). As a result, there has been regulatory reaction to each external pressure. For example, the general response to diminishing supplies of low cost fuel and inflation has been reform and experimentation in electricity rate structures.

THE PRICING ALTERNATIVES

The traditional pricing system for electricity has involved declining marginal (and average rates) with increasing use and demand. For small users (largely residential), there are declining block schedules for kwh usage. For large users (commercial and industrial), there are declining energy (kwh) charges coupled with declining capacity (kw) charges, i.e., rates that decline with increased kw capacity. The latter are generally utilized at the time of maximum demand. Thus, electricity price has essentially two components: energy or kwh rates which decline with kwh consumption; and demand or kw rates which decline with maximum kw demand.

The conventional method of pricing, rates based on average or unit accounting cost, focuses on three kinds of costs in establishing electricity prices: customer costs (a function of customer number), operating costs (a function of kwh usage), and demand costs (a function of maximum kw demand). The latter can be categorized as to generation capacity costs, transmission capacity costs, and distribution capacity costs. Similarly, prices based on marginal cost are the sum of marginal generation costs (capacity and operating), marginal transmission costs (capacity and operating), marginal distribution costs (capacity and operating), and marginal customer costs.

The Options

The electricity rate options involve choices of costing method and whether or not to apply time differentiation. There are four basic options (Uhler, 1977):

1. Non-time differentiated average cost (NTDAC). This option is the traditional regulatory approach involving electricity rates based on some variation of fully distributed, imbedded, or historical accounting cost. Rates do not vary with time of usage.

2. Non-time differentiated marginal cost (NTDMC). This option involves electricity rates based on some variation of incremental or marginal cost (e.g., long-run incremental costs). Rates do not vary with time of consumption.

3. Time-differentiated average cost (TDAC). This option involves electricity rates based on average accounting cost but with adjustments for time of usage. The peak load pricing can take the form of either seasonal, time-of-day rate variations, or both. The critical aspect is that rates vary with time of consumption i.e., rates vary with peak and off-peak periods.

4. Time-differentiated marginal cost (TDMC). This option involves electricity rates based on marginal cost adjusted for time of usage. The peak load pricing can take the form of either seasonal, time-of-day rate variations, or both. The critical aspect is that rates vary with time of consumption, i.e., rates vary with peak and off-peak periods.

This categorization indicates that time-differentiated or peak load pricing can be based on average cost as well as marginal cost. Recent experimentation with peak load pricing has involved peak and off-peak rates based on both average and marginal cost. As indicated below, peak load pricing based on average cost can be viewed as a practical compromise which minimizes the potential problem of excess revenue generation (i.e., revenues in excess of operation and other relevant costs including an adequate rate of return) occurring under peak load pricing based on marginal cost (Uhler, 1977). In brief, marginal cost pricing is not synonymous with peak load pricing. Electricity rate levels can be based on either average or marginal costs. Electricity rate structures can be based on average cost, marginal cost, or some other consideration (e.g., value of service); electricity rate structures can also be time differentiated.

Trends in Average Prices

It is instructive to examine past pricing trends under conventional average cost pricing. The price measure employed is cost per kwh, or electricity revenues divided by kwh sales. The data sources include the Federal Power Commission publications: Statistics of Privately Owned Electric Utilities in the United States; Statistics of Publicly Owned Electric Utilities in the United States; and the Rural Electrification Administration publication, Annual Statistical Report, Rural Electric Borrowers.

Viewing a composite of investor-owned electric utilities, publicly-owned electric utilities, and rural electric cooperatives, one finds average electricity prices (in actual terms) in the United States to be:

	Residential	Commercial-Industrial	Aggregate
1961	2.47¢	1.48¢	1.80¢
1965	2.25	1.38	1.67
1970	2.10	1.38	1.63
1975	3.30	2.55	2.83

Viewing the overall average price (in actual terms) for the three ownership categories, one finds:

	Investor-Owned	Publicly-Owned	Rural Cooperatives
1961	1.82¢	1.38¢	2.30¢
1965	1.69	1.32	2.02
1970	1.67	1.30	1.83
1975	2.92	2.18	2.67

Both data sets indicate the significant upsurge in actual electricity prices that has occured since 1970.

Table 13 provides the average annual growth rates in electricity prices for the United States and for an ORBES region sample. The growth rates for the United States are categorized by both ownership type and by user class. The growth rates for the ORBES region sample are categorized by both state and by user class. The price trends are calculated for three different historical periods: 1961-1975, 1965-1975, and 1970-1975. The annual growth rates are expressed in actual terms and, when applicable, in real terms. Given the more recent actual price trends (i.e., 1965-1975, 1970-1975), it is reasonable to conclude that 5.0 percent establishs a somewhat conservative estimate of future per annum increases in actual electricity rates; in contrast, 11.0 percent establishs more liberal estimate of future per annum increases in actual electricity rates.

Tables 14 and 15 present real average price projections. The real price projections employ actual 1975 kwh prices at their base. Prices are estimated at 5-year intervals through the year 2000. The real price projections are made under three different annual growth rate assumptions, i.e., 5.0 percent increase in actual prices (the conservative benchmark), 8.0 percent increase in actual prices (a midpoint estimate), and 11.0 percent increase in actual prices (the liberal benchmark). The annual inflation rate incorporated in the real electricity price projections is 5.5 percent. Thus, the projected price reflect only real increases in electricity prices. Table 14 exhibits the price projections for customer categories while Table 15 exhibits the real price projections for the six states represented in the ORBES region sample.

The price projections in Table 14 can be viewed as illustrative of what may happen to real electricity prices for the various user categories in the next several decades; however, they do not take into account regulatory effects such as industrial users bearing a greater burden of the real rate increase than commercial and residential users (Mann and Witt, 1977). Similarly, the price projections in Table 15 can be viewed as illustrative of what may happen to real electricity prices in the six states represented in the ORBES region, however, the projections do not take into account effects such as interstate differences in regulation and differences in accessibility to relatively low cost fuel. The projections in Table 14 and 15 indicate a wide range of possible real average electricity prices by the year 2000, given different assumptions regarding the rate of increase in actual electricity prices.

A Comparison of Marginal Cost and Average Cost Pricing

There are important conceptual differences between marginal cost and average cost pricing as applied to the public utility sector. For example, the relationship between average and marginal cost on a historical basis is not identical to the relationship between average and marginal cost on a current basis (Cicchetti, Gillen, and Smolensky, 1977). That is, marginal cost estimation by definition is forward-looking (it generally incorporates a future time horizon of some specified duration). Since the actual costs

TABLE 13

ACTUAL AND REAL AVERAGE ANNUAL GROWTH RATE IN UNITED STATES AND ORBES REGION ELECTRICITY PRICES, 1961-1975[1]

	1961-1975 Actual	1961-1975 Real	1965-1975 Actual	1965-1975 Real	1970-1975 Actual	1970-1975 Real
I. United States						
Investor-Owned Electrics	3.4%	-1.0%	5.6%	-0.2%	11.8%	3.2%
Publicly-Owned Electrics	2.6	-1.1	4.3	-0.7	10.9	2.3
Rural Electric Cooperatives	1.1	-3.3	2.8	-3.2	7.8	0.4
Residential	2.1	-2.2	3.9	-1.5	9.5	2.5
Commercial-Industrial	4.0	-0.5	6.3	0.2	13.1	3.2
Total	3.2	-1.1	5.4	-0.4	11.7	3.1
III. ORBES Sample[2]						
Illinois	1.5%	-2.3%	3.1%	-1.8%	7.7%	0.8%
Indiana	1.7	-3.8	3.3	-3.9	7.9	-2.4
Kentucky	1.9	1.3	3.9	1.6	8.2	-0.1
Ohio	3.0	-2.0	6.2	0.8	12.7	2.8
Pennsylvania	4.5	0.3	6.5	1.3	13.7	5.6
West Virginia	4.5	0.0	7.2	1.2	14.7	2.7
Residential	1.8	-2.3	3.3	-1.8	8.6	1.9
Commercial	2.2	-2.1	3.9	-1.8	9.4	-1.0
Industrial	4.1	-0.2	7.3	1.6	14.6	-1.6
Total	3.1	-1.2	5.5	0.0	11.7	2.7

[1] The real growth rates are a result of adjustments for inflation (as measured by the Consumer Price and Wholesale Price Indices) during the period, 1961-1975.

[2] Based on a sample of 39 investor-owned electric utilities located in the ORBES region. The sample accounts for 90.1 percent of 1975 kwh sales in the six states region.

TABLE 14

PROJECTIONS OF REAL AVERAGE ELECTRICITY PRICES (BY USER) FOR THE ORBES REGION, 1975-2000[1]

	Actual 1975	1980	1985	1990	1995	2000
I. 5 Percent Annual Growth						
Residential	3.35¢	3.27¢	3.20¢	3.12¢	3.05¢	2.97¢
Commercial	3.24	3.17	3.09	3.02	2.95	2.88
Industrial	2.04	1.99	1.94	1.90	1.85	1.81
Total	2.69	2.62	2.56	2.50	2.45	2.39
II. 8 Percent Annual Growth						
Residential	3.35¢	3.76¢	4.23¢	4.76¢	5.35¢	6.02¢
Commercial	3.24	3.64	4.09	4.60	5.18	5.82
Industrial	2.04	2.30	2.58	2.90	3.26	3.66
Total	2.69	3.02	3.40	3.82	4.30	4.83
III. 11 Percent Annual Growth						
Residential	3.35¢	4.32¢	5.57¢	7.18¢	9.26¢	11.93¢
Commercial	3.24	4.18	5.39	6.94	8.95	11.54
Industrial	2.04	2.63	3.39	4.37	5.64	7.27
Total	2.69	3.47	4.47	5.76	7.43	9.58

[1]Price is measured in cents per kwh. The price projections are based on 1975 data for a sample of 39 investor-owned electric utilities located in the ORBES region. The real electricity price projections incorporate an annual inflation rate of 5.5 percent.

TABLE 15

PROJECTIONS OF REAL AVERAGE ELECTRICITY PRICES (BY STATE) FOR THE ORBES REGION, 1975-2000[1]

	Actual 1975	1980	1985	1990	1995	2000
I. 5 Percent Annual Growth						
Illinois	2.71¢	2.65¢	2.58¢	2.52¢	2.46¢	2.41¢
Indiana	2.28	2.23	2.17	2.12	2.07	2.02
Kentucky	2.31	2.26	2.20	2.15	2.10	2.05
Ohio	2.75	2.69	2.62	2.56	2.50	2.44
Pennsylvania	3.04	2.97	2.90	2.83	2.77	2.70
West Virginia	2.54	2.48	2.42	2.37	2.31	2.26
II. 8 Percent Annual Growth						
Illinois	2.71¢	3.05¢	3.42¢	3.85¢	4.33¢	4.87¢
Indiana	2.28	2.56	2.88	3.24	3.64	4.09
Kentucky	2.31	2.59	2.92	3.28	3.69	4.15
Ohio	2.75	3.09	3.48	3.91	4.39	4.94
Pennsylvania	3.04	3.42	3.84	4.32	4.86	5.46
West Virginia	2.54	2.85	3.21	3.61	4.06	4.56
III. 11 Percent Annual Growth						
Illinois	2.71¢	3.50¢	4.50¢	5.81¢	7.49¢	9.66¢
Indiana	2.28	2.94	3.79	4.89	6.30	8.12
Kentucky	2.31	2.98	3.86	4.95	6.38	8.23
Ohio	2.75	3.54	4.57	5.89	7.60	9.80
Pennsylvania	3.04	3.92	5.05	6.52	8.40	10.83
West Virginia	2.54	3.27	4.22	5.44	7.02	9.05

[1]Price is measured in cents per kwh. The price projections are based on 1975 data for a sample of 39 investor owned electric utilities located in the ORBES region. The real electricity price projections incorporate an annual inflation rate of 5.5 percent.

of generation plant and fuel have been increasing rapidly, one anticipates that the difference between current average and marginal cost (adjusted for price level changes) is significantly less than the difference between historical average cost and marginal cost.

Boiteaux (1960) argued that the difference between current average cost (AC_c) and historical average cost (AC_a) for French electricity production in the late 1950's was similar to the difference between current average and marginal cost (MC). That is, $AC_c > AC_a$, to the same degree as $AC_c > MC$; therefore AC_a tended to approximate marginal cost. However, for electric utilities in the United States in the 1970's, it is reasonable to presume that $MC > AC_c > AC_a$. Disregarding the difficulties of determining the extent to which $MC > AC_c$ and $MC > AC_a$ (or conversely, $AC_c > AC_a$), conservative estimates of effects of marginal cost replacing average cost as the pricing base can be generated by focusing on the difference between MC and AC_c; liberal estimates can be generated by focusing on MC and AC_a.

Morton (1976) indicated that since long-run average cost (LRAC) is the average cost of electricity from all existing plants priced at historical cost, it will be lower than both current average cost and long-run incremental cost (LRIC). LRAC incorporates both the cost of new output as well as the cost of old output; LRIC focuses only on the cost of producing new output. And, as emphasized previously, peak load pricing can be adopted under either LRAC or LRIC standards, e.g., a LRAC price of 4¢ per kwh can have deviations for peak and off-peak; a LRIC price of 5¢ per kwh can have variances for peak and off-peak.

The regulatory process tends to minimize the differences between electricity prices "based" on marginal cost and electricity prices "based" on average or imbedded cost. Since accounting costs have been (and will probably continue to be) the dominant consideration in the determination of the revenue requirements for electric utilities in the regulatory process, and since marginal cost tends to be higher than historical average cost; meeting the revenue requirement constraint has involved setting some rates less than marginal cost (Electric Utility Rate Design Study, 1977). In constraining marginal cost rates, the result is that they tend to converge toward average cost rates. Thus, marginal cost pricing in practice deviates significantly from marginal cost pricing in theory. In brief, a set of marginal cost rates must meet the regulatory revenue requirements standard determined by accounting costs. Given the substantial differences between marginal and actual average cost, the former must be adjusted downward to yield the required revenues. In practice, marginal cost rates are not identical to marginal cost but are instead "based" on marginal cost subject to the revenue requirement constraint (Electric Utility Rate Design Study, 1977).

Marginal Cost Pricing

Marginal cost is the specific cost of producing and/or selling a single incremental unit; in electricity, it can be expressed in terms of either a kwh or kw increment. That is, the marginal cost of electricity is the change in total cost by providing additional electricity. It has two primary components: short-run marginal cost (SRMC) which is essentially the change in operating costs by changing the utilization rate of existing capacity; and long-run marginal cost (LRMC) which is essentially the change in operating costs and the incremental capacity costs that ensue from capacity expansion. In sum, marginal cost is simply the cost (or savings) incurred in providing more (or less) electricity.

The marginal cost of electricity is affected by multiple factors (Cicchetti, Gillen, and Smolensky, 1977). Marginal cost varies with voltage (reflecting differences in transmission-distribution losses at different voltage levels) at which the consumer receives service, with time (hours, days and seasons) of usage, quantity of use, and consumer density in the service area.

The recent experience with marginal cost pricing in the United States has involved both peak load pricing for electricity based on marginalist principles as well as electricity pricing (without time differentiation) based on marginal cost (Joskow, 1976). In the context of peak load pricing, the application of marginalist principles has generally involved peak users paying marginal operating plus marginal capacity costs; in theory, off-peak users pay only marginal operating costs. However, Wenders (1976) criticized this traditional marginalist approach, particularly under conditions of different generation technology being employed to produce electricity demand of different durations. That is, he advocated off-peak prices including an element of marginal capacity cost, thus reducing the peak marginal cost price.

Shepherd (1966) distinguished between marginal cost and marginalist pricing. Marginal cost pricing was defined as setting peak and off-peak rates to reflect user contributions to peak demand. In contrast, marginalist pricing was defined as having rate differentials encouraging off-peak usage and discouraging peak consumption but with the rates having little resemblance to marginal cost (e.g., average cost based rates). Non-marginalist pricing was defined as having prices ignoring cost differentials. Anti-marginalist pricing was defined as having price differentials contrary to actual cost differentials. In Shepherd's framework, marginal cost pricing incorporates time differentiated (peak and off-peak) rates. Marginalist pricing is oriented toward increasing off-peak consumption rather than toward economizing on capacity, i.e., marginalist pricing does not involve structuring of rates in accordance with marginal cost differentials.

The calculation of marginal cost generally involves the projection of operating and capacity costs for a specified time frame (e.g., ten years). By definition, the projections exclude historical or imbedded costs, focusing instead on the change in electricity cost over time with capacity expansion and demand increments. As indicated by the Electric Utility Rate Design

Study (1977), marginal cost estimation has three components: marginal customer costs, marginal energy costs, and marginal capacity costs. It may be argued that the conversion from average cost rates to marginal cost rates would alter significantly the demand forecasts upon which the marginal cost rates are based. The result could be a revision of projected demand, capacity requirements, and associated costs. In practice, however, the regulatory process ensures slow price adjustments; and new prices require long time periods to have effect since electricity demand is linked to appliance and equipment stocks (Turvey and Anderson, 1977). Therefore, while feedback effects from the adoption of marginal cost pricing on capacity requirements and electricity costs are important, these effects are sufficiently lagged that rate-setters can wait until the new prices have had an effect on demand forecasts, and then price adjustments can be made.

It may be instructive to examine some marginal cost estimates for electricity provision. One can obtain a comparison of historical average cost and projected marginal cost from a Environmental Protection Agency study (1974) of five electric utilities. One of the electric utilities examined was Potomac Electric Power Company. The firm's 1972 costs (in cents per kwh) were estimated to be:

	Average Cost	(off-peak costs) SRMC	(peak costs) LRMC
Residential	2.48¢	.70¢	8.13¢
Commercial	2.19	.70	2.50
Industrial	1.43	.70	2.12

The cost estimates indicate that average cost is below long-run marginal cost (LRMC) and exceeds short-run marginal cost (SRMC). In the Potomac Electric Power case, SRMC ranged from 29 to 49 percent of average accounting cost; LRMC exceeded average cost by 1.1 to 3.3 times. In similar estimates for Duke Power Company, SRMC across user categories ranged from 16 to 49 percent of average accounting cost; LRMC exceeded average cost by 1.2 to 2.5 times.

Scherer (1976) estimated the incremental costs for a thermal electric power system (New York State Electric and Gas Corporation) under different pollution emmission constraints. The study focused on estimating actual marginal cost during several time periods within a demand cycle when a power sytem operates subject to specified pollution limits. Marginal cost was defined as the increment to total cost when one additional kw is used in the system during a specific time period; average cost was defined as total annualized costs divided by the aggregate energy delivered at all load centers during all time periods within one year. The average cost calculations were on a current basis, i.e., there was a fixed cost factor involving insurance and taxes but not including depreciation or other sunk costs.

The summary results in the Scherer analysis indicated that peak marginal cost, in certain locations within the system, can be 3-4 times average cost, and can exceed 10 times base load marginal cost. Also, marginal cost for base, low, intermediate, and peak periods can vary significantly across load centers within a specific power system. The marginal cost estimates (expressed in cents per kwh and in 1970 dollars) for coal-fired steam plants for seven different load centers were:

	1	2	3	4	5	6	7
Base Period	0.59¢	0.56¢	0.50¢	0.48¢	0.54¢	0.49¢	0.59¢
Low	0.59	0.56	0.54	0.52	0.56	0.54	0.62
Intermediate	0.74	0.70	0.67	0.65	0.69	0.67	0.76
Peak	3.42	3.13	3.11	2.94	3.23	3.13	3.78

The current average cost estimate was approximately 0.85¢. All estimates included both operating and capacity costs. Peak marginal cost varied from 3.4 to 4.4 times current average cost. Peak marginal cost was generally 4-5 times intermediate demand marginal cost; peak marginal cost was generally 5-6 times low demand marginal cost; and peak marginal was generally 6-7 times base period marginal cost. Peak marginal cost exceeded average cost, however average cost in turn exceeded the marginal cost associated with the intermediate, low, and base demand periods.

Cicchetti, Gillen, and Smolensky (1977) provided marginal cost estimates for three electric utilities: Wisconsin Power and Light Company (investor-owned), Sacramento Municipal Utility District (municipally-owned), and Los Angeles Department of Water and Power (municipally-owned). We focus on the cost estimates for Wisconsin Power and Light since, similar to the electric utilities in the ORBES region, it is primarily coal-fired (72 percent in 1974). The other two utilities are heavily dependent on hydro, oil, and nuclear. The cost estimates are expressed in cents per kwh and in 1975 dollars.

	high voltage	primary voltage	low voltage
winter weekday peak			
energy	2.30¢	2.38¢	2.46¢
capacity	.95	1.23	1.46
	3.25¢	3.61¢	4.12¢
summer weekday peak			
energy	1.77¢	1.84¢	1.90¢
capacity	.95	1.23	1.65
	2.72¢	3.16¢	3.55¢
weekend off-peak	1.30¢	1.34¢	1.38¢
nighttime off-peak	.93¢	.95¢	.98¢

The case study indicates that both marginal energy and capacity cost vary with voltage and with time of consumption. The capacity cost estimates incorporated generation, distribution, and transmission capacity change through 1983; the energy cost estimates were for 1975. The Wisconsin Power and Light estimates can be viewed as representative of the overall electric utility industry, i.e., a medium sized utility, diverse customer mix, diverse generating equipment, and kw demand increasing at a growth rate similar to the national average (Cicchetti, Gillen, and Smolensky, 1977).

Time Differentiated Pricing

A number of different rate structures can be employed in peak load pricing. Wenders and Taylor (1976) noted several variations. As noted previously (Uhler, 1977), time differentiated rates may or may not be based on incremental cost. Furthermore, although marginal cost tends to vary with peak and off peak usage, there are numerous exceptions (Cicchetti, Gillen, and Smolensky, 1977). And it may make practical (but not economic) sense to vary prices with time or peak-off peak when incremental cost does not vary.

Time differentiated pricing is essentially prices varying with either kwh usage, kw demand, or both over a daily and/or seasonal cycle. It is generally based on marginalist principles which postulate that an electric utility should expand output as long as consumers are willing to pay the incremental cost of additional production. Its primary purpose has been to improve system load factors. It offers a solution to the problem of supplying peak demands, but again it is not in practice equivalent to marginal cost pricing. For example, De Salvia (1969) estimated that is some cases the ratio of peak marginal cost/off-peak marginal cost to be in excess of 37:1 and the ratio of peak marginal cost/intermediate demand marginal cost to be in excess of 24:1. In practice, price differentials of this magnitude would not be allowed since at the very mininum, drastic changes in usage patterns would result (thus causing new peaks). That is, customers would seek to avoid peak consumption and thus would shift usage to the original off-peak periods.

In addition, price differentials of the above magnitude would not be tolerated in a regulatory environment due to the potential excess revenue problem. As indicated previously (Electric Utility Rate Design Study, 1977), meeting the revenue standard in the regulatory process generally leads to setting some rates below marginal cost. The practical consequence is to constrain rates based on marginal cost to yield total revenues that match total accounting cost including the permitted rate of return. The end results is "marginal cost" rates that diverge significantly from actual marginal cost.

THE POTENTIAL EFFECTS OF TIME DIFFERENTIATED PRICING

The arguments for peak load or time differentiated pricing are generally phrased in terms of capacity investment savings. That is, unless price elasticity of demand is zero, time differentiated pricing will mean less capacity required to meet peak demands than under uniform rates over time. In addition to the savings on deferred capacity, there are also potential savings in fuel costs, particularly in the context of rapidly increasing fuel prices. The mix of capacity cost and fuel cost savings will vary with the plant mix across electric utilities. For example, a typical power system consists of a specific mix of plants to serve different types of loads: peak loads, intermediate loads, and base loads. Each type of load or demand involves a different ratio of capital to fuel costs, e.g., peak loads are generally met with plants having relatively low capital costs and high fuel costs while base loads tend to require plants which are fuel efficient but involve relatively high capital costs. While deferring some peaking capacity and deferring some generation capacity whose criterion for installation is to provide reserve margin or reliability, peak load pricing simultaneously will tend to increase the capacity requirements for base load generation.

A theme that prevails herein is that the effect on capacity requirements and associated fuel costs from peak load pricing is difficult to determine, i.e., "hard" data on capital investment deferment and fuel cost savings are difficult to obtain. A particular difficulty in evaluating the potential benefits from time differentiated pricing is determining the alteration of load curves. No extensive experience in the United States has been reported upon which to base these determinations (Federal Energy Administration, 1977). However, preliminary analyses show potential and substantial long-term savings from time differentiated pricing. In brief, since we are on the threshold of peak load pricing in the United States it is much too early to conclusively measure the impact on capacity utilization, capacity requirements, etc. (Joint Economic Committee, 1974). Since we have had little prior experience in the United States with differentiated rates, the results of consumption shifts with peak load pricing are essentially conjectural (Berlin, Cicchetti, and Gillen, 1974). However, as experience and data are accumulated, the effects will become easier to estimate.

The United Kingdom Experience

A pricing experiment (under the auspices of the Electricity Council) was conducted in England during the period of 1966-1972; the experiment combined seasonal and time-of-day rate structures for residential users. The average load factor without the experimental rates was 50 percent; with the three experimental rates, the annual or average day load factor increased to 51, 57, and 60 percent (Boggis, 1976; Joint Economic Committee, 1974). Under a combined seasonal and time-of-day rate schedule in which the peak price was 300 percent of standard price, intermediate price was 80 percent of standard, and off-peak price was 40 percent of standard; load factors experienced a 14 percent increase to 57 percent. Under a seasonal rate schedule to which peak price was 150 percent of standard price and off-peak price was 70 percent of standard, load factors experienced an increase of 20 percent to 60 percent.

There are little data available in the English experiment as to the effect on capacity requirements from the peak load (marginal cost based) pricing. It is possible that the period 1966-1972 was insufficient in duration to ascertain the long-run impact on usage, operating costs, and capital investment costs as compared to the French experience of over 20 years. In this context, Wenders and Taylor (1976) noted that the load factor results reflected more the elevation of consumption valleys than the shaving of consumption peaks. That is, the peak load data (hourly and seasonal) indicated little decrease in peak demands. Therefore the capital savings effect from this rate experiment may have been minimal. National Economic Research Associates (1977) provided an estimate of 3 percent decrease in peak load megawatt demand as one of the effects of the experiment.

The French Experience

The French initiated their "green tariff," a marginal cost based peak load pricing system, in 1956. There was a transition period of adoption from 1957 through 1963. The peak load pricing system applied only to industrial consumers and incorporated peak and off-peak energy charges as well as peak and off-peak kw capacity charges. The statistics indicate that the effects on load factors for the period 1954-1974 included: an annual percentage decline in energy consumed of 0.4 at the hourly peak; a 0.6 annual percentage decline in the winter daily peak; and a 2.0 percent annual decline in the summer daily peak (Balasko, 1976). The capital investment savings are estimated to be 6,500 megawatts of capacity by 1980, i.e., it is estimated that without the peak load pricing scheme, Electricite de France (EDF) would need 6,500 megawatts of capacity in addition to the 47,000 megawatts of capacity planned for 1980. In brief, after 24 years of peak load pricing, the estimated savings is nearly 14 percent of actual megawatt capacity.

National Economic Research Associates (1977) reported a steady flattening of both daily and annual load curves over the period 1958-1975. For example, the winter load factor increased from 72 percent in 1952 to 87 percent in 1975. Average winter peaks relative to summer off-peak consumption decreased from 2.0 to 1.6 in the period of 1958-1975. In brief, the French experience with industrial peak load pricing over several decades indicates both substantial improvements in load factors and substantial savings in capacity requirements.

The United States Experience

The Federal Energy Administration (1977) investigated the effects of selected load management strategies (including time-of-day pricing) on two electric utilities. The first electric utility was coal fired with a large industrial load; the second electric utility was oil fired with a large residential load. The analysis involved cost simulations based on historical accounting data for 1974. The operating benefits from time-of-day pricing were an estimated 4 percent annual decline in operating costs for both electric utilities and an estimated 7 percent decline in peak demand. The elapsed time necessary for the substantial decline in peak demand was not specified.

Acton, Manning, and Mitchell (1977) reported on a time-of-day pricing experiment in Los Angeles. However, the experiment was not initiated until 1977, therefore, unlike the British and French experience, the time elapsed is insufficient to determine with any accuracy the effects on daily and annual load factors, operating (fuel) costs and capacity requirements. For example, 30 months data are certainly not comparable with the French experience with peak load pricing of over two decades. The same can be concluded about a combined time-of-day and seasonal pricing experiment in Arkansas (Kehler, 1977). The latter experiment was initiated in late 1975. No significant shifts occurred in the early stages of the experiment. Again, the relatively short duration of the experiment does not allow for accurate measurement of the long-run effects on usage, load factors, operating costs, and capacity requirements. Holeman (1978) reported some tentative results from the Arkansas experiment. One, the time-of-day rates produced substantial differences between peak and off-peak kw demand for the time-of-day sample and the control sample. Two, the time-of-day rates have reduced kwh monthly usage 10 to 20 percent in the early stages of the experiment.

In general, implementation of time-of-use rates for commercial-industrial consumers in the United States is a very recent phenomenon. Therefore, detailed analyses of effects have not been published (Malko and Simpson, 1977). Long Island Lighting Company implemented time differentiated pricing for its largest 175 customers in February 1977; Central Hudson Gas and Electric (New York) implemented peak load pricing for its 50 largest industrial users in March 1978. Other peak load pricing schemes include Wisconsin Power and Light (130 largest commercial and industrial users, January 1977); Commonwealth Edison (700 industrial users, November 1977); Detroit Edison (2,100 industrial users, March 1976); and Consumers Power (3,000 commercial and industrial users, April 1976).

An up to date summary of various regulatory pricing reforms and experiments is provided by the United States Department of Energy (1979). As stated previously, in most cases, the time elapsed since the initiation of the reforms and experiments has been insufficient to ascertain both their short-run and long-run impact. Pacific Gas and Electric Company implemented time-of-day and seasonal rates for large users in February, 1977; preliminary results indicate a 3 percent kw shift from peak to off-peak periods. Southern California Edison Company and San Diego Gas and Electric Company report similar preliminary results with time differentiated pricing. The Los Angeles Department of Water and Power initiated voluntary peak load pricing in December 1978; total participation is estimated to be 5,000 customers. Virginia Electric and Power Company initiated voluntary time-of-use rates for residential consumers in 1977; this is to be extended an a mandatory basis to 20,000 residential customers in 1980. Long Island Lighting Company in early 1980 will implement mandatory time-of-use pricing for 1,100 large residential users. Wisconsin Electric Power Company in July 1978 implemented mandatory time-of-use pricing for 580 large residential consumers. Commonwealth Edison Company initiated a residential pricing experiment for over 500 customers in late 1978.

Uhler (1978), in a recent survey, indicated that substantial rate structure reform has taken place in the United States. Since January 1976, approximately 25 states have approved time differentiated electricity rates; approximately 30 states have initiated voluntary or mandatory load management experiments; and more than 35 state regulatory commissions have issued orders or decisions relating to time differentiated pricing. Forty-one states now have some form of seasonal peak load pricing while 26 states have some form of time-of-day peak load pricing. Uhler (1978) noted that the empirical data is too meagre to provide generalizations as to the load factor, cost, and capacity requirements effects of rate structure reform. In brief, the current advocacy of time-of-use pricing is not based on extensive empirical results.

The Electric Utility Rate Design Study

An important part of the Electric Utility Rate Design Study (1977) was the employment of several simulation models to estimate the capacity and cost effects of time differentiated pricing. The computer models simulated the operation of an electric utility over a specified time period comparing, among other things, the effects of non-time differentiated versus time differentiated rates. Each of the two simulation models employed data from a single electric utility for evaluating the benefits from load shifts. In doing so, the models simulated capacity expansion plans for 10-20 years. Each simulation model employed a base case (non-time differentiated pricing without load shifting) and several load shifting cases. The load shifting cases were presumed to be representative of the type of load changes to be anticipated from time differentiated pricing. Finally, the differences were calculated between the alternative simulation runs and the base case thus determining the estimated cost effects that can be attributed to time differentiated pricing.

The methodology of the simulation analyses presumed the potential benefits from the implementation of peak load pricing to be determined by specific system characteristics. That is, the potential savings from time differentiated pricing are enhanced by general system (supply) characteristics such as: a wide range of fuel costs per kwh, low capacity utilization rates on generating units having low fuel costs, the wholesaling of off-peak energy at low kwh rates, and generation expansion plans that include high fuel cost units. In addition, the potential savings from time differentiated pricing are enhanced by load (demand) characteristics such as: low annual load factors, low daily load factors particularly on peak days, highly seasonal peak load patterns, and a high proportion of loads whose demands are relatively price elastic. In sum, cost savings are presumed to be influenced by both demand conditions (e.g., load served, peaking conditions) and supplyconditions (e.g., generation system characteristics, planned capacity) confronting each electric utility.

One electric utility analysed was Northern States Power Company (Power Technologies, Inc., 1977). This electric utility experiences summer peaks, has a one-third residential consumer mix, and has a generation mix of 90 percent coal-nuclear. The firm had an annual load factor of 54 percent in 1975 with a peak load of 4206 megawatts. The simulation exercise incorporated a planning period of 1976-1990 with time differentiated rates being imposed in 1977. The simulation focused on all customer categories. The base case projected the original load patterns without time differentiated pricing. The three simulated cases incorporated different assumptions as to peak load shifting but incorporated the common premise that 100 percent of the load shift was recovered in off-peak periods. That is, the three simulated cases varied as to peak periods and recovery patterns.

In the Northern States Power Company simulations, the base case annual peak load was projected to be 9935 mw in 1990. One simulation under time differentiated pricing projected a peak load capacity in 1990 of 9278 mw (a 5.6 percent decrease from the base case) with a 1.4 percent decline in operation costs and a 7.1 percent decline in total costs. A second simulation projected 1990 peak load capacity to be 9579 mw (a 3.6 percent from the base case) with a 1.4 percent decrease in operating costs and a 4.6 percent decrease in total costs. A final simulation projected 1990 peak load capacity to be 9087 mw (an 8.5 percent decrease from the base case) with a 1.5 percent decrease in operating costs and a 6.4 percent decrease in total costs. In brief, these time differentiated pricing simulations indicated capacity savings of approximately 6.0 percent over a 14-year period (1977-1990) with total costs savings of approximately 6.0 percent.

The second electric utility analysed was Southern California Edison (Systems Control, Inc., 1977). This utility experiences summer peaks, has a generation mix of 50 percent oil-gas, and had a annual load factor of 61 percent in 1975 with a peak load of 11,081 mw. Again, the simulation exercise incorporated a planning period of 1976-1990 with time differentiated rates commencing in 1977. This simulation focused on industrial users only. The base case projected the original load pattern without time differentiated pricing. The three simulation cases varied as to peak patterns and recovery periods but incorporated the common premise that energy shifted from peak is reconstituted at off-peak (total energy delivered remains constant).

In the Southern California Edison simulations, there were three sets of results. One simulation under time differentiated pricing projected peak load capacity to decline 10.6 percent from the base case by 1990 with a 4.2 percent decline in operating costs and a 4.1 percent decline in total costs. A second simulation projected peak load capacity to decrease 5.2 percent from the base case by 1990 with a 2.6 percent decrease in operating costs and a 2.1 percent decrease in total costs. A final simulation projected peak load capacity to decrease 5.2 percent from the base case by 1990 with a 2.6 percent decline in operating costs and a 3.3 percent decline in total costs. In brief, these time differentiated pricing simulations indicated capacity savings of approximately 7.0 percent over a 14-year period with total cost savings of approximately 3.2 percent.

The two simulations indicate that time differentiated pricing can generate capacity savings ranging from 4.0 to 11.0 percent, operation cost savings ranging from 2.0 to 4.0 percent, and total cost savings ranging from 2.0 to 7.0 percent. These are estimates for a time interval of 14-years from the adoption of time differentiated pricing.

THE IMPLICATIONS FOR THE ORBES REGION

The simulation results previously discussed were dependent on assumptions regarding load shifting. The assumptions concerning changing load shapes from time differentiated pricing can be viewed as reasonable conjectures, however, they do lack extensive empirical support. Therefore, the simulation results must be viewed as highly tentative.

The assumptions regarding load shifting were necessitated by the situation of no reliable body of data being available at present concerning consumer response to time differentiated pricing (Electric Utility Rate Design Study, 1977).

> "At this point in time there does not appear to be a reliable body of data concerning expected consumer response.... Overall energy consumption price elasticity data may be satisfactory foundation for the forecasting of total consumption as a function of average price, but these data do not indicate if consumers will shift their consumption (load) pattern and, if so, in what manner (p. 102)."

In brief, the simulations did not incorporate price elasticity effects; they did not account for the potential change in electricity demand due to the rate restructuring. The simulations only accounted for declines in peak loads under specified load shifts. In sum, price elasticity data for electricity demand can provide the basis for forecasting energy usage in response to changes in average prices. The price elasticity data cannot be relied on to determine whether or not consumers will alter consumption patterns (as a results of time differentiated rates), to determine the exact nature of the shift in usage patterns, and to determine the time period necessary for the consumption changes.

Electricity generation capacity (in megawatts) in the six states encompassing the ORBES region experienced an average annual growth rate of 4.1 percent for 1961-1975; however, capacity increased at the lesser annual rate of 3.8 percent for 1970-1975. We now examine the potential capacity reduction effects from time differentiated pricing. This time differentiated pricing is presumed to be based on marginal cost, although time differentiated pricing based on average cost will possibly produce similar results. The effects are analyzed under different average electricity demand (and corresponding capacity requirements) growth conditions, e.g., annual growth rates of 3, 4, and 5 percent. The effects are also analyzed under different peak load capacity reductions, e.g., 10, 15, and 20 percent. The capacity effects are predicted for the year 2000 assuming the immediate implementation of time differentiated pricing for electricity.

Table 16 exhibits estimates of capacity reduction effects from time differentiated rates for the six states region. The electric utility simulations indicated that peak load capacity can be reduced by as much as 10 percent by time differentiated pricing (based on marginal cost) over a 14-year period. The French experience over a somewhat longer time period indicated capacity savings of nearly 15 percent. Table 16 exhibits estimated reductions in required capacity from time differentiated pricing

TABLE 16

POTENTIAL MW CAPACITY REDUCTION EFFECTS FROM TIME DIFFERENTIATED RATES--THE SIX STATES REGION

	MW Capacity 1974[1]	Projected MW Capacity in 2000	Time Differentiated Rate Capacity Reduction Effect 10 Percent	15 Percent	20 Percent
Case 1 = 3 Percent Annual Growth Rate in Average Electricity Demand					
Illinois	25625	55262.6	49736.3	46973.2	44210.1
Indiana	12517	26994.0	24294.6	22944.9	21595.2
Kentucky	11472	24740.4	22266.4	21029.3	19792.3
Ohio	22945	49483.0	44534.7	42060.6	39586.4
Pennsylvania	22793	49155.2	44239.7	41781.9	39324.2
West Virginia	12347	26627.4	23964.7	22633.3	21301.9
Region	107699	232262.6	209036.4	197423.2	185810.1
Adjusted Annual Growth Rate in Peak Demand (%)			2.57	2.33	2.08
Case 2 = 4 Percent Annual Growth Rate in Average Electricity Demand					
Illinois	25625	71044.5	63940.0	60387.8	56835.6
Indiana	12517	34703.0	31232.7	29497.6	27762.4
Kentucky	11472	31805.8	28625.2	27034.9	25444.6
Ohio	22945	63614.3	57252.9	54072.2	50891.4
Pennsylvania	22793	63192.9	56873.6	53714.0	50554.3
West Virginia	12347	34231.7	30808.5	29096.9	27385.4
Region	107699	298592.2	268732.9	253803.4	238873.7
Adjusted Annual Growth Rate in Peak Demand (%)			3.56	3.33	3.08

(Continued)

TABLE 16 (Continued)

	MW Capacity 1974[1]	Projected MW Capacity in 2000	Time Differentiated 10 Percent	Rate Capacity 15 Percent	Reduction Effect 20 Percent
Case 3 = 5 Percent Annual Growth Rate in Average Electricity Demand					
Illinois	25625	91114.1	82002.7	77447.0	72891.3
Indiana	12517	44506.4	40055.8	37830.4	35605.1
Kentucky	11472	40790.7	36711.6	34672.1	32632.6
Ohio	22945	81584.9	73426.4	69347.2	65267.9
Pennsylvania	22793	81044.4	72940.0	68887.7	64835.5
West Virginia	12347	43901.9	39511.7	37316.6	35121.5
Region	107699	382942.4	344648.2	325501.0	306353.9
Adjusted Annual Growth Rate in Peak Demand (%)			4.56	4.32	4.07

[1]The 1974 generation capacity data is derived from Exhibit 6 in a memorandum (April 16, 1979) from Owen Lentz, Executive Manager, East Central Area Reliability Coordination Agreement, to Dr. Walter Page, Associate Professor Economics, West Virginia University.

by the year 2000 to range from 23,000 mw (the 10 percent reduction case) to 46,400 mw (the 20 percent reduction case) given a 3 percent annual growth rate for average demand. Under the assumption of 4 percent annual growth in average demand, the estimated reductions in required capacity range from 29,900 mw to 59,800 mw. Under the assumption of 5 percent annual growth in average demand, the estimated reductions in required capacity range from 38,300 mw to 76,600 mw. As indicated by the tabular material, the estimated reductions in peak load capacity can be translated into lesser annual growth rates for peak electricity demand. For example, a 20 percent reduction in capacity requirements by the year 2000 in the case of an annual growth rate of 3 percent indicates that peak demand is increasing at an annual rate of approximately 2.08 percent.

Table 17 exhibits estimates of capacity reduction effects from time differentiated rates for the ORBES region. The estimated reductions in required capacity by the year 2000 range from 16,600 mw to 33,200 mw given 3 percent annual growth in average demand. Under the assumption of 4 percent annual growth in average demand, the estimated reductions in required capacity range from 21,400 mw to 42,800 mw. Under the assumption of 5 percent annual growth in average demand, the estimated reductions in required capacity range from 27,400 mw to 54,800 mw. The reductions in peak load capacity in the 3, 4, and 5 percent annual growth cases can be translated into lesser annual growth rates for peak electricity demand in the ORBES region.

Table 18 exhibits estimates of load reduction effects (Table 16 and 17 focus on capacity reduction effects) from time differentiated pricing for the six states region. The estimated reductions in load by the year 2000 range from 17,000 mw to 34,000 mw given 3 percent annual growth in average demand. Under the assumption of 4 percent annual growth in average demand, the estimated load reductions range from 21,800 mw to 43,600 mw. Under the assumption of 5 percent annual growth in average demand, the estimated load reductions range from 28,000 mw to 56,000 mw. The load reductions in the 3, 4, and 5 percent annual growth cases can be translated into lesser annual growth rates for peak electricity demand in the six states region.

In Table 19 are exhibited estimates of load reduction effects from time differentiated rates for the ORBES region. The estimated reductions in load by the year 2000 range from 9,900 mw to 19,800 mw given 3 percent annual growth in average demand. Under the assumption of 4 percent annual growth in average demand, the estimated load reductions range from 12,800 mw to 25,600 mw. Under the assumption of 5 percent annual growth in average demand, the estimated load reductions range from 16,400 mw to 32,800 mw. Similar to the other tabular material, the load reductions in the 3, 4, and 5 percent annual growth cases can be translated into lesser annual growth rates for peak electricity demand in the ORBES region.

TABLE 17

POTENTIAL MW CAPACITY REDUCTION EFFECTS FROM
TIME DIFFERENTIATED RATES--THE ORBES REGION

	MW Capacity 1974[1]	Projected MW Capacity in 2000	Time Differentiated Rate Capacity Reduction Effect 10 Percent	15 Percent	20 Percent
Case 1 = 3 Percent Annual Growth Rate in Average Electricity Demand					
Illinois	14432	31123.9	28011.5	26455.3	24899.1
Indiana	10420	22471.7	20224.5	19100.9	17977.4
Kentucky	11472	24740.4	22266.4	21029.3	19792.3
Ohio	17568	37887.0	34098.3	32203.9	30309.6
Pennsylvania	10890	23485.3	21136.8	19962.5	18788.2
West Virginia	12347	26627.4	23964.7	22633.3	21301.9
Region	77129	166335.7	149702.2	141385.2	133068.5
Adjusted Annual Growth Rate in Peak Demand (%)			2.57	2.33	2.08
Case 2 = 4 Percent Annual Growth Rate in Average Electricity Demand					
Illinois	14432	40012.3	36011.1	34010.5	32009.8
Indiana	10420	28889.1	26000.2	24555.7	23111.3
Kentucky	11472	31805.8	28625.2	27034.9	25444.6
Ohio	17568	48706.7	43836.0	41400.7	38965.4
Pennsylvania	10890	30192.2	27173.0	25663.4	24153.8
West Virginia	12347	34231.7	30808.5	29096.9	27385.4
Region	77129	213837.8	192454.0	181762.1	171070.3
Adjusted Annual Growth Rate in Peak Demand (%)			3.56	3.33	3.08

(Continued)

TABLE 17 (Continued)

	MW Capacity 1974[1]	Projected MW Capacity in 2000	Time Differentiated Rate Capacity Reduction Effect		
			10 Percent	15 Percent	20 Percent
Case 3 = 5 Percent Annual Growth Rate in Average Electricity Demand					
Illinois	14432	51315.5	46183.9	43618.2	41052.4
Indiana	10420	37050.1	33345.1	31492.6	29640.1
Kentucky	11472	40790.7	36711.6	34672.1	32632.6
Ohio	17568	62466.1	56219.5	53096.2	49972.9
Pennsylvania	10890	38721.3	34849.2	32913.1	30977.0
West Virginia	12347	43901.9	39511.7	37316.6	35121.5
Region	77129	274245.6	246821.0	233108.8	219396.5
Adjusted Annual Growth Rate in Peak Demand (%)			4.56	4.32	4.07

[1]The 1974 generation capacity data is derived from Exhibit 6 in a memorandum (April 16, 1979) from Owen Lentz, Executive Manager, East Central Area Reliability Coordination Agreement, to Dr. Walter Page, Associate Professor Economics, West Virginia University.

TABLE 18

POTENTIAL MW LOAD REDUCTION EFFECTS FROM
TIME DIFFERENTIATED RATES--THE SIX STATES REGION

	MW Load 1974[1]	Projected MW Load in 2000	Time Differentiated Rate Load Reduction Effect 10 Percent	15 Percent	20 Percent
Case 1 = 3 Percent Annual Growth Rate in Average Electricity Demand					
Illinois	18585	40080.2	36072.2	34068.2	32064.2
Indiana	10387	22400.5	20160.4	19040.4	17920.4
Kentucky	8360	18029.1	16226.2	15324.7	14423.3
Ohio	21228	45780.1	41202.1	38902.1	36624.1
Pennsylvania	16790	36209.2	32588.3	30777.8	28967.4
West Virginia	3303	7123.2	6410.9	6054.7	5698.6
Region	78653	169622.3	152660.1	144178.9	135698.0
Adjusted Annual Growth Rate in Peak Demand (%)			2.57	2.33	2.08
Case 2 = 4 Percent Annual Growth Rate in Average Electricity Demand					
Illinois	18585	51526.3	46373.7	43797.4	41221.0
Indiana	10387	28797.6	25917.8	24478.0	23038.1
Kentucky	8360	23177.8	20860.0	19701.1	18542.2
Ohio	21228	58854.0	52968.6	50025.9	47083.2
Pennsylvania	16790	46549.8	41894.8	39567.3	37239.8
West Virginia	3303	9157.5	8241.7	7783.9	7326.0
Region	78653	218063.0	196256.6	185353.6	174450.3
Adjusted Annual Growth Rate in Peak Demand (%)			3.56	3.33	3.08

(Continued)

TABLE 18 (Continued)

	MW Load 1974[1]	Projected MW Load in 2000	Time Differentiated Rate Load Reduction Effect		
			10 Percent	15 Percent	20 Percent
Case 3 = 5 Percent Annual Growth Rate in Average Electricity Demand					
Illinois	18585	66082.2	59474.0	56169.9	52865.8
Indiana	10387	36932.8	33239.5	31392.9	29546.2
Kentucky	8360	29725.4	26752.9	25266.6	23780.3
Ohio	21228	75479.8	67931.8	64157.8	60383.8
Pennsylvania	16790	59699.7	53729.7	50744.7	47759.8
West Virginia	3303	11744.4	10570.0	9982.7	9395.5
Region	78653	279664.3	251697.9	237714.6	223731.4
Adjusted Annual Growth Rate in Peak Demand (%)			4.56	4.32	4.07

[1] The 1974 generation load data is derived from Exhibit 6 in a memorandum (April 16, 1979) from Owen Lentz, Executive Manager, East Central Area Reliability Coordination Agreement, to Dr. Walter Page, Associate Professor of Economics, West Virginia University.

TABLE 19

POTENTIAL MW LOAD REDUCTION EFFECTS FROM
TIME DIFFERENTIATED RATES--THE ORBES REGION

	MW Load 1974[1]	Projected MW Load in 2000	Time Differentiated Rate Load Reduction Effect 10 Percent	15 Percent	20 Percent
Case 1 = 3 Percent Annual Growth Rate in Average Electricity Demand					
Illinois	6800	14664.8	13198.3	12465.1	11731.8
Indiana	7509	16193.8	14574.4	13764.7	12995.0
Kentucky	8360	18029.1	16226.2	15324.7	14423.3
Ohio	14744	31796.8	28617.1	27027.3	25437.4
Pennsylvania	5631	12143.8	10929.4	10322.2	9715.0
West Virginia	3076	6633.7	5970.3	5638.6	5307.0
Region	46120	99462.0	89515.7	84542.6	79569.5
Adjusted Annual Growth Rate in Peak Demand (%)			2.57	2.33	2.08
Case 2 = 4 Percent Annual Growth Rate in Average Electricity Demand					
Illinois	6800	18852.8	16967.5	16024.9	15082.2
Indiana	7509	20818.5	18736.6	17695.7	16654.8
Kentucky	8360	23177.8	20860.0	19701.1	18543.2
Ohio	14744	40877.3	36789.6	34745.7	32701.8
Pennsylvania	5631	15611.8	14050.6	13270.0	12489.4
West Virginia	3076	8528.1	7675.3	7248.9	6822.5
Region	46120	127866.3	115079.6	108686.3	102292.9
Adjust Annual Growth Rate in Peak Demand (%)			3.56	3.33	3.08

(Continued)

TABLE 19 (Continued)

	MW Load 1974[1]	Projected MW Load in 2000	Time Differentiated Rate Load Reduction Effect 10 Percent	15 Percent	20 Percent
Case 3 = 5 Percent Annual Growth Rate in Average Electricity Demand					
Illinois	6800	24178.6	21760.7	20551.8	19342.9
Indiana	7509	26699.6	24029.6	22694.7	21359.7
Kentucky	8360	29725.4	26752.9	25266.6	23780.3
Ohio	14744	52424.8	47182.3	44561.1	41939.8
Pennsylvania	5631	20022.0	18019.8	17018.7	16017.6
West Virginia	3076	10937.2	9843.5	9296.6	8749.8
Region	46120	163987.6	147588.8	139389.5	131190.1
Adjusted Annual Growth Rate in Peak Demand (%)			4.56	4.32	4.07

[1] The 1974 generation load data is derived from Exhibit 6 in a memorandum (April 16, 1979) from Owen Lentz, Executive Manager, East Central Area Reliability Coordination Agreement, to Dr. Walter Page, Associate Professor of Economics, West Virginia University.

The mw capacity and mw load data for both the six states regions and the ORBES region indicate the potential for significant reductions in load and required capacity from time differentiated pricing. The data indicate that reasonable estimates of potential load and required capacity reductions from peak load pricing for electricity are not, by any measurement, negligible. However, the effect in the short-run on peak demands and capacity requirements from time differentiated pricing may be minimal, particularly in the context of slow adjustment in usage patterns of electricity users. In addition, for the ORBES region, the potential reductions in load capacity from time differentiated pricing have a much higher probability associated with them than the potential reductions in generating capacity. This is due to the potential for the ORBES region becoming a more important exporter of electric power by the year 2000 than it is at present.

The focus in this section has been on the effects of peak load pricing on electric utility generating capacity. Other regulatory reforms are taking place, however, in general these reforms have direct consequences primarily for utility finance and user class revenues and probably have minimal consequences for capacity requirements and associated costs. For example, the imposition of lifeline rates generally affects the distribution of revenues across customer classes. The adoption of automatic cost adjustment clauses generally affects the speed with which rate increases can be implemented. In brief, this report has focused on regulatory reform concerning rate level and rate structure determination, with particular emphasis on issues such as time differentiation and the cost basis for rates. These particular reforms will tend to have impact only on variables such as load factors, load patterns, and capacity requirements. Regulatory reforms concerning administrative procedure, and changes in the very fabric of the regulatory process have been ignored. These latter types of regulatory reform obviously could have affects on distribution of wealth-income, utility profits, and utility financing.

The regulatory reform of time differentiated pricing will have its primary impact on capacity requirements and associated costs. It is difficult to perceive any significant impact that peak load pricing will have on variables such as profits and utility revenues. Future electric utility profits will continue to be a product of regulatory constraints, i.e., rates of return will be adequate to attract capital and compensate existing investors. The rate of annual increase in average electricity prices will be dampened somewhat by regulatory reforms such as peak load pricing, however, the critical determinants of per annun increases in electricity prices will continue to be inflation rates and the increasing cost of energy.

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