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MASTER

Summary I

Time-of-Use Electricity Price Effects

Prepared for the U.S. Department of Energy
Office of Utility Systems

Allen K. Miedema • S. B. White

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TIME-OF-USE ELECTRICITY PRICE EFFECTS

SUMMARY I

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Prepared for
U.S. Department of Energy
Office of Utility Systems

By
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ABSTRACT

In 1975 the Federal Energy Administration, now the Department of Energy (DOE), initiated 16 rate demonstration projects. This report summarizes a standardized analysis of data from the residential portion of six of those projects: Arizona, Connecticut, Ohio, Rhode Island, Wisconsin, and the Blue Ridge Electric Membership Corporation study of the North Carolina project.

A brief description of the DOE rate demonstration program is provided along with a statement of RTI's objectives in the analysis of TOU rate effects. The report also summarizes the individual project results, which indicate that the experimental TOU rates generally reduced both peak period and total electricity usage on both average and peak days, since off-peak usage was usually about the same for both TOU and control customers.

Analysis methods and data limitations are fully described in a style of presentation intended for a range of readers, including those with relatively little background in statistics or econometrics. Additional details on project specific results beyond those provided in the summaries are given. Finally, some qualitative conclusions and impressions about TOU rates that have been suggested by these analyses are offered.

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CHAPTER 1: INTRODUCTION

In 1975 the Federal Energy Administration, now part of the U.S. Department of Energy (DOE), initiated experiments to determine how household consumption of electricity is affected by time-of-use pricing.* These rate demonstration projects were funded by the Federal Energy Administration, participating utilities, and state governments.

The DOE rate demonstration program was established to fulfill three main objectives: (1) to demonstrate the technical and administrative feasibility of implementing TOU rate schedules, (2) to demonstrate and gauge the customer's acceptance of these rates, and (3) to gather and provide data for analyzing the impacts of TOU rates on customer and class load patterns.

In fall 1977, DOE contracted with the Research Triangle Institute (RTI) to perform a standardized analysis on the data from the residential portions of these studies. The RTI analysis includes several major tasks. The first task was to complete the Analytical Master Plan, which was done in early 1978. This Plan summarizes RTI's analytical approach and lists the complete series of final reports. The second task, which is now in progress, is to provide a complete series of project-specific interim and final reports, including reports on 13 of the 16 rate demonstration projects.

The Arizona, Connecticut, Ohio, Rhode Island, and Wisconsin rate demonstration projects are covered in this report as well as the Blue Ridge Electric Membership Corporation study, one of two components of the North Carolina Rate Demonstration Project. All of these projects observe the effects of TOU electricity rates on household electricity consumption.

*These first eight projects were started in 1975 in Arizona, Arkansas, Connecticut, California (Los Angeles), New Jersey, Ohio, Wisconsin, and Vermont. Subsequently, six projects were added in California, North Carolina, Oklahoma (Edmond), Puerto Rico, Rhode Island, and Washington.

Under TOU rates higher prices are charged for electricity during those parts of the day when demand and system costs are higher, and lower prices during times that costs are lower. The findings reported in this summary examine the effects of these temporal variations in electricity prices on household electricity consumption.

The objective of the analyses summarized here is to determine how electricity consumption by residential customers on experimental TOU rate schedules differ in the short run from usage patterns under the existing rate schedule. Specifically, how do residential load curves change when TOU rates are implemented? Also, what effect do TOU rates have on system loads?

This chapter has sketched the history of the DOE rate demonstration program and the main objectives of DOE and RTI. Chapter 2 provides an overview of the design, analytical methodology, and results of the six projects included in this summary report.

Chapter 3 explains in more detail the two types of analytical procedures used to assess the effectiveness of the TOU rates: the comparative analysis and the response surface, or demand, analysis. Both the comparative and demand analyses relied upon a variety of estimation procedures. The two types of comparative procedures used in the RTI analyses are known as analysis of variance (ANOVA) and analysis of covariance (ANCOVA). Chapter 3 outlines the differences between these comparative approaches and describes their applications to the projects in this report.

In applying response surface, or demand, analyses to the TOU projects, the orientations of both the statistician and the economist are brought to bear. They are reflected in the development of two types of models, identified respectively as pragmatic and demand-theoretic models. Chapter 3 also points out the similarities of and differences between the two models,

and summarizes the experimental design, sample design, and data file limitations which apply to both comparative and demand analyses.

Chapter 4 offers the most comprehensive description of the six projects in this report. It includes a detailed summary of the sampling and stratification techniques, data collection and editing procedures, and analytical methods applied in each project. Chapter 5, the final chapter, offers some conclusions and interpretations regarding the results reported in Chapter 4.

This report is intended as a modest contribution to the overall discussion of TOU rate policies. The results summarized here give some general impressions about the magnitude and direction of short-run TOU rate effects. Some of these results may also be useful as preliminary inputs to cost-benefit analyses of TOU rates.

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CHAPTER 2: SUMMARY OF INDIVIDUAL PROJECT RESULTS

This chapter highlights the design and methodology and presents a brief summary of the findings for each of the six projects covered by this report. An expanded discussion of the results for each project can be found in Chapter 4.

Before turning to the individual project analyses, a few general observations can be made about the results summarized in this chapter. Certain general patterns emerged from these analyses. All studies showed some reduction in usage during the peak period under the TOU rates. However, reduction in peak-period usage was not accompanied by statistically significant increases in base-period usage. Total usage seemed either to decline or remain the same in all projects. Customers on TOU rates in most of these projects also tended to use less electricity than control group customers during the peak hour, although those reductions were not always statistically significant. Finally, peak-day usage shifts and average-day usage shifts appeared to be about the same. No obvious generalizations can be made by comparing winter and summer season usage, although the Connecticut and Wisconsin studies showed evidence of seasonal variation.

The Connecticut, Ohio, and Wisconsin projects, having relatively higher TOU price ratios and price differences but representing a relatively smaller percentage of the residential class, had the largest number of statistically significant load shifts. Like the Connecticut and Ohio studies, the Arizona project also involved voluntary participants representing a small proportion of the residential population, and suggested generally significant reductions in peak-period usage. Again, no obvious generalizations can be made from these observations.

Arizona. In the Arizona project 140 voluntary households were placed on one of 28 TOU electricity rates between May and October 1976. These volunteers were divided into three groups distinguished by the length of the peak rating period (3, 5, and 8 hours).

A comparative analysis of 1975 and 1976 for Group I customers showed fairly convincingly that, as a group, the experimental participants reduced their electricity consumption during the three-hour peak rating period by 7-16 percent. To a lesser extent, Group I experimental households reduced consumption during the intermediate period and shifted some consumption to the base period. Total consumption appears to have decreased slightly.

A regression analysis of data from all three groups failed to demonstrate significant elasticities (degree of responsiveness to price) for peak, intermediate, or base prices among test customers; in other words, there were no detectable price-related differences between the consumption patterns of different households that faced alternative TOU electricity prices.

The results of this analysis and all other experiments reported in this summary are limited by their experimental and rate designs. They are strictly applicable only to portions of the residential populations included within the service area under study. In this case, results apply only to portions of the residential populations of Phoenix and Yuma.

Connecticut. From October 1975 to October 1976, 200 customers of the Connecticut Light and Power Company were placed on a seasonal TOU rate. The experimental rate schedule used three rating periods during weekdays and two on weekends. An equal number of customers on the existing rate served as a control group. All participation in the study was voluntary but customers on the experimental rate received a "lump sum" payment before the experiment began.

A comparative analysis of the electricity consumption patterns of the experimental customers on the TOU rate and the control group on the existing (declining block) rate showed that during the summer months the experimental group used less electricity during the peak and intermediate periods without any corresponding increase during the base period. Consequently, overall consumption during the summer months was reduced for the experimental group.

By contrast, during the winter months the experimental group used significantly more electricity than the control group during the base period and considerably less than the control group during the peak period. The experimental group's shifts in usage from peak to base period offset each other, so that overall consumption during the winter months was about the same for both the experimental and the control group.

Projections to the population represented by the sample indicate that under the experimental rate schedule, 12.7 MW would be saved for the winter hour of system peak and 69.5 MW for the summer hour of system peak. These results are strictly applicable only to approximately 45 percent of the residential population within the Connecticut Light and Power Company service area.

Ohio. In the Ohio project 160 customers of the Dayton Power and Light Company (100 on a seasonal TOU rate and 60 on the control rate) became part of an 18-month study from June 1976 to November 1977. The experimental rate schedule used two rating periods during weekdays and a single rating period on weekends and holidays. Participation in the study was voluntary, and participants did not receive any direct compensation.

A comparative analysis, by calendar months, of the electricity consumption patterns of customers on the TOU rate and a control group on the existing (declining block) rate showed that customers on the TOU rate used less

electricity than the control group during the six-hour period of peak prices and used correspondingly more electricity during the base period of low prices. As a result of these offsetting effects, overall consumption was unaffected. Tests of hypotheses showed the peak-period decreases (ranging from 21 to 38 percent on a monthly basis) to be statistically significant. On the other hand, the base-period increases were not significant (at the 5 percent level) because of much larger customer-to-customer variation in base-period usage.

During the sampling process, a large number (about 80 percent) of the customers selected to participate in the study were not included for various reasons, such as meter installation problems, refusal to participate, and moving plans. The final sample of about 39,000 residential customers constituted 20 percent of the sampled population and 12 percent of all residential customers in the Dayton Power and Light Company service area.

North Carolina BREMC. The Blue Ridge Electric Membership Corporation placed 102 residential customers on a seasonal TOU rate for a 12-month period beginning in October 1977. The experimental rate schedule used three daily rating periods during the winter and two during the summer. A total of 98 customers on the existing rate served as control group. Participation in the study was mandatory and customers did not receive incentive or participation payments.

Electricity consumption patterns were examined by rating period (peak, intermediate, base, and overall) for both the average day of the month and for the day of system peak. The results indicated that throughout the 12-month study period, consumption patterns under the TOU rate schedule differed very little from those under the existing (declining block) rate schedule. There was no indication of either a conservation effect by customers on the

TOU rate schedule or of a shifting of electricity usage by those on the TOU rate from the period of highest price to the period of lowest price. In general, the findings of this study showed a negligible response to the TOU rate schedule used in the experiment.

The results apply to nearly the entire group of residential customers on the Blue Ridge system. Preliminary analysis of a subsample of high-usage customers revealed more of the load shifting responses expected of TOU customers. However, possibly because of the smaller sample size of the high-usage group, those estimated responses, while relatively large in percentage terms, were not statistically significant.

Rhode Island. The Rhode Island project was a 13-month controlled experiment (November 1977 to December 1978) in which 170 customers of the Blackstone Valley Electric Company were placed on a seasonal TOU rate that had two demand charges. Three rating periods were used during summer weekdays and two rating periods during winter weekdays. All weekends and holidays had a single rating period. One hundred and thirty customers on the existing rate served as a control group. Participation in the study was mandatory; however, customers on the TOU rate received \$100 and control customers received \$25 before the experiment began.

The basic time unit for comparison was the calendar month. For each of five calendar months, 20 population parameters (see Table 3-1, p. 15) were estimated for customers on the TOU and control rate schedules. These estimated parameters were compared to determine if differences between the consumption patterns of the two groups were statistically significant. The results are inconclusive as only one of the 20 parameters -- proportion of monthly electricity used during the peak period -- showed significant differences (proportions for TOU rate customers were smaller by 5 to 10

percent). There were other indications that customers were responding to the TOU rate but the level of response was only minimal, generally in the 5 to 15 percent range; none were statistically significant. For example, under TOU pricing monthly consumption was slightly lower during the peak period and was slightly higher during the base period. Consumption during the hourly periods before and after the peak period was generally higher for the experimental customers. These results are tentative, however, because certain difficulties with the sample design suggest an alternative method of analysis.

The results apply to approximately 60 percent (or 40,000) of the 66,149 residential customers served by the Blackstone Valley Electric Company in January 1977. Customers who could not be metered and those who planned to move during the experiment were excluded.

Wisconsin. A total of 552 households in the Wisconsin Public Service Corporation (WPSC) service territory were initially placed on one of 11 experimental rates. The 11 rates included nine TOU rates, a flat rate, and a TOU rate that included a demand charge in the peak period. Each TOU rate included two weekday rating periods: peak and base. On weekends and holidays, base prices applied to all hours. Ninety-two households were placed on the existing rate and served as a control group. TOU rates were in effect for three years beginning in May 1977 and participation was mandatory. No compensation payments or incentives were given.

This analysis covers the average weekday and day of system peak data for the summer (July-August) of 1977 and the winter (December-February) of 1977-78. All experimental rates were investigated except the TOU rate that had a demand charge. The nine TOU rates were divided into three groups defined by the length of the peak rating period (6, 9, or 12 hours). Within each group were rates having peak:base price ratios of 2:1, 4:1, and 8:1.

Comparisons of the average load curves of TOU and control households indicated that the TOU rates induced significant reductions in peak-period electricity usage, regardless of the season or the length of the peak period. Base-period usage was slightly reduced in the summer and unchanged in the winter. Consequently, the average total daily usage of TOU customers was always less than that of the control group. Differences between the average daily load curves of flat rate and control customers were very small and never statistically significant.

Responses to the TOU rates on the seasonal days of system peak were not found to differ significantly from those of the average days of each season. This may have been partly due to the poorer precision with which peak day responses can be measured.

There was some evidence that shorter peak periods induced greater hourly reductions in electricity usage with the maximum reductions occurring in the middle of the period. For longer peak periods, the reductions in usage were spread fairly evenly over the peak hours.

Elasticities of substitution between peak and base electricity usage were estimated to be significantly greater than zero in each season. For a 100 percent increase in the peak:base price ratio, the ratio of peak:base electricity usage declined by about 12 percent in the summer and 6 percent in the winter. Thus, there was more substitution of base for peak electricity in the summer than in the winter.

Weekend usage by TOU customers was the same as that of the control group in the winter, and the same as, or less than, that of the control group in the summer. This occurred even though base prices were in effect during all weekend hours, making electricity less expensive for TOU customers than for control customers.

Projections of these findings to the population represented by the sample indicate that approximately 40 MW in the summer and 30 MW in the winter would have been saved if TOU rates similar to those of the experiment had been implemented in 1976. The analysis results are strictly applicable only to about 43 percent of the residential population within the WPSC service area in 1976. This group accounted for roughly 60 percent of total residential electricity consumption in the WPSC area.

CHAPTER 3: ANALYSIS METHODS AND DATA LIMITATIONS

Time-of-use rate experiments are generally undertaken to determine whether and how much time-of-use rates affect the shape of average customer's load curve. This chapter outlines the two basic methods used to make those determinations and summarizes their relative strengths and weaknesses as well as the limitations of the experimental data to which they are applied.

The first section in this chapter describes comparative analysis procedures. The goal of this analysis is simply to estimate changes that would be observed in the shape of the average residential load curve if the TOU rate were in effect for an average residential customer. Of course, these comparisons use the TOU rate (or rates) actually included in the experiment; and all changes are relative to the estimated average residential load curve for customers on the existing residential rate.

Section 3.2 describes the second analysis procedure, referred to as response surface, or demand, analysis. This analysis is able to project the load shaping effects of TOU rates not actually included in the experiment. The final section outlines the limitations of the experimental data sets that apply to the findings under either approach.

3.1 Comparative Analysis

The goal of a comparative analysis is to measure changes in the shape of an average customer's load curve that are caused by the implementation of a particular TOU rate or rates. The changes are estimated for a particular group of customers -- in these studies, usually a portion of the residential customers -- and for a particular period. Two unavoidable facts prevent complete certainty about any of the estimated changes in load shapes: (1) it is

generally too expensive to monitor all customers and (2) a customer can be billed under only one rate schedule at a time. To deal with the first of these two conditions, a sample of customers is typically taken to represent the particular group (population) of interest. Immediately this introduces some uncertainty because the sample group may not be completely representative of the population of interest. Further uncertainty is introduced with either of the following two alternatives for dealing with the second condition.

One alternative is to monitor a single experimental group during two different periods. During the first period the experimental group remains on the existing electricity rate, and during the second period it is placed on a time-of-use rate. Under this approach, it is necessary to control for differences between the two periods of interest. However, very few of the rate demonstration projects were designed to accommodate this comparative analysis approach; the Arizona and Wisconsin projects are two exceptions.

A second and more commonly used alternative is to monitor two customer groups simultaneously while each group is on a different experimental rate. Although this approach removes differences that occur over time, such as weather, it obviously introduces differences between the load shapes of two groups that may be caused by the unique characteristics of individual households, e.g., number and type of appliances. The two types of comparative procedures used in the analyses by RTI differ by the amount of extraneous variations that are controlled in the analysis. They are known as analysis of variance (ANOVA) and analysis of covariance (ANCOVA).

3.1.1 Analysis of Variance Models

Essentially the ANOVA procedure involves the computation and comparison of means for the kWh usage variables of interest (see Table 3-1,

p. 15). If the customers on each experimental rate were simply a random sample of all the customers, means and variances for the customers on each experimental rate could be computed directly. These means could then be compared statistically to determine whether the variables of interest differ for the two (or more) groups. However, most of the rate demonstration projects utilized stratified samples that included a higher proportion of certain customers, e.g., high-usage customers, than actually existed in the population. This procedure complicates the analysis but, given the same sample size, produces results that are more accurate than those based on a random sample. In accounting for this stratified sampling procedure, means are computed for experimental customers within each stratum (usually defined by customers' prior kWh usage and occasionally by location) for each experimental rate. The strata means are then weighted in proportion to the estimated number of customers in each stratum to develop population estimates of the usage values for each experimental rate group. The ANOVA procedure makes no further attempt to control for sources of differences between the load patterns of the experimental groups.

ANOVA is applied in all comparative analyses for projects that involve only a single TOU rate. For projects that include several TOU rates, ANCOVA is applied only to those involving at least 40 customers.

The basic time unit for all comparative analyses is the calendar month. This requires additional data processing efforts in building analysis files but eliminates comparisons of usage during different time periods, which would occur if billing month data were used. The calendar months selected for analysis always cover the winter and summer seasons, which are of primary interest to the utility. Table 3-1 lists the parameters that are estimated with the ANOVA model for the population of inference. Average values of

these parameters are estimated separately for both the control and TOU rate customers. The estimated averages are the best estimates of mean values that would have been observed if each had actually been implemented for the represented portion of the residential population. The parameters shown in table 3-1 were selected because they are important response measures for comparing the shapes of load curves for customers on the control and experimental rates.*

Some general comments may help the reader understand these parameters. Parameters 1-6 of table 3-1 measure average usage per customer during certain hours of only one day of the month, the day of system peak. For example, parameter 1 measures usage during the hours defined as the peak period on that day and parameter 6 measures total usage over all hours. Parameters 4 and 5 measure usage during only a single hour on the peak day: the hours before and after the peak period, respectively. These variables determine whether the TOU rates cause a surge in demand at those times. Parameters 7-12 are identical to parameters 1-6 except that they are averaged over all days of the month.

The word "demand" is usually defined in electricity load research as the instantaneous load (in kilowatts) that a customer or customer group imposes on the utility system. "Diversified demand" is the average of two or more customers' "demands" at any instant. The word "diversity" connotes the extent of differences among individual customers' load curves. For example, if all customers had identical load curves, there would be no diversity -- all customers' demands would peak at the same time. Therefore, the average

*These parameters were chosen after discussions with regulatory and utility representatives during a two-day DOE-sponsored conference in Washington, D.C., in December 1977.

Table 3-1. List of Parameters Estimated in Comparative Analysis
(estimated per customer)

	Parameter Number	Description
Average for Day of Monthly System Peak	1	kWh - peak
	2	kWh - intermediate
	3	kWh - base
	4	kWh - during 1 hr preceding peak period
	5	kWh - during 1 hr following peak period
	6	Total kWh
Average for all Days of Month	7	kWh - peak
	8	kWh - intermediate
	9	kWh - base
	10	kWh - during 1 hr preceding peak period
	11	kWh - during 1 hr following peak period
	12	Total kWh
Average per Customer	13	Diversified demand at time of observed monthly system peak
	14	Noncoincident maximum demand
Average for Subset of Hours during Month	15	Average hourly kWh consumed during all hours of observed system load greater than 80% of <u>annual</u> system peak
	16	Average hourly kWh consumed during all hours of observed system load greater than 90% of <u>annual</u> system peak
	17	Average hourly kWh consumed during all hours of observed system load greater than 95% of <u>annual</u> system peak
Ratio	18	Proportion of total kWh used during peak period on peak day (#1/#6)
	19	Proportion of total kWh used during peak period on average day (#7/#12)
	20	Class load factor based on diversified demand at time of observed monthly system peak (#12/#13÷ 24)

"maximum diversified demand" for the group would be the sum of their individual maximum demands, also called "noncoincident maximum demand," divided by the number of customers in the group. Given these definitions, it follows that parameter 13 is the average kWh usage per customer during the single hour in each month when the largest hourly demand was observed on the entire utility system. By contrast, parameter 14, noncoincident maximum demand, is the estimated average over all customers in the effective population of their individual maximum hourly kWh usages. This is computed as the weighted average of the maximum that was observed for each sample customer within each month.

Parameters 15-17 provide usage characteristics on a per customer basis averaged over subsets of hours identified by the magnitude of the observed load on the utility system. For example, parameter 16 averages hourly kWh consumption over those hours in the month when system load exceeds 90 percent of the annual system peak.

Parameters 18 and 19 are the proportion of total usage during the peak period on the day of system peak and for the average of all days in the month, respectively.

Load factor, the ratio of the average load to the peak load, can be measured by system or class. Class load factor, parameter 20, is the ratio for the residential customers of average hourly usage to average usage during the hour of system peak within each month. The numerator in this ratio is parameter 12 divided by 24 (hours per day) and the denominator is parameter 13.

3.1.2 Analysis of Covariance Models

Like analysis of variance, the basic purpose of analysis of covariance is to compare customers' kWh usage responses to specific experimental

electricity rates. However, ANCOVA also incorporates detailed variables, called "covariates," that describe the characteristics of participating households to isolate more precisely the effect of the TOU rate. Because ANCOVA introduces these covariates, an explicit regression model must be specified and estimated. The following ANCOVA model is a highly simplified example that incorporates only a single covariate (normally there will be several) and two rates (one existing and one TOU).

$$Y = a + bR + cZ + dRZ + e,$$

where Y = kWh usage variable,

R = 1, if the customer is on the TOU rate; 0 otherwise,

Z = household-specific variable, e.g., total kW capacity of household appliances,

a, b, c, d = regression parameters, and

e = error term.

A model such as this can be estimated either within each stratum or over all strata simultaneously, provided that the coefficients of the model are stable across strata. If the coefficients are stable, population-weighted means for the household-specific independent variables can be computed and inserted into such a model to estimate the population value of the dependent (kWh usage) variable. If they are not stable, one approach is to compute stratum means for each independent variable. These means are then inserted into the estimated stratum-specific ANCOVA models to develop corresponding estimates of the dependent variables for each experimental rate. Finally, these can be weighted over all strata to obtain population estimates of the dependent variables for each experimental rate.

In principle, all of the parameters of table 3-1 could be used as dependent variables in models such as this. However, in practice it may be desirable to use all 24-hourly kWh usage values and appropriate aggregations of those values, e.g., peak-period kWh usage.

One advantage of the ANCOVA procedure is that it can provide a single linear relationship that is a reasonable representation of the response to a time-of-use rate by any customer within the population of interest. Thus, the relevant household-specific variables could be inserted into an ANCOVA model to project an individual household's response to TOU rates. To obtain this linear relationship, skillful modelling is needed to eliminate instability in the regression parameter estimates across the strata that define the sample. When such instability is unavoidable, the ANCOVA model must be estimated only within strata. Even in this case, ANCOVA, as opposed to ANOVA, can potentially reduce the unexplained variability among kWh usage observations and, therefore, more precisely isolate the effect of TOU rates.

The ANCOVA procedure is particularly appropriate for rate demonstration projects that were poorly stratified or involved a relatively small number of observations per experimental rate. The procedure is also appropriate if the available information about the experimental sampling procedures prevents computation of accurate sample weights. The latter situation also hampers (or prevents) extrapolation of the results beyond the actual sample to the population of interest.

3.2 Response Surface/Demand Analysis

The term "response surface" is used in statistics to refer to a function that predicts how a dependent (response) variable changes as other variables (factors) are changed. Response surface analysis is typically associated with experiments in which responses at specified levels of quantitative

factors are used to estimate responses at factor levels not included in the experiment. The experimental design will often test the specified levels of each factor in all combinations. An example of such an experiment that is familiar to students of elementary statistics is one in which the yield of a particular variety of grain from several test plots is measured after applying different amounts of nitrogen (N), phosphorus (P), and potash (K) during the growing season. Two levels each of N, P, and K tested in all combinations would require eight (2^3) treatments. Some of the rate demonstration projects were similarly designed as factorial experiments in which the kWh usage (yield) of several groups (plots) of test customers (grain plants) on a single type of TOU rate (grain variety) was measured after applying different combinations of peak, intermediate, and base period kWh prices (N-P-K combinations). The purpose of such agricultural experiments is to obtain an accurate measurement of potential yields for N-P-K combinations not actually included in the experiment but still within the range of the actual fertilizer dosages applied. Similarly, the purpose of factorial TOU rate experiments is to obtain accurate measurements of the kWh usage responses for peak-intermediate-base (P-I-B) kWh price combinations not actually included in the experiment.

In this agricultural experiment, the use of different brands of fertilizer on each experimental plot would confuse (statisticians say "confound") the measurement of the N-P-K dosage effects. One would not know whether different yields were due to different dosages or to different brands of fertilizer. Similarly, the use of a different "brand" of TOU rate for each experimental group of customers would confound the measurement of price effects. For example, valid estimation of the price response function could not be developed if some experimental groups have different peak-period hours than others in addition to different P-I-B kWh price combinations.

However, if the TOU experiment is reasonably well designed, a functional relationship can be developed between kWh usage and TOU prices as well as other household characteristics thought to affect electricity usage. The development of such relationships is likely to be referred to as "demand analysis" by economists or econometricians. (Demand here does not refer to kW demand but rather to commodity consumption.) This occurs since demand functions, as generally understood by economists, can be thought of as special cases of response surfaces. The response variables are the quantities of commodities, such as peak and off-peak electricity, that are demanded as final consumer goods. The factors affecting each quantity include its price and that of closely related commodities, e.g., the price per kWh used off peak, if the relevant quantity is peak kWh.

The perspectives of both the statistician and the economist are essential because each provides an alternative approach to response or demand function estimation. They are somewhat arbitrarily distinguished here as pragmatic and demand-theoretic modelling approaches.

Before contrasting the two types of models, their four most important common features should be emphasized. First, and most obvious, both attempt to estimate the same underlying relationships between kWh usage and kWh prices by time of use. Second, neither model provides estimates of the type provided by comparative analyses, i.e., neither provides estimated differences between the existing load curves for residential customers on declining block rates and the load curves that might be observed under a TOU rate. Response surface models are only able to compare and extrapolate the effects of TOU rates that are identical in all respects except for the prices charged in identical rating periods. Therefore, if a TOU rate of the type used in the rate experiment is actually in effect, response surface analysis results

can be used to project the effects of TOU price changes on the shape of residential customers' load curves.

Third, both models can incorporate the relevant sample stratification scheme in much the same way as described for ANCOVA models in section 3.1.2. That is, the models can be estimated separately, within strata, or, if the statistical model is acceptable, over all strata. In either case, the sampling weights should be used to develop population estimates.

The fourth common feature is that both pragmatic and demand-theoretic models provide elasticity estimates. An elasticity is simply a number that indicates the percentage change in one variable that will accompany each 1 percent change in another. For example, an own-price elasticity of demand for peak electricity of -0.2 means that an increment of 1 percent in the peak price will reduce kWh usage in the peak period by 0.2 percent. These elasticities are just one way of characterizing the parameters of the response functions, regardless of how they are estimated. In logarithmic demand models, the parameters of the response functions are elasticities, whereas elasticities are functions of the estimated parameters in linear demand models.

With that background and description of their common features the discussion now turns to details that describe and contrast the advantages and disadvantages of the two generic types of estimation procedures. First, we describe the pragmatic approach, and second, the demand-theoretic approach.

3.2.1 Pragmatic Models

A pragmatic model is a straightforward statement of a hypothesized statistical relationship between, on the one hand, the kWh usage variables of interest and, on the other hand, the kWh prices and other independent variables thought to affect kWh usage. The following equation is a highly

simplified example of such a model, using some of the defined variables and simplifications of section 3.1.2:

$$Y = a + \sum_{i=1}^m b_i P^i + cZ + \sum_{i=1}^m d_i ZP^i + e$$

where P = price per kWh during peak hours (the price during all other hours is assumed constant for this experiment),

m = highest power of the price term incorporated in the model, and
all other variables are defined on page 18.

This model assumes that the data available for estimation is from an experiment wherein only the peak price is varied. If one or two other kWh prices, say, the intermediate- and base-period prices, were also varied, they would also appear in the model. The Y variable can represent any one of a vast number of kWh observations such as kWh usage in any one of the 24 hours of an average day, kWh usage during only the peak hours of the average day, etc. Both the right- and left-hand variables can be transformed; the most common is the logarithmic transformation.

Finally, the model can be expanded to incorporate a large number of independent variables other than price, including a full complement of interaction terms. Interaction terms are actually new independent variables that are developed by multiplying two or more independent variables together to form "cross-product" terms. The purpose of such interaction variables is to capture an "interaction effect." For example, a high peak price in summer may not shift electricity demand unless the household also has central air conditioning. This would be indicated by a significant coefficient in the interaction term which is the cross-product of peak price and the variable indicating the presence of central air conditioning. These terms are similar to the last set in the above model where each price term is multiplied by Z

and can conceivably include all possible cross-product terms involving all independent variables in the model. In practice, with a large number of independent variables, all interaction terms cannot be included because the number of terms quickly exceeds the number of observations (households) in the experiment. Furthermore, such terms may offer little help in reducing the unexplained variation in the kWh usage variables of interest.

One pragmatic model commonly used in electricity demand analysis, especially in the RTI analyses, is a simple double-logarithmic model, so called because all continuous variables -- both dependent and independent -- are transformed by substituting their logarithms into the model. For example, if both the peak (P_1) and off-peak (P_2) prices are varied in an experiment, a highly simplified version of such a model might be

$$\ln Y = a + b \ln P_1 + c \ln P_2 + d \ln Z + e$$

where $\ln$ denotes the natural logarithm and other variables are defined as above.

This type of model has at least two advantages in estimating electricity demands. First, unlike some linear models with untransformed variables, the size of residuals (actual minus predicted values of kWh usage) from such regressions tends to appear unrelated to the size of the predicted values. This is critical because one underlying assumption of the model is that such a relationship will not exist.

The second advantage is that elasticities can be read directly from the estimated model. For example, the b and c coefficients in the above model are the own- and cross-price elasticities of demand during the peak period if Y is kWh usage during the peak period; and vice versa if Y is kWh usage during the off-peak period. This latter advantage is relatively minor since

elasticities can always be computed, regardless of the model. However, the variances of elasticity estimates from more complex models are often difficult, and sometimes impossible, to estimate directly; therefore, whether or not the estimated elasticities differ from zero by a statistically significant margin is often difficult to determine.

In summary, pragmatic electricity demand models encompass a very large number of model specifications. As a practical matter, simple double-logarithmic models are preferred for much of RTI's analysis involving such models. Regardless of their particular statistical specification, all pragmatic models presuppose a relationship between the quantity of electricity used during each rating period and the relevant prices charged during those periods. However, the models do not incorporate assumptions about the manner in which households actually make those electricity purchase decisions. Those assumptions -- which are sometimes empirically verifiable -- are the distinguishing feature of demand-theoretic models.

3.2.2 Demand-Theoretic Models

By definition a theory suggests relationships that are either accepted or proposed as demonstrable truth. Often these are relationships among observable quantitative variables. A famous example in the physical sciences is the theory of relativity. In the social sciences one of the best known is the theory (law) of demand: the consumption of a product will decline as its price rises. This also is a generally accepted idea whose validity can be and has been tested empirically. But actually the theory of demand, as developed by economists, suggests other less well known relationships among prices, consumption, and income; these relationships can also be tested. Econometric models that incorporate all or some of them are referred to as demand-theoretic models.

What does all this have to do with electricity demand? Why should this theory be used if pragmatic models are adequate for estimating the relationship between electricity usage and TOU prices? First, if the theory is correct, it will -- like any valid theory -- more clearly identify relationships among the variables of interest, in this case kWh usage and prices. The result may be more accurate estimates of price effects.

Second, the theory implies constraints which, if correct, enable the estimation of elasticities that cannot be estimated with pragmatic models. This is analogous to estimating x and y when $x + y = 2$. With only the relationship $x + y = 2$ neither can be estimated, but, if some theory implies that $x = 1$, y can also be determined.

Finally, demand-theoretic models are fundamentally linked to an equation (called a utility function) that can be used, conceptually at least, to measure consumer satisfaction. Therefore, the estimation of demand-theoretic models provides a logically consistent vehicle for estimating, in dollar terms, how much consumers value (or dislike) particular TOU rate adjustments. For example, a woman may see a pair of shoes she particularly likes for which she would gladly pay \$100. If, instead, she is able to purchase the shoes for \$75, her personal valuation of the shoes exceeds the price paid and she has gained a "consumer surplus." Similarly, the value of electricity may exceed its price for some customers. Any cost-benefit analysis of TOU rates would be logically incomplete without estimates of such gains of consumer surpluses in the off-peak periods and losses in the peak period.

What then are these relationships implied by demand theory? Generally, they are conditions that define expected demand responses to both price and income changes. One of these conditions is that the amount of electricity demanded in each daily rating period would remain constant if all individuals' incomes and the prices of all goods and services, including the price

of electricity in each rating period, doubled at the same time. Another is that a change in the off-peak price will cause an electricity consumer to change his peak kWh usage by an amount that is identical to another quantity. That quantity will equal the change in off-peak consumption that occurs if the on-peak price change equals the off-peak price change. A third implication of the theory is that the sum of a household's expenditures on individual items must equal its total expenditures.

It would be convenient if these conditions alone implied directly estimable versions of demand-theoretic models for electricity (or any other) commodities. Unfortunately they do not. In practice, statistically convenient assumptions -- assumptions not actually implied by demand theory -- must be imposed to resolve this dilemma. Two basic types of assumptions are used. The first arbitrarily selects a specific equation that represents the utility function. The second makes further assumptions about the way families spend money.

The first type of assumption, which is sometimes the only one needed to develop a statistical model, is to assume a specific functional form for the utility function. With these functions and the mathematics of economic theory, demand functions can be developed that both meet the conditions implied by the theory and can actually be estimated using linear or nonlinear estimation procedures. The specific functional forms are divided into two types -- inflexible and flexible.* However, regardless of the type, these

*The former include Leontief, Cobb-Douglas, Stone-Geary (linear expenditure system), Direct Addilog, and Quadratic functional forms. These specifications are inflexible in the sense that the functions themselves impose certain constraints on the relationships among elasticities and do not provide the opportunity to test empirically whether these constraints are valid. Flexible functional forms, on the other hand, do not incorporate such constraints. The most well known flexible forms are the Translog, Generalized Leontief, and Generalized Cobb-Douglas.

specific functional forms are usually sufficient to operationalize the theory of demand. The practical outcome for our applications is an estimable model of electricity demand.

The second type of assumption presumes some knowledge about how families spend money. While not always necessary to develop estimable electricity demand models, these assumptions nevertheless often dramatically improve the apparent suitability of the demand model (judged in terms of statistical test criteria such as F-statistics). Furthermore, their application often averts expensive and complicated nonlinear estimation problems by introducing linear models. Two examples of this second type of assumption are "homotheticity" and "separability."

Homotheticity is an especially convenient assumption which states that the shares of disposable income spent on each final consumer good, including electricity, do not change with income. This assumption, which is imbedded within some inflexible functional forms but not in any flexible ones, can convert demand functions from nonlinear statistical models to linear models. One of the flexible functional forms, the Translog, is used along with some of the same simplifications that describe the double-log model to illustrate the effect of the assumption. Although the non-homothetic Translog function is a complicated nonlinear equation, the homothetic version can be written as

$$S_1 = a + bX_1 + cX_2 + dX_3 + fZ + e$$

where

$$S_1 = P_1 Y_1 / \text{disposable income},$$

$$Y_1 = \text{peak kWh consumption},$$

$$X_i = \ln(P_i / \text{disposable income}), \text{ for } i = 1, \dots, 3,$$

P_3 = price index for all consumer goods other than electricity, and other variables are defined on page 18.

A similar model is defined for the off-peak period. The b and c parameters from these two regression models can then be used directly, along with average estimates of S_1 and S_2 , to estimate the own- and cross-price elasticities of demand for peak and off-peak electricity.

Even further statistical convenience can be achieved with the separability assumption. Under this assumption, the household is assumed to "group" its purchase decisions by first deciding how much to spend on broad categories of consumer goods, e.g., electricity, food, clothing, and only then deciding how much of the designated budget for each group to spend on its components, e.g., peak and off-peak electricity. Its effect can be illustrated by the change it implies for the Translog function described above. Under separability the designated electricity budget -- total expenditures on electricity -- replaces disposable income in the S and X variables of the above model and the X_3 variable is dropped. Furthermore, only one of the two equations, peak or off-peak, is estimated to obtain own- and cross-price elasticities. However, these elasticity estimates are "partial" because they are constructed under the assumption of a fixed electricity budget. Therefore, they need to be adjusted by estimating the effect of the relevant kWh price changes on the size of that budget.

Although the Translog model was used above for illustrative purposes, the same types of assumptions are applied when other functional forms are used to specify the utility function. Accordingly, similar combinations of the relevant prices, income, and electricity expenditures appear in those models.

In summary, both pragmatic and demand-theoretic models have positive and negative features. On the one hand, pragmatic models generally are more straightforward and are often easier to estimate and interpret. On the other

hand, however, it is questionable to use elasticities from such models for evaluating consumer satisfaction with TOU rates. Incorporating restrictions from demand theory into pragmatic models is also difficult and, in some cases, logically inconsistent. Nevertheless, pragmatic models are applied in the RTI analyses whenever feasible.

Demand-theoretic models also provide several significant advantages, including (1) the possibility of greater precision in estimating demand functions, (2) a method for estimating elasticities where it might otherwise be infeasible, and (3) the vehicle for measuring a primary factor in any cost/benefit analysis of TOU rates -- a monetary valuation of consumer (dis)satisfaction with TOU rate adjustments. At the same time, demand-theoretic models have significant disadvantages. First, complex and expensive nonlinear estimation procedures are often involved unless the models are quite restricted. Second, the resulting estimates of variability (standard errors) of elasticities are difficult to calculate, making it difficult to determine whether the elasticities are different from zero. Third, as a practical matter, estimating such models often involves statistically convenient assumptions that have no foundation in demand theory per se, and may therefore vitiate some of the advantages of appealing to the theory. Fourth, it is often unclear how covariates should be incorporated in such models and, under any demand-theoretic approach, incorporation is difficult for relatively unrestricted versions, which require nonlinear estimation. As a consequence, RTI's analyses use these demand-theoretic models selectively, most often to determine the comparability between the electricity demand elasticities that are estimated under the two approaches.

Whatever the level of sophistication in the models chosen for either comparative analysis or response surface/demand analysis of electricity

usage, the value of the resulting estimates is significantly affected by the experiments. For that reason, the discussion now turns to a description of the experimental design, sample design, and data file limitations of the rate demonstration projects.

3.3 Data Limitations

The term "data limitation" as used here refers to a factor that inhibits inferences about the load shape effects of TOU rates were they to be implemented. Three basic types of data limitations are apparent in the rate demonstration projects: (1) experimental design, (2) sample design, and (3) data file limitations. Each of these is discussed below.

Experimental Design Limitations. The experimental design encompasses all of the particular details of a given experiment. Some of the major considerations include:

1. the duration of the experiment,
2. the types of educational material used,
3. the terms of customer participation,
4. the exact configuration of design points, and
5. the manner in which fuel adjustment charges and general rate increases are handled.

Although these are only some of the experimental design conditions of the electricity rate experiments, they show that, regardless of the sample design or quality and detail of the collected data, all measured responses in a given study are, strictly speaking, fully conditional on the entire spectrum of experimental design conditions.

Two particular experimental design problems merit special attention. Combining separate factors in such a way that their effects cannot be

separately identified in the first of these. For example, if the experimental group on a particular time-of-use rate is simultaneously exposed to the experimental rate and to unusually aggressive customer education efforts, while the control group is only observed, the TOU rate effects are completely confounded with the educational effects, and comparisons with the control group do not identify rate effects alone.

A second problem is that many of the rate demonstration projects have poor configurations of design points relative to many proposed response surface models. This often results from trying to achieve revenue neutrality through rate adjustments rather than through direct payments. An extreme example will illustrate the point. Revenue neutrality usually means that all experimental rates will yield the same revenue if the representative customer had zero own- and cross-price elasticities of demand by time of use. Thus, the amount of electricity consumed in the peak and off-peak periods are assumed fixed. Also, the total revenue a customer is assumed to generate is fixed at the level required by the utility to achieve the allowable rate of return. Therefore, if either peak or off-peak price is known, the remaining price can be found. While this example overstates the problem to some extent, it nonetheless illustrates a general design tendency. Overcoming this problem may require stringent assumptions. For instance, one may be forced to use (functions of) the ratio of on-peak to off-peak price as opposed to (functions of) their absolute levels. In a first-order double-logarithmic model, however, such an assumption would imply that the own- and cross-price elasticities are identical in absolute magnitude but opposite in sign.

Sample Design Limitations. Sample design limitations generally suggest some sample-related potential bias in the parameters estimated from test

data. The use of the term "bias" suggests the existence of some population for which inferences are desired.

Usually the population of customers for which inferences are desired is either the entire class of residential customers in a utility's service area or some specific subgroup of this class (for which a time-of-use rate might be implemented by the utility). Achieving valid statistical inferences to this population is, in a strict sense, virtually impossible, because the population is constantly changing as customers move in and out of the service area. A reasonable substitute target population is the class of residential customers who have active accounts on a specific date. To obtain valid estimates for this population, a probability sample of the target population must be exposed to each experimental rate.

Unfortunately, two general types of exclusions have occurred in most of the DOE experiments, causing the eventually observed populations to be qualitatively different from the target population.

The first type exclusions are defined as those subgroups excluded before sample selection. Typically, these include:

1. customers with fewer than 12 months billing history,
2. customers with at least one estimated bill in the last 12 months,
3. customers with seasonal accounts, and
4. customers with low prior usage.

These exclusions reduce the target population of residential-class customers to a subset referred to as the sampled population.

The sampled population is further reduced in size by the second type of exclusions: customers who were contacted for participation in an experiment but excluded because of technical circumstances or customer actions or attitudes. Exclusions due to technical circumstances include incompatible wiring

in homes, meter inaccessibility, and failure of the interviewer or company to locate the candidate. These exclusions attributable to customer actions or attitudes include refusal to participate, removal because of excessive complaints, and removal because of certain questionnaire responses indicating, for example, that the candidate intends to move or is a renter. These exclusions reduce the sampled population down to the effective population which is, strictly speaking, the only population to which valid inferences can be drawn.

Data File Limitations. Data file limitations generally occur without respect to the quality of the experimental and sample designs. These limitations include missing data, misreported data, inadequacy of sample replacements, inaccurately imputed values, insufficient documentation, and aggregated usage data.

In some cases, these data file limitations further restrict the size of the effective population. Inferences to the total population or to the sampled population require the assumption that customers not in the effective population will respond to the experimental rate in the same manner as those represented in the sample.

Even for the effective population, a number of additional qualifications apply to the analysis results. They may be summarized as follows:

- The results strictly apply only to the represented portion of the residential class as of the time the sample was drawn.
- The results of comparative analyses apply only to comparisons of the particular TOU and control rate schedules incorporated in the experiment.
- Editing procedures normally remove a small number of customers from the original sample before analysis. The extent to which this affects the population of inference is unknown.

- During the experiments some customers were dropped because they moved or their meters malfunctioned. Extrapolating observed load patterns from the remaining sample to the initial effective population requires the assumption that such attrition does not introduce systematic bias.
- Participants knew that the experiment was limited to a specified period after which they would return to the existing rate schedule. This may have discouraged them from investing in appliances and home improvements that are financially attractive under TOU rates.
- Actual implementation of a TOU rate schedule would not have involved the incentive payments or personal contact that customers on the experimental rate schedule received in some cases prior to or during the study (for example, pre-test interviews). Any benefit or adverse effects that may accompany such contacts or payments are ignored in estimating the observed responses.
- All results reflect primarily short-term responses of represented residential customers. Information provided by the experiments does not enable statistical inferences to be made about the long-term responses of some future customers to the TOU rate schedule.
- Some experiments included relatively small numbers of experimental customers on each TOU rate. Consequently, real responses to TOU rates could have been difficult or impossible to detect.
- In some experiments the participants were billed under a plan that equalized monthly bills. Typically this is not taken into account in the analyses, so any resulting effects are ignored.
- Any analyses that utilize household data obtained from questionnaires are subject to all errors, omissions, and biases in those data.
- Actual implementation of TOU rates would typically involve a large number, if not all, residential customers. Therefore, since experimental customers were generally isolated geographically, their responses do not incorporate the effects of advertising, publicity, and frequent contact with others on TOU rates that would normally occur.

CHAPTER 4: PROJECT-SPECIFIC RESULTS

This chapter summarizes the results for each rate demonstration project analysis prepared to date: Arizona, Connecticut, Ohio, North Carolina (Blue Ridge Electric Membership Corporation), Rhode Island, and Wisconsin. A description of each project is provided, which includes the survey design, sampling methodology, and rate structures used. The findings section provides information by project on the variations in electricity demand under TOU rates compared with demand under conventional rates.

Although the designs and analysis methodology varied among the six projects, certain broad comparisons of the studies and end results can be made. Table 4-1 gives study characteristics by project, allowing the major aspects of each project to be compared. The variation in the percentage of customers represented by the results, the effective population, is notable. It is as low as 12 percent for the Ohio project and as high as 88 percent for the North Carolina BREMC project.

Table 4-2 summarizes the TOU rates used in each study. In addition to showing the number of TOU rates of each type and the number of hours in each of the three rating periods -- peak, intermediate, and base -- by season, the table also indicates the associated ranges of peak- to base-period kWh price ratios, and the ranges of absolute differences between the peak and base prices for each rate group. It is obvious and significant for the interpretation of results that there are marked differences among these price ratios and price differences.

Table 4-3 shows the relationship between the methodologies discussed in Chapter 3 and the applications reported here. As indicated, four of the studies involved only ANOVA. The other two, Arizona and Wisconsin, involved both ANCOVA and demand analysis.

Table 4-1. Major Study Characteristics by Project

Project	Customer Participation		Experimental Period	Number of Experimental Rates	Sample Size		Percentage of Service Area Residential Customers in	
	Mandatory	Payments			Control	Experimental	Sampled Population	Effective Population
Arizona	No	Yes	May 76-Oct 76	28	0	140	55	19
Connecticut	No	Yes	Oct 75-Oct 76	1	200	200	63	29
North Carolina (BREMC)	Yes	No	Oct 77-Oct 78	1	98	102	100	87
Ohio	No	No	June 76-Nov 77	1	60	100	58	12
Rhode Island	Yes	Yes	Nov 77-Dec 78	1	130	170	100	60
Wisconsin	Yes	No	May 77-May 80	10*	92	506	44	43

* Not including a three-part rate applied in the experiment.

Table 4-2. Summary of Time-of-Use Electricity Rates by Project

Project	Number of Rates	Season	Combined Length of Weekday Rating Period			Length of Weekend Rating Period			Range of Weekday Peak to Base Price Ratios	Weekday Price Differential (\$/kWh), Peak minus Base Price
			P	I	B	P	I	B		
Arizona	16	Summer	3	10*	11	3	10*	11	2.75 to 12.0	7.0 to 13.0
	6	Summer	5	8*	11	3	8*	11	3.0 to 6.0	5.0 to 10.0
	6	Summer	8	5	11	8	5	11	1.67 to 6.0	3.0 to 7.0
Connecticut	1	Summer	4*	9*	11	13	-	11	16.0	15.0
		Winter	4*	9*	11	13	-	11	16.0	15.0
North Carolina (BREMC)	1	Summer	8	-	16	8	-	16	2.1	1.26
		Winter	8*	8*	8	8*	8*	8	3.8	3.39
Ohio	1	Summer	6	-	18	-	-	24	22.8	8.7
		Fall	6	-	18	-	-	24	7.8	2.7
		Winter	6	-	18	-	-	24	22.8	8.7
		Spring	6	-	18	-	-	24	7.8	2.7
Wisconsin†	3	Summer	6*	-	18	-	-	24	2 to 8	3.10 to 11.08
		Winter	6*	-	18	-	-	24	2 to 8	2.64 to 9.32
	3	Summer	9	-	15	-	-	24	2 to 8	2.86 to 8.55
		Winter	9*	-	15	-	-	24	2 to 8	2.45 to 8.31
	3	Summer	12	-	12	-	-	24	2 to 7.6	2.62 to 6.61
		Winter	12	-	12	-	-	24	2 to 6.9	2.31 to 5.88
	1	Summer	-	-	24	-	-	24	N/A	0
		Winter	-	-	24	-	-	24	N/A	0
Rhode Island‡	1	Summer	9	4	11	-	-	24	1.8	1.53
		Winter	13	-	11	-	-	24	1.8	1.53

* Total of two non-adjacent periods.

† Three-part rate not included.

‡ A demand charge for generation facilities was applied during peak hours to the average of the four highest 15-minute demands in the billing cycle. In addition, a demand charge for distribution facilities was applied to the average of the four highest 15-minute contiguous demands during all hours of any day in the billing cycle.

Table 4-3. Type of Analysis Used

Project	Comparative Analysis		Response Surface/ Demand Analysis	
	ANOVA	ANCOVA	Pragmatic	Demand-Theoretic
Arizona		X	X	X
Connecticut	X			
Ohio	X			
North Carolina	X			
Rhode Island	X			
Wisconsin		X		X

Tables 4-4 and 4-5 provide some overall estimates of percentage reductions in kWh usage during selected summer and winter months, respectively, and contain estimates for the peak, intermediate, and base periods on both the average day and the peak day in the month identified (usually the peak month). Percentage reductions are also shown for usage during the peak hour of the month. Only the estimates with asterisks are different from zero by a statistically significant margin. The estimates for Arizona and Wisconsin were developed by grouping a number of customers with the same TOU rating periods but different TOU prices. These TOU groups were then compared to the control group to develop overall estimates of percentage reductions.

Although these studies are dramatically different, some general patterns emerge from tables 4-4 and 4-5. First, TOU rates uniformly seemed to reduce usage during the peak period, albeit by very small and insignificant amounts for some studies. Second, base period usage seldom appeared to increase by a statistically significant margin; sometimes it actually declined. Third, total usage generally seemed either to decline or remain the same under TOU rates. Fourth, customers on TOU rates generally appeared to use less electricity than their counterparts in the control group during the peak hour, although those reductions were not always statistically significant. This suggests the possibility of some capacity savings with certain TOU rates. Fifth, peak day usage shifts generally appeared to be about the same as those on average days, suggesting that TOU customers did not have dramatically different usage patterns on very hot or cold days. Finally, no generalizations are obvious from comparisons of usage during the winter and summer seasons, although certain patterns are evident for specific studies, especially Connecticut and Wisconsin.

Table 4-4. KWh Usage Reductions by TJU Customers, Selected Summer Months*[†]
(as percent of control group usage)

Project	Average Day				Peak Day				Peak Hour	Month [§]
	Peak	Intermediate	Base	Total	Peak	Intermediate	Base	Total		
Arizona	7.3*	1.5	- 3.4	1.3						July 1976
Connecticut	30.9*	16.8*	0.2	12.6*	39.0*	22.7*	3.5	19.1*	39.0*	June 1976
Ohio	38.0*	--	- 5.9	3.9	39.7*	--	-12.6	4.4	40.2*	August 1976
Rhode Island	10.2	1.2	-11.0	- 2.4	7.6	11.7	-19.6	0.8	- 8.0	June 1978
Wisconsin										July-August 1977
6 hr. peak	25.6*	--	5.3	10.2	28.0*	--	10.2*	14.3	26.6	
9 hr. peak	22.9*	--	10.9	15.3*	22.9*	--	7.7	12.9	21.9	
12 hr. peak	20.7*	--	10.4*	15.5*	21.3*	--	9.2	14.5	19.6	

[†]Only estimates that were different from zero by a statistically significant margin (10 percent level) are denoted by an asterisk. Dashes indicate that associated estimates were undefined; and blanks, that they could not be estimated due to data constraints.

^{††}The NC-BREMC project is omitted because system demand is lowest in summer.

[§]Most are for actual peak months, days, and hours. Only August and September 1976 system load data were available for Ohio.

Table 4-5. KWh Usage Reductions by TOU Customers, Selected Winter Months*†
(as percent of control group usage)

Project	Average Day				Peak Day				Peak Hour	Month [§]
	Peak	Intermediate	Base	Total	Peak	Intermediate	Base	Total		
Connecticut	18.7*	1.8	-18.5*	- 3.7	14.4*	- 0.1	-23.1*	- 6.4	12.0	January 1976
Ohio	21.2	--	-11.6	- 5.8						January 1977
NC-BREMC	2.1	- 2.6	- 4.0	- 1.7	0.0	- 6.4	- 7.1	- 4.2	- 0.1	February 1978
Rhode Island	11.7	--	0.6	5.5	23.5	--	10.0	18.7	26.1	February 1978
Wisconsin										December-February 1978
6 hr. peak	15.2*	--	- 0.3	7.5	21.7*	--	2.5	3.8	23.8*	
9 hr. peak	8.1	--	- 4.1	1.2	15.7	--	4.7	9.3	20.7*	
12 hr. peak	8.4	--	- 1.6	3.5	12.0	--	4.8	8.0	21.6*	

*Only estimates that were different from zero by a statistically significant margin (10 percent level) are denoted by an asterisk. Dashes indicate that associated estimates were undefined; and blanks, that they could not be estimated due to data constraints.

†The Arizona project is omitted because the study covered only summer months.

§Most are for actual peak months, days, and hours. Only August and September 1976 system load data were available for Ohio.

In referring to tables 4-1 and 4-2, it is of interest to note that the largest number of statistically significant load shifts seemed to appear in the projects -- Connecticut, Ohio, and Wisconsin -- that had relatively higher TOU price ratios and TOU price differences. Furthermore, two of these same studies--Connecticut and Ohio--involved voluntary participation and all three represented a relatively smaller percentage of the residential class. The Arizona study was somewhat anomalous but also generally suggested significant reductions in peak-period usage, possibly attributable in part to its voluntary nature and relatively small effective population. By contrast, both the Rhode Island and NC-BREMC studies were mandatory and both involved TOU prices with lower ratios and differences.

Before turning to the more detailed project-specific results, a technical comment will be useful for interpreting the ANOVA results. For the four projects in which ANOVA was applied, the applicable parameters of table 3-1 were estimated for the effective population. That is, separate estimates were developed for the control and experimental rate schedules assuming that these rates were applied to the effective population. The estimates, coupled with distributional assumptions, were used to test whether significant differences existed between the true population parameters for the two groups. Results of tests of hypotheses concerning these parameters were also developed. These estimates are displayed in the full project--specific reports prepared for each project.

4.1 Arizona*

4.1.1 Project Description

The Arizona Rate Demonstration Project, which was begun in 1975,

*Research Triangle Institute, Time-of-Use Electricity Price Effects, Arizona, Final Report prepared for the U.S. Department of Energy, Office of Utility Systems, Contract No. CR-04-80220-00, RTI Project No. 41U-1542/00-10F, December 1978.

Table 4-6. Summary Features of the Arizona Rate Demonstration Project

Participating Agencies/Utilities: U.S. Department of Energy, Arizona Public Service Company, Arizona Solar Research Commission, Dynamic Sciences, Inc.

Customer Participation: voluntary.

Study Period: baseline period, six months, May 1975 to October 1975; test period, six months, May 1976 to October 1976.

Metering: standard three-dial meters.

Rates: 28 residential TOU rates with three daily rating periods--peak (P), intermediate (I), base (B). Sixteen Group I rates, six Group II rates, and six Group III rates where the number of hours in the P, I, and B periods are, respectively, 3-10-11 (I), 5-8-11 (II), and 8-5-11 (III).

Number of Customers: 140 customers on TOU rates only--80 in Group I, 30 in Group II, and 30 in Group III.

Incentives/Revenue Neutralizers: individual bill adjustments to achieve monthly credits equal to 20 percent of "estimated bills" under conventional rates.

involved experimental evaluations of TOU rates both alone and combined with load control devices or special educational efforts by the staff of the participating utility, the Arizona Public Service Company (APS). The portion of the project involving TOU rates alone is summarized in table 4-6.

Three groups of TOU rates were offered on an annual basis to randomly selected volunteer residential customers in the Yuma and Phoenix metropolitan areas. These two areas account for most of the summer peaking on the APS system. The volunteer customers were required to have their baseline electricity usage metered by time of use between May 1975 and October 1975 while they remained on the conventional APS residential rate. Then, during May 1976 to October 1976, all participants were billed under TOU rates. The rate

schedules were adjusted to ensure that no household paid more than its previous year's bill. If a household's total usage and time pattern of usage had been identical to that of corresponding months of the previous year, the customer would have been assured of a bill 30 percent lower than the prevailing conventional rate. Any divergence from each household's previous year's usage within each of the three daily rating periods was billed or credited at the variable charges specified by one of the 28 unique TOU rates.

Five customers were placed on each of the 28 rates, or a total of 140 volunteers. Of these 28 rates, the 16 Group I rates incorporated a three-hour peak period from 2:00 to 5:00 P.M.; the six Group II rates, a five-hour peak period from 2:00 to 7:00 P.M.; and the six Group III rates, an eight-hour period from 2:00 to 10:00 P.M. Since the same 13 hours (9:00 A.M. to 10:00 P.M.) were covered by the peak and intermediate periods together for all three groups, the lengths of the intermediate periods were 10, 8, and 5 hours for Group I, II, and III, respectively. All other hours were designated as base hours.

For Group I the highest rate was 16¢, 5¢, and 3¢ (16/5/3) in the peak, intermediate, and base periods, respectively, and the lowest was 8/4/1. For Group II the highest rate was 12/6/4 and the lowest was 6/4/1. Finally, for Group III the highest was 9/4/2 and the lowest was 4/3/1.

The 140 participants in the experiment were among those eventually retained from simple random presamples of the Phoenix and Yuma service areas. At the time the presamples were selected, the Phoenix and Yuma service areas contained 165,000 and 16,000 qualified (summer-peaking) households, respectively, or about 63 percent of the total 286,000 residential accounts in the APS system. A substantial number (68 percent) of those in the presample were rejected--some because their billing histories were shorter than one year and

some because of inaccessible service entrances, insufficient space to accommodate the TOU meter, or incompatible wiring for the TOU meters. Because of these rejections during sample selection and other subsequent attrition, the effective population was approximately 19 percent of all residential customers served. Due to these restrictions, the results, strictly speaking, apply only to those Phoenix and Yuma residential customers who would have volunteered for the study and would not have been excluded for the above reasons. Thus, the nature of the sample finally selected for the Arizona project limits the population to which these results can be projected accurately.

For various reasons, including both customer billing under a default scheme (which prevented bills larger than they would have been under the prevailing conventional rates) and the absence of appropriate demographic data, the sample was further pared through editing at the time of analysis to about 70 percent of its original size depending on the particular month(s) and group of customers involved.

4.1.2 Findings

Two types of analyses were completed. A comparative analysis was applied to determine whether TOU rates, as compared with conventional rates, created a difference in household consumption of electricity. A demand analysis was conducted to estimate demand elasticities.

The comparative analysis was completed for customers in Group I--the group that had identical hours in the peak, intermediate, and base periods in 1975 and 1976. This analysis showed fairly convincingly that, when on time-of-use rates, the customers in Group I reduced their electricity consumption during the peak rating period by 7-16 percent and the intermediate period by

1-9 percent. There is less evidence that some of this electricity consumption was shifted to the base period and that overall electricity consumption declined slightly.

These results are presented graphically in the four panels of figure 4-1, which show monthly weather-adjusted average daily kWh usage for each of the three daily rating periods for 1975 and 1976, together with average total daily kWh usage. The charts reflect both the 7 to 16 percent reductions in peak period kWh usage from June to October and the reductions in intermediate-period usage in each of the months. The lack of statistical significance in either the average increase in base period consumption or in the average decrease in overall electricity consumption is apparent from the small between-year differences shown in the last two panels of figure 4-1.

By contrast, the regression analysis failed to detect any price elasticities that were significantly different from zero for peak, intermediate, or base period consumption; that is, kWh consumption did not change significantly as time-of-use prices were varied.

Figure 4-1. Arizona. Comparison of Weather Adjusted 1975 and 1976 Average Daily kWh Electricity Usage of Group I Customers

There may have been many reasons for observing, on the one hand, reductions in peak and intermediate kWh usage due to TOU rates and, on the other hand, zero elasticities for peak, intermediate, and base prices. However, one possible explanation is that the customer education literature appeared to emphasize conservation during the peak and intermediate periods without emphasizing the differential gains that customers could achieve at the various price combinations. Another possible explanation is that this finding is not a paradox. Rather, a TOU rate may have a "once-and-for-all" effect on load shapes that remain basically unchanged if only TOU prices are changed.

Thus, overall conclusions for the study are: (1) The customers who participated in the Arizona experiment (and whose electricity consumption could be compared before and after) did reduce their electricity consumption during the peak period by 7-16 percent and during the intermediate period by 1-9 percent. Some of the reduction may have been shifted to the base period and overall electricity consumption may have declined slightly. (2) No statistically significant price elasticities were observed for TOU prices; that is, the participants' time-of-use patterns of electricity consumption did not vary with the time-of-use pattern of peak electricity prices. However, the complexities of the Arizona study design may obscure proper interpretation of this finding.

4.2 Connecticut*

4.2.1 Project Description

The Connecticut Rate Demonstration Project began in October 1975 as a one-year controlled experiment in which 200 Connecticut Light and Power

*Research Triangle Institute, Time-of-Use Electricity Price Effects, Connecticut, Final Report prepared for the U.S. Department of Energy, Office of Utility Systems, Contract No. CR-04-80220-00, RTI Project No. 41U-1542/00-11F, August 1979.

Table 4-7. Summary Features of the Connecticut Rate Demonstration Project

Participating Agencies/Utilities: U.S. Department of Energy, Connecticut Light and Power Company, Connecticut Public Utilities Control Authority, Connecticut Department of Planning and Energy Policy, and the Connecticut Office of Consumer Counsel.

Customer Participation: voluntary.

Customer Interviews: pre- and post-test questionnaires administered to both experimental and control customers.

Study Period: one-year baseline period, beginning October 1974; one-year test period, beginning October 1975.

Metering: fifteen-minute kWh meters.

Rates: Existing (declining block) rate and one TOU rate which included three daily rating periods on weekdays -- peak (P), intermediate (I), base (B) -- and two daily rating periods on weekends and holidays -- I and B.

Number of Customers: 200 customers on TOU rate; 200 in control group.

Incentives/Revenue Neutralizers: variable lump sum payment (\$50-\$150, depending on prior usage) before start of study.

Company (CLP) residential customers were placed on a seasonal TOU rate. Three rating periods were used during weekdays and two rating periods on weekends and holidays. The three weekday prices were 16¢, 3¢, and 1¢ per kWh; the weekend prices were 3¢ and 1¢ per kWh. An equal number of customers on a conventional rate served as a control group. Table 4-7 summarizes the major features of the Connecticut project.

In 1974, one year before the project started, a standard residential load research study was implemented within the CLP service area. Fifteen-minute magnetic tape recording meters were used to obtain detailed information on electricity usage patterns on a sample of 250 residential dwellings. Sample customers for the load research study were selected from the group of

residential customers in the CLP service area that remained after all farm customers, customers with less than a 12-month billing history for 1973, and customers having any estimated bills during 1973 had been excluded. These exclusions reduced the number of residential customers in the CLP service area from approximately 471,000 to 296,776.

The load research study ended on October 15, 1975, and the rate demonstration project began on the following day. An attempt was made to enroll all of the 248 remaining participants in the load research study as members of the TOU rate group. Twenty-nine customers refused to participate and 20 could not be contacted. Consequently, 199 load research customers were actually placed on the experimental rate. During the experimental test period, 17 of the 199 experimental customers relocated. New families that moved into the vacated residences were not included in the test.

The control group was obtained from the list of alternates previously selected and the rate assigned to this group was an existing rate. A total of 200 control customers (40 per stratum) was established as the desired sample size. In order to obtain these 200 control customers, 378 customers were screened. However, only 192 customers were actually included in the study. Meter installation problems accounted for about one-third of the rejections, and seasonal customers or customers planning to move accounted for another third.

Because of rejections during sample selection, the effective population was estimated to contain 134,788 customers. This was approximately 45 percent of the residential customers in the population actually sampled.

4.2.2 Findings

Four winter months, December 1975 to March 1976, and four summer months, June 1976 to September 1976, were analyzed. In each of the eight

months examined, the experimental group consumed less electricity during the peak period than the control group. This holds true for both the day of system peak (parameter 1) and for all days of the month (parameter 7). This and other findings described here are summarized graphically in figure 4-2. For the latter case, the reduction in consumption ranged from 19 to 25 percent for the four winter months and from 23 to 31 percent for the four summer months. Usage during the peak period is also reflected through parameters 18 and 19, which measure, respectively, the proportion of total usage in the peak period for the day of system peak and for the month. The experimental group had significantly lower proportions for each month.

In the four winter months the levels of consumption during the intermediate period for the experimental and control groups did not differ statistically. The four summer months show an entirely different pattern. In each summer month, the experimental customers used significantly less electricity during the intermediate period than the control customers. For the day of system peak the reduction ranged from 14 to 23 percent, and for all days in the month the reduction ranged from 12 to 17 percent.

The experimental group used significantly more electricity than the control group during the base period in each winter month. This was the case for both the day of system peak (parameter 3) and for the average over all days (parameter 9). The magnitude of the increased usage ranged from 13 to 23 percent. However, from June through September the experimental group used about the same amount of base period electricity as customers on the control rate.

Customers in the experimental group consumed significantly less total electricity than their counterparts in the control group during the summer

Figure 4-2. Connecticut. Top: Average Weekday Load Curve, June 1976; Bottom: Average Weekday Load Curve, January 1976

months due to consumption patterns during the peak and intermediate periods. These patterns suggest that during the summer months, the experimental customers conserved energy, whereas during the winter months, these customers are shifted usage from the peak period to the base period. These same patterns were evident for weekdays and weekend days within a month.

This study showed two distinct seasonal patterns. First, in the summer months, customers on the experimental and control rates used about the same amount of electricity during the base period. During the peak and intermediate periods, the experimental group consumed less, causing the total consumption to be significantly reduced. The cause of this reduction is unknown.

Second, total consumption in the winter months did not differ significantly for the experimental and control customers. During the peak period the experimental customers used less electricity than the control group; however, this reduction was offset during the base period when the experimental group used more electricity than the control group. Thus, in the winter months, customers appeared to be shifting usage from the peak to the base period.

The impact of TOU pricing of electricity on the hourly system load was estimated for the peak winter and summer months (January and June). For the peak winter month, the estimated impact of implementing the experimental rate on the population of inference was a reduction in the system peak of 8 to 13 MW. For the peak summer month a reduction of 70 to 83 MW was estimated.

4.3 Ohio*

4.3.1' Project Description

In the Ohio Rate Demonstration Project, 100 residential customers of the Dayton Power and Light Company (DPL) were placed on a TOU rate schedule from June 1976 to November 1977. The experimental rate schedule used two rating periods on weekdays and one rating period on weekends and holidays. The rating period also varied by season. The spring and fall peak price was 3.1¢ per kWh and the summer and winter peak price was 9.1¢ per kWh; for all seasons the base price was 0.4¢ per kWh. The base period included all weekend hours. Sixty customers on the existing (declining block) rate served as a control group. Thirty-minute kWh meters were used to monitor customers in the experiment. Participation in the study was voluntary, and customers did not receive any direct compensation for their participation. Table 4-8 summarizes the major features of the Ohio project.

Selection of sample customers excluded those without a 12-month billing history for April 1974 to April 1975, bulk-metered residences, company employees, residents on "frozen" rates, and customers with less than 6,000 kWh annual usage. The group that was sampled contained approximately 196,000 of the 337,000 residential customers living in the DPL service area.

About 80 percent of the customers selected to participate in the study were not included for such reasons as meter installation problems, refusal to participate, and moving plans. Based on the combined number of rejections for the experimental and control groups, customers in the final sample represent about 39,000 residential customers (the effective population). This

*Research Triangle Institute, Time-of-Use Electricity Price Effects, Ohio, prepared for the U.S. Department of Energy, Office of Utility Systems, Contract No. CR-04-80220-00, RTI Project No. 41U-1542/00-12F, December 1979.

Table 4-8. Summary Features of the Ohio Rate Demonstration Project

Participating Agencies/Utilities: U.S. Department of Energy, Ohio Public Utilities Commission, Dayton Power and Light Company.

Customer Participation: voluntary.

Customer Interviews: pre- and post-test questionnaires administered to control and experimental customers.

Study Period: test period of 18 months, from June 1976 to November 1977.

Metering: 30-minute kWh meters.

Rates: existing (declining block) rate and a seasonal TOU rate with two daily rating periods on weekdays -- peak (P) and base (B) -- and one rating period on weekends and holidays (B).

Number of Customers: 100 customers on the seasonal TOU rate, 60 in control group.

Incentives/Revenue Neutralizers: revenue-neutral TOU rate.

group constitutes approximately 20 percent of the sample population and 12 percent of all residential customers.

4.3.2. Findings

Five summer months (August and September 1976 and July to September 1977) and two winter months (December 1976 and January 1977) were selected for analysis. Because of certain confounding stratification problems in the sample design the data for the two test groups were analyzed as simple random samples.

In five of the seven months examined, the experimental group consumed significantly less electricity during the peak period (parameter 7) than the control group. These results are illustrated in figure 4-3 by the plots of load curves for the average August weekday and for the peak summer day which occurred in August. The reduction in consumption ranged from 24 percent in

August 1977 to 38 percent in August 1976. Usage reductions of approximately 21 percent occurred in December 1976 and January 1977. However, the differences were not statistically significant for these two months because the estimated standard errors for both the control and experimental groups were almost double those observed in the other months. This is probably due to high usage by the electric heating customers during the two winter months, causing much higher usage variations since some sample customers did not heat with electricity. Numerically, the difference in consumption for the two groups over the seven months ranged from 1.52 to 2.62 kWh per customer per day. Significant reductions in peak-period usage were also observed for the days of monthly system peak (parameter 1) during August 1976 and September 1976 (the only months for which system data were available).

Usage during the peak period is also reflected through parameters 18 and 19 which measure, respectively, the proportion of total usage in the peak period for the day of system peak and for the month. Since the TOU rate schedule caused a reduction in usage during the peak period but did not affect total consumption, these proportions were significantly lower for the experimental group in each of the seven months.

In six of the seven months examined, the experimental customers used more electricity during the base period than the control customers. These increases tend to offset the reduction in consumption observed in the peak period, suggesting that the TOU rate schedule is causing customers to shift usage from the peak to the base period. The winter months showed a more pronounced shift in usage from peak to base period. Tests of hypotheses failed to detect the base-period increases as being statistically significant because of relatively large customer-to-customer variation in base-period usage.

Figure 4-3. Ohio. Top: Average Weekday Load Curves, August 1976; Bottom: Day of System Peak Load Curves, August 1976.

The experimental group did not differ significantly from the control group in total monthly consumption (parameter 12) and total consumption for the day of system peak (parameter 6) because a decrease during the peak period was offset by an increase during the base period. The experimental group's estimated monthly consumption was slightly higher in three of the seven months and slightly lower in the remaining four months.

4.4 North Carolina--Blue Ridge Electric Membership Corporation*

4.4.1 Project Description

The Blue Ridge Electric Membership Corporation (BREMC) TOU pricing experiment began in October 1977. It was a 12-month controlled experiment in which 102 BREMC residential customers were placed on a seasonal TOU rate schedule. Three rating periods were used during the winter season and two rating periods during the summer season. The three winter prices were 4.62¢, 2.28¢, and 1.23¢ per kWh; the summer prices were 2.44¢ and 1.18¢ per kWh. A total of 98 customers on the existing (declining block) rate served as a control group. Fifteen-minute kWh meters were used to monitor electricity consumption. Participation in the study was mandatory. Participants did not receive any direct compensation; however, the experimental rate was designed to be revenue-neutral. Table 4-9 summarizes the major features of the BREMC project.

Sample customers were selected from among the 29,594 residential customers in the BREMC service area (26,042 non-seasonal and 3,552 seasonal) as of the April 1977 billing file. The sample was originally designed to select

*Research Triangle Institute, Time-of-Use Electricity Price Effects, North Carolina Blue Ridge Electric Membership Corporation, Final Report prepared for the U.S. Department of Energy, Office of Utility Systems, Contract No. EC-77-C-01-8684, RTI Project No. 41U-1542/00-15F, April 1980.

Table 4-9. Summary Features of the Blue Ridge Study

Participating Agencies/Utilities: U.S. Department of Energy, North Carolina Utilities Commission, Research Triangle Institute, ICF, Inc., Blue Ridge Electric Membership Corporation.

Customer Participation: mandatory.

Customer Interviews: pre- and post-test questionnaires administered to control and experimental customers.

Study Period: one year; beginning October 1977.

Metering: 15-minute kWh meters.

Rates: existing (declining block) rate and a seasonal TOU rate with three daily rating periods, peak (P), intermediate (I), and base (B), in the winter months (November-April), and two rating periods, I and B, during the summer (May-October).

Number of Customers: 102 customers on the TOU rate schedule; 98 in control group.

Incentives/Revenue Neutralizers: no participation payments. Revenue-neutral TOU rate.

200 customers randomly from among the non-seasonal population and to place them into 32 strata. The size of the seasonal population, however, was larger than expected, and three additional seasonal strata were added to accommodate this group. After this stage of the sampling, there were 102 customers in the experimental group and 98 customers in the control group. Some of the sample customers were found to be on commercial meters or moved early in the study, reducing the final sample to 192 customers.

Thirty-four customers were excluded from the final sample. The major reasons for these exclusions were meter installation problems, moving outside the service area before the test began, and seasonal customers coded as non-seasonal. The effective population is estimated to contain 25,667 customers, or approximately 87 percent of the sampled population.

4.4.2 Findings

Under TOU pricing one would expect customers to conserve electricity by simply using less during the period of highest price or to shift a portion of their usage from the peak pricing period to some other period where the price is lower. However, no evidence of either of these responses was found in any of the 12 months analyzed (October 1977 through September 1978). Differences between the estimated population means, overall and by rating period, are small and can be attributed to chance variation; that is, the observed differences are no larger than one would expect if both samples of customers had been placed on the same rate. The similarities of the load curves for the two groups are depicted for the peak month in figure 4-4.

With respect to the percentage of daily consumption by rating period, no significant differences were found between customers on the control and the experimental rate forms. Differences between the estimated usage totals for the average day were also small. Thus, little evidence of a response to TOU pricing was found. In June and September, significant differences between the control and experimental groups were found, but in each case the customers on the experimental rate schedule used more electricity. It is difficult to attribute this increase in consumption to TOU pricing. However, the TOU rate structure used in this study is such that during the summer months, a customer using, say, 600 kWh (of which 450 kWh are used during the peak period of 7:00 A.M. - 11:00 P.M.) would pay 3.14¢ per kWh. Under the existing (declining block) rate, a customer using 600 kWh would pay 3.61¢ per kWh. This represents a 13 percent decrease for the customer on the TOU rate.

The estimated mean consumption and noncoincident demand levels for the experimental group exceeded those of the control group in most comparisons. This suggests the possibility that customers in the experimental group were

Figure 4-4. North Carolina - Blue Ridge Electric Membership Corporation. Top: Day of System Peak Load Curves, February 1978; Bottom: Average Daily Load Curve, February 1978.

inherently heavier users of electricity than those in the control group -- in other words, that the two sample groups were not balanced. To check for this possibility, comparisons of socioeconomic and demographic variables were developed for the experimental and control groups. While these comparisons were not statistical, the patterns of differences between these variables failed to show any gross evidence of imbalances.

4.5 Rhode Island*

4.5.1 Project Description

The Rhode Island TOU pricing experiment began in November 1977. It was a 13-month study in which 170 Blackstone Valley Electric Company (BVE) residential customers were placed on a seasonal TOU rate with a two-part demand charge. Summer weekdays had three rating periods and winter weekdays had two rating periods. All weekends and holidays were under a single rating period. The summer weekday prices were 3.38¢, 2.38¢, and 1.85¢ per kWh and the winter weekday prices were 3.38¢ and 1.85¢ per kWh. The weekend and holiday price was 1.85¢ per kWh. During all peak hours a demand charge of \$1.38 per kW was levied as well as a demand charge of \$1.42 per kW during all hours. One hundred thirty customers on the existing residential rate served as a control group. Fifteen-minute kWh tape recording meters were used to monitor customers in the experiment. Participation in the experiment was mandatory; however, participants were compensated for their cooperation. Table 4-10 summarizes the major features of the Rhode Island project.

The January 1977 billing file constituted the sampling frame from which a total of 300 residential customers were selected to participate in the

*Research Triangle Institute, Time-of-Use Electricity Price Effects, Rhode Island, Draft Final Report prepared for the U.S. Department of Energy, Office of Utility Systems, Contract No. CR-04-80220-00, RTI Project No. 41U-1542/00-14F, Submitted December 1979.

Table 4-10. Summary Features of the Rhode Island Rate Demonstration Project

Participating Agencies/Utilities: U.S. Department of Energy, Rhode Island Public Utilities Commission, Blackstone Valley Electric Company.

Customer Participation: mandatory.

Customer Interview: pre- and post-test questionnaires administered to experimental customers. Control group was contacted only at the start of the study.

Study Period: test period, 13 months, beginning in November 1977.

Metering: 15-minute kWh meters.

Rates: existing (declining block) rate and one seasonal TOU rate with two demand charges. On weekdays there were three daily rating periods during the summer and two during the winter. All weekends and holidays had a single rating period.

Number of Customers: 170 customers on the TOU rate; 130 customers in the control group.

Incentives/Revenue Neutralizers: lump sum payment made at the beginning of the study -- \$25 to control group customers and \$100 to customers on the TOU rate.

Rhode Island demonstration project. This file contained 66,149 residential customers with active accounts. Since participation in the study was mandatory, no customers were excluded before sample selection.

The sampled population was divided into three strata: general residential customers, customers with controlled water heating, and customers with electric space heating. The general residential category contained about 95 percent of all residential customers.

A random process was used to assign selected customers within a given stratum to the TOU rate or the control group. Within a given stratum, customers with less than one year's billing history had a selection probability

of one-half that for other customers. Normally, unequal selection probability would be taken into account at the analysis stage. In this case, because of incomplete information on selected customers, sample customers in each stratum were treated as a simple random sample. This does not pose a serious problem since the proportion of customers without a 12-month billing history is relatively small.

Although participation in the Rhode Island study was mandatory, 40 percent of the customers selected did not participate. The two primary reasons for the rejections were meter installation problems and plans to move from the service area during the test period.

The sampled population consisted of all residential customers in the Blackstone Valley Electric Company service area with active accounts during the January 1977 billing month. This population totaled 66,149 customers. Due to exclusion during sampling, the estimated number of customers in the effective population was reduced to approximately 60 percent of the sampled population, or 39,813.

4.5.1 Findings

Three winter months, January 1978 to March 1979, and two summer months, June and July 1978, were selected for analysis. Based solely on statistical tests, the results are inconclusive. Of all the parameters compared each month, only one -- proportion of monthly electricity used during the peak period -- indicated differences that were statistically significant (proportions for TOU rate customers were smaller by 5 to 10 percent). In many instances, the mean difference in response between customers on the control and TOU rates was not statistically significant because of large variances among customers within a stratum.

When parameter estimates are considered alone, usage patterns indicate that customers are responding to the TOU rate but the level of response is minimal. Some of these response indicators include:

- Monthly consumption during the peak period (parameter 7) was slightly lower under TOU pricing. Four of the five months examined showed decreases ranging from 4 to 12 percent.
- Monthly base period usage (parameter 9) was generally higher for customers on the TOU rate. The two summer months showed increases of 11 and 15 percent.
- Usage during the hourly periods before and after the peak period (parameters 10 and 11) was slightly higher for the experimental customers -- increases generally ranged from 5 to 15 percent.
- Consumption during hours when system load was near annual maximum (parameter 17) was lower for customers on the TOU rate -- decreases ranged from 6 to 26 percent.
- Maximum diversified demand and class coincidence factor were generally lower (by 10 to 15 percent) for customers under TOU pricing. Class load factor based on maximum diversified demand was higher (by 10 to 20 percent) for the experimental group.

Given the stratification scheme employed in the Rhode Island study and the variability observed in the response measures, an alternative analysis is recommended. A covariance analysis is suggested as a means for reducing the within-stratum variance. Assuming that the underlying assumptions are valid, the ANCOVA technique provides a means for adjusting for differences in variables that were measured in the study but were not controlled.

4.6 Wisconsin*

4.6.1 Project Description

The Wisconsin Rate Demonstration Project began in May 1976 and ended in May 1980. A total of 644 Wisconsin Public Service Corporation

*Research Triangle Institute, Time-of-Use Electricity Price Effects, Wisconsin, Interim Draft Report prepared for the U.S. Department of Energy, Office of Utility Systems, Contract No. CR-04-80220-00, RTI Project No. 41U-1542/00-02I, submitted May 1979.

(WPSC) customers were included in the project. Five hundred fifty-two customers were placed on one of 11 experimental rate schedules: nine TOU rates, a flat rate, and a three-part rate.* Ninety-two customers on the existing (declining block) rate served as a control.

The nine TOU rate schedules were divided into three groups defined by the length of the non-holiday weekday peak rating periods. Three Group I rate schedules had a six-hour peak period, three Group II rate schedules had a nine-hour peak period, and three Group III rate schedules had a 12-hour peak period. All other hours, including weekends and holidays, were designated as base hours. Each group contains three rate schedules with peak to base price ratios of 2:1, 4:1, and 8:1.† Table 4-11 summarizes characteristics of the Wisconsin project.

The sample was drawn from a population consisting of all 1976 WPSC non-farm, non-seasonal residential customers who had a 12-month billing history and whose average monthly usage exceeded 100 kWh in 1975. This sampled population (approximately 217,000) was stratified into nine groups according to their 1975 annual consumption. Simple random sampling was used within each stratum to produce the desired number of participants. Approximately 43 percent of all WPSC residential accounts were represented by the sample.

Participation in the study was mandatory. Customers were billed under revenue-neutralized rates. The rates ensured that the average household's bill would be nearly identical to its bill under the existing rates, if its consumption level and pattern were unchanged during the experimental period.¶

*Data from the 46 customers on the three-part rate were not analyzed.

†For the 12-hour peak the price ratio was 7.6:1 in the summer and 6.9:1 in the winter.

¶Of course, customers not consuming the average proportion of on-peak electricity experienced bill increases or decreases under the TOU rate schedules depending upon whether they used a higher or lower proportion of their electricity on peak than the average customer.

Table 4-11. Summary Features of the Wisconsin Rate Demonstration Project

Participating Agencies/Utilities: U.S. Department of Energy, Wisconsin Public Service Corporation, Public Service Commission of Wisconsin.

Customer Participation: mandatory.

Study Period: baseline period, 12-15 months ending April 1977; test period, 3 years, May 1977 to May 1980.

Metering: 15-minute kWh meters

Rates: nine time-of-use (TOU) rate schedules with two daily rating periods (peak and base) on weekdays and one rating period (base) on weekends and holidays. Of these nine TOU rates, three rates have daily peak rating periods of six hours (Group I); three have nine-hour peak periods (Group II); and three have 12-hour peak periods (Group III). A flat rate and a TOU rate with a demand charge were also included in the experimental rates. Rate schedules differ slightly by season and by urban and rural areas.

Number of Customers: a total of 644 customers were involved in the demonstration project: 46 customers on each of the 9 TOU rates, 92 customers on the flat rate, 92 on the control (declining block) rate, and 46 on a three-part rate.

Incentives/Revenue Neutralizers: Rate schedules were designed to leave the average customer's bill approximately unchanged in moving from the traditional rates to the test rates. No compensation was given to customers whose bills were higher because of their particular TOU usage pattern.

4.6.2 Findings

Analyses were completed for two summer months (July 1977 to August 1977) and three winter months (December 1977 to February 1978). These months were chosen because they contain the day of system peak for the winter and summer seasons, and because they are reasonably representative months for the two seasons.

Thirty-four sample customers with electrically heated homes, all of whom were facing the same TOU rate, were excluded from the analysis. The exclusion was necessary since there was no corresponding control group. Therefore, these results do not apply to the 2.3 percent of the WPSC households that have electric space heating.

Regression analyses, specifically ANCOVA analyses, were conducted to measure changes in consumption of electricity caused by TOU prices. The analyses indicate that daily electricity usage was clearly affected by the TOU rate structure. In both the summer and winter seasons, average consumption of all TOU customers declined in the peak rating period. Since reductions in base consumption of TOU households were not as great, consumption during the base period became a larger proportion of total daily consumption. However, load curves of individual experimental households varied considerably in their sensitivity to time-differentiated electricity pricing.

In each of the summer and winter seasons, the estimated average daily load curve of households on the flat rate schedule was very similar to that estimated for the control group. In fact, at the 5 percent level of significance, at no hour did the average household usage on the flat rate and average household usage in the control group differ by a statistically significant margin. On the summer day of system peak, flat rate customers used significantly less electricity from about 1:00 A.M. to 8:00 A.M. and from 2:00 P.M. to 3:00 P.M. No attempt was made to explain these differences, since they may have been due to nothing more than chance variation on the winter day of system peak data.

A comparison of daily consumption of the TOU households with the control group showed that all experimental groups averaged 21 to 25 percent less electricity than the control group during the peak period in the summer and

from 8 to 15 percent less electricity than the control group during the winter months. This and other findings are shown graphically for the summer season in figure 4-5, which presents overall average load curves for all of the TOU rate customers, regardless of the peak:base price ratio, for each length of the peak period.

The average total daily electricity usage for TOU households in each of the three rate groups was less than the average for the control group in both the summer and winter months. Average differences in the summer ranged from 10 to 16 percent, and average differences in the winter ranged from 1 to 8 percent.

The hours immediately preceding or following peak rating periods showed no significant needle peaking. Small demand peaks often occurred in the base hours adjacent to the peak period. Generally, demand during these adjacent hours was not significantly greater than that of the control groups.

Hourly fluctuations in estimated load curves made the responses of the residential class to the TOU rate schedule difficult to predict. On the summer day of system peak, TOU experimental households used from 21 to 28 percent less electricity than the control group, and on the winter day of system peak, TOU households consumed from 12 to 22 percent less electricity. Total peak-day consumption during the summer was 13 to 15 percent less for TOU households than for the control group and 4 to 9 percent less during the winter for these same households. As these figures indicate, responses to TOU pricing on both the peak day and the average day were greater in the summer than in the winter.

The percentages of total kWh consumed on peak by households on the three TOU rates within a rate group (Groups I, II, and III) were inversely related to peak:base price ratios; that is, the percentage of consumption during the

Figure 4-5. Average and Peak Day Summer Load Curves, Wisconsin

peak period declined as the peak:base price ratio increased. Direct comparisons of differences in peak-period usage between the TOU and control group households showed no such pattern.

Elasticities of substitution were estimated for the peak and average days of each season. These elasticities measure the degree to which the peak:base price ratio affects the proportion of total daily electricity consumed during the peak period; i.e., the willingness of households to substitute consumption in the base period for consumption in the peak period.* These estimates were greater than zero by statistically significant amounts in nearly all cases. This means that the substitution of base for peak electricity increased with the associated price ratio.

Elasticities of substitution were significantly higher for all groups in the summer than in the winter, with summer estimates ranging from 0.105 to 0.137; and winter, from 0.031 to 0.086. This difference may be caused by air conditioners, which contribute greatly to summer peak-period reductions in consumption but have no counterpart in the winter, and the larger number of peak-rated evening hours during the winter, which may have decreased opportunities for convenient reductions of electricity usage. Neither explanation was empirically verifiable, although extensions of the basic analysis procedure provided some casual support.

It would have been of interest to estimate own- and cross-price elasticities of demand in addition to elasticities of substitution. Unfortunately, restrictions placed on the permissible combinations of peak and base prices by the revenue neutrality constraint produced dependencies between the

*For example, an elasticity of substitution of 0.1 means that a 1 percent increase in the peak:base price ratio will decrease the peak:base consumption ratio by 0.1 percent.

two sets of prices that prevented the estimation of demand elasticities with pragmatic models (see section 3.2), and demand-theoretic models were not applied for this study.

Peak periods among the three experimental groups differed in the number and location of their peak hours. The effects of each rate structure on consumption during selected peak-rated hours common to all three groups were examined. Generally, the shorter the peak period, the greater the hourly reductions in peak-period consumption. Furthermore, for short peak periods (five contiguous hours or less), the maximum response occurred near the middle of the period, while for longer peak periods (nine or more contiguous hours) the response was fairly even over the peak hours.

The summer system peak hour occurred in a period of high, but not maximum, residential demand, while the winter system peak hour did occur at a time of maximum residential demand. Average estimates over the nine TOU rate schedules of the potential capacity savings from the implementation of TOU rates were greater for the winter hour (40 MW) than the summer hour (32 MW), but both savings represented approximately 23 percent of residential demand.

Weekend consumption by TOU households was in nearly all cases not greater, and in some cases in the summer, significantly less than weekend consumption by the control group. This occurred despite the fact that base-period prices were in effect for TOU households throughout the weekend, thereby providing lower prices for weekend electricity to TOU households than to control households. Continued conservation on weekends by TOU households in the summer may have been due to reduced weekday use of air conditioners that carried over to the weekend.

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CHAPTER 5: CONCLUSIONS AND GENERAL IMPLICATIONS

The findings in Chapter 4 are by nature detailed and project specific. Furthermore, they reflect only the objective outcomes of the analyses RTI has conducted on the rate demonstration project data. This chapter first presents some unifying qualitative conclusions and then offers some concepts about TOU rate effects; these ideas are not empirically verified, but nevertheless are suggested by the analysis to date.

One major conclusion is that understanding the data limitations of the individual rate demonstration projects is essential to gain a proper perspective on the results. The three types of data limitations discussed in Chapter 3 -- experimental design, sample design, and data file limitations -- are equally important. These limitations must be incorporated into any interpretation of quantitative results for each project in order to avoid distortion.

A second conclusion is that TOU rates have mixed effects. Volunteer customers and high-usage customers generally appear to be more responsive to TOU rates. TOU rates with demand charges also seem to stimulate more responsiveness, although this is a tentative finding.

Third, within the range of effects observed, the analyses reported here do not constitute a statement for or against a TOU rate policy. Rather, the information provided by these analyses is only an input to a more ambitious cost-benefit analysis that would consider many other factors before evaluating a TOU policy.

Fourth, the same price elasticity concept must be used when comparing elasticities of electricity demand by TOU. Elasticities can be partial or full, and compensated or uncompensated. They can also apply to different lengths and locations of rating periods, to different types of residential

customers, to different types of TOU rates, and over different ranges of prices. These distinguishing characteristics are not unimportant subtleties; they are critical differences.

Fifth, many of the rate demonstration projects, e.g., Arizona and Wisconsin, included TOU rates that were designed to achieve revenue neutrality in such a way that price elasticities are very difficult or impossible to estimate. Elasticity estimates can often be salvaged only at the expense of restrictive assumptions (in demand-theoretic models) that cannot be tested.

Further impressions suggested by the analyses have not yet been rigorously tested. These ideas are potentially useful because they provide guidance for further analysis of the existing experimental data and for the design and analysis of future TOU rate experiments.

One impression is that TOU price elasticities are generally small and that they are functions. Specifically, the response to variations of the price of electricity by time of use is very possibly a function of the appliance characteristics of households, the electricity price level, etc. Thus, a household with many luxury appliances such as an air conditioner and a swimming pool may be more susceptible to TOU price inducements than other customers.

Second, the new "TOU rate structure effect" may be stronger than the "TOU price variation effect." More precisely, changing from a declining block or flat residential rate to one particular TOU residential rate may have a greater effect on the shape of the average residential load curve than will any future variations in kWh prices by TOU. This concept rationalizes the simultaneous existence of small TOU elasticities and significant changes in the load shapes when customers on existing rates are compared to those on a TOU rate.

Third, the financial incentive provided by a TOU rate may have to reach a "threshold" level to stimulate a significant response by most customers. For example, an average customer is probably less likely to exhibit moderate load shifting behavior if he can save only \$5 to \$10 per month. He is more likely to do so if the savings exceeded a threshold of \$20 to \$25 per month. Of course, no customer is "average," so the threshold could vary a great deal among individual households.

Finally, the long-run effects of TOU rates may be more pronounced than the short-run effects -- where the long run is defined as a period within which a substantial number of new residential investments would be practical. For example, TOU rates could have small effects in the short-run DOE experiment periods but substantial effects in the long run due to investments in storage devices such as hot brick storage heaters.

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