A RAND NOTE

PROJECTING RESPONSE TO TIME-OF-DAY ELECTRICITY RATES

Jan Paul Acton, Rolla Edward Park

December 1984

N-2041-MD

Prepared for

The Maryland Power Plant Siting Program

Rand
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PREFACE

Beginning in the mid-1970s, commercial and industrial customers began to face time-of-day (TOD) electricity rates in some U.S. utilities; residential customers faced experimental TOD rates in other utilities. Since then, several thousand customers in each of these classes have been placed on TOD rates in several states. Utilities in other states are considering applying TOD prices to their customers and state regulators are trying to determine the probable effects if such rates are offered.

This Note draws upon an extensive body of recently completed empirical studies to help load forecasters and policy analysts determine the likely effects of TOD rates. Each of these studies employs individual customer data and information originally collected on an hour-by-hour (or finer) basis.

With the support of a contract with the Maryland Power Plant Siting Program, we recommend suitable empirical models for projecting the effect of TOD rates and illustrate the calculation of effects on consumption, bills, and economic well being associated with changing from current rates in Maryland to TOD rates that have been proposed by the Potomac Electric Power Company (PEPCO) and the Baltimore Gas and Electric Company (BGE).

The Note should be of interest to individuals who wish to understand the demand for electricity under alternative pricing schemes.

Projections for business customers are based on estimates reported in R. E. Park and J. P. Acton, *Response to Time-of-Day Electricity Rates by Large Business Customers: Initial Analysis of Data from Ten U.S. Utilities*, The Rand Corporation, R-3080-HF/MD/RC, September 1983, which was also prepared under this contract. Projections for residential customers are based on J. P. Acton, B. M. Mitchell, and R. Sohlberg, *Estimating Residential Electricity Demand Under Declining-Block Tariffs: An Econometric Study Using Micro-Data*, The Rand Corporation, P-6203, November 1978 (for analyzing the effects of flattening), and on W. G. Manning, Jr., and J. P. Acton, *Residential Electricity Demand Under Time-of-Day*

Pricing: Exploratory Data Analysis from the Los Angeles Rate Study, The Rand Corporation, R-2426-DWP/HF, December 1980 (for analyzing the effects of TOD rates).

SUMMARY

Time-of-day electricity rates were applied to a significant number of U.S. electricity customers in the mid-1970s. Many electric utilities, regulators, and customers are interested in the potential impacts such rates could have on individual customers and groups of customers. The Note draws upon two source of U.S. data to help project such effects. For business customers, the Rand data base of approximately 6000 customers from ten utilities is used. For residential customers, the results of several rate experiments are synthesized to make projections.

For business customers, we employ the statistical model reported in a companion study prepared for the John A. Hartford Foundation and the Maryland Power Plant Siting Program.[1] Two methods are used to project changes in utility load curves: Method 1 takes account of customer mix (by two-digit standard industrial classification (SIC) code); Method 2 accounts for customer mix, differences in prices, and other factors. The projections explain 40 to 80 percent of the utility-to-utility variance observed in our ten-utility sample. We illustrate the two projection methods using proposed time-of-day rates for large commercial and industrial customers in Maryland's Potomac Electric Power Company (PEPCO) and Baltimore Gas and Electric Company (BGE) service territories. Overall, the projected load changes are quite modest, reflecting the small change in loads in the ten utilities.

The residential analysis is drawn from a large body of published studies, including non-time-of-day electricity rates as well as TOD rates. The non-TOD studies are particularly useful for analyzing response to price changes by level of use and other household characteristics such as specific appliances. We used them to project the effects on demand and economic well being of changing from declining block rates to flat rates in Maryland's two largest utility systems. We

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[1] Rolla Edward Park and Jan Paul Acton, *Response to Time-of-Day Electricity Rates by Large Business Customers: Initial Analysis of Data from Ten U.S. Utilities*, The Rand Corporation, R-3080-HF/MD/RC, September 1983.

reviewed time-of-day effects reported in several studies drawn from residential rate experiments. We based projections on the Los Angeles Electricity Rate Study, a study of approximately 1200 households with detailed information on appliances, level of use, and other household characteristics. We compared the Los Angeles projections with those in Wisconsin and North Carolina and found that, when local factors are taken into account, highly consistent findings result. This model is applied to proposed TOD rates for residential customers in PEPCO and BGE. The changes in use, load shape, and economic well being are reported for each level of use, although the proposed rates are applied only to the very largest customers by the utilities.

ACKNOWLEDGMENTS

This study benefited from the cooperation and review of many persons. In the first place, individuals in the load forecasting and rate departments of Pacific Gas and Electric Company, Southern California Edison Company, Los Angeles Department of Water and Power, Wisconsin Electric Power Company, Wisconsin Power and Light, Madison Gas and Electric, Commonwealth Edison, Consolidated Edison, Long Island Lighting Company, and Consumers Power Company all were generous with time and explanations that made it possible for us to acquire and develop the data used for the business customer analysis.

During the course of this research, Suzanne Watkins of the Maryland Power Plant Siting Program and Matt Kahal of Exeter Associates provided detailed suggestions and guidance. The present Note was reviewed by them, by Daniel Kohler of Rand, and by members of the rate staff at both Potomac Electric Power Company and Baltimore Gas and Electric Company. In addition, three anonymous reviewers provided detailed comments on behalf of the Power Plant Siting Program. We appreciate the assistance of each of these persons.

CONTENTS

PREFACE iii

SUMMARY v

ACKNOWLEDGMENTS vii

FIGURES xi

TABLES xiii

Section

I. INTRODUCTION AND SUMMARY 1

Projections for Business Customers 2
Projections for Residential Customers 3

II. EVALUATION AND DEMONSTRATION OF ALTERNATIVE METHODS FOR PROJECTING BUSINESS CUSTOMER RESPONSE TO TOD RATES 5

A Model of Business Customer Response to TOD Rates 5
Two Projection Methods 13
Comparison of In-Sample Projections 17
Comparison of Out-of-Sample Projections 20
Application to Maryland 24
Discussion 30

III. REVIEW OF SELECTED RESIDENTIAL STUDIES AND APPLICATION TO RATE STRUCTURE CHANGES 34

Review of Residential Response to Non-TOD Electricity Rates 34
Review of Residential Response to TOD Rates 37
Illustrative Application of Forecasting Models to Rate Changes 53

BIBLIOGRAPHY 67

APPENDIX A A.1
APPENDIX B B.1
APPENDIX C C.1

FIGURES

1. Relative Peak Hourly Consumption 8

2. Illustrative Effects of Rate Flattening on Consumption and Welfare 53

TABLES

1. Utilities Supplying Raw Data 6

2. Nonlinear Estimates of Equation (1) 11

3. Illustration of Projection Method 1: Average Response by Industry 14

4. Illustration of Calculation of Adjustment Factor for Use in Projection Method 2: Adjustment for Prices and Other Factors 16

5. Summary of Illustrative Projections for SCE/T73 Customers (N=438) 17

6. Comparison of In-Sample Projections 19

7. Change in Relative Peak Load for PEPCO D.C. TOD Customers .. 21

8. Application of Projection Method 1 to PEPCO's D.C. Customers 22

9. Calculation of Adjustment Factor for PEPCO D.C. TOD Customers for Use in Projection Method 2 23

10. Summary of Projections for PEPCO D.C. TOD Customers (N=258) 23

11. Application of Projection Method 1 to PEPCO's Maryland Customers 24

12. Terms of PEPCO's TOD Rate and Its Standard Rate for Large Customers 26

13. Calculation of Adjustment Factor for PEPCO's Maryland Customers for Use in Projection Method 2 27

14. Summary of Projections for PEPCO's Maryland Customers (N=116) 27

15. Application of Projection Method 1 to BGE's Customers 28

16. Terms of BGE's TOD Rates and Its Standard Rates for Large Customers 29

17. Calculation of Adjustment Factors for BGE Customers for Use in Projection Method 2 30

18. Summary of Projections for BGE's Customers (N=488) and for BGE/GL Customers (N=1360) 31

19. Summary Estimates of Residential Price Elasticities of Demand for All Households 35

20. Residential Price Elasticity Estimates by Level of Use 36

21. Definitions of Variables in Estimated Demand Equations 43

22. Estimated Own- and Cross-Price Elasticities from Main Effects Model 44

23. Own-Price Elasticities for Weekday Electricity Use by Level of Use 46

24. Full Price Elasticities of Weekday Consumption Demand: Los Angeles 48

25. Own- and Cross-Price Full Elasticities: Wisconsin Summer 6- and 9-Hour TOD Plans 50

26. Other Estimate of Customer Response 1 to TOD Rates Across Several Residential Experiments Weekdays, Stage I, Basic Model 51

27. Calculated Effect of Rate Flattening on Consumption, Bills and Economic Well-Being per Month 55

28. Terms of PEPCO's MD-R-TM Rate 56

29. Summary of Effects of PEPCO's Proposed TOD Rate on Consumption, Bills, and Welfare, by Level of Use (Summer) .. 59

30. Summary of Effects of PEPCO's Proposed TOD Rate on Consumption, Bills, and Welfare, by Level of Use (Winter) .. 60

31. Terms of BGE TOD and Standard Rates 62

32. Summary of Effects of BGE's Proposed TOD Rate on Consumption, Bills, and Welfare, by Level of Use (Summer) .. 63

33. Summary of Effects of BGE's Proposed TOD Rate on Consumption, Bills, and Welfare, by Level of Use (Winter) .. 65

I. INTRODUCTION AND SUMMARY

Time-of-day (TOD) electricity rates were first applied to some large U.S. businesses in the mid-1970s.[1] They were also applied on an experimental basis to some residential customers in the late 1970s. By now, over 12,000 large industrial and commercial firms are subject to such rates in more than half the states. In a few states, residential customers are also subject to TOD rates that apply either to the very largest consumers or on an optional basis. Other states are considering introducing TOD tariffs, and those with such tariffs already in place are considering extending them to cover additional (smaller) customers.

Utilities need to forecast future demand for use in capacity planning and rate design. The effects of TOD rates should be taken into account in the forecasts. Forecasting in a broad sense must also take into consideration a myriad of demographic, economic, technological, social, climatological, and other factors that may affect demand. Over the long run, technological advances and changes in economic activity or lifestyles can fundamentally alter energy use patterns. It lies beyond our charter to address all of these sources of long-term change. In this Note, we are concerned with the narrower task of determining the immediate effect of TOD rates on business and residential customers' load shapes. We take all of the other factors as given and ask what is the short-run incremental effect of a change in rate structure. Our use of the word "projecting" rather than "forecasting" is meant to emphasize this distinction.

In this Note, we show how the results of previous Rand studies can be used to project the effects of TOD rates on business and residential class load curves. Projection methods for business customers are based

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[1] In a few instances offpeak waivers in demand (kw) charges have existed for several decades, but systematic variation in energy (kwh) and/or demand (kw) charges by time of day did not begin until recently in the United States. See Joskow (1979) for a survey of those developments. Several European countries have applied time-of-day rates to business and residential customers for several decades. See, among others, the studies in Nelson (1964) and Mitchell, Manning, and Acton (1978).

on results described in Park and Acton (1983). These methods are described, evaluated, and applied to potential TOD customers in Maryland in Sec. II below. The projection method for residential customers is based on Rand's residential electricity rate study and a survey of existing TOD and non-TOD empirical studies. Projections for residential customers are described in Sec. III. Our major results may be briefly summarized as follows.

PROJECTIONS FOR BUSINESS CUSTOMERS

We describe two methods for projecting overall change in business customer load patterns; the two methods differ in their detail and the ease with which they can be applied. The first takes account of differences in customer mix. Some industrial classifications respond more than others; a utility with a high concentration of customers in responsive industries can expect a larger overall response to TOD rates than can another utility that serves mostly unresponsive industries. The second method also takes account of customer mix, and in addition accounts for differences in electricity prices and other factors.

We compare the two methods by making in-sample projections for the ten utilities that we used to estimate the model. The first method explains about 80 percent of the utility-to-utility variance in response, and the second method explains about 40 percent. These high R-squared values for projecting average response by utility contrast markedly with the low R-squared values for projecting individual customer response as reported in Park and Acton (1983); the law of large numbers makes projecting for groups of customers much more precise than projecting for individuals.

We also compare the two methods by projecting out-of-sample for the Potomac Electric Power Company's TOD customers in Washington, D.C. PEPCO's customers are largely government office buildings classified as "commercial" for these projections. Response to TOD rates by the commercial firms in our sample has been insignificantly different from zero to date, and so the model projects a near-zero response for PEPCO's D.C. customers. The observed response for these customers was a 1 percentage point reduction in relative peak load. Random variation in relative peak load from one year to the next is sufficiently great that

it could easily account for the observed change, even if the systematic response to TOD rates were in fact zero.

We also apply both methods to project changes in load for PEPCO's and Baltimore Gas and Electric's new TOD rates in Maryland. For PEPCO's largely commercial customers, both methods project a near-zero response. BGE's TOD customers include more industrial firms, and consequently we project a larger response for them--up to a 1.7 percentage point decrease in relative peak load for the largest customer class.

We recommend using both methods to make projections of business customer response to TOD rates in other areas. Although the first method performs substantially better than the second for in-sample projection, we expect that the second method will tend to perform better in cases where spreads between peak and offpeak prices differ substantially from those in our sample.

PROJECTIONS FOR RESIDENTIAL CUSTOMERS

The residential projections are based on non-TOD and TOD models selected from a review of published studies: Acton, Mitchell, and Sohlberg (1980); Manning and Acton (1980). We used these models to project the effects of introducing flat rates (a constant price per kwh, as opposed to declining block rates) or TOD rates for residential customers.

The review of studies analyzing electricity demand under non-TOD rates indicates price elasticities ranging from -0.12 to -0.35 in the short run and -0.60 to -1.20 in the long run (this is a judgmental 80 percent confidence band). There is virtually no chance that price leaves consumption unaffected. Higher levels of use, greater holdings of appliances, and hotter weather all increase levels of use and price elasticities.

We reviewed several studies of residential electricity demand under TOD rates, concentrating on the studies based on the Los Angeles, Wisconsin, and North Carolina rate experiments. When comparable analytic techniques are used, highly consistent findings emerge across the studies. Own-price elasticities within a period of the day--that is, the effect of a change in TOD price during a few hours on electricity consumption during those hours--are statistically

significant in the Los Angeles and Wisconsin experiments. Over all customers, they average around -0.10 during morning and early afternoon and fall somewhat in the late afternoon, evening, and overnight periods. Households at higher levels of use show greater price elasticities, primarily because of their larger stocks of appliances. Air conditioning, electric space heating, water heating, clothes dryers, stoves, and swimming pools all increase the price elasticities notably. The findings of these TOD studies appear to be transferable across a wide variety of utility settings once allowance is made for local factors such as customer mix, appliance holdings, and weather.

The non-TOD models are used to project likely effects of rate flattening in Maryland by using the terms of PEPCO's Maryland rate. In the winter, this rate has a declining block feature. If it is replaced by a uniform price per kwh that, ex ante, raises the same revenue, then consumption is projected to rise by 2 kwh per month for customers averaging 130 kwh/mo and it is expected to fall by 299 kwh per month for customers averaging 3000 kwh/mo. Economic welfare increases between 1/2 cent and $1.55 per month per customer for these consumption levels, assuming that the flat rate reflects the marginal costs of supply.

We use the results of a Rand study to project the effects of new TOD rates for PEPCO and BGE. Although the rates apply only to the very largest residential customers, we calculate effects on consumption, bills, and economic welfare at each of 16 different consumption ranges. Compared with the present rate structures, these TOD rates reduce peak period consumption and increase offpeak consumption in both summer and winter. Changes in economic welfare are quite modest for the proposed rates for most customers. In PEPCO's rate, average monthly welfare gains exceed $1 only for consumption above 2500 kwh per month in the summer and do not exceed $1 on average in winter. In BGE's rate, summer welfare gains exceed $1 on average above 800 kwh per month, because of the greater differences between peak and offpeak charges.

II. EVALUATION AND DEMONSTRATION OF ALTERNATIVE METHODS FOR PROJECTING BUSINESS CUSTOMER RESPONSE TO TOD RATES

In this section, we describe two methods for projecting business response to TOD rates. Both methods are based on models estimated in Park and Acton (1983); they differ in the level of detail of the information that goes into the projections. We compare the two projection methods against observed response in two settings: (1) in-sample projection (that is, projecting for the utility/customer categories that were used to estimate the model), and (2) out-of-sample projection (using data on PEPCO's TOD customers in Washington, D.C.). Finally, we illustrate the application of the methods to two groups of business customers that have only recently come under TOD rates: PEPCO's and BGE's TOD customers in Maryland. Consumption data under TOD rates were not yet available for these outcomes when this Note was written.

A MODEL OF BUSINESS CUSTOMER RESPONSE TO TOD RATES[1]

The Data

The ten utilities listed in Table 1 supplied us with load data for their large customers currently on mandatory time-of-day rates. The original data are very detailed; at a minimum, they include hour-by-hour energy (kwh) consumption for each customer, and most of the utilities supplied half-hourly or 15-minute data. Thus we have up to 4 x 24 x 365 = 35,040 consumption figures per customer per year in the raw data files.

Table 1 shows for each utility the approximate number of customers in the raw files and the dates the data cover. The number of customers is much higher for some of the utilities than it is for others. The data span periods ranging from the two years to over five years, depending on the utility. Data for eight of the ten utilities include, for some or all of their customers, loads both before and after TOD rates were introduced.

[1] This subsection is based on Park and Acton (1983, Secs. II and III).

Table 1

UTILITIES SUPPLYING RAW DATA

Utility	Customers	Years
California		
Southern California Edison (SCE)	575	5
Los Angeles Department of Water and Power (DWP)	262	5
Pacific Gas and Electric (PGE)	1382	6
Midwest		
Wisconsin Electric Power Company (WEP)	588	4
Madison Gas and Electric (MGE)	32	4
Wisconsin Power and Light (WPL)	407	4-1/2
Commonwealth Edison (CMN)	540	2
Consumers Power Company (COP)	2065	4
New York		
Long Island Lighting Company (LIL)	429	5
Consolidated Edison (CON)	65	2-1/2
Total	6345	

NOTE: Customer counts exclude accounts with no standard industrial classification (SIC) code information. All data extend through 1980. There are no data on loads before TOD rates were introduced for CMN and COP.

We selected observations for one summer month (June) and one winter month (November) each year. These months were chosen to avoid, to the extent possible, times when prices were changing for a lot of customers--for example, months during which rates were changing from summer to winter schedules, or months during which time-of-day tariffs were introduced for the first time. A priori, these may not seem to be typical summer and winter months. However, initial analysis of two alternative months--February and August--suggests that June and November are not atypical.

We analyze *changes* in relative peak load, calculated by taking differences separately for summer and winter months. For example, the summer 1977 change in relative peak load is June 1977 relative peak load minus June 1976 relative peak load. Thus the "change" file that we analyze includes each year observations only for customers observed both

that year and the year before. After the data were processed into working files for analysis, there were 19,535 total observations on year-to-year changes in relative peak load, including 3296 for changes when TOD rates were introduced.

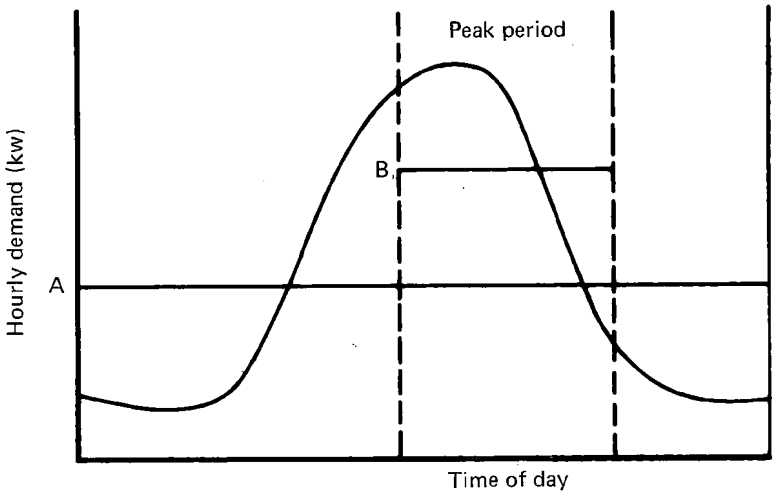
The consumption data were supplemented by information on prices, weather, and industrial classification. We calculated prices for each customer each month using the utilities' rate sheets. We took into account applicable fuel cost adjustments and any discounts (such as high-voltage discounts) that applied to each customer. Weather variables are heating and cooling degree-days reported at the major weather station located nearest each customer. Industrial classification is each customer's primary two-digit SIC code from utility records.

Definition of Response: Change in Relative Peak Load

We shall measure customers' response to TOD rates by changes in their relative peak loads--the ratio of their average energy consumption during peak hours to their average weekday consumption around the clock. We expect that TOD rates tend to flatten load curves and hence to reduce relative peak load. However, many factors other than TOD rates affect load shapes. Relative peak load will *increase* for some customers when TOD rates are introduced, because the effect of the other factors outweigh the effect of the TOD rates.

The concept of relative peak load is illustrated in Fig. 1, which shows the average weekday load curve for a particular hypothetical customer during a particular month. The horizontal line A shows this customer's average load over the full 24-hour period; the horizontal line B is his average load during just the peak period. Relative peak load for this customer is the ratio of the height of B to the height of A. Relative peak load can be expressed either as a decimal fraction or as a percentage. In Fig. 1, average load during peak hours is about 60 percent higher than 24-hour average consumption. Thus, relative peak load is equal to 1.6, or 160 percent.

Change in relative peak load is simply the difference between relative peak load during a particular month this year and relative peak load during the same month last year. If Fig. 1 represents this year, and the same customer last year had a relative peak load of 170 percent,



$$\text{Relative peak consumption} = \frac{\text{Peak kwh/peak hours}}{\text{Total kwh/total hours}} = \frac{B}{A}$$

Fig. 1 -- Relative Peak Hourly Consumption

then the change in relative peak load is 160 - 170 = -10 percentage points. Note that by this definition, both increases and decreases in relative peak load of more than 100 percentage points are possible.

A complete characterization of response would involve several other measures in addition to change in relative peak load. These additional measures include (1) change in total energy consumption; (2) change in relative load during shoulder periods, or even better, change in relative load hour by hour throughout the day; (3) change in weekend loads; (4) change in maximum demand or load factor; and (5) change in

load at the time of the system peak. Our future work may analyze one or more of these additional measures.

The Estimated Model

Consider a specific industrial firm. In general, that firm's relative peak load will be a function of many factors including the industrial processes it uses, the electricity prices it faces, peak period definitions, detailed characteristics of the firm, weather conditions, demands for its products, prices of nonelectricity inputs, and a host of unquantifiable factors whose effects can be summarized by a random error term. This relationship can be expressed as an equation setting relative peak load equal to a possibly nonlinear function of the above variables. By subtracting last year's equation from this year's equation, we can in principle derive an equation that focuses directly on year-to-year *changes* in peak load. If the original equations are linear, then all of the right-hand-side variables enter the new equation as year-to-year changes as well. Thus, any variables that do not change, such as certain characteristics of the firm, and the intercept term, drop out of the difference equation. This has the important advantage that persistent, but unmeasurable, individual firm effects no longer complicate the estimation.

If the original functions are nonlinear, however, things can get very complicated. Then the right-hand side of the difference equation is the difference of two nonlinear functions. This has two implications. First, unchanging variables do not necessarily drop out of the difference equation. Second, the equation may be very complex and difficult to estimate.

We elect to cut through these complexities by specifying directly an equation to explain *changes* in relative peak load. Our specification should be thought of as a simple approximation to the more complex equation that would result from the derivation sketched above.

We specify a model of the form

$$\text{change in relative peak load} = (aS)(bX) + u \qquad (1)$$

where

S is a vector of SIC code designations;
a is a vector of SIC response coefficients to be estimated;
X is a vector of explanatory variables including prices and other variables to be described below;
b is a vector of coefficents for X to be estimated;
u is a random error term.

Written out in full, the expression on the right hand side of the equation is

$$(a_1S_1 + \ldots + a_{16}S_{16})(b_0 + b_1X_1 + \ldots + b_7X_7) + u \ .$$

The explanatory variables that enter the vector X are:[2]

PK	The change in peak period energy price differential from one year to the next.
PD	The change in peak period demand price.
PN	The change in noncoincident demand price.
PKHRS	The number of hours per weekday in the peak period.
SHORT	A dummy variable equal to one for utilities with short peak periods (eight hours or less), and equal to zero for utilities with longer peak periods.
SIZE	A measure of customer size.
SIZE_SQ	The square of SIZE.

Our nonlinear least squares estimates of equation (1) are shown in Table 2.[3] The estimated response coefficients in vector a are negative and significant at the 0.05 level for six of the industrial classifications. They are positive but insignificant for four classifications, including commerical firms. But in all cases, the

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[2] For more details about the definitions of the variables, see Park and Acton (1983, Sec. IV).

[3] In estimating Eq. (1), we impose one linear constraint on the elements of a. For a discussion of this and other features of the estimation procedure, see Park and Acton (1983, pp. 33-34).

Table 2

NONLINEAR ESTIMATES OF EQUATION (1)

Industrial Classification	Vector a Coefficient	Standard Error
00 Industrial nec	-0.472	0.293
20 Food products	-1.198	0.457
24 Wood products	-14.502	2.105
26 Pulp and paper	-0.524	0.861
28 Chemicals	-0.098	0.405
29 Petroleum	0.088	0.334
30 Rubber and plastics	-2.677	0.722
32 Stone, clay, glass	-0.835	0.668
33 Primary metals	-6.207	0.710
34 Fabricated metals	-0.823	0.575
35 Machinery	-3.448	0.622
36 Electrical machinery	-1.007	0.567
37 Transportation equipment	-0.887	0.270
48 Communications	0.125	0.383
49 Utilities	0.823	0.899
50 Commercial	0.063	0.192
Variable	**Vector b Coefficient**	**Standard Error**
Intercept	2.159	0.337
PK	0.663	0.097
PD	0.307	0.043
PN	0.184	0.049
PKHRS	-0.160	0.026
SHORT	-1.482	0.216
SIZE	0.0189	0.0030
SIZE-SQ	-0.000112	0.000019

NOTE: Dependent variable is change in relative peak load (percentage points).

response is quite precisely estimated, with standard errors less than 1 percentage point in all except one industrial classification. With 95 percent confidence, we can say that response by the commercial firms in our sample has so far been de minimus: no more than a 0.3 percentage point reduction in relative peak load.

The estimated coefficients of the price variables are statistically significant and have the correct (positive) sign: A higher price results in a larger value for the multiplier bX and hence a larger estimated reduction in relative peak load when it is multiplied by the (negative) industry factor aS. The length of the peak period and the size of the firm also significantly affect response.

Two possible problems with the specification of Eq. (1) are worth mentioning. First, the equation omits any measure of economic activity. Since changes in economic activity can lead to changes in relative peak load and may be correlated with other variables in the model, the estimates in Table 2 may be biased by the omission. Fully satisfactory measures of economic activity (disaggregated by region, month, and industry) are not available. In Park and Acton (1983, Eq. (5-7)), we used geographic and temporal dummy variables in an attempt to control for (unmeasured) differences in economic activity. We found that the estimated coefficients of some of the other variables were substantially affected, suggesting that the estimates in Table 2 are indeed biased. However, when we used the equation with the dummy variables for projection, we found that it did not perform as well as the simpler equation (1).[4]

Second, the additive specification of the multiplier bX implies that relative peak load changes systematically even during years when prices do not change. This should not be a serious problem when the equation is used to project changes in relative peak load during years when TOD prices are introduced, which is the way we use it here. However, the implication could be avoided with a more complicated nonlinear specification such as:

$$\text{change in relative peak load} = (aS)(bX)(cP) \qquad (2)$$

where

S and a are as in Eq. (1);

X and b are vectors of nonprice variables and

[4]See footnote 8 below.

coefficients, including a constant term;
P and c are vectors of prices and coefficients,
with no constant term.

We may attempt to deal with these possible problems in future work. Here, we make use of the Table 2 estimates of Eq. (1) and find that they seem to perform satisfactorily.

TWO PROJECTION METHODS

Method 1: Average Response by Industry

Projected Response. As shown in Table 2, some industrial classifications tend to respond more to TOD rates than do others. Our first projection method uses only average response by industry, together with the industrial mix for a particular utility, to project response. The calculations for this method are illustrated in Table 3 using Southern California Edison's medium-sized industrial customers (the so-called T73 customers) as an example.

As input, this method uses the proportion of class load accounted for by each of the two-digit SIC codes listed. In our notation, SIC code 00 includes all customers with (industrial) SIC codes that are not included in the other two-digit codes that are explicitly set out in the table, and SIC code 50 includes all (commercial) customers with two-digit codes of 50 or greater. The proportions for the SCE/T73 customers are shown in column (2) of the table.

Method 1 projects response for a given utility as a weighted average of industry-by-industry response, using the utility's industry mix as weights. In the table, we multiply the average response in column (1) times the proportions in column (2) and sum the results in column (3) to project average response for the SCE/T73 customer class: a 1.5 percentage point reduction in relative peak load.

The response used in these calculations is the estimate of the industry effects shown in Table 2. We have reset insignificant positive response to zero for four SIC codes, since TOD rates should not cause increases in relative peak loads.

Table 3

ILLUSTRATION OF PROJECTION METHOD 1:
AVERAGE RESPONSE BY INDUSTRY

Industry	Average Response (1)	SCE/T73 Proportion (2)	Projection (3)
00	-0.47	0.213	-0.100
20	-1.20	0.060	-0.072
24	-14.50	0.003	-0.044
26	-0.52	0.046	-0.024
28	-0.10	0.069	-0.007
29	0.00	0.034	0.000
30	-2.68	0.078	-0.209
32	-0.84	0.066	-0.055
33	-6.21	0.085	-0.528
34	-0.82	0.075	-0.062
35	-3.45	0.059	-0.204
36	-1.01	0.090	-0.091
37	-0.89	0.073	-0.065
48	0.00	0.010	0.000
49	0.00	0.038	0.000
50	0.00	0.000	0.000
Projected response			-1.466
Standard error for response			(0.085)
Standard error for change			(0.510)

NOTE: "Response" is percentage points change in relative peak load.

Estimated Standard Errors. Our projection is both an estimate of the average short-run response of a particular group of firms to TOD rates and an estimate of the year-to-year change in relative peak load by those firms when TOD rates are introduced. Although these two things are numerically equal, they are conceptually distinct. "Response" is a partial concept; it represents only the effect of TOD rates. "Change" comes about for many other reasons in addition to the introduction of TOD rates. Thus change is more variable than response, and we must calculate two standard errors for the projection: the standard error for reponse and the standard error for change.

The standard error for response measures the statistical precision of our estimate of the short-run effect of TOD rates. Equivalently, it measures the precision with which the height of the regression surface in Table 2 is estimated. Response to TOD rates is quite precisely estimated; a 95 percent confidence band is -1.466 ± 1.96 x 0.085, or a reduction in relative peak load of between 1.3 and 1.6 percentage points.

The standard error for year-to-year change is larger than the standard error for response, because relative peak load is affected by many factors in addition to TOD rates. These other factors, which are treated as random in our model, cause changes in relative peak load by individual firms, or by finite groups of firms, to lie above or below the regression plane. Change is less precisely estimated than is response; a 95 percent confidence band is -1.466 ± 1.96 x 0.510, or a reduction in relative peak load of between 0.5 and 2.5 percentage points.[5]

Method 2: Adjusting for Prices and Other Factors

Table 2 shows that price plays a significant role in determining response to TOD rates. Higher peak period energy price differentials and higher peak demand prices are both associated with larger responses in our regression estimates. The length of the peak period and customer size also play a role in determining response. This suggests that we might be able to improve on the Method 1 projections, which are based solely on differences in industry mix, by also taking into account prices and other factors.

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[5]Technically, the standard error for response is calculated as sqrt(w' COV w), where w is the vector of industry proportions (column (2) in Table 3) and COV is the estimated variance-covariance matrix for the industry response coefficients a in Eq. (1). The standard error for change is calculated as sqrt(s**2/N + w' COV w), where s is the standard error of estimate for the equation and N is the number of firms in the group for which the projection is being made. Both are calculated using software coded for the SAS procedure MATRIX (SAS Institute Inc., 1982). A listing of the program, which calculates both projected response and estimated standard errors for all ten in-sample utility/customer categories, is in Appendix A.

Table 4

ILLUSTRATION OF CALCULATION OF ADJUSTMENT FACTOR
FOR USE IN PROJECTION METHOD 2:
ADJUSTMENT FOR PRICES AND OTHER FACTORS

Variable	Estimated Coefficients (1)	SCE/T73 Values (2)	Adjustment Factor (3)
Intercept	2.1586	1.000	2.159
PK	0.6634	0.250	0.166
PD	0.3069	3.789	1.163
PN	0.1837	-2.194	-0.403
PKHRS	-0.1601	5.540	-0.887
SHORT	-1.4821	1.000	-1.482
SIZE	0.0189	1.671	0.032
SIZE_SQ	-0.0001	3.643	-0.000
Adjustment factor (multipliers)			0.730

Adjustment Factor. The estimated model treats response as the product of two factors: the response based on industry mix calculated above, times an adjustment for prices, length of peak period, and firm size. Table 4 illustrates the calculation of the adjustment factor using values for SCE/T73 customers.

Column (1) shows the estimated coefficients from Table 4. Column (2) shows the values of the variables that we use in calculating the factors for SCE/T73 customers. The values are weighted averages of these variables for SCE/T73 customers.[6] The coefficients in column (1) are multiplied by the values in column (2) to get column (3), then added up to give the adjustment factor 0.730.

Projected Response. The adjustment factor times the Model 1 projection (1.466 percentage points reduction in relative peak load) yields a price-adjusted projection of 1.069 percentage points reduction in relative peak load.

[6] The mean of SIZE_SQ is not generally equal to the square of the mean of SIZE. The mean of SIZE_SQ should either be calculated separately using individual customer data, as here, or alternatively, calculated as some factor K times the square of the mean of SIZE. In our data, K is roughly equal to 1.8.

Estimated Standard Errors. The standard errors for response and for change are calculated in the SAS program in Appendix A.

Comparison of Projected and Observed Response

The projections are compared to the actual change for SCE/T73 customers in Table 5. In this illustrative calculation, both Method 1 and Method 2 come reasonably close to the observed response. Neither projection is significantly different than the actual observed response. (The appropriate standard errors to use in making this comparison are the standard errors for change.) In the following subsection we shall make projections for the other nine utility/customer categories in our sample. We shall find that Method 1 continues to perform well, while Method 2, on the other hand, is generally farther from the mark.

COMPARISON OF IN-SAMPLE PROJECTIONS

We can compare the two methods for in-sample projection by repeating the calculations described above for the other sample utilities. We used both projection methods to project response for each of the ten utility/customer classifications that we observed both before and after the introduction of TOD rates. The results are in Table 6.

Table 5

SUMMARY OF ILLUSTRATIVE PROJECTIONS FOR SCE/T73 CUSTOMERS (N=438)
(Percentage points of change in relative peak load)

Projection Method	Projection	Standard Error for Response	Standard Error for Change
Method 1: Based on industry mix	-1.47	(0.09)	(0.51)
Method 2: Industry mix plus adjustment for prices	-1.07	(0.16)	(0.53)
Actual	-1.32	--	(0.39)

The actual changes in relative peak load upon introduction of TOD rates are listed in column (1) of the table, and their standard errors in column (2). Columns (3) through (8) show the results of the two projection methods. Projection Method 1, based on industry mix only, does a very good job of reproducing the observed pattern of average response in these ten utility/customer categories. R-squared (weighted to account for the different total size of the ten customer groups, as measured by their initial-year electricity consumption) is a very respectable 0.82.[7] This contrasts with an R-squared of at most 0.056 for explaining variance in *individual customer* response with the equations estimated in Park and Acton (1983). The law of large numbers makes it much easier to explain utility/customer category average response than to explain individual customer response.

Contrary to our expectations, Method 2, using information on prices, length of peak period, and average customer size does not help the projections; in fact, it degrades them substantially. Use of the multiplicative adjustment factor reduces weighted R-squared to 0.38.[8]

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[7] R-squared is the weighted fraction of variance in response listed in column (1) explained by "projections" in columns (1), (3), and (6), respectively. Calculated as

$$1 - \Sigma\, w(i)\, (r(i,j) - r(i,1))^2 / \Sigma\, w(i)\, (r(i,1) - m)^2$$

where

w(i) is the initial year kwh consumption weights for customer class i = 1, ..., 10;
r(i,j) is the projected response for customer class i in column j = 1, 3, 6;
m is the weighted mean change in relative peak load
$= \Sigma\, w(i) r(i,1) / \Sigma\, w(i)$;
and all summations are over i = 1, ..., 10 customer classes.

[8] We also tried a third projection method that started with the Method 1 projections based on industry mix, then applied a multiplicative adjustment factor based on Park and Acton (1983, Specification (7), Table 4.1). We used weighted sample mean values for the regional and temporal dummy variables and the weather variables, and utility-specific means for the price and other variables. This third method produced in-sample projections with a negative R-squared value; that is, it projected less well than we could do by assuming that all utility/customer categories exhibit the overall mean response.

Table 6

COMPARISON OF IN-SAMPLE PROJECTIONS
(Percentage points of change in relative peak load)

Utility	No. of firms	Actual		Method 1: Industry Mix			Method 2: Industry Mix + Prices, etc.		
		Change (1)	Std Err (2)	Proj (3)	Std Err for Response (4)	Std Err for Change (5)	Proj (6)	Std Err for Response (7)	Std Err for Change (8)
SCE/A81	88	-1.43	(0.40)	-0.83	(0.11)	(1.13)	-0.45	(0.09)	(1.12)
SCE/T73	438	-1.32	(0.39)	-1.47	(0.09)	(0.51)	-1.07	(0.16)	(0.53)
DWP	159	-0.17	(0.44)	-0.47	(0.08)	(0.84)	-0.61	(0.16)	(0.85)
PGE/A23	65	-1.89	(0.52)	-2.01	(0.19)	(1.32)	-1.20	(0.15)	(1.31)
PGE/A22	395	-0.96	(0.41)	-1.10	(0.07)	(0.53)	-0.30	(0.08)	(0.53)
WEP	335	-2.40	(0.51)	-2.07	(0.18)	(0.60)	-1.92	(0.18)	(0.60)
MGE	16	-1.70	(4.47)	-2.11	(0.20)	(2.64)	-4.23	(0.43)	(2.66)
WPL/C84	89	-0.22	(2.70)	-1.17	(0.09)	(1.12)	-0.66	(0.12)	(1.12)
LIL	175	0.13	(0.74)	-0.42	(0.06)	(0.80)	-0.52	(0.10)	(0.80)
CON	51	0.01	(0.36)	-0.24	(0.05)	(1.47)	-0.54	(0.13)	(1.48)
R-squared(a)		1.00		0.82			0.38		

(a) See footnote 7 for a description of the R-squared calculations.

Why does the use of additional information degrade the projections? After all, the coefficients of price and the other variables are generally highly significant in the estimated equations. The answer lies in the fact that the estimates are based on over 19,000 observations, most of them for changes in relative peak load under continuing standard rates or continuing TOD rates, whereas the projections are only made for the 3296 observations when TOD rates were first introduced. Thus the estimates are based in large part on the contrast between (1) unchanging rates, with little corresponding change in relative peak load on average, and (2) increasing peak price differentials, with a corresponding modest reduction in relative peak load on average. Although price is an important variable in explaining this contrast, it appears that it is not helpful in explaining differences in response within the subsample of observations for introduction of TOD rates.[9]

COMPARISON OF OUT-OF-SAMPLE PROJECTIONS

In the previous subsections we described two methods for projecting response to TOD rates based on regression results reported in Park and Acton (1983), then compared the two methods in projecting average response for ten utility/customer categories in our sample. We can also compare their performance in projecting response for one utility not included in our sample. PEPCO introduced TOD rates for 258 of its large commercial and industrial customers in the District of Columbia in June 1980.

PEPCO supplied us with data on hour-by-hour electricity consumption by its TOD customers for the period starting one year before and ending one year after introduction of TOD rates. We processed the data to obtain results that are comparable to those for our previous analysis of data from ten other utilities. That is, we calculated weekday average hourly kwh consumption during peak, shoulder, and offpeak periods for each customer each month. We then calculated relative peak load for

[9] This observation is confirmed by regressions that estimate the various Park and Acton models using only the 3296 observations. The results are generally either insignificant or contrary to prior expectations.

each customer as the ratio of peak kwh to overall average kwh. Then we calculated change in relative peak load as the difference between a month under TOD rates and the same month a year earlier. Finally we calculated a weighted average of the individual customers' changes in relative peak load each month. The results are shown in Table 7.

The PEPCO experience is broadly consistent with that of the other ten utilities: On average, PEPCO experienced a 1.01 percentage point reduction in relative peak load when they introduced TOD rates.

In Table 8, we use projection Method 1 to project change in relative peak load for PEPCO. PEPCO's D.C. customers are largely government office buildings and most have commercial SIC codes. The industry mix changes very little from month to month; we use the proportions averaged over all 13 months in column (1) of Table 8. Projected response is -0.032 percentage points using the average industry responses in column (1).

Table 7

CHANGE IN RELATIVE PEAK LOAD FOR PEPCO D.C. TOD CUSTOMERS

Change From	To	Percentage Points	Standard Error
Jun 1979	Jun 1980	-0.05	(0.33)
Jul 1979	Jul 1980	-1.47	(0.48)
Aug 1979	Aug 1980	-2.17	(0.36)
Sep 1979	Sep 1980	-2.14	(0.38)
Oct 1979	Oct 1980	-0.42	(0.33)
Nov 1979	Nov 1980	-1.74	(0.27)
Dec 1979	Dec 1980	-0.99	(0.27)
Jan 1980	Jan 1981	-2.95	(0.27)
Feb 1980	Feb 1981	-0.10	(0.29)
Mar 1980	Mar 1981	0.97	(0.42)
Apr 1980	Apr 1981	1.64	(0.47)
May 1980	May 1981	-0.89	(0.30)
Jun 1980	Jun 1981	-2.30	(0.29)
Average		-1.01	(0.10)

Table 8

APPLICATION OF PROJECTION METHOD 1
TO PEPCO'S D.C. CUSTOMERS

Industry	Average Response (1)[a]	PEPCO/D.C. Proportions (2)	Projection (3)
00	-0.47	0.066	-0.031
20	-1.20	0.001	-0.001
48	0.00	0.017	0.000
49	0.00	0.064	0.000
50	0.00	0.852	0.000
Total			-0.032
Standard error for response			(0.061)
Standard error for change			(0.657)

[a] Percentage points of change in relative peak load.

Table 9 shows the calculation of the adjustment factors for use in Method 2 projections. The prices are from PEPCO's rate sheets for "Time Metered General Service, Schedule GT," effective May 31, 1980. They have been deflated to 1976 first quarter dollars to be consistent with the values used in estimating the equation in Park and Acton (1983). The deflator is the implicit GNP price deflator, which had a value of 185.16 in the fourth quarter of 1980 and 131.29 in the first quarter of 1976.[10] Thus, the published prices are multiplied by 131.29/185.16 = 0.709 to convert them to 1976 dollars. The multiplicative factor is calculated in column (3) to be 1.324. Applied to the Method 1 projection, that yields a Method 2 projection of 1.324 x (-0.032) = -0.042 percentage points.

Table 10 summarizes the projections for PEPCO's D.C. TOD customers. Although the projected response is smaller than the observed response, the standard error for change is such that the observed response falls well within a 95 percent confidence band around the projection. PEPCO's DC customers may have responded more to TOD rates than did the average commercial customer in our ten utility sample, but the data do not

[10] Economic Report of the President, January 1983.

Table 9

CALCULATION OF ADJUSTMENT FACTOR FOR PEPCO D.C. TOD CUSTOMERS FOR USE IN PROJECTION METHOD 2

Variable	Estimated Coefficients (1)	PEPCO D.C. Values (2)	Adjustment Factor (3)
Constant	2.1586	1.000	2.159
PK	0.6634	0.708	0.470
PD	0.3069	5.039	1.546
PN	0.1837	-0.612	-0.112
PKHRS	-0.1601	8.000	-1.281
SHORT	-1.4821	1.000	-1.482
SIZE	0.0189	1.329	0.025
SIZE_SQ	-0.0001	3.177	-0.000
Adjustment factor (multiplier)			1.324

require us to accept that conclusion. The year-to-year random variation in relative peak loads for individual firms is sufficiently great that the observed 1 percentage point decrease by this group of 258 firms could easily have resulted from chance, even if their true response were zero. Thus we conclude that the model performs reasonably satisfactorily in this out-of-sample test.

Table 10

SUMMARY OF PROJECTIONS FOR PEPCO D.C. TOD CUSTOMERS (N=258)
(Percentage points of change in relative peak load)

Projection Method	Response	Standard Error for Response	Standard Error for Change
Method 1:			
Based on industry mix	-0.03	(0.06)	(0.66)
Method 2:			
Adjustment for prices	-0.04	(0.08)	(0.66)
Actual	-1.01	--	(0.10)

APPLICATION TO MARYLAND

In this subsection we make projections for three groups of commercial and industrial customers that have recently gone on TOD rates in Maryland. These are PEPCO's business customers with maximum kw demand in excess of 1000, BGE's primary voltage customers (Tariff Schedule P; monthly demand in excess of 1500 kw plus grandfathered smaller customers), and BGE's general service customers (Tariff Schedule GL; monthly demand in excess of 200 kw).

PEPCO's Maryland TOD Customers

We used data supplied by PEPCO on 116 TOD customers in Maryland to calculate the industry mix shown in column (1) of Table 11. PEPCO's Maryland customers, like their D.C. customers, are largely commercial. Consequently, the response projected using Method 1 is quite small. The estimated standard error for change is larger than for PEPCO's D.C. customers in large part because the number of customers in the Maryland group is smaller.

Table 11

APPLICATION OF PROJECTION METHOD 1
TO PEPCO'S MARYLAND CUSTOMERS

Industry	Average Response (1)[a]	PEPCO/MD Proportions (2)	Projection (3)[a]
00	-0.47	0.045	-0.021
20	-1.20	0.003	-0.003
32	-0.84	0.038	-0.032
36	-1.01	0.008	-0.008
48	0.00	0.019	0.000
49	0.00	0.056	0.000
50	0.00	0.865	0.000
Total			-0.037
Standard error for response			(0.052)
Standard error for change			(0.977)

[a] Percentage points of change in relative peak load.

For Method 2 projections, we use rates from PEPCO's MD-GT tariff sheet dated February 24, 1983. The terms of PEPCO's MD-GT tariff are given in Table 12. For use in calculating the adjustment factor, we deflated the summer prices to first quarter 1976 values using 215 as an approximate current value of the GNP deflator.[11] The TOD differentials are substantial and result in a large multiplicative adjustment factor as calculated in Table 13. Applying the adjustment to the Method 1 projections results in the projections summarized in Table 14.

BGE's TOD Customers

BGE supplied data on electricity consumption by SIC code for 488 primary voltage customers with monthly demand in excess of 1500 kw plus grandfathered smaller customers (Schedule P), and an additional 1360 general service customers with monthly demand in excess of 200 kw (Schedule GL). BGE's customers include a higher fraction of industrial firms than do PEPCO's, as shown in column (2) of Table 15. This results in higher Method 1 projections for BGE--almost a full percentage point reduction in relative peak load for Schedule P customers and a quarter of a percentage point for Schedule GL.

For Method 2 projections, we use rates from BGE's TOD tariff sheets (P and GL) effective June 1984. The terms of BGE's TOD tariffs are given in Table 16. For use in calculating the adjustment factor, we deflated the summer prices to first quarter 1976 values in the same way as we did for PEPCO.[12] Large TOD differentials result in even larger multiplicative adjustment factors (Table 17) than for PEPCO. Applying these factors to the Method 1 projections, we calculate the projections shown in Table 18.

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[11] Thus, the deflator factor is 131.29/215 = 0.611, and PK = 0.611 x (4.410 - 2.546) = 1.138; PD = 0.611 x 6.60 = 4.030; and PN = 0.611 x (7.65 - 4.65) = 1.833.

[12] Thus, PK = 0.611 x (3.373 - 1.534) = 1.124; PD = 0.611 x 9.81 = 5.994; and PN = 0.611 x (-9.24) = -5.646 for Schedule P, and PK = 0.611 x (4.644 - 2.319) = 1.421, PD = 0.611 x 11.61 = 7.094, and PN = 0.611 x (-9.04) = -5.523 for Schedule GL.

Table 12

TERMS OF PEPCO'S TOD RATE
AND ITS STANDARD RATE FOR LARGE CUSTOMERS

Rate	Summer (Jun-Oct)	Winter (Nov-May)
TOD Rate: MD-GT		
Customer charge ($/mo)	225	225
Energy charge[a] (cents/kwh)		
Peak (noon-8pm, M-F)	4.410	3.948
Intermediate (8am-noon + 8pm-midnight, M-F)	3.533	3.704
Offpeak (midnight-8am, M-F + weekends and holidays)	2.546	2.546
Demand charge ($/kw/mo)		
Peak period	6.60	0
Non-coincident	7.65	7.65
Standard Rate: MD-GS		
Customer charge ($/mo)	0.0	0.0
Energy charge[b] (cents/kwh)		
First 6000 kwh	6.226	5.137
Next 200 hours use of billing demand but not more than 200,000 kwh	3.830	3.199
Additional kwh	2.808	2.175
Demand charge ($/kw/mo)		
First 25 kw	0.0	0.0
Next 75 kw	5.75	4.65
Excess over 100 kw	4.65	3.55

[a]Plus fuel adjustment all kwh (equals about .1 cent/kwh in 1983).

[b]Plus fuel adjustment all kwh (equals about 2.6 cents/kwh in 1983).

Table 13

CALCULATION OF ADJUSTMENT FACTOR FOR PEPCO'S MARYLAND CUSTOMERS FOR USE IN PROJECTION METHOD 2

Variable	Estimated Coefficients (1)	PEPCO/MD Values (2)	Adjustment Factor (3)
Constant	2.1586	1.000	2.159
PK	0.6634	1.138	0.755
PD	0.3069	4.030	1.237
PN	0.1837	1.832	0.337
PKHRS	-0.1601	8.000	-1.281
SHORT	-1.4821	1.000	-1.482
SIZE	0.0189	1.880	0.036
SIZE_SQ	-0.0001	6.360	-0.001
Adjustment factor (multiplier)			1.758

Table 14

SUMMARY OF PROJECTIONS FOR PEPCO'S MARYLAND CUSTOMERS (N=116)
(Percentage points of change in relative peak load)

Projection Method	Response	Standard Error for Response	Standard Error for Change
Method 1:			
Based on industry mix	-0.04	(0.05)	(0.98)
Method 2:			
Adjustment for prices	-0.06	(0.10)	(0.98)

Table 15

APPLICATION OF PROJECTION METHOD 1 TO BGE'S CUSTOMERS

Industry	Average Response[a] (1)	BGE/P Proportions (2)	BGE/P Projection[a] (3)	BGE/GL Proportions (4)	BGE/GL Projection[a] (5)
00	-0.47	0.049	-0.023	0.084	-0.039
20	-1.20	0.031	-0.037	0.041	-0.049
24	-14.50	0.000	-0.000	0.001	-0.015
26	-0.52	0.021	-0.011	0.007	-0.004
28	-0.10	0.078	-0.008	0.014	-0.001
29	0.00	0.013	0.000	0.001	0.000
30	-2.68	0.016	-0.043	0.007	-0.019
32	-0.84	0.027	-0.023	0.004	-0.003
33	-6.21	0.085	-0.528	0.010	-0.062
34	-0.82	0.019	-0.016	0.009	-0.007
35	-3.45	0.032	-0.110	0.009	-0.031
36	-1.01	0.032	-0.032	0.011	-0.011
37	-0.89	0.022	-0.020	0.001	-0.001
48	0.00	0.010	0.000	0.025	0.000
49	0.00	0.006	0.000	0.005	0.000
50	0.00	0.558	0.000	0.769	0.000
Total			-0.853		-0.248
Standard error for response			(0.059)		(0.027)
Standard error for change			(0.479)		(0.286)

[a] Percentage points of change in relative peak load.

Table 16

TERMS OF BGE'S TOD RATES AND
ITS STANDARD RATES FOR LARGE CUSTOMERS

Rate	Summer (Jun-Sep)	Winter (Oct-May)
TOD Rate: P		
Customer charge ($/mo)	425	425
Energy charge[a] (cents/kwh)		
Peak (10am-8pm, M-F)	3.373	1.841
Intermediate (7am-10pm + 8pm-11pm, M-F)	2.453	1.841
Offpeak (11pm-8am, M-F + weekends and holidays)	1.534	1.229
Demand charges ($/kw/mo)		
Peak period	9.81	0.0
Noncoincident	0.0	5.02
Standard Rate: T		
Customer charge ($/mo)	425	425
Energy charge[b] (cents/kwh)		
First 300,000 kwh	2.452	2.243
Next 500 kwh per kw of billing demand	1.752	1.603
Additional kwh	1.338	1.224
Demand charges ($/kw/mo)		
Noncoincident	9.24	4.75
TOD Rate: GL		
Customer charge ($/mo)	130	130
Energy charge[a] (cents/kwh)		
Peak (10am-8pm, M-F)	4.644	2.666
Intermediate (7am-10pm + 8pm-11pm, M-F)	3.482	2.666
Offpeak (11pm-8am, M-F + weekends and holidays)	2.319	1.891
Demand charges ($/kw/mo)		
Peak period	11.61	0.0
Noncoincident	0.0	6.04
Standard Rate: G		
Customer charge ($/mo)	8.50	8.50
Energy charge[b] (cents/kwh)		
First 24,500 kwh	7.635	5.342
Over 24,500 kwh	3.047	3.047
Demand charges ($/kw/mo)		
Over 60 kw	9.04	4.70

[a] Plus fuel adjustment all kwh.
[b] Plus fuel adjustment all kwh .

Table 17

CALCULATION OF ADJUSTMENT FACTORS FOR BGE CUSTOMERS
FOR USE IN PROJECTION METHOD 2

Variable	Estimated Coefficients (1)	TOD Rate: P BGE Values (2)	TOD Rate: P Adjustment Factor (3)	TOD Rate: GL BGE Values (4)	TOD Rate: GL Adjustment Factor (5)
Constant	2.1586	1.000	2.1586	1.000	2.1586
PK	0.6634	1.124	0.7457	1.421	0.9427
PD	0.3069	5.954	1.8396	7.094	2.1771
PN	0.1837	-5.646	-1.0372	-5.523	-1.0146
PKHRS	-0.1601	10.000	-1.6010	10.000	-1.6010
SHORT	-1.4821	0.000	0.0000	0.000	0.0000
SIZE	0.0189	1.209	0.0229	0.188	0.0036
SIZE_SQ	-0.0001	2.629	-0.0003	0.064	-0.0000
Adjustment factor (multiplier)			2.1281		2.6663

DISCUSSION

Based on the in-sample and out-of-sample tests reported above, we conclude that projection Method 1 (based on industry mix) and Method 2 (adjusted for prices and other variables) both perform reasonably well. Doing in-sample projections, Method 1 explains over 80 percent of the weighted variance in utility/customer category average response. Method 2 does not do quite so well, explaining only slightly less than 40 percent of the variance. But for both methods, all ten of the observed utility/customer category responses fall well within the projected 95 percent confidence band.

Table 18

SUMMARY OF PROJECTIONS FOR BGE/P CUSTOMERS (N=488)
AND FOR BGE/GL CUSTOMERS (N=1360)
(Percentage points of change in relative peak load)

Projection Method	Projection	Standard Error for Response	Standard Error for Change
		BGE/P	
Method 1: Based on industry mix	-0.85	(0.06)	(0.48)
Method 2: Industry mix plus adjustment for prices	-1.81	(0.21)	(0.52)
		BGE/GL	
Method 1: Based on industry mix	-0.25	(0.03)	(0.29)
Method 2: Industry mix plus adjustment for prices	-0.66	(0.11)	(0.30)

In making out-of-sample projections for PEPCO's DC customers, both methods project a response to TOD rates of no more than a 0.2 percentage point decrease in relative peak load (a 95 percent confidence bound). This is substantially smaller than the observed decrease in relative peak load of 1.0 percentage points, but this is not a reason to reject our projection. Factors other than the introduction of TOD rates could result in year-to-year changes in relative peak load for this group of customers of between plus and minus 1.3 percentage points (95 percent confidence band). The observed 1 percentage point decrease is comfortably inside the calculated confidence band.

As this is written, there is no way to test the out-of-sample projections for potential TOD customers in Maryland, since consumption data under TOD rates are not yet available. However, the illustrative projections for these customers do seem reasonable. For PEPCO's largely commercial customers, both methods project a response to TOD rates of no more than a quarter of a percentage point decrease in relative load (95 percent confidence bound).

BGE's TOD customers include more industrial firms, and consequently we project a larger response for them. For the largest customers, the Method 1 confidence band for response to TOD rates is about -0.7 to -1.0 percentage points, and Method 2 gives a range of -1.3 to -2.1. For BGE's medium sized customers, the Method 1 confidence band is -0.2 to -0.3 percentage points, and Method 2 yields -0.5 to -0.8.

When the two projection methods differ (as they do for BGE), how should one choose between them? Based on in-sample R-squared, Method 1 wins hands down, but we think it would be a mistake to discard Method 2. The reason is that both economic theory and our empirical estimates say that prices matter; other things being equal, we expect that a tariff with a very high peak price differential will result in a larger response than will one with a small differential. Method 2 allows for the effect of prices; we expect that it will tend to perform better than Method 1 especially in cases where peak price differentials differ substantially from those in our sample.

The best approach may be to use both methods. When their projections differ substantially, that suggests that both of them should be treated with a little extra caution.

III. REVIEW OF SELECTED RESIDENTIAL STUDIES AND APPLICATION TO RATE STRUCTURE CHANGES

In this section we review published residential studies of the demand for electricity. We focus on studies that are important in projecting probable effects on Maryland customers if they changed from their present electricity rate structures. In particular, we were asked to address the effects of time-of-day rates and of "rate flattening"--that is, moving from a declining block rate structure to one with a more uniform price per kwh consumed. As a consequence, we first review a substantial number of recent studies of the overall price sensitivity of demand for electricity. Second, we review a few of the most applicable residential TOD demand studies. Third, we apply the results of each type of study to illustrate the calculation of response to flat rate structures and TOD rate structures that might apply in Maryland. We show how to calculate effects on consumption, bills, and economic welfare.

REVIEW OF RESIDENTIAL RESPONSE TO NON-TOD ELECTRICITY RATES

In preparing this summary, we reviewed 34 published studies of residential electricity use drawn from North America.[1] They contain a variety of sources of data, levels of aggregation, types of models employed, and so forth.

A wide range of findings are reported in the 34 studies we reviewed, although findings are similar when studies based on disaggregated data are used and when comparable definitions of price are used. The studies are listed in the bibliography at the end of this Note. We also reviewed the surveys prepared by Taylor (1975), Anderson (1981), Nemetz et al. (1980), and Denny et al. (1979). Details of this review are contained in Appendix B. The major characteristics of studies reviewed are summarized on pages B.1-B.3. Residential sector

[1] The discussion in this section draws heavily upon the study by Acton, Mitchell, and Sohlberg (1980) and the testimony by Acton before the British Columbia Utilities Commission in the matter of B.C. Hydro's 1983 rate case.

price and income elasticities are reported on pages B.4-B.7. Long-run appliance saturation elasticities are reported on page B.8. From this review, we think that the range of values shown in Table 19 is likely to encompass the true value of price elasticity applicable to the Maryland utilities in the short run and in the long run. These are necessarily judgmental statements on our part, but we think many other analysts would come to similar conclusions after reviewing a similar set of studies. The range of values is intended to be wide enough to include the true value of price elasticity with a probability of 80 percent. That is, if one takes the range of values we suggest, then the actual elasticities in any particular instance would be encompassed by this "confidence band" 80 percent of the time.

The reviews of other analysts are broadly consistent with this summary as well. Taylor (1975) reports the results of a survey in which he reviews studies through the early 1970s. In addition, Anderson (1981) presents a survey of residential studies that also contains 80 percent confidence bands of probable values of price elasticities.

Although there are relatively few studies that test directly the effect of level of use on price elasticities, the evidence suggests that price elasticity increases with level of consumption. That is, the *proportional price response* increases with level of use--on top of the fact that the *absolute* response is greater because the amount of consumption is greater. Among other things, this increasing price elasticity of demand is implied by studies that allow for different elasticities that are due to such characteristics as appliance holdings.

Table 19

SUMMARY ESTIMATES OF RESIDENTIAL PRICE ELASTICITIES OF DEMAND FOR ALL HOUSEHOLDS

Short Run			Long Run		
Low	Medium	High	Low	Medium	High
-0.12	-0.20	-0.35	-0.60	-0.90	-1.20

One such study, Acton, Mitchell, and Sohlberg (1980), found that differences in appliance holdings affect both the overall level of use and the price elasticity of demand. These elasticities by level of use are shown in Table 20. These elasticities should be viewed as reflecting short-run behavior, since they are based on a particular stock of appliances.[2]

In general, weather plays a very important role in the level of electricity use. More extreme temperatures--both hot and cold--increase use considerably. There is some disagreement whether the effect is linear in degree-days (or degree-hours) of temperature variation, but the effect is clear and statistically significant whenever analysts have examined it.

There has been considerably less attention given to the question of the effects of weather on price sensitivity, but when it has been analyzed, researchers have found that--if anything--price responsiveness increases when weather is extremely hot. Price responsiveness does not seem to change as the weather gets colder. The reason may be that--for a given increase in price--households are more likely to turn off air conditioners when they leave a house than they are to turn down (or off) electric heating. See, for example, Lillard and Acton's (1981) study of seasonal price responsiveness under a variety of seasonal and nonseasonal electricity rates.

Table 20

RESIDENTIAL PRICE ELASTICITY ESTIMATES BY LEVEL OF USE

0-150kwh/mo	151-400kwh/mo	401-1000kwh/mo	1001+ kwh/mo
-0.25	-0.35	-0.44	-0.54

[2] The elasticities are calculated as follows: The elasticities are calculated for assumed appliance holdings that are, respectively, one-half standard deviation below the mean appliance holding, at the mean, one-half standard deviation above the mean, and one standard deviation above the mean. These appliance holdings apply approximately to the range of monthly consumption indicated.

The effect of income is largely reflected through the purchase of appliances. All other things the same, higher income households own more electricity-using appliances and they tend to live in larger houses. Consequently, the effect of income is mainly to increase usage in the long run. When short-run demand models are estimated, and when the analyst includes appliance holdings as explicit explanatory variables, then the short-run income elasticity of demand for electricity is found to be very small and/or not statistically significantly different from zero.

The overwhelming conclusion of these studies is that the level of price affects the quantity of electricity demanded in both the short run and in the long run. Although the magnitude of price elasticity may vary with the data, price used, and other factors, the price effects are statistically significantly different from zero by conventional standards of statistical inference. These empirical studies virtually rule out the possibility that price and quantity are unrelated.

REVIEW OF RESIDENTIAL RESPONSE TO TOD RATES

Introduction

In this section we summarize some of the most applicable studies on the demand for electricity under time-of-day rates. The studies reviewed all draw upon experimental data from the United States. In the period 1975 to 1980, several U.S. utilities tested the effects of one or more time-of-day rate structures on a number of their households. The experiments varied considerably in their objectives, scope, and the nature of statistical analysis that could be performed. We focus attention on the studies most suitable for forecasting in another utility system--such as those in Maryland.

Because these studies rely upon experimental data, we are generally able to control statistically for the factors that may account for patterns of electricity use and thus isolate price-related response better than was possible with the non-TOD studies reviewed above. Furthermore, most experiments were designed and conducted in a manner that makes the marginal price faced by customers clear, so we have less confusion between marginal and average price effects in these studies than with non-TOD studies.

Experiments have their limits, however, and these are relevant to our forecasting application. First, because they were of limited duration (one to three years), the resulting responses should be viewed as short run; households did not have the time or incentives to make major capital investments that may be observed with permanent time-of-day rates. In general, this will mean that the short-run response to TOD rates is smaller than the likely long-run response. Second, because these are experiments, there is always a question of whether experimental behavior is representative of nonexperimental behavior. When analysts were able to address this question,[3] there seems to be no evidence of experimental bias, but we must retain a degree of caution.

Studies Reviewed

During the late 1970s, 14 major TOD experiments were conducted in cooperation with the U.S. Department of Energy. These experiments have led to a large number of studies, perhaps exceeding 100, although only a fraction of these studies are directly useful for making projections. Many of the studies contained a single time-of-day rate, and therefore could not yield estimates of statistical demand curves (i.e., the relationship between price and quantity) in different hours of the day. Others had such limited sample size (as few as three households in an extreme instance) that the results should not be extrapolated to other settings.

We focus our attention on the studies that include data from experiments that provide more general purpose quantitative results. Most analysts feel that the studies conducted in Los Angeles, Wisconsin, North Carolina, and Southern California Edison are most suitable for this purpose.[4] The first three of these studies have been extensively analyzed and reported in literature and the findings seem to be transferable to other settings. The Southern California Edison experimental results are more recent and less extensively analyzed;

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[3] See Manning and Acton (1980) for an analysis of the effects of different compensation schemes within the Los Angeles study.

[4] See Hill et al. (1979), Aigner (1981), Caves and Christensen (1980), Acton (1982), and Kohler and Mitchell (1983).

furthermore, they seem to be less applicable in other settings (see the discussion of transferability below).

Principal Findings from the Rate Experiments

The principal findings from these rate experiments can be summarized in qualitative form as follows:[5]

- TOD rates have a statistically significant effect on patterns of demand. In general, own-price effects (i.e., the effect of a TOD charge on electricity consumption during the period to which it applies) are statistically different from zero. Cross-price effects (i.e., the effect of a TOD charge in one period of time on electricity use in another period) are positive but frequently not statistically different than zero. The magnitude of own-price effects is greater than the magnitude of cross-price effects. Households are more price responsive during the morning and early afternoon; they are less price responsive in the early evening and overnight periods.
- Appliance holdings are statistically related to the total electricity consumption and the consumption within different periods of time. Particular electricity-using appliances such as air conditioning, electric water heating, electric space heating, electric stoves, electric clothes dryers, and swimming pool pumps have important effects on the hourly profile of electricity use. The effects of different appliances are not uniform across the day but rather have different impacts at different hours of the day.
- The presence of some appliances enhances the price response that households display to TOD rates. Overall, the more appliances a household has, the more price responsive it is. Households with particular appliances--such as air

[5] This review is based on the studies by Manning and Acton (1980), Mitchell and Acton (1983), Kohler and Mitchell (1983), Caves and Christensen (1980), Miedema et al. (1981), Lillard and Aigner (1984), as well as the survey articles by Faruqui and Malko (1983), Faruqui, Aigner, and Howard (1981), and Hill et al. (1982).

conditioning, swimming pools, and electric space heating--are especially price responsive to TOD rates.

- Once appliances are taken into account, income has a very small effect on total electricity consumption or its profile by time of day. It also seems to have little effect on price response to TOD rates. In the long run, income probably affects electricity consumption through the choice of electricity-using appliances.
- Weather accounts for a major portion of the differences in household use of electricity from day to day and month to month. Extremes of weather do not seem to diminish the price response to TOD rates; if anything, household response to TOD prices seems to *increase* in hotter weather and stay the same during colder weather. Likewise, the price response on system peak days does not seem to be importantly different than the response on nonpeak days.
- Other variables that are statistically related to electricity consumption include family size, housing type, number of rooms, and whether an adult is normally at home during a particular period of time.
- There is relatively less evidence on the differences between urban and rural households, but it appears that rural households may be slightly more price responsive their urban counterparts--perhaps due to rescheduling of farm-related activities or water pumping equipment.

The Model of Demand for Electricity and Price-Related Effects

We reviewed the principal empirical findings from studies conducted in Los Angeles, Wisconsin, and North Carolina. Our primary discussion is focused on the Los Angeles results, which are most applicable for the detailed forecasting analysis reported below and which appear to be highly transferable to other settings.

From Los Angeles, we draw upon two types of models: (1) single equation ad hoc models, which explain electricity consumption in a particular period of time as a function of a series of variables (including prices in other periods), and (2) the hybrid demand model,

which combines the features of engineering-economic models of electricity consumption with the properties of systems of demand curves that satisfy particular conditions of the theory of demand for a consumer good. Both types of models provide consistent findings--either could be used for applied forecasting, depending upon the interests of the analyst making the projections and the computing resources available.

Single-Equation Model of Demand from the Los Angeles Experiment. The Los Angeles study used peak pricing periods as short as three hours and as long as 12 hours. It ran for three years and included 1800 households on one of 34 time-of-day or six seasonal and flat rates. Peak period prices ranged from 5 to 13 cents per kwh and offpeak prices ranges from 1 to 2 cents per kwh. Considerable attention was given to assuring that there was good representation of different household characteristics (including appliances) as well as weather conditions and other factors that might account for differences in electricity use.[6]

Manning and Acton report the results of exploratory analysis of data from the Los Angeles experiment. They use an extensive set of explanatory variables and impose a minimum of structure to "let the data speak for themselves." They explore a variety of alternative specifications and find that a double logarithmic specification provides the best fit. Because the data consist of a pooled time series of observations across customers, coefficients were estimated using generalized least squares (GLS). They estimate a so-called "main effects" model in which prices and a variety of other explanatory variables enter in an additive fashion. The general form of this model is

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[6] See Acton, Mitchell, and Manning (1977), Manning, Mitchell, and Acton (1979), and Chow and Mitchell (1979).

$$\log (K + 0.1) = a_{i0} + \alpha_i \lambda + \sum_{j=1}^{5} a_{ij} \log p_j$$

$$+ \sum_{j=1}^{4} b_{ij} DZ_j + \sum_{j=1}^{4} d_j Z_j$$

$$+ \Sigma e_{ij} X_j ,$$

where a, b, d, and e are coefficients to be estimated and the variables are defined as in Table 21. Table 22 presents own- and cross-price effects for weekday consumption. Own-price effects are relatively small but highly statistically significant. They average about -0.10 in the morning and early afternoon, fall to -0.08 in the late afternoon and fall even lower in the evening and overnight. Almost all of the cross-price effects have the expected positive sign but, with the exception of the equation for 9 a.m. to noon, cross-price coefficients are not statistically significant. The effects of other variables, especially the appliance variables and other household characteristics, are consistent with the qualitative summary of results presented above.

The results just discussed for the simple model assume identical price response for all households. We might expect, however, that some households would have appliances whose use could be rescheduled. Thus, a household's price response may be a function of appliance holdings. We examined this hypothesis with a model that contains interactions between each of the five TOD prices and each of the appliance stock variables in each of the five equations. The general form of the interactive equation is

Table 21

DEFINITIONS OF VARIABLES IN ESTIMATED DEMAND EQUATIONS

DEPENDENT VARIABLE

K_i = daily kwh in period i.

INDEPENDENT VARIABLES

λ = the inverse Mill's ratio for selection bias correction.

p_j = price in period j.

Z_1 = 0 if no air conditioning; otherwise = log(AC • CDH),

where $AC = \Sigma_i \omega_i A_i$ for four air conditioning appliances,[a] and

CDH = cooling degree hours measured as deviations from 65°F.

Z_2 = 0 if no HEAT; otherwise = log ROOMS • log(HEAT • HDH),

where HEAT = electric space heating, and

HDH = heating degree hours measured from 65°F.

Z_3 = 0 if no swimming pool; otherwise = log (length times width of pool).

Z_4 = $\log \Sigma \omega_i A_i$ for all other appliances

where A_i = count of appliances i in the household, and

ω_i = average kwh for appliance j.[a]

DZ_j = 0 if appliance i is absent and equals 1 if it is present.

X_j = a series of nonappliance, household-specific variables, including income, family size, number of rooms, and dummy variables for adult normally home daytime, evenings, and weekends.

[a] Values of ω are given in Appendix C.

Table 22

ESTIMATED OWN- AND CROSS-PRICE ELASTICITIES
FROM MAIN EFFECTS MODEL

(|t| in parentheses)

Period	9 a.m.-Noon	3 p.m.-Noon	Price 3-6 p.m.	6-9 p.m.	9 p.m.-9 a.m.
9 a.m.-noon	-0.1047 (5.93)	-0.0264 (1.07)	+0.0478 (2.11)	+0.0750 (2.66)	+0.0804 (2.39)
Noon-3 p.m.	+0.0043 (0.23)	-0.1020 (3.95)	+0.0128 (0.54)	+0.0547 (1.85)	+0.0278 (0.79)
3-6 p.m.	+0.0149 (0.88)	+0.0041 (0.17)	-0.0774 (3.57)	+0.0365 (1.35)	+0.0297 (0.63)
6-9 p.m.	+0.0109 (0.77)	-0.0005 (0.02)	-0.0153 (0.84)	-0.0509 (2.26)	-0.0099 (0.36)
9 p.m.-9 a.m.	-0.0065 (0.42)	+0.0128 (0.59)	+0.0164 (0.82)	+0.0191 (0.77)	-0.0581 (1.96)

$$\log (kwh_i + 0.1) = a_{i0} + \alpha_i \lambda + \sum_{k=1}^{5} a_{ik} \log p_k + \sum_{j=1}^{4} b_{ij} \log p_i \, DZ_j$$

$$+ \sum_{j=1}^{4} c_{ij} \log p_i \, Z_j + \sum_{j} d_{ij} Z_j$$

$$+ \sum_{j} e_{ij} X_j$$

This specification is used for the residential TOD projections and the coefficients and their standard error are presented in Appendix C. In general, the t statistics on individual coefficients are small and often less than 1. However, when Manning and Acton perform an F test for omitting a given set of interactions for a particular equation, they reject the hypothesis that the set of coefficients is equal to 0 in most cases.

The predicted price elasticity in the interactive model can be illustrated by calculating the value at mean levels of explanatory variables for different levels of monthly use. In a specification of the model where only own prices were interacted with the DZs and Zs, the own-price elasticity for a household in group k is given as

$$\text{own } \eta_{ik} = a_{ii} + \sum_{j=1}^{4} b_{ij} \overline{DZ}_{jk} + \sum_{j=1}^{4} c_{ij} \overline{Z}_{jk}$$

Table 23, reproduced from Acton and Mitchell (1981), illustrates the difference in these elasticities for (a) households with 16 different levels of monthly use and their associated mean appliance holdings, and (b) households with a higher level of use, characterized by the average values of appliances, air conditioning, electric space heating, as well as a large swimming pool. Elasticities are dramatically higher for high-use households than they are for low-use households. The effect of adding a swimming pool to households whose other characteristics remain the same is illustrated at mean values for households in the 1001-1100 kwh/month stratum.

Hybrid Demand System Models from the Los Angeles Experiment.[7] The hybrid demand system was developed to take advantage of both engineering-economic relationships explaining the demand for electricity as well as the properties of economic demand models regarding the consumption of related consumer goods. As applied by Mitchell and Acton (1980) and Kohler and Mitchell (1983) the process consists of two steps: (1) the household's "reference" pattern of consumption is determined on the basis of weather conditions and household specific characteristics such as appliance holdings, household size, and whether an adult is normally home during a period of time; (2) the household's total electricity consumption and consumption in each period of time is estimated as a function of TOD prices and stock of appliances. As Kohler and Mitchell demonstrate, the hybrid demand system can be interpreted as a complete demand system, consistent with demand

[7] This section draws heavily upon Kohler and Mitchell (1983).

Table 23

OWN-PRICE ELASTICITIES FOR WEEKDAY ELECTRICITY USE BY LEVEL OF USE

Household Consumption (kwh/mo)	Time Period				
	9 a.m.- Noon	Noon- 3 p.m.	3 p.m.- 6 p.m.	6 p.m.- 9 p.m.	9 p.m.- 9 a.m.
	All Households				
1-200	-0.088	-0.008	-0.001	-0.012	-0.056
201-400	-0.075	-0.051	-0.032	-0.018	-0.038
401-500	-0.074	-0.066	-0.049	-0.031	-0.039
501-600	-0.089	-0.105	-0.069	-0.040	-0.035
601-700	-0.093	-0.128	-0.090	-0.048	-0.039
701-800	-0.125	-0.166	-0.112	-0.073	-0.051
801-900	-0.163	-0.222	-0.151	-0.091	-0.074
901-1000	-0.160	-0.212	-0.136	-0.092	-0.060
1001-1100	-0.197	-0.260	-0.167	-0.117	-0.082
1101-1200	-0.246	-0.313	-0.202	-0.150	-0.089
1201-1300	-0.231	-0.295	-0.202	-0.139	-0.077
1301-1400	-0.259	-0.341	-0.225	-0.162	-0.116
1401-1500	-0.265	-0.349	-0.250	-0.167	-0.083
1501-2000	-0.274	-0.368	-0.259	-0.174	-0.073
2001-2500	-0.309	-0.417	-0.400	-0.210	-0.062
2501+	-0.259	-0.405	-0.338	-0.180	-0.035
	Households with Pools[a]				
1001-1100	-0.328	-0.395	-0.235	-0.189	-0.135

[a]Calculated at mean value of all nonpool explanatory variables for one stratum of use. Mean pool size for households having pools is used in each stratum prediction.

equations derivable from a utility function for electricity services by time of day and a composite commodity for all other goods. We will not repeat that derivation here, but rather only report the principal findings when the hybrid demand system is estimated using the Los Angeles experimental data. The important conclusion is that the magnitude and pattern of response is similar to the single equation estimates presented above and used for Maryland projections.

Price responsiveness to TOD prices in the hybrid demand model can vary with appliance holdings, as they did with the single equation model above. Table 24, reproduced from Kohler and Mitchell, presents the full-price elasticities of demand on weekdays measured from the Los Angeles data for four combinations of major appliances that were found to be especially important. The models are highly consistent with the pattern observed for demand in the single equation results presented above. For households with neither pool nor air conditioner, the own-price elasticities are between -0.03 and -0.07. The cross-price elasticities are even smaller and negative in sign. These households appear to make small reductions in loads in all periods of time when peak period time-of-day prices are increased.

Households with an air conditioner, a pool, or both are more price responsive. Own-price elasticities range up to -0.26 and, as found with the single equation models, greater elasticities are found in morning and afternoon hours and the lowest elasticities in the 6 p.m. to 9 p.m. period. Even in the early evening hours, the own-price elasticity for households with both an air conditioner and a pool is roughly twice that for households without.

The patterns of cross-price elasticities indicate that households with pools reduce electricity use in both peak period and, to a small degree, in periods just before and after peak periods; in other offpeak periods they increase loads. These households therefore exhibit net complementarity of demand in periods adjacent to the peak period and load shifting at hours farther from the peak period. In contrast, for households with only air conditioners, electricity is a net complement. These response patterns are quite plausible. Pool owners may reset the automatic clocks that control water pumping operations to new hours. Households with air conditioners can cool more intensively before and after the peak-price hours, but their reduction in use during the peak period is the dominant effect.

Table 24

FULL PRICE ELASTICITIES OF WEEKDAY CONSUMPTION DEMAND: LOS ANGELES

(At 5 cents/kwh)

Price Elasticity in Period:		... as a Function of Price in Period: (1)	(2)	(3)	(4)	(5)
Pool and Central Air Conditioning						
09-12	(1)	-0.26	-0.05	0.03	0.04	0.12
12-15	(2)	-0.03	-0.15	-0.02	0.01	0.08
15-18	(3)	0.01	-0.02	-0.10	-0.04	0.03
18-21	(4)	0.02	0.01	-0.04	-0.10	-0.00
21-09	(5)	0.06	0.06	0.03	-0.00	-0.26
Pool, No Air Conditioner						
09-12	(1)	-0.24	-0.03	0.05	0.05	0.10
12-15	(2)	-0.03	-0.12	-0.01	0.01	0.08
15-18	(3)	0.04	-0.01	-0.10	-0.04	0.04
18-21	(4)	0.03	0.01	-0.03	-0.10	0.02
21-09	(5)	0.04	0.04	0.02	0.01	-0.18
No Pool, Central Air Conditioning						
09-12	(1)	-0.07	-0.03	-0.05	-0.02	-0.00
12-15	(2)	-0.02	-0.08	-0.04	-0.02	-0.02
15-18	(3)	-0.02	-0.03	-0.06	-0.04	-0.02
18-21	(4)	-0.01	-0.01	-0.04	-0.07	-0.04
21-09	(5)	-0.00	-0.01	-0.02	-0.04	-0.09
No Pool or Air Conditioning						
09-12	(1)	-0.05	-0.02	-0.02	-0.01	-0.03
12-15	(2)	-0.01	-0.03	-0.03	-0.02	-0.04
15-18	(3)	-0.01	-0.02	-0.04	-0.03	-0.03
18-21	(4)	-0.01	-0.01	-0.02	-0.06	-0.03
21-09	(5)	-0.01	-0.01	-0.02	-0.02	-0.07

Comparison with Other Studies and Transferability of Findings

The time-of-day experiments conducted in Wisconsin, North Carolina, and Southern California Edison are also important for projecting TOD response in Maryland. If they produce consistent findings with the detailed Los Angeles results reviewed above, they provide added evidence that behavioral response to TOD rates may be generalizable over a broader set of circumstances; if they produce important conflicts, then the analyst is faced with a choice of the most suitable estimates for Maryland's circumstances. We find that the Los Angeles results are confirmed by findings from these other experiments. When comparable estimating models are used, the Wisconsin experiment produces results which are statistically significant and highly consistent with the Los Angeles findings just reviewed. The North Carolina and Southern California Edison results are on an average similar to the Los Angeles and Wisconsin findings, but of lower statistical significance, due to more limited sample sizes and experimental design. We conclude that the Los Angeles and Wisconsin findings are transferable to a wide variety of settings--including settings with important differences in weather--once allowance is made for local values of appliances and weather conditions.

Kohler and Mitchell estimated the hybrid demand model using Wisconsin data. The results over the six- and nine-hour peak rates are shown in Table 25. Since the Wisconsin experimental design kept revenue under TOD rates the same on average as non-TOD rates, an overall elasticity of demand[8] for electricity cannot be estimated. Table 25 shows full price elasticities[9] for assumed overall elasticity values of -0.1 and -0.2, which bracket the values estimated in Los Angeles. The full-price elasticities are highly consistent with the values from the single equation estimates presented above and with the hybrid model estimated with Los Angeles data. The principal difference is that the

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[8] Overall price elasticity measures a change in electricity consumption where the average price of electricity rises or falls.

[9] Full-price elasticity measures complete effect of a price change in period i on consumption in period i. It takes account of both the effect in overall expensiveness of electricity as well as its relative expensiveness in one time period.

Wisconsin own-price elasticities are somewhat greater in the overnight period (20-08). Appliance-specific effects and their interaction with changes in weather are also very similar between Los Angeles and Wisconsin. When the hybrid model estimated on Los Angeles data is used to predict consumption under Wisconsin TOD rate structure, the results are very similar to the predictions of the Wisconsin model estimated on Wisconsin data--again confirming the basic behavioral similarities of these findings.

Kohler and Mitchell also estimated the hybrid model using North Carolina data. They obtained similar findings with respect to appliances, weather, and other household characteristics to those found in Los Angeles and Wisconsin. The average price effects estimated with North Carolina data are similar to those estimated with the hybrid model on Los Angeles data, but the statistical significance is very low.

Table 25

OWN- AND CROSS-PRICE FULL ELASTICITIES: WISCONSIN SUMMER 6- AND 9-HOUR TOD PLANS

	Assuming $\eta^* = -0.1$, Price at			Assuming $\eta^* = -0.2$, Price at		
kwh at	08-17	17-20	20-08	08-17	17-20	20-08
			Urban Households			
08-17	-0.094	-0.034	0.050	-0.135	-0.051	0.027
17-20	0.042	-0.128	0.007	0.001	-0.145	-0.016
20-08	-0.002	0.095	-0.172	-0.043	0.078	-0.195
			Rural Households			
08-17	-0.095	0.024	-0.008	-0.136	0.007	-0.031
17-20	-0.014	-0.075	0.014	-0.055	-0.095	-0.009
20-08	0.038	-0.042	-0.076	-0.003	-0.059	-0.099
			All Households			
08-17	-0.096	-0.012	0.029	-0.137	-0.029	0.006
17-20	0.023	-0.109	0.008	-0.018	-0.126	-0.015
20-08	0.013	0.043	-0.136	-0.028	0.026	-0.149

NOTE: η^* is the overall price elasticity.

Kohler and Mitchell suggest that this is due to the very limited price variation in the North Carolina experimental design, along with inadequate sample sizes. When the hybrid model estimated on Los Angeles data is used to predict load changes in North Carolina, the reductions are somewhat higher, but within the confidence band of hybrid model estimates on North Carolina data.

Caves, Christensen, and Herriges (1983) have also considered the question of transferability of experimental findings from one setting to another. They use a somewhat different modeling approach than Kohler and Mitchell, though it is in the spirit of the hybrid demand system described above. The key price effects are estimated as an Allen elasticity of substitution between peak and offpeak periods. Although we think this parameter is less useful for projections than the full-

Table 26

OTHER ESTIMATE OF CUSTOMER RESPONSE 1
TO TOD RATES ACROSS SEVERAL RESIDENTIAL EXPERIMENTS
WEEKDAYS, STAGE I, BASIC MODEL

	Summer		Winter	
Experiment	Estimate	Standard Error	Estimate	Standard Error
CP&L	0.19	(0.07)	0.13	(0.05)
Connecticut	0.10	(0.02)	0.14	(0.01)
Los Angeles 1	0.19	(0.03)	0.15	(0.03)
Los Angeles 2	0.16	(0.04)	0.09	(0.03)
Los Angeles 3	0.13	(0.02)	0.09	(0.02)
Los Angeles 4	0.10	(0.03)	0.06	(0.03)
Los Angeles 5	0.13	(0.06)	0.19	(0.04)
Los Angeles 6	0.12	(0.02)	0.09	(0.02)
Los Angeles 7	0.11	(0.02)	0.09	(0.01)
SCE 1	0.14	(0.02)	0.07	(0.02)
SCE 2	0.16	(0.02)	0.08	(0.02)
Wisconsin 1	0.13	(0.03)	0.12	(0.02)
Wisconsin 2	0.13	(0.03)	0.07	(0.02)
Wisconsin 3	0.13	(0.03)	0.09	(0.02)
Pooled estimate	0.13	(0.01)	0.10	(0.01)

SOURCE: Caves, Christensen, and Herriges (1983).

price elasticities reported above, it confirms the similarity of response to prices in different settings. Caves, Christensen, and Herriges estimate the same model using data from five experiments. The basic model explains the log of the ratio of peak to offpeak consumption as a function of the log of the ratio of peak to offpeak price, regardless of the length of peak pricing periods and not accounting for other factors. The results are presented in Table 25 (from page 12 of their study) for weekday consumption. The important conclusion from our perspective is that the North Carolina (CP&L), Connecticut, Los Angeles, Southern California Edison, and Wisconsin estimates are remarkably similar to the pooled estimate of 0.13 during the summer and .10 during the winter, and they are quite close to the findings reported by Manning and Acton and by Kohler and Mitchell. The authors also estimate more complex models that take account of appliances and weather. The basic price-related effects remain similar across experiments and the appliance and weather effects are similar to the qualitative summary we presented above. We conclude that the Caves, Christensen, and Herriges findings also indicate that similar behavioral patterns are being observed when comparable models are estimated across experimental data sets.

Aigner and Leamer (1982) also test for transferability of experimental results using a very sophisticated Bayesian framework to determine how much of a "donor" utility's data should be combined with a recipient utility's data in estimating demand equations. When experimental results are transferable, 100 percent of the donor utility's data should be pooled with the recipient utility's in making predictions; when the results are not transferable, no pooling should take place. Aigner and Leamer tested the transferability of Southern California Edison and Los Angeles experimental results to the Kansas Power and Light service territory. They conclude that the Los Angeles results are highly applicable but that the Southern California Edison results are not.

ILLUSTRATIVE APPLICATION OF FORECASTING MODELS TO RATE CHANGES

Rate Flattening

Many utilities, including those in Maryland, charge their residential customers on a declining block rate: The price per kwh falls as consumers move to higher levels of consumption. Rate flattening removes part or all of this feature and charges a more-nearly constant price per kwh. Figure 2 illustrates such a change for a two block rate structure. Under the declining block rate, the customer pays P_1 cents per kwh up to some number of kwh per month, then pays P_2 cents per kwh above that level. The flat rate, P_f, charges the same price at all levels of use.

Welfare Changes Associated with Rate Flattening. In general, the cost of supplying an incremental kwh of electricity to a customer (or to two different customers) is the same as the cost of supplying the first few kwh, so that a declining block rate departs from the marginal cost of supply and a flat rate structure can more closely reflect the

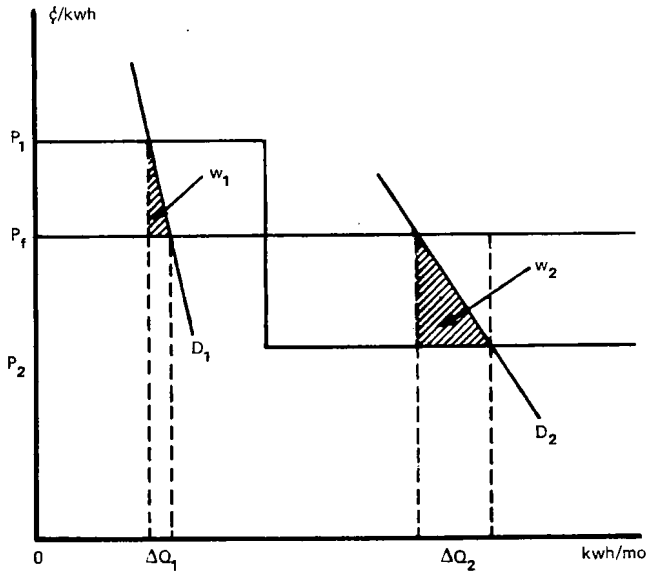

Fig. 2 -- Illustrative Effects of Rate Flattening on Consumption and Welfare

resource costs. If P_f equals marginal costs, then the welfare gains of switching from a block rate structure are shown in Fig. 2 for two customers whose demand curves are D_1 and D_2.[10] Customers on demand curve D_1 increase their consumption, leading to a net welfare gain of W_1.[11] Likewise, the net gain in social well-being for changes by customers on the D_2 demand curve is given by the amount W_2. The size of the welfare gain for an individual customer depends upon the change in price and the elasticity of demand for electricity. For the entire utility, the sum of welfare gains depends upon the distribution of customers at different levels of use.

Bill Changes from Rate Flattening. The size of the bill change to a particular customer also depends upon the change in price levels and the elasticity of demand. In many instances, the utility will consider a flat rate that attempts to raise the same revenue as the declining block rate. We define ex ante revenue neutrality as a flat price per kwh that raises the same revenue as the block structure *if* customers do not change their level of use. If X_1 represents the total number of kwh billed at price P_1 in the first block of the rate structure, and X_2 represents the total number of kwh billed at the second block price, then P_f is a revenue neutral flat rate if it satisfies the condition

$$(P_f - P_1)X_1 = -(P_f - P_2)X_2 \ .$$

Applications to Rate Flattening in Maryland. The total demand equation reported by Acton, Mitchell, and Sohlberg is well suited to analyzing the effects of rate flattening, because it takes account of appliance holdings and provides different elasticities by level of use. Specifically, we do the calculations for the distribution of appliances that yields the elasticities given in Table 20 above. We illustrate the

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[10] This welfare calculation is based on changes in producer and consumer surplus; see Acton and Mitchell (1983) for a discussion of applied welfare analysis for residential electricity rate changes.

[11] This improvement consists of an increase in consumer surplus given by the trapezoid bounded by D_1 and the P_1 and S_1 lines, less the loss in excess profits to the utility, given by the rectangular area bounded by P_1 and P_f.

effects of a change from PEPCO's residential block rate structure in Maryland. That rate charges a constant price of 7.18612 cents per kwh in summer months (June through October) and a declining block price during the other months. In winter, the charge is 7.18612 cents per kwh for the first 750 kwh per month and then 5.20212 cents per kwh above 750 kwh per month. In both seasons, a monthly customer charge of $3 applies and a constant fuel rate of 2.45812 cents/kwh is added to all kwh for illustrative purposes. We assume that a flat price in the winter would charge 6.676 cents per kwh and that the monthly customer charge remains unchanged.[12] Table 27 gives the effects on consumption, bills, and economic well-being at five specific levels of consumption.[13]

Table 27

CALCULATED EFFECT OF RATE FLATTENING ON CONSUMPTION, BILLS AND ECONOMIC WELL-BEING PER MONTH

Interval Kwh per Month Value Used for Calculation	0-150 130	151-400 350	401-1000 750	1000+ 1500	 3000
Bill under declining block rate (cents/month)	12.34	28.15	56.90	99.17	183.71
Bill under flat rate (with adjustment)	11.84	26.98	54.72	94.40	185.81
Change in kwh	2	9	25	-131	-262
Change in well-being	$0.001	$0.02	$0.06	$0.77	$1.55

[12] To select a flat rate that is revenue neutral, we need to know the distribution of consumption. We assume that approximately 75 percent of the residential kwh is billed at the first block price and the remainder at the second block price, which makes the illustrative flat rate ex ante revenue neutral.

[13] For these calculations, we used the arc elasticity formula, $\eta = [(\Delta Q/\Delta P)] \cdot [P_1 + P_2)/(Q_1 + Q_2)]$, and solved for the new level of consumption using values for elasticities taken from Table 20.

Time-of-Day Rates

PEPCO's TOD Rate. We first illustrate the effects of switching to a residential TOD rate using the terms of PEPCO's proposed TOD rate MD-R-TM. For comparison purposes, we used the declining block rate in effect in February 1983 as the standard rate. Under the terms of the proposed TOD rate, the customer charge is raised from $3 to $12.15 per month and three pricing periods are employed: peak, shoulder, and offpeak periods. The terms of the rate are given in Table 28. For purposes of this calculation, we treated the monthly maximum demand charge of $2.65/kw during summer months as an equivalent price per kwh assuming a uniform level of demand over peak hours in the month. Although PEPCO's suggested rate applies only to customers at very high levels of use, we calculate illustrative effects for the full spectrum of level use to judge the effects on customers and utility loads. The welfare effects and bill comparisons are calculated in accordance with the discussion in Park and Acton (1983, pp. 48-51) using the Turvey approximation.

Table 28

TERMS OF PEPCO'S MD-R-TM RATE

	Summer (June-Oct)	Winter (Nov-May)
Energy charge (cents/kwh)		
Peak (noon-8pm, M-F)	7.895	5.908
Shoulder (8am-noon + 8pm-midnight, M-F)	5.636	5.747
Offpeak (midnight-8am, M-F + weekends and holidays)	4.979	4.979
Plus: Customer charge $12.15/month and fuel adjustment. (Fuel rider less 2.45812 cents/kwh. fuel rider added to all kwh equals 2.45812 cents/kwh in illustrative calculations of effects so net effect is zero.)		

The Manning and Acton (1980) model with price-appliance interactions is used for these projections in welfare analysis because the results of that study are very robust and consistent with other detailed econometric studies, because the price elasticities vary with changes in customer characteristics, and because the software is well developed for the task. In this model, the characteristics of households at different strata of monthly consumption are used to calculate the expected effects. For this application, we use the stratum-specific appliance holdings and other characteristics of households from the Los Angeles electricity rate study, which is based on in-person interviews with 2,689 households. Households at higher levels of use have systematically more extensive holdings of electricity-using appliances and we believe that the usage-specific appliance stocks provide reasonable approximations of appliance holdings in Maryland if state-specific information is not available.

Method of Calculation. Projections in Maryland are made in the following manner. Denote mean values of all non-price explanatory variables for a household in stratum t as x_t; denote the marginal TOD price in period i as $P - TOD_{it}$, and marginal price under standard electricity rates as $P - STD_{it}$.[14] Then projected monthly energy consumption in period i for a household in stratum t under TOD rates is given by

$$kwh_{it} = f_i\ (P - TOD_{it},\ x_t),$$

where the coefficients are taken from the interactive specifications estimated by Manning and Acton. The corresponding projections under a standard rate substitute $P - STD_{it}$ in this equation, so that the difference in consumption is

[14] Marginal prices are used in these projections because they are the source of prices used in the estimating equations and because inframarginal changes are unimportant compared with marginal changes; see Acton, Mitchell, and Sohlberg (1980).

$$\text{DIFFERENCE} = f_i\ (P - TOD_{it},\ x_t) - f_i\ (P - STD_{it},\ x_t).$$

The coefficients used for this projection are given in Appendix B, along with the definitions of explanatory variables. Since the Los Angeles experiment was conducted during the late 1970s, we adjust prices for inflation in utility projections. We used a value of 1.57 to deflate 1983 prices to a value corresponding to 1978 levels.[15]

The Manning-Acton equations were estimated for consumption in three-hour blocks of time from 9:00 a.m. to 9:00 p.m., a single overnight period of 12 hours, and a 48-hour weekend. Making a projection for a TOD rate then does not correspond precisely with these time periods, so we took prorata shares of predicted quantities for the time periods under the two different prices that apply.

The confidence band for our predictions depends on the number of households in a given stratum. To make the findings comparable across strata, we assumed that projections apply to 200 households in each stratum. The standard error of estimate for the log-log equations is about 0.5. This produces a standard deviation of about ± 3.5 percent for projected mean consumption by 200 households and about ± 3 percent for the differences in consumption and changes in bills and economic welfare.[16] A 95 percent confidence band for the differences would be about ± 6 percent.

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[15] The price index for urban consumers was 195.4 in 1978 and 292.4 in December 1982; 292.4/195.4 = 1.50. Source: *Economic Report of the President*, February 1983, p. 221.

[16] The error term n enters the projection equations as multiplicative factor exp (n). Thus, one standard deviation above a projection for an individual customer is exp (0.5) = 1.65 times the projection, and one standard deviation below is exp (-0.5) = 0.61 times the projection. The standard error for projecting the mean consumption for a group of 200 customers is 0.5/sqrt(200) -0.035, and the corresponding multipliers are exp (0.035) = 1.036 and exp (-0.035) = 0.966, or about ± 3.5 percent. The standard error for differences is given by the square root of $[\sigma_1^2 + \sigma_2^2 - 2\rho\sigma_1\sigma_2]$ where σ_1 is the standard error of the prediction under standard rates, σ_2 under TOD rates, and ρ is the covariance between the two errors; we assumed a value of 0.6 for ρ in making these projections.

Table 29 presents the results of the calculations for the summer and Table 30 presents the results for the winter. Overall, the relative consumption (percentage of kwh in the month) averages about 25 percent for the peak period, about 22 percent for the shoulder period, and the balance in the offpeak period under the standard rate in these tables. Changes in total consumption associated with changing to these rates are modest for most customers, reaching about -30 kwh per month above 2500 kwh per month. The changes in peak demand, however, are much more notable. For customers above 1100 kwh per month, the peak period reduction ranges from 19 to 76 kwh in the summer and from 8 to 34 kwh in the winter.

Table 29

SUMMARY OF EFFECTS OF PEPCO'S PROPOSED TOD RATE ON CONSUMPTION, BILLS, AND WELFARE, BY LEVEL OF USE

Season--Summer

		Change in:				
Stratum	kwh/mo	Peak kwh	Shoulder kwh	Offpeak kwh	Bill	Economic Welfare($)
1	0-200	-0	1	1	7.90	0.02
2	201-400	-1	1	2	6.37	0.05
3	401-500	-2	1	3	4.90	0.07
4	501-600	-3	2	4	4.04	0.10
5	601-700	-5	2	5	2.97	0.13
6	701-800	-7	3	6	1.99	0.18
7	801-900	-10	5	8	1.14	0.24
8	901-1000	-11	5	8	0.19	0.25
9	1001-1100	-14	7	10	-0.81	0.33
10	1101-1200	-19	9	12	-1.93	0.41
11	1201-1300	-20	9	12	-3.22	0.43
12	1301-1400	-25	12	15	-3.69	0.54
13	1401-1500	-28	12	14	-5.14	0.56
14	1501-2000	-33	14	16	-7.66	0.67
15	2001-2500	-54	12	8	-14.73	0.78
16	2501+	-76	24	22	-21.60	1.29

Table 30

SUMMARY OF EFFECTS OF PEPCO'S PROPOSED TOD RATE ON CONSUMPTION, BILLS, AND WELFARE, BY LEVEL OF USE

Season--Winter

Stratum	kwh/mo	Change in: Peak kwh	Shoulder kwh	Offpeak kwh	Bill	Economic Welfare($)
1	0-200	-0	-0	0	6.73	0.00
2	201-400	0	-0	1	3.78	0.00
3	401-500	1	-1	1	1.10	0.01
4	501-600	1	-1	1	-0.50	0.01
5	601-700	2	-1	1	-2.38	0.02
6	701-800	3	0	2	-4.05	0.04
7	801-900	-4	-0	3	-5.24	0.02
8	901-1000	-4	-0	3	-4.01	0.02
9	1001-1100	-6	-1	3	-3.98	0.03
10	1101-1200	-8	-2	3	-3.92	0.04
11	1201-1300	-8	-2	3	-3.70	0.04
12	1301-1400	-10	-3	3	-3.68	0.05
13	1401-1500	-12	-3	4	-3.50	0.05
14	1501-2000	-14	-3	5	-3.12	0.06
15	2001-2500	-25	-1	11	-2.23	0.10
16	2501+	-34	-4	11	-0.45	0.14

Although the residential projections are based on direct estimation of actual kwh levels in different periods of the day, the effects can be expressed as changes in relative peak load as was done for business customers. For customers in stratum 9 (1001-1100 kwh/month) relative peak load is reduced by 6.3 percentage points under TOD rates and for customers in stratum 16 (2501+ kwh/month) relative peak load decreases 9.5 percentage points. This level of response is similar to that of business customers in the most responsive industrial classifications.

The proposed TOD rate raises bills at lower levels of use (below 1000 kwh in the summer and below 500 kwh in the winter) and lowers bills at higher levels of monthly consumption. The combination of the lower bill effects and the adjustments that customers are prepared to make means that customers at higher levels of use, above 2000 kwh per month, can expect a bill reduction of 15 or 22 dollars a month or more due to

switching to time-of-day rates. The welfare gains associated with these changes are relatively modest and exceed $1 per customer per month only at the highest levels of use. The reasons for these modest welfare changes include the small difference between peak and offpeak prices relative to the standard rate under the terms of the proposed PEPCO time-of-day tariff.

BGE's TOD rate. We performed a similar analysis of probable effects of the proposed BGE TOD rate shown in Table 31. Tables 32 and 33 present the projected effects on customers identified at 16 levels of use. The BGE rate is proposed for experimental application to 200 households with consumption of at least 2000 kwh in one or more summer months, but we calculated effects at all levels of use.

Qualitatively, the BGE rate effects on consumption, bills, and welfare are similar to PEPCO's rate effects. The magnitudes of change are greater at any level of use because the spread between peak and offpeak prices is greater in the BGE rate than in the PEPCO rate. Assuming these price levels reflect the marginal cost of supply in each of the rating periods, welfare gains in excess of $1 per customer per month are found at consumption levels of 800 kwh/month in summer months and are found above 2000 kwh/month in winter. The summer welfare gains exceed $3 per month for customers with monthly consumption over 1400 kwh. Furthermore, the changes in customer bills, including the effects of altered consumption patterns, produce lower expected bills for customers with net welfare gains, reinforcing the attractiveness of the rate to customers.

Table 31

TERMS OF BGE TOD AND STANDARD RATES

	Summer (June-September)	Non-Summer (October-May)
Energy charges:[a]		
On-Peak (10am-8pm, M-F)	13.150 cents/kwh	5.930 cents/kwh
Intermediate-Peak (7am-10am + 8pm-11pm, M-F)	3.662 cents/kwh	5.930 cents/kwh
Off-Peak (all other hours)	2.187 cents/kwh	2.187 cents/kwh
Plus:		
Customer charge: $8.00 per month		
Energy charges:[a]		
1-500 kwh/mo	6.09 cents/kwh	6.09 cents/kwh
500+ kwh/mo	6.09 cents/kwh	3.78 cents/kwh
Plus:		
Customer charge: $3.25 per month		

[a]Plus fuel rate (added to all kwh; equals 1.340 cents/kwh in illustrative calculations of effects).

Table 32

SUMMARY OF EFFECTS OF BGE'S PROPOSED TOD RATE ON CONSUMPTION, BILLS, AND WELFARE, BY LEVEL OF USE

Season--Summer

		Change in:				
Stratum	kwh/mo	Peak kwh	Shoulder kwh	Offpeak kwh	Bill	Economic Welfare($)
1	0-200	-1	0	2	3.93	0.07
2	201-400	-3	-1	5	3.02	0.18
3	401-500	-5	-2	7	1.97	0.30
4	501-600	-8	-2	9	1.38	0.44
5	601-700	-12	-3	10	0.49	0.59
6	701-800	-18	-4	13	-0.44	0.85
7	801-900	-27	-5	16	-1.53	1.21
8	901-1000	-28	-5	17	-1.99	1.27
9	1001-1100	-38	-6	21	-3.65	1.68
10	1101-1200	-51	-8	24	-5.49	2.15
11	1201-1300	-53	-9	24	-6.74	2.23
12	1301-1400	-67	-10	30	-7.28	2.81
13	1401-1500	-74	-12	29	-9.32	3.02
14	1501-2000	-88	-14	34	-11.93	3.60
15	2001-2500	-138	-29	21	-22.02	4.91
16	2501+	-197	-34	48	-24.77	7.49

Table 33

SUMMARY OF EFFECTS OF BGE'S PROPOSED TOD RATE ON CONSUMPTION, BILLS, AND WELFARE, BY LEVEL OF USE

Season--Winter

		Change in:				
Stratum	kwh/mo	Peak kwh	Shoulder kwh	Offpeak kwh	Bill	Economic Welfare($)
1	0-200	0	-0	2	1.90	0.04
2	201-400	0	-1	4	-1.50	0.08
3	401-500	0	-1	6	-4.62	0.12
4	501-600	-2	1	9	-5.58	0.08
5	601-700	-4	2	11	-5.39	0.11
6	701-800	-7	1	12	-5.33	0.16
7	801-900	-12	0	12	-5.38	0.22
8	901-1000	-12	0	14	-5.02	0.23
9	1001-1100	-17	-1	13	-5.32	0.31
10	1101-1200	-24	-3	14	5.53	0.40
11	1201-1300	-25	-2	16	-5.28	0.42
12	1301-1400	-33	-5	15	-5.54	0.52
13	1401-1500	-36	-4	18	-5.38	0.58
14	1501-2000	-44	-4	22	-5.15	0.69
15	2001-2500	-73	3	46	-4.05	1.11
16	2501+	-102	-4	48	-1.68	1.51

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APPENDIX A

APPENDIX A

```
//P0780R00 JOB (3762,20,133),'MTXPRED',CLASS=N
//  EXEC SAS,REGION=1000K,OPTIONS='NONEWS'
//SYSIN DD *

*******  PROC MATRIX PROGRAM TO PREDICT UTILITY/CUSTOMER CATEGORY
*******  RESPONSE BASED ON SIC DISTRIBUTION;
*******  THIS RUN USES MODEL ESTIMATED IN NONLIN RUN
*******  (JOB 0044, 16 JUL 83);
*******  DOES PREDICTIONS & R**2 FIRST, THEN STD ERR CALCS;
*******  SAVED AS MTXPRED ON USER53;

PROC MATRIX PRINT;

*******  W IS 1000S OF AVERAGE KWH FOR EACH UTIL/CUST CAT BY SIC2;
*******  FROM PRED.PGM4 JOB 1396, 27 JUN 83;

W=
214.390 215.196  36.066  49.984   2.814  19.662  28.361  74.190
  3.728  67.760 /
  6.344  61.025  66.665  31.198   1.572   2.153  28.512 130.858
  5.239  28.144 /
  0.      3.333   0.      0.      0.      0.     57.446  26.794
  0.721   0.    /
 36.172  46.785   5.812   0.      0.      0.     56.482  14.402
  0.538   0.    /
140.222  69.657  14.813  10.792   0.224   3.294  19.997  42.054
  0.197  28.688 /
133.264  34.709   0.     200.387  0.      1.283 134.199  88.801
  0.      0.    /
  8.597  79.271   7.404  12.032   1.194   0.     11.680   7.058
  1.210  15.089 /
133.256  66.391   1.229   1.939   0.      0.     48.238  65.145
  0.      0.    /
 43.589  86.240 101.871  34.553   0.925   4.551   5.605  35.158
  0.955  10.123 /
  0.     75.767  57.404  12.790   0.      1.831   0.     21.249
  1.277   9.943 /
  8.637  59.401 104.787   0.      1.802   1.810  10.617  20.327
  2.789   0.    /
 76.940  90.497  55.098  10.086   0.369  10.928  47.629  49.779
  3.154   0.    /
156.485  74.089   6.951  57.884   0.     66.318  37.396   5.237
  0.281 115.446 /
  0.     10.006   4.922  23.024   0.      6.556   0.     18.351
  0.    115.132 /
  0.     38.453  11.677  32.957   0.      0.     15.508  42.181
  0.490   2.553 /
  0.      0.    117.972 334.817   0.    163.938  63.387 287.896
```

```
 15.372 804.563 ;

******* NORMALIZE EACH UTIL/CUST CATEGORY'S SIC WEIGHTS (W)
******* AND CALCULATE UTIL/CUST CATEGORY WEIGHTS (CATW);


CATW=W(+,);
DO J=1 TO 10;
  W(,J)=W(,J)#/CATW(1,J);
  END;
PRINT W;

CATW=CATW#/CATW(,+);

******* RCACT IS ACTUAL RESPONSE BY UTIL/CUST CATEGORY;

RCACT=
-.014269 -.013238 -.023996 -.001706 -.017005  .001325 -.018901
-.009606 -.002213  .000090 ;

******* RS IS AVERAGE RESPONSE BY SIC2 (NONLINEAR ESTIMATE FROM
******* JOB 0044, 16 JUL 83);

RS=
-.004723 -.011979 -.145017 -.005242 -.000979  .000000 -.026770
-.008350 -.062068 -.008235 -.034485 -.010068 -.008873  .000000
 .000000  .000000 ;

******* CALCULATE UTIL/CUST CATEGORY PREDICTED RESPONSE (RCPRED) AS
******* WEIGHTED AVERAGE OF SIC RESPONSE, USING THAT CATEGORY'S
******* SIC WEIGHTS;

RCPRED1=RS*W;

******* ADJUST PREDICTIONS BASED ON MULTIPLICATIVE
******* FACTOR CALCULATED USING UTIL/CUST CATEGORY
******* SPECIFIC MEANS FOR PRICE, LENGTH, AND SIZE;

******* COEFF IS FROM JOB 0044, 16 JUL 83;

COEFF=
 2.15863586   .66335714   .30691264   .18365311  -.16014333
-1.48213601   .01891824  -.00011211;

******* X IS WEIGHTED MEAN VALUES OF INDEPENDENT VARAIBLES
******* FOR EACH UTILITY/CUSTOMER CATEGORY FROM JOB 1592, 6 JUL 83;
******* (EXCEPT INTERCEPT AND SHORT DUMMY ARE SET TO 0 OR 1);

X=
1.000000  1.000000  1.000000  1.000000  1.000000  1.000000
1.000000  1.000000  1.000000  1.000000 /
 0.24970   0.22510   0.90630   2.68870   1.41840   1.11600
```

```
 0.36770   0.77090   1.00690   0.90170 /
 1.74780   3.78860   0.07230   0.00000   3.49450   3.37800
 1.02400   -.47300   -.08070   9.20000 /
 -.71420  -2.19440   0.00000   -.02680  -2.26610  -2.76270
 0.00000   0.00000   0.00000  -7.18070 /
 5.70810   5.53980  12.00000   8.00000  11.00000  14.18710
 5.01280   4.99980  14.00000  14.00000 /
1.000000  1.000000  0.000000  1.000000   .000000   .000000
1.000000  1.000000   .000000   .000000 /
12.48180   1.67120   3.79510   6.54390   0.68950   5.73940
 9.82680   1.42800   0.21030  16.85220 /
229.4680    3.6430   28.3750  106.2560    0.7040   87.8280
178.9360    2.4420    0.0490  485.2730;

******* CALCULATE ADJUSTED UTIL/CUST CATEGORY PREDICTIONS;

MULT=COEFF*X;
RCPRED2=RCPRED1#MULT;

******* CALCULATE SUMS OF SQUARES ABOUT 0 (SS0), ABOUT THE MEAN
******* (SSM), AND ERRORS (SSE) FOR R-SQUARED CALLCULATIONS;

SS0=RCACT##2;
SSM=(RCACT+.00969704)##2;
SSE1=(RCACT-RCPRED1)##2;
SSE2=(RCACT-RCPRED2)##2;
SS0=SS0*CATW';
SSM=SSM*CATW';
SSE1=SSE1*CATW';
SSE2=SSE2*CATW';
RSQ1=1-SSE1#/SSM;
RSQ2=1-SSE2#/SSM;

PRINT RCPRED1;
PRINT RCPRED2;
PRINT RSQ1;
PRINT RSQ2;

******* STANDARD ERROR OF PREDICTION ESTIMATES ARE BASED ON THE
******* NONLINEAR ESTIMATE OF THE COVARIANCE MATRIX FOR THE
******* COEFFICIENTS;

******* SEB IS ASYMPTOTIC STANDARD ERRORS FOR THE COEFFICIENTS;

SEB=
.33730942 .09692569 .04314671 .04893027 .02593166 .21554526
.00297498 .00001930 .00292769 .00457193 .02104808 .00860605
.00405056 .00333691 .00721684 .00667872 .00709573 .00574776
.00621639 .00567462 .00269989 .00383344 .00899029;


******* CORR IS THE ASYMPTOTIC CORRELATION MATRIX OF THE COEFF;
```

```
CORR=
1.000000  .379930  .350573  .204146 -.985255 -.982981  .391365
-.356594 -.145003 -.025531  .397694 -.100566 -.125521 -.215021
 .096991 -.162265  .527735 -.018326  .325999 -.104177  .035110
-.084683 -.171605 /
 .379930 1.000000  .329556  .274249 -.398850 -.425190  .480787
-.417194 -.142981  .007881  .410847 -.117414 -.133877 -.242521
 .135585 -.174871  .597390 -.016512  .289221 -.103823  .060712
-.094249 -.244053 /
 .350573  .329556 1.000000  .707105 -.356153 -.384394  .324269
-.296690 -.115809 -.004115  .419531 -.105239 -.135618 -.239373
 .232389 -.135564  .471823 -.005767  .244163 -.090368  .088114
-.104570 -.197849 /
 .204146  .274249  .707105 1.000000 -.204314 -.233100  .177001
-.164624 -.082336 -.036785  .296634 -.052755 -.073791 -.129035
 .047871 -.064215  .290735 -.018989  .159606 -.039251 -.061415
-.040217 -.110568 /
-.985255 -.398850 -.356153 -.204314 1.000000  .955122 -.424320
 .373192  .137855  .027626 -.415970  .095775  .121265  .208259
-.097268  .155774 -.495665  .019668 -.289443  .101521 -.038258
 .081682  .167621 /
-.982981 -.425190 -.384394 -.233100  .955122 1.000000 -.450234
 .422419  .155225  .022457 -.384486  .110103  .134430  .231475
-.106968  .175711 -.592373  .017425 -.361498  .112660 -.041911
 .091867  .186672 /
 .391365  .480787  .324269  .177001 -.424320 -.450234 1.000000
-.967740 -.136189 -.037312  .300194 -.108955 -.120590 -.220745
 .090388 -.158492  .678204 -.032388  .229523 -.123644  .075302
-.087073 -.187150 /
-.356594 -.417194 -.296690 -.164624  .373192  .422419 -.967740
1.000000  .123109  .030658 -.266078  .099171  .109443  .201707
-.083241  .142751 -.602017  .027288 -.232645  .111025 -.071980
 .079912  .170012 /
-.145003 -.142981 -.115809 -.082336  .137855  .155225 -.136189
 .123109 1.000000 -.093813 -.167867 -.048003 -.039601 -.045235
-.086600 -.081348 -.198255 -.053699 -.142846 -.088513 -.092816
-.012545 -.013988 /
-.025531  .007881 -.004115 -.036785  .027626  .022457 -.037312
 .030658 -.093813 1.000000 -.066896 -.060174 -.057117 -.081904
-.031829 -.096470 -.043939 -.042672 -.048811 -.089344 -.052768
-.029967 -.053003 /
 .397694  .410847  .419531  .296634 -.415970 -.384486  .300194
-.266078 -.167867 -.066896 1.000000 -.121810 -.138336 -.230606
 .082515 -.182420  .345528 -.047189  .145189 -.139444 -.001282
-.089666 -.188113 /
-.100566 -.117414 -.105239 -.052755  .095775  .110103 -.108955
 .099171 -.048003 -.060174 -.121810 1.000000 -.017200 -.014677
-.068377 -.041866 -.152936 -.033606 -.102385 -.049245 -.067407
-.001391  .003317 /
-.125521 -.133877 -.135618 -.073791  .121265  .134430 -.120590
 .109443 -.039601 -.057117 -.138336 -.017200 1.000000 -.002499
-.074430 -.032718 -.170225 -.031588 -.111231 -.042399 -.067941
```

```
 .003503  .012919 /
-.215021 -.242521 -.239373 -.129035  .208259  .231475 -.220745
 .201707 -.045235 -.081904 -.230606 -.014677 -.002499 1.000000
-.121683 -.032835 -.297473 -.044176 -.184410 -.051478 -.105673
 .013857  .037219 /
 .096991  .135585  .232389  .047871 -.097268 -.106968  .090388
-.083241 -.086600 -.031829  .082515 -.068377 -.074430 -.121683
1.000000 -.100778  .129153 -.022878  .050047 -.080668  .018745
-.052359 -.094760 /
-.162265 -.174871 -.135564 -.064215  .155774  .175711 -.158492
 .142751 -.081348 -.096470 -.182420 -.041866 -.032718 -.032835
-.100778 1.000000 -.224745 -.054262 -.155620 -.082701 -.103908
-.006377 -.002652 /
 .527735  .597390  .471823  .290735 -.495665 -.592373  .678204
-.602017 -.198255 -.043939  .345528 -.152936 -.170225 -.297473
 .129153 -.224745 1.000000 -.038678  .331827 -.161946  .055750
-.118814 -.250629 /
-.018326 -.016512 -.005767 -.018989  .019668  .017425 -.032388
 .027288 -.053699 -.042672 -.047189 -.033606 -.031588 -.044176
-.022878 -.054262 -.038678 1.000000 -.034725 -.051432 -.034407
-.015845 -.026626 /
 .325999  .289221  .244163  .159606 -.289443 -.361498  .229523
-.232645 -.142846 -.048811  .145189 -.102385 -.111231 -.184410
 .050047 -.155620  .331827 -.034725 1.000000 -.116227 -.005499
-.072204 -.147208 /
-.104177 -.103823 -.090368 -.039251  .101521  .112660 -.123644
 .111025 -.088513 -.089344 -.139444 -.049245 -.042399 -.051478
-.080668 -.082701 -.161946 -.051432 -.116227 1.000000 -.091390
-.014532 -.021516 /
 .035110  .060712  .088114 -.061415 -.038258 -.041911  .075302
-.071980 -.092816 -.052768 -.001282 -.067407 -.067941 -.105673
 .018745 -.103908  .055750 -.034407 -.005499 -.091390 1.000000
-.043774 -.075560 /
-.084683 -.094249 -.104570 -.040217  .081682  .091867 -.087073
 .079912 -.012545 -.029967 -.089666 -.001391  .003503  .013857
-.052359 -.006377 -.118814 -.015845 -.072204 -.014532 -.043774
1.000000  .019459 /
-.171605 -.244053 -.197849 -.110568  .167621  .186672 -.187150
 .170012 -.013988 -.053003 -.188113  .003317  .012919  .037219
-.094760 -.002652 -.250629 -.026626 -.147208 -.021516 -.075560
 .019459 1.000000;

COV=CORR;
DO I=1 TO 23;
  COV(I,)=CORR(I,)#SEB;
  END;
DO J=1 TO 23;
  COV(,J)=COV(,J)#SEB';
  END;

******* SIGMA2 IS VARIANCE IN MEAN DUE TO INDIVIDUAL FIRM VARIATION;
******* N IS NUMBER OF OBSERVATIONS FOR EACH UTILITY;
```

```
SIGMA2=
1 1 1 1 1 1 1 1 1 1;
SIGMA2=SIGMA2#.01105197;
N=
88 438 335 159 16 175 65 395 89 51;
SIGMA2=SIGMA2#/N;

******  STD ERR FOR SIC ONLY PREDICTIONS;

STDERR1=W(1:15,1:10)'*COV(9:23,9:23)*W(1:15,1:10);
STDERR1=DIAG(STDERR1);
STDERR1=STDERR1(+,)+SIGMA2;
STDERR1=STDERR1##.5;
PRINT STDERR1;

*******  CALCULATE PARTIAL F PARTIAL BETA PER BILL ROGERS;

DO I=1 TO 8;
  X(I,)=X(I,)#RCPRED1;
  END;
DO I=1 TO 15;
  W(I,)=W(I,)#MULT;
  END;

*******  CONCATENATE PRICE ETC MATRIX AND SIC PROPORTION MATRIX;

X=X//W(1:15,1:10);

*******  CALCULATE AND PRINT STANDARD ERRORS OF PREDICTIONS;

STDERR2=X'*COV*X;
STDERR2=DIAG(STDERR2);
STDERR2=STDERR2(+,)+SIGMA2;
STDERR2=STDERR2##.5;
PRINT STDERR2;
```

APPENDIX B

SELECTED CHARACTERISTICS OF THE MODELS SURVEYED

Study	Consumer Sector Evaluated	Time Period	Structure		Fuel Prices Used
			Equation Type	Equation Form	
	(1)	(2)	(3)	(4)	(5)
Houthakker-Verleger-Sheehan (1974)	R	1960-1969	Electricity	log-linear	none
Baughman-Joskow (1975)	R	1969	Total Energy Energy split Appliance	exponential logit logit	 natural gas, number 2 fuel oil
Halvorsen (1975)	R	1961-1969	Electricity	log-linear, exponential (price variable logged)	all types of residential gas
Wilder-Willenborg (1975)	R	1973	Electricity	mixed log-linear, exponential (price variable logged)	none
Hyndman-Mathewson (1975)	R	1958-1971	Energy split Electricity	linear	oil, natural gas
Battalio-Kagel-Winkler-Winett (1976)	R	1975	NA	NA	NA
Cohn-Hirst-Jackson (1977)	R	1951-1974	Electricity	log-linear	natural gas, fuel oil
Fuss-Hyndman-Waverman (1977)	R	1958-1971	Electricity	mixed log-linear, exponential	none
	C	1960-1971	Electricity	linear	Price variable expressed as a ratio of electricity to a substitute fuel: natural gas, coal or oil
	I	1961-1971	Total energy Energy split	translog	coal, liquified petroleum gas, fuel oil, natural gas, motor gasoline
McFadden-Puig-Kirshner (1977)	R	1975	Electricity Appliance	log-linear logit	none natural gas
Taylor-Blattenberger-Verleger (1977)	R	1956-1972	Electricity	log-linear	natural gas
	R	1961-1972	Appliance	log-linear for all appliances except linear for refrigerators	natural gas

SELECTED CHARACTERISTICS OF THE MODELS SURVEYED

Study	Consumer Sector Evaluated	Time Period	Structure		Fuel Prices Used
			Equation Type	Equation Form	
	(1)	(2)	(3)	(4)	(5)
Lyman (1978)	R	1959-1968	Electricity	linear, log-linear, exponential and mixed log-linear, exponential	natural gas
	C,I	1961-1968			
Chern-Just-Holcomb-Nguyen (1978)	R,C,I	1955-1974	Electricity	mixed log-linear, exponential (price variable logged)	natural gas: R,C,I; number 2 fuel oil: R,C; number 6 fuel oil: I; coal: I
Yang (1978)	R	1962-1975	Electricity	log-log	natural gas
Parhizgari-Davis (1978)	R	1964-1974	Electricity	log-log	none
Denny-Fuss-Waverman (1979)	I	1962-1975	Energy split Electricity	mixed log-linear	4 different types of oil, coal, coke, natural gas
Houthakker (1979)	R	1964-1976	Electricity	log-log	natural gas
Walker (1979)	R	1972-1975	Electricity	log-log	none
Pindyck (1979)	R	1960-1974	Total Energy Energy split	translog	solid fuel, liquid fuel, gas
	I	1963-1973	Total Energy Energy split	translog	solid fuel, liquid fuel, gas
Spann-Beauvais (1979)	All	1960-1973	Electricity	mixed log-linear	number 6 fuel oil
Smith (1980)	R	1957-1972	Electricity	log-linear	natural gas
Wang-Chern (1980)	I	1959-1976	Electricity	double-logarithmic	oil, coal, natural gas
Sahi-Erdman (1980	R,C,I	1963-1974	Energy split	double-logarithmic	oil, natural gas
Berndt-May-Watkins (1980)	R,C,I	1961-1976	Energy split Electricity	linear, log-linear mixed log-linear	combined "other" energy
Nemetz-Hankey-Zethoff (1980) (Reviews other studies)	R	1958-1971	Electricity	double-logarithmic, exponential, non-linear	none, heating oil natural gas
Chern-Dick-Gallagher-Holcomb-Just-Nguyen (1980) (Obtained from Chern et al., 1982)	R,C,I	1955-1976	Electricity	dynamically specified logarithmic Koyck	number 2 fuel oil, natural gas for R & C number 6 fuel oil, coal, and natural gas for I
Acton-Mitchell-Schlberg (1980)	R	1972-1974	Electricity	linear	natural gas

SELECTED CHARACTERISTICS OF THE MODELS SURVEYED

Study	Consumer Sector Evaluated	Period	Structure		Fuel Prices Used
			Equation Type	Equation Form	
	(1)	(2)	(3)	(4)	(5)
Hartman-Werth (1981)	R	1960-1975	Electricity	linear	none
Wills (1981)	R	1975	Electricity	linear	natural gas
Roth (1981)	R	1974-1977	Electricity	linear, log-log	natural gas
Common (1981)	R	1968-1978	Electricity	log-log	none
Besen-Kirby-Negri-Wetzel (1981)	R	1973,1975, 1976,1978-79	Electricity	linear	none
Cocke-Smith-Johnston-Howard (?)	R	1975-1979	Electricity	log-log	none
Betancourt (1981)	All	1972-1975	Electricity	mixed log-linear	none
Chung-Aigner (?)	C,I	1975-1979	Electricity	translog	none
Colombia-Pacific Resources Group, Ltd. (1981)	All	NA	Energy split	NA	NA
Dent-Kim-Chan-Felipe-Flynn-Ioannov (1982)	I	1975-1980	Electricity	spline	fuel oil, natural gas
Archibald-Finifter-Moody (1982)	R	1975	Electricity	linear	none
McRae-Webster (1982)	I	1962-1976	Energy split	translog	natural gas, fuel oil, coal, motor gasoline, LPG
Chern-Just-Chang (1982)	R,C,I	1955-1976	Electricity	mixed log-linear	none
Helliwell-Margolic (1982)	All	1961-1980	Energy split	mixed log-linear	oil, gas
Lillard-Acton (1982)	R	1975-1977	Electricity	mixed log-linear	none

Note: NA indicates not available or not applicable.
R: Residential; C: Commercial; I: Industrial;
All: Non-differentiated total demand.

RESIDENTIAL SECTOR PRICE AND INCOME ELASTICITIES

Date	Study	Data Type	Data Time Period	Price Elasticity Short-Run	Price Elasticity Long-Run	Income Elasticity Short-Run	Income Elasticity Long-Run	Type of Price	Notes
		(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
May 1974	Houthakker-Verleger-Sheehan	CS-TS: USA, States	1960-1971	-0.03/-0.09	-0.45/-1.20	0.13/0.15	1.60/2.20	M	
Feb 1975	Halvorsen[1]	CS-TS: USA, States	1961-1969	---	-1.00/-1.21	---	0.47/0.54	M*	[1]Results for structural equations.
May 1975	Hyndman-Mathewson	CS-TS: 4 Canadian Provinces	1958-1971	---	-0.107	---	0.332	A	
Dec 1976	Battalio-Kagel-Winkler-Winett	NA	1975	0.0/-0.15[2]	---	---	---	NA	[2]Price changes are experimentally induced.
Jan 1977	Taylor-Blattenberger-Verleger[3]	CS-TS: USA, States	1956-1972 1956-1972	-0.07/-0.08 -0.16/-0.66	-0.81/-0.82 -0.46/-0.30	0.09/0.10 0.22/0.57	1.05/1.08 1.00/1.36	M	[3]First row of values, flow adjustment models. Second row, capital-stock models. Based on Anderson; not independently reviewed.
Mar 1977	Cohn-Hirst-Jackson	CS-TS: USA, States	1951-1974 1960-1974 1965-1974 1969-1974	-0.14 -0.20 -0.16 -0.14	-1.16 -0.89 -0.78 -0.47	0.02 0.10 0.06 0.16	0.16 0.46 0.43 0.56	A	
Aug 1977	McFadden-Puig-Kirshner	CS: USA, Households	1975	---	-0.66/-0.73	---	0.39	M	[4]Elasticity calculated for Ontario, 1971, not significant at .05 level.
1977	Fuss-Hyndman-Waverman	CS-TS: Canada, Provinces	1958-1971	-0.14[4]		(positive)[5]		M	[5]Statistically significant at better than 0.01.
July 1978	Yang	CS-TS: USA, States	1962-1975	-0.567		0.309		M	

RESIDENTIAL SECTOR PRICE AND INCOME ELASTICITIES

Date	Study	Data		Price Elasticity		Income Elasticity		Type of Price	Notes
		Type	Time Period	Short-Run	Long-Run	Short-Run	Long-Run		
		(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
Oct 1978	Chern-Just-Holcomb-Nguyen[6]	CS-TS: USA, States by census region	1955-1974	-0.33 -0.22 -0.35 -0.27 -0.31 -0.47 -0.57 -0.19 -0.08	-1.50 -0.60 -1.22 -0.73 -1.12 -0.95 -1.07 -0.43 -0.37	0.07 0.34 0.06 -0.01 0.21 0.30 0.27 0.45 0.01	0.32 0.91 0.19 -0.02 0.77 0.61 0.51 1.03 0.04	A	[6] First row of values, New England; second row, Mid Atlantic; third row, East North Central; fourth row, West North Central; fifth row, South Atlantic; sixth row, East South Central; seventh row, West South Central; eighth row, Mountain; ninth row, Pacific. Results are for third stage least squares (3SLS).
Dec 1978	Parhizgari-Davis	CS-TS: USA, States	1964-1974	-0.04[7] -0.15 -0.19	---	0.71	---	M	[7] Elasticities are for 3 marginal block prices.
1978	Lyman[8]	CS-TS: USA, Areas served by 67 utilities for 10 geographic regions	1959-1968	---	-1.02 -1.15 -0.13 -1.05 -0.82 -1.17 -1.13 -0.58 -1.36 -0.19	---	0.17 0.55 0.24 0.35 0.30 0.08 -2.07 -2.14 -0.54 0.11	A	[8] Elasticities are for the following regions: West Coast, Northwest, North Midwest, Midwest, Middle Atlantic, Southwest, North Texas, South Texas, South, Florida and Gulf. Calculated at sample means.
June 1979	Houthakker	CS-TS: USA, States	1964-1976	-0.111	-1.4	0.139	1.8	M	
1979	Walker	TS: A Texas community residents	1972-1975	-0.14	---	0.74	---	M	
1979	Pindyck[9]	CS: 9 OCED countries	1960-1974	---	-0.30/-0.39 -0.25/-0.30	---	1.00[10] 1.00[10]	A	[9] First row of values is for Canada; second for U.S. at 1965 and 1973 means. [10] Constrained to unity by assumption.
1979	Spann-Beauvais	TS: A Virginia utility	1960-1973	-0.31[11]	-0.44[11]	0.64[11]	0.91[11]	M	[11] Peak demand elasticities.
1980	Acton-Mitchell-Sohlberg	CS-TS: Los Angeles County census tracts	-1974	-0.35	-0.70[12]	0.38	0.40[12]	M	[12] ...luding March-April 1974 ...ings in which DWP curtail- ...ordinance was in effect.

RESIDENTIAL SECTOR PRICE AND INCOME ELASTICITIES

Date	Study	Data		Price Elasticity		Income Elasticity		Type of Price	Notes
		Type	Time Period	Short-Run	Long-Run	Short-Run	Long-Run		
		(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
Apr 1980	Smith[13]	TS: 27 Investor-owned utilities	1957-1972	-0.11/-1.57		0.21/1.62		A	[13] The results are for 2SLS. The range indicates values across 27 utilities.
1980	Sahi-Erdmann	CS-TS: 7 Canadian regions	1963-1974	---	-0.988	---	---	A	
1980	Brendt-May-Watkins	TS: Alberta	1961-1976	-0.24	-0.6	0.37	0.95	A,M	
Apr 1980	Nemetz-Hankey-Zethoff	CS-TS: Canadian Atlantic Provinces	1958-1971	---	-0.29[14] -0.19[15]	---	---	A,M	[14] From Fuss-Waverman (1975) per household. [15] From Fuss-Hyndman-Waverman (1977) per household.
1980	Chern-Dick-Gallagher-Holcomb-Just-Nguyen	CS-TS: USA, States	1955-1976	-0.210[16] -0.218 -0.349 -0.254 -0.299 -0.355 -0.392 -0.139 -0.076	-1.154 -0.618 -1.091 -0.700 -1.079 -0.728 -0.907 -0.373 -0.402	---	---	NA	[16] Rows are for New England, Middle Atlantic, East North Central, West North Central, South Atlantic, East South Central, West South Central, Mountain and Pacific States, respectively.
Sor 1981	Lillard-Acton	CS-TS: Individual households Los Angeles	1975-1977	-0.0576		0.2[17]			[17] The principal long-run effects of income may act through housig value, appliances and pool ownership. Based on seasonal and non-time-of-day plans in the Los Angeles rate experiment.
May 1981	Hartman-Werth	CS-TS: USA, States	1960-1975	-0.19		0.9		M	
July 1981	Common	CS-TS: U.K.	1968-1978	-0.214	-0.212[18]	0.476	0.441[18]	A	[18] From a partial adjustment model which showed that .937 was the ratio of long-run to short-run elasticity.
1981	Roth	TS: A south-western utility, residents in U.S.	1974-1977	-0.11[19]				A,M	[19] The elasticity is for marginal price. Average price elasticity is +0.39.

RESIDENTIAL SECTOR PRICE AND INCOME ELASTICITIES

Date	Study	Data		Price Elasticity		Income Elasticity		Type of Price	Notes
		Type	Time Period	Short-Run	Long-Run	Short-Run	Long-Run		
		(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
Aug 1981	Beaen-Kirby-Megri-Wetzel	CS: USA	1973, 1975, 1976, 1978-1979[20]	-0.40	-0.90	0.13	0.22	M	[20] 4 different data sets are used. The results reported here are for the most recent years (i.e., 1978-79).
1981	Betancourt	CS-TS: 6 U.S. utilities in different census regions	1972-1975[21]	-0.17[22]	---	---	---	A	[21] He has also used 1972-1976 period but obtained unexpected signs on some elasticities. [22] This is a peak demand elasticity and reflects only conservation, no shifting.
Oct 1981	Wills	CS: Massachusetts districts	1975		-0.27			M	
Nov 1981	Colombia-Pacific Resources Group, Ltd.	Canada	NA	-0.47[23]				NA	[23] Peak demand elasticity.
	Cocke-Smith-Johnston-Howard	TS: California	1975-1979	-0.15	---	---	---	A	
Jan 1982	Helliwell-Margolic	CS-TS: 4 Canadian regions	1961-1980[24]	---	-0.53	---	---	F	[24] For some equations 1955-1980 data was used.
June 1982	Chern-Just-Chang	CS-TS: USA, States	1955-1976	-0.48[25] -0.39	---	0.15	---	A,M	[25] These elasticities refer to average and marginal price elasticities, respectively.
1982	Archibald-Finifter-Moody	CS: USA, States	1975	-0.39	---	0.11	---	M	

Note: A indicates average price.
M indicates marginal price.
M* indicates a theoretical model in which both average and marginal price elasticities are identical (price data was A or F).
F indicates a price for a fixed amount of electricity, either average or marginal price.
NA indicates not available or not applicable.
TS indicates time-series data.
CS indicates cross-sectional data.
CS-TS indicates pooled CS and TS data.
Elasticities [illegible] in short- and long-run columns are ambiguously defined in the refer[illegible] cited.

LONG-RUN APPLIANCE SATURATION PRICE ELASTICITIES

Date	Study	Data		Long-Run Price Elasticities								Notes
		Type	Time Period	Heater	Cooking Fuel	Clothes Dryers	Space Heating	Food Freezing	Air Conditioning: Room	Air Conditioning: Central	Dishwashing	
Feb 1975	Baughman-Joskow	CS: USA, States	1969	-1.77	-0.78	-0.53	-2.08	NA	NA	NA	NA	
Jan 1977	Taylor-Blattenberger-Verleger[1]	CS-TS: USA, States	1960-1972	-0.26	-0.45	0.11	-0.87	-0.32	-0.42	-0.56	NA	[1] Based on Anderson's review. Not independently verified.
Aug 1977	McFadden-Puig-Kirshner	CS: Households	1975	-1.95	NA	NA	-2.95[2]	NA	-0.17[3]	NA	NA	[2] Value is for water and space heating. Elasticity is positive for space heating alone. [3] Not specified whether room, multiple room or central.

Note: NA indicates not available.
CS indicates cross-sectional data.
CS-TS indicates pooled cross-sectional and time-series data.
Elasticities are evaluated at sample mean

COMMERCIAL SECTOR PRICE AND OUTPUT ELASTICITIES

Date	Study	Data		Price Elasticity		Output Elasticity		Notes
		Type	Time Period	Short-Run	Long-Run	Short-Run	Long-Run	
		(1)	(2)	(3)	(4)	(5)	(6)	(7)
1977	Fuss-Hyndman-Waverman	CS-TS: Canada, Provinces	1960-1971		-0.31	(positive) [1]		[1] Elasticity with respect to retail sales; statistically significant at better than 0.01 level.
1978	Lyman [2]	CS-TS: USA, Areas served by utilities for 10 regions	1961-1968	-3.64 -0.92 -1.33 -2.60 -1.15 -0.27 -4.56 -1.15 -0.75 -0.65		---	1.00 [3]	[2] Figures in Col. (4) pertain to regions. Elasticities are for the following areas: West Coast, Northwest Mid Northwest, Mid-west, Middle Atlantic Southwest, North Texas, South Texas, South, Florida and Gulf. [3] Number of customers. Constrained to unity by assumption. Elasticity with respect to income per house-hold not reported.
Oct 1978	Chern-Just-Holcomb-Nguyen [4]	CS-TS: USA, states by census regions	1955-1974	-0.47 -0.33 -0.43 -0.09 -0.39 -0.66 -0.25 -0.48 -0.40	-1.31 -0.51 -1.60 -1.02 -1.27 -1.29 -1.60 -0.90 -0.66	0.25 [5] 1.22 [5] 0.20 NA 0.33 [5] 0.33 [5] 0.03 [5] NA 0.31 [5] 0.18 [6] 0.51 [6] 0.08 [6] 0.02 [7] 0.10 [6] 0.20 [7] 0.03 [6] 0.54 [7] 0.78 [7]	0.70 [5] 1.88 [5] 0.76 NA 1.09 [5] 0.65 [5] 0.20 NA 0.52 [5] 0.51 [6] 0.78 [6] 0.30 [7] 0.25 [6] 0.34 [7] 0.39 [6] 0.17 [7] 1.01 [7] 1.31 [7]	[4] First row, New England; second row, Mid Atlantic; third row, East North Central; fourth row, West North Central; fifth row, South Atlantic; sixth row, East South Central; seventh row, West South Central; eighth row, Mountain; ninth row, Pacific. Results are for third stage least squares. [5] Real income per capita. [6] Population. [7] Number of customers. Note 6 and 7 not reviewed.

COMMERCIAL SECTOR PRICE AND OUTPUT ELASTICITIES

Date	Study	Data		Price Elasticity		Output Elasticity		Notes
		Type	Time Period	Short-Run	Long-Run	Short-Run	Long-Run	
		(1)	(2)	(3)	(4)	(5)	(6)	(7)
1980	Sahi-Erdmann	CS-TS: 7 Canadian regions	1963-1974	---	-1.388	---	---	
1980	Brendt-May-Watkins	TS: Alberta	1961-1976	-0.95/-0.84 [8]	---	---	---	[8] These elasticities refer to 1961 and 1976, respectively.
1980	Chern-Dick-Gallagher-Holcomb-Just-Nguyen	CS-TS: U.S. states	1955-1976	-0.294 [9] -0.208 -0.289 -0.172 -0.355 -0.589 -0.171 -0.438 -0.205	-1.508 -0.348 -1.410 -1.154 -1.176 -1.201 -1.425 -0.873 -0.366	---	---	[9] Rows are for New England, Middle Atlantic, East North Central, West North Central, South Atlantic, East South Central, West South Central, Mountain and Pacific States, respectively.
June 1982	Chern-Just-Chang	CS-TS: U.S. states	1955-1976	-0.58 [10]		0.94		[10] Mean of average price elasticities for the states.
?	Chung-Aigner	TS: 64 large customers of PGE	1975-1979	-0.079 [11]				[11] Non-weighted average of peak price elasticities.

Note: NA indicates not available, or not applicable.
TS indicates time-series data.
CS indicates cross-sectional data.
CS-TS: indicates pooled CS and TS data.

INDUSTRIAL SECTOR PRICE AND OUTPUT ELASTICITIES

Date	Study	Data		Price Elasticity		Output Elasticity		Notes
		Type	Time Period	Short-Run	Long-Run	Short-Run	Long-Run	
		(1)	(2)	(3)	(4)	(5)	(6)	(7)
1977	Fuss-Hyndman-Waverman	CS-TS: Canada, 5 Regions	1961-1971		-0.74 [1]		--- [2]	[1] Mean value for Ontario 1961-1971 [2] Not reported. Electricity cost share declines as output increases indicating a value below 1.00.
1978	Lyman [3]	CS-TS: USA, Areas served by utilities for 10 regions	1961-1968	-0.86 -1.59 -2.31 -0.44 -1.64 -1.07 -3.52 -1.67 -2.58 -0.27		---	1.00 [4]	[3] Figures in Col. (4) pertain to regions including West Coast, Northwest, North Midwest, Midwest, Middle Atlantic, Southwest, North Texas, South Texas, South, Florida and Gulf. [4] Number of customers. Constrained to unity by assumption. Elasticity with respect to income per household not reported.
Oct 1978	Chern-Just-Holcomb-Nguyen [5]	CS-TS: USA, Regions	1955-1974	-0.06 -0.02 -0.32 -0.26 -0.15 -0.28 -0.10 -0.19 -0.03	-0.16 -0.04 -0.54 -0.87 -0.71 -0.55 -0.62 -0.39 -0.09	0.50 1.01 0.74 0.25 0.21 0.48 0.17 0.38 0.32	1.14 1.55 1.28 0.83 1.03 0.96 1.03 0.80 0.90	[5] The first row of values is for New England; second row, Mid Atlantic; third row, East North Central; fourth row, West North Central; fifth row, South Atlantic; sixth row, East South Central; seventh row, West South Central; eighth row, Mountain; ninth row, Pacific. Results are for third stage least squares (3SLS).
1979	Pindyck [6]	CS-TS: 9 OCED Countries	1959-1974	---	-0.61 -0.63	---		[6] First row gives elasticities for Canada; second for U.S.

INDUSTRIAL SECTOR PRICE AND OUTPUT ELASTICITIES

Date	Study	Data		Price Elasticity		Output Elasticity		Notes
		Type	Time Period	Short-Run	Long-Run	Short-Run	Long-Run	
		(1)	(2)	(3)	(4)	(5)	(6)	(7)
Aug 1979	Denny-Fuss-Waverman	CS-TS: 20 Canadian industries in 4 provinces	1962-1975	-0.531 [7]	-0.618 [7]	---	---	[7] Non-weighted averages for 20 industries.
May 1980	Chang-Chern [8]	TS: USA, 16 industries	1959-1976	-0.61	-1.14	0.40	0.76	[8] Elasticities are unweighted averages for 16 industries.
May 1980	Brendt-May-Watkins	TS: Alberta	1961-1976	-1.15/-1.04 [9]				[9] These elasticities refer to 1961 and 1976, respectively.
1980	Sahi-Dermann	CS-TS: 7 Canadian regions	1963-1974	---	-0.799			
1980	Chern-Dick-Gallagher-Holcomb-Just-Nguyen	CS-TS: U.S. states	1955-1976	-0.038 [10] -0.081 -0.391 -0.172 -0.077 -0.298 -0.111 -0.201 -0.041	-0.114 -0.114 -0.594 -0.595 -0.433 -0.541 -0.481 -0.421 -0.104			[10] Data are for New England, Middle Atlantic, East North Central, West North Central, South Atlantic, East South Central, West South Central, Mountain and Pacific States, respectively.
May 1982	Dent-Kim-Chan-Felipe-Flynn-Ioannou	TS: For 11 Ontario industries	1975-1980	-0.203/-0.183 [11] -0.213/-0.219 -0.185/-0.193	---	2.187/2.171	---	[11] Winter/summer noon hour price elasticities in 1975, 1978, 1980, respectively, in each row.
1982	McRae-Webster	CS-TS: [12] Canada	1962-1976	-0.39 [13] -0.26 0.00 -0.29 -0.32				[12] Results without pooling across regions were better. [13] Elasticities are for Atlantic, Quebec, Ontario, Prairies, and British Columbia, respectively.

INDUSTRIAL SECTOR PRICE AND OUTPUT ELASTICITIES

Date	Study	Data		Price Elasticity		Output Elasticity		Notes
		Type	Time Period	Short-Run	Long-Run	Short-Run	Long-Run	
		(1)	(2)	(3)	(4)	(5)	(6)	(7)
June 1982	Chern-Just-Chang	CS-TS: U.S. states	1955-1976	-0.51[14] -0.85	-1.17[14] -1.92			[14]Average price elasticities for New York and Nevada, respectively. These span the range.
?	Chung-Aigner	TS: 64 large customers of PGE	1975-1979	-0.11[15]	---	---	---	[15]Non-weighted averages of peak price elasticities.

Note: TS indicates time-series data.
CS indicates cross-sectional data.
CS-TS indicates pooled CS-TS data.
Elasticities between short- and long-run columns are ambiguously defined in the reference cited.

APPENDIX C

SAMPLE SIZE 15062
SUM OF WEIGHTS . . . . . 1.5797D+03
ESTIMATED STD DEV . . . . . 1.4604D+00
R SQUARED 0.2010

VARIABLE	COEFFICIENT	ESTD STD DEV	T
0	-1.6473D+00	3.2099D-01	-5.1317
2 P1	-7.0257D-02	2.6472D-02	-2.6540
3 P2	-1.8872D-02	2.4378D-02	-0.7741
4 P3	5.0783D-02	2.2375D-02	2.2696
5 P4	8.5116D-02	2.7910D-02	3.0497
6 P5	8.8100D-02	3.3212D-02	2.6527
7 OWNER	1.1495D-01	8.5951D-02	1.3374
8 VALUE	1.6584D-01	2.6978D-02	6.1472
9 RENT	3.5153D-01	5.0985D-02	6.8948
10 INC	-3.8733D-02	2.2961D-02	-1.6869
11 HOMEWD	1.0630D-01	2.5499D-02	4.1689
12 HOMEWE	-7.4152D-02	2.8038D-02	-2.6447
13 HOMEWN	8.1289D-04	4.3521D-02	0.0187
14 ACWD	1.4840D-01	3.5702D-02	4.1567
15 APPL	5.8734D-01	3.4689D-02	16.9317
16 POOL	-1.1191D+00	6.1906D-01	-1.8077
17 SIZE	2.5064D-01	9.7075D-02	2.5819
22 ROOMS	2.1486D-01	6.6248D-02	3.2433
23 FAM	2.3126D-01	2.6677D-02	8.8684
24 ARCDT	1.5213D-02	1.9721D-02	0.7715
25 HEATT	8.0846D-02	3.0893D-02	2.6170
32 DEL	5.8587D-02	2.8008D-02	2.0917
33 LAMBDA	-5.8223D-01	1.7944D-01	-3.2448
35 ARCD>0	-1.2220D-01	1.9981D-01	-0.6116
36 HEAT>0	-7.2523D-01	2.5473D-01	-2.8471
39 RMARCD>	-2.5071D-01	1.1554D-01	-2.1700
40 RMARCDT	3.5360D-02	1.1194D-02	3.1540
37 RMHEAT>	2.8819D-01	1.4846D-01	1.9413
38 RMHEATT	-2.1051D-02	1.7894D-02	-1.1764
45 P1.ARCDT	-2.7775D-03	5.1755D-03	-0.5367
44 P1.ARCD>	5.7578D-02	5.4669D-02	1.0532
47 P1.HEATT	-3.3801D-02	1.4496D-02	-2.3317
46 P1.HEAT>	-4.6578D-02	1.0474D-01	-0.4447
41 P1.POOL	-1.8592D-01	6.7648D-01	-0.2748
42 P1.SIZE	-1.5057D-02	1.0639D-01	-0.1415
43 P1.APPL	3.1170D-02	3.5594D-02	0.8757

26 K1 DEPENDENT VARIABLE

ANALYSIS OF VARIANCE

SOURCE	DF	SS	MS	F
REGRESSION	35	8.0619D+03	2.3034D+02	108.000
ERROR	15026	3.2047D+04	2.1328D+00	
TOTAL	15061	4.0109D+04		

SAMPLE SIZE 15062
SUM OF WEIGHTS . . . . . 1.6367D+03
ESTIMATED STD DEV . . . . . 1.5281D+00
R SQUARED 0.2520

VARIABLE		COEFFICIENT	ESTD STD DEV	T
0		-1.3547D+00	3.3675D-01	-4.0230
2	P1	6.2621D-03	1.8311D-02	0.3420
3	P2	-2.4697D-02	3.4493D-02	-0.7160
4	P3	1.1784D-02	2.3415D-02	0.5032
5	P4	6.2154D-02	2.9237D-02	2.1259
6	P5	1.9560D-02	3.4789D-02	0.5623
7	OWNER	9.9779D-02	8.9897D-02	1.1099
8	VALUE	1.4361D-01	2.8281D-02	5.0779
9	RENT	3.0150D-01	5.3411D-02	5.6449
10	INC	-5.4330D-02	2.4086D-02	-2.2557
11	HOMEWD	1.0952D-01	2.6767D-02	4.0915
12	HOMEWE	-8.0258D-02	2.9427D-02	-2.7274
13	HOMEWN	6.5947D-03	4.5819D-02	0.1439
14	ACWD	1.9281D-01	3.7440D-02	5.1500
15	APPL	5.1531D-01	3.5189D-02	14.6440
16	POOL	-1.0056D+00	5.4313D-01	-1.8514
17	SIZE	2.2918D-01	8.5083D-02	2.6937
22	ROOMS	2.5040D-01	6.9447D-02	3.6057
23	FAM	2.8118D-01	2.7321D-02	10.2916
24	ARCDT	6.4451D-02	2.1917D-02	2.9407
25	HEATT	8.5422D-02	3.0635D-02	2.7884
32	DEL	5.6945D-02	2.9378D-02	1.9384
33	LAMBDA	-5.9861D-01	1.8828D-01	-3.1793
35	ARCD>0	-3.9257D-01	2.1688D-01	-1.8101
36	HEAT>0	-5.9246D-01	2.5335D-01	-2.3385
39	RMARCD>	-5.4346D-01	1.2534D-01	-4.3358
40	RMARCDT	6.2496D-02	1.2425D-02	5.0300
37	RMHEAT>	2.4160D-01	1.5733D-01	1.5356
38	RMHEATT	-2.8021D-02	1.9968D-02	-1.4033
52	P2.ARCDT	-3.4305D-02	6.6970D-03	-5.1225
51	P2.ARCD>	2.2255D-01	6.8866D-02	3.2317
54	P2.HEATT	-4.0377D-02	1.4798D-02	-2.7286
53	P2.HEAT>	3.8349D-02	1.0967D-01	0.3497
48	P2.POOL	-7.6584D-02	9.0551D-01	-0.0846
49	P2.SIZE	-3.3574D-02	1.4145D-01	-0.2373
50	P2.APPL	-4.0663D-02	4.4389D-02	-0.9161

27 K2 DEPENDENT VARIABLE

ANALYSIS OF VARIANCE

SOURCE	DF	SS	MS	F
REGRESSION	35	1.1821D+04	3.3774D+02	144.642
ERROR	15026	3.5086D+04	2.3350D+00	
TOTAL	15061	4.6907D+04		

SAMPLE SIZE 15062
SUM OF WEIGHTS . . . . . 1.7833D+03
ESTIMATED STD DEV . . . . . 1.4021D+00
R SQUARED 0.2437

VARIABLE		COEFFICIENT	ESTD STD DEV	T
0		-9.9538D-01	3.0853D-01	-3.2261
2	P1	1.3869D-02	1.6787D-02	0.8261
3	P2	3.1398D-03	2.3389D-02	0.1342
4	P3	-3.7327D-02	2.7990D-02	-1.3336
5	P4	3.7842D-02	2.6796D-02	1.4122
6	P5	2.7209D-02	3.1913D-02	0.8526
7	OWNER	6.7879D-02	8.2796D-02	0.8198
8	VALUE	1.3337D-01	2.5910D-02	5.1476
9	RENT	2.7700D-01	4.8996D-02	5.6535
10	INC	-5.8474D-02	2.2115D-02	-2.6442
11	HOMEWD	6.1002D-02	2.4469D-02	2.4930
12	HOMEWE	-4.9484D-02	2.6976D-02	-1.8344
13	HOMEWN	7.8621D-02	4.1796D-02	1.8810
14	ACWD	1.9595D-01	3.4374D-02	5.7004
15	APPL	5.1812D-01	3.0295D-02	17.1026
16	POOL	-9.4959D-01	4.9979D-01	-1.9000
17	SIZE	2.0316D-01	7.8309D-02	2.5944
22	ROOMS	2.5123D-01	6.3635D-02	3.9480
23	FAM	3.0297D-01	2.5051D-02	12.0942
24	ARCDT	3.4621D-02	2.2759D-02	1.5212
25	HEATT	3.0982D-02	3.2459D-02	0.9545
32	DEL	2.3171D-02	2.6943D-02	0.8600
33	LAMBDA	-6.5685D-01	1.7294D-01	-3.7982
35	ARCD>0	-1.1919D-01	2.1606D-01	-0.5517
36	HEAT>0	-2.6978D-01	2.3723D-01	-1.1372
39	RMARCD>	-6.5424D-01	1.2496D-01	-5.2357
40	RMARCDT	7.6650D-02	1.2928D-02	5.9292
37	RMHEAT>	2.1748D-02	1.4724D-01	0.1477
38	RMHEATT	2.8843D-02	2.1006D-02	1.3731
59	P3.ARCDT	-4.0674D-02	6.0468D-03	-6.7265
58	P3.ARCD>	3.0758D-01	6.0315D-02	5.0996
61	P3.HEATT	-1.5353D-02	1.3194D-02	-1.1637
60	P3.HEAT>	9.4023D-02	9.0845D-02	1.0350
55	P3.POOL	1.5805D+00	7.9188D-01	1.9959
56	P3.SIZE	-2.7224D-01	1.2361D-01	-2.2024
57	P3.APPL	-4.6653D-02	3.6036D-02	-1.2946

28 K3 DEPENDENT VARIABLE

ANALYSIS OF VARIANCE

SOURCE	DF	SS	MS	F
REGRESSION	35	9.5211D+03	2.7203D+02	138.370
ERROR	15026	2.9541D+04	1.9660D+00	
TOTAL	15061	3.9062D+04		

SAMPLE SIZE 15062
SUM OF WEIGHTS . . . . . 1.8200D+03
ESTIMATED STD DEV . . . . . 1.1814D+00
R SQUARED 0.2059

VARIABLE		COEFFICIENT	ESTD STD DEV	T
0		-2.1273D+00	2.6137D-01	-8.1389
2	P1	1.2059D-02	1.4148D-02	0.8523
3	P2	1.6381D-03	1.9718D-02	0.0831
4	P3	-1.6414D-02	1.8113D-02	-0.9062
5	P4	-4.6003D-02	2.7219D-02	-1.6901
6	P5	-1.0891D-02	2.6880D-02	-0.4052
7	OWNER	-1.2796D-02	6.9484D-02	-0.1842
8	VALUE	2.0592D-01	2.1809D-02	9.4421
9	RENT	4.1555D-01	4.1205D-02	10.0849
10	INC	1.6373D-02	1.8707D-02	0.8752
11	HOMEWD	-4.6101D-02	2.0640D-02	-2.2336
12	HOMEWE	-3.0043D-02	2.2686D-02	-1.3243
13	HOMEWN	1.0291D-01	3.5335D-02	2.9125
14	ACWD	9.8102D-02	2.8942D-02	3.3896
15	APPL	4.2643D-01	2.5623D-02	16.6425
16	POOL	-7.8741D-01	4.2561D-01	-1.8501
17	SIZE	1.5145D-01	6.6652D-02	2.2722
22	ROOMS	2.4186D-01	5.3574D-02	4.5144
23	FAM	2.7948D-01	2.1074D-02	13.2620
24	ARCDT	-4.1083D-02	1.9715D-02	-2.0838
25	HEATT	3.0082D-02	2.7766D-02	1.0834
32	DEL	4.0569D-02	2.2655D-02	1.7908
33	LAMBCA	-3.6677D-01	1.4684D-01	-2.4977
35	ARCD>0	4.6008D-01	1.8570D-01	2.4776
36	HEAT>0	-1.9339D-01	1.9950D-01	-0.9693
39	RMARCD>	-5.6520D-01	1.0727D-01	-5.2691
40	RMARCDT	6.5993D-02	1.1185D-02	5.9002
37	RMHEAT>	-3.6056D-02	1.2348D-01	-0.2920
38	RMHEATT	3.6743D-02	1.7975D-02	2.0441
66	P4.ARCDT	-2.9653D-02	5.5213D-03	-5.3706
65	P4.ARCD>	2.9930D-01	5.4073D-02	5.5351
68	P4.HEATT	-3.9351D-03	1.2740D-02	-0.3089
67	P4.HEAT>	-5.8399D-02	8.2007D-02	-0.7121
62	P4.POOL	6.0301D-02	6.5825D-01	0.0916
63	P4.SIZE	-3.3984D-02	1.0305D-01	-0.3298
64	P4.APPL	-2.0309D-02	3.0905D-02	-0.6571
29	K4	DEPENDENT VARIABLE		

ANALYSIS OF VARIANCE

SOURCE	DF	SS	MS	F
REGRESSION	35	5.4363D+03	1.5532D+02	111.295
ERROR	15026	2.0970D+04	1.3956D+00	
TOTAL	15061	2.6407D+04		

SAMPLE SIZE 15062
SUM OF WEIGHTS . . . . . 1.4849D+03
ESTIMATED STD DEV . . . . . 1.3079D+00
R SQUARED 0.1803

VARIABLE		COEFFICIENT	ESTD STD DEV	T
0		-9.7597D-01	2.8805D-01	-3.3882
2	P 1	-7.5210D-03	1.5640D-02	-0.4815
3	P 2	1.4121D-02	2.1814D-02	0.6473
4	P 3	1.6233D-02	2.0030D-02	0.8104
5	P 4	2.2899D-02	2.4970D-02	0.9170
6	P 5	-4.2884D-02	3.7419D-02	-1.1460
7	OWNER	1.1605D-01	7.6893D-02	1.5092
8	VALUE	1.6054D-01	2.4162D-02	6.6440
9	RENT	3.3953D-01	4.5632D-02	7.4406
10	INC	2.0606D-02	2.0599D-02	1.0003
11	HOMEWD	-1.1979D-02	2.2862D-02	-0.5240
12	HOMEWE	-2.9956D-02	2.5137D-02	-1.1917
13	HOMEWN	3.1611D-02	3.8991D-02	0.8107
14	ACWD	7.9599D-02	3.2007D-02	2.4870
15	APPL	4.9575D-01	4.0831D-02	12.1415
16	POOL	-2.0598D+00	7.5615D-01	-2.7241
17	SIZE	3.5516D-01	1.1870D-01	2.9922
22	ROOMS	2.9156D-01	5.9468D-02	4.9029
23	FAM	2.4380D-01	2.3335D-02	10.4475
24	ARCDT	-5.0241D-02	1.6317D-02	-3.0791
25	HEATT	1.1934D-01	2.5410D-02	4.6965
32	DEL	5.3846D-02	2.5112D-02	2.1442
33	LAMBDA	-3.7850D-01	1.6084D-01	-2.3532
35	ARCD>0	4.2504D-01	1.7336D-01	2.4518
36	HEAT>0	-4.0493D-01	2.4095D-01	-1.6806
39	RMARCD>	-3.2616D-01	9.6596D-02	-3.4800
40	RMARCDT	4.0499D-02	8.8943D-03	4.5534
37	RMHEAT>	1.8335D-01	1.3134D-01	1.3960
38	RMHEATT	-3.2855D-03	1.4095D-02	-0.2331
73	P5 .ARCDT	5.3085D-04	5.4783D-03	0.0969
72	P5 .ARCD>	-1.7024D-03	6.1738D-02	-0.0276
75	P5 .HEATT	-1.2830D-02	1.3244D-02	-0.9083
74	P5 .HEAT>	1.5563D-01	1.1444D-01	1.3600
69	P5 .POOL	-1.4566D+00	7.2661D-01	-2.0046
70	P5 .SIZE	2.1204D-01	1.1426D-01	1.8558
71	P5 .APPL	2.4716D-02	4.2812D-02	0.5773

30 K5 DEPENDENT VARIABLE

ANALYSIS OF VARIANCE

SOURCE	DF	SS	MS	F
REGRESSION	35	5.6527D+03	1.6151D+02	94.422
ERROR	15026	2.5702D+04	1.7105D+00	
TOTAL	15061	3.1354D+04		

Table 2

VARIABLE DEFINITIONS

DEPENDENT VARIABLES

K1	log (kwh + 0.1) for 9 a.m.-noon weekdays
K2	log (kwh + 0.1) for noon-3 p.m. weekdays
K3	log (kwh + 0.1) for 3-6 p.m. weekdays
K4	log (kwh + 0.1) for 6-9 p.m. weekdays
K5	log (kwh + 0.1) for 9 p.m.-9 a.m. weekdays

INDEPENDENT VARIABLES

Price Variables

LP1	log (price during 9 a.m.-noon weekdays)
LP2	log (price during noon-3 p.m. weekdays)
LP3	log (price during 3-6 p.m. weekdays)
LP4	log (price during 6-9 p.m. weekdays)
LP5	log (price during 9 p.m.-9 a.m. weekdays)

Demographic Variables

ACWD	runs air conditioner weekdays
FAM	log (family size)
HOMEWD	adult home weekdays
HOMEWE	adult home weekends
HOMEWN	adult home weeknights
INC	log (income)
OWNER	dummy variable for owner
RENT	log (rent + 1.0)
ROOMS	log (rooms)
VALUE	log (home value + 1.0)

Weather Variables

ACT	average daily cooling degree hours
AHT	average daily heating degree hours

Appliance Variables

AIRCDT	log (weighted sum of air conditioner X ACT + 1.0)
APPL	log (appliance aggregate); see fn. 4 for def. of weights.
BWTV	black-and-white TVs
COLORTV	color TVs
COMBSTV	combined electric/natural gas stoves
DISHWASHER	has a dishwasher
EDRYER	has an electric dryer
ESTV	electric stoves
FFRIG	main refrigerator is frost-free
FRIG	refrigerators
FREEZE	has a freezer
GDRYER	has a gas dryer
HEATT	log (electric space heat AHT + 1.0)
POOL	has a swimming pool (apartment house pools excluded)
SCSTV	main stove is self-cleaning
WASHER	has a clothes washer

$$APPL = \log \left[\left(\sum_{i=1}^{12} \omega_i A_i \right) \right]$$

where ω_i is the weight and A_i is the number of appliances of type i.[1]

[1] The values of the weights used in this aggregation are frost-free refrigerator (106), manual defrost refrigerator (52), dishwasher (25), gas dryer (8), electric dryer (72), clothes washer (8), electric water heater (333), electric stove (87), combined electric/gas stove/oven (43), freezer (95), black and white TV (30), and color TV (30).