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Optional Time-of-Use Prices for Electricity: Analysis of PG&E's Experimental TOU Rates

by Kenneth Train and Gil Mehrez

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OPTIONAL TIME-OF-USE PRICES FOR ELECTRICITY: ANALYSIS OF PG&E'S EXPERIMENTAL TOU RATES

Final Report

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Abstract

We examine customers' time-of-use (TOU) demand for electricity and their choice between standard and TOU rate schedules. We specify an econometric model in which the customer's demand curves determine the customer's choice of rate schedule. We estimate the model on data from Pacific Gas & Electric Company's experiment with optional TOU prices in the residential sector. With the model, we compare the TOU consumption and price elasticities of customers who chose TOU rates with those who chose standard rates. We also estimate the impact of the TOU rates on the utility's revenues and costs. The analysis suggests that the TOU rates offered under PG&E's experiment decreased PG&E's profits and hence contributed to higher general rate levels. The model can be used, however, to design optional TOU rates that increase profits and lower general rate levels.

Optional Time-of-Use Prices for Electricity

by

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I. Introduction

Economists have argued for many years that electricity rates that vary by time of day should be implemented in place of non-time-differentiated rates (Houthakker, 1951; Boiteux, 1960; Williamson, 1966). Under these time-of-use (TOU) rates, prices are higher during the peak time of day, when electricity capacity is strained and marginal costs of production are higher, than in off-peak periods, when marginal costs are lower. By moving prices closer to marginal cost in each time period, economic efficiency is enhanced.

In practice, TOU prices for electricity have nearly always been offered on a voluntary basis, at least in the residential sector[1]. That is, instead of replacing non-time-differentiated rates with TOU rates, as economists generally have recommended, regulators have usually approved TOU rates only when they are offered to customers as an option, with each customer able to choose between the non-time-differentiated rates and the TOU rates.

The offering of optional TOU rates has spurred spirited controversy among intervenors in utility ratemaking proceedings and heated debate among researchers. The implications of optional TOU prices for economic efficiency, and, more directly, for the welfare of parties to the ratemaking proceedings, are not the same as those for mandatory TOU prices (Caves et al, 1987; Mackie-Mason, 1990; Train, 1988, 1991.) In particular, it is possible that the offering of optional TOU rates will decrease the utility's profits. This reduction in profits will either be passed onto shareholders in terms of lower returns or to ratepayers in the form of higher rates. California's energy utilities are regulated under the Electric Rate Adjustment Mechanism (ERAM), which requires that undercollection of revenues in one period be recouped in future periods; a similar mechanism oerates on the cost side. Consequently, in California, any loss to the utility that the optional TOU rates induce is borne by ratepayers.

Optional TOU rates need not reduce the utility's profits. Depending on customer's demand curves and other factors, the offering of optional TOU rates can increase the utility's profits and lead, under regulatory procedures like those in California, to a general rate reduction. Circumstances under which each of these two outcomes will occur are described in the following

[1] Boiteux (1988) reports that of the seven European countries with TOU electricity rates for residences, six offer them on an optional basis. Aigner (1988) recounts a similar story for the U.S., where optional TOU electricity rates are becoming fairly widespread while mandatory TOU rates, in the residential sector at least, have been applied nearly exclusively in experiments of limited coverage and duration. In the commercial and industrial sectors, mandatory TOU rates for electricity are more common, though optional applications still outnumber mandatory ones.

section.

The issue of whether optional TOU rates increase or decrease utility profits, and hence lead, under ERAM, to a general rate reduction or increase, is an empirical question. This question serves as the motivation for our analysis. In particular, we examine the optional TOU rates that Pacific Gas and Electric Company (PG&E) offered to its residential customers as part of an experiment on TOU pricing conducted in 1985-86. We estimate an econometric model of customers' TOU consumption and their choice between TOU and standard, non-time-differentiated rates. We use this model to determine whether the optional TOU rates that PG&E offered under this experiment increased or decreased PG&E's profits and hence contributed to a decrease or increase in general rates.

The next section describes, in broad terms, the conditions under which optional TOU rates can be expected to increase or decrease utility profits. Section III then describes the choice process of customers in deciding between TOU and standard rates; this discussion motivates the specification of the econometric model. Section IV describes PG&E's experiment with optional TOU rates and identifies the data that we use in our analysis. Section V presents the results of our model estimation. In section VI, the estimated model is used to determine whether the optional TOU rates that PG&E offered increased or decreased its profits. Directions for further analysis are enumerated in section VII. A technical appendix presents the detailed specification of the econometric model and describes the estimation procedure.

II. The Issue of Optional TOU Rates

As stated above, the offering of optional TOU rates can, depending on customers' demand curves and other factors, either increase or decrease the utility's profits. Consider first an extreme, but illustrative, example of how the offering of optional TOU rates can reduce a utility's profits. Suppose each customer has a fixed level of demand in each period of day. If optional TOU rates are offered, customers with relatively low peak consumption and relatively high off-peak consumption will choose the TOU rates, since their energy bills will decrease by doing so. Customers with relatively high peak consumption and low off-peak consumption will choose to remain on the standard rates since the TOU rates would cause them to have higher bills. Since the TOU consumption of each customer is fixed, the utility must still provide the same amount of electricity in each period as before the offering of the TOU rates; consequently, the utility's costs of production are the same. However, since the customers who chose TOU rates receive lower bills for their consumption, the revenues of the utility decrease. With lower revenues and the same costs, the utility's profits decline.

As stated above, the loss in utility profit need not be borne by the utility's shareholders. If, as in California, rates are adjusted to recoup the lost revenues, then rates rise for all customers. This means that customers who are on the standard rates are hurt, even though they did not change their consumption or choose the TOU rates.

The parties who oppose optional TOU rates are those who have the greatest chance of being harmed. In California, these are customers who expect not to choose TOU rates. Furthermore, and in many ways more importantly, customers in one sector can object to optional TOU rates being offered in other sectors. For example, advocates for residential customers have objected to optional TOU rates in the agricultural sector on the grounds that these rate options serve simply as rate reductions to the agricultural sector, which require that residential customers carry a larger burden for revenue requirements.

Optional TOU rates can reduce utility profits, and hence serve to raise rates generally, under far less extreme conditions than the example given above. In the example, customers were assumed to have fixed consumption in each time period, such that their consumption levels did not change under TOU prices. Actually, consumers can be price responsive and the same phenomenon occur. That is, optional TOU rates can decrease utility profits even if consumers are price sensitive. Suppose consumers who choose TOU prices reduce their consumption in the peak in response to the higher peak price. The utility's costs of producing will decline since it does not need to produce as much electricity in the expensive, peak period. However, this cost savings might be less than the loss of revenue that occurs from the customers receiving a lower bill under TOU rates; if the cost reduction is less than the revenues reduction, then profits will fall.

Optional TOU rates need not decrease utility profits: it is possible that profits will increase with the offering of optional TOU rates. An example will illustrate this possibility. Suppose that a group of customers can easily shift a large share of their consumption from the peak to the off-peak. If TOU rates were offered to these customers, they would choose them even if the price difference between peak and off-peak were very small. They would shift their consumption from the peak to the off-peak and, by doing so, obtain a lower energy bill. The utility's costs would drop since it is producing less in the peak and more in the off-peak, and these cost reductions would exceed the slight loss in revenues from these customers.

Optional TOU rates can therefore increase or decrease utility profits and hence either decrease or increase general rates under regulatory procedures like those in California. Which of these two events occurs depends, as the examples given above indicate, on (i) the extent to which the TOU rates provide a bill reduction for some customers at their current consumption levels, versus, (ii) the extent to which customers are willing and able to shift consumption in response to the TOU prices. If the former effect is larger, then the optional TOU rates will reduce profits; while profits will rise if the latter effect is larger.

An interesting result completes the picture. It has been shown that, in most situations, it is possible to design optional TOU rates that increase profits and hence can result in a general rate reduction (see Mackie-Mason, 1990, and Train, 1988). The design of these rates requires information on the marginal costs in each time period and the price responses of customers. However, even without this information, the result shifts the terms of the debate. Instead of discussing whether TOU rates are beneficial or harmful in general, the issue becomes: do particular TOU rates that have been proposed or offered increase or decrease utility profit? And what TOU rates can be offered that will increase utility profits and hence lead to a general rate reduction? These questions are the topic of our analysis.

III. Customer's Choice between TOU and Standard Rates

In this section we describe the standard economic theory of customer choice between optional rate schedules (Faulhaber and Panzar, 1977; Brown and Sibley, 1986; Train, 1991). This theory has implications for the appropriate specification of the empirical analysis.

Consider first a customer facing standard, non-time-differentiated rates for electricity. The customer obtains value from its consumption of electricity that is greater than the amount that the customer has to pay for the electricity (otherwise the customer would not consume any electricity.) The amount by which value exceeds the amount the customer pays is called the consumer surplus. As depicted in Figure 1, consumer surplus is the difference between the demand curve (which denotes the customer's willingness to pay) and the price (which is the amount that the customer is required to pay.)

Consider now two time periods, called the peak and the off-peak. The customer's demand in each period is shown in Figure 2. Under standard prices, which are the same in both period, the customer obtains surplus equal to the area ACD in the peak and the area FGK in the off-peak. Under TOU prices, the customer faces a higher price in the peak and lower price in the off-peak. In the peak the consumer obtains surplus equal to area ABE, which is less than the surplus he obtained in the peak under standard prices. The loss in surplus in the peak is the shaded area EBCD. In the off-peak the customer obtains surplus equal to area FHJ, which is greater than the surplus he obtained in the off-peak under standard prices. The gain in surplus in the off-peak is the shaded area KGHJ.

In accordance with standard economic concepts, the customer is assumed to choose the rates that provide him with the greater surplus. That is, the customer chooses TOU rates only if the surplus that he obtains under TOU rates exceeds the surplus that he obtains under standard rates. In the context of Figure 2, the customer chooses TOU rates only if the gain in surplus that arises because of the lower price in the off-peak (i.e., the shaded area in the off-peak graph) is greater than the loss in surplus from facing a higher price in the peak (i.e, the shaded area in the peak graph.)

Several implications for the empirical analysis are immediately obvious. First, the demand curves of the customer determine whether he chooses TOU rates. The econometric model that describes the customer's choice between TOU and standard rates should therefore depend on the customer's TOU demand curves. This dependence has been ignored in most previous work on optional TOU rates (Goett, 1988; Caves, et al., 1989).

Second, if all customers have the same demand curves in the peak and off-peak, then all customers will make the same choice; that is, either all customers will choose TOU rates or all customers will choose standard rates. Conversely, if some customers choose TOU rates and some choose standard rates, it must be the case that the demand curves for customers differ. This fact has important implications for the specification of the econometric model of electricity demand. Previous analyses of optional TOU rates have utilized models for which the expected demand for all customers with the same characteristics (such as income) were the same. These models imply, therefore, that all customers with the same characteristics will make the same choice between TOU and standard rates, which is inconsistent with observed choices. An econometric model is required that explicitly allows the demand curves for customers to differ. Furthermore, the distribution of demand curves needs to be estimated as well as the average demand.[2]

The relation between customers' demand curves and their choices between TOU and standard rates can be derived, at least qualitatively, from the analysis of Figure 2. In particular, the following results are obtained:

1. A customer with lower peak demand is <u>more likely</u> to choose TOU rates than a customer with higher peak demand, all else held equal. In Figure 2, shifting the demand curve in the peak period to the left reduces the loss of consumer surplus (i.e., points B and C move to the left such that area EBCD is smaller). With less loss, it is more likely that the gain in the off-peak will exceed the loss in the peak.

2. A customer with higher demand in the off-peak is <u>more likely</u> to choose TOU rates than a customer with lower off-peak demand, all else equal. Shifting the demand curve in the off-peak out to the right increases the gain in consumer surplus.

3. A customer with greater price response in the peak is <u>more likely</u> to choose TOU rates than a customer with less price response. In Figure 2, if the peak demand curve rotates around point C becoming less steep (i.e., point B moves to the left and point C stays the same), then the loss of consumer surplus becomes less. Note that a less steep demand curve represents greater price response.

4. A customer with greater price response in the off-peak is <u>more likely</u> to choose TOU rates than a customer with less price response. In Figure 2, a less steep demand curve in the off-peak (obtained by moving point H to the right and keeping G at the same place) increases the gain in surplus from TOU rates.

5. A customer with greater ability and willingness to shift consumption from the peak to the off-peak (that is, with greater cross-price response) is <u>more likely</u> to choose TOU rates than a customer who would not shift as readily. This result is not represented in Figure 2, which implicitly assumes no cross-price responses. However, it is clearly the case that any shifting of demand from the peak to the off-peak increases the gain in surplus in the off-peak and reduces the loss in the peak.

Results 3-5 are particularly important to the issue of whether optional TOU rates increase or decrease the utility's profits. As stated in section II, optional TOU rates necessarily reduce the utility's profits if customers have fixed demands with no price response. However, if customers are price responsive, then optional TOU rates can possibly increase utility profits and hence lead to a general rate reduction. Price responsive customers will, under TOU prices, decrease their consumption in the peak and increase their consumption in the off-peak. The utility benefits since the number of kWhs demanded in the peak period, which are relatively expensive to

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[2] Nearly all previous analyses of TOU demand have examined mandatory TOU rates, in which the distribution of demand curves is not critical and the task is to estimate average price responses. See, for example, the articles edited by Lawrence and Aigner (1979) and Aigner (1984.) Three studies have analyzed data from optional TOU rates, namely, Hausman and Trimble (1984), Goett (1988), and Caves et al (1989.) Of these, only Hausman and Trimble estimated the distribution of price responses.

produce, decreases and the number of kWhs demanded in the off-peak, which are relatively inexpensive to produce, increases. In this regard, the fact that the customers with greater price responses are more likely to choose TOU rates, all else equal, serves to increase the likelihood that optional TOU rates increase utility profits.

The empirical analysis must be designed to estimate the price responses of customers, and to do so in a way that recognizes that customers who chose TOU rates can be expected to have different price responsiveness than those who choose to remain on standard rates. Without this information, it is not possible to determine whether the optional TOU rates increased or decreased the utility's profits.

A critical econometric issue arises because of the fact that customers choose between TOU and standard rates on the basis of their demand curves. Figure 3 illustrates the issue. The figure depicts the peak-period demand curves of two customers who have the same characteristics but different demand in the peak period. Customer 2 has greater peak-period demand than customer 1. Consistent with result (1) above, suppose that customer 1, who has the lower peak demand, chooses TOU rates while customer 2, who has greater peak demand, decides to remain on standard rates. The observed data points are therefore points A and B (point A is the demand of customer 1 under TOU rates and point B is the demand of customer 2 under standard rates.) The difference in the consumption of these two customers is QB-QA. Under traditional empirical analysis, this difference would be taken as the estimated price response: the difference in consumption of two customers who are the same except that one faces a higher price than the other. However, this difference in observed consumption is larger than the actual price response. The actual price response of customer 1 is the movement from point C to point A: the quantity QC-QA.

The problem is that the difference between points B and A is due to two factors, only one of which is the actual price response. The difference between points B and A is comprised of the difference between B and C plus the difference between C and A. The difference between points B and C is the difference in the original demand curves of the two customers; it is this difference that caused customer 2 to choose TOU rates while customer 1 chose standard rates. The difference between points C and A is the price response of customer 1.

To estimate the price response of customers to TOU rates, the empirical analysis must be designed to decompose the observed differences in consumption into these two parts: (i) the difference in consumption that reflects differences in demand curves and leads to different choices between TOU and standard rates, and (ii) the difference in consumption that reflects a response to price by those customers that chose TOU rates. Both parts are required in order to determine the impact of optional TOU rates on the utility's profits.

The econometric model and estimation procedure that we specify (see the Appendix) incorporate the essential features of customers' choice process. In particular, the model: (i) recognizes that the customer's choice between TOU and standard rates depends on the customer's demand curves in the peak and off-peak periods, (ii) recognizes that different customers have different demand curves and estimates the distribution of these demand curves as well as the average demand curve, (iii) in estimating the price responses of customers, accounts for the fact that customers choose the rates they face. The econometric model is used to determine the demand levels and price elasticities of customers who chose TOU rates, customers who chose standard rates, and all customers combined. The impact of PG&E optional TOU rates on PG&E's profits are calculated from these estimates.

IV. Data

The analysis is conducted on data from a specially designed experiment on optional TOU rates conducted by PG&E. These are the same data that Goett (1988) analyzed; Caves et al. (1989) examined data from an earlier phase of this same experiment.[3] The experiment offered different TOU rates to different customers and observed the TOU consumption of customers who chose the TOU rates as well as a sample of customers who chose to remain on the standard rates. Unlike data from a non-experimental setting, the TOU rates that were offered varied over customers, and the TOU consumption of customers under standard rates is known. Both of these elements enhance the ability of the econometrics to infer the underlying distribution of demand curves. Nevertheless, high correlations among the price variables allow only a restricted distribution of demand curves to be estimated. Further work, including the construction of experiments designed with explicit recognition of the underlying behavioral/econometric model to be estimated, is needed to estimate less restricted, and more realistic, distributions of demand curves.

In 1983, the California Public Utilities Commission ordered PG&E to test the customer acceptance, load impacts, and the cost and revenue implications of optional TOU tariffs. During 1984, PG&E developed an experimental design and recruited residential customers for participation in the experiment.[4] In addition to a currently existing TOU tariff (labeled D-7), seven new TOU tariffs were established (labeled D-8A through D-8G.) The tariffs differed in the peak and off-peak prices that were charged in each block, the thresholds at which rates changed in each period (that is, the definition of the blocks), and the hours that were labeled as peak and off-peak. The characteristics of the tariffs are given in Table 1.

Residential customers whose consumption during the previous twelve months exceeded 800 kWh per month were targeted for recruitment. A random sample of this population was drawn in each geographical region, and sampled customers were offered one of the TOU tariffs. All customers who chose to switch to the TOU tariff were included in the experiment, as well as a random sample of customers who chose not to switch. Meters were installed on all customers in the experiment, beginning sometime around early 1985 (the date of meter installation varied over customers.) During 1985, all customers were billed under the standard, non-TOU rate (labeled D-1), though the TOU consumption of each customer was recorded. In early 1986, approximately half of the customers who had volunteered for the TOU tariff were switched to

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[3] Hausman and Trimble (1984) analyzed data from Vermont's optional TOU rates, which were permanent rather than experimental. The non-experimental nature of the rates meant that prices under the TOU tariff did not vary over customers and that TOU consumption was recorded only for customers who chose the TOU rates. These limitations hinder the econometrics. However, the permanence of the rates can be expected to induce long-run responses by customers which might not be captured in experiments of limited duration. For example, customers can invest in timers for air-conditioners and other appliances which are cost-effective for the customer only if the TOU rates were expected to continue for a sufficiently long period.

[4] Details of the experiment are described in PG&E (1985a).

the TOU tariff that had been offered to them; the other half were continued on the standard rates. The selection of customers into these two groups was random. All customers' TOU consumption was recorded through the end of 1986.

In short, the experimental design consists of approximately two years of TOU consumption data for each of three groups of customers: (A) customers who chose for the TOU tariff and were charged under standard rates in 1985 and under TOU rates in 1986, (B) customers who chose the TOU tariff but were charged under the standard tariff for the entire two-year period, and (C) customers who chose the standard tariff and were charged standard rates for both years. The design allows comparison of: (1) pre- versus post-treatment consumption of customers who chose TOU rates (group A in 1985 compared to 1986), (2) pre-treatment consumption of customers who chose TOU tariffs versus that of customers who chose standard rates (1985 for groups A and B compared to group C), (3) consumption of customers who chose TOU rates versus that of customers who chose standard rates (1986 for group A compared to group C), and (4) consumption of customers who chose TOU rates and were placed on TOU rates versus consumption of customers who chose TOU rates but were placed on standard rates (1986 for group A compared to group B.)

The distinctions among these comparisons is evident in reference to Figure 3. The first and fourth comparisons provide estimates of the quantity QC-QA, which is the price response of customers who chose TOU rates. The second comparison gives an estimate of the quantity QB-QA, which is the difference in the consumption of customers who chose TOU rates and those who chose standard rates when both sets of customers are under standard rates. This difference arises because, as stated above, customers with lower peak period demand and higher off-peak demand are more likely to choose TOU rates. The third comparison gives a measure of the quantity QB-QA and serves as a check on the other comparisons (since quantity QB-QA equals the sum of quantities QB-QC and QC-QA.)

Table 2 gives the total number of eligible customers and the number included in the analysis. The first row reports the number of customers who were offered an optional TOU rate (36,742 customers) and the number who chose to switch to the TOU rate (4,081). For the estimated demand curves to be meaningful, the same definition of the peak period is required for all customers (or, alternatively, the demand parameters must be explicitly represented as functions of the definition of the peak, an approach which we did not attempt.) Schedules D-7, D-8C, D, E, and G impose the same definition of the peak, while the other schedules use different definitions. We eliminated from analysis all customers who were offered schedules D-8A, B, and F.[5] The second row of Table 2 reports the number of customers who were offered one of the five TOU rates that had consistent definition of the peak (31,727 customers) and the number of these customers who chose the TOU rates (3,532). Not all customers who were offered TOU rates were included in the experiement (that is, not all customers had TOU meters installed on their residences). All customers who chose TOU rate were potentially included; however, some of these customers did not participate because they moved away, a TOU meter could not be

[5] Note that, to avoid self-selection bias (Heckman, 1979), all customers who were offered these schedules were eliminated, not just customers who chose these schedules. We re-estimated the models using all households, including those who were offered schedules D-8A, B, and F. The goodness-of-fit statistics became worse, the standard errors for most parameters became larger, and some estimated parameters took the wrong signs.

installed, or for other reasons. Of the customers who did not choose TOU rates, a random sample of about one-in-ten was drawn, and TOU meters were installed on these huseholds when possible. The third row of Table 2 gives the number of customers who were offered one of the five installed. That is, the third row gives the number of customers who were included in our analysis. The final row reports the sampling proportions for these customers (with the method of calculating these proportions given in the footnote to the table).

V. Estimation

The technical appendix gives details of the econometric model and its estimation. As suggested by the analysis of section II, the customer is assumed to have demand curves in the peak and off-peak periods. Different customers have different demand curves, such that there is a distribution of demand curves in the population. Each customer chooses TOU rates if, given his demand curves, he would obtain greater consumer surplus under TOU rates than under standard rates. Therefore, the choice between TOU and standard rates depends on the customer's demand curve. Some customers choose TOU rates while others choose standard rates because different customers have different demand curves.

The demand curves provide all the information that is used to determine a customer's TOU consumption and his choice between TOU and standard rates. The demand curves of each customer is assumed to be linear, with a y-intercept and a slope for the customer's peak period demand curve and a separate y-intercept and slope for his off-peak demand curves. The y-intercept denotes the level of demand, while the slope denotes the price responsiveness of the customer. Different customers have different demand curves; consequently, there is a distribution of y-intercepts and slopes for the peak and off-peak demand curves. We estimate the average and variance of the distribution of the y-intercepts and slopes. For example, the y-intercept of the peak period demand curve for a particular customer denotes the level of this customer's peak period demand; the average and variance of this y-intercept across customers is estimated. Similarly, the slope of the peak demand curve denotes the price responsiveness of the customer; the average and variance over customers of this slope is estimated. And similarly for the y-intercept and slope of the off-peak demand curves.

Table 3 gives estimates of the distribution of demand curves. Three models are presented, with the estimates for the models given in the three columns. The models differ in the extent to which demand curves are estimated to vary over customers. These differences are discussed in the next paragraph. Consider first the similarities among the models. In all three models, the average y-intercept, for both the peak and off-peak demand, is specified to depend on a variety of factors, including the weather and number of members in the household. For example, a cooling degree day variable[6] enters the peak demand equations with a positive sign (11.83 in all three models). This result reflects the fact that the average level of peak period demand is higher in hot months, when air conditioners are used extensively, than in more mild months. Similarly, households with more members have, on average, a higher level of demand than households with fewer members. The components of the average y-intercepts are given in the

[6]Cooling degree days is the amount by which average temperature exceeds 65 degrees in each day, summed over all the days in the month. When the average temperature is below 65 degrees, the value for that day is zero.

top part of Table 3. The estimates all take the expected signs and are fairly similar in all three models.

The average slopes for the peak and off-peak demand curves are also estimated in all three models. These estimates are given in the part of the table labeled "Price coefficients of demand." For example, the average slope of the peak period demand curves is estimated in the first model to be -186.0. This estimate means that if the price in the peak period is raised by one cent (and the off-peak price is held constant), then consumption in the peak period will decrease, on average, by 1.86 kWh per month per customer. (Note that price is denoted in dollars, such that a one cent change is a 1/100 th change in the price variable.) The average slope in the off-peak is -1617.1. for the first model, meaning that a one cent price rise decreases off-peak consumption by -16.171 kWh per month per customer, on average. The average slope for off-peak demand is considerably higher than that for the peak demand because the off-peak period is considerably longer than the peak (18 hours versus 6 hours--not given in the table) and average consumption in the off-peak is greater than that in the peak (893 kWh/month versus 184 kWh/month--also not given in the table). Elasticities of demand, which measure price responsiveness in a way that normalizes for differences in level of consumption are discussed below. The estimate labeled "cross-price" in Table 3 gives the average slope of the peak period demand curve with respect to the off-peak price, and vice-versa. This figure denotes the extent to which customers shift consumption from the off-peak to the peak when the off-peak price rises (and the opposite: the extent to which customers shift from the peak to the off-peak when the peak price rises.) The positive sign of this average slope indicates, as expected, that peak demand increases when the off-peak price rises (with the peak price held constant.) This result is consistent with the finding of Hausman and Trimble (1984) that peak and off-peak electricity consumption are substitutes.

The three models in Table 3 differ in the extent to which the variances of the y-intercepts and slopes of the demand curves are estimated. In column 1, the y-intercepts of peak and off-peak demand vary over customers due to unobserved factors but the slopes are constant (that is, variances are estimated for the y-intercepts but not the slopes.) In column 2, the slopes vary over customers but the y-intercepts vary only with observed factors (that is, the variances of the slopes are estimated but not of the y-intercepts.) In column 3, the y-intercepts for peak and off-peak demand and the slope of peak demand vary due to unobserved factors (that is, variances are estimated for the y-intercepts and for the slope of the peak demand curves, but not for the slope of the off-peak demand curves.)[7] The estimated variances are all positive, as required for variances.

The estimates for model 3 (i.e., the model with the most complete set of estimated variances) imply average price elasticities of -0.09 in the peak and -0.20 in the off-peak. These elasticities represent short-run response, with the customer's appliance holdings and housing characteristics held constant. Goett estimated average elasticities of -0.16 and -0.35 in the peak and off-peak. His estimates are slightly higher than ours. However, his specification does not reflect the bi-directionality of causation (by which customers choose between the two rate schedules based on their demand curves and then, given their chosen rate schedule, respond to the prices under the schedule.) Consequently, Goett's estimates can be expected to capture some of the effect of

[7] Due to the high correlation among variables, the variance in the slope of the off-peak demand curves cannot be estimated.

demand on choice of rate schedule (i.e., amount QB-QC in Figure 3) rather than simply the effect of prices on demand (amount QC-QA).[8]

VI. Impacts of PG&E's Optional TOU Rates

The estimated model is used to determine the impacts of the optional TOU rates that PG&E offered under its TOU experiment. Table 4 contains the results. Recall that PG&E designed several TOU rate schedules and offered each schedule to a different group of customers. We restricted out analysis to the five schedules that used the same definition for the peak period, namely, noon to 6 p.m. on weekdays. Each column in Table 4 gives results for the customers who were offered each rate schedule. For example, the first column indicates that 11.3% of the customers who were offered TOU schedule D7 chose to be on the schedule. Of those customers who chose this TOU schedule, the model predicts that their consumption in the peak would be 187.8 kWh per month, on average, if they faced the standard rates. (Note that this is the amount that they are predicted to consume under standard rates even though they faced TOU rates.) The model predicts an average peak period consumption of 206.2 kWh/month for customers who chose not to switch from standard rates to the D7 TOU rates. Other figures in the table are interpreted analogously.

The estimated consumption levels and elasticities given in parts I and II of the table are used to compare customers who chose TOU rates with those who chose standard rates. For all five optional TOU rate schedules, the model indicates that customers who chose TOU rates would have lower peak consumption than customers who chose standard rates, if both groups of customers faced standard rates. This result is expected since customers with a lower ratio of peak to off-peak consumption under standard rates obtain a greater bill reduction by switching to TOU rates. Customers who chose TOU rates are found to have, on average, more elastic demand in the peak and less elastic demand in the off-peak. This result is consistent with the findings of Goett (1988). The higher peak elasticity is intuitive: customers who are more able and willing to reduce consumption in the peak are more likely to choose TOU rates. The lower off-peak elasticity is theoretically possible but not as intuitive. With all other factors (such as consumption levels) held constant, customers who are <u>more</u> price responsive are expected to choose TOU rates more readily since they can benefit more from the lower off-peak price. However, all other factors are not held constant in the population of all customers; in particular, the level of off-peak consumption is higher for customers who chose TOU rates than those who chose standard rates. With larger off-peak consumption, the average off-peak elasticity can be smaller for customers who chose TOU rates compared to those who chose standard rates, because, with a higher level of off-peak consumption, the percent change in consumption is smaller even though the absolute change is larger.

Part III of the table gives estimates of the impact of the TOU rates on the customers who chose

[8] Elasticity estimates are not available for other studies of optional TOU rates. Caves et al estimate a model of the share of consumption in the peak and off-peak given total consumption in both periods; elasticities can therefore not be determined. Hausman and Trimble report that their estimated parameters imply that nearly all of a household's energy expenditures are "committed," which implies that price elasticities are very low. However, they do not report elasticity estimates.

them, as well as the resulting impacts on the utility. Before discussing these results, it is important to note that the TOU rates that PG&E offered were designed for the purpose of generating data that could be used to estimate models of TOU demand. The rates were <u>not</u> designed to increase surplus or profits. Our analysis of the impacts of these rates is intended simply to serve as an example of how the model can be used to evaluate optional TOU rates and to illustrate the potential impacts of TOU rate offerings.

As expected, customers who chose TOU rates are forecast to decrease their consumption in the peak and increase their consumption in the off-peak in response to TOU prices. These estimated changes are the price response only (i.e., quantity QC - QA in Figure 3), after netting out the differences in demand that cause the customers to choose TOU rates (quantity QB - QC). This latter quantity is the difference in estimated consumption under standard rates, which is given in Part I of the table. For schedule D7, the quantity QB - QC in the peak is 187.8 - 206.2 = -18.4. Comparing this figure with the price response of -18.03 indicates that, for this schedule, about half of the observed difference in peak consumption between customers who chose TOU rates and those who chose standard rates is due to price response; the other half is the difference in demand that induced the customers to choose TOU or standard rates.

Under all five TOU schedules, customers are found to increase their off-peak consumption more, in absolute terms, than they decrease their peak consumption. However, since off-peak consumption levels are greater than peak consumption levels, peak consumption decreases by a greater percentage than off-peak consumption increases. Under three of the TOU rate schedules customers who chose TOU rates receive smaller bills, on average, under TOU rates than they would have received under standard rates. For the other two schedules, customers increase their off-peak consumption sufficiently that their average bills actually increase under TOU rates.

The change in utility costs is calculated by multiplying the change in peak and off-peak consumption by the marginal cost of production in each period. The California Public Utilities Commission has approved TOU marginal cost figures for PG&E.[9] The relevant figures are 0.11684 and 0.05644 dollars per kWh in the peak and off-peak, respectively, for summer months, and 0.05913 and 0.05120 for peak and off-peak in the winter. Using these figures, the utility's costs are calculated to have risen as a result of the optional TOU rates. That is, the extra cost associated with the additional off-peak consumption is greater than the cost savings from the reduction in peak consumption.

The change in profits is the change in the customer's bill (which is utility revenue) minus the change in costs. Note, of course, that this change in profit is not actually retained or borne by the utility, but is (at least partially) passed onto consumers. For all five TOU schedules, the utility's profits are predicted to have declined, which means that, under California's regulatory procedures, the optional TOU rates contributed to a general rate increase. As stated above, this result does not mean that the TOU rates were poorly designed, since the objective in designing them was not to increase profits or decrease rates but rather to generate useful data. Nevertheless, the result indicates the potential danger of optional TOU rates to customers who

[9]These costs consist of variable cost of production given capacity as reported in PG&E (1985b) plus marginal capacity cost as reported in PG&E (1985c, Appendix C).

must bear any lost profits through higher rates.

As discussed in Section II, optional TOU rates can be designed that increase utility profits and hence lead to a general rate reduction. The estimated model is a tool for the design of such TOU rate schedules. In fact, this is the primary purpose of the model.

VII. Further Work

As demonstrated in the previous section, the estimated model is capable of forecasting the impacts of optional TOU rates. It is recommended that utilities use this model, or a model like it, to evaluate TOU rate schedules before the rates are offered and to design optional TOU schedules that increase surplus and profits. In future research, we plan to calculate optimal optional TOU rates, that is, the rates that provide the greatest increase in surplus. These optimal rates can be determined under the constraint that the utility's profits not decrease. Consumer surplus and utility profits under standard rates, mandatory TOU rates, and the optimal optional TOU rates can be compared.

Other avenues for future research involve the specification and estimation of the model. Estimation methods are required that allow estimation of the entire model simultaneously. Simulation procedures for estimation are a promising possibility. The specification can be generalized in several ways to represent more accurately customers' choice process. The most prominent potential generalizations involve: (i) adding income effects, (ii) allowing more flexible cross-price effects, (iii) allowing additional factors (representing, for example, inertia, transaction costs, or altruistic concern about the environment) to enter the choice of tariff that do not enter the demand equations (as in Train, 1990), and (iv) capturing the learning process of customers, by which customers learn about their TOU demand and price responses by being under a TOU tariff. These generalizations will add to the complexity of the estimation and hence will need to be undertaken in conjunction with the development of improved estimation methods.

TECHNICAL APPENDIX
Econometric Model of Customers' TOU Demand and Choice between TOU and Standard Rates

A.1 Specification

Electricity is usually charged in blocks. In the PG&E experiment, the TOU and standard tariffs both consisted of inverted blocks. We adopt the approach developed by Burtless and Hausman (1978) and Hausman (1985) for nonlinear prices: the customer is considered to face a marginal price which is the rate in the block in which the customer consumes and to have "virtual income" which is the customer's income plus the difference between the marginal price and intra-marginal price for each lower block times the length of the block.[1] Let P_{pm} and P_{om} be the peak and off-peak marginal prices faced by the customer in month m and let VY_m be the virtual income of the customer in month m. Prices and virtual income vary over months because the customer's consumption level varies (putting the customer in different blocks) and the thresholds and rates under a given tariff are different in different seasons.

For reasons to be described later, we assume a Gorman indirect utility function:

$$U_m = VY_m - \alpha_{pm}P_{pm} - \alpha_{om}P_{om} - \frac{1}{2}\beta_p P_{pm}^2 - \frac{1}{2}\beta_o P_{om}^2 - \theta P_{pm}P_{om}.$$

By Roy's identity, the peak and off-peak demand functions are:

$$X_{pm} = \alpha_{pm} + \beta_p P_{pm} + \theta P_{om}$$

$$X_{om} = \alpha_{om} + \beta_o P_{om} + \theta P_{pm}.$$

The parameters are specified to vary over time and customers as follows:

$$\alpha_{pm} = \bar{\alpha}_{pm} + \eta_1 + \mu_{pm}$$

$$\alpha_{om} = \bar{\alpha}_{om} + \eta_2 + \mu_{om}$$

$$\beta_p = \bar{\beta}_p + \eta_3$$

$$\beta_o = \bar{\beta}_o + \eta_4$$

$$\theta = \bar{\theta} + \eta_5$$

where $\bar{\alpha}_{pm}$ and $\bar{\alpha}_{om}$ are linear-in-parameters functions of observed variables where the variables

[1] For example, if the tariff is 7c per kwh for up to 500 kwh's and 10c beyond and the customer consumes in the second block, then the marginal price is 10c and virtual income is the customer's income plus $15 (3c/kwh times 500 kwh's), which is the "discount" the customer receives from the lower first block price.

may vary over m but the parameters do not. The vector $\tilde{\eta} = (\eta_1, \eta_2, \eta_3, \eta_4, \eta_5)$ varies over customers with distribution N(0,W) where W has elements denoted ω_{11}, ω_{12}, etc. The vector $\tilde{\mu}_m = (\mu_{pm}, \mu_{om})$ is independent of $\tilde{\eta}$ and uncorrelated over m.

To facilitate interpretation, consider the y-intercept of the peak demand function: α_{pm}. The average y-intercept for customers with the same observed variables is $\bar{\alpha}_{pm}$ in month m. Each customer's actual y-intercept differs from the average. This difference consists of a component η_1 that is constant over months, and a part μ_{pm} that varies over months and represents factors that reveal themselves to the customer on a month-to-month basis (such as whether the customer takes a trip). The customer knows η_1 and learns μ_{pm} when month m arrives; the researcher observes neither η_1, nor μ_{pm}. The other demand parameters are interpreted analogously.

The customer chooses TOU rates if its expected utility over the course of a year is greater under TOU than standard rates.[2] Let r_m and VY^S_m denote the marginal price and virtual income in month m that the customer would face under the standard tariff; and let s_m, t_m, and VY^T_m be the marginal peak and off-peak prices and virtual income in month m under the TOU tariff. Total expected utility under each tariff is:[3]

$$TEU^T = \sum_{m=1}^{12} VY^T_m - \bar{\alpha}_{pm}s_m - \bar{\alpha}_{om}t_m - \frac{1}{2}\bar{\beta}_p s_m^2 - \frac{1}{2}\bar{\beta}_o t_m^2 - \bar{\theta}s_m t_m$$

$$-\eta_1 s_m - \eta_2 t_m - \frac{1}{2}\eta_3 s_m^2 - \frac{1}{2}\eta_4 t_m^2 - \eta_5 s_m t_m$$

$$TEU^S = \sum_{m=1}^{12} VY^S_m - (\bar{\alpha}_{pm} + \bar{\alpha}_{om})r_m - \frac{1}{2}(\bar{\beta}_p + \bar{\beta}_o + 2\bar{\theta})r_m^2$$

$$-(\eta_1 + \eta_2)r_m - \frac{1}{2}(\eta_3 + \eta_4 + 2\eta_5)r_m^2$$

The customer calculates TEU^T and TEU^S exactly and chooses TOU rates only if $TEU^T > TEU^S$. The researcher, however, does not observe $\tilde{\eta}$ and hence ascribes a probability that the customer chooses the TOU tariff:

[2]Under PG&E's experiment, the TOU rates lasted one year and customers could not switch to TOU rates after initially choosing standard rates. Customers were allowed to drop out of the experiment, in which case a customer on TOU rates would return to standard rates. In fact, however, most of the customers who dropped out did so because they moved. In non-experimental applications, customers can switch between rates; however, due to psychic and actual transaction costs, customers can be expected to use some horizon larger than a month for evaluating tariffs.

[3](i) The customer does not observe $\tilde{\mu}_m$ prior to month m and utilizes its expectation, which is zero. (ii) The customer would utilize expected, or "normal", weather in the calculation of CDD. For there PG&E data, estimated parameters are essentially the same whether actual or normal weather is used. (iii) The customer might apply a time discount. However, in the PG&E experiment, the customer did not know when the TOU rates would start and hence could not determine when to start the discounting.

$$P^T = \text{Prob}(TEU^T > TEU^S)$$

$$= \text{Prob}\{[\sum_{m=1}^{12} VY_m^T - VY_m^S - \bar{\alpha}_{pm}(s_m - r_m) - \bar{\alpha}_{om}(t_m - r_m) - \frac{1}{2}\bar{\beta}_p(s_m^2 - r_m^2) - \frac{1}{2}\bar{\beta}_o(t_m^2 - r_m^2) - \bar{\theta}(s_m t_m - r_m^2)]$$

$$> [\sum_{m=1}^{12} \eta_1(s_m - r_m) + \eta_2(t_m - r_m) + \frac{1}{2}\eta_3(s_m^2 - r_m^2) + \frac{1}{2}\eta_4(t_m^2 - r_m^2) + \eta_5(s_m t_m - r_m^2)]\}$$

The left hand side of the inequality is observed by the researcher; denote it as SYS. The right hand side, labeled -ERR, is not observed by the researcher but is known to be distributed normal with zero mean and variance $VAR = kWk'$ where the 1x5 vector k has elements $\Sigma(s_m-r_m)$, $\Sigma(t_m-r_m)$, $\frac{1}{2}\sum(s_m^2 - r_m^2)$, $\frac{1}{2}\sum(t_m^2 - r_m^2)$, $\sum(s_m t_m - r_m^2)$ with the summations over m=1, ... , 12 (such that $ERR=\eta k'$). Consequently, $P^T = \Phi(\frac{SYS}{VAR^{1/2}})$, which is a probit model whose argument is nonlinear in parameters.

If the customer chooses TOU rates, its peak consumption in month m is:

$$X_{pm}^T = \bar{\alpha}_{pm} + \bar{\beta}_m s_m + \bar{\theta} t_m + \eta_1 + \eta_3 s_m + \eta_5 t_m + \mu_{pm}.$$

The customer knows all of these terms when month m arrives and calculates its demand exactly. The researcher, however, does not observe η_1, η_3, η_5, or μ_{pm}. Furthermore, while these terms have zero mean in the entire population, they do not have zero mean in the sub-population of customers who chose TOU rates. More fundamentally, the fact that the customer chose TOU rates reveals information to the researcher about the customer's actual parameters. Using Heckman's (1979) general result, we know that:

$$E(\eta_1 + \eta_3 s_m + \eta_5 t_m + \mu_{pm} / TEU^T > TEU^S)$$

$$= \frac{COV_{pm}^T}{VAR^{1/2}} \frac{\phi(SYS/VAR^{1/2})}{\Phi(SYS/VAR^{1/2})}.$$

where COV_{pm}^T is the covariance of $\eta_1 + \eta_3 s_m + \eta_5 t_m + \mu_{pm}$ with ERR in the probit model. This covariance is linear in parameters, with variables that are functions of prices and coefficients that are elements of W. For example, if W is diagonal (ie, no covariances), then:

$$COV_{pm}^T = -\omega_{11}\sum_{n=1}^{12}(s_n - r_n) - \omega_{33}s_m\frac{1}{2}\sum_{n=1}^{12}(s_n^2 - r_n^2) - \omega_{55}t_m\sum_{n=1}^{12}(s_n t_n - r_n^2).$$

The peak demand equation becomes:

$$X_{pm}^T = \bar{\alpha}_{pm} + \bar{\beta}_p s_m + \bar{\theta} t_m + COV_{pm}^T \cdot K^T + \varepsilon_{pm}^T.$$

where $K^T = \left(\frac{1}{VAR^{½}}\right) \frac{\phi(SYS/VAR^{½})}{\Phi(SYS/VAR^{½})}$

and $\quad \varepsilon^T_{pm} = \eta_1 + \eta_3 s_m + \eta_5 t_m + \mu_{pm} - E(\eta_1 + \eta_3 s_m + \eta_5 t_m + \mu_{pm} / TEU^T > TEU^S)$.

The remaining error term ε^T_{pm} now has zero mean by construction.[4]

The customer's off-peak demand, given that it chooses TOU rates, is:

$$X^T_{om} = \bar{\alpha}_{om} + \bar{\beta}_o t_m + \bar{\theta} s_m + COV^T_{om} K^T + \varepsilon^T_{om}$$

where COV^T_{om} is the linear-in-parameters covariance of $\eta_2 + \eta_4 t_m + \eta_5 s_m$ with ERR in the probit model. The demand equations for a customer that chose standard rates are:

$$X^S_{pm} = \bar{\alpha}_{pm} + \bar{\beta}_p r_m + \bar{\theta} r_m - COV^S_{pm} K^S + \varepsilon^S_{pm}$$

$$X^S_{om} = \bar{\alpha}_{om} + \bar{\beta}_o r_m + \bar{\theta} r_m - COV^S_{om} \cdot K^S + \varepsilon^S_{om}$$

where COV^S_{pm} is the covariance of $\eta_1 + (\eta_3 + \eta_5) r_m$ with ERR, COV^S_{om} is the covariance of $\eta_2 + (\eta_4 + \eta_5) r_m$ with ERR, and

$$K^S = \frac{1}{VAR^{½}} \frac{\phi(SYS/VAR^{½})}{\Phi(-SYS/VAR^{½})}.$$

To aid interpretation, consider, for example, the case in which only ω_{11} is non-zero in W. That is, all customers have the same price coefficients and y-intercepts for off-peak demand and differ only in their y-intercepts for peak demand. The peak demand equation becomes:

$$X_{pm} = \begin{cases} \bar{\alpha}_{pm} + \bar{\beta}_p s_m + \bar{\theta} t_m - \omega_{11} \sum_{n=1}^{12} (s_n - r_n) K^T + \varepsilon^T_{pm} & \text{if customer chose TOU tariff} \\ \bar{\alpha}_{pm} + \bar{\beta}_p r_m + \bar{\theta} r_m + \omega_{11} \sum_{n=1}^{12} (s_n - r_n) K^S + \varepsilon^S_{pm} & \text{if customer chose standard tariff.} \end{cases}$$

A customer who chose TOU rates consumes less in the peak than a customer who chose standard rates, for two reasons. First, the peak price is higher under TOU rates than standard rates. The response to the higher price is captured by $\bar{\beta}_p$ which is presumably negative. Second,

[4]Note that the customer reveals information about its $\tilde{\eta}$ when choosing a tariff, but not about $\tilde{\mu}_m$. At the time of choosing between tariffs, the customer is assumed not to know $\tilde{\mu}_m$, which is revealed to the customer only when month m arrives. COV_m depends therefore on elements of W but not on the distribution of $\tilde{\mu}_m$. The remaining error term $\varepsilon_{pm}{}^T$ incorporates μ_{pm} entirely plus the researcher's remaining uncertainty about η_1, η_3, and η_5.

the customer chose TOU rates because its peak consumption was lower. This latter effect is captured in the last term before the error. K^T, K^S, $\Sigma(s_n\text{-}r_n)$, and ω_{11} are necessarily positive, such that a positive amount is being subtracted in the function for the customer who chose TOU rates and a different positive amount added for a customer who chose standard rates. The ability of the model to differentiate these two directions of causation is one of its important features.

Consider now the specification of the indirect utility function. The Gorman form gives linear demand equations with no income effect. There are three interrelated reasons for this specification. (1) We interpret the demand equations as applicable only within the range of price differences across tariffs, in which case linearity can be considered a first order approximation. (2) The model is intended primarily to provide information on the distribution of demand parameters for a population with given (fixed) characteristics, including income. As such the model is a short-run forecasting tool for use in designing tariffs for the population on which it is estimated. Households with greater income may consume more electricity and have different price responses than lower income families. These differences are captured, however, in these households' individual parameters, through higher α's and different β's. With the demand equations seen as applicable only within the relevant range of electricity prices, the inclusion of no income effect actually implies that the addition to virtual income that a tariff provides does not affect the customer's consumption. This assumption is not unreasonable, given the negligible size of this addition compared to total income. (3) The model places relatively few informational requirements on the customer. The parameters of linear demand correspond to information that the customer can intuitively consider, namely, the magnitude of demand in each period and the amount that the customer expects to respond to a unit change in price.

A.2 Estimation

Marginal prices and virtual income under the block rate tariffs are determined through an instrumental variables approach similar to that proposed by Rosen (1976) and Hausman, Kinnucan, and McFadden (1979). A regression model of TOU consumption is estimated that includes exogenous variables only. This model is used to predict each month's TOU consumption for each customer. Under each tariff (the standard tariff and the TOU tariff that the customer was offered), the block in which this predicted consumption falls is identified. The marginal price and virtual income associated with this block is used as the instrument for price and virtual income for that customer in that month under that tariff. For the purpose of calculating these marginal prices and virtual income, we use the regressions of TOU consumption that were performed by Goett on these data and reported in his Appendix B.

The model can conceivably be estimated by full information maximum likelihood. However, the highly nonlinear form of the model and the high correlations among variables make MLE unstable. We instead chose a sequential estimation approach that exploits the robustness of linear regression and hence can perhaps be expected to produce better estimates in finite samples. The procedure consists of the following steps. First, the probit model of tariff choice is estimated using ML on the data relating to this choice alone. The estimated parameters are used to calculate a consistent estimate of K. Using the estimated K, the demand equations are estimated by least squares. Note that, given K, the demand equations are linear in parameters, with all parameters in the complete model identified.

The empirical analysis is hindered by the fact that the TOU tariffs were designed such that, for each tariff, the "average price" in the peak is 2.5 times that in the off-peak, where average price in each period is defined as the total revenues that PG&E would obtain for consumption in that period if all customers were charged under the TOU tariff, divided by the total kWh's that would be consumed in the period (with this latter figure calculated on the basis of some assumptions about the TOU consumption of customers; for details, see PG&E, 1985.) Marginal prices in the peak and off-peak are not perfectly correlated under the TOU tariffs because of the block rate nature of the tariffs: different customers consumer in different blocks such that the ratio of marginal prices for each customer is not 2.5. However, the amount of independent variation in peak and off-peak prices is severely limited by this aspect of the experimental design.

In the probit model of tariff choice, the limitation is most severely felt in the estimation of elements of VAR, which is a linear combination of elements of W, the variance/co-variance matrix for the parameters. Convergence was achieved only when all elements of W except ω_{11} are restricted to zero. Strictly speaking, this specification is equivalent to assuming that the y-intercept of peak demand varies over customers but the price coefficients and the y-intercept of off-peak demand do not. We interpret the model more generally, however. Recall that the purpose of the estimation of the probit model is to obtain a consistent estimate of K. Given the high correlation among variables that enter VAR, using only those that interact with ω_{11} is likely to capture nearly all the variation in K that would occur with an unrestricted W. Table 5 gives the estimated parameters of the probit model. The demand regressions are presented and discussed in Section V.

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Figure 1. Consumer Surplus

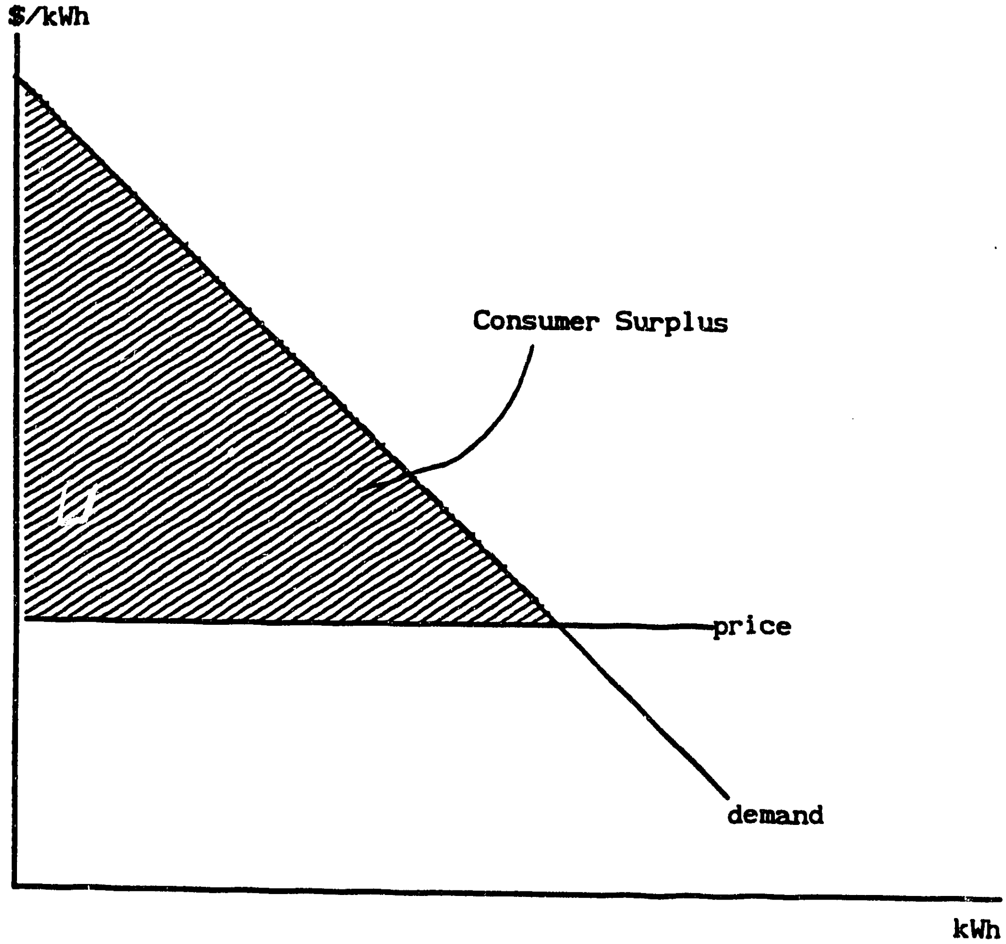


Figure 2. Peak and Off-Peak Demand

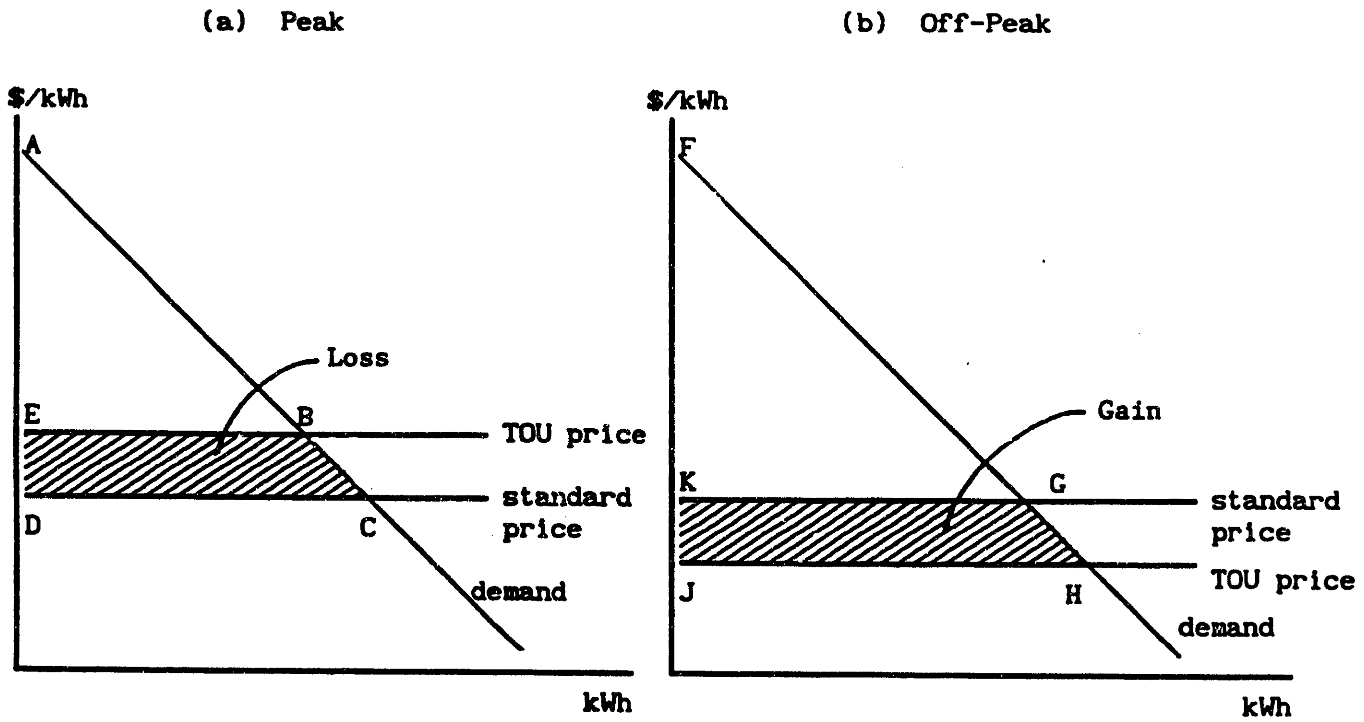
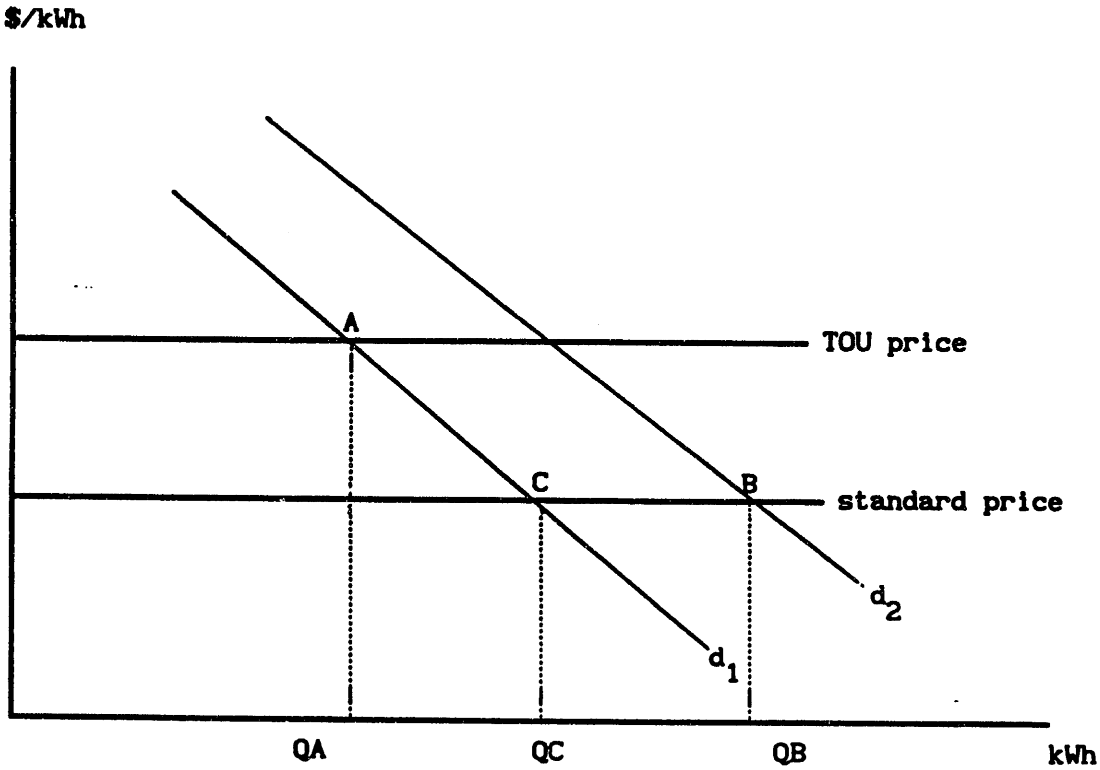


Figure 3. Peak Period Demand



d_1 = peak period demand curve of customer 1, who chooses TOU rates

d_2 = peak period demand curve of customer 2, who chooses standard rates

QA = consumption of customer 1 under TOU price

QB = consumption of customer 2 under standard price

QC = consumption of customer 1 under standard price

Table 1

TARIFF CHARACTERISTICS
January 1, 1985

Standard Tariff	Price per kWh		
	Tier 1	Tier 2	Tier 3
D-1	.06688	.08694	.11300

TOU Tariffs	Price per kWh				Peak Time
	Peak		Off-peak		
	Tier 1	Tier 2	Tier 1	Tier 2	
D-7	.12862	.19228	.05145	.07691	noon - 6:00 p.m. M-F
D-8A	.12862	.19228	.05145	.07691	summer: noon - 6:00 p.m. M-F winter: 3:00 - 6:00 p.m. M-F
D-8B	.12862	.19228	.05145	.07691	2:00 - 8:00 p.m. M-F
D-8C	.15917*	.19228	.04380*	.07691	noon - 6:00 p.m. M-F
D-8D	.17037	—	.06815	—	noon - 6:00 p.m. M-F
D-8E	.11147	.16664	.05573	.08332	noon - 6:00 p.m. M-F
D-8F Summer	.13492	.19464	.05815	.08390	noon - 6:00 p.m. M-F
D-8F Winter	.08216	.11853	.05477	.07902	3:00 - 9:00 p.m. M-F
D-8G	.12540	.16301/.19604**	.05225	.06792/.08168**	noon - 6:00 p.m. M-F

Tier lengths depend on the customer's location and whether or not the customer is "all electric." Different tier lengths apply in summer and winter.

*Peak and off-peak consumption are combined to determine whether the Tier 1 price is charged (i.e., the Tier 1 threshold is based on total kWh in peak and off-peak).

**D-8G contains three tiers in each period.

Table 2

CUSTOMER SAMPLE

	Total	Customers who chose:	
		TOU Tariff*	Standard Tariff**
Mailings	36,742	4,081	32,661
Customers offered D-7, D-8C, D, E, G	31,727	3,532	28,195
Customers included in analysis	2,571	2,343	228
Weight		0.122	10.021

Weight equals the proportion of the population that chose each tariff divided by the sample proportion. For customers who chose the TOU tariff, 0.122 = (3,532/31,727) / (2,343/2,571). Weight is therefore proportional to the inverse of the sampling frequency among customers who chose each tariff.

*These customers consist of those placed on TOU in 1986 and those who were required to remain on standard rates in 1986. That is, these customers consist of groups A and B as described in thetext.

**These customers consist of group C as described in the text.

Table 3

REGRESSION MODEL OF TOU DEMAND

Variable	Parameter	Model (standard errors in parentheses)		
		1	2	3
Components of y-intercept of peak demand	$\bar{\alpha}_{pm}$			
Constant		148.3 (3.56)	148.5 (3.56)	148.4 (3.56)
Cooling degree days if household has air conditioner, zero otherwise		11.83 (0.151)	11.83 (0.151)	11.83 (0.151)
1 if household had electric water heater, zero otherwise		33.27 (0.976)	33.33 (0.976)	33.28 (0.976)
Number of members in household		4.158 (0.247)	4.175 (0.247)	4.163 (0.247)
Square footage of house (in 000s)		0.0191 (0.0006)	0.0191 (0.0005)	0.0191 (0.0006)
February dummy		-15.42 (2.13)	-15.43 (2.13)	-15.42 (2.13)
March dummy		-36.6 (2.15)	-36.57 (2.15)	-36.58 (2.15)
April dummy		-46.51 (2.08)	-46.5 (2.08)	-46.51 (2.08)
May dummy		-45.83 (2.09)	-45.79 (2.09)	-45.82 (2.09)
June dummy		-31.48 (2.15)	-31.44 (2.15)	-31.47 (2.15)
July dummy		-15.83 (2.10)	-15.80 (2.10)	-15.82 (2.10)
August dummy		-28.29 (2.11)	-28.28 (2.11)	-28.29 (2.11)
September dummy		-43.62 (2.05)	-43.61 (2.05)	-43.62 (2.05)
October dummy		-44.72 (2.07)	-44.72 (2.07)	-44.72 (2.07)
November dummy		-13.47 (2.05)	-13.50 (2.05)	-13.48 (2.05)
December dummy		6.58 (2.26)	6.51 (2.26)	6.57 (2.26)

Table 3, continued Variable	Parameter	Model (standard errors in parentheses) 1	 2	 3
Components of y-intercept of off-peak demand	$\bar{\alpha}_{om}$			
Constant		837.3 (12.7)	838.6 (12.7)	837.6 (12.7)
Cooling degree days if household has air conditioner, zero otherwise		70.88 (2.02)	70.92 (2.02)	70.9 (2.02)
1 if household has electric water heater, zero otherwise		243.9 (3.49)	243.69 (3.48)	243.9 (3.49)
Number of members in household		29.62 (0.884)	29.62 (0.884)	29.63 (0.884)
Square footage of house (in 000s)		0.0797 (0.002)	0.0798 (0.0020)	0.0797 (0.002)
January dummy		-67.45 (8.08)	-67.35 (8.08)	-67.43 (8.08)
February dummy		-137.6 (7.76)	-137.4 (7.76)	-137.5 (7.76)
March dummy		-174.9 (7.86)	-174.7 (7.86)	-174.8 (7.86)
April dummy		-252.5 (7.60)	-252.3 (7.60)	-252.5 (7.60)
May dummy		-273.7 (7.64)	-273.4 (7.64)	-273.6 (7.64)
June dummy		-278.0 (7.83)	-277.6 (7.83)	-277.9 (7.83)
July dummy		-270.7 (7.67)	-270.3 (7.67)	-270.6 (7.67)
August dummy		-286.1 (7.67)	-285.8 (7.67)	-286.0 (7.67)
September dummy		-300.1 (7.48)	-299.8 (7.48)	-300.0 (7.48)
October dummy		-264.6 (7.55)	-264.4 (7.56)	-264.6 (7.55)
November dummy		-154.8 (7.50)	-154.7 (7.50)	-154.8 (7.50)
Price coefficients of demand Same price in peak	$\bar{\beta}_p$	-186.0 (20.8)	-131.7 (23.2)	-170.4 (29.4)
Same price in off-peak	$\bar{\beta}_0$	-1617.1 (90.0)	-1573.6 (89.9)	-1604.3 (91.6)
Cross-price	$\bar{\theta}$	126.0 (27.6)	69.56 (29.4)	109.9 (35.0)

Table 3, continued

Variable	Parameter	Model (standard errors in parentheses)		
		1	2	3
Variance terms				
Variance in y-intercept of peak demand	ω_{11}	2438. (206.)	—	1886. (762)
Variance in y-intercept of off-peak demand	ω_{22}	3457. (1203.)	—	3499. (1205.)
Variance in same-price coefficient of peak demand	ω_{33}	—	155017. (13853.)	37988. (50476.)
Variance in same-price coefficient of off-peak demand	ω_{44}	—	406127. (121401.)	—
Method: weighted least squares				
R^2		.1812	.1812	.1812
Mean square error for system		1.000346	1.000336	1.000152

Table 4

IMPACTS OF OPTIONAL TOU RATES

	D7	D-8C	D-8D	D-8E	D-8G
Proportion who chose TOU	.1130	.1251	.1455	.0574	.1044
I. Average consumption under standard rates					
Customers who chose TOU rates					
Peak (kWh/month)	187.8	187.9	165.8	194.7	199.3
Off-peak (kWh/month)	859.9	857.5	825.7	907.7	868.5
Customers who chose standard rates					
Peak (kWh/month)	206.2	188.0	179.4	198.2	205.5
Off-peak (kWh/month)	859.3	815.9	790.5	896.0	845.0
II. Average elasticities					
Customers who chose TOU rates					
Peak: same price	-0.111	-0.114	-0.137	-0.106	-0.104
Peak: cross price	0.062	0.063	0.073	0.058	0.059
Off-peak: same price	-0.198	-0.197	-0.217	-0.180	-0.193
Off-peak: cross price	0.014	0.014	0.015	0.012	0.013
Customers who chose standard rates					
Peak: same price	-0.087	-0.099	-0.103	-0.082	-0.085
Peak: cross price	0.058	-0.065	0.068	0.053	0.057
Off-peak: same price	-0.203	-0.220	-0.227	-0.179	-0.203
Off-peak: cross price	0.014	0.015	0.016	0.012	0.014
III. Impacts of TOU on customers who chose TOU rates					
Change in consumption					
Peak (kWh/month)	-18.03	-14.53	-17.26	-12.76	-16.94
Off-peak (kWh/month)	52.03	56.30	69.78	34.74	49.07
Change in bill (dollars/month)	-1.71	-6.37	0.17	0.72	-2.10
Change in utility costs (dollars/month)	7.54	10.76	9.08	3.63	7.45
Change in utility "profits" (dollars/month)	-9.26	-17.15	-8.94	-2.91	-9.57

Table 5

PROBIT MODEL OF TARIFF CHOICE WITH

$$VAR^{1/2} = \sqrt{\omega_{11}} \sum (s_m - r_m)$$

Variable*	Parameter	Estimate	Standard Error
Variance term:			
Virtual income	$1 / \sqrt{\omega_{11}}$	0.00345	0.000613
Components of y-intercept of peak demand:			
$\sum (s_m - r_m)$ times:	$-\bar{\alpha}_{pm} / \sqrt{\omega_{11}}$		
Constant		-5.112	1.798
Cooling degree days if household has air conditioner, zero otherwise		-0.0632	0.0581
1 if household has an electric water heater, zero otherwise		-0.01065	0.2113
Number of members in household		-0.1340	0.0655
Square footage of house (in 000s)		-0.071	0.132
February dummy		1.653	1.756
March dummy		3.769	1.960
April dummy		0.440	1.815
May dummy		2.130	1.326
June dummy		0.761	1.694
July dummy		-0.449	1.357
August dummy		-1.291	1.332
September dummy		-0.789	1.436
October dummy		-0.204	1.357
November dummy		0.592	1.076
December dummy		2.262	0.784
Components of y-intercept of off-peak demand:			
$\sum (t_m - r_m)$ times:	$-\bar{\alpha}_{om} / \sqrt{\omega_{11}}$		
Constant		-6.963	5.060
Cooling degree days if household has air conditioner, zero otherwise		-0.817	0.378
1 if household has electric water heater, zero otherwise		-0.533	0.392

Variable*	Parameter	Estimate	Standard Error
Number of members in household		-0.156	0.0962
Square footage of house (in 000s)		-0.234	0.213
January dummy		-3.924	4.022
February dummy		3.386	3.112
March dummy		7.644	2.989
April dummy		4.236	2,610
May dummy		4.776	2.179
June dummy		2.327	2.542
July dummy		0.958	2.231
August dummy		3.648	2.415
September dummy		1.354	2.745
October dummy		2.226	2.327
November dummy		3.935	2.333
Price coefficients of demand:			
Same-price coefficient in peak $\sum (s_m^2 - r_m^2)$	$-\frac{\bar{\beta}_p}{\sqrt{\omega_{11}}}$	25.78	5.682
Same-price coefficient in off-peak $\sum (t_m^2 - r_m^2)$	$-\frac{\bar{\beta}_0}{\sqrt{\omega_{11}}}$	37.27	36.01
Cross-price coefficient $\sum (t_m s_m - r_m^2)$	$-\frac{\bar{\theta}}{\sqrt{\omega_{11}}}$	7.68	17.38

Method: Maximum likelihood on weighted observations.

Log likelihood at zero -1734.25
Log likelihood at convergence -748.228

Weighted number of households choosing TOU 221
Weighted number of households choosing standard 2281
2502

* Each variable is divided by $\sum (s_m - r_m)$, which is the observed portion of $VAR^{1/2}$.

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