DO TIME-OF-USE RATES CHANGE LOAD CURVES?

PREPARED FOR THE LOS ANGELES DEPARTMENT OF WATER AND POWER AND THE ELECTRIC POWER RESEARCH INSTITUTE, INC.

JAN PAUL ACTON AND BRIDGER M. MITCHELL

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Time-of-use (TOU) pricing of electricity has been practiced to some degree for several decades. Today such pricing is a matter of extensive discussion and consideration as electric utilities respond to the provisions of the Public Utilities Regulatory Policies Act of 1978 (PURPA). Among other things, that act requires a good-faith hearing, conducted in public, about the "cost-effectiveness" of time-of-use rates. To meet the requirements of PURPA—and to make an informed judgment about the desirability of time-of-use rates for any particular utility system—presents empirical and methodological challenges to the electric utility industry and its regulators.

Rand's work in electricity demand and pricing has been supported since the mid-1970s variously by the Los Angeles Department of Water and Power, the National Science Foundation, the U.S. Department of Energy, the California Energy Commission, the Electric Power Research Institute, and Rand's own corporate resources.

The present report—jointly supported by the Los Angeles Department of Water and Power and the Electric Power Research Institute—provides a discussion of the methodological problems encountered when one attempts to determine whether or not TOU rates change utility load curves in a beneficial way. In addition, it presents the latest data available on the effects of TOU rates in European and U.S. utilities that actually apply such rates. The report should be of interest to the participants in PURPA hearings and to utility officials who wish to understand the possible impact of TOU rates on their systems.
Rand researchers have published several studies in which they have examined in detail several aspects of the costing and pricing of electricity in the United States and Europe over the past several years. In the spring of 1977, Rand analysis formed part of the background material used in the preparation of the President's national energy plan proposals to Congress. Subsequently, Rand analysis has been discussed by critics of TOU pricing. A shorter version of this report by two of the Rand researchers involved throughout the process was published in *Public Utilities Fortnightly*, Vol. 105, No. 11, May 22, 1980.
SUMMARY

Time-of-use (TOU) pricing of electricity may offer the possibility of improving the efficiency with which electricity is produced and supplied. But unless TOU rates induce sufficient changes in load, the implementation costs will outweigh the efficiency gains. In examining the possible effects of TOU pricing on manufacturing customers, the analyst faces both a methodological and an empirical challenge.

The methodological challenge is that it is not always possible to observe electricity customers under both TOU and non-TOU rates with all non-rate factors held constant. Instead, it is generally necessary to compare a load curve with TOU pricing against a load curve that might have occurred in the absence of TOU prices. The analyst can employ before-and-after or side-by-side data for the analysis. Each has its drawback and in the end the analyst is left with several less than perfect ways to proceed.

The empirical challenge is that data are not always available in ideal form. Short-term data are becoming available in a number of U.S. electric utility systems with TOU pricing, but these rates have only been in effect since 1977. The report examines data covering more than 300 industrial and commercial customers from four utilities in California and Wisconsin. At present, longer-term data must necessarily come from European electric utilities that have practiced TOU pricing for 15 or more years. The report examines in detail the load experience of the French and British utility systems.

By employing a variety of approaches for systematic analysis the report concludes that TOU rates do indeed affect load shapes among industrial and larger commercial customers in both Europe and the United
States. The magnitude of reductions in peak period loads within the TOU class range from 1 to 10 percent for U.S. utilities that have had TOU rates in effect for only one or two years. The longer-term French and British data suggest that peak load reductions in the TOU class may reach between 13 and 35 percent, depending on the method used for analysis. In both the United States and Europe, there is considerable variation from customer to customer in the degree of response—with the majority of customers showing modest load changes and a significant minority showing quite strong adjustment. In general, firms show a greater percentage response to TOU pricing (1) when they have electric-intensive loads, (2) when they have discrete loads that can be reduced, (3) when excess production capacity allows concentrating activities and off-peak periods, and (4) when cogeneration is available.

A judgment about the overall desirability of TOU rates must consider revenue effects, rate structure design, metering costs, cost tracking, and net benefits—all of which lie beyond the scope of this report. But three of the four U.S. utilities reviewed have conducted a benefit/cost evaluation of their TOU rates and have found them desirable, and all four of the utilities intend to extend the rates to additional customers.
ACKNOWLEDGMENTS

A draft of this study was read by rate officials and analysts familiar with the U.S. and European electrical systems reviewed in this report. Their several suggestions, along with those of Rand reviewer Stephen Carroll, improved the text at several points and the authors are grateful for the assistance.
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I. INTRODUCTION

Time-of-use (TOU) rates have attracted the attention of electric utilities, their regulators, intervenors in rate cases, and--most recently--the U.S. Congress. Several articles in Public Utilities Fortnightly have hailed TOU rates as "correct in theory," appropriate for today's circumstances, and promoting "a more efficient allocation of society's scarce energy resources."[1] Others have criticized them as ineffective, wasteful of resources, and "not a suitable device for producing capacity or energy savings."[2] But little systematic, quantitative analysis of the actual effects of TOU rates is available. Indeed, some critics claim there can be no evidence of the magnitude of reduction in the peak loads that result from applying TOU rates to industrial customers.[3]

If TOU rates affect customers' loads in predictable ways, they enable utilities to increase their operating efficiency, reduce capacity requirements, and lower costs. If they fail to alter loads, the costs of TOU metering will eat up any potential efficiency gains.[4] Only empirical analysis of individual utilities' experiences--suitably adjusted for their particular conditions--will answer the fundamental question: Do TOU rates change loads?

[4] Even then, TOU rates might still be judged desirable if they more accurately reflect the cost of serving different customers.
The Public Utility Regulatory Policies Act of 1978 (PURPA) requires state regulatory commissions to review electric utility costing and ratemaking and to consider TOU rates. Rates for each customer class "shall be on a time-of-day basis which reflects the costs of providing electric service to such class of electric consumers at different times of the day unless such rates are not cost-effective with respect to such class."[1] A TOU rate is deemed cost-effective "if the long-run benefits of such rate to the electric utility and its electric consumers in the class concerned are likely to exceed the metering costs and other costs associated with the use of such rates."[2]

To meet PURPA requirements, one or more regulatory hearings will be held in every state over the next two years to determine the "cost-effectiveness" of TOU rates. These evaluations will require empirical data that will be difficult to assess. The question remains: How would you know if time-of-use rates were effective?

In an attempt to answer this question, we first analyze the principal methods of measuring load changes caused by TOU rates and then summarize the effects of applying these methods to load data from utilities that have TOU rates. Of course, an extended evaluation of the desirability of TOU pricing must also consider revenue effects, rate structure design, additional metering costs, "cost-tracking," and net benefits. These important issues must be taken up elsewhere.

II. THE METHODOLOGICAL CHALLENGE

Our goal is to determine what—if any—changes in load curves have resulted when electricity has been priced by time of use. Two system load curves must be compared—the curve under TOU pricing and the curve that would have resulted if conventional rates had been in effect in the same circumstances. Because the second curve is not observed, some method must be developed to estimate it. This is a challenging task, made difficult because circumstances rarely remain the same. Reliable measurement of TOU effects depends on a careful examination of the types of data, customer response, and evaluation methods.

SOURCES OF DATA

Several types of load data are available. The analyst can examine before-and-after (or "time series") data and side-by-side ("cross-section") data. He can compare load data at the system (aggregate) level and at the individual customer (disaggregate) level. Each type of data permits some aspect of responsiveness to be examined, but each also involves methodological difficulties. In the end, no single method is fully satisfactory.

Before-and-After vs. Side-by-Side Data

Most available data involve before-and-after comparisons of (1) loads in a base year under a conventional rate and (2) loads for the same customers in a subsequent year under a TOU rate. Setting aside the effects of non-tariff factors for the moment, we see that the observed load differences constitute customers' net responses to a change in all elements of the rate structure—the peak and off-peak (and shoulder) period rates, the length and hours of the rate periods, and the ratios
of the demand rates to energy rates. The principal methodological challenge is to control for non-tariff factors between the two years—for example, overall growth in electricity use and the number of customers—in order to infer what would have happened to the load had the conventional rate remained in effect. Such adjustments are generally more easily made for short time periods.

Alternatively, side-by-side comparisons can be made between one utility with a conventional rate structure and another with TOU rates. However, unless the two utilities have a similar mix of customers and all non-tariff factors are identical, side-by-side data also require adjustment. If a single utility places some of its customers on TOU rates and leaves the remainder on conventional rates, its two customer groups can be compared without having to adjust for factors that vary across utility systems, although adjustments may still be required for differences between the two groups.

It is not always possible to obtain satisfactory load data under conventional rates for comparison with load curves under TOU rates, particularly when analyzing the loads of individual customers. In these cases, the unobserved load curves can be hypothesized by assuming, for example, that under conventional rates customers would have constant demands 24 hours a day. Because many types of customers are known to have uneven loads that are highest at the system peak hours, this method of measuring the effects of TOU rates is especially conservative. Some peak-hour load reductions that would be stimulated by TOU rates will go entirely undetected and the magnitude of other reductions will be underestimated.
System Load vs. Individual Load Data

Load data can be analyzed at two levels: (1) the total load of the system or of the TOU customer class and (2) the loads of individual TOU customers. Of primary interest to utility management, aggregate system load data can be easily obtained. Changes in the system load will directly affect capacity expansion decisions, costs, and revenues. However, because each system's load conditions and mix of customers are idiosyncratic, the magnitude of TOU response measured from a system load curve may be particular to that system. TOU class load studies show widely varying responsiveness to TOU rates, ranging from no adjustment to almost complete shifting of peak loads.

Data for individual customers can sometimes be obtained from periodic load studies and may be augmented by sampling within important customer groups. Such disaggregated data allow analysts to take account of the effect of the customer mix on the class load response and to forecast the TOU class response in another utility with a different customer mix. To avoid attributing a spuriously large (or small) effect to the class as a whole the analysis of aggregate TOU load changes needs to be based on systematic sampling and statistical inference.

ASPECTS OF CUSTOMER RESPONSE

Rate Element Effects

Data from a single utility cannot identify the separate effects of TOU rate elements. For example, if electricity use grows more slowly at peak hours following adoption of the TOU rate, it may be due to the higher (peak) price at those hours, or to the lower (off-peak) price at other hours, or to both prices. Put differently, it is impossible to
tell whether a TOU rate "shaves peaks," "fills valleys," or "shifts load." All of these responses happen together. Furthermore, the effect of a still higher peak price cannot be determined from observing a single TOU rate.

As more utilities shift to TOU pricing it will be possible to measure the separate effects of rate elements by comparing load changes of different utilities that have similar rate structures. For example, the long-standing TOU tariffs in France and Britain have their counterparts in several new TOU rates in the United States. Two utility systems in California have separate energy and demand charges in peak, shoulder, and off-peak hours for very large users that are similar to the rate elements in the Green Tariff in France. Wisconsin's largest users are billed under 14-hour daytime peak energy and demand charges that resemble the standard British industrial rate. And the ex-post coincident demand charge used by San Diego Gas and Electric has its counterpart in the Load Management Warning tariff in Britain.

**Short-Term and Long-Term Effects**

The effect of TOU rates depends very much on how long they have applied; we distinguish short-term and long-term adjustments. During the first year or two that a TOU rate is in force, a utility's customers may change the hours when they use electrical equipment and how much they use it. However, in this short time most customers cannot make significant changes in production capacity or plant design; major plants and equipment have long economic lifetimes and several years are needed to replace or expand facilities. Fortunately, apart from swings in the overall level of economic activity, most non-tariff factors that affect electricity loads change rather slowly, so, at a given level of
production, the principal differences in a customer's before-and-after load curves will be related to tariff changes. Data for measuring short-term adjustment are now available from several of the first U.S. utilities to shift to TOU rates; we review these effects below.

Ten to twenty years after TOU rates have taken effect, the rate structure has become another economic parameter that firms can use in making decisions about new equipment, expansion of plant capacity, labor contract negotiation, and the use of other sources of energy. Consequently, sizable long-term changes in load curves may have occurred, but measuring them is complicated by changes in non-tariff factors. And the only available load curve data ten or more years after the introduction of TOU rates come from a few foreign utilities, among them Electricité de France, which pioneered TOU pricing over 20 years ago, and the Central Electricity Generating Board in Great Britain, which has had TOU rates for more than a decade.

**Intermediate-Term Effects**

Under some TOU rate structures, load changes occur when seasonal surcharges go into effect or when peak hours change from one season to another. These intermediate-term effects result from production rescheduling made possible by customers' long-term plant and equipment investments or labor-scheduling agreements. Consequently they are revealed only several years after the enactment of TOU rates. Intermediate-term adjustments do not include permanent, year-round load changes resulting from long-run redesign of plant and production.
METHODS OF EVALUATION

The alternative sources of data, level of aggregation, and time frame for analysis lead to some 15 or 20 evaluation methods. As a practical matter, four general methods are used: (1) evolution of load curves, (2) trends in hourly load, (3) load shapes of individual customers, and (4) rate structure experimentation.

Evolution of Load Curves

Readily available system load data have frequently been used to detect the presence of TOU effects. Changes in the system load curve can be compared over a one- to two-year period, or over a decade or more, by normalizing the curves for growth in load. Short-term analysis is least affected by changes in non-tariff factors, but it cannot detect customer responses that depend on changes in capacity, plant design, and the like. Long-term system load curve changes will be influenced by other economic and social factors, so that analysis based exclusively on a long-run comparison of system loads is unlikely to be reliable.

Few systems have introduced TOU rates for all of their customers, so the change in the system load curve mixes the response of TOU customers with the patterns of use under non-TOU rates. Separate analysis of a fixed population of TOU customers overcomes this difficulty. The evolution of individual customer loads, particularly when before-and-after data are available, provides better control for such important factors as customer mix and industrial process, and such data indicate the speed with which customers change usage in response to TOU rates.
Trends in Hourly Load

A second evaluation method analyzes long-term trends in load at each hour of the day. Customer responses to TOU rates would cause slower growth in load at the peak hours as compared to off-peak (and shoulder) hours. Rate structure effects may be isolated by sharp changes in load trends at peak hours and trends in nearby hours permit control of non-tariff factors. Using this method, French utility statisticians have compared hourly trends in the months before and after seasonal rate changes; the results measure intermediate-term TOU adjustments.

Load Shapes of Individual Customers

The hourly loads of a single customer under TOU rates may be compared with a flat load curve that, hypothetically, he would have under conventional rates. When lower loads at peak hours are systematically found for a number of customers, it is strong evidence that they have changed loads in response to the rates, since in the absence of low off-peak rates, production is generally more costly in off-peak hours. However, load shapes showing maximum use in peak hours do not necessarily indicate a lack of response; customers with peak loads at the TOU peak hours may reduce them under TOU rates and still have new load curves that are flat or that peak in those hours. If before-and-after load data could be obtained for individual customers, this type of long-term response could be measured, provided that reliable adjustments could be made for the long-term changes in other factors. However, such data are not generally available.
Individual industrial customers' loads can be compared on a side-by-side basis by selecting one group of customers on TOU rates and another on conventional rates. Ideally, individual customers would be matched in terms of industry, production technology, and labor conditions. To date no such study has been conducted with data from a single utility that would ensure similarity of non-tariff factors. However, in earlier research with W. G. Manning, Jr., we analyzed load curve differences between individual customers in French and U.S. utilities, matching customers by industrial classification.[1] This method has its drawbacks: non-tariff factors that may cause differences in loads between customers in the two systems cannot be controlled for, and industrial processes being matched may not be the same--since different countries employ different classification schemes.[2]

Experimentation

By offering a variety of different TOU rates to systematically selected customers one can measure the separate effects of several rate

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[2] For example, French studies include both petroleum pipelines and refineries under the heading "petroleum industry" while U.S. SIC codes classify petroleum pipelines under "transportation" and refinery operations under "manufacturing." A review (Londwatt, published in 1978) of our first study that used individual French industrial customer data (Mitchell, Manning, and Acton, 1977) found that one of the pipeline load curves had inadvertently been labeled "refinery." This mistake, brought to our attention in spring 1977, was corrected prior to use of the material by the White House energy staff and before Congressional testimony was presented. A second error, involving the conversion of French subscribed demand rates to equivalent prices per kWh was also corrected. Apart from these two lapses, the Londwatt review confirmed the factual accuracy of the initial Rand study. All subsequent Rand publications contain corrected figures and tables. See, e.g., Mitchell and Acton (1977), Acton, Mitchell, and Manning (1978), and Mitchell, Manning, and Acton (1978).
elements and rate levels on customer loads, rather than just the overall
effect of the complete TOU rate structure. Because experiments are
expensive, they have been conducted on a short-term basis and almost
exclusively with residential customers. These data are still being
analyzed and will not be discussed further here.[1]

[1] See Electricity Council of London (No Date); Acton, Manning,
and Mitchell (1978); Lawrence (1977); and Hill et al.(1979).
III. WHAT DO THE UTILITY DATA SHOW?

Because no one method for estimating the effect of TOU rates on system load curves and industrial customers covered by TOU rates is ideal, we look at the results of several different approaches. With sufficient data, each method could be applied within a single utility, but long-term data are available only from foreign systems in which TOU rates have been standard for a decade or more. We review long-term estimates from France, where the most extensive analyses have been made, and briefly examine corresponding evidence from Britain. We then survey the short-term results now available from several U.S. utilities that introduced TOU rates in 1977.[1]

FRENCH EXPERIENCE WITH TOU RATES

Electricité de France (EdF), a winter-peaking system, was the first electric utility to use a nationwide TOU rate. Its staff conducted extensive load studies that provide a sound basis for analyzing long-term TOU effects. The well-known Green Tariff was developed in the 1950s to reflect the twin peaks in EdF's winter weekday load curve. The tariff, introduced as an option in 1957, initially applied to high-voltage customers (above 63 kV) and was based on an analysis of system marginal costs.[2] By 1963, 88 percent of the eligible customers served at high and medium voltage levels had selected the Green Tariff, and in 1968 it was made standard at those voltage levels.

[1] The effect of TOU rates on residential customers in Europe is analyzed in Mitchell, Manning, and Acton (1978, Ch. 6).
[2] See Nelson (1974) for articles by EdF engineers that provide the analytical foundation for the original tariff.
Electricity Rates

From November through February EdF experiences its greatest demand and has reduced hydro resources. There are three Green Tariff rate periods in these months:

- **Peak hours**: 7 a.m.-9 a.m. and 5 p.m. to 7 p.m. Monday through Saturday.[1]
- **Shoulder hours**: 6 a.m. to 10 p.m. except Sunday and peak hours.
- **Off-peak hours**: 10 p.m. to 6 a.m. and all day Sunday.

Rates also vary seasonally: in October and March, the peak hour rate is eliminated and the shoulder rate applies without change from 6 a.m. to 10 p.m.; from April through September lower shoulder and off-peak rates apply. High-voltage customers pay separate energy and subscribed demand charges in each rate period; these rates decline from the peak to shoulder to off-peak periods.[2] Figure 1a shows the energy rates for the most common form of the Green Tariff.

A customer who is highly sensitive to the price of electricity might respond to these rates and have the hypothetical load curve shown in Fig. 1b. Such users with production flexibility would minimize load during morning and afternoon peak hours, make maximum use of electricity during night and weekend off-peak hours, and use an intermediate amount during shoulder hours. We first examine system load data for evidence of such load changes and then turn to individual customer data.

[1] In 1979, the peak hours were adjusted to 9 a.m.-11 a.m. and 6 p.m.-8 p.m. to reflect the long-term shift in EdF's load curve.

[2] If actual demand exceeds subscribed demand, the subscribed level is increased or a substantial penalty is assessed. Customers may select from five versions of the tariff, choosing the schedule that most nearly matches their load pattern in several rate periods. The rates, but not the tariff structure, also vary with the supply voltage. See Mitchell, Manning, and Acton (1978), Ch.4) for additional details of the tariff.
Evolution of the System Load Curve

From 1955 to 1975 EdF's peak demand grew at an annual rate of 6.28 percent while total kWh grew by 6.58 percent annually.[1] Figure 2 shows how the shape of the system load curve has changed since the introduction

Fig. 2. French Daily Load Curves for Representative January Workdays

of TOU rates. To compare the load shapes in 1952 and 1975, the load must
be normalized. In Fig. 2a for each year the average daily load curve for
six workdays in January is divided by the average EdF load on those days.
In 1952 the peak demand was about 38 percent greater than the mean demand,
but by 1975 the peak was only 14 percent above that year's mean. The
load shapes may also be compared by dividing each year’s load curve values
by the peak load of that year. Figure 2b displays the same data in this
form. In 1952 the lowest demand was about 44 percent of the peak, and by
1975 the minimum was up to 70 percent of peak.[1]

Based on this evolution of the system load curve, Yves Balasko
(1976) estimated the additional peak demand that EdF would face in 1980
if it were required to supply the quantity of energy projected for that
year but in the shape of the 1956 load curve. This method finds that an
increase of 6500 MW of capacity would be necessary—almost 14 percent of
EdF's projected capacity.

Should the improvement in EdF's load curve over this period be
attributed solely to the incentive effects of the Green Tariff? We
think not. Secular trends in industrial production, changes in work
habits, and altered residential consumption patterns may also have con-
tributed to the improvement. At the same time, if peak consumption by
non-TOU customers grew very rapidly, system load data would tend to
understate the response by Green Tariff customers. Analysis of indivi-
dual customer's load curves can help to disentangle these effects.

[1] Some consultants (e.g. Nissel, 1979, p. 21) have mistakenly
suggested that a load comparison like Fig. 2a demonstrates "peak shav-
ing" effects of a rate, while Fig. 2b suggests "valley filling." The
same information is, of course, contained in each pair of curves; nei-
ther representation can distinguish the two effects.
Analysis of Individual Load Curves

Class Load Data. EdF has studied December 1974 peakload conditions using daily load curve data for all industrial customers (including the national railway) served at high voltage in France.[1] The purchased electricity load of these very large customers as a class shows a modestly lower peak period demand compared with off-peak. Individual customers' loads take one of four characteristic shapes shown in Fig. 3. Most customers have either flat or day-peaking profiles. However, two groups show pronounced load reductions during the four peak hours or throughout the peak and shoulder hours. Collectively, customers in the third and fourth groups reduce peak-period purchases over 600 MW compared with off-peak purchases. As noted earlier, it is impossible to know from these data alone whether customers in the first and second groups have changed their loads as a result of TOU rates. But there can be little doubt that customers in the third and fourth groups are responding specifically to the TOU rates. Indeed, these customers might have been noticeably day-peaking before TOU rates were applied, in which case the nominal reduction of 600 MW for the class would understate the total response.

Individual Customer Loads. The load curves of individual customers in the third and fourth groups also illustrate TOU rate effects.[2] For example, the cement plant's winter load curve in Fig. 4 closely resembles the hypothetical load shape in Fig. 1b of an idealized firm. The

[2] See Mitchell, Manning, and Acton (1978, Ch. 5) for a detailed presentation of individual customer load curves.
Fig. 3 Classification of Load Curves of French High-Voltage Industrial Customers, Excluding Selfproducers—December Weekday, 1974

Source: Ploeger (1978)
Sunday load curve, when off-peak prices apply all day, makes clear that electricity rates dominate scheduling considerations in this plant. Additional data from the spring, summer, and fall show that it also responds to the TOU features of the Green Tariff throughout the year, reducing load during shoulder-rate hours. A second example (Fig. 5) shows a modern refinery's characteristic winter and summer daily load curves. This customer can supply much of its electricity requirements by generating its own power and its demands for purchased power are

![Graph showing load curves for a French cement plant.](source)

**Figure 4.** Winter Load Curves for a French Cement Plant

![Graph showing load curves for a French petroleum refinery.](source)

**Fig. 5.** Winter and Summer Load Curves for a French Petroleum Refinery with Self-Generation
shown by the shaded load curves. During the winter, the refinery makes maximum use of self-generation during the peak and shoulder hours. In the summer months, when EDF's rates are lower, it purchases a nearly constant amount of power at all hours. Other examples of firms with specific tariff-related load reductions occur in ferro-alloy, electrometallurgy, electrochemical, pumping and pipeline, cold storage, and some commercial operations.

Subscribed Demand Levels. The Green Tariff provides strong price incentives for not subscribing for power that is not needed. It also imposes surcharges for exceeding subscribed levels. Because customers are committed to those power levels for a five-year period, subscribed demand levels provide an indication of longer-term load patterns.

In 1978, the pattern of subscribed demand for both high voltage and medium voltage customers (Fig. 6) followed the hypothetical response curve of Fig. 1b, with a maximum difference between the total summer off-peak demand (31,711 MW) and total winter peak demand (26,051 MW) of some 18 percent. During winter months, contractual demand was 12 to 14 percent lower in peak hours than shoulder hours.

Fig. 6. Subscribed Maximum Winter Demand for Green Tariff Customers Served at Medium and High Voltage Levels, 1978
Side-by-Side Comparisons of Individual Industry Data. Using results from EdF load studies of high-voltage customers, analysts at The Rand Corporation compared load curves of 17 individual industries under TOU rates in France with load curves for the same industries served under conventional rates in two California utilities. To ensure comparability of production processes, the U.S. firms were classified at the 3- and 2-digit SIC level to correspond with French industrial classifications.[1] This side-by-side method of analysis assumes that if introduced into the United States, TOU rates would leave total kWh unchanged but would shift load curves to the shapes observed in French industries. No adjustment was made for non-tariff differences between utilities on the grounds that industrial processes are internationally similar and relatively little affected by weather and other local factors. For the U.S. mix of manufacturing industries, the TOU effects calculated by this method indicate a 15 to 35 percent long-term reduction in peak-period class demand and energy.

Trends in Hourly Load. Yvette Pioger (1977) at EdF has analyzed the trends in hourly loads for twenty years of TOU rates. This method isolates the speed with which adjustment to TOU rates has occurred by measuring load changes when peak rates go into effect each November. The estimates control for growth factors and seasonal effects such as weather and hours of daylight.

[1] These industrial comparisons are based on load studies comprising 250 firms in France and 175 firms in California. See Mitchell, Manning, and Acton (1978, Ch. 8).
Pioger calculates the hourly relative demand in each week of the year by dividing the hourly system load by each week's average daily demand.[1] The effect of TOU peak rates is brought out by comparing relative demands at 8 a.m. and 10 a.m. in the fall. During October, consumption at both hours is priced at shoulder energy and demand rates; in November, peak rates apply at 8 a.m., but shoulder rates remain unchanged at 10 a.m. If customers have responded to TOU rates, the demand at 8 a.m. in November will decline in comparison with the demand at 10 a.m. Furthermore, the relative decline at 8 a.m. will increase from 1957, when TOU rates were first applied to a portion of high voltage users, until at least 1968, when all medium and high voltage customers faced TOU rates.

Figure 7 shows the trends in relative demand at these hours during 1956-1976. During the morning hours the system load is near its

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[1] Relative demand is $\pi_{hi} = KW_{hi} / \left( \frac{1}{24} \sum_{h} KW_{hi} \right)$, where $KW_{hi}$ is the mean weekday demand at hour $h$ in week $i$. 

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Fig. 7. Evolution of Relative Demand at 8 A.M. and 10 A.M. During a Week Before and a Week After Peak Rates Take Effect on November 1, Electricité de France, 1956-1976.
daily peak, so demand, relative to the daily average, is greater than 1.0. Because loads at other hours were growing more rapidly, relative demand at both 8 a.m. and 10 a.m. declines over time. In October, the relative decline in loads at 8 a.m. and 10 a.m. is almost identical (Fig. 7a), showing the common effect of the same TOU rates at both hours and of other factors that influence load over time. In addition, the pattern at 10 a.m. in November is almost identical to that at 10 a.m. in October---showing the basic similarity of the two weeks. The peak-period pattern in November, however, is distinctly different than the shoulder-period pattern: relative demand at 8 a.m. declines about twice as rapidly as at 10 a.m.

After 1968, the decline in relative demand at 10 a.m. levels off, perhaps marking the point at which a general evolution of daytime load patterns ended. The continuing decline in 8 a.m. relative demand in November probably reflects the longer term adjustments of customers to TOU rates.

Throughout the four winter months the trend in relative peak usage continued to decline at a faster rate than shoulder period usage. Pioger estimates that by 1965 the Green Tariff had reduced system load some 700 MW at 8 a.m.; she conservatively assumes that the Green Tariff had no further effect on relative demand after 1966, so the same relative effect implies a 1400 MW reduction in 1975 when the system load had doubled. This intermediate-term TOU effect amounts to some 5 percent of the total system load.
BRITISH EXPERIENCE WITH TOU RATES

Electricity in England and Wales is generated by the nationalized Central Electricity Generating Board (CEGB) and supplied under a common wholesale tariff to twelve Area Boards which distribute energy and set retail tariffs. At high voltages, these rates closely follow the terms of the wholesale tariff. Unlike in France, customers in Britain may choose between a conventional rate and a TOU rate with a single long peak period (12 or more hours) with a 2:1 ratio between peak and off-peak energy charges (formerly a difference of about 1 cent per kWh; presently about 2 cents per kWh). Typically, peak demand rates apply from 8 a.m. to 6 p.m. and peak energy rates from 7 a.m. until 10 p.m. or midnight.\footnote{In the early 1960s, Area Boards offered these optional TOU rates to higher voltage customers and special discount rates to residential customers who installed storage radiators for space heating. By 1969, most residential customers could choose an unrestricted TOU rate.}

System Load Curve and Individual Customer Data

Over the first decade of TOU rates the British daily load curve has become considerably flatter (Fig. 8). Peddie (1975) calculates that if Britain's 1972/73 energy requirements had been demanded in the shape of the 1960/61 load, an additional 4700 MW of demand would have resulted—an increase of 13 percent of the 1972/73 average winter weekday system peak load. As in France, non-tariff factors may also have contributed to the long-term improvement in the system load curve.

Individual customer data show that the degree of British response to TOU tariffs is comparable to French firms that operate similar processes. As one example, Fig. 9 shows the winter load curve for a

\footnote{See Mitchell, Manning, and Acton (1978, Ch. 4).}
sample of larger British firms in the chemical and allied industries.

Substantial winter daytime reductions in energy occur during peak hours. Similar tariff-related load reduction patterns are observed in the British cement, brick, pottery, glass, petroleum refining, industrial gases, and steel and foundries industries.

**Load Management Effects**

The British rate structure makes extensive use of a tariff for voluntary curtailment of load by large industrial customers. When the CEGB anticipates an unusually high level of demand relative to available resources, it issues a Load Management Warning for specific hours of the following day. The Area Boards then notify some 120 customers who have special agreements that provide for substantial reductions in payments for maximum demand when load is shed during Load Management Warning periods. In total, the load shed by these customers is some 1200 MW, or about 40 percent of the load management class demand. This reduction represents nearly 11 percent of the entire industrial load at the time...
of the system peak and over 3 percent of the system's wintertime peak load.[1]

The British and French experience with TOU rates is remarkably consistent--especially in light of the substantial differences in lengths of peak periods and levels of rates. Aggregate system effects have been calculated to be very similar by utility analysts in each country. Although there is considerable variation within industrial groupings in each country, firms in a given industry show similar character and magnitude of response to peak/off-peak rate differentials.

In both countries, the rates have now been in effect for over fifteen years, and it is difficult to judge how fast such a response would occur in another utility system. Further, the changed energy circumstances of the 1980s may mean that this experience would not be duplicated in England or France if TOU rates were introduced for the first time today. Initial U.S. data under TOU rates provide some evidence of the short-run response that may be experienced under present-day circumstances.

EARLY U.S. EXPERIENCE WITH TOU RATES

In the late 1970s several state regulatory commissions ordered the first mandatory TOU rate structures for electricity consumers. Comparative data for the first one or two years of experience are available from Pacific Gas & Electric (PG&E), Southern California Edison (SCE), and Wisconsin Power and Light (WP&L). In addition, the San Diego Gas and Electric Company (SDG&E) has a TOU rate for larger customers, with

economic incentives similar to Britain's Load Management tariff. We use these data to illustrate the short-term evolution of class loads and changes in individual load curves.

Table 1 summarizes the principal features of these TOU rates. PG&E's and SCE's rates have a three-level peak/shoulder/off-peak structure for both demand and energy charges; the peak periods change seasonally. WP&L has a simple peak/off-peak rate that applies fourteen hours each day except Sunday. SDG&E's rate has a three-level energy charge and a single demand charge that applies to the customer's half-hourly maximum demand at the time of the system's peak--determined after the fact each month.[1]

The PG&E and SCE rate structures resemble the French Green Tariff, with the notable difference that there is a single peak period lasting four to six hours. Before introducing the TOU rates these utilities had conventional three-part tariffs with customer, maximum demand, and energy rate elements that did not vary with time of use.[2]

PG&E load curve data permit before-and-after comparisons for individual customers. During the first two years of TOU rates several firms made sizable reductions in peak-period relative loads. The load curves in Fig. 10 are illustrative of responsive cement and industrial gases customers; they resemble the load shapes of French firms in the same industries.[3] Other firms—in the paper, glass, chemical, manufacturing, industrial gases, and steel industries—had reductions of 5 to 31

[1] TOU customers may elect to have an on-site real-time signal which displays the system's demand to help anticipate the peak period. [2] PG&E's customers could arrange to be exempted from the demand charge in late night hours. [3] Each figure plots the hourly load relative to the daily mean load.
Table 1

EARLY TOU RATES FOR LARGE U.S. CUSTOMERS

<table>
<thead>
<tr>
<th>Utility and Period</th>
<th>Winter Season</th>
<th>Demand Rates</th>
<th>Summer Season</th>
<th>Energy Rate $^{a}$</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Rate ($/kW)</td>
<td>Hours</td>
<td>Rate ($/kW)</td>
<td>Hours</td>
</tr>
<tr>
<td>PG&amp;E (2/4/77)$^{b}$</td>
<td>2.30</td>
<td>1630-2030, M-F</td>
<td>3.45</td>
<td>1230-1830, M-F</td>
</tr>
<tr>
<td>Peak</td>
<td>0.28</td>
<td>10 hours, M-F</td>
<td>0.85</td>
<td>8 hours, M-F</td>
</tr>
<tr>
<td>Shoulder</td>
<td>0</td>
<td>Other hours &amp; holidays</td>
<td>0</td>
<td>Other hours &amp; holidays</td>
</tr>
<tr>
<td>Off-peak</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>SCE (10/14/77)$^{c}$</td>
<td>2.10</td>
<td>1700-2200, M-F</td>
<td>2.10</td>
<td>1200-1800, M-F</td>
</tr>
<tr>
<td>Peak</td>
<td>0.25</td>
<td>9 hours, M-F</td>
<td>0.25</td>
<td>8 hours, M-F</td>
</tr>
<tr>
<td>Shoulder</td>
<td>0</td>
<td>Other hours &amp; holidays</td>
<td>0</td>
<td>Other hours &amp; holidays</td>
</tr>
<tr>
<td>Off-peak</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>SDG&amp;E (9/17/77)$^{d}$</td>
<td>6.10</td>
<td>Coincident with Monthly Peak</td>
<td>6.10</td>
<td></td>
</tr>
<tr>
<td>Peak</td>
<td>1700-2100, M-F</td>
<td>1000-1700, M-F</td>
<td>3.05</td>
<td></td>
</tr>
<tr>
<td>Shoulder</td>
<td>5 hours, M-F</td>
<td>4 hours, M-F</td>
<td>2.65</td>
<td></td>
</tr>
<tr>
<td>Off-peak</td>
<td>Other hours &amp; holidays</td>
<td>Other hours &amp; holidays</td>
<td>2.45</td>
<td></td>
</tr>
<tr>
<td>WP&amp;L (ave. 1977)</td>
<td>4.50</td>
<td>0800-2200, M-Sat.</td>
<td>4.50</td>
<td>Same</td>
</tr>
<tr>
<td>Peak</td>
<td>0$^{e}$</td>
<td>Other hours &amp; holidays</td>
<td>0$^{e}$</td>
<td>Same</td>
</tr>
<tr>
<td>Off-peak</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

$^{a}$Energy rates apply at same hours as demand charges and include adjustment charges in effect on date shown.

$^{b}$PG&E seasons: Winter, Oct.-April; Summer, May-Sept.

$^{c}$SCE seasons: Winter, Nov.-April; Summer, May-Oct.

$^{d}$SDG&E Seasons: Winter, Oct.-April; Summer, May-Sept.

$^{e}$Up to twice peak period level.
percent in peak-period relative demand.[1] Furthermore, an hourly trend analysis of individual load curves on a month-by-month basis shows that these firms adjust the timing of their maximum loads when the seasonal shift in the peak period occurs. SCE customers in the cement, rubber, chemical, and steel industries have demonstrated similar load responses after one year under TOU rates.[2] These short-run responses have been accomplished by scheduling changes using existing equipment; we can anticipate greater effects in the longer run as additional scheduling changes are made and investments take place to exploit TOU rates.

At this early stage with TOU rates, most of the PG&E and SCE customers on TOU rates have made little or no load response. Despite this, as shown in Figs. 11 and 12, TOU rates have already significantly

![Graphs](image)

Fig. 10. August Load Curves of Two Firms Which Respond to TOU Rates, PG&E

[1] PG&E (1979, Table 19) and Reynolds and Creighton (1980).
Fig. 11. Relative Load Curves of TOU Class on July Weekdays, PG&E

Source: PG&E (1979, p. 41)

Fig. 12. Relative Load Curves of TOU Class on Summer Weekdays, SCE

Source: SCE (1979)
affected the relative load curves of the TOU customer class in both utilities. During the weekday peak periods, the class relative demand (kW) was reduced by 1.3 to 2 percent in PG&E and 0.6 to 1.6 percent in SCE.[1] Linear regression analyses by the utilities' statisticians using monthly data confirm these values and establish that the reductions during peak periods are statistically significant. However, SCE analysts report that in their system no reduction in relative demand was detected on the 10 peak days of the year.

SDG&E's substantial charge for demand coincident with the monthly system peak ($6.10/kW), as well as their TOU energy rates, have reduced relative coincident peak demand and altered load curves. In the first year under TOU rates, average energy use during peak hours by the original group of 16 TOU customers fell by 5-6 percent when normalized by total weekday use in the season. The utility's analysts report that coincident billing demand fell by 3.5 percent for the class.[2] Figure 13 shows the average summer weekday TOU class load curves before and after the introduction of the new rate.

The WP&L two-level TOU rate took effect in January 1977 for 140 large industrial and commercial customers. Its energy price varies by just over 1 cent/kWh between peak and off-peak hours throughout the year, and the $4.50/kW maximum demand charge applies only during peak hours. This tariff is notable for its 14-hour peak period: 8 a.m.-10 p.m., Monday-Saturday. WP&L engineers have applied three methods to measure individual and class load changes. They surveyed customers

[1] SCE also reports relative reductions in peak period energy of 0.7-1.2 percent.
to determine shifts in production activities and use of machinery and estimated a 25 MW reduction in peak period demands. This represents 10 percent of the large commercial and industrial TOU class peak load. [1] Second, using individual customer load data, WP&L analysts found that for almost half of the customers, off-peak demands were greater than peak demands for at least one month during the first year. Conservatively assuming that these customers had the same demands in both peak and off-peak periods before introduction of the TOU rate, and neglecting any response by other customers, they estimate a peak load reduction of 22 MW. [2]

Finally, the before-and-after TOU class load curves plotted in Fig. 14 on the day of the system's monthly peak demand in December show flatter relative class loads after TOU rates took effect. These comparisons may include some TOU adjustment that had already begun in 1976.

when customers were offered exemption from demand charges at off-peak hours. Calculations using a load study sample of customers who were recorded before any TOU rate elements were introduced indicate that the relative use of peak period declined some 9.7 percent.[1]

Like utilities in California and Europe, WP&L finds that firms with electric arc furnaces and drying ovens, motor test facilities, pipeline and pumping loads, and pulp and paper operations are especially responsive to TOU rates. WP&L's customer survey found that in the case of approximately 75 percent of the customers, TOU rates had resulted in making no special investments. However, others indicated that the TOU rates had already led them to install new equipment, including electric ovens and demand controllers.[2] The effectiveness of WP&L's TOU rate after only one year may seem unusual given its broad peak period and relatively modest peak/off-peak rate differential. A contributing factor may be WP&L's extensive customer outreach program prior to introducing the new rate.

IV. ASSESSING TIME-OF-USE RATES

We can now return to our question: Do TOU rates change load curves?

TOU rates do change the load curves of both individual customers and utility systems. To determine these effects, load data must be assessed by methods that compare loads under TOU rates with loads under conventional rates and that also control for changes in non-tariff factors. Several methods based on before-and-after and side-by-side data permit measurement of the quantitative effect of TOU rates. Although no method is perfect, each supports the basic finding that in both Europe and the United States TOU rates change load curves.

MAGNITUDE OF RESPONSE

The magnitude of the load changes depends on the length of time TOU rates have been applied and the number of customers they cover. In the long term--ten or more years after introducing TOU rates--there are sizable reductions in system peak load; they may amount to as much as 13 or 14 percent in France and Britain if the utilities were required to serve today's energy needs in the form of previous time-of-use profiles. In the short term--after just one or two years--the effects are measurable and statistically significant, but are generally much smaller in the few U.S. utilities that have introduced TOU rates for their largest customers. The U.S. changes range from less than 1 percent to almost 10 percent of the TOU class peak load.

Table 2 summarizes the changes in the average load during the peak periods in the six utility systems examined. The length of the peak rating period has little effect on the magnitudes of response. In
Table 2
SUMMARY OF ESTIMATED REDUCTIONS IN PEAK PERIOD LOAD

<table>
<thead>
<tr>
<th>Utility</th>
<th>Estimating Method</th>
<th>Type of Data</th>
<th>Percent Reductions in</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td></td>
<td></td>
<td>System Load (kW)</td>
</tr>
<tr>
<td>Long-Term Change</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>EDF (France)</td>
<td>Evolution of load curve</td>
<td>System load</td>
<td>14</td>
</tr>
<tr>
<td>EDF</td>
<td>Individual customer load shapes</td>
<td>Subscribed demand</td>
<td>12-14</td>
</tr>
<tr>
<td>CEGB (Britain)</td>
<td>Evolution of load curve</td>
<td>System load</td>
<td>13</td>
</tr>
<tr>
<td>Intermediate Term Change</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>EDF</td>
<td>Trends in hourly load</td>
<td>System load</td>
<td>5</td>
</tr>
<tr>
<td>CEGB</td>
<td>Individual customer load shapes</td>
<td>Load management customers</td>
<td>40</td>
</tr>
<tr>
<td>Short Term Change</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>PG&amp;E</td>
<td>Evolution of load curve</td>
<td>TOU class</td>
<td>1.3-2.0</td>
</tr>
<tr>
<td>SCE</td>
<td>Evolution of load curve</td>
<td>TOU class</td>
<td>0.6-1.6 0.7-1.2</td>
</tr>
<tr>
<td>SDG&amp;E</td>
<td>Evolution of load curve</td>
<td>TOU class</td>
<td>3.5&lt;sup&gt;c&lt;/sup&gt; 5-6</td>
</tr>
<tr>
<td>W&amp;L</td>
<td>Customer survey</td>
<td>Reported scheduling and equipment changes</td>
<td>10</td>
</tr>
<tr>
<td>W&amp;L</td>
<td>Evolution of load curve</td>
<td>TOU class</td>
<td>9.7</td>
</tr>
</tbody>
</table>

<sup>a</sup>See text for sources of estimates.
<sup>b</sup>Response to load management warnings above normal TOU response.
<sup>c</sup>Reductions in demand coincident with system peak.
Europe substantial long-term reductions in both system loads and industrial customer loads occur under the 12-hour peak period of the British tariff as well as the twin 2-hour peak periods of France's tariff. In the United States, the largest peak load response has occurred under WP&L's 14 hour peak period.

Peak day effects are less certain. EdF finds major reductions during the system's peak week, and in Britain, demand reductions by industrial Load Management Warning customers account for over 3 percent of the entire system load on peak days. At PG&E and WP&L, relative load in the TOU class has been reduced on peak days of the month, and at SDG&E a coincident demand charge at the time of the system's monthly peak produces a 3.5 percent drop in the TOU class peak load. However, SCE analysts find no change in the TOU class peak load during the ten peak days of the first year.

HOW MUCH MORE RESPONSE CAN WE EXPECT?

At this time, it is not clear that load changes caused by TOU rates introduced in the United States only in the last few years will ever reach the magnitude observed abroad 15 to 20 years after similar rates took effect. Although Wisconsin data already show 10 percent reductions in the TOU class peak load, changes in other U.S. utilities after one or two years are considerably smaller. Side-by-side analysis of European and U.S. load curves indicates that if U.S. manufacturing industries eventually demonstrate the same degree of TOU response as counterpart industries in Europe, then in the long term the peak period relative loads would be reduced by 15 to 35 percent in that group. Given manufacturing's relative share in U.S. electricity consumption, this amounts to 3.2 to 7.5 percent of non-coincident peak demand in U.S.
utilities.[1]

As for individual customers' adaptation to TOU rates, U.S. data for large customers thus far substantiate foreign experience that even in the long term, customer response is highly variable. Most customers remain day-peaking and make at most minor changes in their peak demands. But a significant minority of customers react, some quite rapidly and substantially. Some U.S. customers have already made capital investments to take advantage of the TOU rate structure, although the majority accomplish their changes by rescheduling selected activities that require significant amounts of electricity. In general, customer-by-customer studies of response in Europe and the United States[2] have found that

(1) The largest percentage reductions occur in industries having electric-intensive loads, e.g., electric heating, pumping, and compression.

(2) Sizable reductions also occur when firms have discrete loads that can be reduced, stopped, or shifted, e.g., crushing, grinding, and liquefaction operations.

(3) Response to TOU rates is enhanced when firms have excess production capacity that allows concentrating activity in off-peak periods.

(4) Greater response occurs when cogeneration is available.[1]

The potential long-run systemwide effects in the United States have several components, each of which will increase the aggregate effects observed to date. Over the next several years, response by large commercial and industrial users presently covered by TOU rates is expected to grow as these customers make longer run investments and scheduling changes on top of their present adjustments. In addition, the TOU rates are being extended to several hundreds of other commercial and industrial users in these utility systems, so the aggregate class response will increase. Finally, we have confined this survey to one class; the total system effect will be greater if residential and smaller commercial users are offered TOU rates.

**ARE TOU RATES WORTHWHILE?**

Ultimately, a judgment about the benefit or "cost-effectiveness" of TOU rates must take account of many factors that vary from utility to utility. The peak load changes that would be experienced by any particular U.S. utility contemplating TOU rates will vary with its customer mix, the details of the proposed rate, and the number of customers covered. The value of load changes to the utility will be a function of its specific incremental operating and capacity costs, and the net benefits to consumers will depend on their valuation of electricity at peak and off-peak hours. A comprehensive analysis of these factors is beyond

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[1] Hourly modulation in cogeneration takes place only when condensing equipment is available; seasonal modulation can occur by turning off stand-alone generation units.
the scope of this report.[1]

Although present U.S. experience shows generally modest percentage reductions in peak loads, they are the result of applying TOU rates to only a small number of customers whose annual electricity bills typically exceed $100,000. Consequently, at this scale, even extremely modest percentage changes in load can overcome the costs of implementing a TOU rate. Three of the four U.S. utilities we examined have conducted some form of cost-benefit analysis and concluded that TOU rates are worthwhile.[2] And all four utilities plan to extend their TOU rates on a mandatory basis to more of their larger customers.

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