ELECTRICITY PRICING AND LOAD MANAGEMENT:
FOREIGN EXPERIENCE AND CALIFORNIA OPPORTUNITIES

PREPARED FOR THE CALIFORNIA STATE ENERGY RESOURCES CONSERVATION AND DEVELOPMENT COMMISSION

BRIDGER M. MITCHELL, WILLARD G. MANNING, JR., JAN PAUL ACTON

R-2106-CERCDC
MARCH 1977

Rand
SANTA MONICA, CA 90406
The research described in this report was supported by the California State Energy Resources Conservation and Development Commission under Contract No. 4-0080. Reports of The Rand Corporation do not necessarily reflect the opinions or policies of the sponsors of Rand research.
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PREFACE

Proposals for fundamental changes in the tariffs under which electricity is sold in the United States have attracted the widespread attention of consumer groups, environmental advocates, energy policymakers, utilities, and regulatory commissions. Some of the most promising opportunities for increasing the efficiency of both the capital and the fuel used in the electricity sector are found in proposals to adopt forms of peak-load pricing and direct management of consumer electrical loads.

Although foreign utilities have used peak-load pricing and load-management techniques for many years, these methods have not been adopted in the United States. To examine the experience accumulated in six European countries, the authors have interviewed engineers, economists, and managers in utilities, private industry, and government in Finland, France, West Germany, Norway, Sweden, and the United Kingdom.

This report, prepared for the California Energy Resources Conservation and Development Commission, summarizes the information and data compiled in this survey and projects the potential effects of peak-load rates on consumers of industrial electricity in California. The findings should be of interest to state and federal regulatory bodies and energy agencies, to legislative committees charged with energy policy, to utilities in the United States and abroad, and to the broader audience concerned with the more efficient use of energy resources.
SUMMARY

The costs of supplying electricity vary according to regular hourly and seasonal patterns. Because a utility maintains sufficient capacity to generate and distribute electricity to meet the maximum amount demanded at any time, the cost of supplying power at hours of peak demand is higher than it would be if the same amount of electricity were used at all hours of the day, throughout the year.

European utilities have historically sold electricity at rates that reflect these daily and seasonal differences in supply costs. Until very recently such time-related peak-load methods of pricing have not usually been a part of American practice. Seasonal and time-of-day tariffs are now attracting the attention of American utilities and regulatory bodies because peak-load pricing promises to reduce the use of electricity during high-cost periods, to shift electrical loads to lower-cost hours or to alternative and less-expensive sources of supply, and to encourage greater efficiency in both the production and consumption of energy. In addition to their peak-load tariff policy, European utilities also frequently use more active approaches to modify the load patterns of their customers, such as by promoting appliances that use electricity predominantly during off-peak hours and by installing equipment that permits the utility to interrupt power supplied to selected end-uses.

European utilities determine the structure of their electricity tariffs according to the principle that the terms of the tariff should signal to the customer the marginal costs of supplying power at the time that it is consumed. Utilities base the design of their tariffs on analyses of the daily and seasonal variations in marginal costs, and these analyses form an integral part of the long-run planning of the electrical system. In practice, there are substantial differences in the tariffs of different countries; these differences reflect the costs of fuel, the availability of hydroelectric resources, demand patterns, and other economic circumstances facing individual utilities.

A number of industrial firms operating in major European countries adjust their production activities so that they can economize on electricity consumed during peak hours. The techniques used by customers to reduce peak-hour loads depend specifically on the nature of their production processes, the economic demand for their products, and the structure of the tariff. Many industrial plants can schedule regular maintenance during peak hours, store heated or cooled materials for use when electricity is more expensive, increase the electricity generated as a by-product of normal production (by using steam or gases from industrial processes), and schedule work-force activity for off-peak periods.

The load curves of a large number of individual firms and major industries in France, England, and Wales show that significant quantities of industrial load are shifted to off-peak hours. Measured load reductions in cement, brick, glass, iron and steel, electrometallurgical, and petroleum refining industries establish that some individual firms can reduce their peak-hour consumption of electricity by 25 to nearly 100 percent in response to peak-load tariffs. Moreover, in return for special terms, some firms are willing to curtail their operations sharply during peak hours, and to have their supply of power interrupted in response to announced warnings
of impending excess peak demands during the season of greatest consumption. Overall, European utilities with peak-load tariffs have achieved substantial reductions in the aggregate peak load of their industrial customers.

European utilities use active load-management techniques, in conjunction with peak-load tariffs, to induce millions of residential customers to adopt load shifting, even though, by comparison with industrial firms, they individually consume relatively small amounts of electricity. Storage units for both space and water heating draw electricity during overnight off-peak hours and have sufficient capacity to provide services for a 24-hour period. They are controlled by a time clock on the customer’s premises, or by a coded pulse injected into the electrical distribution system, or by a radio signal. Widespread adoption of residential storage devices has successfully shifted load and increased off-peak demand to the point that in some cases it is nearly as large as the primary system peak. In such systems, balanced growth in load is achieved by limiting the rate at which new storage units are installed and by innovation in appliance technology. Where utilities are operating in cold climates and have substantial hydroelectric resources, load management emphasizes the use of direct electrical heating that can be interrupted from a central control point to limit peak demands in the distribution system. European utilities employ a wide variety of load-management techniques, and those used by a particular system depend on the structure of its marginal costs and the local circumstances of its residential consumers.

The opportunities for shifting electrical peak loads in California are most readily assessed for industrial consumers. Comparisons of industry-specific load curves for French firms in 18 industrial groups with their California counterparts in the same industries establish the potential for substantial load shifting in California. If California utilities were to sell power to customers in these 18 industries under peak-load tariffs, backed by economic incentives for off-peak consumption similar to the incentives offered by French high-voltage tariffs, the amount of electricity used during a 4-hour peak period could be reduced by 54 million to 76 million kilowatt-hours per month, or by 33 to 46 percent of the present statewide peak-hour industrial demand. Load shifts of this magnitude would result in more efficient uses of fuel and achieve savings of as much as $1.3 million per month. If all types of industries in California were to respond to peak-load tariffs in a similar fashion, the load shifts and fuel savings would be some 80 percent larger.

The full benefits of industrial load shifting in California would be achieved gradually over a period of several years as industries incorporated design changes into expansion and replacement of existing productive facilities. Reductions in peak-period demand could help existing generating plants to operate more efficiently and could postpone or eliminate the need to construct new facilities to provide peaking capacity. In all California industries combined, there is the potential to achieve a reduction of at least 0.8 to 1.4 million kilowatts, which is approximately 5 percent of the annual statewide peak demand and is equivalent to as many as seven peaking units of 200 megawatts each.
ACKNOWLEDGMENTS

This study has benefited immeasurably from a forthright exchange of information of many dedicated experts and scholars in seven countries. We wish to express our special thanks to Madame Y. Pioger of Electricité de France, Mr. T. A. Boley of the Electricity Council of London, and Dr. Ingo Vogelsang of the Rheinische Friedrich-Wilhelms University, Bonn, for the enthusiasm and patience with which they assisted our efforts. We are also greatly indebted to the following individuals for contributing information and comments to this report:

Finland
   H. Backström
   A. Jouhki
   K. Leino

K. Lönngren
E. Maijala
A. Puromäki

France
   Y. Balasko
   M. Chambout
   M. Chedorge
   M. Francony
   M. Giron
   M. Goubet

D. Jung
M. Koenig
J. Lorgeou
R. Proner
M. Penel

Norway
   O. Aarvik
   P. Berg
   S. Falck-Jørgensen
   A. Fostervoll
   O. Larsen

K. Saugstad
S. Strøm
T. Thorsen
G. Vatten
J. F. Ziesler

Sweden
   L. Bergman
   G. Carlsson
   S. Haal
   H. Karlin

H. Ljung
M. Lönnrudh
A. Lundquist
E. Skalsky

United Kingdom
   J. G. Boggis
   J. Bond
   M. Bridge
   J. A. C. Brown
   P. G. Caudle
   Mr. Foister

P. K. Griffiths
R. W. Orson
J. Rhys
F. L. Taylor
J. H. Watkinson
P. E. Watts
West Germany
Mr. Aundrup
M. Lange-Hüsken
Mr. Klonka
Mr. Mueller
J. Müller
D. Schmitt
W. Schultz

Mr. Stumpf
P. Suding
Dr. H. Trenkler
K. Wendt
W. Wendt
Mr. Zybell

California
A. Beringsmith
L. De Simone
L. Gardner
W. Illingworth

M. Moore
S. Reynolds
H. Sipe
D. Whitney

In addition, draft versions of this study have been improved from the comments of W. Ahern, C. Cicchetti, J. DeHaven, J. McCall, W. Mooz, and H. Sklar.

Finally, we are grateful to David Gold, Heather Hanunian, and Ed Woo, whose extra dedication made possible the computations reported in Section V, and to our editor, Dorothy Stewart, whose patient efforts helped us to complete this study.
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I. INTRODUCTION

In the aftermath of the 1974 oil embargo, public attention in the United States has been focusing increasingly on the performance of the electricity sector throughout the country. The prices of most sources of energy have been continuously and dramatically rising since the early 1970's; concurrently, the traditional methods of pricing electricity have been under attack by a diverse group of critics who call for fundamental revisions in the structure of electricity rates. "Generic" rate cases before public utility commissions in Wisconsin, New York, and California have led to orders requiring utilities to devise peak-load tariffs under which the price of electricity varies according to the time of day or the month in which it is used. Government agencies and some utilities have begun to inquire into the benefits to be gained from techniques for managing and shifting electrical loads. Some of these studies are designed to test or demonstrate the feasibility of a particular technology, such as remote load control or the use of storage units for space heating. Others focus on measuring the effectiveness of peak-load pricing in persuading customers to modify conventional patterns of using electricity and in assessing (a) the impact of such pricing schemes on consumer budgets, environmental objectives, and energy requirements and (b) their contribution to greater economic efficiency.

Utilities supplying electricity in the United States have had very limited experience in the techniques of peak-load pricing and load management. Historically, most utilities have enjoyed a long-term pattern of declining unit costs—i.e., the happy conjunction of realizing economies of scale in the construction of ever-larger generating plants and the benefits of technological progress that have lowered generation and transmission costs at a given scale of output. As a consequence, utilities have increased the consumption of electricity by widely promoting its use; they have employed a variety of techniques, including promotional advertising and tariffs with declining unit prices that encourage the purchase of new electrical appliances. Before the 1970's, most utilities concentrated on the need to construct new facilities to provide additional capacity, and adopted a passive attitude toward the pattern of their consumers' demands. Thus the characteristic approach was to take the consumer's load curve as given and then supply the electricity needed to meet his demands at minimum overall cost.

The pricing and load-management practices in many foreign utilities are in sharp contrast to those in the United States. Historically, most industrial economies abroad have had to face substantially higher energy costs than those prevailing in the United States. Also, in some utilities, notably those in France and the United Kingdom, economists have had a major role in establishing the principles to be followed in setting tariffs. As a result, foreign utilities have taken a more active approach to customers' loads: they have not merely accepted the existing load patterns but have tried to reduce costs by actually shaping the system load. To accomplish this task, they have provided price incentives to induce customers to

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2 See Acton, Manning, and Mitchell (forthcoming) or Manning, Mitchell, and Acton (1976).
shift their peak-load usage to lower-cost hours, and have established direct control systems for those uses of electricity most susceptible to interruption or scheduled operation.  

STUDY APPROACH

In this study, we examine the pricing and load-management experience of selected foreign utilities and the opportunities for applying their methods in California. In our survey of pricing and load-management practices, we have conducted an extensive review of the published literature and have drawn on a previously conducted survey of residential tariffs in European utilities. However, the most important information for this study has been obtained in numerous in-person interviews with experts and officials in six European countries. Data and explanations of load-management practices have been gathered from managers, engineers, and economists in public and private utilities, from government planning and regulatory officials, and from managers and consultants responsible for energy use in private industry.

This study has three major objectives. The first is to review the principal factors that determine the costs of supplying electricity. By understanding the basic economic principles governing the supply of electricity and its load management, we can better understand how these factors, which differ widely among countries, strongly influence the major forms of electricity tariffs and load-management measures that are in use abroad. Furthermore, these principles should play a central role in any evaluation of the desirability of employing load-management measures in the United States and in the design of peak-load tariffs for American usage.

The second objective is to assemble evidence of the extent to which consumers' loads are responsive to tariff provisions, and the extent to which load-management measures are able to achieve load shifting. In collecting such evidence, our goal has been to report specific, quantitative measurements of the effectiveness of these methods. This report constitutes the first systematic and comprehensive assessment of foreign utility pricing and load-management practices—and of their effects on the consumption of electricity—available in the United States.

The third objective is to extrapolate the observed European response to peak-load tariffs to the industrial sector of California. Our estimates should be regarded as only initial first approximations for three reasons: (1) A lack of load-curve data for European industries prior to the introduction of peak-load pricing limits our ability to measure the full effect of time-of-day tariffs abroad. (2) Important differences in European and California industrial technologies undoubtedly exist that would result in a different degree of responsiveness—either more or less—in California. (3) The level and structure of the marginal costs of supplying electricity in California probably differ in some particulars from the costs found in foreign utili-

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1 The almost total absence of peak-load pricing in U.S. electric utilities contrasts sharply with the routine use of these pricing methods in other regulated U.S. industries, such as telephones and airlines. An economic explanation for this puzzling behavior lies beyond the scope of the present study. However, some American electrical utilities have made use of special tariffs for interruptible power; for examples, see Sherry (1975).

2 This survey was made in the process of designing the Los Angeles residential peak-load pricing experiment. See Mitchell and Acion (forthcoming).

3 England, Finland, France, Germany, Norway, and Sweden were visited.
ties. Our purpose, however, is not to forecast what load changes will be realized if foreign methods of pricing and managing electricity are adopted in California, but rather to provide a first, overall assessment of the potential for using such methods in one important region of the American economy. The full extent of the gains that might be achieved, as well as the costs of pursuing such policies, must await further research.

THE RELEVANCE OF FOREIGN EXPERIENCE

Many separate aspects of the accumulated experience of foreign utilities are of potential interest in assessing the electrical energy policy in the United States and in improving our methods of pricing and managing electricity. The lessons from foreign experience can be broadly grouped into those related to the supply and pricing of electricity and those related to the demand for electricity. Of particular interest in the supply of electric power are foreign methods of planning and evaluating system expansion, measuring marginal costs of supply, and using marginal cost analysis to design tariffs. With respect to the demand for electricity, changes in European industrial patterns of demand and changes in residential use and ownership of appliances in response to peak-load tariffs and to energy prices that are generally higher than those found in the United States are of special importance in assessing the value of adapting foreign practices to American requirements. It may also be instructive to evaluate the several modes of general management, ownership, control, and finance of the electrical utility sector abroad so as to interpret the degree of success that different systems have achieved in striving for an efficient use of energy resources.

In this report we are limited to describing only a few aspects of this extensive body of experience: (a) the response of consumers to peak-load pricing, (b) the techniques of active load management, and (c) the general determinants of the marginal costs of supplying electricity on which both tariff design and load-management policies are based. It is useful, however, before we turn to a detailed examination of these three important areas, to explain why the level of success that foreign utilities have achieved in their financial performance and in promoting shifts in system load curves is only incidental to our central goal of assessing the effects of peak-load pricing and load management.

It is occasionally suggested that because a number of foreign electric utilities are operated by a national public authority their experience has little relevance for American needs. A point of particular confusion is the belief that nationalized electric utilities receive regular subsidies from the public treasury, and that such financing invalidates data about consumer use in response to price incentives. In fact, public utilities, such as those in France and the United Kingdom, are customarily operated as independent, self-financing authorities whose revenues must cover their operating and capital costs. Not surprisingly, European—no less than

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6 The generating resources, degree of interconnection with other utilities, and the patterns of consumer electricity loads are all important factors in determining the marginal costs of supplying electricity and therefore the potential gains from greater load-management activities. In sharp contrast with European practice, American utilities do not collect and analyze data showing the marginal costs of supplying electricity by hour or seasonal period.

7 Nissel (1976), for example, expresses this view.
American—utilities do come under considerable public pressure to limit rate increases. Following the 1974 oil embargo, such pressures made foreign governments reluctant to permit electricity prices to rise immediately to the level that would allow the utilities to recover all of their increased operating costs. Nationalized French and English utilities, for example, incurred significant deficits that are only now being recouped from higher rates. But this experience is not dissimilar to the difficulties that regulated U.S. utilities faced in obtaining rate relief during the same period, and it is also reminiscent of the low rates of return earned during the period of national price control in the United States after August 1971.

In any case, regardless of whether the level of a utility's tariff was sufficient to cover all of its costs at the time, our focus here is on consumer responses to the tariff structures and other load-management techniques that were actually in operation. Consumers' incentives to shift load from peak to off-peak periods depend principally on the differences between peak and off-peak prices, which are, at most, only slightly affected by an increase in the general level of the price structure required to convert a deficit into a surplus. For this reason, the analysis of consumer responses to tariff structures and load-management policies need not be concerned with the nature of the ownership or with the financing of the utilities.

Foreign utilities have undoubtedly failed to achieve all of the cost reductions that are possible from shifting the system load curve. In some instances, the implementation of the marginal cost principles on which tariffs were originally designed has in practice contained shortcomings. For example, during the last several years the system peak load in France has shifted from the early morning period (7 A.M. to 9 A.M.) when peak prices are in effect, into the later morning hours, yet the hours used for peak pricing have remained unchanged. In England and Wales, the Central Electricity Generating Board has constructed facilities for generating capacity at a more rapid rate than the rate at which demand has increased, with the result that substantial excess capacity is now in place. In Germany, rapid adoption of storage heating has threatened to shift the system peak into the late evening. And in several countries, political consideration of potential adverse effects on local employment in particular industries has led to price subsidies for electricity.

However, it is not necessary that a utility be operated perfectly in order for its experience to provide useful and valid information about the effectiveness of tariff structures and load-management policies. It is by analyzing the incentives provided to individual customers and then observing their specific load responses to these incentives that we can determine how successful such management methods can be in affecting consumer behavior. The system-wide benefits to be achieved by using these techniques will depend on how consistently they are related to the structure of each utility's marginal costs. When other considerations intervene, some of the gains in economic efficiency that could be achieved are sacrificed for other objectives.

ASSESSING BENEFITS AND COSTS OF LOAD SHIFTING

In this report, our investigation of the effects of electricity pricing and load management is limited to measuring the shifts in customer and utility load curves and does not extend to the costs and benefits of achieving these changes. Although a reduction in peak loads and a corresponding increase in the use of electrical energy...
at off-peak periods will generally allow the utility to supply the same amount of energy at lower total cost, the net benefits of such shifts can only be evaluated by a careful analysis of the costs of supplying power in different periods, the costs imposed on consumers in shifting loads, and the added costs of implementing peak-load pricing and direct load-control technologies. Although such an analysis lies beyond the scope of this study, we may briefly outline the principal factors on which such an assessment would be based.

For the utility, the gain from shifting consumer loads results from a reduction in the amount of fuel that is burned as well as from a reduction in the capacity required to meet peak demand. Savings on running costs are realized when production can be (a) increased in a period when only baseload, fuel-efficient generating units are in use and (b) reduced during peak periods when the more fuel-intensive units must also be operated. However, implementation and metering costs must be deducted from these gains.

For the consumer, there are some costs associated with modifying his load pattern, including elements of inconvenience in shifting activities to different hours. Commercial and industrial consumers may incur higher costs of production in the course of modulating their load patterns: they may maintain a greater production capacity than that needed under conventional tariffs, when production is held partly idle during peak-tariff hours; or they may have to pay shift differentials to compensate workers for the inconvenience of employment during off-peak periods; or, in some instances, they may incur the investment and operating costs of generating their own power.

The optimal load curve will be found at that point at which the utility's incremental cost savings achieved through the additional shifted load are just balanced by the incremental cost increases to its customers. Although this point is not easily determined, a completely flat system load curve is not likely to be optimal; there is no reason to believe that, when consumer inconvenience is accounted for, the incremental costs are less than the incremental benefits up to that point. And since time must be allowed for the maintenance of equipment for generating and distributing electricity, it is useful to have some slack periods in the system load curve. Moreover, even if a relatively flat system load curve were desirable, it would not normally be efficient to achieve it by requiring that each individual customer have a level load: Some customers will want to use more electricity at certain hours and will be willing to pay the full marginal costs of that service, whereas others will be willing to reduce consumption at those hours in order to reduce their expenditures.

OVERVIEW OF THE REPORT

In the next section, we will review the basic economic considerations that determine the costs of supplying electricity and discuss how European electricity tariffs are designed to reflect the structures of marginal costs. We will examine the importance of the system load curve as an indicator of supply costs and the techniques available to the utility for shifting and controlling customer loads.

In Section III, we will give a detailed report on the quantitative responses of European industries to peak-load and interruptible electricity tariffs, and in Section IV we will supplement these data with a comparative examination of active load-management techniques used in the residential sector.
In Section V, we will review the salient characteristics of California's electricity supply and develop a methodology for estimating the potential effectiveness of peak-load pricing in the industrial sector. We will apply this approach to load-curve and consumption data for selected California industries to gauge the opportunity for industrial load shifting throughout the state. In the concluding section, we will briefly suggest areas for further work that will provide the information needed to make public policy for electricity in regulatory and legislative bodies in the United States.

We make no recommendations in this report with respect to the desirability of adopting foreign pricing and load-management practices in California or in other areas of the United States. As we have noted, an assessment of the net benefits that would be derived from adopting European approaches to the efficient use of electrical energy would require a detailed analysis that lies beyond the scope of this report. If our study evokes a reexamination of the widespread U.S. practice of passively meeting consumer loads and thereby leads to new considerations of the usefulness of peak-load pricing and load management, it will have served its purpose. Further research into the particular cost and demand conditions of individual U.S. utilities is needed before it will be possible to assess the net gains to be achieved from adopting more active load-management strategies and to determine which ones are most effective.
II. BASIC ECONOMICS OF ELECTRICITY SUPPLY
AND LOAD MANAGEMENT

For many purposes, electricity may be regarded as a homogeneous good whose useful, physical characteristics are essentially the same regardless of when it is consumed. However, the costs of supplying electricity vary over the course of a single day, as well as over the days of the week and according to the season of the year. In this section, we will examine the nature of these time-related variations in costs, which result principally from variation in the demand for electricity; we will also describe how tariffs can be based on principles of marginal cost analysis in order to reflect the cost structures of the electricity-supplying utilities and thereby provide consumers with economic incentives for the efficient use of electricity.

THE NATURE OF ELECTRICITY COSTS

The cost of supplying electricity may be conceptually divided into the cost of resources used to provide energy—the quantity of electricity consumed per unit of time, measured in kilowatt-hours (kwh)—and the cost of resources used to provide capacity—the maximum instantaneous amount of energy that can be supplied at any one moment, measured in kilowatts (kw). Both the energy and the capacity costs vary over the course of a single day as well as over the days of the week and according to the time of the year.

Capacity, measured in kilowatts, is needed in all stages of producing and providing electricity—for generating power from falling water, from combustion of fossil fuels, or from nuclear reactions; for the transmission of electricity from the generators to the general area of consumption; and for the distribution of power at useful voltages to final users. If the peak load can be reduced, less capacity is needed at each stage, since under the terms of its franchise, the utility must supply whatever amount of electricity its customers demand. The capital costs per kilowatt of capacity are high in every stage, and as a first approximation, a reduction in peak-hour or peak-season demand indicates the opportunity for substantial savings in the invested capital required to supply electricity.

Although capital costs constitute the greatest fraction of the total costs of producing electricity, the cost of labor and the costs of the fuel consumed are nonetheless significant. Moreover, the technology available for producing electricity makes it possible to choose one of several different mixes of capital, labor, and fuel to produce the same quantity of electricity. The opportunities for trading-off lower capital costs for higher fuel expenses are greatest in power generation, although some possibilities for substitution also exist at other stages of production. At one

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1 Engineering usage distinguishes "demand"—the instantaneous rate of use of electricity, measured in kilowatts (kw)—and "energy," the accumulated use over some period of time, measured in kilowatt-hours (kwh). In contrast, economists use the word "demand" to refer to the quantity of electricity (kwh) that a consumer wishes to use at a specified price.

2 A more technical discussion of many aspects of these issues may be found in Nelson (1964) and Turvey (1969) and in UNIPED, Conference on Electricity Tariffs.
extreme, nuclear generating plants have extremely high capital costs, on the order of $1000 per kw of capacity, but the running costs of the fuel consumed are only about 0.1 to 0.3 cent per kwh. In contrast, gas turbine generators have low capacity costs, about $200 per kw, but consume large quantities of fuel and thus have much higher running costs, about 3 cents to 5 cents per kwh. In general, the total costs of supplying the electricity demanded over the course of a year can be minimized by having a combination of generating plants of different types—some baseload capacity in the form of nuclear or coal-fired units that run continuously, and some intermediate and peaking capacity in the form of oil- and gas-fired units that can be turned on and off to meet variations in total load.

It is difficult to determine the optimal mix of generating plants that should be constructed, especially when the technology for generating and distributing power is continually improving and when uncertainties are constantly occurring in the availability of fuels for producing electricity and of fuels that can substitute for electricity in final use. Typically, at any given moment, a utility will have on hand a mix of generating units of different vintages that it will dispatch in the order of their fuel efficiencies to minimize the short-run operating costs of meeting hourly loads. A reduction in the peak load of the system, and a shift of some of that load to hours when there is lower demand, will result in two types of cost savings. In the short run, the shifted kilowatt-hours can be generated by using more efficient generating units that require less fuel. Over time, this permanent shift in the system load will permit the utility to alter its mix of generating units and save the capital costs of providing peak capacity.

Storage

If electricity is a completely perishable resource, there is no possibility of making productive use of idle capacity in off-peak hours. Suppose, however, that a costless storage medium (a perfect battery) were available in which unused electricity could be held in inventory. With such a device, the utility could operate its generating units at a constant level 24 hours a day, meeting the variations in the load curve by storing up excess energy in slack periods and using it to supplement that generated at peak hours. Storage, then, would effectively solve the peak-load problem at the generation stage. However, if the storage battery were located at the generating site, the size of the transmission and distribution network would still have to be sufficiently large to meet peak demands and would be partly idle at other times. Of course, if storage could be accomplished at the site of final consumption, a uniform load, equal to virtually 100 percent of capacity, could be generated and delivered at all times.

Only imperfect storage media are available. Dams permit water to be stored in reservoirs and released to generating turbines at the time that power is demanded. Because water-driven turbines can be started, stopped, and adjusted very rapidly, hydroelectricity is especially attractive for modulating the quantity of electricity generated in step with the variations in the system load. Naturally occurring sources of elevated water can be supplemented by pumping water uphill to a reservoir and recycling it through turbines at periods of peak demand. Pumped-storage is cost-effective, even though perpetual motion is ruled out by the laws of physics, when low-running-cost electricity, generated from baseload units with excess capaci-
ity, is available to power the pumps in off-peak periods. Finally, individual customers have a variety of possibilities of storing the energy provided by electricity, principally by heating or cooling a storage medium, and drawing on the energy at the time it is needed for consumption purposes.

Because all storage technologies are costly, whether and how much pumped-storage or storage heating is desirable is an economic question that involves trading off the increased capital costs of the storage media for the reduced operating costs they make possible. Utilities have incentives to reduce their costs and to invest in storage technologies, rather than in peak generating units, when it is less costly to substitute such investments for the construction of additional peaking capacity. The utilities' customers, however, have no comparable incentive unless the terms under which they are supplied power induce them to economize on peak-period electricity and increase consumption in the off-peak hours. The structure of electricity tariffs, therefore, is of fundamental importance in encouraging investment in load-shifting technologies.

Whether it will be advantageous for the utility or its customers, or both, to undertake storage and load-shifting investments will depend on the specific supply circumstances of the utility and the demand characteristics of the customers; no general answer is possible. It is therefore especially important that the signals provided to consumers—the prices for electricity at different periods of consumption—accurately reflect the marginal costs to the utility of supplying additional power at those times. If by modulating their loads, customers can reduce their electricity bills under such marginal cost tariffs by more than the costs of inconvenience and additional investment, a net saving of resources will result.

The Load Curve as an Indicator of Marginal Costs

When the total amount of electricity demanded by all of a utility's customers is plotted on a time axis, the system load curve is obtained. The load curve most frequently used is the daily curve that shows continuous changes in load over a 24-hour period (Fig. 1). Weekly, monthly, and annual curves are also relevant to establishing regularities in seasonal and weekend requirements.

The system load curve provides an approximate, but highly useful, indicator of the pattern of marginal costs of supplying electricity. At the time of the system peak demand (for example, at 2 p.m. in Fig. 1), the use of generating and distributing capacity is at a maximum; in periods of substantially lower demand, some units are partly or totally idle. Furthermore, since the generating plants that are used during the peak period frequently include fuel-intensive peaking units, the marginal running cost of meeting additional load at that time will be higher than during slack periods when only the more fuel-efficient units are needed. Thus, in a system consisting primarily of thermal generating units, peaks in the load curve are systematically associated with both increased capacity costs and higher running costs than in periods of lesser demand.4

3 Pumped-storage is by far the most common type of storage used by utilities. However, a variety of new methods are under investigation, including the use of compressed gas and large flywheels.

4 Peak-load conditions may also exist on days of lesser demand if some capacity is unavailable, e.g., because of forced outage or scheduled maintenance. Since maintenance can be undertaken during months of lesser demand, the seasonal variation in effective capacity in a predominantly thermal system is usually considerably less extreme than the daily variation in demand.
In an all-hydroelectric system, there is a different relationship between the load curve and the marginal costs of the system. As noted earlier, the availability of hydroelectric resources permits the utility to reserve energy in a convenient form and to smooth out variations in system loads by modulating the rate at which it releases water for generation. In a totally hydroelectric system, only a small fraction of the capital costs of generation—those of the turbines and penstocks—varies directly with the maximum load, so that despite large hourly variations in system loads, there is relatively little variation in the costs of supplying generating capacity at different hours. Furthermore, the running costs in a hydroelectric system are extremely small. These factors combine to make the capacity costs of the reservoir and of transmission and distribution facilities of much greater relative importance in a hydroelectric system. At the same time, significant proportions of the total costs
of supplying electricity can be saved if demand peaks can be avoided in all segments of the distribution system. Therefore, in determining appropriate pricing signals in largely hydroelectric utilities, greater emphasis is given to the load curve at the distributional level, with the objective of levelling the load in each segment of the network in order to reduce capacity costs. In such systems, more attention must be paid to the characteristics of separate groups of customers than is devoted to the system-wide load curve. Similarly, variations in seasonal demand take on greater importance, since reservoir storage capacity must be sufficient to supply demands over an entire season.

METHODS OF MODULATING THE LOAD CURVE

The utility can influence its customers' loads, and thus the total system load curve, in two fundamental and interrelated ways. First, by providing financial inducements, most importantly through the rates charged for power at different periods of use, it can encourage its customers to alter what would be their habitual pattern of using electricity. Second, it can undertake more direct methods of altering some consumers' loads, including actual control of consumer equipment as well as the promotion of types of appliances that produce a systematic shift of load to off-peak periods.

By establishing a rate structure in which the prices of using electricity correspond to the marginal costs of supply, a utility automatically provides strong financial encouragement to users to restrict their consumption at peak periods and to undertake greater uses at off-peak hours. Large consumers of electricity in industry and commerce have detailed knowledge of the peculiarities of their own production activities and are in the best position to determine whether to economize on their use of electricity and, if so, what changes in production practices or new investments are most effective. The essence of a rate structure based on marginal costs is its reliance on price signals to induce customers to make choices that are in their own and the utility's joint interest. These decisions are decentralized and taken by individual consumers; the utility's role is to set an appropriate rate structure but not to involve itself further in changing consumers' loads.

In contrast, active load-management strategies consist of direct involvement by the utility in the planning of consumer investments and in the control of actual loads. Active load management is thus characterized by a significant amount of centralized planning and decisionmaking and can take many forms. The utility may promote the purchase or conversion of appliances that alter the load curves of a group of consumers to achieve a shape more favorable to the utility's costs of production. It may encourage customers to install equipment capable of using an alternative source of fuel in addition to electricity, so that power can be interrupted without serious inconvenience to the customer. It may take over actual control of the power flowing to particular appliances—such as storage space and water heaters and direct-acting space heating—that perform tasks that are not affected by short interruption of power or the precise hours of operation. Regardless of the specific technology, customers will generally not install appliances with more favorable load patterns or acquiesce in relinquishing control of their power supply unless it is financially advantageous for them to do so. Therefore, tariff policy also plays a key role in facilitating the carrying out of an active load-management program.
Interruptible Loads

The ability to interrupt consumer loads can significantly augment the load control achieved through tariffs and storage appliances alone. The periods of peak daily demand follow quite regular patterns during normal weekdays, and seasonal patterns of demand are also predictable. Nevertheless, the amplitude of the system peak load does vary significantly from day to day. Since capacity must be sufficient to meet the very highest peak load of the year, on most days there will be some excess capacity even at the peak hours. By interrupting service to customers who are able to tolerate a curtailment of supply for minutes or hours at a time, several times a year, the utility can avoid the construction of additional capacity needed only for the days of very greatest demand.  

The tariffs under which interruptible power is sold constitute perhaps the purest form of peak-load pricing in the sense that peak prices apply to only those few hours per year for which a condition of actual shortage is almost certain. During those periods, the price of electricity to “interruptible” customers is very high indeed, reflecting the opportunity cost of the additional capacity required to meet further increments in load. For the remaining days of the year, when a capacity shortage does not threaten, the price during the peak-period hours is substantially lower, but it still exceeds the price during slack hours in order to reflect the higher running costs of the generating mix planned for daily peak hours.

When the additional costs of metering and control are included, interruptible power is of interest to a relatively small number of customers and for a few selected end-uses of electricity. Still, interruptible power can be a potent load-management technique for reducing capacity costs and substituting for the reserve margins that must otherwise be maintained to guard against outages. The extent of utilities’ actual control over interruptible loads varies. In some systems consumers’ space heaters and water heaters can be interrupted by the system dispatcher. In others, the dispatcher uses advance warnings, and customers respond voluntarily.

GENERAL PRINCIPLES OF MARGINAL COST TARIFFS

Tariff policy in European utilities is grounded in the fact that tariffs convey information in the form of prices that influence the consumer’s use of electricity. The fundamental principle that guides tariff design is that the prices that transmit these signals should reflect the marginal costs to the system at the times at which the load is added and the circumstances under which it is added. Tariffs based on

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* In all hydroelectric systems, the major risk is a season-long shortage of water; interruptions, which should occur only a few times in a century, are several weeks or months in duration.

* Under some tariffs, the consumer may choose not to shut off his load, but, instead, to continue to use electricity and pay the peak price; under other tariffs his power is shut off by the utility and he, in effect, faces an “infinite” price.

* In recent American regulatory proceedings, proponents have debated the merits of long-run marginal costs, long-run incremental costs, time-differentiated average costs, and other methods of allocating costs to different periods for the purpose of designating electricity tariffs. A particular point of contention has been the method to be used to adjust rates, once they have been previously determined by one of these methods, to ensure that revenues are equal to total historical costs. For our purposes, it is sufficient to note that European practice, while it varies somewhat, aims to establish rate structures—the timing of tariff periods and the relationships between rates for peak and off-peak periods—on the basis of marginal costs for an optimized system. The level of the rate structure is then adjusted to bring revenues into balance with historical and current costs. Further study of the methods of calculating marginal costs that are used in major European utilities, which are for the most part more advanced than the approximate methods proposed in U.S. proceedings to date, would be highly desirable.
the principle of marginal cost have the further property of ensuring that over a period of time every group of customers will be charged the full costs that they impose on the utility system.

Viewed against this general uniformity of tariff principles, electricity pricing and load-management practices in Europe show substantial heterogeneity. The characteristics of European tariffs range from a time-invariant, subscribed maximum-demand tariff in Norway to seasonal and time-of-day pricing in France and in England and Wales. Some of the more direct load-management techniques include time-of-day interruptions in Germany and England, seasonal interruptions in Norway and France, and, in several countries, the use of storage-heating devices controlled by the utility rather than by the customers. Table 1 lists representative examples of high-voltage tariffs of several European utilities.

Since time-differentiated tariffs and load-management techniques are not costless to execute, it is efficient to implement a tariff or a technique only if the savings to the system and the consumer exceed the costs of doing so. If information and metering were costless, a marginal cost tariff would vary the price continuously over time so that the price would correspond directly to the marginal costs of generation and distribution. Clearly, a much simpler structure will be more tractable for the utility and more acceptable to its consumers. Only in the case of very large consumers of electricity will it be practical to have a tariff with more than a few periods during the day and year at which different prices are charged. For small consumers, the cost of sophisticated metering devices for complex tariffs may more than outweigh any efficiency gains they could achieve, so that a simple tariff structure may be optimal.

In large part, the wide variations in pricing and load-management practice stem from differences among countries in the characteristics of their systems. Comparative statistics of electricity production and generating capacity for several national systems and for California are shown in Table 2.

Because system characteristics vary significantly in Europe, the choice of the optimal pricing and load-management techniques will differ from country to country. Several important dimensions of variation are the time pattern of the costs of producing and distributing power, the time pattern of demand itself, and the nature of the shortages that can occur when supply is inadequate to meet demand. By examining these characteristics in specific European utilities, one can understand the sources of variation in tariffs and in load management in different systems.

The costs of generating and distributing electricity will vary by time of day or by season if the types of generating units in use vary over time. In Stockholm, the steam generated in district heating plants and used to heat commercial and apartment buildings provides a source of nighttime energy at low marginal cost, so that the local utility supplies power under a time-of-day tariff that has a low nighttime charge. The seasonal differentiation of the Norwegian and Swedish State Power Board tariffs reflects the fact that it is more costly to store water for winter use than to use it for run-of-the-river generation. In largely thermal systems, such as those in Germany, France, and England and Wales, the use of only the most efficient plants during the system off-peak periods leads to both seasonal and time-of-day pricing and to active promotion of off-peak uses of electricity.

The magnitude, as well as the temporal pattern, of cost differences will influence the choice of tariff structure and load-management techniques. In Norway, the
## Table 1

### Representative High-Voltage Tariffs in European Utilities

<table>
<thead>
<tr>
<th>European Utility</th>
<th>Fixed Charge ($)</th>
<th>Demand Charge</th>
<th>Energy Charge</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>England (1976): Southeastern Electricity Board (≥650 V)</strong></td>
<td>0.24</td>
<td>5.66/mo</td>
<td>2.03</td>
</tr>
<tr>
<td></td>
<td></td>
<td>4.28/mo</td>
<td>7:30 a.m.-1:30 a.m.</td>
</tr>
<tr>
<td></td>
<td></td>
<td>2.71/mo</td>
<td>1:30 a.m.-7:30 a.m.</td>
</tr>
<tr>
<td></td>
<td></td>
<td>0.70/mo</td>
<td></td>
</tr>
<tr>
<td><strong>Finland (1977): Helsinki Electricity Works</strong></td>
<td>1,692</td>
<td>25.55/yr</td>
<td>4.04</td>
</tr>
<tr>
<td></td>
<td></td>
<td>November-February only</td>
<td>7 a.m.-10 p.m.</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td>3.01</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td>10 p.m.-7 a.m.</td>
</tr>
<tr>
<td><strong>France (1975): Electricité de France (60 kv, 90 kv)</strong></td>
<td>--</td>
<td>P\textsubscript{1}: 12.18/yr</td>
<td>4.30</td>
</tr>
<tr>
<td></td>
<td></td>
<td>7 a.m.-9 a.m., 5 p.m.-7 p.m., November-February\textsuperscript{a}</td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td>P\textsubscript{2}: 4.06/yr</td>
<td>2.38</td>
</tr>
<tr>
<td></td>
<td></td>
<td>6 a.m.-10 p.m., October-March\textsuperscript{a,b}</td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td>P\textsubscript{3}: 2.64/yr</td>
<td>1.96</td>
</tr>
<tr>
<td></td>
<td></td>
<td>6 a.m.-10 p.m., April-September\textsuperscript{a}</td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td>P\textsubscript{4}: 1.01/yr</td>
<td>1.33</td>
</tr>
<tr>
<td></td>
<td></td>
<td>10 p.m.-6 a.m., October-March, and all day Sunday</td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td>P\textsubscript{5}: 0.41/yr</td>
<td>1.27</td>
</tr>
<tr>
<td></td>
<td></td>
<td>30 p.m.-6 a.m., April-September and all day Sunday</td>
<td></td>
</tr>
<tr>
<td><strong>Norway (1975): Water Resources and Electricity Board</strong></td>
<td>--</td>
<td>15.55/yr</td>
<td>0.59</td>
</tr>
<tr>
<td></td>
<td></td>
<td>All year</td>
<td>October-April</td>
</tr>
<tr>
<td><strong>Sweden (1976): State Power Board (30 kv, 70 kv)</strong></td>
<td>36,585</td>
<td>2.44/yr plus</td>
<td>0.83</td>
</tr>
<tr>
<td></td>
<td></td>
<td>25.61/yr</td>
<td>September-April</td>
</tr>
<tr>
<td></td>
<td></td>
<td>For 1-hr demand, all year</td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td>0.71</td>
<td>May-August</td>
</tr>
<tr>
<td></td>
<td></td>
<td>For 6-hr demand, all year</td>
<td></td>
</tr>
<tr>
<td><strong>Sweden (1975): Stockholm Energy Works (100 kv)</strong></td>
<td>36,585</td>
<td>17.07/yr</td>
<td>1.39</td>
</tr>
<tr>
<td></td>
<td></td>
<td>All year</td>
<td>7 a.m.-9 p.m., Monday-Friday</td>
</tr>
<tr>
<td></td>
<td></td>
<td>0.95</td>
<td>All other hours</td>
</tr>
</tbody>
</table>

**NOTE:** Most tariffs are subject to value-added taxes and adjustments for changes in fuel and cost-of-living indices. Rates in dollars are at exchange rates prevailing January 3, 1977; rates in local currencies are given in the Appendix.

**SOURCES:** See the Appendix.

\textsuperscript{a} Except Sunday.
\textsuperscript{b} Except P\textsubscript{1} hours.
Table 2

Electricity Production and Generating Capacity

<table>
<thead>
<tr>
<th>Utility System</th>
<th>Annual Production (millions of kwh)</th>
<th>Installed Capacity (MW)</th>
<th>Generating Resources (MW)</th>
<th>Thermal</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td></td>
<td></td>
<td>Hydroelectric (%)</td>
<td>Steam and Turbine (%)</td>
</tr>
<tr>
<td>Norway (1975)</td>
<td>77,578</td>
<td>16,727</td>
<td>99</td>
<td>1</td>
</tr>
<tr>
<td>Sweden (1975)</td>
<td>79,224</td>
<td>22,819</td>
<td>56</td>
<td>33</td>
</tr>
<tr>
<td>Finland (1975)</td>
<td>25,558</td>
<td>7,395</td>
<td>32</td>
<td>68</td>
</tr>
<tr>
<td>France (1975)</td>
<td>178,514</td>
<td>48,286</td>
<td>37</td>
<td>56</td>
</tr>
<tr>
<td>England (1974-75)</td>
<td>208,215</td>
<td>63,136</td>
<td>1</td>
<td>91</td>
</tr>
<tr>
<td>Germany (1974)</td>
<td>311,710</td>
<td>70,120</td>
<td>7</td>
<td>88</td>
</tr>
<tr>
<td>California (1975)</td>
<td>160,899</td>
<td>36,400</td>
<td>29</td>
<td>66</td>
</tr>
</tbody>
</table>

Elektrizitätswirtschaft, Vol. 26, No. 21, October 13, 1975,
Vereinigung Deutscher Elektrizitätswerke, Frankfurt.
Statistiques de la Production et de la Consommation 1976,
Statistical Yearbook 1974-76, Central Electricity Generating
Board, London.
Quarterly Fuel and Energy Summary—Fourth Quarter, 1975, California
Energy Resources Conservation and Development Commission,
Sacramento, California.
Electricity Forecasting and Planning Report, California Energy
Resources Conservation and Development Commission, Sacramento,
California.

daytime/nighttime cost differential is too small to make time-of-day residential
tariffs worth the incremental metering costs they would create. In the mixed hydro-
thermal system of the Swedish State Power Board, diurnal cost differences are too
small to make storage space heating for the residential consumer cost-effective. In
Stockholm, however, the cost differences are larger and justify storage water heating
but not storage space heating. In Germany, England, and France, the marginal cost
structure that results from extensive reliance on thermal generation implies that
not only should time-of-day tariffs exist, but that it will be mutually advantageous
to the consumer and the utility to use storage devices, despite the added capital costs
for the consumer and incremental distributional and metering costs for the utility.

Because it is also costly to provide reserve capacity, all utility systems run some
risks of electricity shortage during the course of a year. The nature of such potential
shortages depends on the characteristics of the system and affects the type of pricing
and load-management techniques that are employed. The Norwegian load-rate tariff
for residential consumers, with its penalty on load fluctuation but not on energy use
per se, was designed to reflect historical constraints in reservoir and distribution
capacity in a system with abundant sources of hydroelectric energy. In years of
inadequate precipitation, Norwegian utilities interrupt several industrial customers
(e.g., aluminum) for periods that may extend to several months. France has similar long-term contracts with certain industrial clients, including the aluminum industry, to interrupt power for prolonged periods if a dry year should diminish the system's hydroelectric potential.

In largely thermal systems, electricity shortages are likely to be of shorter duration, usually coinciding with the daily peak-load period. In the almost totally thermal British system, the generating authority can shed more than 10 percent of the total industrial load on short notice through interruptible contracts. West German utilities, which are also predominantly thermal systems, tend to have fewer interruptible contracts because they benefit from interconnection through the national grid with Swiss, French, and Austrian hydroelectric facilities.

In mixed hydrothermal systems, shortages are less likely to occur than in systems that must rely predominantly on a single type of generation, since the chance of simultaneously incurring both an energy shortage in hydroelectric units and a capacity shortage in thermal generation is less than the probability of one of those events. Scotland relies on pumped-storage to reduce the risks of thermal capacity shortages and offers no generally available interruptible contract. With regular hydroelectric and pumped-storage units, the French have used short-term interruptible contracts to only a limited extent.

As this discussion has suggested, variations among countries in underlying cost conditions result in important differences in the specific structure and terms of electricity tariffs abroad. The designing of generation and distribution facilities so as to minimize the total costs of supplying power gives rise to a pattern of marginal costs specific to each electricity system. European utilities seek to reduce their overall costs further by requiring consumers to pay rates for electricity that reflect its marginal costs at the time that it is used and by actively promoting the purchase of appliances that lead to cost-effective shifts in load. In the following two sections, we will examine these policies in terms of their effectiveness in foreign utilities.
III. INDUSTRIAL TARIFFS AND LOAD MODULATION

Industrial customers consume a large portion of the total electricity generated in each of the European countries studied. Such customers are typically supplied at medium (5 to 60 kv) or high (60 to 250 kv) voltage. Frequently, even one customer's load is sufficiently large that it is worthwhile for the utility to encourage cost-saving behavior by supplying power under rather elaborate pricing and metering techniques, thereby benefitting both the utility and the customer.

In this section we will review evidence from several countries on the nature and extent to which industrial customers can modify their use of electricity in response to tariff provisions. As noted in Section II, widely differing circumstances governing the cost of supply prevail in different utilities and can give rise to quite different price signals, leading one utility to emphasize maximum-demand charges in its industrial tariff and another to rely on time-of-day energy rates. As a result, actual load patterns in a single industry will vary from country to country. Moreover, the nature of the load modulation that does occur will depend importantly on the characteristics of the firm's production process and on the market for its products. Firms whose electricity costs represent a high percentage of their total fabrication cost (value added), or that generate some of their own power, or that operate in multiple shifts may be especially sensitive to tariff incentives. In some processes, the output is relatively easily stored, whereas in others it must be supplied continuously to the final customer; in still others, there are opportunities for storing intermediate products.

Thus, there is no simple pattern of industrial load response to electricity tariffs. The common element that exists, however, is that a significant portion of the total amount of electricity consumed by industrial customers is susceptible to decentralized adjustment when the appropriate economic incentives are present.

In the discussion that follows, we will first describe the principal features of each country's industrial tariffs to establish the incentives that they provide for load shifting, and then examine several types of evidence of industrial load response to these incentives. Wherever possible, we will draw on data from detailed load studies of specific firms and industries, since these data most directly reveal the magnitude of responsiveness to peak and off-peak rates. In addition to examining the dramatic patterns of load shifting found in these data, we will also examine the evolution of system load curves.

FRANCE

In France, electricity is generated and distributed by a single national utility, Electricité de France (EdF). The structure of tariffs—i.e., the timing of tariff periods and the method of charging for both energy and capacity—is uniform throughout the country. However, small regional differences in the level of rates do exist to

1 Some large firms also generate power for their own industrial processes.
reflect differences in supply costs and to encourage the optimal siting of industrial plants. Customers requiring high-voltage electricity are supplied under the terms of the Green Tariff. Consumers of low-voltage electricity—i.e., residential, agricultural, and small commercial customers—are served under the Universal Tariff.

The Green Tariff

The Green Tariff has five distinct periods, during which different prices apply for both energy (kwh) and power (kw). The structure of the Green Tariff was established to approximate the principal variations in the marginal cost of supplying customers with high-voltage power. The tariff periods closely follow the pattern of system demand during the first years, beginning in 1958, that the tariff was in effect.2

During the four coldest winter months (November through February) the Green Tariff has three distinct periods:

- Peak hours (Pointe): 7 A.M. to 9 A.M. and 5 P.M. to 7 P.M., Monday through Saturday
- Full hours (HP: Heures Pleines): 6 A.M. to 10 P.M. except Sunday and peak hours
- Slack hours (HC: Heures CREUSES): 10 P.M. to 6 A.M. and all day Sunday

In the months of October and March, electricity consumed during the four peak hours is charged at the full-hour rate, so that only full hours and slack hours apply. For the summer months (April through September), again, only full and slack periods are differentiated; but because different prices apply in these months, these hours are considered distinct tariff periods. The five tariff periods are summarized in printed tariffs in the following format:

<table>
<thead>
<tr>
<th></th>
<th>Winter</th>
<th>Summer</th>
</tr>
</thead>
<tbody>
<tr>
<td>Peak (P)</td>
<td>Full (HP)</td>
<td>Full (HP)</td>
</tr>
<tr>
<td></td>
<td>Slack (HC)</td>
<td>Slack (HC)</td>
</tr>
</tbody>
</table>

During each tariff period, a different price per kilowatt-hour is charged. The pattern of these rates is shown in Fig. 2.

One distinctive characteristic of the Green Tariff is the concept of subscribed power. A customer may subscribe to a different level of annual maximum demand (kw) in each of the five tariff periods. Because the effective price per kilowatt is successively reduced in the full and slack hours, the subscribed power provisions of the Green Tariff provide a particularly strong incentive for customers to modulate their loads if they are able to do so. The Green Tariff contracts are for a 5-year term, and subscribed power levels apply for the duration of the contract. The subscribed level may be increased at any time, in which case the new subscribed power level then remains in effect for 5 years.3 If, in a given month, actual demand4 exceeds the

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2 A more detailed description of the Green Tariff is included in the Appendix.
3 In certain instances, e.g., shipbuilding, EdF will enter into a shorter contract if the customer pays an additional demand charge.
4 Consumption is measured by multiple register demand and energy meters. Demand is recorded as mean kilowatts over a 10-minute period.
customer's subscribed power, the excess is billed at the rate of 70 percent of the annual charge per subscribed kilowatt. The effect is to penalize any overrun of subscribed power that occur more than 1 month in a year. If the customer exceeds his subscribed power by a substantial margin, EdF will automatically increase the subscribed power level for his contract. Furthermore, EdF maintains the right to install circuit breakers that can cut off the customer's power when demand exceeds the subscribed level by 10 percent.

The Tariff General is the most common version of the Green Tariff and covers about 85 percent of all Green Tariff customers. The terms of the Tariff General are shown in Table 3.

Firms with different utilization patterns may select one of the three other versions. The Appendix contains a detailed description of all versions and of the medium-voltage tariffs.
Table 3  
General Version of the Green Tariff, 1975

<table>
<thead>
<tr>
<th>Type of Charge</th>
<th>Prices for Supply at 60 to 90 kv</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Winter</td>
</tr>
<tr>
<td></td>
<td>Peak</td>
</tr>
<tr>
<td>Subscribed demand charge</td>
<td>12.18</td>
</tr>
<tr>
<td>($/kw/yr)</td>
<td></td>
</tr>
<tr>
<td>Energy charge</td>
<td>4.30</td>
</tr>
<tr>
<td>(¢/kwh)</td>
<td></td>
</tr>
</tbody>
</table>

**SOURCE:** Calculated from Appendix Table A.2, using rate of exchange prevailing on January 3, 1977.

**NOTE:** Prices exclude the 17.6 percent value-added tax. The amounts of power subscribed during full periods must be at least the amount subscribed during the peak period, and the amounts subscribed during slack periods must be at least the amounts subscribed during full periods.

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**Examples of Industrial Response**

Actual load measurements of selected industrial plants provide the strongest available evidence of the response of high-voltage consumers to peak-load pricing and of the ability of certain firms to modulate their loads. To illustrate this responsiveness, we have selected several examples of daily load curves measured by EdF during a recent winter. These data are obtained from an ongoing EdF study of some 250 industrial customers in two regions of France, a sample of about one-half of the industrial users served at high voltage.

**The Cement Industry.** Figure 3 reproduces the load curves of a large French cement manufacturing plant during a recent December. On weekdays and Saturday, the three-period tariff is in effect. In contrast, on Sunday all hours are slack. The response in the peak hours (7 a.m. to 9 a.m. and 5 p.m. to 7 p.m.) is dramatic; about 50 percent of the peak load is shed during each of the daily peak periods. In addition, average load is reduced somewhat on workdays during the remaining daytime (full) hours. However, on Sunday, when only the slack-hour price applies, the load is essentially constant for the entire 24-hour period at the maximum level observed on weekdays.

Figure 4 reproduces the weekday load curves for the same plant in each of the four seasons. The pronounced 7 a.m. to 9 a.m. and 5 p.m. to 7 p.m. dips during the peak hours observed in December are not present in March, June, and September, the months in which only full-hour (6 a.m. to 10 p.m.) and slack-hour (10 p.m. to 6 a.m.) prices apply. Instead, there is a consistent daytime/nighttime load differential of 40 to 50 percent.

Because electricity costs are about 10 to 20 percent of value added in the cement industry, these plants have strong incentives to make the most economical use of power. Cement plants are normally manned in three shifts. Although the quarry, kiln, and packing processes run continuously (the kiln is typically fueled by coal or
Fig. 3—Winter load curves for a French cement plant

natural gas, with electrical accessories), load can be modulated by shutting off some or all of the cement mills and the raw mills that are used to grind and crush stone.\(^6\)

Milling machinery requires frequent regular maintenance to keep equipment in good condition and to economize on operating costs by ensuring a gradation of sizes of the crushed stone. Maintenance is routinely scheduled during the peak and full tariff hours.

Cement plants exhibit the greatest load modulation when the demand for their product is less than their production capacity. Plants are typically constructed in

\(^6\) Control is automatic in a few plants. In most installations, however, a production engineer monitors the kilowatt meter and manually turns off mills when demand exceeds the subscribed level.
Fig. 4—Midweek load curves for a French cement plant

anticipation of growing demand so that during the initial years of operation they can operate predominantly at night and yet produce sufficient product.

Cement plants have only limited ability to modulate load by season. To some extent, however, they are run at maximum rates in the summer, and the more extensive maintenance is done during the winter; this practice coincides with seasonality of product demand. Clinker (an intermediate product) is accumulated in the spring, and even stored in the open when silo capacity is fully used.

The load curves of individual customers, such as those of the cement plant just described, provide clear evidence of the responsiveness of these customers to the structure of the electricity tariff. However, in order to ascertain the extent to which such load modulation can be practiced throughout the industry, it is useful to examine the aggregate daily load curves for that portion of the cement industry located in two major industrial areas of France for which data are available. As shown in Fig. 5, the combined weekday loads of several plants in these regions closely parallel that of the weekday pattern of the individual plant.

Ferro-Alloys, Iron and Steel, and Electrometallurgy. In this industrial group, a variety of processes lend themselves to some degree of electricity load management. Electrical smelting furnaces can be slowed down, or, where there are several furnaces in one plant, the smelting periods can be staggered. Because ovens retain heat well over short intervals, load modulation for short tariff periods need not disrupt production. Furnaces used to reheat ingots prior to running them into
rolling mills can be shut off during peak hours. Similarly, the maintenance for rolling mills can be scheduled during peak hours.

A number of plants in this industry generate some of their own power by using waste heat, steam, or gases from a primary production process, such as the operation of a blast furnace. In these instances, there are some opportunities to modulate the load of the electric utility by increasing the quantity of self-generated power during peak hours either by using industrial gases produced at other hours and held in storage or by adjusting the rate of production. Finally, certain types of equipment, notably electric arc furnaces, are capable of rapid shutdown without detrimental effect on the process of production. For these specific uses, interruptible-power contracts and tariffs with short peak-price periods are most effective.

Figure 6 shows representative winter (December) daily load curves for a large ferro-alloy plant. During the peak hours, the plant sheds some 80 percent of the load it draws from the utility in both morning and afternoon periods. Outside of peak hours, however, there is no discernible modulation between daytime and nighttime operation for this plant. On Sunday, when only off-peak rates apply, the plant operates uniformly at the maximum weekday level.

In the case of the electrometallurgical plant shown in Fig. 7, load is completely shut off during peak hours. The process itself is visibly more irregular from hour to hour, even on Sunday when the price of electricity is constant at all hours. Little difference between daytime and nighttime operation is apparent.
The aggregate weekday load curve for the electrometallurgy industry is shown in Fig. 8. Significant load reductions, on the order of 200 MW in these regions of France, are seen to occur at peak hours.

**Petroleum Refining.** Although petroleum refining is a continuous process, refinery operations frequently have the flexibility to modulate load taken from the electric utility, particularly in plants possessing some degree of self-generation. Representative load curves of a modern French petroleum refinery are given in Fig. 9. The aggregate weekday load curve shown in Fig. 10 clearly indicates that pe-
troleum plants not only respond to peak-hour changes but also reduce load to a lesser degree during the full hours of the tariff. Sunday load is uniformly at a maximum level.

**Electrochemical Processes.** The opportunities to modulate load in the electrochemical industry depend on the nature of the production processes being used. For example, in the production of chlorine by electrolysis, the mercury cell process can be readily adjusted, whereas the diaphragm process must be run continuously. Because steam is required for some electrochemical processes, plants frequently install generators to provide some of their own electricity, which, to a
Fig. 8—Winter weekday load curve for a sample from the French electrometallurgy industry

certain extent, can be regulated so as to reduce the load on the utility at peak hours. Since the production of liquefied industrial gases can be totally stopped on short notice, liquefaction plants are amenable to special contracts for interruptible power.

The aggregate load response of electrochemical plants in two regions of France is shown in Fig. 11. Here, in contrast to the industries already discussed, the response is far smaller at the peak hours, reflecting the more limited degree of modulation that can be achieved. The relative smoothness of the aggregate curve is indicative of the averaging effect of measuring total response when individual plants have load patterns that do not coincide.

Other Industries. The strong pattern of reduced demand at peak and full hours in the industries reviewed above is persuasive evidence of the potency of the time-of-day price incentives in the Green Tariff. Despite these incentives, it is undoubtedly a fact that there are many other industrial firms that are unable or unwilling to modulate their electricity loads. The load curves of industries such as aluminum refining, automobiles, and aircraft, as well as subways and railways, show maximum usage of electricity during peak or full hours. However, without load-curve data for the same firms supplied under a tariff with uniform pricing at all hours, we cannot infer that such industries have made no reductions in peak-period
demand, but only that the changes, if any, have not been large enough to reduce load below that occurring in off-peak hours. In some operations, perhaps subways and aluminum refining, the tariff has undoubtedly had no effect whatsoever on the use of electricity. In others, high prices during hours of greatest usage may have encouraged industries to use more electrically efficient processes and thus reduce loads at all hours of the day. Because such adjustments cannot be observed without comparable before-and-after load curves, load-shifting measurements based solely on contemporary load patterns will tend to understate the full long-term effect of peak-load pricing.
Fig. 10—Winter weekday load curve for a sample from the French petroleum industry

Fig. 11—Winter weekday load curve for a sample from the French electrochemical industry
Effect of Peak-Load Pricing on System Load Curves

The sampling of load curves for individual plants and industry groups discussed above demonstrates that peak-load pricing is effective in motivating selected industries to modulate their loads in a significant and even striking fashion. But how important are such customer responses for the load curve of the EdF system itself? There are three methods of assessing the aggregate effectiveness of the Green Tariff.

First, one can measure the system load during working days immediately prior to and following the effective date, November 1, of the peak period. By comparing peak loads in this manner, EdF estimates that a saving of some 700 MW during the morning and 500 MW in the afternoon has been realized. However, the magnitude of the reduction calculated in this fashion is likely to underestimate the total savings for three reasons: (1) In such a calculation, it is difficult to adjust fully for the seasonal trend toward colder temperatures and consequent higher November loads, although a 1-week difference should keep this error small. (2) The data reflect differences in the system load in early November, when it is no more than 90 percent of the annual peak load, which occurs between mid-December and January. (3) The time of the system peak has gradually shifted outside of the 7 A.M. to 9 A.M. morning peak-hour tariff period to approximately 9:30 A.M. or 10 A.M. As a result, the system peak now occurs at a time when the restraint on demand is only the full-hour price incentive, rather than the substantially higher peak charge. These qualifications suggest that estimates based on the actual values of peak demand underestimate the full effect that peak-period pricing can have on the system load in the period to which the peak price in fact applies.

A second method of assessing the effectiveness of peak-load pricing in the Green Tariff is to compare the levels of subscribed demand during different tariff periods. Since the tariff itself provides strong price incentives for not subscribing for power that is not needed, and also imposes significant surcharges for exceeding subscribed levels, subscribed demand levels should provide an accurate indication of the long-term pattern of industrial consumers' usage: firms are committed to those power levels for a 5-year period. However, comparison of the total amount of power subscribed in each period can provide only an approximate measure of the effect on system maximum demands that results from the tariff. When several customers actually use power, the peaks in their individual loads during each tariff period will not exactly coincide, so that the sum of their subscribed demands will be an overestimate of their coincident demands at the time of the system peak. Moreover, to the extent that firms have not merely reduced loads during the high-cost hours but have shifted usage into lower-cost tariff periods, the measured differences will overstate the simple reduction in the system-wide peak-period load. Offsetting these factors, however, are the unmeasured reductions in peak-period subscribed levels for firms that nevertheless continue to have their maximum demands in the peak period. For

8 Some observers have been confused by the fact that demand is systematically higher during the winter months when the peak price is in effect. Nimmel (p. 41), for example, notes that EdF's "load increases from 24,000 MW before November 1 to 26,000 MW at the end of January." To conclude as he does "that the peak load rate does not at all reduce the load between 7 and 9 A.M." is as erroneous as it is to infer that because long-distance telephone calling is heaviest during weekday business hours the higher daytime rates for toll calls have had no effect on patterns of telephone use.
these reasons, calculations based on subscribed power levels should be considered to be rough estimates of the effect of peak-period pricing on the system load.

At the end of 1974, the total subscribed power for all Green Tariff (medium- and high-voltage) consumers was 22,741 MW during winter peak hours, 25,478 MW during winter full hours, and 26,560 MW during summer slack hours (Table 4), implying a contractual reduction of 2737 MW, or 11 percent, between full and peak hours in winter. Data for the 600 largest high-voltage industrial consumers show a comparable 13 percent reduction during winter between the power subscribed in the full hours and that subscribed during the peak hours.

A third method of assessing the Green Tariff is to consider the evolution of the French medium- and high-voltage loads over time. Figure 12 compares the average demands in each of the five tariff periods over a 20-year period (1952-1972). It shows that in relative terms the peak- and full-hour loads have decreased over this period. In assessing this evidence, it is necessary to bear in mind that, apart from the favorable incentives established by the Green Tariff, a variety of secular trends in industrial production practices, as well as changes in work habits, may have contributed to the flattening of the load curve. During the same time period, many U.S. utilities have also enjoyed improved load factors.

Table 4

<table>
<thead>
<tr>
<th>Period</th>
<th>All Green Tariff Consumers</th>
<th>High-Voltage Consumers (63 kv and up)</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Subscribed Power (MW)</td>
<td>Decrement (MW)</td>
</tr>
<tr>
<td>P&lt;sub&gt;5&lt;/sub&gt;: slack summer</td>
<td>26,560</td>
<td>33</td>
</tr>
<tr>
<td>P&lt;sub&gt;4&lt;/sub&gt;: slack winter</td>
<td>26,527</td>
<td>516</td>
</tr>
<tr>
<td>P&lt;sub&gt;3&lt;/sub&gt;: full summer</td>
<td>25,478</td>
<td>533</td>
</tr>
<tr>
<td>P&lt;sub&gt;2&lt;/sub&gt;: full winter</td>
<td>22,741</td>
<td>2737</td>
</tr>
<tr>
<td>Total</td>
<td>3819</td>
<td></td>
</tr>
</tbody>
</table>

SOURCE: Electricité de France.

ENGLAND AND WALES

In England and Wales, electricity is generated and sold by publicly owned supply companies. The Central Electricity Generating Board (CEGB) produces and distributes all wholesale energy to 12 local Area Boards under the terms of its Bulk Supply Tariff. Each Area Board is exclusively responsible for the distribution of electricity to industrial and residential customers in one geographic region.

The Area Boards establish their own tariffs based on the bulk rates at which they buy power from the CEGB and on their own local distribution and sales costs. Thus, in contrast to the uniform structure of the French national tariff, customers in England and Wales pay prices that are the result of regional decisionmaking.
Fig. 12—Change of the national consumption pattern over 20 years: 1952-1972 (profile according to Green Tariff rates)

These rates are, however, not widely different because of the dominant effect of the wholesale tariff.

The Bulk Supply Tariff consists of a combination of seasonal, time-of-day, and system peak-load prices. The price of energy varies according to the time of day. In this winter-peaking system, demand charges depend on the Area Board's maximum demand during each period of potential capacity shortage when a "potential peak warning" (PPW) is issued by the CEBG, and on consumption during the actual system peak, determined retrospectively.

The Area Boards convert this ex post tariff into industrial and residential tariffs that establish demand and energy charges for specified time periods. In doing so, they must forecast both their own and the CEBG load curves for the winter. Not surprisingly, the industrial tariffs of the various Area Boards, despite a general

* The Bulk Supply Tariff is described in the Appendix.
structural uniformity, differ in their details. These tariffs tend to have winter (November through February) maximum half-hour demand (kw) charges, sometimes varying by month, and energy rates that vary by time of day, with peak hours from about 8 A.M. to 12 P.M. For some heavy consumers, the published tariffs are unsuitable because these consumers have quite different load characteristics; in such cases (some 18 percent of all high-voltage consumers) special arrangements are made. Special rates are also charged to a selected group of industrial customers during PPW periods.

Responses to Seasonal and Time-of-Day Pricing

The industrial customers of most Area Boards have a choice between tariffs with and without time-of-day rates. Customers with opportunities to modulate their loads will usually select the time-of-day version. Furthermore, a customer whose electricity-utilization periods are long or whose load curves are fairly flat will usually find that the time-of-day rate is cheaper, even if the firm cannot alter its consumption pattern.

The ability of industrial customers to respond to time-of-day tariffs in France is confirmed by several examples from English and Welsh experience. As Fig. 13(a) indicates, an English cement plant is able to reduce its load substantially during the winter weekday period from 8:00 A.M. to 6:00 P.M.; maximum demand outside of this period is billed at a reduced rate if the off-peak demand exceeds the on-peak demand. As Fig. 13(b) indicates, the same plant responds to the time-of-day energy rates by reducing its peak demand during the summer, when it faces only peak-load energy charges from 7:30 A.M. to 1:30 A.M. daily. By comparison, over a 4-hour period, the French cement industry sheds a similar percentage of its load in response to the Green Tariff.

These load curves indicate that a 1-cent summertime differential between peak and off-peak rates is sufficient to induce a marked response in the cement industry even when the peak period is as long as 18 hours.10

One English petroleum firm is able to lower its peak-period consumption of electricity by using about 20 MW of back pressure generated from the steam used in the refining process. Because of its self-generation capacity, this firm has a special arrangement under which it pays a higher energy charge from 7:30 A.M. to 1:30 A.M. every day, and a higher maximum demand charge on winter weekdays from 7:30 A.M. to 7:30 P.M. As Fig. 14 indicates, the weekday demand is lower during the daytime, and on Sunday follows the same pattern of lower demand when higher energy prices prevail. The greater reductions during the weekday peak period are accounted for by the combined effects of kilowatt-hour and kilowatt charges on weekdays.

A firm producing industrial gases responds differently to the various tariffs offered by the Area Boards serving the regions in which the firm’s plants are located. Where one Board has a charge for maximum demand during winter weekdays, the firm routinely operates its liquefiers only during the off-peak (weeknight and weekend) hours; because one of its customers requires continuous gaseous feed, no more

10 The energy rates are 2.03 cents/kwh during peak periods and 1.02 cents/kwh during off-peak periods. Capital costs are recovered by the Area Board through maximum-demand charges levied only during the winter months.
Fig. 13—Load curves for an English cement plant

Source: Unpublished Area Board load study
Fig. 14—Winter load curves for an English petroleum refinery

load can be shifted or dropped. The same plant does not respond to the differential time-of-day energy rates during the summer. In another plant, liquefiers are turned off to save on time-of-day demand charges only if the demand for the liquid gas product is weak. In still other plants having tariffs with smaller daytime/nighttime rate differentials, the operations are run at a uniform level 24 hours a day.

At least one Area Board supplies several medium-sized foundries under time-of-day tariffs. A plant producing pig iron operates with additional overnight and weekend capacity in the winter and achieves a saving of about 2 percent in total cost, net of additional labor costs for shift differentials. Another foundry, which produces large steel castings, is able to meet all of its winter mold shop requirements by using its arc furnaces for melting during off-peak periods. In doing so, it has shifted nearly 9 million kwh, out of a total demand of 10.6 million kwh, from peak periods to off-peak periods.11

Load curves for broadly defined industries confirm the French experience that some industries can, and others cannot, respond to time-of-day rates. Figures 15 and 16, from a recent Electricity Council load study of 350 large industrial consumers, show that two industrial groups, the chemical and allied trades and the bricks/pottery/glass/cement works, have lower demands from 8 A.M. to midnight than during the rest of the day; the other industrial groups studied had flat or day-peaking load curves. These data establish that these two industrial groups are responsive to time-of-day pricing and can achieve about a 25 percent reduction in demand during

Fig. 15—Average winter weekday load curves for the chemical and allied industries in England and Wales

peak hours. Without such tariffs, the load curve would be flat or day-peaking, because normal business hours occur during the day, and nighttime production requires that labor be paid a shift differential. From all but one of the Area Boards, firms can obtain about a 50 percent discount on energy used during nighttime production, roughly between midnight and 8 A.M., which provides the only incentive to use more electricity during the night.\(^\text{12}\)

The load reductions in Figs. 15 and 16 do not show the sharply defined responses observed for similar French industries. The English and Welsh tariffs tend to rely on kilowatt-hour charges for time-of-day pricing, rather than on a mix of kilowatt and kilowatt-hour charges; thus the response patterns in the samples in Figs. 15 and 16 should be smoother than those observed for the same industries in France, because, in the French tariff, the kilowatt charges for different periods of the day heavily penalize failure to reduce load sharply at the beginning of the tariff period.

\(^{12}\) Some Area Boards reinforce this incentive by exempting nighttime consumption from demand charges.
This discrepancy in industrial behavior is also partly due to a statistical artifact. In the case of the French data, all firms faced precisely the same hours for the peak, intermediate, and slack tariff periods. In England and Wales, however, the hours vary from one Area Board to another. In fact, some Area Boards stagger the hours from customer to customer in order to smooth out the distributional load. As a result, in Figs. 15 and 16 a few customers are starting their off-peak period as early as 7 p.m. and ending at 3 a.m. while others start as late as 1 a.m. and run to 9 a.m.

Area Boards stand ready to negotiate the purchase of electricity generated by industrial firms, typically as a by-product of the production of industrial heat. Although these transactions accounted for only 0.2 percent of the total kilowatt-hours consumed in 1974-1975, the existence of a market for privately generated power will provide some encouragement to firms with sources of waste heat to install generators when the Board’s purchase terms are sufficiently attractive.

Potential Peak Warnings (PPWs)

A particularly striking feature of the English and Welsh tariff system for high-

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Note: Sample of customers with at least 5 MW of demand

Source: Unpublished Electricity Council load study

Fig. 16—Average winter weekday load curves for the brick, pottery, glass, and cement industries in England and Wales

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13 See Table A.6 in the Appendix.
voltage consumers is the rather extensive use by some large industrial customers of a tariff for voluntary interruption of power. The operating division of the Central Electricity Generating Board routinely forecasts system demand and on-line generating capacity a day in advance. When a possible shortage is expected, then prior to 5 p.m. the CEBG issues to the Area Boards a PPW covering specified hours during the following day.\footnote{These warning periods are also used in the Bulk Supply Tariff to set demand charges that recover a significant portion of CEBG’s costs of capacity.} In their turn, the Area Boards notify each of their customers supplied under the PPW tariff by telex. Each customer is responsible for shedding the amount of load agreed upon for the warning hours specified. Such warnings can be issued in November through February and cannot exceed a total of 60 weekday hours.

The PPW retail customer receives a discount on the load that he is able to shed during the warning period. In most cases, the customer pays the normal kilowatt charge for his actual maximum load during the warning period and is charged nothing for higher loads in nonwarning hours. Since the interruption is voluntary, the customer does have the option of deciding how much load to shed. However, the PPW tariff is sufficiently attractive that failures to comply amount to less than 1 percent of the load under PPW contracts.

For a PPW contract to be implemented, it must be mutually advantageous for the Area Board and for the customer. Before the Board will offer a PPW tariff, the customer must have a telex terminal (to ensure prompt and reliable communications), a staff ready to implement load-shedding procedures (to ensure compliance), and a sheddable load large enough to cover the administrative and metering costs incurred. For the PPW clause to be to the customer’s advantage, he must have processes that can be quickly turned off for short periods of time or the ability to store intermediate products at a cost less than the savings in electricity charges.

The nature of the potential peak warning response is illustrated by the behavior of two firms. As Fig. 17 indicates, a steel company operating arc furnaces is able to shed over 95 percent of its load in order to save the £4.20 per kilowatt charge it faces for demand during warning periods. A producer of industrial gases has PPW clauses in contracts for two different plants. One plant that produces only liquefied gases reduces its demand almost 80 percent by turning off its liquefiers. Another plant, producing both liquefied gas and a direct gaseous feed, sheds about 53 percent of its load by turning off liquefiers and throttling back other processes to the level demanded by the customers to whom it supplies direct gaseous feed. This plant does not have PPW clauses covering its gaseous production, because the customers for its direct gaseous feed require a continuous input to their own continuous processes.

Although data on PPW contracts and responses are not generally available, we do know that a sample of PPW customers was able to shed nearly 40 percent of its load during a recent PPW day; the response is shown in Fig. 18. In total, the load shed by the nearly 125 PPW customers in England and Wales is between 1100 MW and 1200 MW during a typical warning period.\footnote{These data are from an internal Electricity Council load forecast paper.} This amount represents about 3 percent of the system peak load during the winter and nearly 11 percent of the industrial load in all of England and Wales.
Fig. 17—Load curve for an English steel company during a potential peak warning (PPW): 9 to 10 a.m. and 4:30 to 5:30 p.m.
GERMANY

In West Germany, electricity is produced and distributed by monopoly supply companies organized as municipal companies or as private firms in which government bodies hold minority ownership. Industrial generation of power, primarily in conjunction with process heat, accounts for about 24 percent of Germany's total production of electricity. In the main, public price regulation plays a limited role, which consists of reviewing and approving tariffs for lower-voltage customers.

Companies supplying electricity sell it in the following ways:

1. Under published tariffs, available to all customers. This is the normal form of supply for residential, agricultural, and small commercial firms.
2. Under pro forma contracts with standard terms, available at the discretion of the company. This approach is widely used at medium voltages and for special applications, such as residential storage heating.
3. By special contracts that are privately negotiated with individual high-voltage consumers. The terms of these contracts are private and not subject to regulatory review except in cases of alleged discrimination.
Although the exact terms of pro forma contracts for medium-voltage consumers vary from one West German utility to another, those of the Westphalia utility (VEW) are representative. Rates are based on both the customer's maximum quarter-hour demand and the energy he consumes. Two versions of the basic contract are available, each of which includes a declining-block schedule. In the version that is generally appropriate for low-utilization customers, there are four rate blocks, declining from 6.9 cents to 5.5 cents per kilowatt-hour (17pf to 13.5pf), with a percentage rebate for customers with high utilization. Under the alternative "demand price" contract, there is a demand charge plus two energy price schedules, one for daytime and one for nighttime consumption. During the winter, the peak (daytime) tariff hours are from 6 A.M. to 9 P.M. and the price per kilowatt-hour is 50 to 60 percent higher than that charged for nighttime hours.

For many of the largest high-voltage industrial consumers, the terms of supply are specified in private contractual agreements that are not generally made public. Prices, hours, and conditions of supply are tailored by the utility to the customer's particular circumstances and reflect both the opportunities for selected customers to modulate their loads and the supply conditions of the utility itself. As a result, electricity appears to be supplied to industrial users under highly diverse terms.

Examples of several types of special contracts are included in the Appendix. In the case of a cement plant, which consumes more than 55 percent of its total energy during the off-peak hours, the day is divided into peak, full, and slack tariff periods. The demand charges are set to encourage successively higher use during the full and slack hours. The utilities characterize the cement industry as responding very effectively to peak-hour pricing.

Steel plants, which account for 15 percent or more of total system load for utilities in the heavily industrialized regions of Germany, have special contracts that specify a separate peak-hour period for each month of the year, ranging from a continuous peak period in November (8 A.M. to 6:30 P.M.) to the short peak periods in August (10 A.M. to 12 noon and 8 P.M. to 9 P.M.). Again, the price incentives facing these customers are designed to promote higher off-peak demands. The greatest load modulation is observed when newly constructed plants are initially run at less than capacity or when business conditions result in a temporary decline in production. Heating and rolling processes, as well as arc furnaces, are found to be responsive to peak-hour incentives.

One large plant that produces acetylene operates under a special contract that specifies peak, full, and slack tariff periods. During peak hours, power can be interrupted by the utility on 30 minutes' notice. During full hours, supply is guaranteed half of the time, and during the slack hours, it is fully guaranteed. Because of the interruptible feature of the contract, the firm pays no demand charge; the energy price varies roughly according to the marginal running costs in the three periods.

FINLAND

Electricity in Finland is produced and distributed by the national power board, by municipal utilities, by supply companies with a mixture of local government and

16 See pages 97 and 98 in the Appendix.
private ownership, and by a few privately owned utilities. In addition, a large industrial group owns and operates a power company, including a large nuclear reactor, for its own members. Through the efforts of the Finnish Power Association there has been some standardization of rate structures. The tariffs for the State Power Board and the municipally owned Helsinki Electricity Works typify Finnish tariffs. The State Power Board supplies power under both time-of-day and flat tariffs, with charges for maximum winter demand. Customers of the Helsinki municipal utility face uniform kilowatt and kilowatt-hour rates at all hours, with the exception of several firms that have shifted significant loads and receive about a 50 percent discount on energy consumed during the nighttime hours. However, in 1977, Helsinki will switch to a time-of-day tariff for all large consumers.

In response to time-of-day pricing, some Finnish industries have shifted their peak demands to slack hours. The chemical and chlorine products industries are reported to have nighttime peaks, and deep-freezing processes in the food industry have shifted loads in response to off-peak rates. In addition, some agricultural crops are now dried during the fall harvest in the off-peak period.

An interesting experiment in pricing industrial electricity was conducted in Helsinki during the winter of 1971-1972. The electric utility informed a random sample of eighty industrial customers that for a 1-month period, when they would continue to be charged the normal rate per kilowatt-hour, their bills would be unaffected by the level of their individual maximum demand during that month.

The aggregate load curve for the eighty customers during that experimental month are compared in Fig. 19 with the corresponding load curve during a normally billed winter month. Despite the short-run nature of the experiment, and given the possible incentives for the companies to behave strategically, there is a noticeable difference in behavior and the changes are in the expected direction. Daytime demands were higher and nighttime demands were lower. If one considers 7 A.M. to 4 P.M. to be the daytime period, then the daytime energy consumed increased by 4.1 percent and the nighttime energy consumption fell by about 7.0 percent. Individual responses were presumably larger, because less-than-perfect coincidence of demands reduces the response reflected in average demands. Nevertheless, these magnitudes are significant because both strategic behavior and the short duration of the experimental period would limit the companies’ responsiveness to the exemption from maximum-demand charges.

Norway

The all-hydroelectric nature of Norway’s power supply determines the structure of Norwegian tariffs. In an all-hydroelectric system, running costs are a negligible portion of total costs. The Norwegian Water Resources and Electricity Board (NVE), which dominates the industry through its operation of the national grid and its control of import and export sales, has led the industry to base its revenues on a subscribed demand charge and on only a small energy charge. In most cases, the demand charge does not depend on seasonal or time-of-day factors. Because of the availability of electricity generated from runoff water, energy charges are lower during the summer. In years of scanty rainfall, some large industrial customers (e.g.,

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11 See Tables A.12 and A.13 in the Appendix.
aluminum and hydrogen producers) may have their power interrupted for several months. For example, up to 20 percent of the load consumed in aluminum production will be dropped by shutting off a portion of the electrolysis cells. In return, interruptible power is priced at 75 percent of the secure-power price.

The Oslo municipal utility produces almost all of its own power and is a net exporter of electricity to other utilities. It offers a special time-of-day and seasonal tariff to some of its large industrial customers who use electricity for water heating and other thermal purposes. During the summer runoff period (mid-April to mid-October), surplus electricity is sold on a when-available basis at night (7 P.M. to 7 A.M.) at a price of 3.6 øre/kwh (about 0.66 cent/kwh) with no maximum-demand (kilowatt) charge. In order to benefit from this special contract, the customer must have equipment, such as boilers and water heaters, that can be quickly switched
from electricity to another fuel. Although the Oslo utility does not guarantee delivery, on average it supplies about 2000 hours of electricity for such uses annually.

Since electricity is priced slightly below the equivalent cost of oil under these contracts, the Oslo utility has been able to add 130 MW to its summer nighttime demand. The 2400 water heaters and 50 boilers covered by the special tariff represent 15 percent of the Oslo system's capacity. This is a very sizeable response in view of the fact that the uncertainty of delivery is borne by the customer, who must maintain a supply of alternate fuel.

SWEDEN

Electricity in Sweden is produced and distributed by municipal and privately owned companies and by the State Power Board, which operates the national grid. Although predominantly a hydroelectric system, Swedish utilities rely on thermal generation for about one-quarter of their energy output, and for this reason seasonal and time-of-day pricing is used more extensively in Sweden than in Norway. The structure of the State Power Board tariff consists of a customer charge, two demand charges, and a set of energy charges. The first demand charge is for the maximum 1-hour demand and the second is levied on the maximum demand during a 6-hour period. If a subscriber is willing to pay the additional metering and administrative costs, he can have his demand meter disconnected for the periods when the system load is low, such as during the summer and at nighttime during the winter. Since on winter days the 6-hour peak demand and the system peak are nearly coincident, it is difficult to detect a time-of-day response, per se. Nevertheless, large industrial users have installed and used load-management equipment to minimize the 6-hour demand charge.

The Stockholm Energiverk, a municipal utility that relies on substantial thermal generation from both conventional condensing units and from back-pressure units that use steam from district heating plants, has an explicit time-of-day tariff that includes a 1-hour demand charge. Since most of the industry near Stockholm is served by the State Power Board rather than by the municipal utility, Stockholm has observed little industrial response to its tariff. Nevertheless, there has been some commercial response. One large office building uses off-peak power to charge its storage heating. Its daytime demand is 1400 kw, compared with a nighttime demand of 2800 kw.

The Swedish State Power Board permits both private firms that generate some of their own power and utilities to transmit energy by "wheeling" electricity from one area to another over the national grid. This practice arose because hydroelectric facilities for many companies and utilities are located in the north of Sweden, while most of the population and industry is located in the southern and central areas. A firm that has its own generating units has both a regular contract for power produced and delivered by the State Power Board and a reserve-supply contract covering purchases in the event that its own units fail. The reserve-supply contract

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18 See Table A.15 in the Appendix.
19 The 6-hour demand meter actually integrates over each 6-hour period: midnight to 6 A.M., 1 A.M. to 7 A.M., 2 A.M. to 8 A.M., etc.
20 See Table A.14 in the Appendix.
contains two important provisions. First, the self-generating firm must subscribe to reserve supplies equal to 100 percent of the capacity of its first generator plus 50 percent of the capacity of its second generator, plus 33 percent of its third, etc., in order to cover the possibility of failure. Second, the customer must agree to join the national pool and place his generating units under economic dispatch by the State Power Board so that only the most efficient generators available are in use at any point in time.
IV. LOAD MANAGEMENT IN THE RESIDENTIAL SECTOR

Residential users constitute the largest group of customers supplied by any electricity distributing utility. Although each individual household’s load is quite small, in the aggregate the residential sector, which can account for well over half of a utility’s total production, presents a significant target for load-shifting efforts.

In Europe, many electric utilities have adopted a direct approach to the management of residential loads. The detailed industrial tariffs that are used to signal levels of system marginal costs to large consumers are both too costly to administer for the hundreds of thousands of small customers and too likely to be ignored because their complexity would exceed the potential saving to be realized by an individual household. However, a more favorable load pattern for even a single end-use of electricity, such as water heating, can offer significant system savings if adopted by a sizeable fraction of residential customers. To realize such savings, some foreign utilities actively promote the installation of and conversion to specific appliances by advertising, by financing customers’ capital investments, by assisting manufacturers to design new appliances, and by the actual marketing of appliances. These efforts are accompanied by special tariffs or supply contracts that make it financially worthwhile for the customer to modify his load. Thus, load management in the European residential sector is characterized by centrally made decisions by the utilities to encourage development of more favorable household uses of electricity.

For the same reasons, conservation efforts by electric utilities and government bodies are focused on residential users. Active programs to upgrade home insulation are used by Area Boards in England and Wales, and by utilities in Sweden and France. Several countries responded to the 1974 oil embargo by passing national building codes mandating higher thermal insulation standards for new structures. In contrast, industrial conservation policy in Europe has emphasized public subsidies to promote conversion to more energy-efficient technologies. Each country has shied away from imposing mandatory requirements that would adversely affect its foreign trade position by unilaterally increasing costs in its energy-intensive export industries. Since 1974, the worldwide increase in fuel costs has been reflected in higher electricity prices in most European countries, encouraging large consumers to make choices about the use of fuels on the basis of market prices.

Residential load management requires an analysis of the system load pattern in order to determine what broad changes in residential loads can achieve the greatest savings in system costs. Generally speaking, there are two load-management approaches. The first is designed to shift the load to the off-peak or “valley” periods of the system daily load curve. The second is designed to achieve more nearly flat residential load curves over the 24-hour day. The marginal costs of generating and distributing electricity, and the investment costs of different appliances, affect the load-management approach that is adopted.

Three important factors are involved in the management of residential loads. The first factor concerns the relationship of peak and off-peak marginal costs to the investment costs of load-shifting appliances. In largely thermal systems, such as those in Germany and in England and Wales, the differences in peak and off-peak
generating costs dominate the costs of amortizing investment in residential storage-heating systems and the expense of reinforcing the local distribution networks to handle the additional storage load. In contrast, in systems in which there are only small differences in marginal costs over the daily load cycle, as in Norway and much of Sweden, and in climates where extreme temperatures would require large investments in storage-heating units, it becomes relatively more important to minimize the capacity of the low-voltage distribution network by encouraging high-utilization appliances, such as resistance heating and continuous water heating.

A second factor in the management of residential loads is the choice of a method of controlling appliances. Signals, propagated over the electrical network itself (ripple control) or by means of radio (telecontrol), enable the utility's dispatcher to control directly a large number of the water heaters and space heaters in homes throughout a city. Such direct control systems are costly, because they require a series of transmitters located throughout the distribution network, a receiving unit in each home that can switch the controlled loads through separate circuits, and additional metering that can record consumption when the electricity is used.

Direct control systems do offer numerous opportunities to modulate residential loads. Residential storage devices can have their starting times staggered to level out the load on local distribution equipment. Direct-resistance heating systems can be cycled on and off several times an hour to reduce system load during the peak hours of those days when capacity is actually in short supply. Water heaters can be shut off in the case of an outage or the threat of a system overload.

A less costly but less flexible control method is the use of a time clock at each residence to regulate the controlled loads and the metering at pre-set hours. Within a neighborhood, clock settings can be staggered to avoid local distribution network peaks. However, loads under time-clock control cannot be interrupted or modulated to deal with system peak conditions due to unusual weather or to outages.

A third factor in the management of residential loads is that of offering price incentives to consumers to encourage them to purchase or modify appliances. Storage applications, for both space and water heating, are invariably offered with a time-of-day rate that provides for reduced charges in the off-peak hours. There are two basic approaches. The first, exemplified by the White Meter tariff in England and Wales, is simply to impose a time-of-day tariff for all electricity consumed by the household. Typically, a clock controls both the meter and storage loads, switching them on at the pre-set off-peak hours; during the off-peak period all electricity is billed at the lower rate. The second is to install two separate circuits with different meters; one for the storage appliances and one for the rest of the house. The restricted circuit for the storage appliances is powered only during off-peak hours and is controlled either by a clock or by radio signal; other uses of electricity are billed at a uniform price at all hours. The restricted-circuit approach was the first used in England and Wales, but has now been supplanted by the White Meter option. In contrast, in Hamburg, Germany, the utility initially offered an unrestricted time-of-day tariff but now limits the amount of additional load shifting by supplying off-peak

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1 Similar load-management controls for residential air conditioning are being introduced on an experimental basis by several American utilities.

2 Area Boards in England and Wales have been able to reset residential clocks in substantial numbers to better modulate their loads in order to reduce their payments under the Bulk Supply Tariff to the Central Electricity Generating Board. In one recent case, an Area Board adjusted 800 MW of installed storage space and water-heating load.
power to new customers only for storage heaters. This change became necessary because the promotion of storage heating has been so successful that the system peak during the evening has threatened to become as large as the morning peak.

In the following discussion, we will review the residential load-management techniques used in several countries.

**ENGLAND AND WALES**

In 1961, the Area Boards of England and Wales began an active campaign to promote the residential use of storage units for space heating. The first units were initially one-room radiators that drew power during two periods, an 8-hour overnight period and a 3-hour booster period in midafternoon. Radiators were supplied and metered on a separate circuit that was switched on at those hours by a clock control. The Area Boards used direct advertising to promote conversion from coal to electric storage heat and sold new units to the public in their own appliance stores located throughout the country. The first storage radiators were so successful that by the late 1960s, the midday trough in the system load curve was rapidly filling up. To remedy this situation, new radiators were designed that would not require a midday charge. The new radiators were first offered to the public in 1969 under the White Meter tariff, with its 8-hour overnight discount on kilowatt-hours.³

Today, about 14 percent of the 17 million domestic customers have some form of storage heating, 1.7 million of whom are served under restricted-hour tariffs and 0.6 million under the White Meter tariff. In all, storage heating has an installed capacity of some 15,000 MW. In addition, these tariffs have encouraged widespread use of storage water heating. In recent years, however, the use of electric storage heating has been increasing more slowly as natural gas has become the market leader for central heating.

The restricted-hour and White Meter tariffs were initially promoted under the slogan "half-price electricity." Until the mid-1970’s, this pricing obtained (see Table 5); but in the wake of the 1974 oil embargo, the marked increase in the price of fuel oil led to a uniform increase in all tariff prices, which caused a disproportionate increase in the off-peak rate and invalidated the marketing slogan. Under public pressure, the government subsidized a reduction of the off-peak rate to return it temporarily to a half-price level. This subsidy was reduced in 1975 and discontinued in April 1976.⁴

The Electricity Council has analyzed the effect of storage space heating on the pattern of residential electric loads.⁵ Data from this study, summarized in Table 6 and Fig. 20, suggest that a substantial percentage of annual consumption can be shifted to nighttime hours when a home is converted from direct-resistance heating to storage heating.⁶ When homes with normal insulation are compared, those using direct-resistance heating consume 22 percent of their energy during off-peak hours,

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³ The restricted-hour tariff has been continued for those households with the older equipment. A typical White Meter tariff is shown in Table A.9 in the Appendix.
⁴ See Boley (1976).
⁵ Unpublished load study of domestic customers.
⁶ For the high- and normal-insulation samples, there was only a slightly higher total energy consumption with storage heating.
Fig. 20—Daily pattern of electricity consumption in three types of English homes with different means of space heating (at a winter weekday temperature of 32°F, normal insulation)

(a) Demand by homes with high-capacity storage radiators

(b) Demand by homes with electricaire (central storage) heating

(c) Demand by homes with whole-house direct resistance space heating

Source: Unpublished Electricity Council load study
Table 5
Comparative Energy Charges in England and Wales (1965)

<table>
<thead>
<tr>
<th>Tariff</th>
<th>Pence per Kilowatt-hour</th>
</tr>
</thead>
<tbody>
<tr>
<td>Normal domestic rate</td>
<td>0.66</td>
</tr>
<tr>
<td>15-hour off-peak rate</td>
<td>0.36</td>
</tr>
<tr>
<td>11-hour off-peak rate</td>
<td>0.32</td>
</tr>
<tr>
<td>8-hour off-peak rate</td>
<td>0.30</td>
</tr>
</tbody>
</table>


whereas those with high-capacity storage radiators consume 72 percent off-peak. Similar figures for homes with electricaire heating suggest that some 50 percent of annual electricity consumption can be shifted from daytime to nighttime use by converting a home to storage heating and placing it on a time-of-day tariff. For homes with high-quality insulation, the magnitude of the shift is approximately the same.

The shift in household energy consumption is composed of two elements, one attributable to the change in space heating and the other to changes in other uses of electricity such as dishwashing, clothes washing, and water heating—in response to the time-of-day tariff. By comparing, in Table 6, the high-insulation homes using direct-resistance heating with homes using two types of storage heating, most of which are on the White Meter tariff, we calculate that the storage heater is responsible for shifting 37 to 46 percent of the annual consumption to the off-peak period. The second element of the shift in consumption—one that is not associated with space heating—can be calculated from Table 6 by comparing the off-peak consumption of high-insulation homes, two-thirds of which have White Meter tariffs, with that of normally insulated homes, almost all of which are on conventional tariffs. The calculated shift is some 12 percent of annual kilowatt-hour consumption, a sizeable quantity in view of the fact that the off-peak price prevails only during the relatively inconvenient period of 11 p.m. to 7 a.m.*

Since we do not know the degree to which homes vary in quality of insulation, the impact of storage heating is difficult to measure precisely. However, the British Electricity Council study of household load curves suggests that the installation of storage heating has typically resulted in shifts of 0.8 to 1.4 kw in a household's morning and early afternoon demand on an average day during December and

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* A central heating system using a storage heater and forced-air distribution.

* Some of this 12-percent shift may be due to differences in heat losses between high-insulation homes and normally insulated homes. Homes with high insulation will be able to retain some of the heat that is produced at night into the daytime hours. Homes with normal insulation will lose enough heat during the day to require higher daytime loads. Comparing high-insulation homes with normally insulated homes that have high-capacity storage radiators and electricaire heating suggests that heat-loss differences may account for up to half of the difference in the percentage of annual consumption that occurs off-peak between high-insulation and normally insulated homes with direct heating.
Table 6
Percent of Annual Consumption During Off-Peak Hours*  
(Year Ending March 31, 1975)

<table>
<thead>
<tr>
<th>Type of Heating System</th>
<th>Percent of Consumption</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>High Insulation</td>
</tr>
<tr>
<td>High-capacity storage radiators</td>
<td>71</td>
</tr>
<tr>
<td>Electricaire</td>
<td>80</td>
</tr>
<tr>
<td>Direct-resistance heating (other than ceiling)</td>
<td>34</td>
</tr>
</tbody>
</table>


* Sample from throughout England and Wales. All storage radiator and electricaire homes were on White Meter tariffs. Of the homes using direct-resistance heating, 31 percent of the high-insulation homes and 95 percent of the normally insulated homes were on conventional, rather than time-of-day, tariffs.

January. On cold days, the shifts are large, ranging up to 5 kw per home. Ignoring the midday charge period for heaters purchased under the restricted-hour tariff, the study implies that on an average winter day storage heating shifts a total of 2000 to 3000 MW out of the daytime system load curve and a smaller amount out of the evening load into the nighttime load; and on a cold day, the shift can be 9000 to 10,000 MW.\(^{10}\)

GERMANY

In the predominantly thermal German utilities, residential load management has concentrated on the control of space-heating loads. Some German metropolitan areas have large district heating plants that supply steam to heat multifamily and commercial buildings. Such plants are equipped with back-pressure turbines and constitute a significant generating resource for the utility to use in managing peak loads. In Hamburg, for example, the utility can interrupt the flow of steam for heating on 15 minutes’ notice and use it to supplement other sources of generation for a 1- to 2-hour period.

Over the last 10 years, residential storage heating has been widely promoted by several German utilities and has had a pronounced effect in shifting system loads. For the 1964-1974 period, total electrical energy used in West Germany increased

\(^{*.10}\) The restricted-hour tariff has been continued for those households with older equipment.  
\(^{10}\) Not all of this amount represents a shift from peak to off-peak hours, because part of it is due to the substitution of electric heating for systems fired by coal or fuel oil.
109 percent, but the peak load increased only 84 percent; as a result the mid-December load factor improved from 77 percent to 88 percent. The average overnight load (10 p.m. to 6 a.m.) increased from 54 percent to 75 percent of the daily peak load. These shifts are especially apparent in the comparison of national load curves in Fig. 21.

![Graph](image)

**Fig. 21**—West German network load curves on days of peak demand, 1974 and 1964

During this 10-year period the installed capacity of storage-heating units in West Germany increased from about 1000 MW (in 1965) to 20,000 MW (in January 1975); 89 percent of this load is used to heat residential buildings, 6 percent to heat business establishments, and 5 percent to heat public office buildings. About 7 percent of the 22 million West German households now use storage heating.

The importance of domestic storage heating in the total load curve of a single utility can be seen in the mid-December curve (Fig. 22) for Hamburg (HEW). The bottom curve, which shows the load of residential consumers, peaks at about 7 p.m. and stays at roughly that level into the early morning hours.

The rapid adoption of storage-heating devices has shifted such a significant fraction of load in several systems that if the trend continues, the system peak will occur during the evening at the time that the storage units are first switched on. To cope with these difficulties, several load-management techniques have been employed:
Fig. 22—System load curve for Hamburg: mid-December weekday, 1975 (divided by type of customer)

1. Installation of new capacity has been controlled to keep pace with the increase in system load. Because German utilities have supplied electricity for storage heating under "special contracts" rather than by tariff, they are allowed to determine which customers will receive service.\(^\text{11}\) This selectivity enables the utility to balance the growth of the aggregate load curve and to avoid creating sharp peaks in the local distribution network.\(^\text{12}\)

\(^{11}\) When storage heating was first introduced, it was available under an optional tariff at off-peak rates that applied to all electricity consumed during the nighttime hours. However, by 1974, the nighttime load had increased significantly. Thus, to avoid the additional load shifting of discretionary household activities, the utilities decided to offer service to new storage-heating customers under special contracts in which nighttime rates applied only to heating. ("Old" customers continue to take all of their nighttime energy at the off-peak rates specified in the optional tariff.) A comparison of the load curves of the two groups would be an interesting way to identify discretionary load shifting, but such a study has not been made.

\(^{12}\) It is of interest to note that the solution to the "shifting-peak" problem suggested by Boiteux (1960), Steiner (1957), and Hirschleifer (1958)—that the off-peak price be set at the level necessary to just equate
2. Increasingly sophisticated regulation devices have been built into the storage-heating units. When first introduced, these units were predominantly of the “forward-charging” variety, i.e., they would charge at the greatest rate when initially switched on and gradually draw a reduced amount of current, as shown in Fig. 23(a). By about 1971, the load demand between 10 P.M. and 11 P.M., when these units turned on, had increased to the point that the system peak threatened to shift into that period. As a result, the utilities have introduced “backward-charging” units, which begin with a low initial charge rate that builds up to a maximum at the time that they shut off, as shown in Fig. 23(b). By adjusting the mix of these types of units, the utility can influence the aggregate load on any node of the distribution system, as well as the system load curve.

3. The starting, stopping, and charging times of storage units can be staggered to avoid local needle peaks. Control is accomplished by a mixture of clock control and low-frequency “ripple-control” signals superimposed on the power system. The staggered charging hours shown in Table 7 illustrate the flexibility of control that is possible. In some cases a 2-hour afternoon charge period is also provided for.

Terms for storage-heating installations typically include a fixed charge for the restricted circuit and an energy price that is roughly one-half of the normal domestic rate for unrestricted service. For example, in 1975, storage-heating customers in Hamburg paid an annual charge of $20.58 (49 DM) plus an energy charge of 2.3¢ (5.4 pf)/kwh, instead of 4.4¢ (10.5 pf)/kwh.

The German utilities expect to install storage heating on a controlled basis until the mid-1980’s, when the valleys in system load curves will be filled up. In planning for that condition, residential load management is turning to newer types of heating systems. For example, many new buildings are being heated by floor (radiant) heating, with an 8-hour nighttime charge plus a 2-hour daytime boost. Still in the demonstration phase, “bivalent” residential heating systems that operate on both electricity and another fuel are being tested. During mild periods, these units use electricity to operate the heat pump; but at low temperatures (below 32°F), the second fuel (e.g., oil or gas) is used for direct heating, thus mitigating the weather-generated peaking of the electrical supply systems.

FRANCE

The standard residential tariff in France is a two-part charge: a fixed monthly charge that varies directly with the size of the main circuit breaker, or fuse, and an energy charge that is constant per kilowatt-hour (except for a small first block that

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*peak loads in both periods (rather than at the marginal supply cost)—is not easily applied in this case. Because of the similarity of demands of thousands of residential customers, the market demand curve for electricity for storage heating is highly inelastic except in a very narrow price range; below the break-even price differential, few households will invest in the appliance, whereas above that price differential, such heating is rationally preferred by almost everyone.*

*The newer units also contain logic for sensing both the outside temperature and the residual charge in the storage unit, data that are then used to compute the total charge needed.*
supplements the fixed charge and is billed at a higher rate). Households may choose the alternative "double tariff" and obtain energy during the hours of 10 p.m. to 6 a.m. at about one-half the standard rate by increasing their monthly fixed payments to cover the additional cost of a day/night meter. This time-of-day tariff has been found to be advantageous by some 15 percent of the domestic customers who have both storage heaters and water heaters. A total monthly consumption of at least 800 kwh is generally needed to make the rate worthwhile to the customer. As storage uses have become more widespread, the increase in residential nighttime loads has caused local peaks to begin to appear in sections of the distribution system. Both clock and remote telecontrol methods are increasingly being used to stagger the switch-on times of storage-heating devices.

Until 1973, a simplified version of the Green Tariff was available to larger residential consumers on a pilot basis. Under this peak-load tariff, different rates per kilowatt-hour were charged during peak-, full-, and slack-hour periods, varying seasonally: a single subscribed-demand charge was levied based on the size of the fuse or circuit breaker. However, EdF discontinued this tariff when it found that the cost and complexity of metering outweighed the benefits. For larger residential consumers, EdF has continued to make a tariff available that includes seasonally varying rates.

14 See Table A.4 in the Appendix.
Table 7
Examples of Charging Periods for Storage Heating in Hamburg
(Winter 1974)

<table>
<thead>
<tr>
<th>Type of Control</th>
<th>Installed Capacity (MW)</th>
<th>Charging Times</th>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td></td>
<td>Night (p.m. and a.m.)</td>
<td>From (a.m.)</td>
<td>To</td>
</tr>
<tr>
<td>Forward</td>
<td>20</td>
<td>8:00</td>
<td>4:00</td>
<td></td>
</tr>
<tr>
<td>Forward</td>
<td>35</td>
<td>8:10</td>
<td>4:10</td>
<td></td>
</tr>
<tr>
<td>Early Charge</td>
<td>23</td>
<td>8:20</td>
<td>4:20</td>
<td>1:25</td>
</tr>
<tr>
<td>Forward</td>
<td>31</td>
<td>8:30</td>
<td>4:30</td>
<td></td>
</tr>
<tr>
<td>Forward</td>
<td>14</td>
<td>8:40</td>
<td>4:40</td>
<td></td>
</tr>
<tr>
<td>Forward</td>
<td>39</td>
<td>8:50</td>
<td>4:50</td>
<td></td>
</tr>
<tr>
<td>Forward</td>
<td>33</td>
<td>9:00</td>
<td>5:00</td>
<td></td>
</tr>
<tr>
<td>Early Charge</td>
<td>29</td>
<td>9:10</td>
<td>5:10</td>
<td>1:05</td>
</tr>
<tr>
<td>Forward</td>
<td>31</td>
<td>9:20</td>
<td>5:20</td>
<td></td>
</tr>
<tr>
<td>Forward</td>
<td>38</td>
<td>10:00</td>
<td>6:00</td>
<td></td>
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<td>Backward</td>
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<td>7:20</td>
<td></td>
</tr>
<tr>
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<td>1</td>
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<td>5:00</td>
</tr>
</tbody>
</table>

SOURCE: Hamburg Electricity Works.
FINLAND, NORWAY, AND SWEDEN

Storage space heating is in use only to a limited extent in these Scandinavian countries. Although significant off-peak differences in marginal costs occur in utilities such as the Stockholm and Helsinki municipal supply utilities, which obtain a portion of their power from thermal district heating plants, these cost differences are insufficient to justify the roughly $2500 investment needed for a storage space-heating unit that is adequate for severe winter temperatures. Furthermore, any widespread adoption of storage space-heating units would require reinforcement of the distribution system to handle local peaking and thus offset at least some of the savings in generating costs. Nevertheless, storage water heating can be cost-effective in some of these circumstances. In the Stockholm system, only a small fraction of the dwellings—i.e., semidetached and detached homes—are eligible for the time-of-day tariff. The observable annual shift in load from daytime to nighttime is about 3000 kwh per home for storage water heating plus an estimated 1000 kwh for other uses, such as clothes washing and dishwashing. In aggregate, this amounts to a shift of 25 million to 30 million kwh/year or about 0.8 percent of system load.

In other utilities in these countries, hydroelectric plants are the predominant source of power today, and increased demand is expected to be met primarily by nuclear plants. For these systems, there is only a small daytime/nighttime differential in marginal costs. Historically, these hydroelectric systems have had an abundance of energy, have experienced a high degree of electrification in transportation, heating, and cooking, and have been constrained by the available generating and distributing capacity.

The tariffs reflect this condition, emphasizing maximum-demand charges. In Norway, the load-rate tariff has been in use for many years. For example, the typical homeowner in Oslo subscribes for an annual load at a rate of $22.93 (118 NKr)/kw. He pays 0.58¢ (3 øre)/kwh for energy consumed, but he is charged 2.29¢ (11.8 øre)/kwh for each kilowatt-hour consumed when demand is in excess of the subscribed load. Now that the readily usable hydroelectric sources have been developed, some Scandinavian utilities are anticipating an energy constraint rather than a capacity constraint. Oslo and several other Norwegian utilities are slowly abandoning the domestic load-rate tariff for a more conventional declining block energy tariff, which provides an incentive to economize on kilowatt-hours whenever electricity is used, rather than to economize on maximum kilowatt demand.

Ripple control systems are in use in a number of Swedish and Finnish utilities. In most instances, these systems were initially installed to control street lighting, and with the advent of solid-state receiver units, control is being extended to residential loads. Although there is a limited amount of ripple-controlled storage space heating, direct-control techniques are increasingly being used with direct heating. In advanced systems, computer control permits the utility to turn off residential heating and rotate the reductions among houses. These techniques are effective in meeting emergencies of short duration. Longer interruptions can be tolerated in newer Swedish homes that are constructed to high-insulation standards.
V. IMPLICATIONS OF FOREIGN EXPERIENCE FOR THE CALIFORNIA INDUSTRIAL SECTOR

In previous sections, we have reviewed the several types of electricity tariffs used by selected foreign utilities and the character of electricity demand observed in recent years under the terms of such tariffs. An important part of this study is to make an initial assessment of the changes that might occur in the amount and pattern of electricity use in California if similar peak-load tariffs were adopted. In making this assessment, we must be aware that the response of California electricity users will depend on several factors that may differ from those observed in Europe. These include: the relative costs of other forms of energy; the relative costs of capital and labor; the specific terms of the tariff that would be offered in California; and the technological processes employed in California industries.

The peak-load and time-of-day tariffs found in France and in the United Kingdom are of the form most likely to be considered for adoption in the United States. For this reason, and because relatively specific industry-by-industry load data are available for French industrial customers, we base the bulk of our quantitative assessment on the French experience.

Since industrial use of energy tends to be less dependent on country-by-country factors (such as climate and patterns of ownership and control), and since large industrial customers are likely to be the first customers to face time-of-day tariffs in the United States, we limit our quantitative discussion to the industrial class of users. The use of electricity by commercial and residential customers is much more dependent on climate and on the type of heating and cooling systems employed. Most European utilities are winter peaking, have significant electrical space- and water-heating loads, and frequently have storage devices available to their customers. Their commercial and residential customers make very little use of air conditioning. In contrast, California utilities are summer peaking, have major air conditioning loads, and their customers use natural gas for a significant portion of their space and water heating.

The data presented here are an initial attempt to assess the potential for shifting industrial electricity loads away from peak hours in California utilities. They are forecasts of the changes that will result from time-of-day pricing; rather they are comparisons of the patterns of use of electricity in California with and without the type of response observed in European data. We present a range of possible adjustments based on several methods of calculation. To the extent possible, we have based our calculations on conservative assumptions in order to obtain lower-bound estimates of the potential effect of statewide use of peak-load pricing.

This section is divided into three parts. First, we present a discussion of how different industrial customers may have adapted their use of electricity when peak-load rates were introduced in foreign utilities. This discussion is necessary, both to

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1 We base this observation on a review of discussions in both generic and specific rate cases in U.S. utility commissions. Reasons include the relatively general time-of-day elements of both foreign tariffs, as well as the similarity in underlying generation technology to most U.S. situations. Tariffs based on a predominantly hydroelectric generation base (as in Norway) are less appropriate for most U.S. utilities.
FINLAND, NORWAY, AND SWEDEN

Storage space heating is in use to only a limited extent in these Scandinavian countries. Although significant off-peak differences in marginal costs occur in utilities such as the Stockholm and Helsinki municipal supply utilities, which obtain a portion of their power from thermal district heating plants, these cost differences are insufficient to justify the roughly $2500 investment needed for a storage space-heating unit that is adequate for severe winter temperatures. Furthermore, any widespread adoption of storage space-heating units would require reinforcement of the distribution system to handle local peaking and thus offset at least some of the savings in generating costs. Nevertheless, storage water heating can be cost-effective in some of these circumstances. In the Stockholm system, only a small fraction of the dwellings—i.e., semidetached and detached homes—are eligible for the time-of-day tariff. The observable annual shift in load from daytime to nighttime is about 3000 kwh per home for storage water heating plus an estimated 1000 kwh for other uses, such as clothes washing and dishwashing. In aggregate, this amounts to a shift of 25 million to 30 million kwh/year or about 0.8 percent of system load.

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For simplicity, we will illustrate the process of adaptation over time by using a stylized tariff that does not correspond precisely to the terms of either the French or British peak-load tariff. Instead of the more complicated tariffs with peak, shoulder, and slack periods offered in Europe, the hypothetical tariff has a peak rate during a single 4-hour period and an off-peak rate that applies during the other 20 hours of each day. Furthermore, we use simplified load shapes that are constant at different levels of consumption rather than the continuously varying curves observed in practice.

**Case 1**

In the first case, we consider a firm that initially has a single-shift operation and for which labor costs are not of major importance—either because they are a small part of total production costs or because labor-shift differentials are insignificant. The load curve prior to the introduction of peak-load rates is assumed to have the shape shown in Fig. 24(a).

Unless the firm depicted in Fig. 24(a) requires a long period of time every day for maintenance of equipment, it has excess production capacity for its current level

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**Fig. 24**—Case 1: Initial single-shift operation in which labor costs are small
of output. Therefore, the initial response by this single-shift firm might be to sched-
ule its working hours either earlier or later in the day so that it can entirely avoid
the 4-hour peak charge. Depending on the costs and convenience of operating one
or two shifts during off-peak hours, the firm may operate on a single shift at nonpeak
hours, or it may settle immediately into a pattern of consumption as illustrated in
Fig. 24(b). Over time, as the demand for the product grows, the firm will increase
its level of production in all off-peak hours, up to the level of installed plant capacity.
Only as a last resort will the plant use any electricity during peak-charge hours.²

In general, we will underestimate the reduction in energy used during peak
hours if we are only able to observe the load curve shown in graph (b) of Fig. 24. As
long as the total amount of electricity consumed (the area under a load curve) is the
same over the course of the day, the difference between the electricity used during
peak hours and that used during off-peak hours in graph (b) is smaller than the
difference that results from comparing consumption during peak hours in graphs (a)
and (b). Of course, as production during off-peak hours increases to the capacity
constraint, the difference between peak and off-peak electricity consumption in-
creases and graph (b) becomes a more accurate measure of the shift that has taken
place over time.

Some firms that are initially in the situation of Case 1 will have the additional
possibility of changing the energy intensiveness of their production processes. The
lower off-peak electricity rate may make it advantageous to substitute electricity for
labor, capital, or other inputs. Where such technological possibilities exist, the firm
will, over time, shift to a permanent-load shape of the form illustrated in graph (b)
of Fig. 24. Since in this case the amount of energy per unit of output increases, we
cannot unambiguously assert that observing only graph (b) will underestimate the
amount of energy reduction during peak-charge hours. However, for the same level
of plant output, the energy intensiveness of the process would have to increase quite
substantially for the lower graph not to be a conservative measure of change.³

Cas e 2

As a second case, we consider a plant that initially uses electricity during three
shifts and has a load curve as shown in graph (a) of Fig. 25. Multishift operation is
needed either because the plant capacity is not adequate to meet total production
in a single shift or because minimum levels of operation are required at all hours
for the technological process involved. As in Case 1, we assume that labor cost
differentials are relatively unimportant. If a minimum level of plant operation (at
the K' level) is needed, response to the peak-load tariff is shown by the solid line in
graph (b). If there is no reduction in total output of the plant, then area A equals
the sum of areas B, C, and D. If it is not necessary to have a minimum level of
operation so that all of the load can be shed during peak hours, then the new load

² As noted in Section III, the French cement industry follows a pattern of production and plant
construction similar to that outlined here. Excess capacity is deliberately created in the short run; all
crushing and grinding activities are scheduled for off-peak hours, whereas maintenance of the equipment
is scheduled daily for the peak-charge period. Only as total production reaches a plant's maximum
capacity is any crushing and grinding scheduled for the peak period.

³ For instance, at the same level of plant output, switching from a one-shift, 8-hour process to a
three-shift, 20-hour off-peak process will yield a conservative measure unless the amount of electricity
per unit of output increases by more than 250 percent.
Fig. 25—Case 2: 24-hour operation in which labor costs are small and a minimum level of electricity is required.

The load curve may be more like the broken line in graph (b), where area A equals the sum of areas B, B', C, and C'.

In Case 2, the firm can minimize cost by just rescheduling its operations to concentrate energy use in off-peak hours. Consequently, changes in its load pattern in response to time-of-day tariffs should be observed relatively rapidly. If the total quantity of electricity used over the day remains the same, then a calculation based solely on graph (b) will again provide a conservative measure of the amount of energy reduction that occurs in changing from the load curve in graph (a) to that in graph (b).

Case 3

In Case 3, we assume that the initial position of the firm is a single-shift operation with important labor costs. Under such circumstances, when a time-of-day rate is applied, the firm can be expected to shift some, but not all, of its production to off-peak hours. At the same time that electricity costs fall (moving to off-peak production), labor costs rise because shift differentials must be paid to labor. The optimal amount of shifting will be determined by the way in which the costs of

* These cost differences may be due either to large shift differentials that must be paid to labor or to relatively small pay differentials per worker combined with a large labor cost per unit of product.
production vary in each period as a result of different combinations of labor, energy, and capital inputs. The form of the new load curve is given in graph (b) of Fig. 26. In general, consumption during peak hours will not be reduced to zero. Again, because we are able to observe the load curve only after the tariff has been in effect, we will have a conservative measure of the reduction that occurred in peak-period energy consumption.\footnote{As noted in Case 1, only a substantial increase in the electricity intensity of the production process would modify this conclusion.}

The conservative estimate of the reduction in peak electricity use is reinforced by the likely adjustment in total plant output. Since, in Case 3, labor costs are a significant portion of total costs, the price of the output can be expected to rise and, as long as the demand for the final good is not perfectly inelastic, the overall level of output will fall. Consequently, area A will generally be greater than area B, and the difference between peak and off-peak electricity consumption observed in graph (b) will understate the reduction that would be calculated from a comparison of the curves in graphs (a) and (b). Case 3 could also be generalized to a situation in which the firm initially has nonzero consumption of electricity in the second and third shifts (as in the initial position shown in graph (a) of Fig. 25; after adaptation to the time-of-day tariff, the plant's load shape would resemble that shown in graph (b) of Fig. 26).
Case 4

The load curve for the fourth case, starting from a one-shift operation, is shown in Fig. 27. In Case 4, we assume that labor costs are important and that despite the shifting of some activities to off-peak hours, it is still optimal to use greater amounts of electricity during the peak period. This is an especially important case to note, because if we were to observe only the load curve after the tariff had gone into effect (graph (b) of Fig. 27), we might conclude that there had been no response to the time-of-day tariff, whereas, under the postulated conditions, a substantial adjustment has in fact occurred.⁶

![Load curve before introduction of peak-load rates](image)

![Load curve after introduction of peak-load rates](image)

Fig. 27—Case 4: Initial single-shift operation in which labor costs are significant; optimal shifting leaves peak use above off-peak hours

Case 5

Figure 28 illustrates the final case of a plant with a three-shift operation in which electricity consumption is reasonably constant throughout the 24-hour period. The nature and speed of adaptation to a time-of-day tariff depend on whether

⁶ Obviously a similar case will occur when some consumption of electricity initially takes place during the second and third shifts, and when, after optimal rescheduling of activities, peak energy consumption still exceeds off-peak energy consumption.
Fig. 28—Case 5: Three-shift operation in which capital costs are significant

or not the plant has excess production capacity in the short run. In graph (a) of Fig. 28, we assume that the plant is operating near the maximum of its installed production capacity, and consuming energy at a rate of $K_1$ kilowatts day and night. Under these circumstances, unless there is a decline in the demand for the firm's product, time-of-day pricing will have no effect on the use of electricity in the short run. However, if there is some excess production capacity available, then, as shown in graph (b), the firm will expand production in off-peak hours up to the maximum available capacity and consume electricity at a rate of $K_2$ (greater than $K_1$) kilowatts during off-peak hours. The plant will reduce its peak-period use of energy as much as possible while still meeting total demand for its product. In the long run, the plant may find it advantageous, as in graph (c), to expand its production capacity in order to take advantage of the less-expensive off-peak electricity rates. Provided that the additional costs of achieving expanded capacity do not outweigh the savings on electricity rates, capacity will be expanded to a level $K_3$ (greater than both $K_1$ and $K_2$) in order to eliminate most or all of the electricity used during peak hours.

Several of the French industries described in Section III have load curves that are consistent with this hypothetical pattern of evolution. Despite the fact that a
number of firms—in the petroleum refining, electrochemical, cement, and air products industries—are commonly considered to operate continuous processes and thus to be unable to modify their daily pattern of use, their individual load curves under peak-load tariffs clearly demonstrate that many of these industries have a significant degree of adaptability.


In summary, the five cases we have discussed illustrate that a variety of initial conditions will underlie the pattern and speed of industrial adaptation to time-of-day electricity rates. Although we expect to observe relatively few differences in the shapes of load curves after a peak-load tariff has been in effect for some time, there are several different starting positions from which the ultimate load shapes may evolve. Since we are limited to observing only the ex post load curves of European industrial customers some years after the introduction of time-of-day rates, we will generally tend to underestimate the shift in peak-period consumption that has taken place over time. Our measures of the effects of time-of-day rates on peak-period electricity consumption can therefore be regarded as conservative estimates of the potential load shifting that could be achieved in California.

DATA AND METHODOLOGY

In attempting to draw implications for California from the pattern of electricity consumption observed for European industrial customers, we will consider the applicability of that experience in the California context and then describe the data and methods to be used to estimate the potential for load shifting in California industry.

Applicability

If California's industrial customers were in exactly the same economic position today that their French industrial counterparts occupied at the initiation of time-of-day pricing, we would expect that over time the shapes of the load curves for California industries would eventually come to closely resemble those seen in France today. For these conditions to prevail, the terms of the tariffs would have to be identical, the technologies would have to be identical, and the relative prices of factor inputs, such as labor, capital, and energy, would have to be the same in both situations.

Although not all circumstances in California are identical with those in France, the potential California time-of-day tariffs appear to be very similar to French time-of-day rates. Although the overall price level and specific terms of California's peak-load tariffs (especially the peak hours and mixture of kilowatt and kilowatt-hour charges) will vary from utility to utility, a basic similarity in tariff structure can be expected throughout the state. The first California time-of-day tariff, which will go into effect in February 1977 for the 120 largest customers served by the Pacific Gas & Electric Company (PG&E) is remarkably similar to the French industrial tariff. Table 8 shows the terms of the two tariffs for the peak season (4 months in France, 5 months in PG&E's service territories). Each tariff has three distinct periods: peak, shoulder or full, and off-peak or slack. Columns (1) and (2) show the
### Table 8
Comparison of Peak Season Time-of-Day Rates in France and California

<table>
<thead>
<tr>
<th>Period</th>
<th>Actual Tariff</th>
<th>Effective Price$^a$</th>
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</thead>
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<tr>
<td></td>
<td>$$/kw/mo (1)</td>
<td>c/kwh (2)</td>
</tr>
<tr>
<td>France$^b$ (November-February)</td>
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<tr>
<td>Peak (4 hr, 6 days/wk)</td>
<td>3.04c</td>
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<td>Shoulder (12 hr, 6 days/wk)</td>
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<td>Off-peak (8 hr, 6 days/wk; all day Sunday)</td>
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<td>California (PG&amp;E) (May-September)</td>
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<tr>
<td>Peak (6 hr, 5 days/wk)</td>
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</tr>
<tr>
<td>Shoulder (8 hr, 5 days/wk; 14 hr on Saturday)</td>
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<tr>
<td>Off-peak (10 hr, 6 days/wk; all day Sunday)</td>
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*a Based on consumption of electricity at a constant rate during each period of time.

*b General Tariff version of the Green Tariff for customers served at 60 to 90 kV, based on the rate of exchange prevailing on January 3, 1977. "Full" and "slack" periods have been relabeled "shoulder" and "off-peak" for comparison with the PG&E tariff.

*c Monthly portion of the annual charge for subscribed power.

*d Monthly portion of the annual charge for power subscribed during a shoulder period, which is billed at an amount no less than the amount subscribed during the peak period.

*e Monthly portion of the annual charge for power subscribed during an off-peak period, which is billed at an amount no less than the amount subscribed during the shoulder period.
actual prices under each tariff. To make it easier to compare the cost savings from shifts in electricity use under different combinations of kilowatt and kilowatt-hour charges, column (3) restates the tariffs in terms of the equivalent price per kilowatt-hour in each time period.\(^8\)

Although at every period the rate in the French tariff is greater than the PG&E time-of-day rate, the relative price incentives for shifting load are almost identical. The ratio of peak-period to shoulder-period prices (using the equivalent amounts) is between 2.6:1 (for France) and 2.8:1 (for PG&E). The ratio of the equivalent peak to off-peak prices is about 4 to 1 in both tariffs. Consequently, if anything, the PG&E tariff sends a slightly stronger relative price signal to California industrial customers than does the French tariff. Of course, the absolute difference between peak-period and shoulder-period charges, or between shoulder-period and off-peak period charges, is greater in France than in this particular California tariff, so that some benefit-cost comparisons will show a greater absolute gross benefit under the terms of the French tariff than under the PG&E tariff.

There are three principal reasons to expect that the calculated responsiveness of French industrial customers will provide a conservative estimate of the long-run load changes that can be expected from California industrial customers in corresponding industries.

First, as we discussed above, the observed load curves will frequently understate the reduction in peak use that has occurred over time in response to the introduction of time-of-day tariffs, particularly when the use of electricity during peak hours still exceeds that during off-peak hours (see Fig. 27).

Second, all forms of energy have, for several years, been more costly in most European countries than in the United States. Consequently, European industries have already exploited possibilities for economizing on energy consumption that remain untapped in the United States. Also, the relatively greater scarcity and higher cost of alternative forms of energy, such as natural gas and fuel oil, have meant that European industrial customers could not as readily substitute them for electricity in industrial processes.

Third, in calculating the degree of industrial load shifting in California, we assume that total electricity use remains the same over the course of the day. But in some cases, the introduction of a time-of-day tariff can be expected to lower total electricity use somewhat, so this method of calculation will provide an underestimate of the capital and operating cost savings that will result from time-of-day pricing.

The import of these three factors is that by applying evidence of load shifting from French industrial customers to California industrial customers, we will get lower bound estimates of the potential for reducing peak-period electricity consumption.

\(^{7}\) For purposes of comparing the two tariffs, the French subscribed demand charge is stated as a monthly amount, even though it applies to the maximum kilowatt demand in a 4-month period.

\(^{8}\) The equivalent price is calculated by dividing the kilowatt charge by the total number of hours to which it applies and adding this amount to the price per kilowatt-hour. This amount indicates the saving per kilowatt-hour when a customer reduces his consumption by 1 kilowatt of demand throughout the time period.
DATA USED

Our calculations of potential load shifting among California industrial customers are based on detailed load study data for both French and California industrial customers. The French high-voltage tariff has two types of time-of-day charges: one is based on maximum kilowatt demand subscribed in each of three time periods in the winter (and two time periods in the summer); the other is a different charge per kilowatt-hour consumed in each of these five time periods. The subscribed number of kilowatt-hours can be renegotiated every 5 years. From a study of a sample of some 250 French firms (about half of France's large industrial users), we have available data on both the industries' subscribed demand levels and their daily load curves, from which we can calculate kilowatt-hour usage by period. Based on the U.S. Standard Industrial Classification (SIC) Codes, eighteen of these industries closely correspond to industries found in California. The data from the remaining French industries were not used for calculating the potential for load shifting in California.

Data for California industries are taken from load studies of individual industrial customers of two major utilities—one in Northern California and one in Southern California. Load data for a total of approximately 175 customers in 13 industry groupings (based on 4-digit SIC coding) are available for either a 2- or 3-month period for each customer. For 5 additional industrial groupings, we have good French load data but no corresponding load curves within our sample of California industries (although such industries are located in California). For these groups, we took total electricity consumed in the corresponding California industry and based our estimates on the assumption that the initial load curves were flat. (These five industrial groups are indicated by an asterisk in Tables 9 and 11, below.)

Methods for Calculating Response to Peak-Load Pricing

Four methods are used to calculate the potential impact of peak-load pricing in California industries. The methods reflect different assumptions about the change inferred in France or calculated in California. In the French data, we can use either subscribed demand data or load study data to calculate the magnitude of load reduction in foreign industries. In California, we can estimate the potential change in peak-period consumption either by assuming a reduction in energy use during peak-charge hours proportional to that in the French data or, alternatively, by postulating that California customers will alter production so that their load curves take the shape of their foreign counterpart industries. These alternative assumptions combine, as shown in Fig. 29, to yield the four separate methods of estimating impact. We will discuss two of the methods in detail to illustrate the steps used in our calculations. As noted earlier, throughout our calculations we will assume that

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8 The dates for the load study were chosen in advance by Edf's analysts. The study covered the third Wednesday in December and the following Saturday and Sunday. The net system load was lower than the historical average on this Wednesday, but we have been unable to detect any systematic bias in the percentage difference between peak-hour and slack-hour demand. Analysis of a sample of industries taken the same day a year later showed similar responses to the ones reported here.

10 This is a conservative assumption, since the demands of most of these customers are likely to peak during the daytime. Consequently, their true response would be greater than we have calculated.
Basing the French calculation on data from

(a) Reduction in peak period consumption proportional to French data or
(b) California industries taking the load shape of French industries

<table>
<thead>
<tr>
<th></th>
<th>(a) subscribed demand</th>
<th>(b) load study</th>
</tr>
</thead>
<tbody>
<tr>
<td>Method 1</td>
<td>Method 2</td>
<td></td>
</tr>
<tr>
<td>Method 3</td>
<td>Method 4</td>
<td></td>
</tr>
</tbody>
</table>

Fig. 29—Matrix illustrating how alternative assumptions about French and California load changes yield four methods of calculating load response in California.

Total electricity consumption in California remains the same and that only the time at which it is used is affected.

Method 1 is based on first determining the percentage difference between the subscribed kilowatt demand in slack-hour periods and that in peak-hour periods in a French industry. We then multiply this percentage amount, δ, by the average number of kilowatts currently demanded in the corresponding California industry during peak hours and obtain the estimated California reductions in peak-period energy for a 4-hour period, shown as the shaded area (R) in graph (b) of Fig. 30.¹¹

Since we assume that the total amount of energy consumed remains unchanged, there is a corresponding increase in off-peak use of energy. For simplicity, we have shown this increase as cross-hatched areas (S); our estimates of the amounts of peak-period energy reductions are unaffected by the particular hours in which increased off-peak usage occurs.

In some French industries, subscribed demand in peak periods is as large as that subscribed in slack periods. In this case, our Method 1 calculation ascribes no response to California industry. As discussed in the context of Case 4 (Fig. 27), above, this procedure imparts a conservative bias to the calculated response.

At the other methodological extreme, our Method 4 uses data from the French load study, rather than the subscribed levels of demand, to calculate the mean kilowatt demand in slack and peak periods. We then determine the fraction of the total energy consumed by each French industry that is used during the 4-hour peak period. That is, in graph (a) of Fig. 31, we calculate the dotted areas (P) as a percentage of the total area under the French industry's load curve. We then assume that the California industry shifts to a new load shape such that the same percentage of its energy is consumed during a 4-hour peak period. This new on-peak level of consumption is shown as the dotted area (P') in graph (b), and the estimated reduction in peak-period energy consumption obtained by this method is shown as the

¹¹ For this calculation, the response from French data was estimated by using demand from midnight to 6 A.M. for slack and 7 A.M. to 9 A.M. for peak hours. In California, the period from noon to 4 p.m. was used to calculate the 4-hour tariff (and noon to 6 p.m. for a 6-hour calculation). These periods cover the time of system peak in most California utilities throughout the year.
shaded area (R). Because total energy consumption is unchanged, there is again an increase in off-peak usage which is shown as the cross-hatched areas (S).

In contrast to Method 1, this method of calculating change in response to a peak-load tariff can generally accommodate the case in which French demand (observed or subscribed) is greater during peak periods than during slack periods. The only exception that occurs is when the California industry is already observed to use a lower portion of its total energy during the 4-hour peak-charge period than that used by the French industry.\(^\text{12}\) In this case, the amount of reduction (R) is assumed to be zero.

The other two methods of calculating change are now easily summarized.

Method 2. The average values of demand observed during slack and peak periods from the French load study (rather than the subscribed demand levels) are used to calculate the percentage reduction in peak-period maximum demand (instead of calculating the portion of total energy that is consumed during a peak period). That is, if graph (a) of Fig. 30 were modified to show mean kilowatt demand in each time period, then the percentage reduction, \(\delta\), would be applied to California industry as shown in graph (b).

Method 3. The subscribed levels of demand in the slack and peak periods for French industry (rather than the observed mean kilowatt demand from the load

\(^{12}\) That is, the sum of areas \(R\) and \(P'\) in the California graph is a smaller proportion of the total area under the curve than are the areas \(P\) in the French graph.
Fig. 31—Percentage reduction in peak period energy estimated by Method 4

study) are used to calculate the amount of energy used during peak hours as a proportion of total energy use (instead of calculating percentage reductions in energy use). That is, graph (a) of Fig. 31 is reinterpreted to show subscribed levels of demand in each time period and the rest of the calculation is made as illustrated in graph (b).

PROJECTED EXTENT OF LOAD SHIFTING IN CALIFORNIA INDUSTRIES

In California, electricity is produced from a mixture of hydroelectric, thermal, nuclear, and pumped storage facilities. In most cases, thermal generation from fuel oil represents the marginal generation unit at all hours of the year. Furthermore, the daily load curves of the largest utilities have a single peak with a pronounced difference between the daily high and low load that usually exceeds the difference between peaks in any 2 months of the year by almost a factor of 2. The annual peak occurs in the summer, so that a time-of-day tariff based on principles of peak-load pricing would generally be expected to have a single peak period—perhaps applicable throughout the year—as opposed to the twin morning and afternoon peak periods observed in France and Britain. For illustrative purposes, all of our calculations are based on a single peak period that either extends from noon until 4 P.M. or from

13 A small amount of energy is supplied by internal combustion or gas-turbine peaking units.
noon until 6 P.M. every weekday. In many utilities, an intermediate shoulder period rate would be justified, and perhaps some adjustment of peak periods from one season to another. Nevertheless, we limit our calculations to the effects of a simple peak/off-peak tariff.

The advisability of charging peak-load electricity rates to all industrial customers depends on a comparison of benefits and costs. The benefits of reduced capital and operating expenses to the utility (as well as environmental and other benefits that might accompany a reduction in peak-period energy use) must be compared with the costs of metering and administering a more complex tariff, the impact on the markets for industrial products, and possibly adverse environmental impact due to increases in energy use during off-peak hours.

The California Public Utilities Commission has ordered that time-of-day pricing be implemented for the largest industrial and commercial customers in the state without delay and has directed that suitable metering be installed on smaller commercial and industrial users so that they could also face time-of-day rates in the future. Although no schedule has been established for extending time-of-day pricing to these additional consumers, it appears that within a few years a large fraction of the electricity supplied to industrial customers in the state will be sold under a time-of-day electricity tariff. Consequently, an estimate of the load response that can be expected in all industrial categories can be helpful in both anticipating future energy needs and in assessing the possible benefits of a widespread implementation of peak-load pricing.

Electricity Sales of California Utilities

Although California utilities sell electricity to industrial, commercial, and residential users, we restrict our calculations of the projected impact of a time-of-day tariff to the effect on industrial customers only. Time-of-day pricing is also expected to influence the patterns of energy use of larger commercial customers, who use large amounts of electricity for lighting and air conditioning. However, due to the absence of air conditioning in European commercial buildings, there is little foreign data that can be used to anticipate that response. Therefore, we have not attempted to project the impact on statewide energy use that would result from load shifts of commercial customers.

Our estimates of the impact of time-of-day pricing in California are based on electricity sales of the four largest state utilities. Together, these utilities sold 10.7 billion kilowatt-hours in April 1976—some 87 percent of the total electricity consumed in the state. In these utilities, industrial consumption constitutes about 25 percent (2.7 billion kWh) of the total consumption. Our principal calculations are based on the expected response by the industrial customers in 18 SIC code groupings for which we have good matches with French industry. These 18 industrial groupings accounted for 1.23 billion kWh in April, or about 46 percent of all the industrial electricity consumption by customers in these four largest utilities.

In constructing estimates of the potential effect of peak-load pricing in California, our first step was to assess, industry by industry, the potential changes in daily

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14 In Decision No. 8559, dated March 16, 1976, resulting from its generic electricity rate case (Case No. 8804).
patterns of electricity consumption. To do this, we used the information from the study of French industrial customers and applied it to the sample of California industrial customers, using the four methods described above. We then estimated the potential state-wide effect by scaling-up the estimates for this sample of California firms. To do so, we used data for each industry on the aggregate amount of electricity consumed and assumed that the statewide response during peak hours would be proportional to that estimated for our sample.

**Impact of Time-of-Day Pricing on Eighteen Industries**

The 18 groups of industries for which we have French data are listed in Table 9. As shown in the second column of the table, these 18 industries consume 1232 million kWh per month, of which 164 million kWh (13 percent) is used during the weekday 4-hour (noon to 4 P.M.) period. Depending on which of our four methods is used to calculate shift in energy use from peak to off-peak hours, between 54 and 67 million kWh of monthly peak-period energy is expected to be shifted to off-peak periods if California industries respond in a manner similar to the response of their French counterparts. This amounts to a reduction of 33 to 41 percent of the energy now consumed by those customers during that 4-hour period.

Generally speaking, of the four methods used, Method 1 yields the least expected change and Method 3 the greatest. This is in part due to the fact that for some industries Method 3 is the only one that yields an estimated change in peak-period consumption. The zero impact calculated under the other methods occurs because the corresponding French customers in these industrial groups currently consume a higher proportion of electricity during peak hours than do their counterparts in California; therefore, under Methods 1, 2, and 4, we assign a zero value to the expected reduction in California. However, Method 3 yields an expected reduction because, despite higher actual demand during peak hours, the French industries subscribe to the same level of demand in both slack and peak periods. This uniformity of subscribed demand occurs because the Green Tariff gives no discount for lower levels of subscribed demand in the slack period and because firms may wish to maintain the option of expanding production in off-peak periods.

In both relative and absolute terms, the industry that yields the greatest expected reduction in peak-period energy use is petroleum refining. Depending on the method used, we calculate potential reductions in peak-period use of electricity in this industry to be between 80 and 93 percent. The size of potential load response is due both to the amount of electricity consumed by California refineries and the major response shown in the French data. Other industries that make up a significant portion of this calculated change include blast furnaces and steel works; indu-

for this scaling calculation. Originally, we had expected to use data for the first 6 months of 1976, but a machine-readable copy was not available in time for use in this study. Use of April-only data does not seem to result in a significant misrepresentation of the relative shares of energy consumed by different industrial groupings, because industrial use of energy generally does not display pronounced seasonal effects.

17 Because our sample of California load curves is drawn from the largest industrial customers, there is a possibility that the statewide extrapolations overstate the total impact of peak-load pricing if the (proportionate) response of the smaller consumers is not as great as that of the larger ones. However, the comparison of customer-specific and system-wide impacts in subscribed kilowatt usage in France suggests that this is not a major source of bias (see Table 4).
Table 9
Projected Effects of Time-of-Day Pricing on Monthly Electricity Consumption
in 18 Industrial Groups, 4-Hour Peak Period
(Million kwh)

<table>
<thead>
<tr>
<th>Industry</th>
<th>(1) SIC Code</th>
<th>(2) Total Current Consumption per Month</th>
<th>(3) Total Current Weekday Consumption, Noon to 4 p.m.</th>
<th>(4) Estimated Monthly Reduction in Peak-Period Consumption</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td></td>
<td>Total</td>
<td>Estimated</td>
<td>Method 1</td>
</tr>
<tr>
<td>Textile mill production</td>
<td>22</td>
<td>17.0</td>
<td>0.3</td>
<td>0.3</td>
</tr>
<tr>
<td>Paper and allied production</td>
<td>26</td>
<td>39.0</td>
<td>1.5</td>
<td>1.5</td>
</tr>
<tr>
<td>Industrial inorganic chemicals</td>
<td>281</td>
<td>202.0</td>
<td>3.1</td>
<td>3.1</td>
</tr>
<tr>
<td>Plastics</td>
<td>282</td>
<td>33.0</td>
<td>0.4</td>
<td>0.4</td>
</tr>
<tr>
<td>Petroleum refining</td>
<td>291</td>
<td>398.0</td>
<td>38.4</td>
<td>38.4</td>
</tr>
<tr>
<td>Paving and roofing materials</td>
<td>295, 299</td>
<td>8.0</td>
<td>0.1</td>
<td>0.1</td>
</tr>
<tr>
<td>and miscellaneous*</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Rubber and miscellaneous plastics</td>
<td>300</td>
<td>81.0</td>
<td>2.0</td>
<td>2.0</td>
</tr>
<tr>
<td>Cement (hydraulic)</td>
<td>324</td>
<td>64.0</td>
<td>2.8</td>
<td>2.8</td>
</tr>
<tr>
<td>Blast furnace and steel works</td>
<td>331</td>
<td>116.0</td>
<td>5.3</td>
<td>5.3</td>
</tr>
<tr>
<td>Iron and steel foundries*</td>
<td>332</td>
<td>18.0</td>
<td>0.5</td>
<td>0.5</td>
</tr>
<tr>
<td>Electric light and wiring equipment</td>
<td>364</td>
<td>7.0</td>
<td>0.0</td>
<td>0.0</td>
</tr>
<tr>
<td>Communication equipment</td>
<td>366</td>
<td>59.0</td>
<td>11.9</td>
<td>0.0</td>
</tr>
<tr>
<td>Electronic components and</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>accessories</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Motor vehicles</td>
<td>367</td>
<td>66.0</td>
<td>9.6</td>
<td>0.0</td>
</tr>
<tr>
<td>Ship and boat building and</td>
<td>371</td>
<td>42.0</td>
<td>9.4</td>
<td>0.0</td>
</tr>
<tr>
<td>repairing</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Miscellaneous transportation equipment</td>
<td>373</td>
<td>9.0</td>
<td>1.7</td>
<td>0.0</td>
</tr>
<tr>
<td>Engineering, laboratory, scientific</td>
<td>379</td>
<td>3.0</td>
<td>0.6</td>
<td>0.0</td>
</tr>
<tr>
<td>and research instruments</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Surgical, medical, and dental</td>
<td>381</td>
<td>5.0</td>
<td>0.7</td>
<td>0.0</td>
</tr>
<tr>
<td>instruments</td>
<td>384</td>
<td>5.0</td>
<td>1.2</td>
<td>0.0</td>
</tr>
<tr>
<td>Total</td>
<td></td>
<td>1232.0</td>
<td>164.4</td>
<td>54.4</td>
</tr>
</tbody>
</table>

*Indicates load study data available for the industry in French sample but not in California sample. See text for basis of calculating impact of time-of-day pricing in California.

†Indicates an amount less than 0.1 million kwh.
trial inorganic chemicals; rubber and miscellaneous plastics; communications equipment; and hydraulic cement.

Because petroleum refining is an especially large contributor to this projected reduction, it is useful, both for determining expected reductions in the 18 industries and for extrapolating the findings to industries in the rest of the state, to identify the contributions of petroleum refining separately from those of other industrial customers. The results of this type of breakdown are shown in Table 10. The final column of Table 10 indicates the total projected reduction when the method giving the greatest impact is used for each industry. The total projected reduction in peak-period use of electricity ranges between 33 and 46 percent for the 18 industries covered by the sample. Reductions made by petroleum refineries are expected to account for half to three-quarters of these reductions.

For reference, we also calculated the impact on peak-period energy consumption that could be expected if the same degree of change were observed in response to a tariff with a 6-hour peak charge, extending from noon to 6 p.m. Table 11 gives the results of this estimation. The basic patterns resemble those in Table 9 for a 4-hour peak period, although the amounts are greater. Projected reductions in peak-energy use range from 81 to 94 million kwh, out of a total of 242 million kwh/month currently consumed during the 6-hour period by these customers. By taking the maximum of each of the four methods for each industry, we obtain a reduction in peak-energy use of 109 million kwh. Depending on the method of calculation used, this amounts to a reduction of 33 to 45 percent of peak-period energy for the 18 industries as a whole, and 13 to 26 percent for the 17 industries other than petroleum refining.

In planning for the growth of state energy supplies, it is important to know the potential impact of peak-load tariffs on the maximum kilowatt demand as well as on the kilowatt-hours of electricity consumed during peak and off-peak periods. A different level and duration of maximum demand will affect both the amount and mix of new capacity needed for generation, transmission, and distribution, and it will also affect the amount and type of fuel burned to supply that energy. To have a fully satisfactory basis for calculating this impact, we would need a statewide load study showing the contribution of these 18 industries to statewide electricity load curves—data that are not currently available. We can, however, approximate the expected effect of time-of-day pricing on maximum kilowatt demand during a peak time period by means of the following procedure.

If we divide the estimated reduction in peak-period kilowatt-hour consumption by the number of hours to which the peak rate applies, we obtain an average reduction in peak kilowatt demand. This method of calculation implicitly assumes that the industries are making a proportional reduction in energy use at every moment. But individual firms do not have completely flat load curves. If a time-of-day rate were introduced that included a significant charge based on maximum

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18 The PG&E time-of-day rate for its largest customers has a 6-hour peak charge from 12:30 p.m. to 6:30 p.m. for 5 months of the year.
19 The effects of a 6-hour tariff are calculated by assuming that California industrial customers maintain, for 6 hours, the same (relative) level of electricity consumption as that maintained by their French counterparts during the 2-hour morning peak period of the French tariff. Although French industrial customers face peak rates for a total of only 4 hours per day, the peak rates are in effect 6 days (24 hours) per week. For our illustrative California tariff, we assume a 9-hour peak period that is in effect 5 days (30 hours) per week.
Table 10
Estimated Statewide Reduction in Monthly Electricity Consumption for 18 Industries During a 4-Hour Peak Period (Million kwh)

<table>
<thead>
<tr>
<th>Industry</th>
<th>Current Level of Electricity Consumption During 4-Hour Peak Period</th>
<th>Estimated Monthly Reduction in Peak-Period Consumption</th>
<th>Total Reduction When Method Giving Greatest Impact Is Used For Each Industry</th>
</tr>
</thead>
<tbody>
<tr>
<td>Petroleum refining</td>
<td>46.2</td>
<td>38.4 (83%) 43.0 (93%) 36.9 (80%) 42.3 (92%)</td>
<td>43.0 (93%)</td>
</tr>
<tr>
<td>17 other industries</td>
<td>118.2</td>
<td>16.0 (14%) 14.7 (12%) 29.8 (25%) 18.8 (16%)</td>
<td>33.1 (28%)</td>
</tr>
<tr>
<td>Total for 18 industries</td>
<td>164.4</td>
<td>54.4 (33%) 57.7 (35%) 66.7 (41%) 61.1 (37%)</td>
<td>76.1 (46%)</td>
</tr>
</tbody>
</table>
Table 11

Projected Effects of Time-of-Day Pricing on Monthly Electricity Consumption
in 18 Industrial Groups, 6-Hour Peak Period
(Million kwh)

<table>
<thead>
<tr>
<th>Industry</th>
<th>SIC Code</th>
<th>Total Current Consumption per Month</th>
<th>Total Current Weekday Consumption, Noon to 6 p.m.</th>
<th>Estimated Monthly Reduction in Peak-Period Consumption</th>
</tr>
</thead>
<tbody>
<tr>
<td>Textile mill production</td>
<td>22</td>
<td>17.0</td>
<td>3.0</td>
<td>0.6 0.0 0.4 0.0</td>
</tr>
<tr>
<td>Paper and allied production</td>
<td>26</td>
<td>99.0</td>
<td>17.2</td>
<td>2.3 1.9 2.3 1.9</td>
</tr>
<tr>
<td>Industrial inorganic chemicals</td>
<td>281</td>
<td>202.0</td>
<td>35.7</td>
<td>4.6 6.4 2.3 3.9</td>
</tr>
<tr>
<td>Plastics</td>
<td>282</td>
<td>33.0</td>
<td>5.8</td>
<td>0.5 0.2 0.5 0.2</td>
</tr>
<tr>
<td>Petroleum refining</td>
<td>291</td>
<td>398.0</td>
<td>69.3</td>
<td>57.5 66.5 54.5 63.1</td>
</tr>
<tr>
<td>Paving and roofing materials and miscellaneous*</td>
<td>295, 299</td>
<td>8.0</td>
<td>1.4</td>
<td>0.1 0.0 0.1 0.0</td>
</tr>
<tr>
<td>Rubber and miscellaneous plastics</td>
<td>300</td>
<td>81.0</td>
<td>15.8</td>
<td>2.8 0.0 5.6 0.0</td>
</tr>
<tr>
<td>Cement (hydraulic)</td>
<td>324</td>
<td>64.0</td>
<td>13.2</td>
<td>4.2 4.0 4.6 4.4</td>
</tr>
<tr>
<td>Blast furnace and steel works</td>
<td>331</td>
<td>116.0</td>
<td>23.9</td>
<td>7.9 9.1 8.5 9.5</td>
</tr>
<tr>
<td>Iron and steel foundries*</td>
<td>332</td>
<td>18.0</td>
<td>3.2</td>
<td>0.7 0.4 0.7 0.4</td>
</tr>
<tr>
<td>Electric light and wiring equipment</td>
<td>364</td>
<td>7.0</td>
<td>1.3</td>
<td>0.0 0.0 (a) 0.0</td>
</tr>
<tr>
<td>Communication equipment</td>
<td>366</td>
<td>59.0</td>
<td>17.0</td>
<td>0.0 0.0 6.1 6.1</td>
</tr>
<tr>
<td>Electronic components and accessories</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Motor vehicles</td>
<td>367</td>
<td>66.0</td>
<td>14.1</td>
<td>0.0 0.0 1.9 0.0</td>
</tr>
<tr>
<td>Ship and boat building and repairing</td>
<td>371</td>
<td>42.0</td>
<td>12.1</td>
<td>0.0 0.0 4.3 0.0</td>
</tr>
<tr>
<td>Miscellaneous transportation equipment</td>
<td>373</td>
<td>9.0</td>
<td>2.3</td>
<td>0.0 0.0 0.6 0.0</td>
</tr>
<tr>
<td>Engineering, laboratory, scientific and research instruments</td>
<td>379</td>
<td>3.0</td>
<td>0.8</td>
<td>0.0 0.0 0.3 0.0</td>
</tr>
<tr>
<td>Surgical, medical, and dental instruments</td>
<td>381</td>
<td>5.0</td>
<td>1.1</td>
<td>0.0 0.0 0.2 0.0</td>
</tr>
<tr>
<td></td>
<td>384</td>
<td>5.0</td>
<td>1.7</td>
<td>0.0 0.0 0.7 0.0</td>
</tr>
<tr>
<td>Total</td>
<td></td>
<td>1232.0</td>
<td>242.2</td>
<td>81.0 86.5 93.6 89.5</td>
</tr>
</tbody>
</table>

*Indicates load study data available for industry in French sample but not in California sample. See text for basis of calculating impact of time-of-day pricing in California.

(a) Indicates an amount less than 0.1 million kwh.
kilowatt demand, customers would tend to reduce their maximum demand during peak hours by a proportionately greater amount than they would reduce their kilowatt-hour usage during the same period. However, because the peaks of individual customers' demands occur at different times, the reduction of the collective maximum demand will generally be somewhat less than the sum of the reductions in individual demands.

Table 12 gives the estimated reduction in maximum kilowatt demand obtained by using four methods of calculation. The estimated reduction ranges from 596,000 kw to 827,000 kw, depending on the method used. As with projected reductions in kilowatt-hours per month, the petroleum refining industry is expected to contribute half to three-quarters of the reduction calculated for the 18 industries.

Projected Effect on Other Industries in the State

The calculations we have reported above for 18 groups of industrial customers involve somewhat less than half of the electricity consumed by all types of industrial customers in the state. Since we do not have French load data for other industrial groups, we cannot make detailed estimates of the potential impact of peak-load pricing for every industry. However, we can roughly estimate the potential effect of peak-load pricing for the remaining industrial groups by assuming that those industries will, on average, have the same percentage response to peak-load pricing that characterizes the 17 nonpetroleum industries covered by our sample.

The results of this calculation in Table 13 show that we would expect the remaining industrial groups to reduce their peak-period use of energy by 23 million to 55 million kwh under a 4-hour tariff and by 38 million to 75 million kwh under a 6-hour tariff. The combined effect of a 4-hour tariff on energy reduction by all industries in the state is 81 million to 131 million kwh/month, and the combined effect of a 6-hour tariff is 122 million to 184 million kwh/month. This amounts to a reduction in peak-period electricity use of 23 to 37 percent.

CONCLUSION

European industrial customers have shown considerable responsiveness to the terms of peak-load electricity tariffs. Industrial customers in California can expect to face electricity prices in the future that offer similar economic incentives to reduce the use of electricity during peak periods and to shift consumption to shoulder or off-peak periods. Based on a study of French industrial customers served by a time-of-day tariff, we can anticipate a substantial adjustment in the pattern of electricity consumption by major industries in California. Using conservative meth-

---

20 For instance, the PG&E tariff charges $3.45/kw per month during peak hours.
21 For this calculation, we assume there are 23 weekdays per month; for each method, the estimated change in monthly kilowatt-hours during the 4-hour peak period is divided by the 92 weekday hours per month to which the charge applies.
22 In making these calculations, we assume that the remaining industries in the state consume the same proportion of energy during peak-charge hours as do the nonpetroleum industries in our sample. (We tested the hypothesis of equality of the proportions and accepted it at the 0.005 level of significance.) For each of the four methods, we then applied the percentage reduction in peak-energy use calculated for all industries (except petroleum refining) in our sample.
<table>
<thead>
<tr>
<th>Industry</th>
<th>Current Mean Demand During 4-Hour Period (noon to 4 p.m. weekdays)</th>
<th>Estimated Reduction in Maximum Demand</th>
<th>Total Reduction When Method Giving Greatest Impact Is Used For Each Industry</th>
</tr>
</thead>
<tbody>
<tr>
<td>Petroleum refining</td>
<td>502</td>
<td>422 (84%)</td>
<td>467 (93%)</td>
</tr>
<tr>
<td>17 other industries</td>
<td>1285</td>
<td>174 (14%)</td>
<td>160 (12%) 323 (25%) 204 (16%)</td>
</tr>
<tr>
<td>Total for 18 industries</td>
<td>1787</td>
<td>596 (33%)</td>
<td>627 (35%) 724 (41%) 664 (37%)</td>
</tr>
<tr>
<td>Method</td>
<td>Projected Impact for 18 Industries in Sample (1.2 billion kwh/month)</td>
<td>Projected Impact for All Other Industries (1.4 billion kwh/month)</td>
<td>Total Projected Statewide Impact for All Industries Served by Four Largest Utilities in the State (2.7 billion kwh/month)</td>
</tr>
<tr>
<td>--------</td>
<td>-----------------------------------------------------------------</td>
<td>---------------------------------------------------------------</td>
<td>-----------------------------------------------------------------------------------------------</td>
</tr>
<tr>
<td></td>
<td>Reduction in Peak-Period Energy Use (millions kwh/month)</td>
<td>Percent of Peak-Period Energy</td>
<td>Reduction in Peak-Period Energy Use (millions kwh/month)</td>
</tr>
<tr>
<td>1</td>
<td>54.4</td>
<td>33</td>
<td>27.3</td>
</tr>
<tr>
<td>2</td>
<td>57.7</td>
<td>33</td>
<td>23.4</td>
</tr>
<tr>
<td>3</td>
<td>66.6</td>
<td>41</td>
<td>48.7</td>
</tr>
<tr>
<td>4</td>
<td>61.1</td>
<td>37</td>
<td>31.2</td>
</tr>
<tr>
<td>Total reduction when method giving greatest impact is used for each industry</td>
<td>76.1</td>
<td>46</td>
<td>54.6</td>
</tr>
</tbody>
</table>

**4-Hour Peak Tariff**

<table>
<thead>
<tr>
<th>Method</th>
<th>Projected Impact for 18 Industries in Sample (1.2 billion kwh/month)</th>
<th>Projected Impact for All Other Industries (1.4 billion kwh/month)</th>
<th>Total Projected Statewide Impact for All Industries Served by Four Largest Utilities in the State (2.7 billion kwh/month)</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Reduction in Peak-Period Energy Use (millions kwh/month)</td>
<td>Percent of Peak-Period Energy</td>
<td>Reduction in Peak-Period Energy Use (millions kwh/month)</td>
</tr>
<tr>
<td>1</td>
<td>81.0</td>
<td>33</td>
<td>40.6</td>
</tr>
<tr>
<td>2</td>
<td>86.5</td>
<td>36</td>
<td>37.7</td>
</tr>
<tr>
<td>3</td>
<td>93.6</td>
<td>39</td>
<td>66.7</td>
</tr>
<tr>
<td>4</td>
<td>89.5</td>
<td>37</td>
<td>43.5</td>
</tr>
<tr>
<td>Total reduction when method giving greatest impact is used for each industry</td>
<td>108.7</td>
<td>45</td>
<td>75.4</td>
</tr>
</tbody>
</table>
ods of calculation, we have estimated the potential impact on California industry if California customers show the same type and degree of adjustment as that shown by their French counterparts.

Based on a sample of 175 California customers in 18 industrial groupings, we calculate that energy use would be reduced during a 4-hour peak period by a minimum of 54 million to 76 million kwh/month. This represents 33 to 46 percent of the energy used during the peak period by these customers. If firms in other industrial groupings in the state respond to the same degree as that estimated for customers in our sample (excluding the petroleum refineries), then the statewide reduction in electricity used during a 4-hour peak period will be 81 million to 131 million kwh/month. In percentage terms, this is a reduction of 23 to 37 percent of the electricity used by industry during the hours between noon and 4 p.m., 5 days per week. The corresponding statewide effects of a 6-hour peak-load tariff are 122 million to 184 million kwh/month, or 23 to 35 percent of the industrial electricity used during those hours.

Potential shifts in energy use of this magnitude have important implications for utilities relative to both operating and capital costs. Reductions in electricity used during the period of the system peak will permit utilities to supply the same quantity of electricity at off-peak hours more efficiently and therefore to lower the cost per kilowatt-hour supplied. If electricity use is shifted from peak to shoulder periods, then the value of the energy saving is given by the difference between short-run marginal costs in the two time periods. We can illustrate the magnitude of this saving by taking the largest calculated changes in 4-hour peak-period use, in which case we estimate that a reduction of 131 million kwh/month in the industrial use of electricity could be achieved statewide during a 4-hour peak period. If the difference between short-run marginal costs for peak and shoulder periods is between 0.2 and 1.0 cent/kwh shifted from the peak period, this implies a saving in short-run operating costs of between $262,000 and $1,307,000 per month. The implied savings in short-run operating costs from a 6-hour tariff is $368,000 to $1,841,000 per month based only on the response calculated for customers in these 18 industries. The projected savings in all industries in the state would be about 1.8 times as large as these amounts.

Over the long term, reductions in energy use during peak periods will permit utilities to postpone or eliminate additions to peaking capacity, as well as to achieve a more efficient operation of a given mix of generation units. The combined value of savings in operating and capacity costs is given by differences in long-run marginal costs between peak and off-peak periods. If energy use at peak periods is shifted to a shoulder or off-peak period, and if the difference between long-run marginal costs in each period is about 3 cents per kwh, then the value of this adjustment

---

12 For illustrative purposes, we have chosen the lower figure (0.2 cent/kwh) to correspond to the minimum difference between peak and shoulder energy charges under the PG&E time-of-day rate. Although it is not necessarily a reflection of short-run marginal costs, it is a minimum cost saving to customers who shift use. The value of 1 cent/kwh may be closer to the difference between short-run marginal costs under conditions of supply faced by many California utilities. For instance, this amount is consistent with the difference between peak and off-peak energy supplied by the Los Angeles DWP's pumped-storage facility at current levels of off-peak short-run marginal cost.

13 The calculation of long-run marginal costs is a major undertaking and would yield different values for each utility. These illustrative numbers are taken from the terms of the PG&E tariff. In general, we expect differences in the current tariff to understate differences in long-run marginal costs because in the aggregate, total revenue is not permitted to exceed total costs.
in the pattern of use by the 18 industrial groupings is nearly $2.3 million per month from a 4-hour tariff and $3.3 million per month from a 6-hour tariff. If similar calculations were made for all industrial customers in California rather than for just the 18 industries for which we have detailed data, the combined savings in operating and capital costs would be about 1.8 times as large.

The savings in capacity costs for the utility are reflected in the potential effect of time-of-day tariffs on the long-run need for capital plant expansion. Our calculations indicate that in the 18 industries for which we have detailed data, a statewide reduction of as much as 827 megawatts (MW) in peak-period demand is possible, and when all industrial customers are considered, the reductions could reach 1421 MW. Ignoring the corresponding reduction in reserve capacity that might be made, this reduction in peak demand is equivalent to eliminating or postponing three to four peaking units of 200-MW capacity each, due to the response of the 18 industries, or five to seven peaking units, due to the statewide effect of all industrial customers.

An alternative way to view this reduction is to compare it with the annual statewide peak level of electricity consumption. On June 28, 1976, the four major utilities all experienced the highest level of demand for the entire year because of a widespread heat wave. The peak level of production (excluding power sold to other utilities) was 28,784 MW. Our calculations indicate that the 18 industries alone would be expected to reduce their peak demand by an amount that is almost 3 percent of the statewide annual peak. This estimated reduction is a normal shifting of load induced by the terms of a time-of-day tariff; it does not depend on a special effort or on interruption of supply to these customers. The calculated statewide effect from all industry is about 5 percent of the annual statewide peak.
VI. THE NEED FOR FURTHER RESEARCH

If electricity tariffs and load-management decisions are to improve the efficiency with which energy resources are used, they must be based on sound measures of the marginal costs of supplying service under different conditions. Furthermore, if consumers’ choices of energy use are to be consistent with supply costs, the level of peak and off-peak rates and the timing and length of one or more peak periods must be closely matched to the incremental costs of delivering additional electricity during each period. And in weighing alternative strategies for active load management, utilities and their regulators need to calculate the cost savings from given shifts in load on the basis of accurate measurement of those costs.

European utilities, especially those in Sweden and France, have conducted detailed studies of marginal costs as a basis for planning system expansion and setting tariffs. Historically, American electric utilities have not undertaken analyses of their marginal costs. Instead, cost-of-service studies have been used to allocate common costs on an historical, fully distributed basis to various classes of customers. However, much of the data needed to conduct an analysis of marginal costs are regularly collected by utility engineers. The short-run marginal costs of running different generating units are routinely used to dispatch the system economically. And the investment planning process is frequently based on projections of growth in load curves and the use of computer models that minimize the present value of total system costs when plant mix, fuel and water availability, environmental restrictions, and other factors are varied.

A major thrust of further research should be directed toward marginal cost studies of electricity supplied by selected American utilities under a variety of conditions. In a pioneering effort in this direction, Cicchetti, Gillen and Smolensky (1976) have laid out a simple method for approximating marginal costs and have applied it in case studies of three utilities in California and Wisconsin. An important next step will be to refine the cost analysis methodology to include a full reoptimization of the mix of generating plants that will take into account load-curve shifts in response to the introduction of peak-load tariffs and active load management.1

The interconnection of separately managed utilities offers possibilities for reducing overall costs by reducing the generating capacity required to maintain a given standard of reliability, as well as possibilities for exchanging energy between systems during periods when their marginal costs differ significantly. When tariffs include seasonal or time-of-day variations in rates, the availability of interconnected resources becomes an important determinant of tariff levels and structure. For example, a utility’s access to the hydroelectric or pumped-storage capacity of another utility can substantially modify the length of the optimal peak-pricing period and the magnitude of the difference between peak and off-peak marginal costs in an otherwise all-thermal system. The efficient management of interconnected utilities,

1 One method of calculating long-run marginal costs, used by Cicchetti et al. and proposed by parties to several regulatory proceedings, is a form of the “difference” method, in which the construction date of a future generating unit is accelerated or retarded and the difference in present value of costs, net of fuel savings, is used to estimate the marginal cost per kilowatt of capacity. The difference method is an approximation of unknown accuracy to the marginal costs that would be obtained if all capacity were reoptimized at a future date.
both in the operation of power-pool markets for short-term exchanges of energy and in the long-term planning of investment, depends on having analyses of both short- and long-run marginal costs for each utility from which the benefits of interdependence can be calculated.

In general, European utilities have a high degree of interconnection, both within a nationalized system and among privately owned systems, as well as between countries. American practice is quite diverse. Preliminary studies of the opportunities for greater interconnection between U.S. systems have foreseen only limited gains. However, these tentative conclusions deserve careful investigation in the context of peak-load tariff structures and load-management techniques.

In certain industries in Europe, self-generation of power from waste heat, by-product fuels, and oil is a significant factor in load shifting for the electric utility and in providing an alternative source of energy, frequently at higher overall levels of energy efficiency than can be obtained by the separate production of power and industrial heat. By and large, American electricity tariffs have not encouraged the development of self-generated power, despite significant industrial potential to do so. New research could usefully be directed toward establishing, for individual processes and industries, the cost conditions under which it would become economically effective to engage in self-generation and toward an investigation of the opportunities and difficulties of allowing larger firms to sell electricity to and purchase electricity from a utility.

The preliminary analysis in Chapter V of the potential for load shifting in California has been restricted in scope and detail by a limited availability of both data and funding. The work could usefully be extended in several directions. First, a subsequent study could assess the opportunities for load shifting in the commercial sector. Because of the importance of air-conditioning to these customers during the peak period in California, the experience of European utilities in supplying electricity to commercial customers is less directly applicable to California. However, in the longer term, building design and the development of technologies for storage cooling may be profoundly influenced by the introduction of peak-load tariffs. And short-term opportunities for managing buildings, cycling compressors, storing cooling media at lower temperatures, and the like suggest that load shifting may be significant in the commercial sector.

The potential for residential load shifting in California is already under investigation in one of the first U.S. residential experiments with peak-load tariffs. This major field study is being conducted by the Los Angeles Department of Water and Power and The Rand Corporation. A second set of experimental studies is being launched by other California utilities in coordination with the Public Utilities Commission and the California Energy Resources and Development Commission. These experiments include a test of the responsiveness of California's residential air-conditioning users to load shifting. A third type of experimental study that would

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8 See Neville et al. (1976) and the National Power Grid System study prepared by the Congressional Research Service.

9 See the Energy Industrial Center Study prepared by The Dow Chemical Company (1975), and A Study of Inplant Electric Power Generation in the Chemical, Petroleum Refining, and Paper and Pulp Industries, prepared by the Thermo Electron Corporation.

10 See Manning, Mitchell, and Acton (1976).

be very profitable would be one assessing the financial attractiveness of both storage-heating and storage-cooling devices for residences under different terms of peak-load pricing and active load management.

Finally, although in this report we have limited our assessment of the potential quantitative effects of peak-load pricing to California, such tariffs are of nationwide importance. Further research into the methodological basis for measuring marginal costs in an electric utility and the potential gains from increased interconnection of utilities, as well as the economic opportunities for industrial co-generation of power, will be of interest throughout the country.
Appendix

EUROPEAN ELECTRICITY TARIFFS

In this appendix, we have collected representative examples of current high voltage and residential tariffs in six European countries. We first describe the terms of the French and British national tariffs in some detail and then give selected examples of German utility tariffs and special contract provisions. Finally, eight tables give data on tariffs in Norway, Finland, and Sweden.

FRENCH TARIFFS

Industrial

The present structure of the Green Tariff (Le Tarif Vert) has been in effect since 1958. The tariff consists of a series of schedules in which prices vary by season of the year and time of day for each geographical area, supply voltage, and range of load duration. As depicted in Fig. A.1, the customer is charged for demand (kw) and energy (kwh) in each of five time periods:

1. Winter peak hours from 7 A.M. to 9 A.M. and 5 P.M. to 7 P.M., Monday through Saturday, November through February.
2. Winter full hours from 6 A.M. to 10 P.M., October through March, with the exception of Sunday and the winter peak hours.
3. Winter slack hours from 10 P.M. to 6 A.M. and all day Sunday, October through March.
4. Summer full hours from 6 A.M. to 10 P.M., May through September, except Sunday.
5. Summer slack hours from 10 P.M. to 6 A.M. and all day Sunday, May through September.

Variants. Five versions of the Green Tariff are offered at the customer’s option. The version appropriate to a particular customer is usually determined by his hours of utilization, which are equal to his annual kilowatt-hours of consumption divided by his annual maximum kilowatt demand:

- Very long utilization: over 5500 hours
- Makeup, or long utilization: 3500 to 5500 hours
- General: appropriate for most customers
- Short utilization: less than 700 or 800 hours
- Security, or emergency supply to self-generators

Demand Charges. Customers are charged for their effective amount of subscribed power. This “reduced power” or “effective” power $P_R$ is calculated from the subscribed capacity $P_i$ in each of the five tariff periods according to the formula

$$P_R = P_i + \sum_{j=2}^{5} c_i (P_i \cdot P_{i-1})$$

(1)

87
Fig. A.1—Energy (kwh) charges in the French Green Tariff (1975)
where $P_i =$ subscribed power in period $i$

$c_i =$ coefficient for the tariff variant chosen.

In this calculation, no discount is given if a customer subscribes to a lesser amount of power during a full period rather than during the peak period (or a slack period rather than a full period), so that $P_1 \geq P_2 \geq \ldots \geq P_5$.

The coefficients depend on which tariff variant the customer selects. The values are given in Table A.1.

Table A.1

<table>
<thead>
<tr>
<th>Period</th>
<th>Version of Tariff</th>
<th>Makeup and General</th>
<th>Very Long Utilization</th>
<th>Short Utilization and Emergency</th>
</tr>
</thead>
<tbody>
<tr>
<td>Peak (P)</td>
<td>1</td>
<td>1.0</td>
<td>1.0</td>
<td>1.0</td>
</tr>
<tr>
<td>Full winter (HPH)</td>
<td>2</td>
<td>0.4</td>
<td>0.65</td>
<td>0.60</td>
</tr>
<tr>
<td>Full summer (HPE)</td>
<td>3</td>
<td>0.2</td>
<td>0.35</td>
<td>0.30</td>
</tr>
<tr>
<td>Slack winter (HCH)</td>
<td>4</td>
<td>0.07</td>
<td>0.08</td>
<td>0.21</td>
</tr>
<tr>
<td>Slack summer (HCE)</td>
<td>5</td>
<td>0.02</td>
<td>0.03</td>
<td>0.06</td>
</tr>
</tbody>
</table>


Each tariff variant consists of one price per kw for reduced power $P_R$ plus five prices for the energy consumed in each of the tariff periods. Tables A.2 and A.3 contain typical values for 1975. The demand charge is further subject to a percentage rebate based on the magnitude of actual, rather than subscribed demand, computed using actual demand levels in the $P_R$ formula (1):

<table>
<thead>
<tr>
<th>Demand, kw</th>
<th>Rebate, %</th>
</tr>
</thead>
<tbody>
<tr>
<td>First 100</td>
<td>0</td>
</tr>
<tr>
<td>Next 200</td>
<td>4</td>
</tr>
<tr>
<td>Next 700</td>
<td>8</td>
</tr>
<tr>
<td>Next 2000</td>
<td>13</td>
</tr>
<tr>
<td>Next 7000</td>
<td>18</td>
</tr>
<tr>
<td>Remainder</td>
<td>24</td>
</tr>
</tbody>
</table>

Demand in Excess of Subscription:

1. Electricité de France (EdF) has the right to install circuit breakers that cut off the customer's power when demand exceeds subscribed levels by more than 10 percent.

2. Actual demand is measured monthly and converted to an "effective" demand $\hat{P}_R$ using the $P_R$ formula (1). Excess demand $\hat{P}_R - P_R$ is billed monthly at the rate of 70 percent of the annual charge per subscribed kw. The effect is to penalize overruns of subscribed power that occur more than one month in twelve.

3. If the customer exceeds his subscribed power by more than 20 percent, EdF
Table A.2
Green Tariff at Medium Voltage, 5/15/30 kv, 1975

<table>
<thead>
<tr>
<th>Tariff Version</th>
<th>Demand Charge (Francs per kw)</th>
<th>Energy Charge (Centimes per kwh)</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td></td>
<td>Winter</td>
</tr>
<tr>
<td></td>
<td></td>
<td>Peak</td>
</tr>
<tr>
<td>Very long utilization</td>
<td>345.66</td>
<td>13.96</td>
</tr>
<tr>
<td>General</td>
<td>128.62</td>
<td>30.84</td>
</tr>
<tr>
<td>Short utilization</td>
<td>51.45</td>
<td>49.94</td>
</tr>
<tr>
<td>Emergency</td>
<td>57.88</td>
<td>49.94</td>
</tr>
</tbody>
</table>

|                         |                               | Summer                           |
|                         |                               | Peak | Full | Slack |
| Very long utilization   | 345.66                        | 13.96 | 10.34 | 6.32  | 6.97  | 6.08  |
| General                 | 128.62                        | 30.84 | 16.77 | 6.89  | 10.66 | 6.56  |
| Short utilization       | 51.45                         | 49.94 | 26.60 | 6.89  | 12.85 | 6.56  |
| Emergency               | 57.88                         | 49.94 | 26.60 | 6.89  | 12.85 | 6.56  |

Reactive energy
Surcharge (at all hours) ............. 2.10 ............. 1.33
Discount (at all hours) ............. 0.83 ............. 0.53

NOTE: Prices exclude the 17.6 percent value-added tax. Tariffs apply in all except selected departments.

will automatically increase the subscribed power level for his contract. Green Tariff contracts are for a 5-year term, and subscribed power levels are for the duration of the contract. If the subscribed level is increased, the new subscribed power level is in effect for five years. However, in certain instances, notably shipbuilding, EdF will enter into a shorter-term contract if the customer pays an additional demand charge.

**Billing for Reactive Energy.** The Green Tariff rates for kw and kwh are set on the assumption that, outside of slack hours, the consumption of reactive energy is 80 percent of the consumption of active energy. When the reactive/active proportion exceeds 60 percent, the excess is billed by adding a surcharge rate per kwh. If the proportion is less than 60 percent, a discount per kwh is allowed; however, the discount is limited to not more than 40 percent of the active energy used in nonslack hours.

**Rationale.** Offering a choice of tariffs to the customer is justified by the following line of reasoning. Assume, first, that there is only a single tariff period, the entire year. For a given maximum demand, marginal costs for energy (kwh) decline with increased hours of use, reflecting costs at both generation and distribution stages. For a group of customers these costs can be approximated by a tariff consisting of a kw and a kwh charge so that the average payment per kwh takes the form of a rate hyperbola, \( P_{\text{kwh}} + P_{\text{kw}} \)/hours. The parameters \( P_{\text{kw}} \) and \( P_{\text{kwh}} \) are chosen so that the rate hyperbola for a group of customers with similar hours of use is tangent to the marginal cost curve at the center of the distribution of customers scattered along the marginal cost line. In the Green Tariff, there are four versions of such rate hyperbolas; as one moves to versions for longer hours of use, the kw charge increases and the kwh rate is reduced (see Fig. A.2). In practice, the cost calculations are made for the five tariff periods of the Green Tariff. As a result, customers would also be
### Table A.3
Green Tariff at High Voltages (Bouches-du-Rhône Department)

<table>
<thead>
<tr>
<th>Voltage (kv)</th>
<th>Tariff Version</th>
<th>Demand Charge (Francs per kw)</th>
<th>Energy Charge (Centimes per kWh)</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td></td>
<td></td>
<td>Winter</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td>Peak</td>
</tr>
<tr>
<td>220</td>
<td>Very long utilization</td>
<td>254.25</td>
<td>6.53</td>
</tr>
<tr>
<td></td>
<td>Makeup</td>
<td>120.05</td>
<td>11.57</td>
</tr>
<tr>
<td></td>
<td>General</td>
<td>100.19</td>
<td>16.38</td>
</tr>
<tr>
<td></td>
<td>Short utilization</td>
<td>40.08</td>
<td>25.95</td>
</tr>
<tr>
<td></td>
<td>Emergency</td>
<td>60.12</td>
<td>25.95</td>
</tr>
<tr>
<td></td>
<td>Reactive energy</td>
<td>Surcharge (at all hours)</td>
<td>1.24</td>
</tr>
<tr>
<td></td>
<td></td>
<td>Discount (at all hours)</td>
<td>0.50</td>
</tr>
<tr>
<td>150</td>
<td>Very long utilization</td>
<td>274.19</td>
<td>7.21</td>
</tr>
<tr>
<td></td>
<td>Makeup</td>
<td>131.74</td>
<td>13.04</td>
</tr>
<tr>
<td></td>
<td>General</td>
<td>100.19</td>
<td>18.32</td>
</tr>
<tr>
<td></td>
<td>Short utilization</td>
<td>40.08</td>
<td>29.16</td>
</tr>
<tr>
<td></td>
<td>Emergency</td>
<td>60.12</td>
<td>29.16</td>
</tr>
<tr>
<td></td>
<td>Reactive energy</td>
<td>Surcharge (at all hours)</td>
<td>1.39</td>
</tr>
<tr>
<td></td>
<td></td>
<td>Discount (at all hours)</td>
<td>0.55</td>
</tr>
<tr>
<td>90/60</td>
<td>Very long utilization</td>
<td>298.84</td>
<td>8.25</td>
</tr>
<tr>
<td></td>
<td>Makeup</td>
<td>149.29</td>
<td>15.26</td>
</tr>
<tr>
<td></td>
<td>General</td>
<td>100.19</td>
<td>21.22</td>
</tr>
<tr>
<td></td>
<td>Short utilization</td>
<td>40.08</td>
<td>33.98</td>
</tr>
<tr>
<td></td>
<td>Emergency</td>
<td>60.12</td>
<td>33.98</td>
</tr>
<tr>
<td></td>
<td>Reactive energy</td>
<td>Surcharge (at all hours)</td>
<td>1.59</td>
</tr>
<tr>
<td></td>
<td></td>
<td>Discount (at all hours)</td>
<td>0.63</td>
</tr>
</tbody>
</table>

**NOTE:** Prices exclude the 17.6 percent value-added tax.

Scattered above and below the mean marginal cost curve because of differences between them in hours of use in each of the five tariff periods. At each voltage level, EdF statistics on consumption measure the hours of use in each of the tariff periods, and a cost study is conducted to establish the generalized marginal cost curve for each period. The coefficients $c_i$ for calculating reduced power $P_i$ are then chosen to approximate the cost curve at a generalized tangency point. The marginal cost curve is fitted for customers in the 0 to 100 kw range. The percentage rebate at higher kw levels reflects economies of scale in the high voltage distribution network. However, with the increased geographic density of customers in recent years there is less justification for a rebate.
Fig. A.2—Four rate hyperbolas for the Green Tariff

Residential

At low voltage, the French residential tariff replaces the subscribed capacity charge, which would require a demand meter, by a fuse or circuit breaker charge, which increases with the maximum current rating of the customer’s service. Because the utility is a monopolist in the supply of master fuses, it can retain control of a customer’s maximum demand and collect the revenue accruing from this charge. Under the standard tariff, a flat rate per kwh applies to all uses of electricity, except that a small initial block at a higher rate is used to recover some fixed costs. A tariff with a reduced energy rate during slack hours is available as an option to the standard tariff; customers who elect the time-differentiated tariff pay a higher fuse charge to cover the added costs of metering. Residential tariffs are shown in Table A.4.

ENGLISH AND WELSH TARIFFS

The retail tariffs of an Area Board are based on retail distribution costs and the payments which the Board must make under the Bulk Supply Tariff to the Central Electricity Generating Board (CEGB) for generating and distributing electricity at the wholesale level. The CEGB rates include two demand charges, three energy rates, a fixed charge, and a fuel escalation clause; see Table A.5. The Bulk Supply Tariff’s energy charges are complex and can best be understood with the aid of a hypothetical Area Board’s load curve, as shown in Fig. A.3. Energy consumed in rectangle A has a price of 0.51 p/kwh; the area is limited in size by the Area Board’s minimum demand between midnight and 8 A.M. Therefore, area A corresponds to the energy consumed overnight at a demand no greater than the Area Board’s minimum demand for that day. The Bulk Supply Tariff charges 1.81 p/kwh for consumption during the Generating Board’s daytime peak half hour before 4 P.M. and for the peak half hour between 4 P.M. and midnight, rectangles B and C, respectively. The two half hours which define these rectangles are determined retrospectively for each day. All other energy consumption is billed at 0.85 p/kwh.
Table A.4
French Residential Tariffs, July 1974

<table>
<thead>
<tr>
<th>Circuit Breaker Size (kW)</th>
<th>Circuit Breaker Charge (Francs/month)</th>
<th>Price per kWh per Month (Centimes)</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Regular Tariff</td>
<td>Peak/Off-Peak Tariff</td>
</tr>
<tr>
<td>3</td>
<td>2.64</td>
<td>7.25</td>
</tr>
<tr>
<td>6</td>
<td>6.30</td>
<td>11.84</td>
</tr>
<tr>
<td>9</td>
<td>9.45</td>
<td>15.77</td>
</tr>
<tr>
<td>12</td>
<td>39.53</td>
<td>46.63</td>
</tr>
<tr>
<td>18</td>
<td>59.29</td>
<td>67.95</td>
</tr>
<tr>
<td>24</td>
<td>--</td>
<td>100.17</td>
</tr>
<tr>
<td>30</td>
<td>--</td>
<td>132.39</td>
</tr>
<tr>
<td>36</td>
<td>--</td>
<td>164.61</td>
</tr>
</tbody>
</table>


*Under both the regular and the optional peak/off-peak tariff, the first kilowatt hours are billed at the rate specified for the first block.

bCustomers selecting the optional peak/off-peak tariff are billed at the slack hour rates from 10 p.m. to 6 a.m.

The Bulk Supply Tariff gives an indirect discount to the Area Board’s nighttime consumption. If an Area Board can shift 1 kW of demand from the rest of the load curve and raise the minimum kW during the midnight to 8 a.m. period, then it receives an effective discount on 8 kWh by increasing the size of rectangle A and reduces its expense in the higher cost areas. If the 1 kW comes from the peak, the savings is 1.30 p per corresponding kW (e.g., 1.81 – 0.51). If the shift comes from other hours, the gain is 0.34 p (e.g., 0.85 – 0.51). This indirect incentive in the Bulk Supply Tariff is reflected in the off-peak energy rates Area Boards charge their industrial customers under the maximum demand tariffs. As Table A.6 indicates, most Boards are passing this cost message on to their consumers.

The Area Boards pay two distinct demand charges to the CEGB. These charges are based on the "peak demands" and "basic demand" of each Board, and are defined as follows. The peak demand kWp is the sum of the kwh consumed by the Board during the two half hours when the CEGB demand is at the annual maximum observed during a potential peak warning (PPW) period before 4 p.m. and, similarly, at the maximum for a PPW period after 4 p.m. PPWs can only occur between October 27th and February 29th. The basic demand kwb is the Board's average kW demand when the CEGB system load is at 90 percent (+ 1 percent) of the system annual peak demand. The Area Board is then billed for peak capacity (or receives a rebate) equal to £8 · (kwp – kwb). In addition, the Board pays a basic capacity charge equal to £20.55 · kwb. Subject to two constraints, the payment cannot be less than £705,000,000 · kwb/Σkwb or greater than £740,000,000 · kwb/Σkwb, where Σkwb is the sum of all Area Boards' basic demands.
Table A.5
Central Electricity Generating Board
Bulk Supply Tariff 1976-1977

TARIFF FOR BULK SUPPLIES TO AREA BOARDS

fixed by the Central Electricity Generating Board (the Generating Board) pursuant to Section 37(1) of the Electricity Act, 1947, for the year ending 31st March 1977

Bulk Supply Points

Service Charge
1 Each Area Board will pay a sum equal to the ascertained annual charges and expenses of providing the bulk supply point capacity to meet its electricity requirements.

Demand Charges

Peaking Capacity Charge or Rebate
2 £8 charge (or rebate) for every kilowatt by which the Area Board’s peak demand exceeds (or falls short of) its basic demand.

Basic Capacity Charge
3 £20.55 for every kilowatt of the Area Board’s basic demand subject to:

(a) a minimum payment by each Area Board equal to that proportion of £705 million which the Area Board’s basic demand bears to the sum of the basic demands of all Area Boards;

(b) a maximum payment by each Area Board equal to that proportion of £140 million which the Area Board’s basic demand bears to the sum of the basic demands of all Area Boards.

4 For the purpose of the above capacity charges:

(i) “peak demand” means the sum of kilowatt-hours supplied to the Area Board during the half-hour of maximum system demand before 16.00 hours and the half-hour of maximum system demand after 16.00 hours during potential peak warning periods;

(ii) “system demand” means twice the number of kilowatt-hours sent out from the Generating Board’s power stations and purchased by the Generating Board from other sources for supply in England and Wales within a single half-hour;

(iii) “potential peak warning periods” means those periods for which the Generating Board has by 17.00 hours on the previous day issued a warning that the maximum system demand may occur. Such periods shall not exceed 60 hours in aggregate and shall be confined to the period 1 November 1976 to 28 February 1977 inclusive, but excluding Saturdays, Sundays, Christmas Day, Boxing Day and New Year’s Day;

(iv) “basic demand” means twice the average number of kilowatt-hours supplied to the Area Board in each half-hour when the system demand during the year is within plus or minus 1 per cent of 90 per cent of the average of the two maximum system demands specified in (i) above.

Energy Charges

Peak Rate
5 1-81p per kilowatt-hour supplied to the Area Board each day during the two half-hours of highest system demand occurring between midnight and 16.00 hours and the two half-hours of highest system demand occurring between 16.00 hours and midnight.

Night Rate
6 0-51p per kilowatt-hour supplied during the period midnight to 08.00 hours each day (unless charged under the Peak Rate above) plus 0-84p for every kilowatt-hour supplied in excess of the number of kilowatt-hours which would have been supplied had the Area Board’s night valley demand on that day been maintained in all half-hours during that period (excepting for any half-hours in the period charged under the Peak Rate above).

“Night valley demand” means twice the number of kilowatt-hours supplied in the half-hour of minimum system demand on each day.

“System demand” is defined in 4 (ii) above.

Standard Rate
7 0-85p per kilowatt-hour supplied throughout the year other than the kilowatt-hours supplied at Night and Peak Rates.

Fuel Cost Adjustment
8 The above kilowatt-hour rates shall be increased or reduced by 0-008 415p for each 1p (0-5 or any greater decimal part of a penny being treated as 1p) by which the national fuel cost per tonne in the year differs from 1430p.

“The national fuel cost per tonne” means the total delivered cost of coal, coke, oil or gaseous fuels consumed at all theGenerating Board’s stations in the period in the year multiplied by 26 and divided by the gross heat content of such fuels in gigajoules.
Fig. A.3—Load curve for hypothetical Area Board

The basic capacity charges are supposed to recover the incremental costs of providing and maintaining most of the CEGB’s generation and transmission plant. The peak capacity charge is intended to recover the costs of using gas turbines and older plants to meet peak demands.

The Bulk Supply Tariff also charges fixed fees, which vary by Board, and a fuel escalation clause. The exact language of the Bulk Supply Tariff for 1976-1977 is reproduced in Table A.5.

Given the ex post determination of demand and energy charges in the Bulk Supply Tariff, differences in expectations about its own and the CEGB’s load curve lead to some heterogeneity in individual Area Board tariffs. Nevertheless, tariffs are sufficiently similar that one can display typical industrial and residential tariffs, as shown in Tables A.7, A.8, and A.9.

GERMAN TARIFFS

The German electricity sector is organized as a series of geographical, privately or municipally owned, monopoly supply and distribution companies with limited public price regulation. For billing purposes customers are grouped into four major categories:

1. Domestic and small commercial customers, who purchase electricity under general, published tariffs.¹ Both the structure and the maximum prices of

¹ A tariff in German usage implies that service is available to all customers at the stated terms; it cannot be offered selectively. A special contract, on the other hand, is offered at the company’s discretion.
### Table A.6
Off-Peak Energy Charges for Industrial Customers
(>650 volt supply)

<table>
<thead>
<tr>
<th>Area Board</th>
<th>Off-Peak Period</th>
<th>Length of Off-Peak Period (hr)</th>
<th>Off-Peak Price (p/kwh)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Eastern</td>
<td>1 a.m. - 7 a.m.</td>
<td>6</td>
<td>0.670</td>
</tr>
<tr>
<td>East Midlands</td>
<td>11 p.m. - 7 a.m.</td>
<td>8</td>
<td>0.785</td>
</tr>
<tr>
<td>London</td>
<td>11 p.m. - 7 a.m.</td>
<td>8</td>
<td>0.932</td>
</tr>
<tr>
<td>Merseyside and North Wales&lt;sup&gt;a&lt;/sup&gt;</td>
<td>--</td>
<td>--</td>
<td>--</td>
</tr>
<tr>
<td>Midlands</td>
<td>1 a.m. - 7 a.m.</td>
<td>6</td>
<td>0.600</td>
</tr>
<tr>
<td>North East</td>
<td>1 a.m. - 7 a.m.</td>
<td>6</td>
<td>0.650</td>
</tr>
<tr>
<td>North West</td>
<td>2 a.m. - 8 a.m.</td>
<td>6</td>
<td>0.600</td>
</tr>
<tr>
<td>South Eastern</td>
<td>1:30 a.m. - 7:30 a.m.</td>
<td>6</td>
<td>0.600</td>
</tr>
<tr>
<td>Southern</td>
<td>Midnight - 8 a.m.</td>
<td>8</td>
<td>0.650</td>
</tr>
<tr>
<td>South Wales</td>
<td>Midnight - 8 a.m.</td>
<td>8</td>
<td>0.675</td>
</tr>
<tr>
<td>South Western</td>
<td>11 p.m.&lt;sup&gt;b&lt;/sup&gt; - 9 a.m.&lt;sup&gt;b&lt;/sup&gt;</td>
<td>8&lt;sup&gt;b&lt;/sup&gt;</td>
<td>0.690</td>
</tr>
<tr>
<td>Yorkshire&lt;sup&gt;c&lt;/sup&gt;</td>
<td>1 a.m. - 7 a.m.</td>
<td>6</td>
<td>0.600</td>
</tr>
</tbody>
</table>

**SOURCE:** Published 1976 tariffs of the Area Boards.

<sup>a</sup>Has a time-undifferentiated declining-block tariff of 1.24 p/kwh for the first 4800 kwh and 1.01 thereafter.

<sup>b</sup>The hours that the customer pays off-peak rates are at the Board's discretion.

<sup>c</sup>Also has various seasonal, time-of-week, and time-of-day combinations.

### Table A.7
Midlands Electricity Board Maximum Demand Tariff
(>650 volt supply)

- **Annual maximum demand charge:**
  - First 250 kw: £0.42/kw
  - Second 250 kw: £0.31/kw
  - Next 2500 kw: £0.28/kw
  - Remaining kw: £0.26/kw
- **Monthly maximum demand charge:**
  - April to October: £0.00/kw
  - November and March: £0.65/kw
  - December to February: £2.45/kw
- **Energy charge:**
  - All day: 1.240 p/kwh
  - 7 a.m. to 1 a.m. daily: 1.240 p/kwh
  - 1 a.m. to 7 a.m. daily: 0.600 p/kwh

<sup>a</sup>Maximum demand for month in question or preceding 11 months, whichever is greater.

<sup>b</sup>If consumer pays the cost of additional demand-metering equipment, the peak rates apply to 8 a.m. to 8 p.m., Monday through Friday only.

<sup>c</sup>Time-of-day rate available only if customer pays for additional metering.
Table A.8

South Eastern Electricity Board Maximum Demand Tariff

Service charge, per month ...................... £0.14

Demand charge:
April to October ................................... £0.41
November and March ............................... £1.59
December and February ......................... £2.51
January ........................................... £3.32

Energy charge:
All day ........................................... 1.13 p
or 1:30 a.m. to 7:30 a.m. daily .................. 0.60 p
7:30 a.m. to 1:30 a.m. daily .................... 1.19 p

aFor loads greater than 30 kw, rates quoted are for voltages greater than 650 V.

Table A.9

South Eastern Electricity Board Domestic Tariffs

<table>
<thead>
<tr>
<th>Tariff</th>
<th>Fixed Charge (per quarter)</th>
<th>Energy Rates</th>
<th></th>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td></td>
<td>Day</td>
<td>Night</td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td>Hours</td>
<td>Hours</td>
<td>p/kwh</td>
<td>p/kwh</td>
</tr>
<tr>
<td>Domestic Two Part</td>
<td>£2.18</td>
<td>2.165</td>
<td></td>
<td>2.165</td>
<td></td>
</tr>
<tr>
<td>Domestic White Meter</td>
<td>£3.42</td>
<td>2.265</td>
<td>10:30 p.m.-7:30 a.m.</td>
<td>0.945</td>
<td></td>
</tr>
<tr>
<td>Domestic White Meter</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>(Economy Six) a</td>
<td>£3.42</td>
<td>2.265</td>
<td>1:30 a.m.-7:30 a.m.</td>
<td>0.740</td>
<td></td>
</tr>
</tbody>
</table>

aFor newer, fast-charging storage devices.

the tariffs are limited by the state (Land) government, to whom the supply company applies for rate changes.

2. Medium voltage customers who are supplied under published tariffs or pro forma contracts with standard, publicly known terms.

3. High voltage customers, many of whom are supplied under special contracts, the terms of which are private and unregulated.

4. Distributing companies, also supplied under special contracts.

Pro Forma Contracts

In the VEW (Rhein-Westphalia) service area, the pro forma contract specifies the supply voltage and the contractual power, in kw. The customer can then choose between two declining-block rate schedules:
A. Zone price (for low utilization customers, up to about 2000-2500 hours per year)

First 60,000 kwh .................. 17.0 pf/kwh
Next 240,000 kwh ................. 16.0 pf/kwh
Next 720,000 kwh ................. 15.0 pf/kwh
Further kwh ..................... 13.5 pf/kwh

The consumer is entitled to a percentage rebate, based on annual hours of utilization (i.e., annual kwh/peak kw) in excess of 1000 hours.

Rebate = (hours - 1000)/200, not to exceed 10 percent

The minimum bill is

1000 hours × 10.0 pf/kwh × contracted power

B. Demand price (for high utilization customers)

Demand charge .................. DM 168/kw

Energy charge .......................... Day .......................... Night
First 240,000 kwh .......... 8.5 pf/kwh 5.5 pf/kwh
Next 720,000 kwh .......... 7.4 pf/kwh 4.6 pf/kwh
Next 3,840,000 kwh ....... 6.3 pf/kwh 3.8 pf/kwh
Next 4,800,000 kwh ....... 6.1 pf/kwh 3.7 pf/kwh
Further kwh ................ 6.0 pf/kwh 3.7 pf/kwh

The day and night periods are

**October 1 to March 31**
Day: 6 a.m. to 9 p.m.
Night: 9 p.m. to 6 a.m.

**April 1 to September 30**
Day: 6 a.m. to 7 p.m.
Night: 7 p.m. to 6 a.m.

The minimum bill is 70 percent of the contracted power plus 1500 hours × 3.0 pf/kwh × contracted power.

Both schedules are subject to inflation adjustments based on:

a. the coal price index and
b. the borrowing rate for utilities in the region

In fact, utilities have not increased rates to the full extent permitted by these clauses, presumably because of elastic demand.

Similar pro forma rate structures exist for the other major German supply companies, with some variation in the off-peak hours and actual price parameters. Such tariffs have the effect of reducing the average price per kwh as hours of utilization increase.

**Special Contracts for High Voltage Customers**

Since the terms of these contracts are private and somewhat similar to trade secrets, no systematic compilation of high voltage rate structures exists for Germany. In general, terms and conditions are closely tailored to the particular circumstances of both the utility and the customer. Examples of these special contracts follow.

A cement firm's contract, with demand terms similar to those in B above, has special provisions which take effect when the firm uses at least 55 percent of its annual energy at night. The provisions are as follows:
Demand Price, DM/kw

| Day Part I | 168 |
| Day Part II, up to 130 percent of contract power | 0 |
| Day Part II, in excess of 130 percent | 9.5 |
| Night, up to 200 percent of contract power | 0 |
| Night, in excess of 200 percent | 7.0 |

The time periods (Parts) are shown in the table below:

<table>
<thead>
<tr>
<th>Day</th>
<th>Day Part&lt;sup&gt;a&lt;/sup&gt;</th>
<th>January, February, November, and December</th>
<th>March and October</th>
<th>April through September</th>
</tr>
</thead>
<tbody>
<tr>
<td>Monday-Friday</td>
<td>I</td>
<td>6 a.m. – 8 p.m.</td>
<td>6 a.m. – 1 p.m.</td>
<td>7 a.m. – 1 p.m.</td>
</tr>
<tr>
<td>Monday-Friday</td>
<td>II</td>
<td>–</td>
<td>5 p.m. – 8 p.m.</td>
<td>–</td>
</tr>
<tr>
<td>Saturdays</td>
<td>I</td>
<td>6 a.m. – 1 p.m.</td>
<td>6 a.m. – 1 p.m.</td>
<td>–</td>
</tr>
<tr>
<td>Saturdays</td>
<td>II</td>
<td>–</td>
<td>–</td>
<td>7 a.m. – 1 p.m.</td>
</tr>
</tbody>
</table>

<sup>a</sup>All other hours are "night."

A rebate is calculated for utilization in excess of 4500 hours,

\[
R = 40 \times \frac{\text{hours} - 4500}{\text{hours} + 4500}
\]

limited to 12.85 percent; the formula is modified when the night rates apply. The minimum bill is 2500 hours \( \times 2.5\) pf/kwh \( \times \) contract power.

Six to eight firms in the steel industry have special contracts with peak hours defined by the following table:

<table>
<thead>
<tr>
<th>Month</th>
<th>Monday-Friday (except holidays)</th>
<th>Saturday</th>
</tr>
</thead>
<tbody>
<tr>
<td>January</td>
<td>7 a.m. – noon</td>
<td>8 a.m. – noon</td>
</tr>
<tr>
<td></td>
<td>5:30 p.m. – 8:30 p.m.</td>
<td></td>
</tr>
<tr>
<td>February-March</td>
<td>8 a.m. – noon</td>
<td>8 a.m. – noon</td>
</tr>
<tr>
<td></td>
<td>6 p.m. – 8:30 p.m.</td>
<td></td>
</tr>
<tr>
<td>April</td>
<td>10 a.m. – noon</td>
<td>10 a.m. – noon</td>
</tr>
<tr>
<td></td>
<td>7 p.m. – 8 p.m.</td>
<td></td>
</tr>
<tr>
<td>May</td>
<td>10 a.m. – noon</td>
<td></td>
</tr>
<tr>
<td></td>
<td>8 p.m. – 9 p.m.</td>
<td></td>
</tr>
<tr>
<td>June-July</td>
<td>10 a.m. – noon</td>
<td></td>
</tr>
<tr>
<td>August</td>
<td>10 a.m. – noon</td>
<td></td>
</tr>
<tr>
<td></td>
<td>8 p.m. – 9 p.m.</td>
<td></td>
</tr>
<tr>
<td>September</td>
<td>10 a.m. – noon</td>
<td>10 a.m. – noon</td>
</tr>
<tr>
<td></td>
<td>7 p.m. – 8 p.m.</td>
<td></td>
</tr>
<tr>
<td>October</td>
<td>10 a.m. – noon</td>
<td>10 a.m. – noon</td>
</tr>
<tr>
<td></td>
<td>5 p.m. – 8 p.m.</td>
<td></td>
</tr>
<tr>
<td>November-December</td>
<td>8 a.m. – 6:30 p.m.</td>
<td>8 a.m. – noon</td>
</tr>
</tbody>
</table>


In nonpeak hours, customers can take up to 130 percent of contractual power at no kilowatt charge.

A large chemical firm producing acetylene has a special contract for interruptible power with three pricing periods.

<table>
<thead>
<tr>
<th>Period</th>
<th>Relative Price</th>
<th>Supply</th>
</tr>
</thead>
<tbody>
<tr>
<td>Point</td>
<td>100%</td>
<td>Interruptible on 1/2 hour notice</td>
</tr>
<tr>
<td>Peak</td>
<td>60%</td>
<td>Power guaranteed 50% of time</td>
</tr>
<tr>
<td>Slack</td>
<td>45%</td>
<td>Power guaranteed 100% of time</td>
</tr>
</tbody>
</table>

The periods are defined as shown below:

<table>
<thead>
<tr>
<th>Month</th>
<th>Point</th>
<th>Peak</th>
<th>Slack</th>
</tr>
</thead>
<tbody>
<tr>
<td>May-August</td>
<td>9:30 a.m. – noon</td>
<td>6 a.m. – 9:30 a.m. noon – 2 p.m.</td>
<td>10 p.m. – 6 a.m.</td>
</tr>
<tr>
<td>September-April</td>
<td>7:30 a.m. – noon</td>
<td>6 a.m. – 7:30 a.m. noon – 6 p.m.</td>
<td>10 p.m. – 6 a.m.</td>
</tr>
<tr>
<td></td>
<td>6 p.m. – 7:30 p.m.</td>
<td>7:30 p.m. – 10 p.m.</td>
<td></td>
</tr>
</tbody>
</table>

NOTE: Times are for Monday through Saturday. Sundays and holidays are "slack."

**Domestic Customers**

German households, farms, and small businesses consuming power at low voltage (220 to 330 V) may choose one of two general two-part tariffs, consisting of a fixed monthly charge plus a price per kwh. The monthly price varies according to the number of rooms in the dwelling (bathrooms and closets are not counted); a room is typically counted for each 30 square meters of floor space. A representative example is

<table>
<thead>
<tr>
<th>Tariff I</th>
<th>Tariff II</th>
</tr>
</thead>
<tbody>
<tr>
<td>Fixed monthly charge, five-room dwelling</td>
<td>DM 12.40</td>
</tr>
<tr>
<td>Energy price</td>
<td>12.5 pf/kwh</td>
</tr>
</tbody>
</table>

For agriculture and business, the fixed charges are similarly scaled according to acreage or installed lighting and power capacity.

In some instances, surcharges can be added for especially electricity-intensive appliances, such as a sauna.

**Storage-Heating Agreements**

Power for off-peak storage heating is typically supplied under pro forma special agreements. The following terms applied in the VEW service territory in February 1975 for a storage-heating circuit which permitted 8 hours of nighttime and 2 hours of daytime charging.
Fixed charge
5.00 DM per month for the first storage unit
Plus 4.00 DM per month for each additional unit

Added charges
1.80 DM per month for the first two rooms
0.50 DM per month for each additional room

Energy charge
5 pf per kwh, subject to the fuel adjustment clause

NORWEGIAN, FINNISH, AND SWEDISH TARIFFS

Tables A.10 to A.17 show tariffs for various categories of users in Norway, Finland, and Sweden.

Table A.10
Norwegian High-Voltage Tariffs, 1975

<table>
<thead>
<tr>
<th>Source</th>
<th>Subscribed Power (kr/kw/yr)</th>
<th>Price per kwh (øre)a</th>
<th>Winter (October-April)</th>
<th>Summer (May-September)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Norwegian Water Resources and Electricity Board (NVE) (65 and 132 kv)</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Winter contract (October to April)</td>
<td>70</td>
<td>3.06</td>
<td>1.52</td>
<td></td>
</tr>
<tr>
<td>All-year contract</td>
<td>80</td>
<td>3.06</td>
<td>1.52</td>
<td></td>
</tr>
<tr>
<td>Oslo Lysverker (load &gt;10 kw)</td>
<td>200b</td>
<td>3.6</td>
<td>3.6</td>
<td></td>
</tr>
</tbody>
</table>

aOne krone (kr) = 100 øre.
bSpecial thermal contracts exempt selected users from the demand charge between 7 p.m. and 7 a.m. from April 16th to October 15th if sufficient hydroelectric power is available.
Table A.11
Norwegian Residential Tariffs, Oslo Lysverker, 1975

Load-rate tariff
Subscribed power ............ 118 kr per kw
Price per kWh ............... 3 øre\(^a\)
                               +11.8 øre for consumption
                               in excess of subscribed
                               level

Block tariff
Fixed charge ............... 118 kr
Price per kWh ............. 7.1 øre for first 9000 kWh/yr
                              4.5 øre for additional kWh

\(^a\)One kr = 100 øre.

Table A.12
Finnish State Power Board High-Voltage Tariffs\(^b\)

<table>
<thead>
<tr>
<th>Tariff</th>
<th>Fixed Charge(^c) (Fmk/yr)</th>
<th>Maximum Demand(^c) (Fmk/MW/yr)</th>
<th>Energy Charge(^c) (Fmk/MWH)</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Day (7 a.m. to 10 p.m.)</td>
<td>Night (10 p.m. to 7 a.m.)</td>
<td></td>
</tr>
<tr>
<td>T0 E0</td>
<td>--</td>
<td>31.45</td>
<td>83.28</td>
</tr>
<tr>
<td></td>
<td></td>
<td>13.41</td>
<td>162.00</td>
</tr>
<tr>
<td>T1 E2</td>
<td>15400</td>
<td>25.04</td>
<td>76.32</td>
</tr>
<tr>
<td></td>
<td></td>
<td>13.41</td>
<td>162.00</td>
</tr>
<tr>
<td>T2 E3</td>
<td>77120</td>
<td>25.04</td>
<td>62.46</td>
</tr>
<tr>
<td></td>
<td></td>
<td>8.34</td>
<td>162.00</td>
</tr>
<tr>
<td>T3 E3</td>
<td>154000</td>
<td>18.48</td>
<td>62.46</td>
</tr>
<tr>
<td></td>
<td></td>
<td>8.34</td>
<td>162.00</td>
</tr>
</tbody>
</table>

\(^a\)For energy supplied at 110 kv.

\(^b\)Load duration determines which tariff (T0, T1, T2, or T3) the customer will be assigned to minimize his electricity bill. The customer can choose either a time-undifferentiated tariff (E0, E1, E2, or E3) or a time-of-day tariff (C0, C1, C2, or C3).

\(^c\)kWh charges are multiplied by \(h_1/b_0\), where \(h_1\) is an index of fuel prices at time 1 and \(b_0\) is the base period. Fixed and maximum demand charges are multiplied by \(1 + 0.5 \left( P_1/P_0 - 1 \right)\), where \(P\) is a cost of living index. Peak rates apply seven days a week.
Table A.18
Helsinki Electricity Works Tariffs
(Fp = 0.01 Fmk)

1977

<table>
<thead>
<tr>
<th>Domestic tariff</th>
<th>36.0 Fmk/yr</th>
</tr>
</thead>
<tbody>
<tr>
<td>Fixed charge</td>
<td>36.0 Fmk/yr</td>
</tr>
<tr>
<td>Running charge</td>
<td>20.0 Fp/kwh</td>
</tr>
<tr>
<td>Energy tariff</td>
<td></td>
</tr>
<tr>
<td>Fixed charge</td>
<td>36.0 Fmk/yr</td>
</tr>
<tr>
<td>Running charge</td>
<td>25.5 Fp/kwh</td>
</tr>
<tr>
<td>Double tariff</td>
<td></td>
</tr>
<tr>
<td>Fixed charge</td>
<td>156 Fmk/yr</td>
</tr>
<tr>
<td>Running charges</td>
<td></td>
</tr>
<tr>
<td>winter (November-February)</td>
<td>27.7 Fp/kwh</td>
</tr>
<tr>
<td>Summer</td>
<td>20.0 Fp/kwh</td>
</tr>
<tr>
<td>Low voltage demand tariff</td>
<td></td>
</tr>
<tr>
<td>Fixed charge</td>
<td>912.0 Fmk/yr</td>
</tr>
<tr>
<td>Active demand charge</td>
<td>156.0 Fmk/kw/yr</td>
</tr>
<tr>
<td>Reactive demand charge</td>
<td></td>
</tr>
<tr>
<td>(exceeding 50 percent of the</td>
<td>37.2 Fmk/kVar/yr</td>
</tr>
<tr>
<td>corresponding active demand)</td>
<td></td>
</tr>
<tr>
<td>Running charge</td>
<td>14.5 Fp/kwh</td>
</tr>
<tr>
<td>High voltage demand tariff</td>
<td></td>
</tr>
<tr>
<td>Fixed charge</td>
<td>6360.0 Fmk/yr</td>
</tr>
<tr>
<td>Active demand charge</td>
<td>96.0 Fmk/kw/yr</td>
</tr>
<tr>
<td>Reactive demand charge</td>
<td></td>
</tr>
<tr>
<td>(exceeding 50 percent of the</td>
<td>37.2 Fmk/kw/yr</td>
</tr>
<tr>
<td>corresponding active demand)</td>
<td></td>
</tr>
<tr>
<td>Running charge</td>
<td></td>
</tr>
<tr>
<td>Day (7 a.m. to 10 p.m.)</td>
<td>15.2 Fp/kwh</td>
</tr>
<tr>
<td>Night (10 p.m. to 7 a.m.)</td>
<td>11.3 Fp/kwh</td>
</tr>
</tbody>
</table>

\[a\] Includes a tax of 1.2 Fp/kwh.

\[b\] Used largely by small commercial establishments and craftsmen.

\[c\] Because of the high fixed charge, only the largest low voltage customers are on this tariff. Demand (kw) is measured in 15 minute periods. The customer is billed for the mean of the two highest values during the restricted time (November-February).

\[d\] Includes a tax of 1.1 Fp/kwh.
### Table A.14

**Stockholm Energiverk High-Voltage Tariffs, 1975**

<table>
<thead>
<tr>
<th>Voltage (kv)</th>
<th>Fixed Charge (Skr/yr)</th>
<th>1-Hour Demand Charge (Skr/kw/yr)</th>
<th>Energy Charge&lt;sup&gt;b&lt;/sup&gt; (öre/kwh)</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td></td>
<td></td>
<td>Monday-Friday (7 a.m.-9 p.m.)</td>
</tr>
<tr>
<td>100</td>
<td>150,000</td>
<td>70</td>
<td>5.7</td>
</tr>
<tr>
<td>30</td>
<td>25,000</td>
<td>80</td>
<td>6.6</td>
</tr>
<tr>
<td>10</td>
<td>1,200</td>
<td>90</td>
<td>7.5</td>
</tr>
</tbody>
</table>

<sup>a</sup>Average of four maximum monthly values, no more than one of which can be from May through August.

<sup>b</sup>Before taxes or fuel adjustment clauses. Percentage markup equals 0.25 (K-320), where K is the average consumer price index during January and February.
Table A.15

Swedish State Power Board (Statens Vattenfallsverk) High-Voltage Tariffs, 1976
(Central Sweden distribution area)

<table>
<thead>
<tr>
<th>Tariff Type and Supply Voltage (kv)</th>
<th>Fixed Charge&lt;sup&gt;a&lt;/sup&gt; (000 Kr)</th>
<th>Subscribed Charge per kw&lt;sub&gt;1&lt;/sub&gt;/yr&lt;sup&gt;a&lt;/sup&gt; (Kr)</th>
<th>Charge per 6-Hour Demand kw&lt;sub&gt;6&lt;/sub&gt;/yr&lt;sup&gt;a&lt;/sup&gt; (Kr)</th>
<th>Price per kw&lt;sub&gt;h&lt;/sub&gt;&lt;sup&gt;a,b&lt;/sup&gt; (öre)</th>
</tr>
</thead>
<tbody>
<tr>
<td>N1 70 and 130</td>
<td>150</td>
<td>10</td>
<td>105</td>
<td>Peak (September-April) = 3.4</td>
</tr>
<tr>
<td>N2 20 and 40</td>
<td>25</td>
<td>12.50</td>
<td>135</td>
<td>Off-Peak (May-August) = 3.5</td>
</tr>
<tr>
<td>N3 6 and 10&lt;sup&gt;c&lt;/sup&gt;</td>
<td>1.2</td>
<td>17.50</td>
<td>155</td>
<td>Day (6 a.m.-10 p.m.) = 4.0</td>
</tr>
<tr>
<td>D3 6 and 10</td>
<td>1.2</td>
<td>17.50</td>
<td>0</td>
<td>Night (10 p.m.-6 a.m.) = 9.6</td>
</tr>
<tr>
<td>E3 6 and 10</td>
<td>1.0</td>
<td>17.50</td>
<td>0</td>
<td>--</td>
</tr>
</tbody>
</table>

NOTES: kw<sub>1</sub> = 1 hour maximum demand,
kw<sub>6</sub> = 6 hour maximum demand.

<sup>a</sup>All charges are marked up by 0.25[K-260-4(year-1972)], where K = consumer price index.

<sup>b</sup>Price per kw<sub>h</sub> is adjusted by the fuel price index in öre/kw<sub>h</sub>, 0.7(C-1) when C > 0.1, where C is a cost of fuel index.

<sup>c</sup>Consumer has a choice of second and third tariffs if he has a short duration load of less than 1000 kw.
### Table A.16
Swedish State Power Board Residential Tariffs, Central Sweden, 1976
(400 volts)

<table>
<thead>
<tr>
<th>Tariff Type</th>
<th>Fixed Charge (kr/yr)</th>
<th>Fuse Charge&lt;sup&gt;a&lt;/sup&gt;</th>
<th>All Hours</th>
<th>Peak 6 a.m.–10 p.m.</th>
<th>Off-Peak 10 p.m.–6 a.m.</th>
</tr>
</thead>
<tbody>
<tr>
<td>E4&lt;sup&gt;b&lt;/sup&gt; (normal residences)</td>
<td>--</td>
<td>S</td>
<td>12.5</td>
<td>--</td>
<td>--</td>
</tr>
<tr>
<td>M4&lt;sup&gt;c&lt;/sup&gt; (typically, residences with electric heating)</td>
<td>--</td>
<td>2S</td>
<td>9.0</td>
<td>--</td>
<td>--</td>
</tr>
<tr>
<td>D4&lt;sup&gt;b&lt;/sup&gt; (typically, residences with storage heating)</td>
<td>144</td>
<td>S</td>
<td>13.0</td>
<td>6.0</td>
<td></td>
</tr>
</tbody>
</table>


<sup>a</sup>Fuse charge parameter (S)
- Main fuse amperage: 16 20 25 35 50 63 80 100 125 160 200
- S (kr/yr): 324 432 564 840 1260 1620 2040 2580 3300 4320 5460

<sup>b</sup>Maximum fuse allowed is 200 amps.

<sup>c</sup>Maximum fuse allowed is 50 amps.

### Table A.17
Stockholm Energifverk Residential Tariffs, 1975

<table>
<thead>
<tr>
<th>Tariff</th>
<th>Annual kWh Range</th>
<th>Fixed Charge (Skr/yr)</th>
<th>Energy Charge (öre/kwh)&lt;sup&gt;a&lt;/sup&gt;</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td></td>
<td></td>
<td>Energy Charge (öre/kwh)&lt;sup&gt;b&lt;/sup&gt;</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td>Day (7 a.m.–9 p.m.)</td>
</tr>
<tr>
<td>Normal tariff</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Apartments</td>
<td>&lt;4500</td>
<td>30</td>
<td>S</td>
</tr>
<tr>
<td>Other</td>
<td>&lt;5040</td>
<td>72</td>
<td>S</td>
</tr>
<tr>
<td>Longtidstariff</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Apartments</td>
<td>&gt;4500</td>
<td>120</td>
<td>2.48</td>
</tr>
<tr>
<td>Other</td>
<td>&gt;5040</td>
<td>172.80</td>
<td>2.48</td>
</tr>
<tr>
<td>Double tariff&lt;sup&gt;d&lt;/sup&gt;</td>
<td></td>
<td>150</td>
<td>1.55</td>
</tr>
</tbody>
</table>

<sup>a</sup>Includes 2 öre/kwh tax. Peak rates apply seven days a week.

<sup>b</sup>Fuse charge parameter (S)
- Main fuse amperage: 25 35 50 63 80 100 125 160 200
- S (kr/yr): 360 600 990 1320 1830 2490 3300 4620 6120 250 300 400 7920 9900 14250

<sup>c</sup>Typically has electric space heating.

<sup>d</sup>Typically has electric space and water heating.
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