SURVEY OF UTILITY REAL-TIME PRICING PROJECTS IN THE U.S.

EMF SPECIAL REPORT

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I learned a lot from studying actual implementations of RTP by PG&E, Southern California Edison Company (SCE), and Niagara Mohawk Power Corporation (NMPC). Special thanks go to Ms. Cynthia M. Crane of PG&E, Dr. Fereidoon P. Sioshansi and Ms. Jennifer M. Fagan of SCE, Mr. Bernie Neenan of NMPC for affording me the opportunity to discuss these experiments with them.

All errors are the author's responsibility alone.

TABLE OF CONTENTS

SUMMARY

Recent advances in metering and control technologies have reduced the costs of spot pricing to a level where it is being considered a viable option for many utilities. As those utilities find themselves scrambling to keep their largest customers, a handful of utilities in the U.S., such as Pacific Gas and Electric Company (PG&E), Niagara Mohawk Power Corporation (NMPC), and Southern California Edison Company (SCE) have begun offering their users what are known as "Real-Time Pricing (RTP)" programs, where rates are calculated each hour to reflect the cost of providing power for a given incremental load. Prices are preannounced, typically twenty four hours in advance in most recent programs, and vary on an hourly basis. Methods for implementing RTP programs vary from utility to utility. Some calculate rates based on actual supply conditions, while others plug in predetermined pricing scenarios according to a defined set of environmental conditions. Most of the utilities in the U.S. that offer RTP are doing so on an experimental basis, usually involving fewer than 20 users. Depending on the utility's generation costs and the customer's usage patterns, savings under RTP plans can often be in the range of 10 to 30 percent.

Experience with real-time utility rates is growing. In this report three major RTP experiments in place at PG&E, NMPC, and SCE are reviewed. The experience to date with RTP has been positive. Those RTP rates that have entered utility operations most effectively have been for larger industrial and commercial users where economic incentives play a larger role. It is notable that commercial sector enterprises such as a food distribution center, a commercial laundry and a large office building with an energy management system have responded more to hourly price signals than large process industries.

RTP is still in its early stages of use, as compared to other service options such as interruptible service and time-of-use(TOU) rates. Previous economic analyses have demonstrated that spot pricing holds the greatest potential for optimally providing service quality to customers with diverse values, but offering pure spot pricing to utility customers is not practically feasible for a number of reasons. RTP which approximates spot pricing more closely than other service menu options holds great potential for efficiency improvements, if employed on a broader scale. Whether enough users will be able to

respond to hourly price signals is a question that remains to be determined.

In this report an attempt is first made to estimate the potential efficiency gains and price sensitivity of a customer to RTP. First, I examined the advantages of RTP when compared with TOU rates due to the superior adaptability of spot pricing to unpredictable fluctuations in demand over time. As marginal costs increase steeply and price elasticities increase, the load leveling effects of RTP are larger than those of TOU rates. The results of a simple Monte Carlo simulation demonstrate the following:

1) RTP is very effective in its response to demand fluctuation. For example, PG&E's load factor under hourly RTP is 68.6 percent, approximately 9.6 percentage points higher than that under TOU rates (with three pricing periods). Unit generating costs were about 1.5 percent lower under RTP.
2) The effects of load leveling and cost gains of RTP are very sensitive to price elasticities and load fluctuations. As price sensitivity and the randomness of hourly load increase, improvements in load factors and cost savings resulting from RTP increase.
3) When unit cost savings under RTP are estimated in comparison with a three-period TOU rate and hourly TOU rate, cost savings are:

    77-82 percent due to load adaptiveness and

    23-18 percent due to the difference in the length of the pricing period.

The second objective of this report is to estimate the effects of RTP on a customer demand and the price sensitivity of a RTP customer using real hourly load and RTP tariff data for a refrigerated warehouse. The resulting price elasticities seem unrealistic. This detailed study is limited to only one customer. More engineering and economic data samples are needed. These responses are short-term. A necessary condition for customers to make capital investments is that utilities and regulatory commissions make a firm commitment to the establishment of an RTP program. Unless such a commitment is made, customers will be very reluctant to make capital investments. Nonetheless, an RTP rate design brings substantial savings to customers even if they do not respond to RTP by making appropriate investments. Actually, as a marketing strategy the utility can provide RTP to customers who have access to alternative power sources to keep them on its system.

As more RTP programs are offered, customer responses will provide additional data, particularly over the longer term, as customers make the capital improvements necessary to participate fully in RTP. The remaining obstacles to be solved are development of hardware and software to administer RTP programs, customer education, and the development of agreements with regulators on appropriate rate design.

1. INTRODUCTION

The structure of the electric power industries in both the U.S. and Japan are undergoing drastic changes as innovative and expanded service options are added. The concepts of unbundling services into a variety of products with corresponding prices are expanding the options open to customers. This trend has several underlying causes. First, recent advances in metering and control technologies make it possible to provide differentiated service options that were not previously feasible. Second, public utility commissions in the U.S. are encouraging service differentiation as a means of matching electric power service offerings more closely to the diversity of customer needs. In Japan, current competitive pressures on the industry are forcing a fresh look at innovative pricing proposals that give more weight to marginal costs. Third, as insurance against possible supply/demand imbalances in the future, some utilities such as those in New England, are designing broad service offerings with differentiated products to provide more efficient methods of balancing supply and demand, should shortfalls occur.

A side benefit from differentiated service offerings is that capital expenditures for additional generation capacity expansion can be postponed or avoided in the long run.

Real-Time Pricing (RTP) is a service option in which the price of electricity varies with time, based on the availability and marginal cost of supply, demand levels, and service values. Customers subscribe to RTP on a contractual basis. Prices are preannounced, typically twenty four hours in advance in most recent programs, and vary on an hourly basis. RTP include spot prices, interruptible rates, and priority service. This study focuses on spot price based rates.

The primary objective of this study is to evaluate the benefits of real-time pricing. The project has the following set of sub-objectives.

1) to review the background and literature that has been developed for real-time pricing.
2) to survey demonstration projects in the U.S.
3) to develop a model for optimizing customer response to real-time pricing.
4) to evaluate the potential impact on individual customers bills.
5) to review the available hardware and software for real-time pricing programs.

In the interim report (March 1989), I focused on sub-objectives 1) and 2). This final report will discuss a study focused on the rest of the sub-objectives. Actually I was unable to achieve sub-objective 3) completely. However, this report provides a preliminary estimate of the potential efficiency gains of RTP.

2. RELATED LITERATURE ON SPOT PRICING THEORY

The idea of setting electricity prices on a spot price basis is quite old. Pricing methods containing elements of spot pricing have been implemented for sales to customers on a limited basis by a number of utilities in the U.S., Europe, and Japan.

The desirability of TOU rates has been the topic of major research by the Electric Power Research Institute (1979). For a good review of the U.S. Department of Energy sponsored residential TOU experiments, see Faruqui and Malko (1983).

Although rates that are effectively spot prices have been in use for some time, the academic literature on spot pricing theory is less well developed. There is, however, a rich literature on optimal pricing and generation planning for electricity. The idea of time-differentiated prices goes back at least to Boiteux (1949). During the 1970's various authors presented prescriptions for TOU pricing in static models. The standard TOU pricing models are surveyed in Crew and Kleindorfer (1979). A number of recent articles have developed pricing structures and analyzed the economic benefits of unbundling service offerings for electric power, including Chao (1983), Chao, Oren, Smith and Wilson (1986), and Chao and Wilson (1987). These studies have demonstrated that, when supply and demand fluctuate over time, a menu of service options based on both the utility's supply costs and customers' value of service can achieve efficiency gains for both consumers and the utility. Chao (1983) notes that efficient prices under fluctuating conditions are expressed as the sum of marginal operating costs and marginal capacity costs, which corresponds to the result demonstrated for peak load pricing by Crew and Kleindorfer (1979).

One way to view spot pricing is that it allows customers to choose their own reliability levels. Chao and Wilson (1987) show that a preannounced service menu with appropriately chosen prices can in principle achieve the same efficiency as an instantaneously computed spot price. Their approach differs from spot pricing because customers must contract in advance, and therefore have no real-time control over their level of service.

Vickrey (1971) first proposed the concept of spot pricing of public utility services, under the name of "responsive pricing". In his novel approach prices can be set after some random variables are observed. Schweppe, along with his colleagues at MIT, was one of the primary forces in developing the concepts and theory of spot pricing of electricity. Originally called Homeostatic Utility Control, spot pricing emerged out of a set of concepts developed in Schweppe (1978). Planning models for spot pricing of electric power service have been analyzed in the literature by Caramanis, Bohn and Schweppe (1982) and Schweppe, Caramanis and Tabors (1985). These pricing analyses include more operational details concerning the utility's costs than the economic analyses, but do not consider the customer's fixed costs and their impact on the customer's decision to participate in the spot pricing program.

Luh and Ho (1982) describes a game theoretic model of "load adaptive pricing". Their formulation allows games between a single utility and a single customer who is not a pure price taker.

A series of articles on spot pricing and "interactive load control" appeared in Electric Review in 1981 and 1982 (Berrie[1981,1982]). Still another term being used for spot price based type rates is dynamic pricing (see Peddie[1981]). The Credit and Load Management Systems (CALMS) is an important system and hardware development project in England, which has major implications for RTP. The key component, the Credit and Load Management Unit (CALMU) is a microprocessor-based metering control and display system designed for residential use. A new version can accept a RTP data stream.

A recent Special Issue of Energy Policy (August,1988) attempts to provide an overall focus for discussing spot pricing in the non-oil sectors. A key question for RTP is : How will customers change their usage pattern in response to price changes? Two methods can be employed to try to answer this question :
1) Direct observations of actual responses.
2) Models of responses.

Unfortunately, not enough direct observations under spot price based RTP are available. A couple of models were developed to analyze the customer's responses to spot prices. An article by Outhred and coworkers (1988) describes optimized industrial plant behavior in response to spot prices and forward contracts of electricity. Simulation studies show the improved economic efficiency and risk sharing of a system of spot pricing and forward contracts, compared with a conventional TOU tariff structure.

David (1988) developed the theory of categorizing consumer load types and proposed appropriate optimization methods for each different types. Schweppe, Daryanian and Tabors (1989) describe the logic and structure for a set of spot price based algorithms designed for use in residential load control system. Daryanian, Bohn and Tabors (1989) formulated the behavior of customers with intermediate or final product storage as the electricity cost minimization problem. For a case study of an air liquefaction plant, the cost savings compared to a flat rate was between 7 percent and 15 percent.

The Electric Power Research Institute (EPRI) published a proceedings of the New Dimensions in Pricing Electricity Conference (EPRI[1989]). Session topics included RTP applications and service differentiation through reliability and quality.

3. SURVEY OF UTILITY REAL-TIME PRICING PROJECTS IN THE U.S.

3.1 Current Experiment Overview

Recent advances in metering and control technologies have reduced the costs of spot pricing to a level where it is being considered a viable option for many utilities. As many utilities today find themselves scrambling to keep their largest customers, a handful of utilities in the U.S., such as Pacific Gas and Electric Company (PG&E) and Niagara Mohawk Power Corporation (NMPC), have begun offering their users what are known as "Real-Time Pricing (RTP)" programs, where rates are calculated each hour to reflect the cost of providing power for a given incremental load. Prices are preannounced, typically twenty four hours in advance in most recent programs, and vary on an hourly basis. Methods for implementing RTP programs vary from utility to utility. Some calculate rates based on actual supply conditions, while others plug in predetermined pricing scenarios according to a defined set of environmental conditions. Most of the utilities in the U.S. that offer RTP are doing so on an experimental basis, usually involving fewer than 20 users. Depending on the utility's generation costs and the customer's usage patterns, savings under RTP plans can often be in the range of 10 to 30 percent.

Important characteristics of spot pricing are:

1) Length of price cycle: time between price level updates. e.g., 1 year, 1 month, 1 day, 1 hour.
2) Period definition: definition of pricing periods within cycle. e.g., three time-of-use periods or 24 hourly periods in a daily cycle.
3) Number of price levels: number of distinct price levels from which the price during a given period may be selected. Can be finite(2 or 3) or continuous.
4) Advance notice: time between posting a price and the time it comes into effect. e.g.,1 month, 24 hours, none.

Most of the ongoing RTP programs have 24 hourly periods in a daily price cycle and 24 hour advanced notice. Major large-customer RTP experiments are in place at the following three utilities: Pacific Gas and Electric Company (PG&E), Niagara Mohawk Power Corporation (NMPC), and Southern California Edison (SCE). Table 3-1 summarizes the major features of the three experiments. The pricing algorithm of A-RTP tariff at PG&E is consistent with the E-20 (TOU) rate

Table 3-1. Features of Large-Customer RTP Experiments

	Frequency	Rate Structure Forecast Deadline	Usage Price	Demand Charge	Short-Term Price Change
PG&E	hourly	4 p.m.	MC*M	Yes	Yes
NMPC	hourly	4 p.m.	MC+profit	No	No
SCE	hourly	4 p.m.	fn(temp)	No	Yes

	No. of Customers Test	Control	Peak Demand[MW] *	Communication	Experiment Duration
PG&E	15	0	1.5	phone,E-mail	5 years
NMPC	15	8	11	E-mail	3 years
SCE	10	0	0.8	phone	4 years

*Peak demand average customer

schedule and its associated curtailable and interruptible options for commercial and industrial customers. These TOU rates include maximum peak-period demand charge and maximum demand charge. A-RTP also has a maximum demand charge, but does not have a maximum peak-period demand charge. The marginal cost revenue requirement calculated for the A-RTP tariff was scaled by the Large Light and Power Class scaling factor adopted in the General Rate Case Decision. The unbundling of the generation-related capacity cost component of the pricing algorithm had the most significant impact on hourly prices of the A-RTP tariff. The reallocation resulted in lower summer on-peak energy prices for most hours and, conversely, much higher dispatch prices for the Load Management Price Signal (LMPS).

NMPC feels that customer recruitment in established RTP programs has suffered from distorted price signals and from the use of energy price adders or multipliers. NMPC is offering very large commercial and industrial customers marginal cost-based pricing on an hourly basis. NMPC use customer specific revenue reconciliation. Their Hourly Integrated Pricing Program (HIPP) bill consists of an energy charge and an access charge. Customer behavior is being evaluated with a controlled experiment (15 treatments and 8 controls).

SCE's RTP experiment focuses on testing customer response to simulated real-time prices. This RTP rate is a collection of nine 24-hour price scenarios. SCE selects a given day's scenario based on the temperature forecast and day type.

RTP is still in its early stages of use compared to other service options such as interruptible service and TOU rates. Previous economic analyses have demonstrated that spot pricing holds the greatest potential for optimally providing service quality to customers with diverse values, but offering pure spot pricing to utility customers is not practically feasible for a number of reasons. RTP which approximates spot pricing more closely than other service menu options holds great potential for efficiency improvements, if implemented on a broader scale. Whether enough users will be able to respond to hourly price signals is a question that remains to be answered.

Under some of the RTP programs, users are given an estimate of the next day's electricity price schedule each afternoon with costs not determined until after actual consumption. Other utilities will notify users of actual power prices before hand, anywhere from one to 24 hours in advance.

Many users that have been participating in RTP programs applaud the concept and feel they are getting a fairer shake in their electricity costs than had normally been the case under conventional rate structures.

I will give full details of customer responses to RTP in each utility's section.

Hardware and Software for Implementing RTP

The utility should be able to change prices as conditions on its systems dictate and communicate these prices to customers on RTP programs. The communication has to be two-way so that the utility can register the customers' aggregate response to varying prices and make the necessary adjustments in the next minute's prices and generation level.

The first requirement is a TOU meter with an appropriate amount of memory. Many utilities have such meters with recorders currently in use for large industrial and commercial customers, many with remote-read capabilities, usually using the telephone as the communication medium. A solid state meter for TOU billing can cost $300-500, a demand recorder nearly $1000. Thanks to rapid cost reductions of microprocessor and increasing number of electronic meters, all-digital meter for residential customers may cost only $100. [1]

The second requirement, the establishment of two-way communications to and from customers is still expensive for all but a few large customers. New developments in communication technologies, however, promise to change this situation by reducing the costs in the near future. For example, SCE is experimenting with a network of high-frequency, low power packet radios in a project called "NetComm" (Sioshansi [1988]). When fully operational, this network can perform many useful functions in addition to RTP such as those listed in Table 3-2. No single function will pay for the network, but collectively, the system is expected to be cost-effective.

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[1] conversation with Mr. Spencer Carlisle, SCE (August, 1989)

Table 3-2. Real-Time Communication Functions

- Real-time pricing
- Load control
- Customer research
- Remote meter reading
- Fault location
- Theft detection
- Capacitor switching
- Load balancing
- Information interchange
- Potential for interactive information services

Utility Attitudes towards Spot Pricing

Sioshansi (1988) examines the main remaining obstacles to spot pricing :

1) development of hardware and software to administer RTP efficiently for all classes of customer;
2) education of customers to enable them to understand and participate properly in spot pricing experimental programs; and
3) appropriate and adequate agreements with regulatory bodies concerning how to set the spot price.

A closely associated concern with the expensive hardware costs is the perceived unpredictability of sales and revenues under spot pricing. But beyond the transition period of experimentation and adjustment, there is no theoretical and empirical evidence to suggest that variable prices will result in increased demand instability and unpredictability. Under the current pricing regime, the utility's revenue stream is fairly stable, even though the cost of providing power varies as demand rises and falls. With spot pricing, the revenues would parallel the costs of production closely and the variations in net revenues would be much smaller.

There is also concern that spot prices will lead to a heightened state of energy-cost awareness, which will result in increased overall energy conservation - not only during the on-peak periods, but also in off-peak periods. Preliminary evidence from several large-scale experiments suggests that overall energy consumption might fall as customers reduce the share of income devoted to electricity usage even if spot prices are designed to be revenue neutral.

3.2 Pacific Gas and Electric Company (PG&E) [2]

PG&E serves about four million customers located within a service territory that stretches throughout northern California. Annual electric revenues amounted to $5.1 billion in 1987. PG&E is the largest investor-owned, combined utility in the U.S.

MIT conducted a spot pricing study for PG&E and SCE in 1982 (Schweppe, Caramanis and Tabors[1982]). This study developed

[2] This section is described based on Crane (1988) and Crane (1989).

several concepts that were considered in planning PG&E's RTP case study. Planning of PG&E's RTP case study began in late 1984. The RTP case study was conducted from July 1985 through the spring of 1986. During 1986 and 1987 the project entered a pilot phase where significant modifications were made to virtually every aspect of rate design, notification equipment, and operating procedures. In 1988 the project entered a three-year demonstration phase which will be characterized by long-term stability in rate design and equipment. A final decision concerning the project's future will be considered when the current contract expires in 1990.

The program reflects PG&E's desire to move away from methods of direct load control, such as automatic air-conditioner cycling devices, and to instead offer users price signals motivating them to shift or curtail load according to their own needs.

RTP Rate Design

The basic A-RTP pricing algorithm is designed to reflect the marginal energy and shortage cost of providing electricity. Originally, the A-RTP tariff was designed to be revenue-neutral with its alternative, mandate TOU rate (E-20). But PG&E felt that the revenue-neutrality was difficult to maintain. In consideration of this, PG&E decided to make the A-RTP tariff a independent subclass of the E-20 tariff so that a separate revenue requirement for the tariff could be calculated. The RTP option is kept parallel with the traditional TOU rate structure available to the equivalent customers who are not participating. An E-20 customer charge of $290 per month and a $1.74 per kW of maximum demand charge in 1987 ($1.92 per kW in 1989) were added.

The unbundling of the generation-related capacity cost component of the pricing algorithm had the most significant impact on hourly prices. In the 1986 rate design most of these costs were included in the summer on-peak energy charge. In 1987, more of the generation-related capacity costs were allocated to the dispatchable Load Management Price Signal (LMPS) since this would more accurately reflect PG&E's cost to serve. The reallocation resulted in lower summer on-peak energy prices for most hours and, conversely, much higher dispatch prices for the LMPS. The participant received price signals that more closely followed PG&E's system costs.

The Commission adopted the Equal Percent of Marginal Cost (EPMC) method of revenue reconciliation. EPMC reconciles the adopted revenue requirement for each customer class to the cost of providing service to that class when rates are above marginal cost. This broad policy was applied to every rate schedule, including the redesign of the A-RTP tariff. A price ceiling of $0.75 per kWh was introduced to provide assurance of rate stability and reduce the degree of risk to the participants.

The three-tier LMPS was designed to test PG&E's ability to induce load shifting or curtailment when system conditions are constrained and PG&E's costs are very high during the hours from noon to 6 p.m. The variable generation cost adders for LMPS tiers were:

Price Signal [c/kWh]	Forecasted Spinning Reserve Margin [%]	Other Dispatchable LM Projects
27	7.4-7.0	-
40	<7.0	Not Requested
53	<7.0	Operated

Figure 3-1 compares the regular hourly prices with the updated prices, which includes the LMPS, for an operation day. Users are notified of load management price signal updates by 11 a.m. on days they will be in effect. PG&E can use the signal to adjust its real-time rates only up to 50 hours per year. This signal was dispatched eight times in 1988 when spinning reserve margins were forecasted to be below 7.5 percent. Up to 1987, the observed load impacts are statistically insignificant. The lack of response indicated that customers were not sensitive to updated hourly prices given on short notice. However, in 1988 for the first year in project history, the LMPS operations resulted in significant load reductions ranging from 1.0 to 1.7 MW per operation. This response indicates that customers are now demonstrating at least some sensitivity to updated hourly prices transmitted on short notice.

Table 3-3 shows a comparison of monthly average prices for RTP and E-20 in 1989. Figures 3-2 and 3-3 compare the average RTP for June and December, by rating period, with the E-20 electric rate schedule (TOU rate) firm energy charge per kWh. The average monthly RTP on-peak summer prices range from 3 to 31 percent higher, while

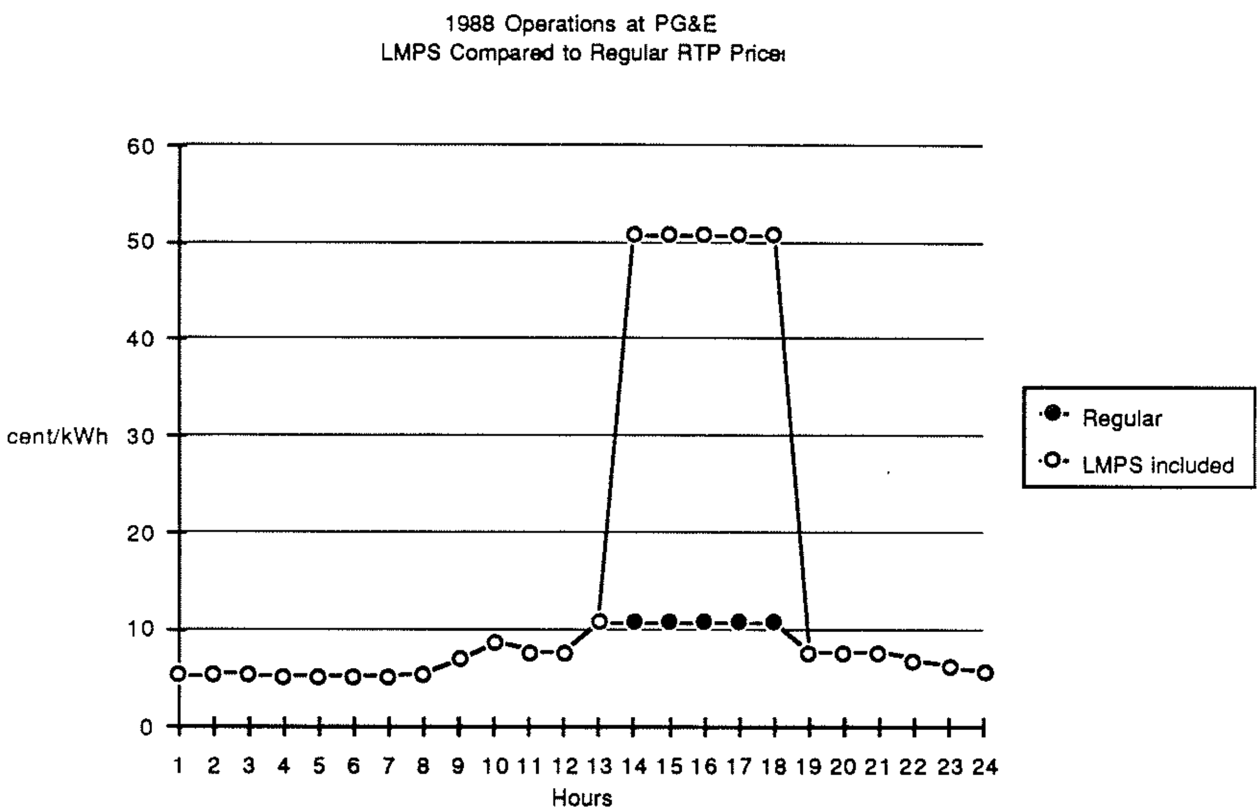


Figure 3-1. Regular Hourly Prices and LMPS of Real-Time Pricing at PG&E

Table 3-3.

PACIFIC GAS AND ELECTRIC COMPANY

1988 MONTHLY AVERAGE RTP/E-20 PRICE PER KILOWATT-HOUR COMPARISON

(Workdays Only and Excluding the LMPS)

		RTP On-Peak	E-20 On-Peak	RTP Partial Peak	E-20 Partial Peak	RTP Off-Peak	E-20 Off-Peak	RTP Minimum	RTP Maximum	RTP Monthly Average
January	1988	0.00000	0.00000	0.06566	0.07220	0.04270	0.03748	0.03971	0.06812	0.05514
February	1988	0.00000	0.00000	0.05772	0.07220	0.04045	0.03748	0.03781	0.05894	0.04980
March	1988	0.00000	0.00000	0.06060	0.07220	0.04375	0.03748	0.03632	0.06181	0.05288
April	1988	0.00000	0.00000	0.06403	0.07220	0.04300	0.03748	0.03988	0.06525	0.05439
May	1988	0.09115	0.07520	0.06248	0.07162	0.04492	0.04201	0.04213	0.09298	0.06160
June	1988	0.07839	0.07633	0.05508	0.07269	0.04239	0.04264	0.04049	0.07893	0.05509
July	1988	0.10034	0.07633	0.06451	0.07269	0.04755	0.04264	0.04448	0.10511	0.06570
August	1988	0.09206	0.07633	0.06082	0.07269	0.04390	0.04264	0.04109	0.09469	0.06087
September	1988	0.09020	0.07633	0.06060	0.07269	0.04387	0.04264	0.04065	0.09343	0.06033
October	1988	0.08767	0.07430	0.06108	0.07430	0.04331	0.03857	0.04064	0.08983	0.05958
November	1988	0.00000	0.00000	0.06536	0.07430	0.04342	0.03857	0.04124	0.07273	0.05530
December	1988	0.00000	0.00000	0.06224	0.07430	0.04639	0.03857	0.04371	0.06491	0.05497

Figure 3-2.

Including LMPS

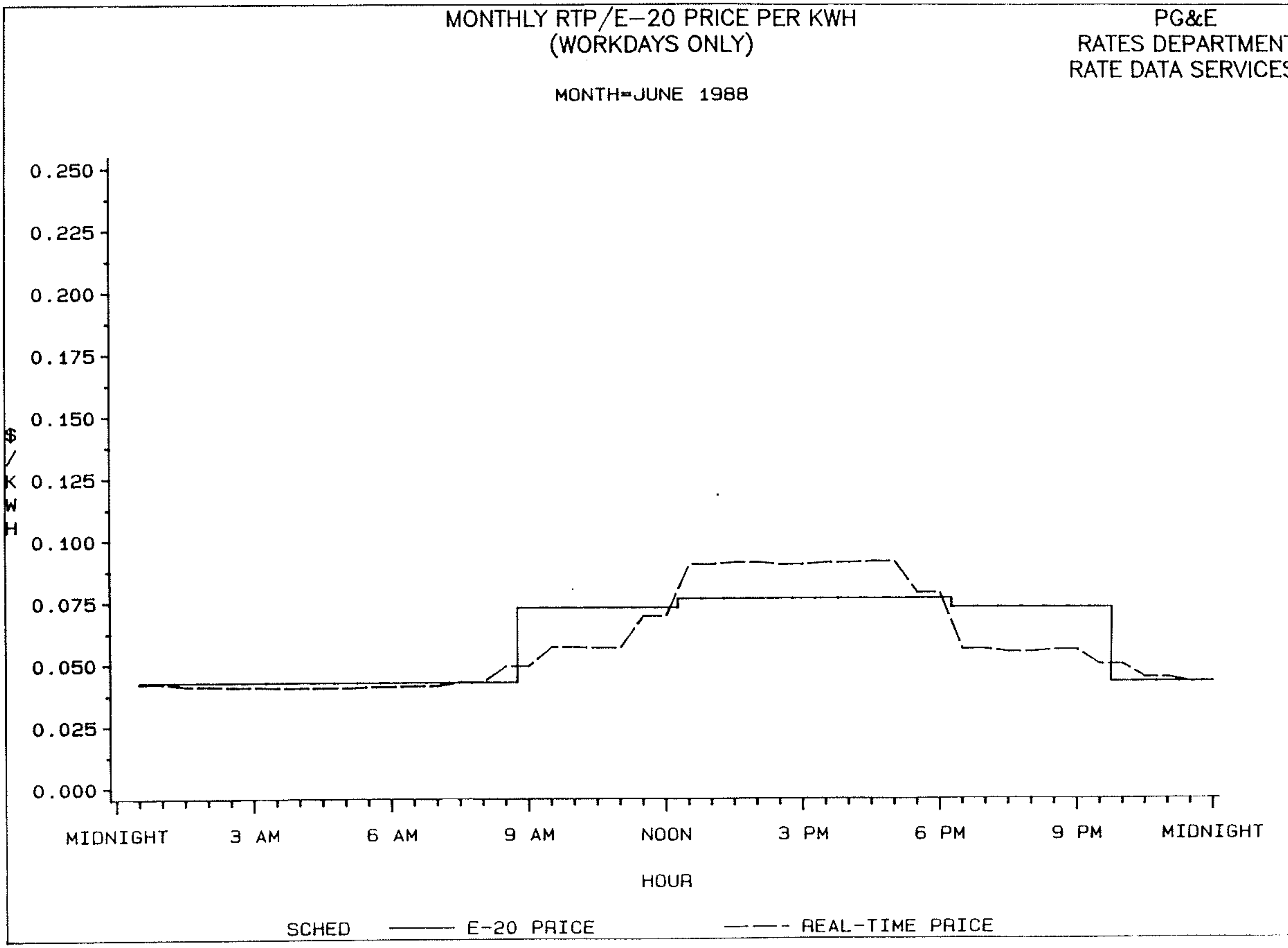
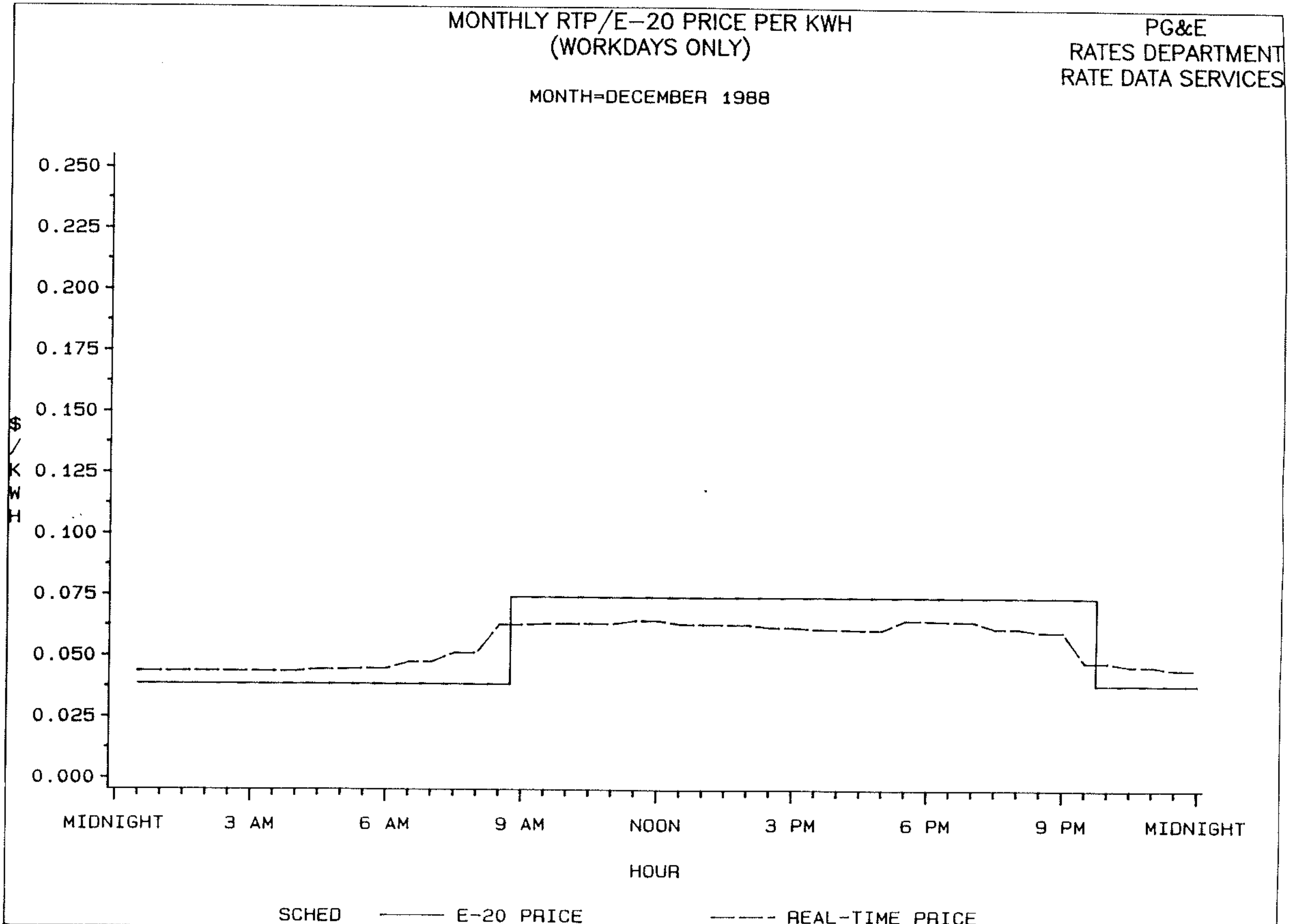


Figure 3-3.



MONTHLY RTP/E-20 PRICE PER KWH
(WORKDAYS ONLY)
PG&E
RATES DEPARTMENT
RATE DATA SERVICES
MONTH=DECEMBER 1988
$/KWH
0.250
0.225
0.200
0.175
0.150
0.125
0.100
0.075
0.050
0.025
0.000
MIDNIGHT
3 AM
6 AM
9 AM
NOON
3 PM
6 PM
9 PM
MIDNIGHT
HOUR
SCHED
E-20 PRICE
REAL-TIME PRICE

they are 10 to 32 percent lower than the E-20 prices for the partial-peak period the entire year. The off-peak RTP prices were higher on average than E-20 for the year. This circumstance is a result of the unavailability of inexpensive hydro power because of drought in Northern California.

RTP Notification and Data Collection System

The original RTP notification system consisted of a Process System Inc. (PSI) S-7000 EC/PC Central Station computer with a modem and specially modified software for transmitting data over telephone lines. This system transmitted the daily price schedules to a printer attached to a PSI recorder at the customer site, simultaneously sending a signal to activate the alarm unit, and monitored the time and date of transmission. Total cost of the original system was about $1500 to $1800 per user.

PG&E's experience demonstrated that any major program expansion would quickly overburden the original system. During 1988, a new RTP electronic mail notification system was developed and installed as shown in Figure 3-4. The upgrade substantially reduced operator time, transmission time, and costs. In addition, it provided increased reliability by providing alternate or backup transmission paths in case of failure.

RTP load data is collected on a weekly basis from Process System solid state recorders at each customer site. The Central Station downloads the data and spools it onto tape. The tape is then delivered to PG&E's mainframe computer for use in billing and analysis. PG&E also maintains a magnetic tape recorder at each customer site for redundancy. Figure 3-5 illustrates the RTP data collection process.

Customer Characteristics and Survey

The project now involves 15 industrial and commercial participants with a minimum demand level of 500 kW. The number of participants is the maximum allowed by the California Public Utilities Commission (CPUC). These participants include the following business types shown in Table 3-4. These diverse business types allow PG&E to ascertain which types of users are best able to respond to price signals and can most benefit from a flexible pricing scheme.

RTP ELECTRONIC MAIL NOTIFICATION SYSTEM

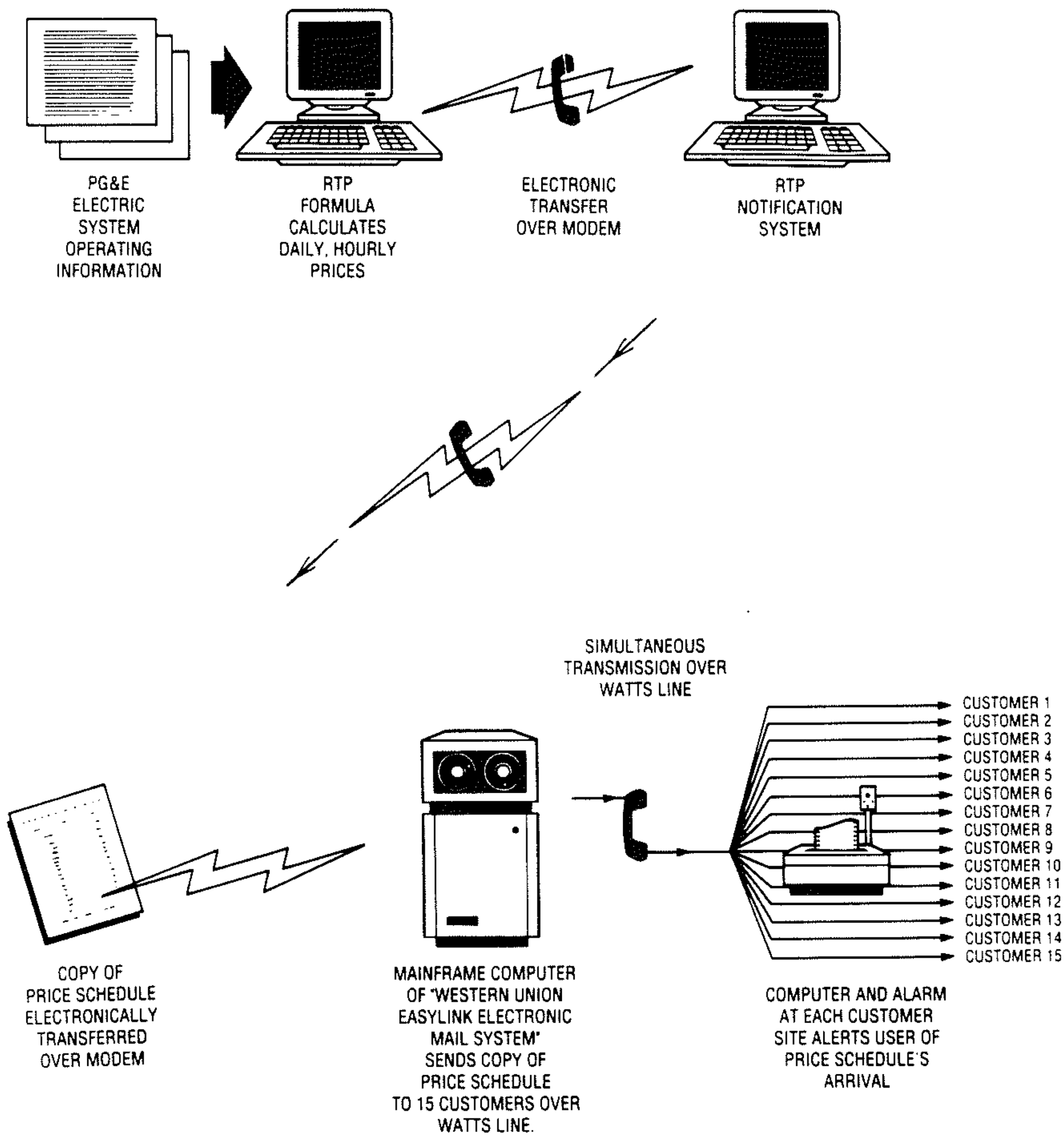


Figure 3-4.

Figure 3-5.

RTP REMOTE METERING AND DATA COLLECTION

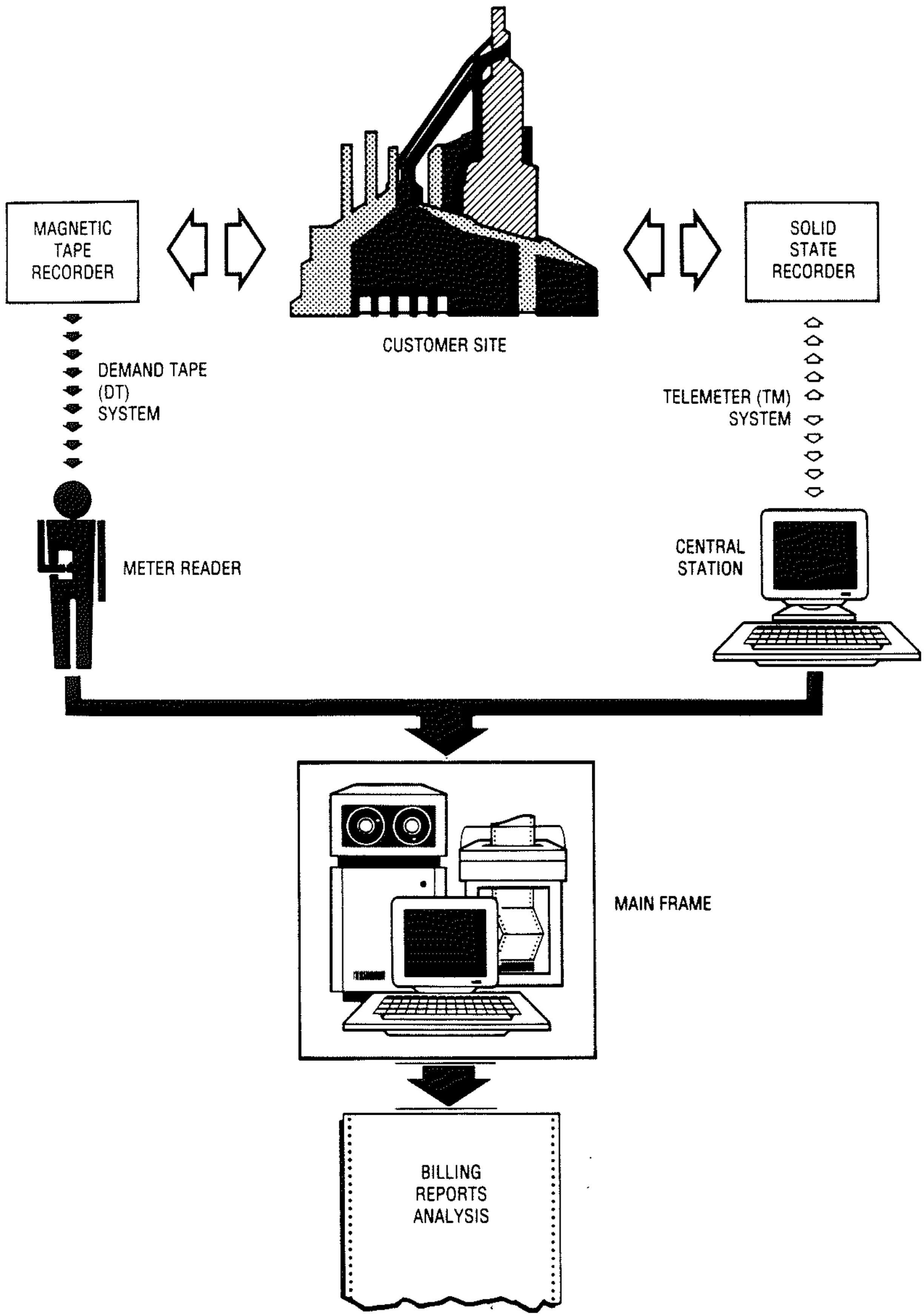


Table 3-4.

CUSTOMER CHARACTERISTICS

Business Type	SIC (a)	Participation Months(b)	1988(c) Load (mwh)	Chapter 6(d) Analysis Designation
Bank Computing Center	60	12	6,800	K
Chemical Manufacturer #1	28	41	33,100	A
Chemical Manufacturer #2	281	37	5,200	D
Commercial Printer	275	4	2,500 & 1,300(e)	S
Corporate Research & Development	873	7	6,200	R
Electric Component Manufacturer	367	28	21,200	E
Electric Equipment Manufacturer	38	12	7,100	N
Food Manufacturer	20	4	7,500 & 3,400(e)	T
Frozen Food Warehouse & Freezing Plant #1	4,222	16	5,800	M
Frozen Food Warehouse & Freezing Plant #2	4,222	11	21,400	O
Frozen Food Warehouse & Freezing Plant #3	4,222	16	2,500	L
Hospital #1	8,062	7	4,000	P
Hospital #2	8,062	15	4,600	I
Mineral Producer	329	13	5,000	J
Residential High School	8,211	15	2,600	H

(a)Two-digit SIC codes are used where necessary to protect the customer's identity.
(b)As of December 31, 1988.
(c)This figure represents the customer's load while on the RTP program during 1988. For those customers who joined during the year, it underestimates their annual load.
(d)This code is provided for cross-reference with the designations used in the analysis (see Table 5-4).
(e)This customer has two accounts on the program.

On average, participants saved 12 percent by being on the A-RTP tariff as compared to the otherwise applicable E-20 rate schedule. Actual savings ranged from 2 to 17 percent due to the mix of business types and ability to respond to price signals. As a class, the A-RTP revenues for 1988 were 8.1 million dollars with consumption of 140,259 MWh (average unit cost = 5.8 cent/kWh)

In the fall of 1988, on-site interviews were conducted with each of the 15 customers to investigate participants' understanding of the rates, their decision processes used in responding to the price signals, and their actions taken when responding. The findings were summarized as follows:

1) All of customers are somewhat or very satisfied with the program. Several customers chose RTP because of freedom, rather than the interruptible or curtailable rate options, which could have saved them more money than RTP.

2) The actions most customers took to reduce loads included manual shutting down equipment, switching at least part of their load to diesel backup generators, using Energy Management Control Systems to limit demands, or rescheduling production. Twelve of the fifteen customers reported they could reduce demand within one hour or less.

3) While most customers said that between one and four hours' notice of a LMPS was sufficient, some indicated they could make greater load reductions if they were noticed the day before.

4) RTP customers expressed positive attitudes toward the program and toward PG&E's assistance in controlling their costs. Most were willing to alter their operating schedules to achieve some control of their costs.

<u>The Effect of RTP on a Daily Share Basis</u>

Table 3-5 shows the differences of the share of total daily usage that each TOU period represents. Both Customers A and D are chemical manufactures and have participated in the RTP program since 1985. Customer A shows virtually no change in the percent distribution of usage across Periods 1 (4/16/86-6/30/87) and 2 (7/1/87-). Customer D shows an over one percent increase in the summer off-

Table 3-5. Differences in Average Summer Workday kWh Shares

	Average Change in Percent Share kWh Consumption in TOU Period [%]	
	Customer A	Customer D
Peak	0.05	-0.8*
Partial-Peak	0.05	-0.3
Off-Peak	-0.10	1.1*

Note)
Peak: 12:00 noon to 6:00 p.m.
Partial-Peak: 8:30 a.m. to 12:00 noon, 6:00 p.m. to 9:30 p.m.
Off-Peak: 9:30 p.m. to 8:30 a.m.
* indicates differences is significant at 0.05 confidence level

peak period, which is due to decreases in both the on-peak and partial-peak periods.

PG&E is requesting permission in their 1990 General Rate Case to expand up to a total of 50 participants by 1992.

3.3 Niagara Mohawk Power Corp. (NMPC)[3]

NMPC serves about 1.4 million customers located within a service territory that extends throughout north-east and north-west New York State. In 1985 NMPC supplied approximately 35 billion kWh of electricity. Total revenues amounted to $2.1 billion in that year.

NMPC began planning for an RTP experiment for large users in the spring of 1986. The objective of the experiment is to measure large industrial customer responses to dynamic, fully time-differentiated, marginal cost-based electricity rates over a broad range of industries. The experiment went into the field on April 1, 1988 with nine customers on RTP and eight serving as a control group.

NMPC developed a unique rate design for their Hourly Integrated Pricing Program (HIPP). The two-part rate design maintains customer specific revenue neutrality with respect to existing TOU rates and with respect to their historically established consumption patterns. The HIPP recovers each customer's previously established fixed cost responsibility through an access charge and collects variable costs through an energy charge. Demand charges are not included in the RTP structure. Energy prices are set equal, on an hourly basis, to NMPC's current marginal costs, including marginal outage costs. The key aspects of the access charge is that it is independent of current usage; thus at the margin it does not alter the incentives provided by energy prices. The rate is implemented so that each customer's individual pre-specified baseline usage pattern. For all departures from baseline usage the customer faces the hourly marginal energy prices. [4]

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[3] The description of NMPC's RTP program is based on Tramutola and Chapman(1988).

[4] The baseline usage pattern is defined as the firm's hourly load profile from July 1, 1986 to June 30, 1987.

There is virtually no evidence on customer preferences regarding notice, so NMPC elected to issue binding price quotes on the afternoon of the business day preceding the day for which the prices apply. This notice policy is similar to that at PG&E and SCE, except that those companies reserve the right to requote prices on short notice under certain conditions.

Among RTP experiments, a unique aspect of the HIPP experiment is the volunteer control group for the controlled test period. The design of the HIPP experiment is shown in Table 3-6. There are three customer categories and three time periods. The three customer groups are:

Non volunteers - those who were offered but refused the HIPP offering.

Volunteer controls - those who accepted the HIPP offering but who remain on standard rates as a control group for a period of eight months.

Volunteer treatment- those who accepted the HIPP offering and are placed on HIPP at its initiation, April 1, 1988.

The three periods are:

Historical - prior to HIPP initiation

Controlled test - April 1, 1988 - November 30, 1988, when the volunteer controls are on SC-3A and the volunteer treatment customers are on HIPP.

Uncontrolled test - After November 30, 1988, when all volunteers are on HIPP.

Comparisons among the customer groups and time periods will allow NMPC to answer the following questions regarding RTP:

Q1) Do usage patterns under standard SC-3A rates provide any indication of the likelihood of volunteering? Compare C1 with A1 and B1.

Q2) Do usage changes between the historical and test periods provide any indication of the likelihood of volunteering? Compare usage changes between historical and test periods for non-volunteers (C2/C1) with the comparable change for volunteer controls (A1/A2).

Q3) To what extent does HIPP cause volunteer customers to alter usage? Compare A2 and B2.

As of May 31, 1989, NMPC has 17 participants served under HIPP. Participants include the following seven industry groups: SICs 26

Table 3-6.

HIPP Experimental Design

	Customer Groups		
Time Period	1 Volunteer Control	2 Volunteer Treatment	3 Non-Volunteers
1. Historical	A1 TOU	B1 TOU	C1 TOU
2. Controlled Test (Phase 1)	A2 TOU	B2 HIPP	C2 TOU
3. Uncontrolled Test (Phase 2)	A3 HIPP	B3 HIPP	C3 TOU

Issues:
1. Does TOU usage determine volunteering
2. Does usage change determine volunteering
3. Do volunteers alter usage

From Caves, Herriges, Mango and Neenan (1988) (paper and allied products), 32 (stone, glass and clay products), 33 (primary metal products), 34 (fabricated metal products), 36 (electric and electronic equipment), 49 (electric, gas and sanitary service), and 82 (educational services). Figures 3-6 and 3-7 present HIPP price trends over the year. Figure 3-6 compares HIPP with SC-3A (TOU) prices for on- (8:00 through 22:00) and off-peak weekday hours while Figure 3-7 focuses on the on-peak period's price variability. Figures 3-8 and 3-9 examine the hourly pattern of weekday HIPP and TOU prices for July 1988 and January 1989.

For the whole year consumption rose by approximately 12.7 million kWh, or about 2.87 percent over baseline levels. The on-peak share of total usage rose from 40.13 to 41.68 percent.

Had the SC-3A rate remained in force and HIPP actual loads been consumed, average cost would have been 5.415 cent/kWh. Average cost under HIPP was 5.092 cent/kWh or 6 percent less than TOU. The HIPP vs TOU bill comparisons reveals savings of over $1.4 million for HIPP Phase 1 customers (9 customers participating from 4/1/88).

3.4 Southern California Edison (SCE) [5]

SCE serves over three million customers located within its 50,000 square miles of service territory throughout southern and central California. Nearly one-third of its $5 billion annual revenue is derived from its 2,500 largest commercial and industrial customers.

The purpose of SCE's RTP program is to conduct a study to determine the feasibility of RTP with respect to : customer response, customer acceptance, hardware and software performance, tariff administration, and cost-effectiveness.

SCE's RTP experiment involves 10 very large commercial and industrial customers who voluntarily agree to participate. This group of customers is not representative of the very large commercial/industrial population as a whole. Rather, it is representative of the types of customers who may eventually volunteer for billing under a real-time tariff once a standard RTP

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[5] The description of SCE's RTP experiment is based on Fagan(1988) and SCE(1989).

Figure 3-6.

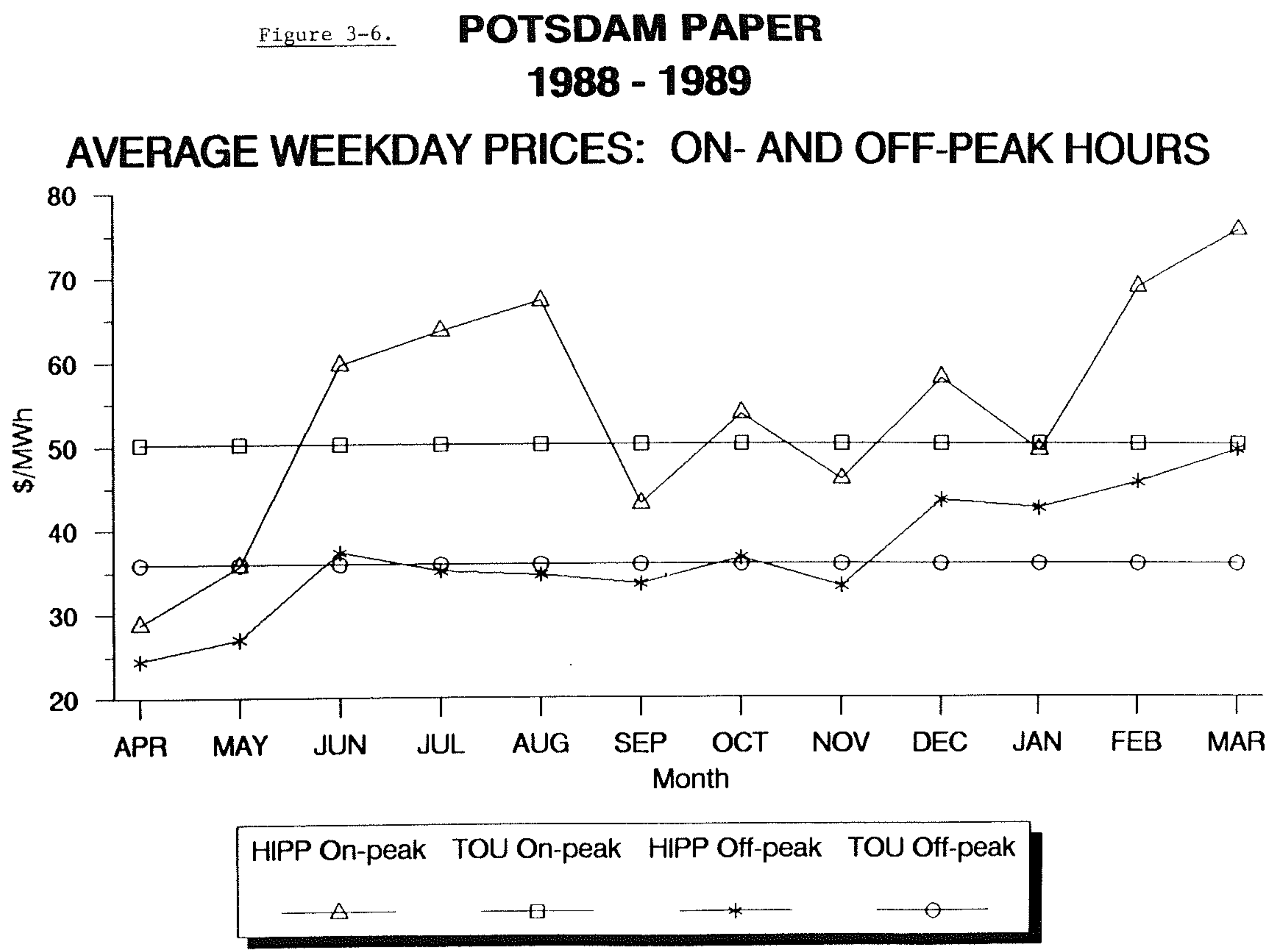

POTSDAM PAPER
1988 - 1989
AVERAGE WEEKDAY PRICES: ON- AND OFF-PEAK HOURS
$/MWh
80
70
60
50
40
30
20
APR
MAY
JUN
JUL
AUG
SEP
OCT
NOV
DEC
JAN
FEB
MAR
Month
HIPP On-peak
TOU On-peak
HIPP Off-peak
TOU Off-peak

Figure 3-7.

1988 - 1989

NMPC

HIPP PRICE RANGES

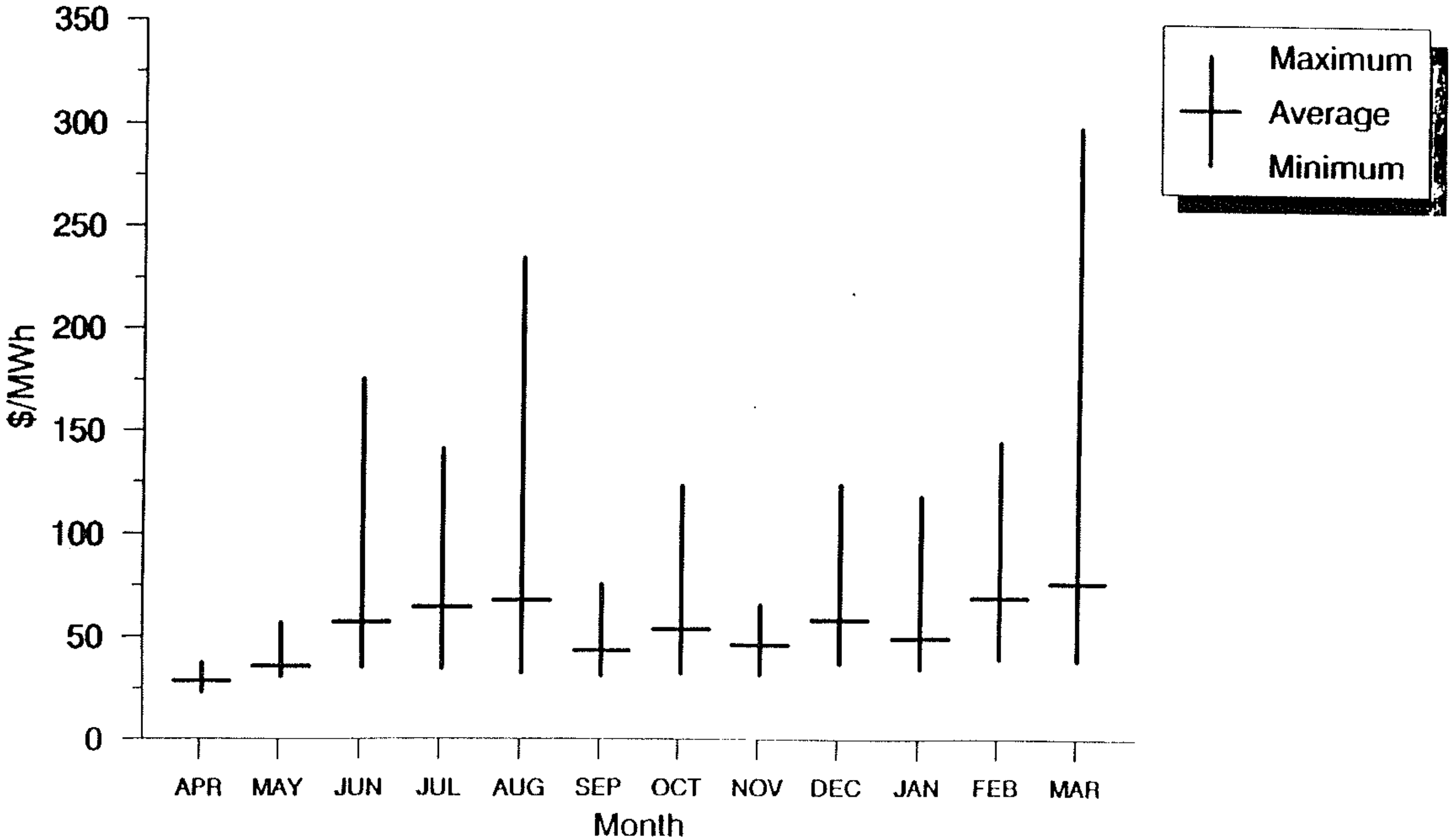


Figure 3-8.

JULY 1988

NMPC

AVERAGE HOURLY PRICES - WEEKDAYS

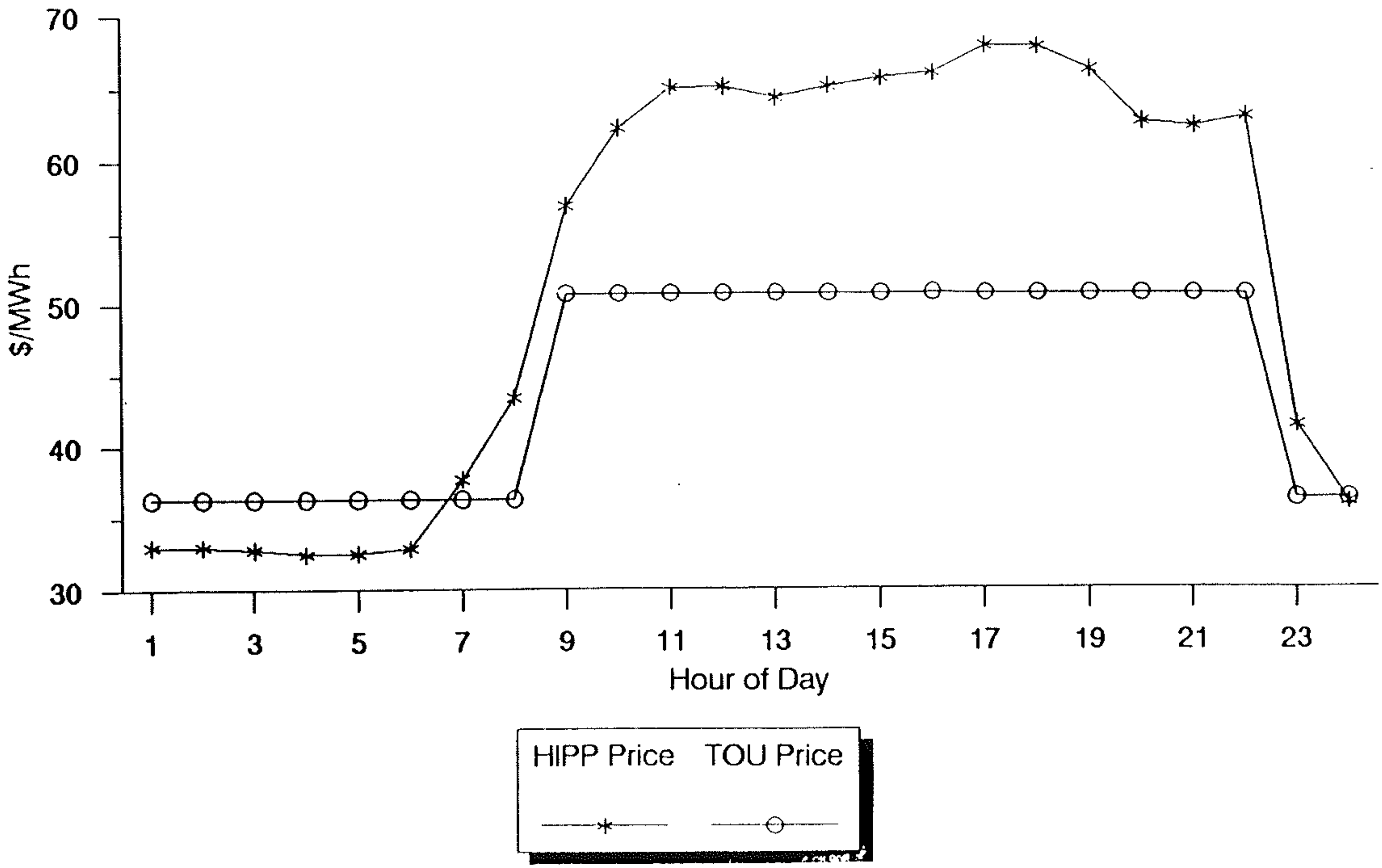
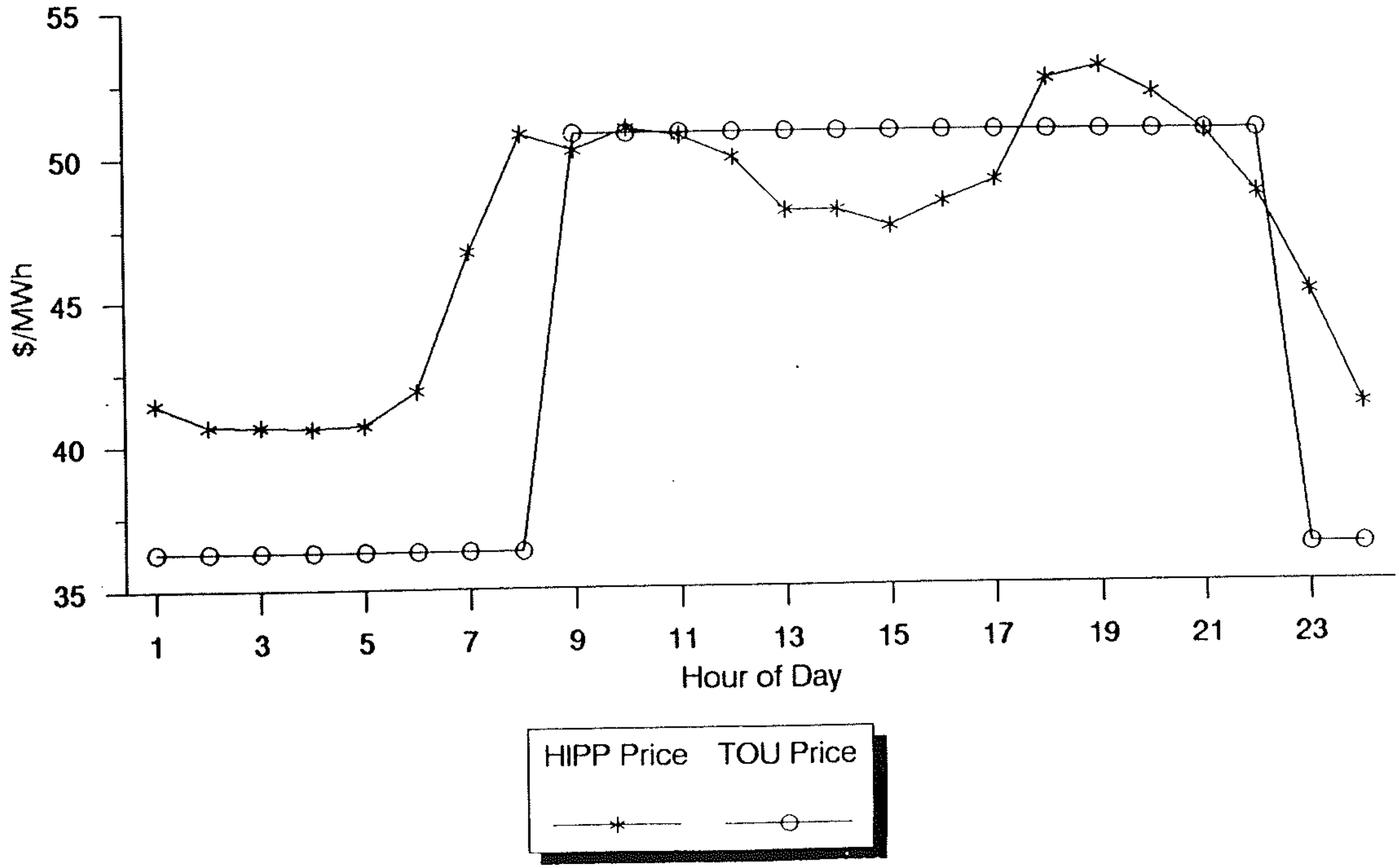


Figure 3-9.

JANUARY 1989

NMPC

AVERAGE HOURLY PRICES - WEEKDAYS



tariff is in place. RTP experiment participants have the following characteristics in common :

1) They have had relatively stable load characteristics over the past five years. (This permits more precise measurement of customer response.)
2) They include both commercial and industrial customers.
3) They represent a wide range of customer types within the commercial and industrial classifications.
4) A few have alternative supply-side options (e.g., cogeneration or standby generation) or demand-side options (e.g., thermal storage or energy management systems).

The real-time rate is designed to be revenue-neutral with SCE's Large Power Rate for the entire Large Power customer population. Under this revenue neutrality standard, the RTP rate has attracted customers with slightly better-than-average load shapes and customers who plan to add new loads during extremely low-cost hours. These customers include : a sports facility, a dairy, a wastewater treatment facility, a large office building, a food distribution center, and several manufacturing facilities. These customers span all four SCE divisions, although the majority are located in a single division (Southern).

SCE's RTP rate is actually a collection of nine 24-hour price scenarios. Each scenario contains a set of prices associated with a particular day type (Day type, in this context, refers both to weather day type and weekday/weekend day type). RTP price scenarios have been developed for the following day-types : Extremely Hot Summer Weekday; Very Hot Summer Weekday; Hot Summer Weekday; Moderate and Mild Summer Weekday; Hot summer Weekend Day; Moderate and Mild Summer Weekend Day; Hot Winter Weekday; Moderate and Mild Winter Weekday; and Winter Weekend Day. Table 3-7 shows a RTP experiment tariff summary (the original schedule RTP-1 from 1/1/88 to 12/31/89). RTP rate levels vary considerably among scenarios, with the highest rates present in the Extremely Hot, Very Hot and Hot Summer Weekday scenarios and the lowest rates present in the Moderate and Mild Weekday and Weekend Day scenarios (as some examples of these scenarios, see Figures 3-10, 3-11, 3-12, and 3-13). SCE selects a given day's scenarios based on the temperature and day-type in effect on that day.

Table 3-7. SCE's RTP Experiment Tariff Summary: RTP-1

Summer Weekday	Approx. Temp.[F]	Weighted Average Price [cent/kWh]	Frequency [Days]
Extremely Hot	>=100	37	3
Very Hot	95-99	22	5
Hot	85-94	11	29
Moderate & Mild	60-84	8	47
Summer Weekend & Holiday			
Hot	>=85	10	15
Moderate	60-84	6	23
Winter Weekday			
Hot	>=84	10	10
Moderate & Mild	45-84	7	159
Winter Weekend & Holiday			
All Days	>=45	5	74

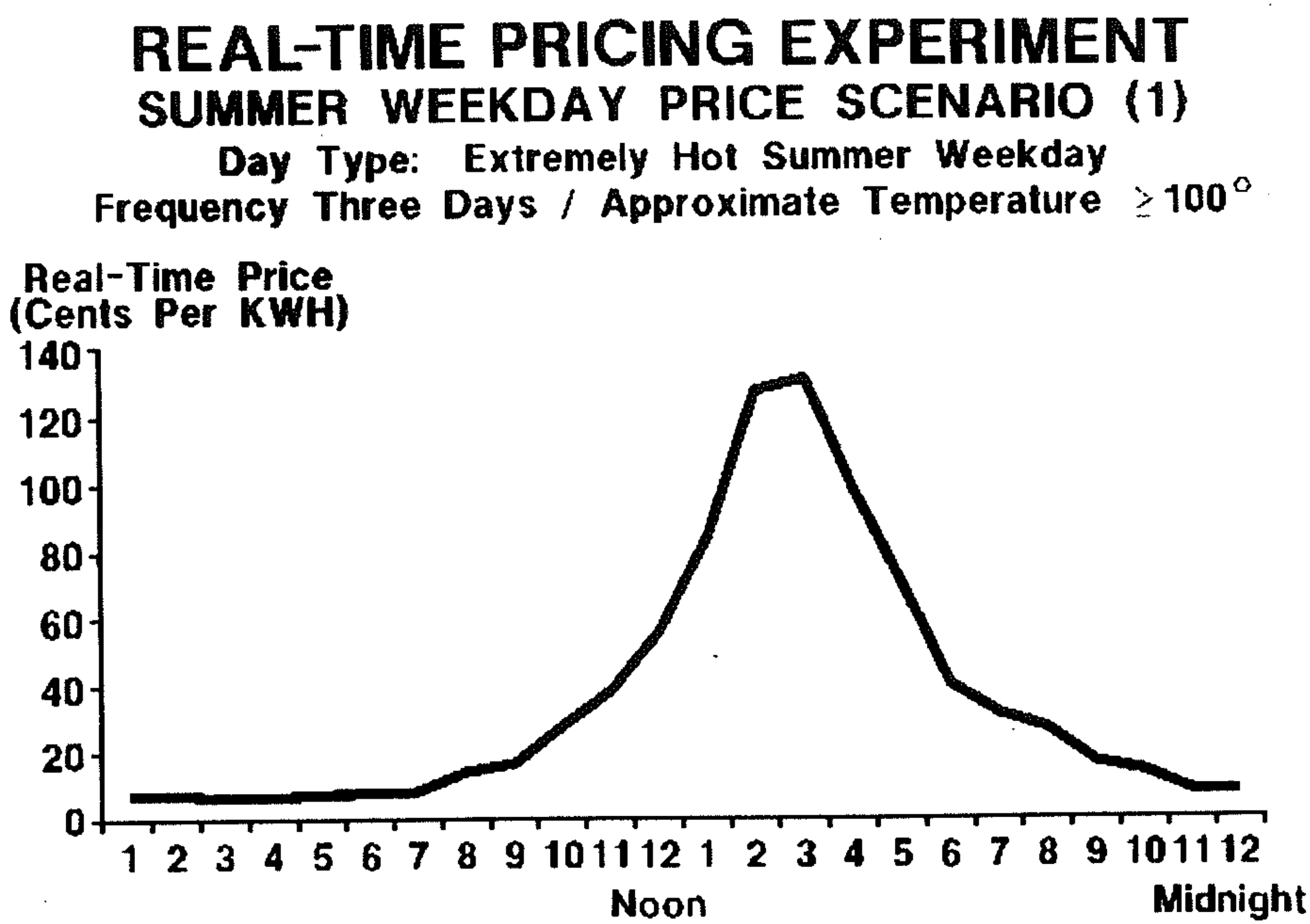


Figure 3-10. RTP-1 at SCE

REAL-TIME PRICING EXPERIMENT

SUMMER WEEKDAY PRICE SCENARIO (2)

Day Type: Very Hot Summer Weekday

Frequency Five Days / Approximate Temperature 95-99°

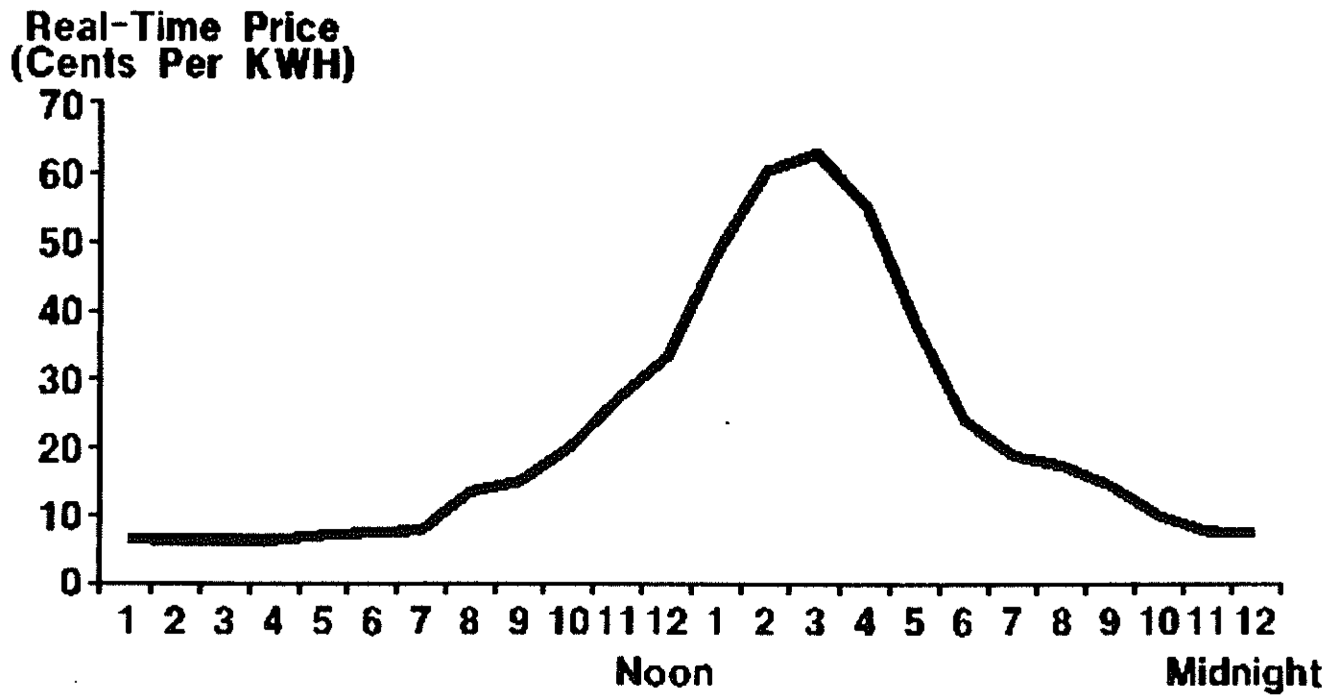


Figure 3-11. RTP-1 at SCE

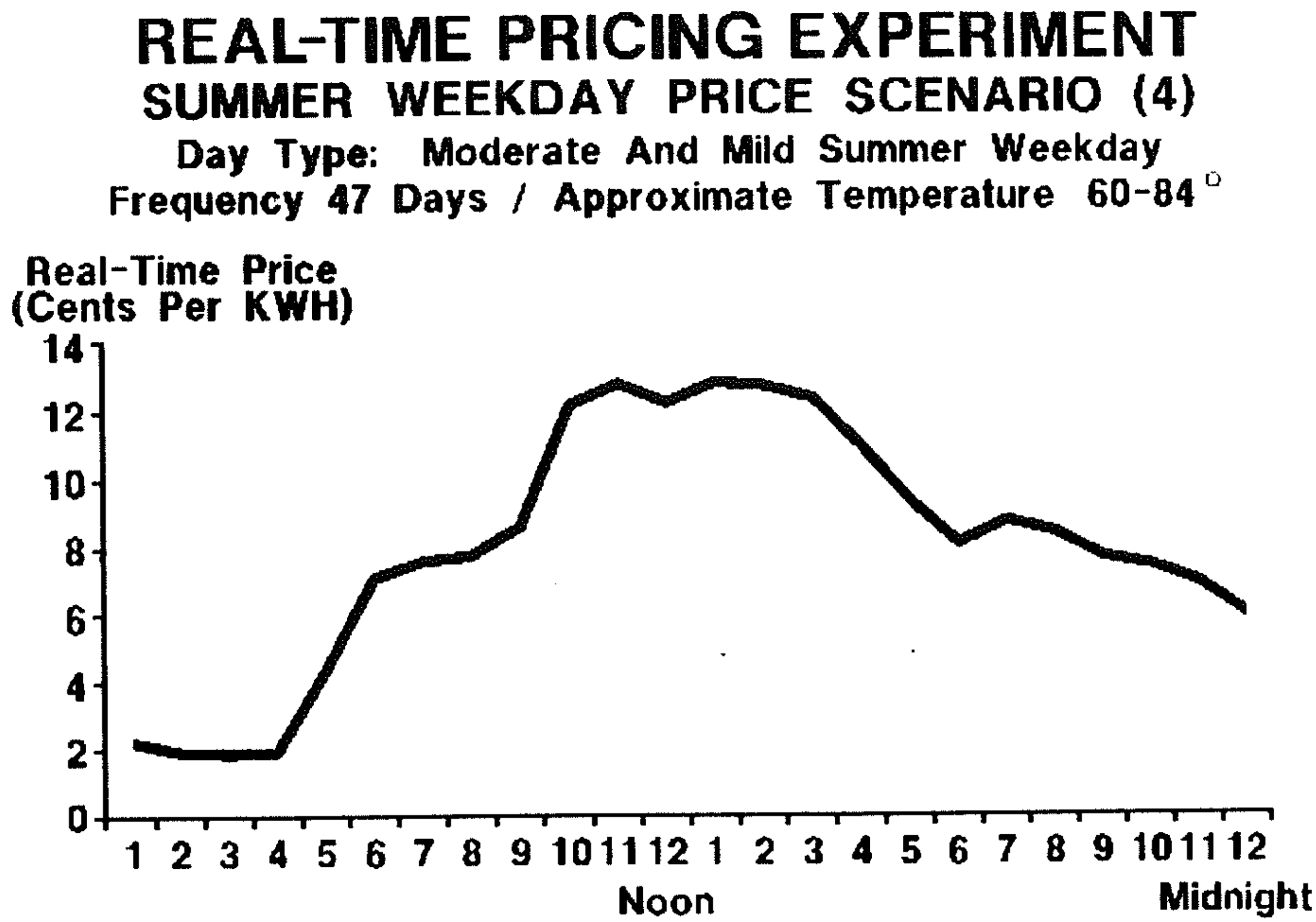


Figure 3-12. RTP-1 at SCE

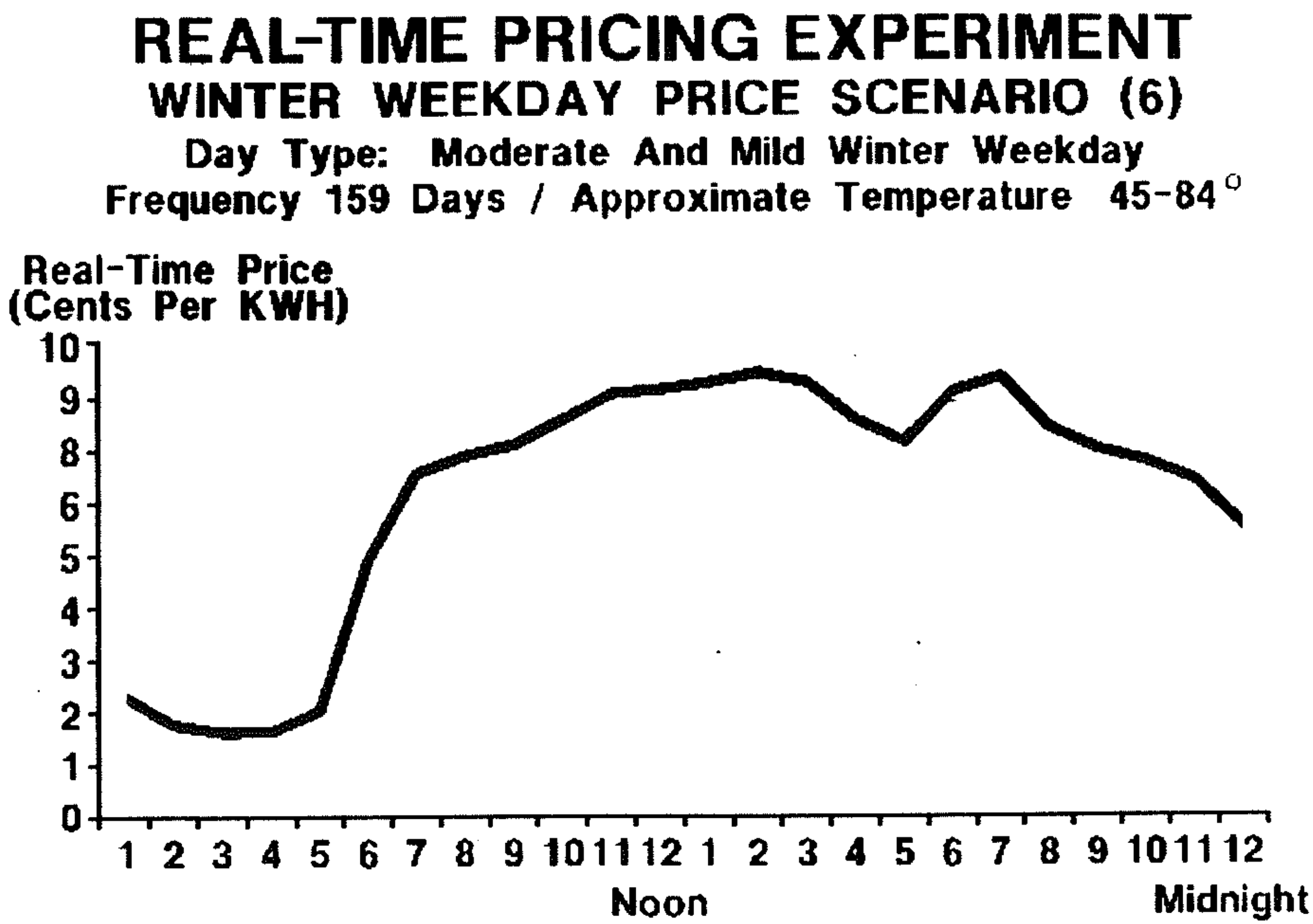


Figure 3-13. RTP-1 at SCE

During very low-cost off-peak hours, customers are charged a rate which reflects the price of rejected economy energy or the cost of unused base load energy (whichever is lower), plus a small increment for contribution to margin. For at least the near term, RTP energy prices in the off-peak period are expected to be substantially below Large Power off-peak energy charges. Revenues undercollected during off-peak hours are offset through a combination of much higher prices charged on Hot to Extremely Hot Summer Weekday hours, and somewhat higher prices charged during all other hours of the year.

During Hot to Extremely Hot Summer Weekday hours, customers face a wide range of prices, in the $.25 to $1.50 per kWh range. These Summer Weekday prices are designed to cover the range of prices customers could expect to see under actual RTP tariff implementation. Over the duration of the experiment, Hot to Extremely Hot Summer Weekday prices simulate system operating conditions during a typical year when actual reserve margins are at or near planning reserve margin levels.

For the next several years, actual reserve margins are expected to be considerably higher than planning reserve margins. Although capacity is not expected to be constrained during the years that the experiment will be under way, customers are charged prices which reflect conditions when capacity constraints are present. These prices are considerably higher than corresponding charges in the standard Large Power rate (although they will only apply less than one percent of the time), and serve two purposes: to test customer response and to recoup some of the revenues undercollected during off-peak hours.

Finally, during all other hours of the year (mid-range hours), prices reflect marginal cost relationships, but embody a revenue reconciliation adjustment. SCE computed the "revenue reconciliation adjustment multiplier" by taking the ratio of revenues required during these mid-range hours to marginal costs forecast for these same hours.

Customers are provided with a 90-day forecast of frequencies of real-time price scenarios approximately one week before the 90-day period begins. In addition, customers are provided with a second forecast reflecting one week's expected prices on the Monday immediately preceding the start of that week. A third 24-hour forecast of prices is supplied to the customer by not later than 4 p.m. on the prior day. This third, 24-hour price forecast contains prices actually charged to the customer most of the time. However, SCE reserves the right to change a given hour's price up to ten minutes before the price becomes effective. This ten minute notice option is used occasionally to simulate system emergencies and to correct for temperature-related forecasting errors.

SCE transmits real-time prices to customers over an IBM Personal Computer linked to a Process Systems S-100 Solid State Recorder with a printer located at each customer's site. The special RTP software used to transmit RTP rates was largely based upon similar software used in the past by PG&E in its RTP program. There are two different records kept of the price transmission at the customer's site : a computer printout of each day's schedule of prices with hourly price updates, and an acknowledgement within the recorder that the price signal was received by the customer. In the event of equipment failure, the customer is charged according to the most recent RTP price forecast in his possession.

The first stage of SCE's Real Time Pricing experiment is currently under way, and will continue until December 31, 1989. During 1988, RTP customers paid 2.3 percent less than what they would have paid had they remained on TOU rate. Although the RTP customer population as a whole saved money during 1988, not all of the RTP customers saved money under RTP. Losses occurred primarily because the RTP discount for service at primary voltage was set at too low a level between January 1, 1988, and October 26, 1988. The RTP primary voltage discount was corrected on October 26, 1988, to reflect the TOU-8 rate schedule voltage level rate difference.

Out of the original population of ten customers in the RTP program, four have dropped out of the program after the first year. For the first three customers, the saving in their bills which they expected under RTP did not occur, largely due to a change in the TOU rate design. A fourth customer became ineligible for a second year on the program after their facility was purchased by another company.

Figure 3-14 shows average profiles overlaid for a commercial laundry. These plots provide a simple comparison of customer usage on an average extremely hot summer weekday, an average hot summer weekday, and an average moderate and mild summer weekday. Only two of ten customers including this commercial

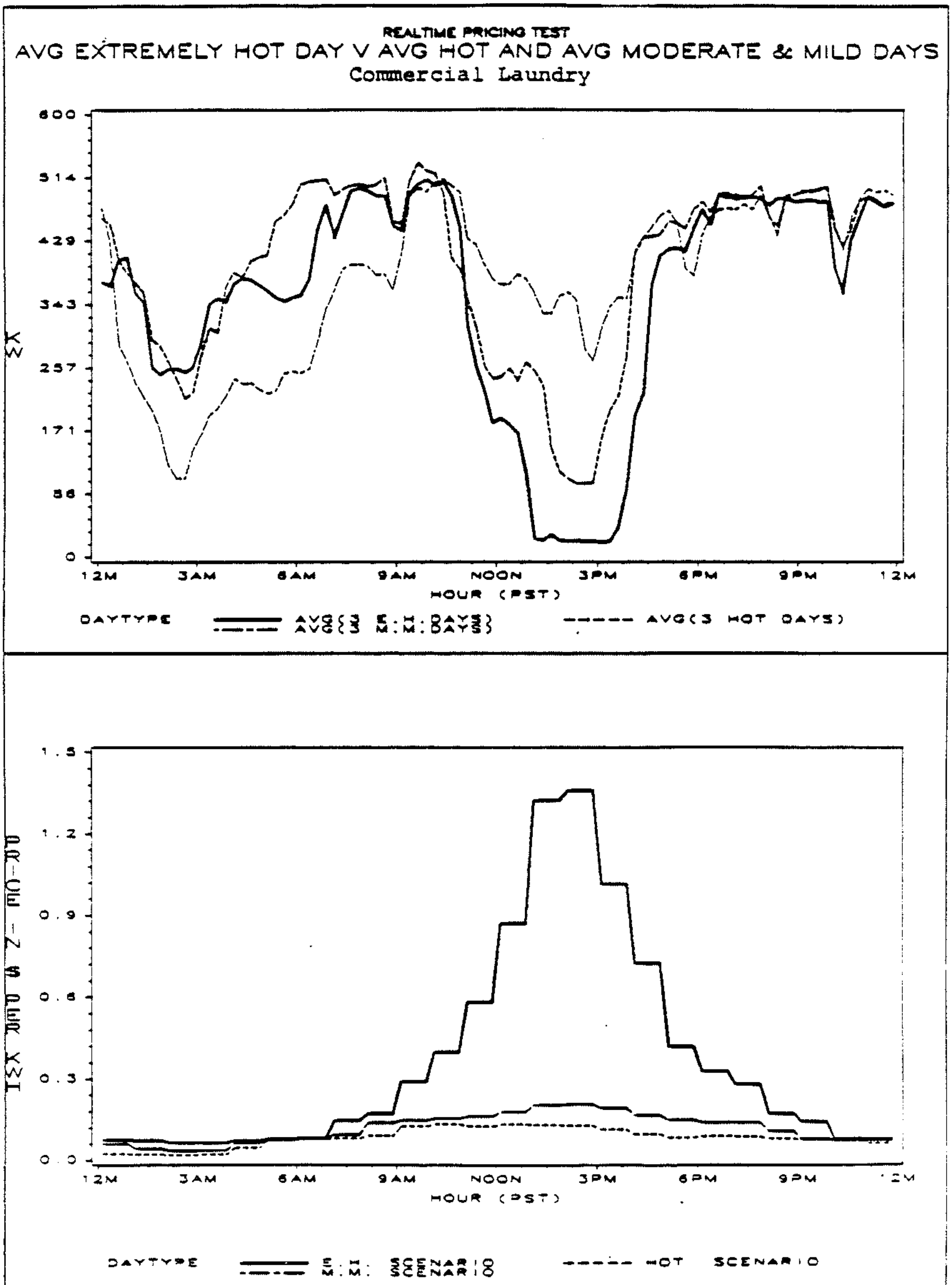

REALTIME PRICING TEST
AVG EXTREMELY HOT DAY V AVG HOT AND AVG MODERATE & MILD DAYS
Commercial Laundry
KW
600
514
429
343
257
171
86
0
12M
3AM
6AM
9AM
NOON
3PM
6PM
9PM
12M
HOUR (PST)
DAYTYPE
AVG(3 E.H.DAYS)
AVG(3 M.M.DAYS)
AVG(3 HOT DAYS)
1.5
1.2
0.9
0.6
0.3
0.0
DAYTYPE
E.H. SCENARIO
M.M. SCENARIO
HOT SCENARIO

Figure 3-14.

laundry and a large office building, significantly reduced their loads by an average of 400 kW per customer on extremely hot summer weekday. A more complete analysis of customer response (measurement of price elasticities) will be undertaken at the end of 1989.

SCE is implementing a second RTP program and tariff from May of 1989. This second program will run through December 1991. In this program, SCE will be testing a revised RTP rate design (RTP-2, Table 3-8) and new RTP communications hardware and software on a new RTP customer population (an additional 10 RTP customers). SCE intends to allow participants in the first RTP program to transfer to the second RTP program after the first program terminates in December 1989.

Spot Pricing Test

In addition to its two-year RTP experiment, SCE also conducted a six-month test of another form of flexible pricing known as Spot Pricing. For SCE, Spot Pricing refers to the sale of nonfirm electric energy on-peak at a discounted, variable rate. These energy sales are "incremental"; that is, they would not occur absent the rate discount.

This six-month test was conducted between July 8, 1987 and December 31, 1987, and involved a single customer, TAMCO, an electric arc furnace plant. Prior to the test, TAMCO had shut its 50 MW electric arc furnace, down during SCE's on-peak period. TAMCO had informed SCE that it could not afford to operate the arc furnace on-peak because SCE's on-peak rates were too high.

Under Spot Pricing, TAMCO was allowed to purchase a defined block of energy on-peak at a discounted, variable rate. Although this rate was designed to escalate in real-time if Edison's marginal energy costs increase significantly or if a capacity shortage is imminent, it remained fixed at the Spot Pricing Minimum Rate level of 6.75 cents per kWh throughout the test.

During the test, SCE sold an additional 6 million kWh to TAMCO during the on-peak period. These additional sales generated about $400,000 of additional revenue from TAMCO, out of which $165,000 represented an additional contribution toward SCE's fixed costs.

Table 3-8.

SOUTHERN CALIFORIA EDISON COMPANY
REAL TIME PRICING -- EXPERIMENTAL RATE SCHEDULE RTP-2

Hour ending @ PST	Extremely Hot Summer Weekday (6 days)	Very Hot Summer Weekday (9 days)	Hot Summer Weekday (13 days)	Moderate Summer Weekday (69 days)	Mild Summer Weekday (51 days)	High Cost Winter Weekday (18 days)	Low Cost Winter Weekday (88 days)	High Cost Weekend (47 days)	Low Cost Weekend (64 days)
1 A.M.	0.03966	0.03913	0.03833	0.03808	0.03893	0.03875	0.03931	0.03930	0.03839
2 A.M.	0.03908	0.03867	0.03798	0.03793	0.03871	0.03866	0.03916	0.03913	0.03833
3 A.M.	0.03863	0.03832	0.03789	0.03801	0.03867	0.03854	0.03910	0.03908	0.03819
4 A.M.	0.03851	0.03827	0.03778	0.03793	0.03860	0.03854	0.03910	0.03908	0.03816
5 A.M.	0.03850	0.03830	0.03778	0.03791	0.03858	0.03870	0.03922	0.03910	0.03810
6 A.M.	0.03951	0.03912	0.03824	0.03851	0.03892	0.04015	0.04049	0.03942	0.03816
7 A.M.	0.06244	0.06191	0.06519	0.06196	0.07466	0.06212	0.06776	0.06780	0.04933
8 A.M.	0.06323	0.06298	0.06583	0.06315	0.07761	0.07444	0.07888	0.06824	0.04991
9 A.M.	0.06593	0.06577	0.06666	0.06615	0.07593	0.10506	0.08427	0.06816	0.06258
10 A.M.	0.07304	0.07079	0.06999	0.06953	0.09117	0.14132	0.08943	0.06792	0.06316
11 A.M.	0.40607	0.13798	0.08333	0.07659	0.10714	0.12611	0.09272	0.06663	0.06295
12 NOON	0.80718	0.18062	0.08970	0.07064	0.09237	0.08714	0.07688	0.06455	0.06298
1 P.M.	1.02516	0.28993	0.11762	0.07687	0.08984	0.07822	0.07599	0.06394	0.06270
2 P.M.	1.78198	0.93061	0.24305	0.10563	0.09934	0.07454	0.07735	0.06845	0.06270
3 P.M.	2.70000	1.11025	0.42884	0.11480	0.09523	0.06781	0.07220	0.06948	0.06276
4 P.M.	1.91956	1.14555	0.22068	0.09145	0.07619	0.06542	0.06903	0.06921	0.06307
5 P.M.	1.53898	0.58765	0.10662	0.06712	0.07171	0.07245	0.08055	0.07073	0.06325
6 P.M.	1.20882	0.24981	0.07528	0.06477	0.06810	0.10872	0.09323	0.07477	0.06333
7 P.M.	1.13823	0.23991	0.08973	0.06791	0.06651	0.21897	0.10318	0.07335	0.06351
8 P.M.	1.13071	0.27220	0.08655	0.06776	0.06598	0.10303	0.08308	0.06962	0.06369
9 P.M.	0.19748	0.10064	0.06675	0.06744	0.06760	0.07087	0.07498	0.06961	0.06363
10 P.M.	0.06462	0.06443	0.06732	0.06353	0.07980	0.06554	0.07249	0.06673	0.06261
11 P.M.	0.06345	0.06296	0.06575	0.06299	0.07208	0.06677	0.07322	0.06417	0.06190
12 MID.	0.06247	0.06170	0.06376	0.06172	0.06539	0.06570	0.06874	0.06167	0.04917

Prices are dollars/kwh and reflect energy charges only.
A non-time differentiated demand charge and customer charge identical to the TOU-8 schedule is also assessed.

Note: Summer - Beginning midnight of first Sunday in April, ending midnight of first Sunday in November.
Winter - Beginning midnight of first Sunday in November, ending midnight of first Sunday in April.

Effective: 7/1/89

Although the Spot Pricing test expired in December 1987, SCE implemented Spot Pricing again during its 1988 Summer billing period (i.e., June 1988 through September 1988) for TAMCO and a second customer, Air Products. SCE has also filed an application with the California Public Utilities Commission (CPUC) requesting that Spot Pricing be established as a permanent, tariffed rate option. If the CPUC approves this application in the Spring of 1989, as expected, up to two dozen of SCE's large interruptible customers may eventually elect to take service under the Spot Pricing rate option.

3.5 Other Utilities' Experiences with RTP Programs[6]

(1) Tennessee Valley's Authority (TVA)

The "Energy Surplus Power (ESP)" program offered by TVA is an interruptible rate. Started in 1986 as an experiment, is has been a permanent program since July 1987. ESP provides large users with surplus power when TVA has excess power available. The power is contracted for on the basis of cost of services estimates, with actual hourly prices calculated and charged expost.

The average ESP price is 2.2 cents per kWh, while the firm rate could be anywhere from 3.8 to 5.0 cents per kWh. Risks involved in using the rate include the possibility of volatile price swings and the risk of being cut off with 5 minutes notice. Users, therefore, are limited to taking only half of their power under the flexible rate unless they have a load over 200 MW.

The TVA charges a $750 per month hook-up fee to participate in the program. This covers the cost of a dummy terminal, printer and dedicated phone line, and the computer system at the utility required to implement the program.

(2) Central Power and Light, Corpus Christi, Texas

Central Power and Light began a real-time rate program available to users bringing new load to the grid in late 1987. It provides an interruptible rate for large industrial customers with a service contract of 2,500 kW or greater. On the average, the rate is one cent less per kWh than the utility's other interruptible rate.

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6 This section is described based on Runnoe (1988).

Prices are calculated after the fact, and users are notified of the actual power's cost at the end of the month. The formula used to calculate the real-time rate, is the same as that used to calculate prices paid to cogenerators. Since no advance price signals are given, users rely on historical data to project upcoming prices.

(3) Houston Lighting and Power

In Houston Lighting & Power's system, the actual price of electricity is not established until after the power is consumed. Customers are given estimates of the next day's rate schedule and are requested to provide the utility with a usage profile of their expected load patterns for the following day. Information is relayed using a fax machine.

When the program was first started in 1984, real-time calculations were performed to determine actual marginal costs. As of July 1, 1987, however, the rate became based on the utility's weighted average of gas supplies which is used as the marginal fuel. The rate is interruptible, designed to give users an incentive to improve load during off-peak hours. On the average, the flexible rate is 30 percent lower than the firm rate. The drawback is that service is interruptible with 10 minutes notice. For users, such as air separators, where 70 to 100 percent of the load can be interruptible, the benefits of RTP can be substantial.

Of Houston Lighting & Power's 35 interruptible customers, 25 are on the real-time pricing program. Participating users sign up for one-day contracts, taking the maximum amount they can afford to have interrupted. A minimum take of 5 MW is required, but some users take as much as 300 to 500 MW.

(4) Gulf States Utilities, Beaumont,Texas

In March 1988, Gulf States Utilities began a real-time pricing program it calls the "economic as available power services" (EAPS). The rate is designed to encourage self-generating customers to back down their own generation and increase purchases of utility power. The program allows users with self-generating capability of 5 MW or greater, on line prior to January 1, 1988, to purchase power from Gulf States Power at the utility's acquisition cost plus a half-cent markup. The minimum purchase requirement is 1 MW on an hourly basis.

At times, Gulf States Power will have the option to purchase cheap short-term power from neighboring facilities at costs lower than their own production costs. Under the program, self-generating users call the utility's dispatch center to find out electricity prices for the current hour and estimates for the next hour. If the rate is below their own production costs, the user can contract for a specified amount for a given number of hours. If estimates for future hours are off, prices are adjusted later.

Though only two users are participating in the program so far, Gulf States Power estimates there are approximately 25 to 30 eligible customers in their service territory.

(5) New England Electric System (NEES)[7]

NEES calls its RTP program "dynamic pricing" and hopes to have commercial and industrial customers with a usage of 500 kW or above on the rate by the winter of 1989. This experiment will involve about ten customers and last two years. NEES will be modeling its system fairly close to the NMPC program, but instead of calculating new prices for each hour, NEES will likely use prefabricated prices based on about one dozen price vectors that will reflect typical summer and winter supply conditions. In this point of prespecified price scenarios, rate design of the dynamic pricing follows SCE's RTP program. RTP price scenarios have been developed for the following four day-types : peak; high; medium; and low demand days and for the following three seasons: winter; summer; and spring/fall.

Since NEES is a member of the New England Power Pool, all of its generation is dispatched centrally by the pool, which keeps its own minute-to-minute price information. Unlike the NMPC program that provides incentives for users to increase load, the NEES price signals will give users incentives to reduce their load, or shift some of it to less costly hours. Because NMPC currently has a capacity surplus, its

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7 The description of NEES's RTP experiment is based on discussions with Dr. Joseph Wharton, manager of rate economics, New England Power Service Company.

marginal costs are lower than its embedded costs, allowing users to add more load at a lower per unit cost.

In capacity-short New England, however, marginal costs are greater than embedded costs. For this reason, increased power purchases will reflect NEES's high cost of supplying power during peak demand periods.

(6) Georgia Power Company

Georgia Power Co. hopes to introduce a RTP program in 1989. It, too, plans on giving users hourly price signals, and will likely start with about a dozen users. The first customers, they predict, will likely be from the chemical, paper and pulp, and steel industries. The utility is currently conducting market research to identify users who would be interested in participating.

Georgia Power Co. also has a 24 hour ahead variable spot price rate, called "variable spot price one (VSP-1)" for residential customers in use in experiments by Integrated Communication Systems of Atlanta, in Roswell, Georgia (Tabors et al., 1988). Information is transmitted to customers concerning the expected value of the hourly energy costs, including capacity and revenue reconciliation for the next 24 hour period. The variable spot price rates are set to occur in one of three tiers. The hours for which the three tiers hold are not known by customers until they are transmitted. These three tiers are limited, however, in amount of time within a year that each can be in effect.

In addition to the three tiers, there is a superpeak tier rate which is intended to act as a "quasi-interruptible rate" to encourage customers to "shut down" when the system is in an extreme peak. This final level is not announced a day ahead but rather given with a half hour warning to customers. As a result, the VSP-1 rate reflects a mixture of the interruptible and the tiered price increments. Within the interruptible category it is an incentive-only rate, i.e., there are incentives not to be on line and no direct penalties for remaining on line except to pay the marginal cost.

(7) Consolidated Edison, New York, N.Y.

Consolidated Edison has also been looking at RTP programs, but has no projected date for implementing one of its own. Feasibility studies are likely to begin in 1989. Because many of the utility's large users are commercial office buildings with minimumly adjustable loads, Consolidated Edison is not sure how effective such a program could be for them.

4. POTENTIAL EFFICIENCY GAINS OF REAL-TIME PRICING

In this chapter, the difference in hourly load and generation costs between RTP and TOU rates caused by random demand fluctuations are investigated using a Monte Carlo simulation. Actual electric power demands and the production costs vary considerably from minute to minute, from day to day and from season to season. If implementation costs are equal, RTP is more desirable than TOU rates since RTP has the capability to adapt to demands and costs which display unpredictable fluctuations over time.

As an ideal case, I assume a continuous spot price in which demand is responding continuously and instantaneously. In practice, the price is only changed intermittently, sometime each hour, and there is some delay in the response of demand to the change in prices. The more frequently the price changes, the smaller the approximation error becomes. One of the important issues is how to determine the appropriate frequency of price update or the pricing cycle length by trading off increasing welfare against the costs of transaction between a utility and customers.

4.1 Real-Time Pricing Based on Marginal Cost

In Vickrey's article (1971) on the proposed concept of spot pricing, he proposed that prices can be set after some random variables are observed, and optimal price should reflect that. I shall accept his proposal here.

In the following analysis I adopt the following assumption: simultaneous decision making both in the demand side and the supply side. This means that there is no time-lag between determination of optimal prices on the supply side and load adjustment on the demand side as marketplace mechanisms will coordinate decisions made by both sides. I also assume that demands in different time periods are mutually independent. This assumption relates to pricing strategy errors arising from the interdependence among demands in different time periods.

There are some candidates for the RTP strategy; among them are the setting of real-time price according to marginal system operating costs, or a pricing strategy derived from the gaming situations between producers and consumers (Luh and Ho, 1982). Implementation of these pricing strategies under RTP inevitably requires the forecast of demand changes in the other time periods, and henceforth unavoidably suffers from errors in forecasting these changes. As the purpose of the analysis is not to investigate the effects of these errors but to evaluate advantage of RTP in one-line adaptation to unexpected change in demands, demands in different time periods are here assumed to be mutually independent. The Monte Carlo simulation technique is employed to evaluate the relative benefits of RTP and TOU rates.

I use the following simplified model:

(A-1) A daily cycle is divided into N periods, in each of which the demand is constant and the price changes only at the beginning of each period.

(A-2) Demand uncertainty is characterized by additive perturbation around a given demand pattern for a day.

(A-3) Demand in each period i is assumed independent of demands in other periods when price changes, as described above.

(A-4) Both the consumer and the producer can know the state of the external factors at period i, w_i, without any delay.

(A-5) The consumer installs a monitoring system and automatic control software which allow hourly response to pricing signals.

Under (A-1), (A-2) and (A-3), the demand in each period i is represented in the following form :

$$\begin{aligned} X_i &= b_i \; P_i + a_i(t) \\ &= b_i P_i + am_i + av_i * w_i(t) \quad \text{for } i=1,2,\ldots,N \end{aligned} \tag{4.1}$$

where P_i is price in the i-th period, and am_i, av_i, b_i are constants.

The first two terms in this last equation of (4.1) represent the mean demand in period i and wi (t) is a zero mean Gaussian random variable with unit variance representing the random demand fluctuation.

The cost function of the utility is approximated by a quadratic function of outputs x as in the following equation:

$$c(x) = c_0 + c_1 x + c_2 x^2 \tag{4.2}$$

where c_i (i=0,1,2) are positive constants.

Maximizing social welfare leads to conventional marginal cost pricing:

$$PS_i (XS_i, w_i(t)) = 2c_2 XS_i + c_1 \quad \text{for all } i \tag{4.3}$$

The optimal demand is derived as follows:

$$\begin{aligned} XS_i (w_i(t)) &= (a_i + c_1 b_i)/(1-2c_2 b_i) \\ &= [am_i + av_i * w_i(t) + c_1 b_i]/(1-2c_2 b_i) \quad \text{for all } i \end{aligned} \tag{4.4}$$

It can be seen from equations (4.3) and (4.4) that real-time pricing based optimal prices varies with time as demand fluctuates.

4.2 Predetermined Prices: a TOU Rate Model

When transaction costs are considered, it generally will be preferable to aggregate prices over time cycles. Needless to say, it also will be desirable to aggregate prices over customer classes and over service areas. However, I only focus on aggregation over time. Rates here are optimal for a given level of aggregation.

The assumption made here is that TOU rates will accurately predict periodical changes in load pattern; in other words, the load pattern at any given time is a known quantity (with the expectation of random fluctuations). The interaction between the consumer and the producer when price is predetermined as TOU rates is as follows. First, prior to a given period the producer fixes the optimal price for that period i (i=1,.....,N), $PT_i(XT_i^*)$, using the expected value of demand XT_i^*, which in turn depends on the mean of the ideal consumption level ami. Second, the consumer determines a reaction strategy XT_i (PT_i, w_i), knowing this predetermined price and w_i in each period. The process is illustrated in the following.

i-th period:

step 1) $$XT_i^*(w_i(t)) = (am_i + c_1 b_i)/(1-2c_2 b_i) \tag{4.5}$$

step 2) $$PT_i (XT_i^*) = 2c_2 XT_i^* + c_1 \tag{4.6}$$

step 3) $$\begin{aligned} XT_i (PT_i , w_i(t)) &= b_i \; PT_i + a_i(t) \\ &= b_i PT_i + am_i + av_i * w_i(t) \end{aligned} \tag{4.7}$$

From equations (4.4) and (4.7), demand fluctuation under RTP is reduced by a factor of $1/(1-2c_2b_i)$, which is less than one. As marginal cost increases steeply and price elasticity increases, the load leveling effects of RTP is larger.

4.3 A Numerical Example

For TOU rates let N be equal to three. A day is then divided into an on-peak period from 9 am to 5 pm, an off-peak period from 11 pm to 7 am and the remaining hours of the day which constitute the mid-peak period. The important characteristics of pricing schemes are summarized in Table 4-1.

Table 4-1. Main Characteristics of RTP and TOU rates in the Simulation

Characteristics	RTP	TOU rates
Cycle Length	1 hour	1 day
Pricing Period	1 hour	8 hours
Number of Levels	24	3

The correlation between standard deviation of demand x_i and that of ideal consumption level a_i is from equation (4.2).

$$s_{ai}/\ s_{xi} = 1-2c_2b_i \qquad \text{for all } i \qquad (4.8)$$

where s_{ai} and s_{xi} are the standard deviations of a_i and x_i, respectively.

TEPCO Case

Use of a numerical example serves to illustrate load leveling effects of RTP and savings in generation costs. For purpose of this example a Japanese electric power company, Tokyo Electric Power Company (TEPCO) serves as a reference utility. Since very little is known about price elasticities to RTP, I assume that price elasticity to RTP is the same as that to TOU rates in the short run. Daily weekday load pattern and load fluctuations are based on the monthly load curve of a Japanese electric power company in July 1983.

Parameters of the cost function are estimated from the data of the same utility in fiscal year 1977:

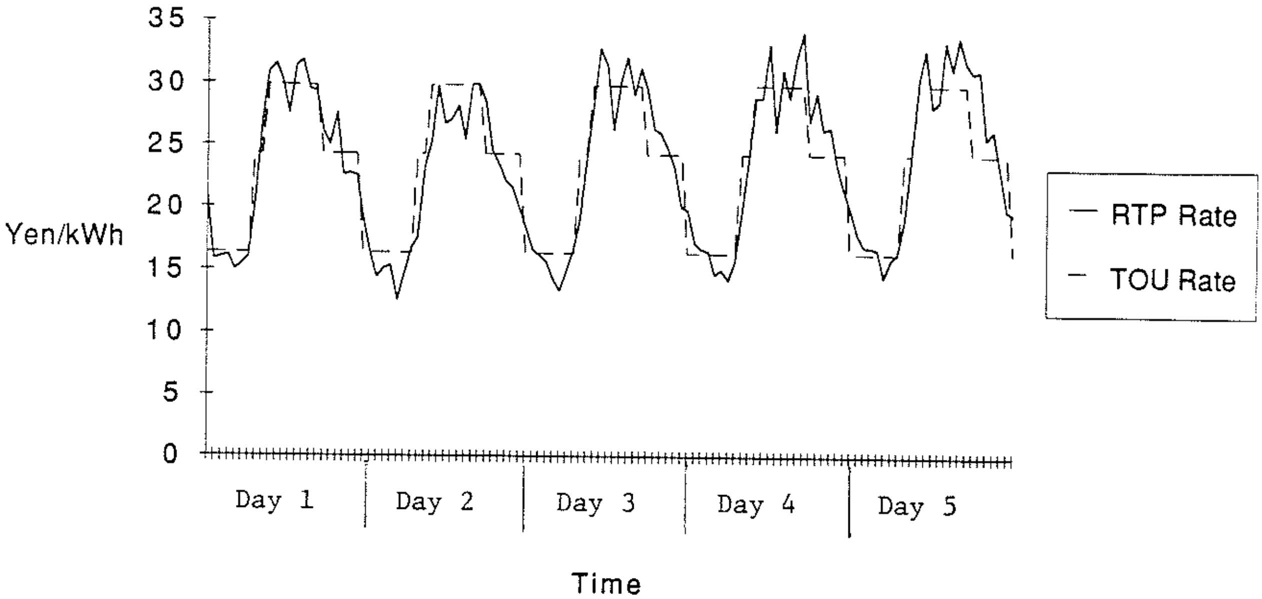
c_0 = 70.36 [Myen/h]
c_1 = 0.1265 [Myen/h/GW]
c_2 = 0.3859 [Myen/h/GW^2] (in 1987 yen)

It is noted that this cost function includes the operating cost but not the investment costs for new facilities constructed in response to increasing demand.

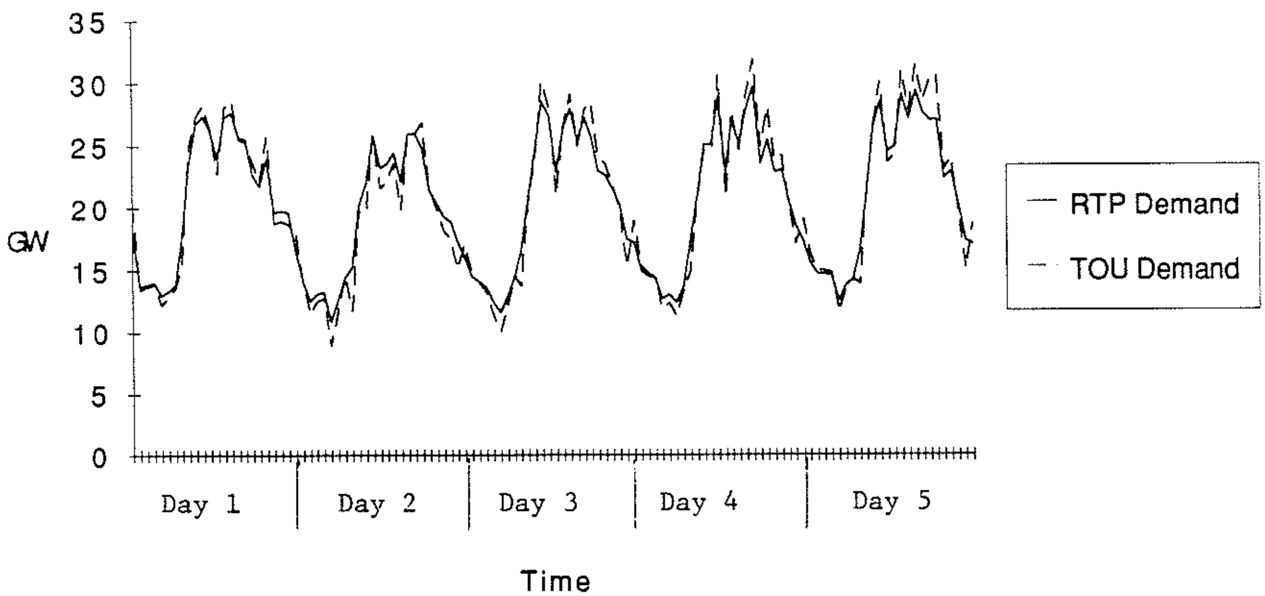
For given fluctuations of ideal consumption level $a_i(t)$, prices and load under RTP and TOU rates are calculated using Monte Carlo simulation. Daily consumption level (i.e., daily kWh) and hourly load fluctuations are simulated. Figure 4-1 shows hourly load and prices for five weekdays under both rates, assuming a price elasticity of -0.6. It is seen from the figure that RTP is effective as a means of load leveling. A five-day load factor under RTP is 68.7 percent, approximately 4.8 percentage points higher than that under TOU rates. However, this effect is not so remarkable since the average daily load pattern is fixed in this simulation.

I also simulated cost gains with respect to TOU rates. Unit cost under TOU rates, i.e., (total generation costs)/(total kWh) was 17.96 yen/kWh in 1987 yen. Under RTP unit cost were decreased by 0.22 yen/kWh or 1.2 percent.

As expected, the effects of load leveling and cost gains of RTP are very sensitive to the price elasticity and load fluctuation. Table 4-2 summarizes results of this sensitivity analysis. As price elasticities are doubled, improvements in load factors are also doubled, and cost gains more than double because of increasing marginal costs ($c_2>0$). Sometimes hourly load of other utilities fluctuates larger, e.g., more than twice. When the randomness of hourly load are doubled, load factors are increased by 1.04 percent, and cost gains double. As the above example illustrates, RTP is very effective in its response to demand fluctuations.



(a) Prices



(b) Electricity Load

Figure 4-1. Prices and Electricity Load under RTP and TOU Rate: TEPCO Case

Table 4-2. Monte Carlo Simulation: Sensitivity Analysis

Case			Price Elasticity -0.3	-0.6
TEPCO	Summer	Mon-Sat*		
Load Factor Improvement[%]**			2.49	4.83
Unit Cost Saving[%]***			0.55	1.21
PG&E	Summer	Mon-Sat		
Load Factor Improvement[%]			5.07	9.63
Unit Cost Saving[%]			0.73	1.52
PG&E	Summer	Mon-Fri		
Load Factor Improvement[%]			4.27	8.27
Unit Cost Saving[%]			0.43	0.98
PG&E	Winter	Mon-Fri		
Load Factor Improvement[%]			2.29	4.39
Unit Cost Saving[%]			0.26	0.52
Adaptiveness of RTP : Hourly TOU vs RTP				
PG&E	Summer	Mon-Sat		
Load Factor Improvement[%]			4.09	7.77
Unit Cost Saving[%]			0.56	1.24

Note)
* Based on load fluctuation from Monday through Saturday
** (LF under RTP)-(LF under TOUP) [percentage points]
*** unit cost=(total cost)/(total kWh)

PG&E Case

Next, I discuss a numerical results of a PG&E case. At first, in order to compare load leveling and efficiency gains of RTP between Japanese and American utilities, a model simulates load fluctuations of PG&E's system from Monday through Saturday in July, 1984.

The following table shows maximum ratios of average to standard deviation of hourly load through monthly load (e.g., monthly load data in July 1984) for each utility:

Utility	Season	Day of Week	S.D./Average [%]
TEPCO	Summer	Mon-Sat	6.3
PG&E	Summer	Mon-Sat	12.9
PG&E	Summer	Mon-Fri	7.5
PG&E	Winter	Mon-Fri	4.2

PG&E's load fluctuations on a hourly basis are larger than TEPCO.

TOU pricing periods in the simulation are defined as follows:

Period	Summer	Winter
on-peak	9-17	7-21
mid-peak	7-9, 17-23	--
off-peak	23-7	21-7

Parameters of the cost function are estimated from the data of the same utility in the summer of 1985:

c_0 = 189.4 [k$/h]
c_1 = 6.21 [k$/h/GW]
c_2 = 2.31 [k$/h/GW^2] (in 1985 dollar)

TEPCO's increasing trend of marginal cost is approximately 20 percent larger than PG&E when assuming an exchange rate of 140 yen/$.

Figure 4-2 shows hourly load and prices for five weekdays under RTP and TOU rates, assuming a price elasticity of -0.6. A five-day load factor under RTP is 68.6 percent, approximately 9.6 percentage points higher than that under TOU rates. Unit cost under TOU rates was 5.04 cent/kWh in 1985 dollar. Under RTP unit cost were decreased by 0.08 cent/kWh, or 1.5 percent.

As in Table 4-2, both load factor improvement and unit cost savings of PG&E case are larger than TEPCO case, mainly due to larger load fluctuations for PG&E's system. However, efficiency gains are not so remarkable since increasing trend of marginal cost is relatively small.

Actually a load pattern of Saturday is similar to that of Sunday for PG&E's system while that of Saturday is similar to that of weekday for TEPCO's system. Therefore, let us simulate load fluctuations of PG&E's system from Monday through Friday.

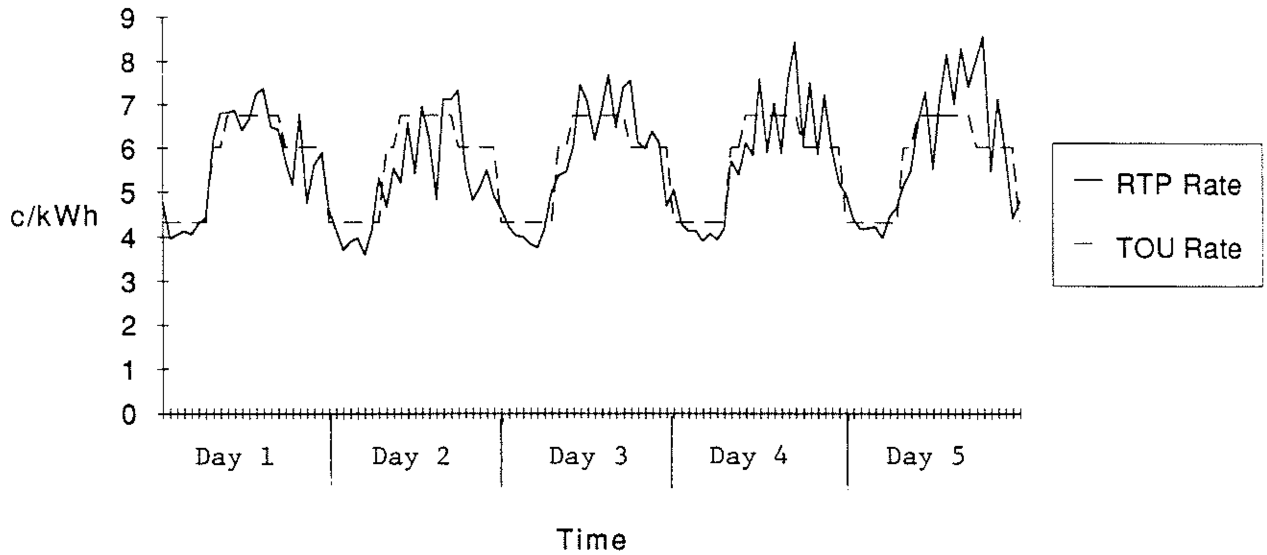
Figure 4-3 shows hourly load and prices for five weekdays under RTP and TOU rates, assuming a price elasticity of -0.6. A five-day load factor under RTP is 68.6 percent, approximately 8.3 percentage points higher than that under TOU rates. Unit cost under TOU rates was 5.02 cent/kWh. Under RTP unit cost were decreased by 0.05 cent/kWh, or 1.0 percent. Basically, these effects of RTP are decreased proportionally to magnitude of load fluctuations, compared the case of Mon-Fri fluctuation with the case of Mon-Sat fluctuation.

Generally speaking, load management effects of RTP might be overestimated judging from only a summer case. I also examine a winter case.

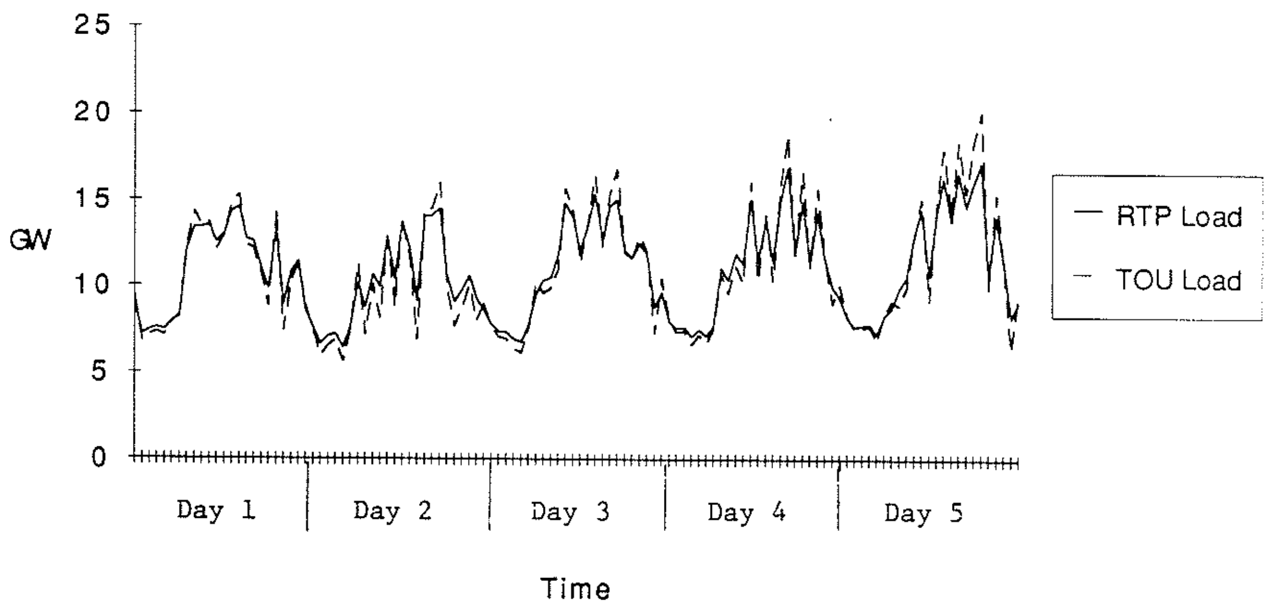
Parameters of the cost function are estimated from the data of the same utility in the winter of 1985:

$$c_0 = 164.1 \text{ [k\$/h]}$$
$$c_1 = 8.09 \text{ [k\$/h/GW]}$$
$$c_2 = 2.41 \text{ [k\$/h/GW}^2\text{]} \qquad \text{(in 1985 dollar)}$$

Figure 4-4 shows hourly load and prices for five weekdays under RTP and TOU rates, assuming a price elasticity of -0.6. A five-day load factor under RTP is 77.5 percent, approximately 4.4 percentage

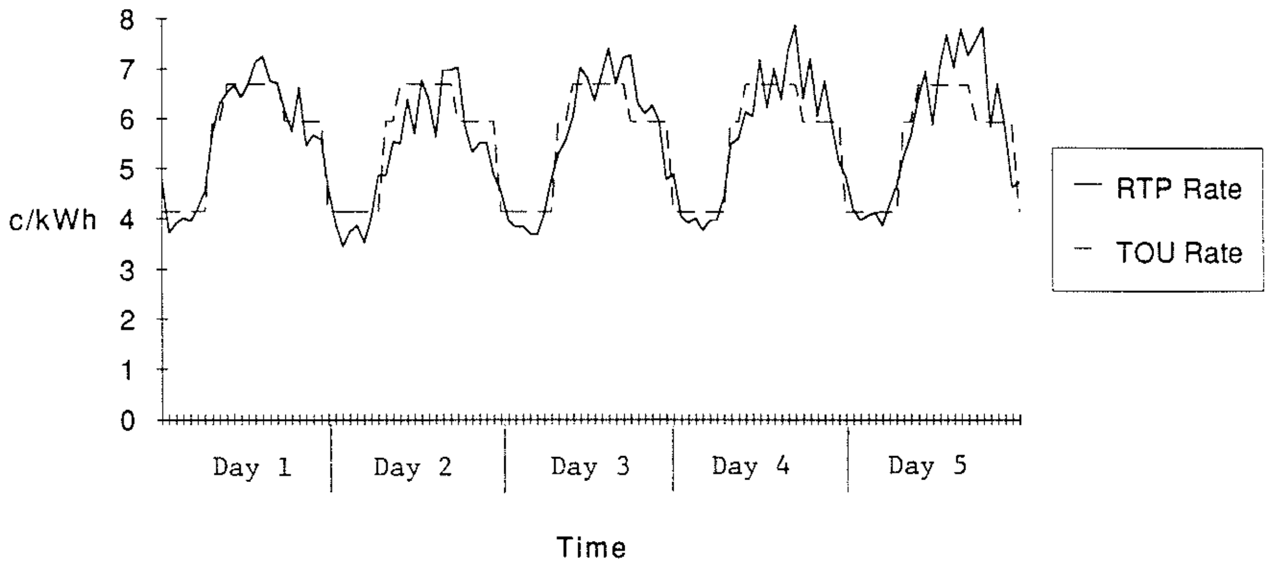


(a) Prices

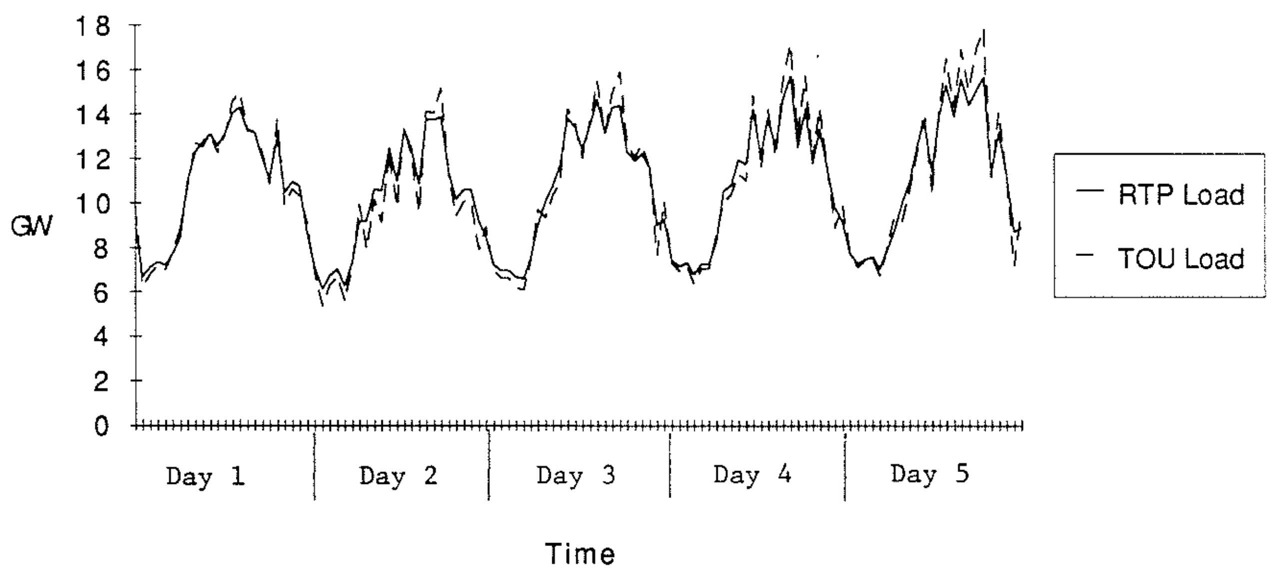


(b) Electricity Load

Figure 4-2. Prices and Electricity Load under RTP and TOU Rate: PG&E Case (Mon - Sat. Load Fluctuation)

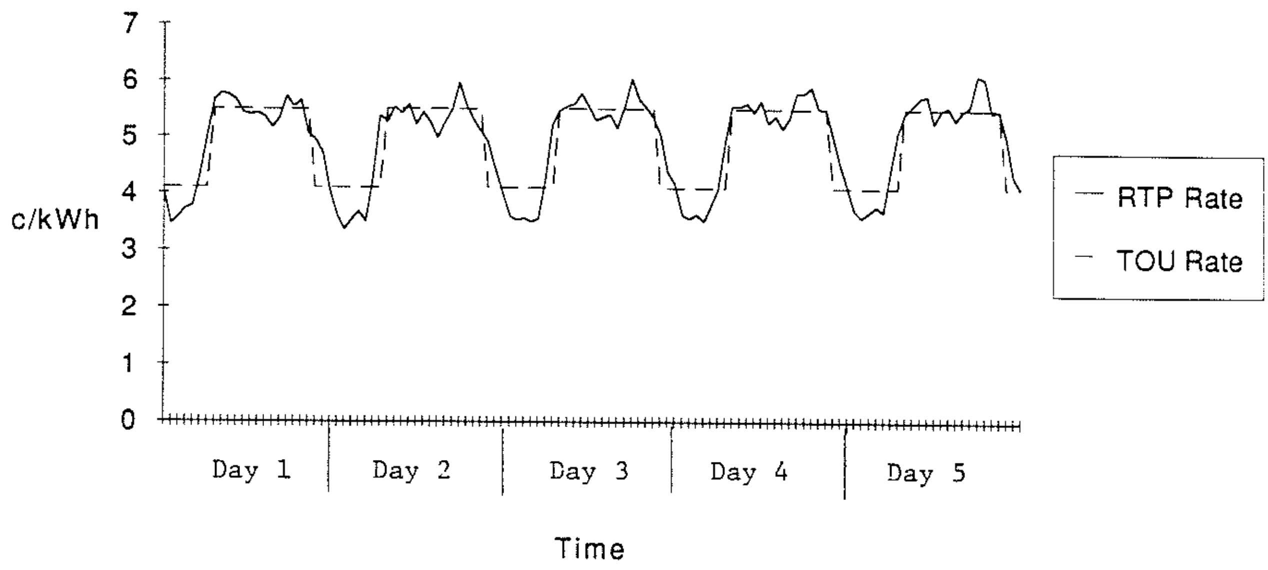


(a) Prices

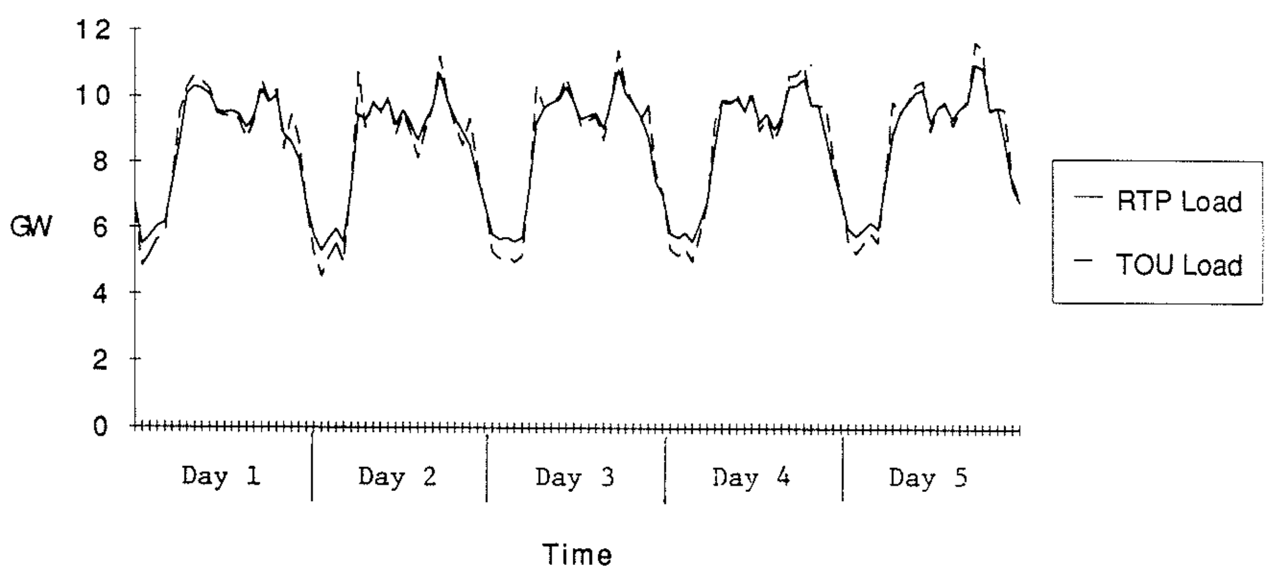


(b) Electricity Load

Figure 4-3. Prices and Electricity Load under RTP and TOU Rate: PG&E Case (Summer Weekday)



(a) Prices



(b) Electricity Load

Figure 4-4. Prices and Electricity Load under RTP and TOU Rate: PG&E Case (Winter Weekday) points higher than that under TOU rates. Unit cost under TOU rates was 4.87 cent/kWh. Under RTP unit cost were decreased by 0.03 cent/kWh, or 0.5 percent. Basically, these effects of RTP are decreased proportionally to magnitude of load fluctuations, compared the winter case with the summer case.

Load Adaptiveness of RTP

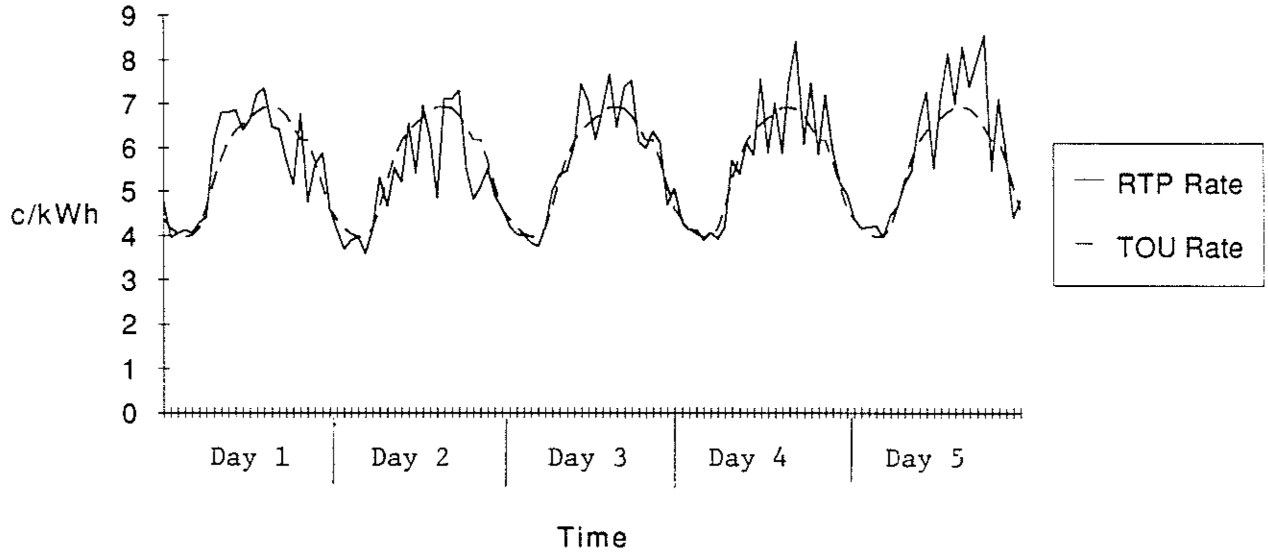
The most important feature of RTP is adaptiveness to random load fluctuations. To examine the comparison between TOU rates and RTP more strictly, the effect attributable to the difference in the length of the daily pricing period should be eliminated. Therefore, I compare hypothetical hourly TOU rate with hourly-updated RTP.

Figure 4-5 shows hourly load and prices for five weekdays under RTP and TOU rates, assuming a price elasticity of -0.6. A five-day load factor under RTP is 63.4 percent, approximately 7.8 percentage points higher than that under TOU rates. Unit cost under TOU rates was 5.04 cent/kWh. Under RTP unit cost were decreased by 0.06 cent/kWh, or 1.2 percent.

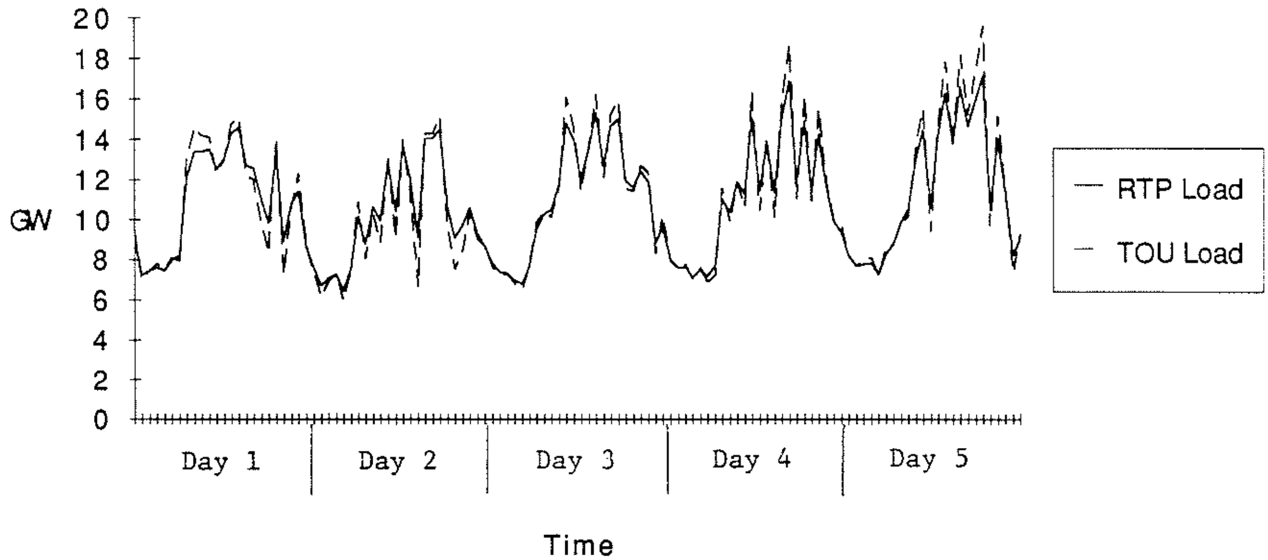
Compared with three period TOU rate (the case of Mon-Sat fluctuation), unit cost savings are :

    77-82 percent due to load adaptiveness and
    23-18 percent due to the difference in the length of the pricing period.

The superior adaptability of RTP to unpredictable fluctuations in demands can be easily recognized.



(a) Prices



(b) Electricity Load

Figure 4-5. Prices and Electricity Load under RTP and TOU Rate: Load Adaptability

5. ESTIMATING THE EFFECT OF REAL-TIME PRICING ON A CUSTOMER'S DEMAND

5.1 Nature of Individual Customer Response

Customers respond to spot prices in two basic ways; modify usage or reschedule usage. Some examples of customer response are:

1) space conditioning: Reset thermostat. Pre-heat or cool at times of low price to make use of a building's thermal storage capability. Use thermal bricks or ice to store thermal energy purchased at times of low prices.
2) water heating: Heat at times of low prices.
3) water pumping: Fill tanks at times of low prices.
4) reschedule production: Reschedule hours of industrial production for processes with high energy usage and low labor cost to times of low prices, assuming sufficient product storage is available.
5) fuel switch: Use electric energy when its price is low and switch to oil or natural gas when the price of electric energy is high.

Main characteristics of industrial response to RTP are summarized as follows:

1) negative initial reaction syndrome
2) response depends on
    - the physical characteristics of the plant
    - the economics of operation
    - the nature of union contracts
    - the management of the company; locally owned or part of a big corporation
    - the character of the work force
    - the location of the plant
3) warning time
4) a very nonlinear function of price
    - threshold effects

5.2 Load Management Effects of RTP on Individual Customer's Load

This analysis has the following objectives:

1) to estimate the effects of RTP on a customer's demand (load management impacts of RTP)
2) to estimate the price sensitivity of a RTP customer

For the following analysis, real data of hourly load and PG&E's A-RTP tariff for a refrigerated warehouse in northern California is used (the data used in the analysis is described in the Appendix). This warehouse participated in the RTP program in January 1988. The customer shows only a short run response to RTP since it has still been on the rate for less than one year. Demand was recorded each 30 minutes under TOU rate schedule E-20S, and hourly under A-RTP. The maximum demand was about 3.5 MW and the electricity consumption amounted to about 1.1 million kWh in June, 1988. This customer's response was not analyzed in Crane (1988).

It is helpful to start with a brief description of the usage patterns of the RTP customer under the 1987 E-20 rates and then under A-RTP. Table 5-1 shows the average usage of the customer during three types of days (workdays, Saturdays, and Sundays and holidays) and the TOU periods for each TOU season. On an average basis, this customer has increased demand in all TOU periods and days in the winter season. On the other hand, it has reduced summer consumption in summer weekends and holidays. It shows an increase in on-peak demand and decreases in partial- and off-peak demand under RTP for summer weekdays. This means that RTP has an adverse effect as a load leveling measure.

The above results characterize the RTP effects on an aggregated TOU basis for each type of day across the seasonal periods. This, however, does not take into account the capacity utilization rate that might not be separated from the effects of the RTP rate.

Next, I look at the percentage distribution of usage within the day. Table 5-2 shows differences in the average workday shares (e.g. the daily on-peak period demand divided by the total daily demand times 100) across the rate within the two season period. The customer shows a significant increase in the summer peak period. In the winter, a 1.3 percent increase in the off-peak share is indicated, with a 1.3 percent demand reduction in the partial-peak period.

Next, the effects of RTP on hourly demand are visualized. Considering the level of economic activity and weather, hourly demand is normalized by the average daily demand. Figures 5-1 and 5-2 show average weekday load patterns under A-RTP and E-20 in the summer and winter, respectively. These figures also present average weekday prices of both rates. Figure 5-1 (b) shows the load management shifts. At first sight it seems an adverse effect because the customer increases daytime demand relatively under A-RTP rate. Figures (c) and (d) show interesting results. They look at a load shift

Table 5-1. TOU Daily Average kWh by Season and Day Type (unit: kWh)

Rate	Season	Day Type	Peak	Partial-Peak	Off-Peak	Total
TOU	Summer	Sat	-	-	31622	31622
RTP	Summer	Sat	-	-	23468	23468
TOU	Summer	Sun	-	-	17049	17049
RTP	Summer	Sun	-	-	16817	16817
TOU	Summer	Week	13969	14863	15384	44216
RTP	Summer	Week	15330	13694	12280	41305
TOU	Winter	Sat	-	-	18506	18506
RTP	Winter	Sat	-	-	27989	27989
TOU	Winter	Sun	-	-	13980	13980
RTP	Winter	Sun	-	-	17294	17294
TOU	Winter	Week	-	17000	10947	27948
RTP	Winter	Week	-	19593	13538	33131

Table 5-2. Differences in Average Workday Percent Shares by TOU Period

	Summer			Winter		
	A-RTP	E-20	Change	A-RTP	E-20	Change
On-peak	36.92	31.33	5.59	-	-	-
Partial-peak	32.82	33.48	-0.67	59.36	60.66	-1.30
Off-peak	30.27	35.19	-4.92	40.64	39.34	1.30

TOU periods of TOU rate schedule, E-20
Summer:
On-peak: 12:00-18:00, Monday through Friday
Partial-peak: 8:30-12:00 and 18:00-21:30, Monday through Friday
Off-peak: 21:30-8:30, Monday through Friday, and all day Saturday, Sunday and holidays

Winter:
Partial-peak: 8:30-21:30, Monday through Friday
Off-peak: 21:30-8:30, Monday through Friday, and all day Saturday, Sunday and holidays

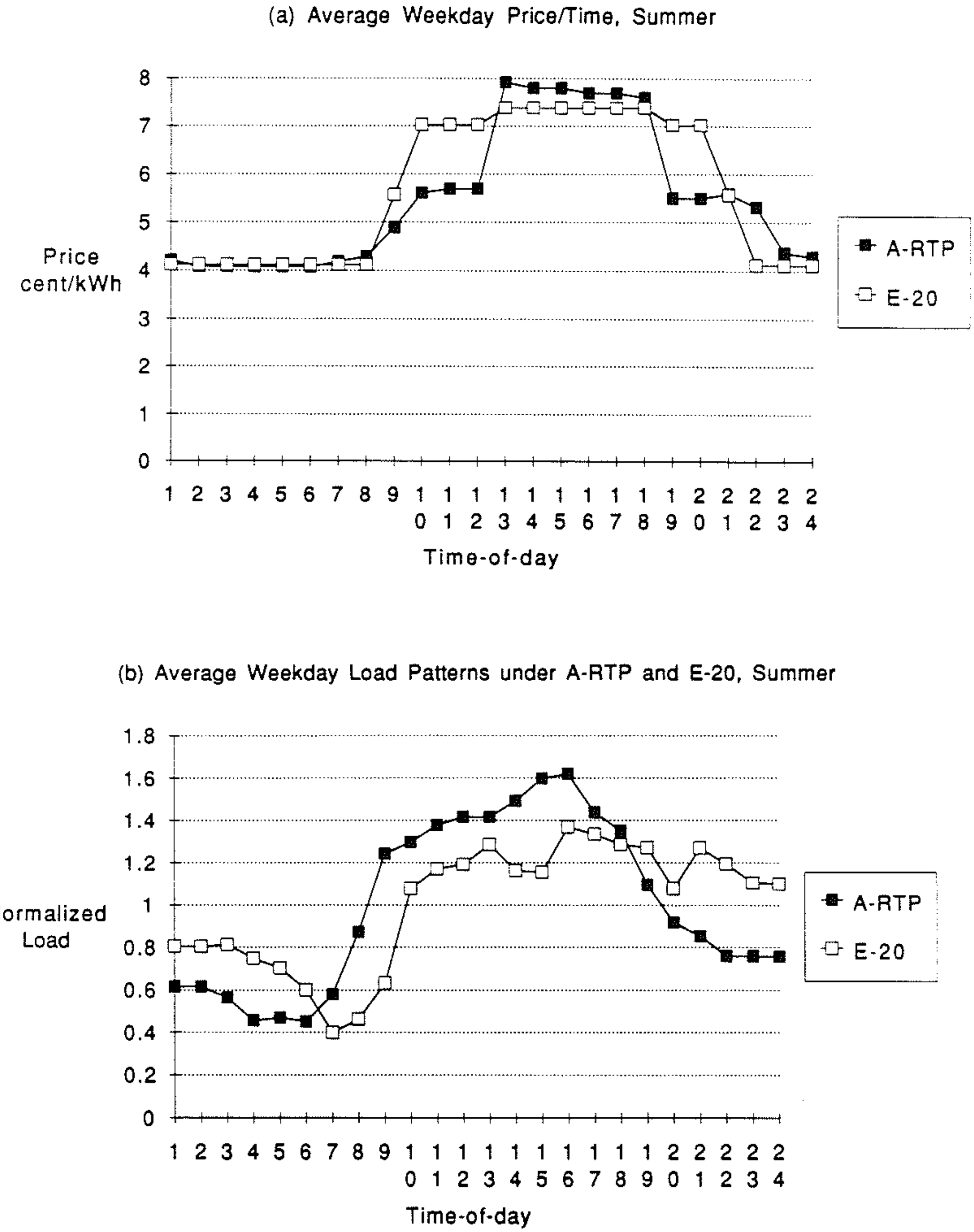
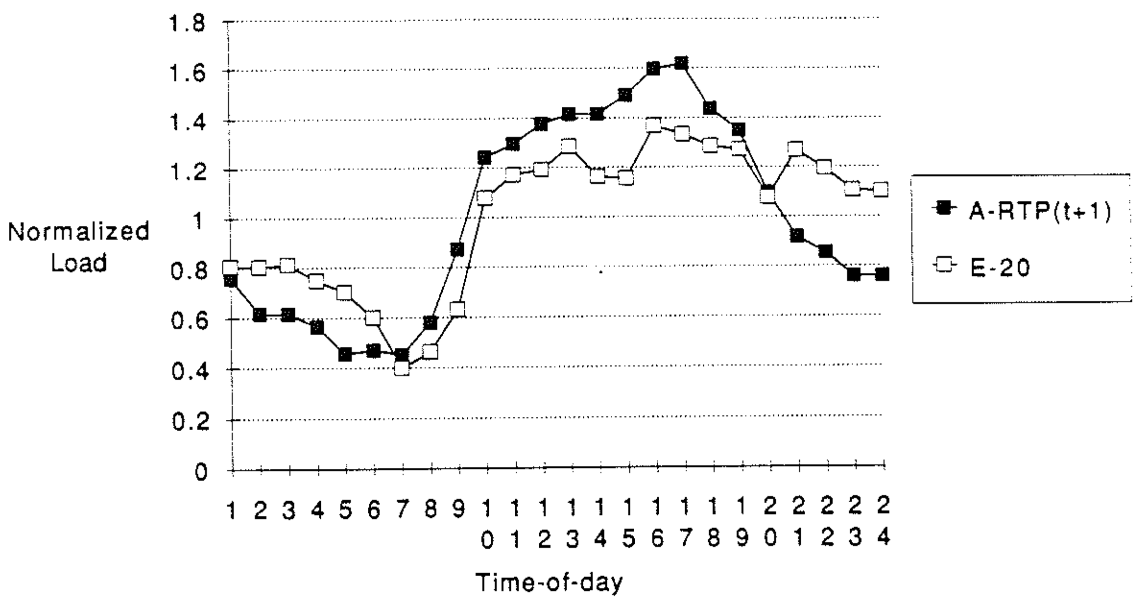


Figure 5-1. Average Weekday Price and Load Pattern in the Summer: Refrigerated Warehouse

(c) Average Weekday Load Patterns under A-RTP and E-20, Summer



(d) Average Weekday Load Patterns under A-RTP and E-20, Summer

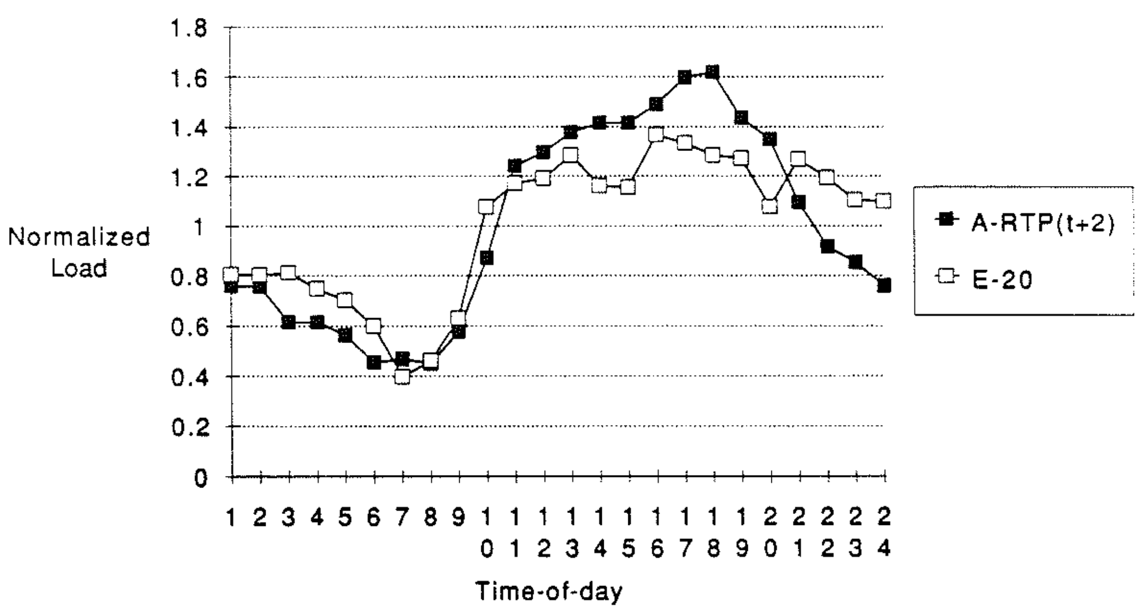


Figure 5-1. (continued)

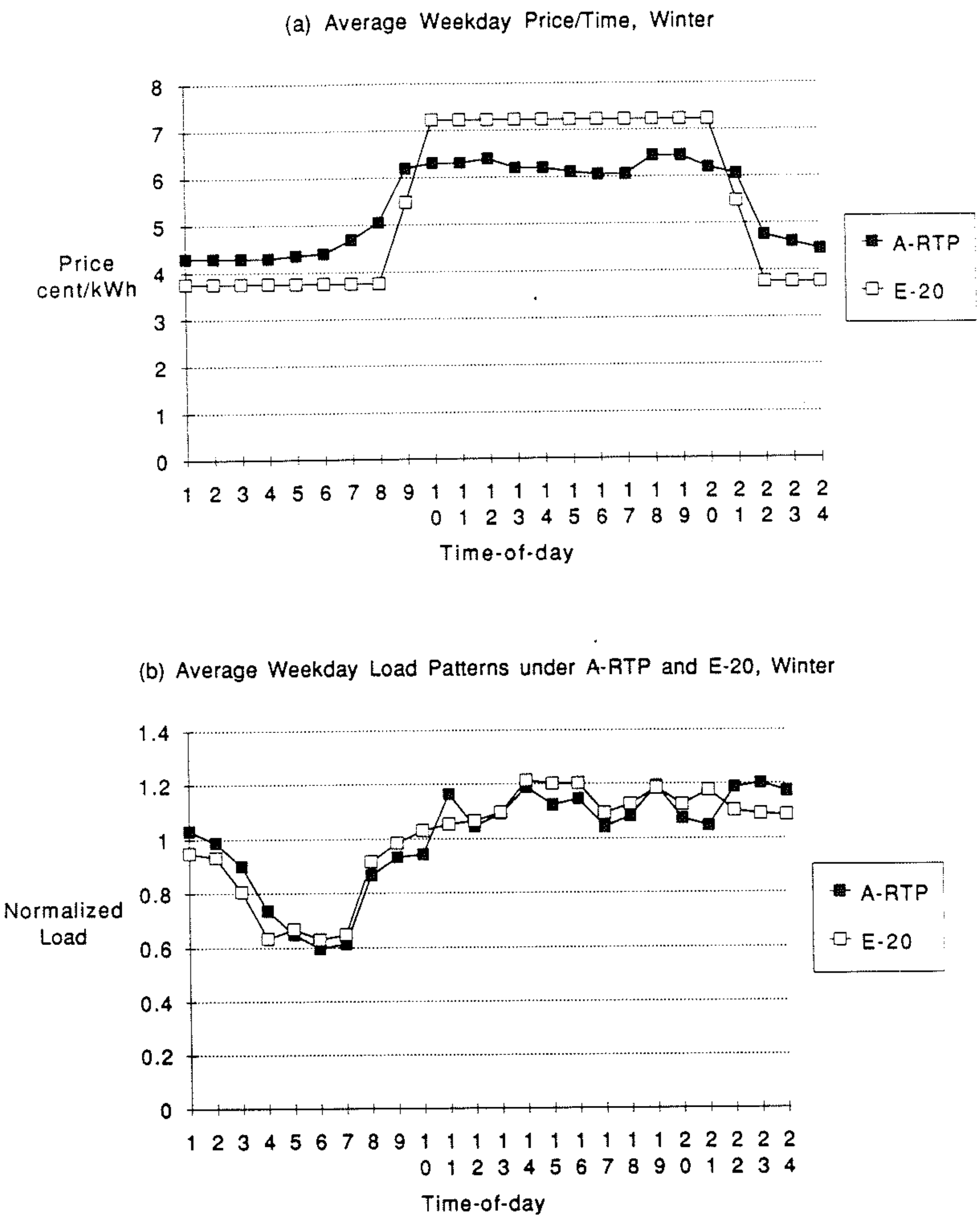


Figure 5-2. Average Weekday Price and Load Pattern in the Winter: Refrigerated Warehouse

of 1 or 2 hours, especially its start-up time (7 to 11 am) under A-RTP. The customer saved its electricity bill of approximately $140 per month or 0.3 percent due to this rescheduling. Figure 5-2 shows a slight increase in off-peak period demand or almost no change under the A-RTP rate.

5.3 Price Sensitivity Estimation

Crane (1988) analyzed load management impacts for two customers, both of whom are considered chemical manufacturers. For both customers, the high prices dispatched during the LMPS operations appear to have been ignored. Apparently they cannot respond to the hourly price variations with short advance notice. Customers report that production and labor commitments also hinder the rapid rescheduling of the production process and/or a shift of production to lower priced periods or days. Both of these factors suggest that a more aggregated analysis of price/demand relationships should be investigated.

Also the production schedules of the customer should be taken into account. Although we do not have customer specific scheduling information, production levels can be inferred from the observed demand profiles. Thus, the daily average price and demand values are computed for two periods of the customer's workday, times when the customer appears to be in production ("Work" periods) and times when production is limited or when the plant is shut down ("Down" periods). These periods are inferred from the customer's seasonal load profile plots for available workdays in 1988.

The production period is defined as 9 a.m. to 7 p.m. for both he summer and winter seasons. To estimate the customer's price sensitivity I use regression analysis to relate the daily ratio of the Work to Down period average real-time prices to the corresponding ratio of Work to Down period average daily demands. This relationship is investigated for both the summer and winter periods since real-time prices are radically different during these times and the customer price sensitivity might be different across these two pricing regimes.

The model is:

$$\ln RD = a + b_1 \ln RP_1 + b_2 \ln RP_2 \qquad (5.1)$$

where:
RD=ratio of daily demand in the Work to the Down periods.
RP_1 =ratio of daily price in the Work to the Down periods in summer (5/24/88 to 6/17/88).
RP_2 =ratio of daily price in the Work to the Down periods in winter (11/22/88 to 12/16/88).

The resulting elasticities are presented in Table 5-3. The summer elasticity is significant but has the wrong sign. The positive elasticity observed is a natural result of operating during the day when prices are higher than in the evening and off-peak periods, because they cannot stop operation of the compressors for cold storage during on-peak period in summer. On the other hand, the winter elasticity shows the correct negative sign, but seems a little too large for a short-run elasticity.

Table 5-3. Estimated Effect of Price Ratio on Demand Ratio: a Refrigerated Warehouse

	Coefficient	t-ratio
Constant	0.217	1.44
Summer Price Effect	0.764	2.03
Winter Price Effect	-0.941	-1.53

R^2(adjusted) = 59.5 %

Next, let us look at other customers' elasticities which were measured in Crane (1989). Analysis of the average seasonal load profiles indicates that four customers tend to have constant load levels, which translates to a Down time of zero. The resulting elasticities for the remaining 11 customers are presented in Table 5-4. Analysis has shown a negative trend in seasonal price elasticities, indicating that customers tend to respond to the hourly price changes. The refrigerated warehouse analyzed above corresponds to customer O in Table 5-4. The difference in price elasticities may be attributed to different ranges of data.

Table 5-4.

ESTIMATED EFFECT OF PRICE RATIO ON DEMAND RATIO

Customer	Constant(a)	Summer Price Effect(b)	Winter Price Effect(b)
A(c)	-	-	-
D	0.144	0.147(d)	-0.156(d)
E	0.227	-0.027	-0.179(d)
H	0.642	-0.068	-0.364(d)
I	0.427	-0.435(d)	-0.200(d)
J	1.050	8.682(d)	-4.742(d)
K	0.219	0.006	-0.127(d)
L(c)	-	-	-
M(c)	-	-	-
N	0.613	0.001	-0.126(d)
O	0.384	-0.083	-0.113
P	0.285	-0.182(d)	0.001
R	0.598	0.081(d)	-0.468(d)
S(c)	-	-	-
T	0.134	0.020	-0.075

(a) Represents the natural log of the average ratio of the WORK time demand to the DOWN time demand. A value of zero indicates no difference in average daily demand in the WORK and DOWN time. A positive value indicates a ratio greater than one (i.e., more consumption in the WORK time), a negative value a ratio less than one (i.e., less consumption in the WORK time).

(b) Represents the natural log of the average change in the WORK/DOWN demand given a one unit change in the WORK/DOWN price ratio for the specified season. A negative value indicates that a customer tends to respond to price changes.

(c) These customers' average seasonal load profile indicate constant load levels. Thus, WORK/DOWN ratios cannot be calculated since the DOWN time is zero.

(d) Significant at the 0.05 confidence level or less.

6. CONCLUSION

Experience with real-time utility rates is growing. In this report three major RTP experiments in place at PG&E, NMPC, and SCE are reviewed. The experience to date with RTP has been positive. Those rates which have been most effective have been for larger industrial and commercial users where economic incentives play a larger role. It is notable that commercial sector enterprises such as a food distribution center, a commercial laundry and a large office building with an energy management system, have responded more to hourly price signals than large process industries.

An attempt has been made to estimate the potential efficiency gains and price sensitivity of a customer to RTP. First, I examined the advantages of RTP when compared with TOU rates due to the superior adaptability of spot pricing to unpredictable fluctuations in demand over time. As marginal costs increase steeply and price elasticities increase, the load leveling effects of RTP are larger. The results of a simple Monte Carlo simulation demonstrate the following:

1) RTP is very effective in its response to demand fluctuation. For example, for PG&E case load factor under hourly RTP is 68.6 percent, approximately 9.6 percentage points higher than that under TOU rate (with three pricing periods). Unit generating costs were reduced by about 1.5 percent under RTP.
2) The effects of load leveling and cost gains of RTP are very sensitive to price elasticities and load fluctuations. As price elasticity and randomness of hourly load increase, improvements in load factors and cost savings resulting from RTP increase.
3) When unit cost savings under RTP are estimated in comparison with three-period TOU rate and hourly TOU rate, cost savings are :
   77-82 percent due to load adaptiveness and
   23-18 percent due to the difference in the length of the pricing period.

The second objective of this report is to estimate the effects of RTP on a customer demand and the price sensitivity of a RTP customer using real hourly load and RTP tariff data for a refrigerated warehouse. The resulting price elasticities seem unrealistic. This detailed study is limited to only one customer. More engineering and economic data samples are needed. These responses are short-term. A necessary condition for customers to make capital investments is that utility and regulatory commission make a firm commitment to the establishment of a RTP program. Unless such a commitment is made, customers will be very reluctant to make capital investments. Nonetheless, an RTP rate design brings substantial savings to customers even if they do not respond to RTP by making appropriate long-term investments. Actually, as a marketing strategy the utility can offer RTP to customers who have access to alternative power sources to keep them on its system.

As more RTP programs are offered, customer responses will provide additional data, particularly over the longer term, as customers make the capital improvements necessary to participate fully in RTP. The remaining obstacles to be solved are development of hardware and software to administer RTP programs, customer education, and the development of agreements with regulators on appropriate rate design.

7. FUTURE RESEARCH

RTP is one of the most important research fields in demand-side management for not only U.S. utilities but also for Japanese utilities. During this survey of the U.S. RTP projects and preliminary evaluations of an RTP system, I identified several issues that required additional research. These issues are as follows:

Theoretical Issues:

1) how to determine the appropriate frequency of price updates or the pricing cycle length for residential, commercial, and industrial customer class.
2) RTP vs reliability-differentiated service.
3) development of a process model for microscopic evaluation of customer responses to RTP.
4) impact of RTP rate design on self-generation.

Practical Issues:

1) reliable measurement of price elasticities.
2) prespecified price scenario vs real-time price updating.
3) a forecast of real-time prices and notification of customers.
4) experimental design issues: e.g., controlled vs uncontrolled experiments; volunteer vs mandatory participation.
5) how to recruit participants for an RTP program.
6) how to integrate an RTP program with other existing demand-side programs.

In Chapter 5 of this report, only one case study was conducted because of a lack of availability of actual RTP experimental data. A comprehensive study analyzing customer response to RTP should include many case studies. A better understandings of these issues, both theoretical and practical, will make more effective introduction of RTP programs into the electricity market possible.

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APPENDIX DATA USED IN CHAPTER 5

Location

The warehouse and processing facilities are located in a 18-acre tract of land situated in an area of the Salinas Valley in northern California which is predominantly agricultural.

Building Profile

Business: Freezer/storage facility

Area: 136,300 sq. feet, combined freezer storage and equipment space

Production

Major production technology: Ammonia refrigerating processing for vegetables

Total production:100 million pounds.

Products: packaged vegetables; pea, cauliflower, broccoli, carrots, strawberry, etc.

Freezing Facilities

Thirteen hundred tons of low temperature (-45 ~ 0 F) refrigeration is available for quick freezing product.

- five individual quick freeze belts
- four plate freezers
- twenty freeze tunnels
- four freezer rooms (total storage capacity=2.9 million ft^3)
- a precooling facility

Hours of Operation

24 hours per day

Electricity Consumption

Total annual purchased power is about 12 million kWh. They have no alternative options for electric power supply. Electricity costs occupy about one-third of total production costs. Estimated percent of existing use is 92 percent for refrigerating including cold storage, 5 percent for lighting, and 3 percent for miscellaneous use.

RTP Data

The warehouse participated in A-RTP tariff of PG&E in January, 1988. Due to highly electricity intensive process, they are very sensitive to electricity costs. However, they did not respond to TOU rates very well because its TOU periods are too broad to adjusts timing of production processes. Hourly price changes in RTP made it possible for them to adjust a start time of freezing. As a result, they saved about 18 percent of electricity costs under A-RTP tariff, compared with conventional TOU rate schedule, E-20.