REAL-TIME PRICING IN CALIFORNIA

R&D ISSUES AND NEEDS

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CHAPTER 1
MARKET-BASED PRICING OF ELECTRICITY

1.1 INTRODUCTION

Real-time pricing strategies offer both the promise of giving customers greater control over their energy costs and mitigating generators' market power. This scoping study has been conducted to identify the R&D issues dealing with real-time pricing of electricity in California. It examines the costs and benefits of real-time pricing from an economic perspective, and is comprised of five chapters. These chapters contains the following types of information:

A summary of existing research on alternative rate designs (Chapter 1)

A review of the status of real-time pricing programs in the US and abroad, with an emphasis on lessons learned from their application (Chapter 2)

A discussion of barriers to the successful implementation of real-time pricing (Chapter 3)

An assessment of the role of enabling technologies in boosting participant impacts (Chapter 4)

A summary of what is known and what is unknown about real-time pricing, to facilitate the development of an R&D agenda by the Commission's PIER program (Chapter 5)

In this chapter, we review alternative types of market-based pricing options, including real-time pricing, under traditional regulated market conditions and under restructured market conditions. We also compare the key features of the CEC's real-time pricing proposal, with its emphasis on two-part pricing, with the proposals put forth by two of the three investor owned utilities in California, which are based on a one-part design. This chapter sets the stage for Chapter 2, which surveys utility experiences with real-time pricing.

1.2 WHY MARKET-BASED PRICING?

While difficulties have been encountered in California's transition to a fully restructured market, the fundamental motivation for electric restructuring remains valid. Once the current transitional difficulties are resolved, and the industry begins its movement toward restructuring, electricity pricing will move from cost-of-service pricing to market-based pricing. Cost-of-service pricing cannot be sustained in a competitive market, since it fails to recognize that different customers may derive very different values from consuming the same amount of electricity.

Market-based pricing provides a rational and efficient way for balancing the demand and supply of electricity. There extensive literature on this topic, dating back to a seminal piece by M. Boiteux published in French in 1949.. In recent discussions on what went wrong in California, both Robert Wilson and William Hogan bring out the need to implement efficient pricing practices.[1]

Given the significant hour-to-hour and day-to-day variation in electricity demand, it is likely that either the power system would need to keep excessive reserves to prevent blackouts from occurring, or customers would have to be prepared for coping with blackouts. Several times during 2001, California's Independent System Operator had to resort to blackouts. Blackouts are a very inefficient way of rationing customer demand, since they affect all customers equally, regardless of the value they place on electricity. A vast literature on the value of service indicates that customers are often willing to pay several times the amount they normally pay per kWh in order to retain power. Table 1-1 summarizes the recent literature on the subject.

Table 1-1
Value Of Service Estimates
Dollars per kWh Unserved

	Residential	Commercial	Industrial	Agricultural	System
PG&E[2]	2.87 to 5.57	9.01 to 19.14	1.6 to 19.14	1.13 to 8.99	
SCE[3]	.53 to 21.92	2.56 to 266.18	N/a	N/a	
SDG&E[4]					19.21
EPRI[5]					4 to 50

EPRI estimated that the annual cost of outages for California businesses ranges between $12 billion to $18 billion dollars.[6] The corresponding cost to the US economy ranges between $104 billion and $ 164 billion.

Technological limitations prevent electricity from being stored economically in large quantities. Notes Borenstein, "storage of electricity is extremely costly and capacity constraints on production from a plant cannot be breached for significant periods of time without risk of costly damage."[7] In a regulated market, cost-of-service pricing is the norm, and rates are typically averaged over the entire year. In some cases, rates may be designed to reflect the hour-to-hour variations in cost of service, and show some diurnal or seasonal variation that reflects *expected* variations in hourly or seasonal costs.

[1] See the Bibliography in Chapter 6 for detailed citations to these three papers.
[2] PG&E (draft), "Value of Service and Benefit-Cost Ratio Calculations in Probabilistic Planning", October 1999, page 11.
[3] SCE, "Customer Value of Service Reliability Study," March 1, 1999, Appendix F, pages 81-82.
[4] SDG&E, "Application for Authority to Provide Customers with Real-Time Energy Meters," December 13, 2000.
[5] EPRI, *The Western States Power Crisis: Imperatives and Opportunities*, An EPRI White Paper, June 25, 2001.
[6] EPRI's Consortium for Electric Infrastructure for a Digital Society (CEIDS), "The Cost of Power Disturbances to Industrial and Digital Economy Companies," July 29, 2001.
[7] Severin Borenstein, "The Trouble with Electricity Markets (and some solutions)," PWP-081, University of California Energy Institute, January 2001.

However, even then, they will not exhibit unanticipated volatility. In a restructured power market, wholesale market prices reflect hourly (and sometimes half-hourly) market conditions, and display considerably greater price volatility. This makes electricity markets "especially vulnerable to supply/demand mismatches due to the extreme inelasticity of supply and demand."[8] Thus, price volatility has to be accepted as a natural occurrence in restructured power markets.

The occurrence of this phenomenon the past two years in California has also been in a variety of restructured power markets over the past decade. The other markets include Australia, Canada (Alberta), New Zealand and the United Kingdom (England and Wales). In the England and Wales market, the pool spot price (PSP) has displayed tremendous variability, even over very short time horizons. During 1991 to 1995, the maximum ratio of the highest to lowest PSP within a day was 76.6. Within a month, the ratio was 107.5, and within a fiscal year it was 117.8.[9]

While *wholesale* price volatility is a natural occurrence in restructured markets, most customers do not want to face volatile *retail* prices for electricity. This finding has been confirmed in a variety of customer surveys that EPRI has conducted since 1997. Thus, there is an opportunity for competitive energy service providers (ESPs) to offer customers a menu of retail pricing products— letting the customers choose products that best match their risk-taking (and risk-avoiding) preferences. This would represent a win-win outcome for both the creative ESPs and their customers, since the ESPs would be able to gain a larger market share and profit margin by superior product differentiation, while the customers would be shielded from price risk.

Some of these products would feature guaranteed prices that may be fixed year round, or vary seasonally and by time of day. Others would feature guaranteed prices for most hours of the year, but allow prices for a few hundred hours to be based on real-time, spot market conditions in the wholesale power market. Finally, some products would feature prices that vary in real-time, year round. Customers with flexible patterns of power usage would select price structures that vary by hour, hoping to secure a lower power bill for the year as a whole. However, some customers may be risk averse, and may wish to limit their price exposure. To limit customer price exposure, ESPs may sell a price cap to customers. In some cases, the cap may be financed by placing a price floor, essentially creating a price collar. In other cases, it may simply be sold as an insurance premium. This would be analogous to the pricing of adjustable rate mortgages in the deregulated banking industry. The development of caps, floors and collars involves the use of financial derivatives, and forms part of the new discipline of financial engineering.[10] Many of these products have already been tried out in gas markets, where marketers and

[8] Ibid.
[9] Robert H. Patrick and Frank A. Wolak, "Using Customer-Level Response to Spot Prices to Design Pricing Options and Demand-Side Bids," in Ahmad Faruqui and Kelly Eakin, editors, Pricing in Competitive Electricity Markets, Kluwer Academic Publishers, 2000
[10] For an introduction, see John C. Hull, **Options, Futures and Other Derivatives**, Prentice Hall, 1997.

brokers have a history of developing customized gas procurement solutions for their customers.[11]

1.3 MENU OF PRICING OPTIONS[12]

A comprehensive menu of pricing products would consist of the following choices:

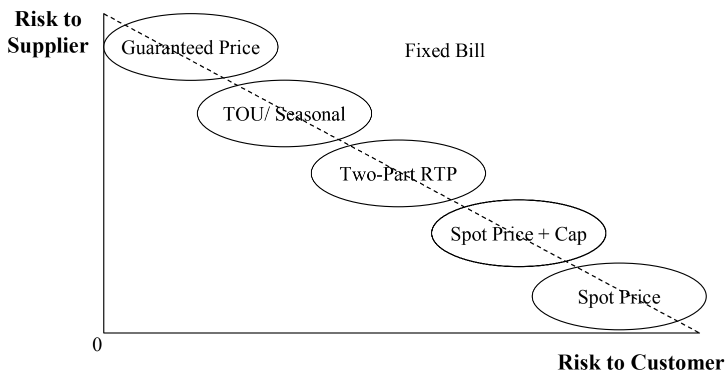
- Guaranteed prices year-round for unlimited purchases of electricity
- Guaranteed prices by season and/or time-of-day for unlimited purchases of electricity
- Guaranteed prices for a block of electricity, expressed in the form of a forward contract
- Discounted and guaranteed prices year-round, with the possibility of curtailment or interruption of service for a certain number of hours, under pre-specified conditions and trigger points
- Coincident peak pricing for unlimited quantities of electricity, where the prices in all tiers except a critical tier vary by time-of-day in a pre-determined fashion; very high predetermined exist in the critical tier, where timing is not specified *ex ante.*
- Spot pricing, with caps and floors, for unlimited quantities of electricity
- Spot pricing for all days of the year; however, the customer buys an option to be excluded from facing spot prices during a few days when critical business conditions prevent modification of baseline schedules[13]
- Two-part pricing, with an access charge for predetermined baseline quantity usage, often specified on a customer-specific basis; there are also spot prices for variations from the baseline
- Spot pricing for unlimited quantities of electricity, often called one-part real-time pricing

Each of these products has different and opposite risk implications for the suppliers and buyers of electricity. For example, in the family of guaranteed pricing products, buyer risk is minimized and supplier risk is maximized. The opposite holds true in the family of spot pricing products. Reflecting this concept of risk sharing, these products can be arrayed along a risk exposure frontier, where supplier risk is shown on one axis and buyer risk on another axis. See Figure 1-1.

[11] Melanie G. Mauldin, "Retail Risk Management: Pricing Electricity to Manage Customer Risk," *The Electricity Journal,* June 1997, pp. 78-83.
[12] For methodology and case studies, consult the papers in Ahmad Faruqui and Kelly Eakin, **Pricing in Competitive Electricity Markets**, Kluwer Academic Publishing, 2001.
[13] A utility case study of this concept, based on the experience of UtiliCorp United, is discussed in Bruce Chapman et al., "Hedging Exposure to Volatile Retail Electricity Prices," *The Electricity Journal*, June 2001, pp. 33-38.

Figure 1-1

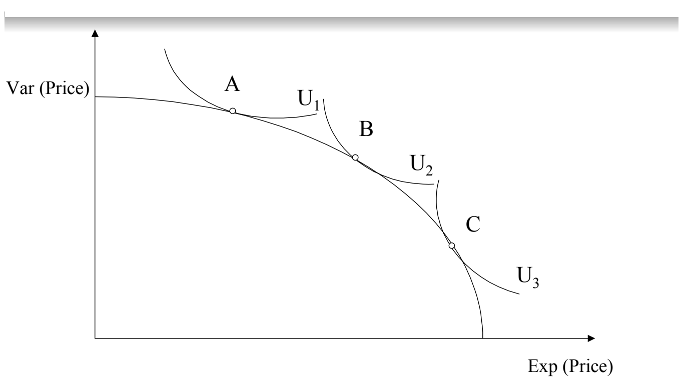
Risk Differentiated Pricing Products



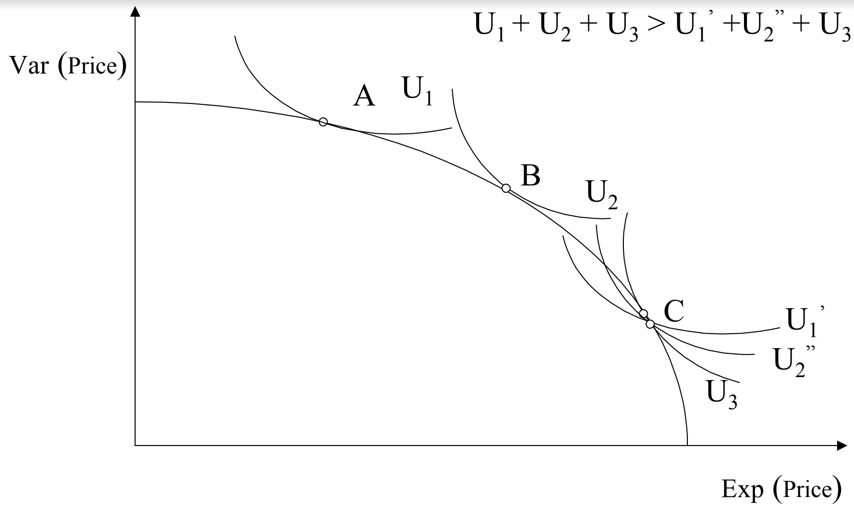
In the real world, there are multiple buyers, and the risk exposure frontiers shown in Figure 1-1 would need to be specified by market segment. A menu-based approach makes sense whether the market is restructured or traditional. By giving customers a choice of pricing products, it maximizes efficiency in consumption. Consider a market where customers have three types of risk-taking preferences: one group is risk taking, another group is risk neutral, and a third group is risk averse. If only a single type of product is offered to all three types of customers, every customer would be either worse off, or no better off, compared to a situation where three different products are offered with varying degrees of price exposure. A graphical example, based on the concept of indifference curves is shown in Figure 1-2.

Figure 1-2

The Efficiency of Market-Based Pricing



The Inefficiency of Uniform Product Pricing



The axes in Figure 1-2 plot both the expected price of electricity and the variance in the price of electricity. The top panel deals with the efficiency of market-based pricing, and offers three different products: Product A has the highest variance of price and the lowest expected price; Product C has the lowest price variance and the highest expected price; Product B is in between. Type 1 customers are risk taking, and choose product A; Type 3 customers are risk averse, and choose product C; while Type 2 customers are risk neutral, and choose product B. The satisfaction levels enjoyed by customers in each type, when they are able to choose products that best match their preferences, are represented by U1, U2 and U3.

Contrast this situation where only a single product, Product C, is offered to all customers. This is a situation of uniform product pricing. All customers are forced to consume this product. Since the product best matches the preferences of Type 3 customers, they are able to attain the same satisfaction level as in the case of market based pricing. However, since Product C does not equally match the preferences of risk-taking Type 1 customers, and risk-avoiding Type 2 customers, they are forced onto lower indifference curves, and are worse off than before.

In a traditional, regulated market, the menu-based products would be offered by a vertically integrated utility. For example, as discussed in Chapter 2, Georgia Power and Duke Power have offered several of the items discussed above to a wide range of customer segments. In addition, the Tennessee Valley Authority, a federal generation and transmission authority that sells power in seven states in the southeastern United States, has offered several menu-based options to its wholesale and retail customers. The provision of real-time pricing in a traditional market provides two major benefits. First, it lowers peak-period power usage, improves system load factor, and lowers the average cost of providing power to all customers. Second, it becomes an instrument of customer retention and economic development, by lowering the year-round cost of electricity to participating customers.

In a restructured market, the vertically integrated utility is replaced by a regulated utility distribution company (UDC) and several competitive energy service providers (ESPs). During a transition period to full competition, the UDC is typically required to offer default service.[14] To maximize the appeal of restructuring to all classes of customers, state regulators have often required the UDC to sell default electricity service at a guaranteed price that is discounted by five to fifteen percent relative to a historical benchmark value.[15] Wherever this has been done, ESPs have found it very difficult to attract customers by selling alternative pricing products to them, since the riskiest product for suppliers—guaranteed pricing—is being offered at a discount by the UDC to customers who do not switch, when it should really be offered at a premium.

All customers who choose not to switch to competitive ESPs can buy power from the UDC on the terms of the default service. Thus, the default service product, which is provided below market, cannibalizes all other products. Customers do not switch, since they can lower their bills by simply doing nothing. If wholesale prices rise above historical levels, the UDCs are forced to absorb the difference. This results in their bankruptcy, and may also be accompanied by the state taking over the function of provider of last resort.

A research issue needs to be addressed here:

- Is it infeasible to implement real-time pricing in a restructured power market, when the UDC is providing default service at a fixed price that is discounted off a historical value, thereby cannibalizing any new products that may be offered by ESPs?

Under normal conditions, the UDC would have no incentive to retain existing customers or to acquire new ones. Thus, it would not typically use RTP as a marketing tool, unlike the vertically integrated utilities in a regulated market. However, since it still needs to ensure that its costs are covered, RTP may be the best method of providing default service. Customers would then be free to shop around for a wide range of price protection or risk management products from the ESPs.[16]

Another research question arises here:

- Should default service be provided on a real-time pricing basis?

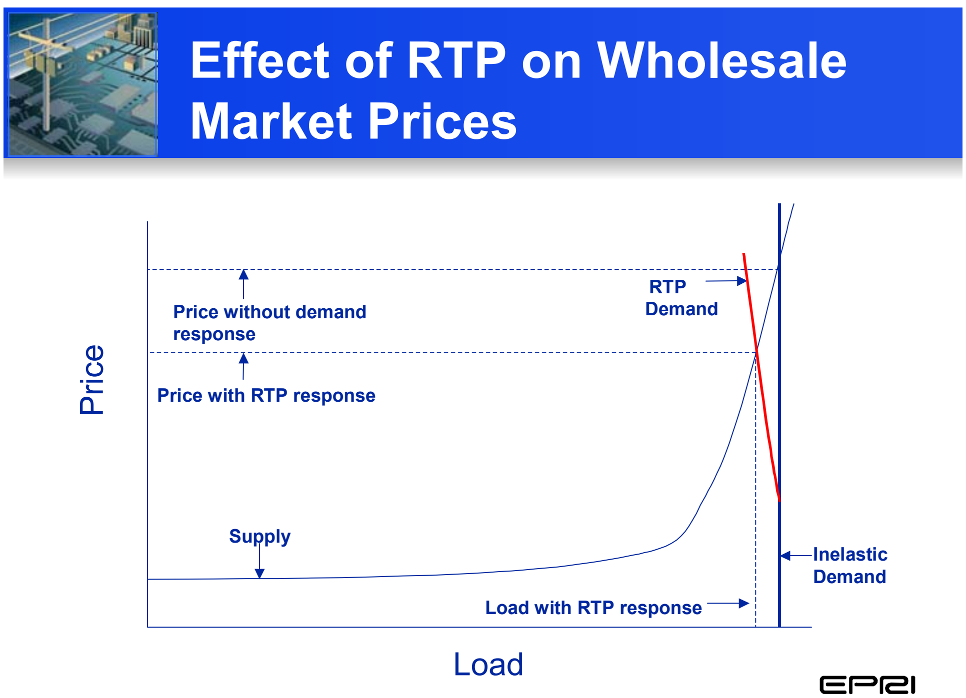
New product designs—that bundle commodity electricity with risk management—would be offered. The more creative ESPs would add other product features to the transaction,

[14] The exception is the state of Texas, where the UDCs are simply the providers of distribution services and default service is awarded through a bid process to independent providers; retail electric providers (REPs) serve as the competitive energy service providers.
[15] Laurence D. Kirsch and Rajesh Rajaraman, "Assuring Enough Generation: Whose Job and How to Do It," *Public Utilities Fortnightly*, April 15, 2001.
[16] At various times, the ESPs may be joined by the independent system operator (ISO) and or power exchange (PX) in providing risk management products.

such as energy efficiency, premium power quality, and digital load management, further enhancing their uniqueness to various customer segments.[17] By expanding the market space, real-time pricing would thus become a gateway to an entirely new world of innovative product design.

Unlike the retail competition in the past two years in California, where scores of ESPs were forced out of the retail marketplace by poor financial performance, this would represent a triple win situation (win-win-win) situation for the UDCs, ESPs and customers.[18] In addition, the presence of real-time pricing would help reduce wholesale power costs and price volatility, benefiting all customers—not just those on RTP. This is shown in Figure 1-3.

Figure 1-3



It is important to note that one does not require "large" elasticities of demand to obtain this benefit, unlike the hypothesis put forth by Paul Krugman. As noted by Patrick and

[17] There is evidence that such integrated practices have been implemented by providers such as Enron for the very largest customers.
[18] For a discussion of why ESPs have failed to accrue profits, see Ahmad Faruqui, "When Will I See Profit?" *Public Utilities Fortnightly*, July 1, 2000.
[20] Robert H. Patrick and Frank A. Wolak, "Using Customer-Level Response to Spot Prices to Design Pricing Options and Demand-Side Bids," in Ahmad Faruqui and Kelly Eakin, editors, *Pricing in Competitive Electricity Markets*, Kluwer Academic Publishers, 2000.

Wolak, "even the smallest half-hourly within-load-period own-price elasticities of demand can imply significant load reductions in response to price increases."[20]
Finally, a very important benefit of real-time pricing is that it serves to mitigate market power. If suppliers know that the market demand curve is perfectly inelastic, they have an incentive to bid prices that exceed their costs of production, leading to a phenomenon known as the "last man bid" problem in the auction design literature. The market-clearing price exceeds the price that would have prevailed under competitive market conditions. During June-November 1998, the market-clearing price in California exceeded the competitive price by about 22%.[21] An earlier study of the England & Wales market had found that generators were bidding at about 50% above short-run marginal costs.[22] Real-time pricing, by introducing elasticity in the market demand curve, would force suppliers to set their price bids at their costs, since otherwise they would risk losing market share. This benefit has been demonstrated at EPRI through the use of a software package, Power Market Simulator.

1.4 RECENT DEVELOPMENTS IN CALIFORNIA

The California Assembly passed a bill, AB 29X, allocating $35 million in General Fund tax revenues for installation of real-time meters on the premises of all customers with a demand in excess of 200 kW. The CEC expects that about 22,000 real-time meters will have been installed or upgraded by October 2001, affecting approximately 30% of peak demand in the state.[23] This would pave the way for implementation of real-time pricing in the state. Anticipating this development, the CEC filed a real-time pricing tariff with the CPUC in June.[24] This tariff was modeled after the approach pioneered by Georgia Power Company in the 1990s. Using a two-part design, Georgia Power was able to attract 1,600 customers to real-time pricing, and to achieve a peak demand reduction of up to 17% on critical days. The CEC tariff design adds a voluntary RTP supplement to a customer's base tariff. The base tariff computation stays unchanged; the RTP tariff applies to the deviations of the customer's actual load from a frozen baseline load. In response to the CEC's filing, the three investor-owned utilities in California filed their proposed real-time pricing designs. We were able to access information on two of these proposals.

San Diego Gas & Electric Company (SDG&E) has proposed a hybrid rate design that combines time-of-use pricing with real-time pricing.[25] Customers would be billed on a

[21] Severin Borenstein, James Bushnell and Frank Wolak, "Diagnosing Market Power in California's Deregulated Wholesale Electricity Market," University of California Energy Institute, PWP-064, Revised, August 2000.
[22] R. A. Brealey and C. Lapuerta, "A Report on Generator Market Power in the Electricity Market of England and Wales," The Brattle Group, London, cited by Derek Bunn, Christopher Day and Kiriakos Vlahos, "Understanding Latent Market Power in the Electricity Pool of England and Wales," in Ahmad Faruqui and Kelly Eakin, editors, *Pricing in Competitive Electricity Markets*, Kluwer Academic Publishers, 2000.
[23] Michael R. Jaske and Arthur H. Rosenfeld, "Developing Demand Responsiveness in California's Energy Markets," 76th Annual WEA Conference, July 2001.
[24] "Petition of the California Energy Commission for Modification of Decision 01-05-064 By Proposing a Real-Time Pricing Tariff," June 21, 2001.
[25] "San Diego Gas & Electric Company's Real-Time Pricing (RTP) Proposal," August 17, 2001.

pre-specified TOU rate schedule most of the time; during critical (but not emergency) conditions, customers would be billed on a one-part real-time price. However, to minimize sharp fluctuations in customer bills, the RTP would not be based on the hourly market price. Instead, it would be a blended price, derived by averaging short, medium and long-term contracted prices with hourly market prices. The rate would only apply to the commodity portion of the customer's bill, and would initially be offered on a voluntary basis. SDG&E calls for the development of an external price signal, from the California Department of Water Resources, and suggests that instead of developing this price signal on a service area basis, it may be appropriate to work with a single, statewide signal. However, this might obscure important local and regional differences in power prices, created by transmission congestion. In addition, the utility suggests that the real-time pricing signal should not be employed during emergency conditions, when the supply curve is almost vertical. This is counter intuitive, since the biggest benefit of real-time pricing is likely to flow during such emergency conditions.[26]

SDG&E's proposal is similar in spirit to the concept of occasional real-time pricing discussed earlier, and reflects the utility's concern that customers are not ready for full-time real-time pricing. The utility states "pure real-time pricing has many drawbacks if technology is not readily available to allow electric end-users to instantaneously respond to real-time transmitted price signal." There is an implicit statement that customers do not have the means for responding in real-time to higher (or lower) prices. However, this statement merely recognizes the "Catch 22" nature of the market place: enabling technologies are not installed on the customer's premise because appropriate real-time pricing structures that would make them economic do not exist.

The digital revolution has created many new technologies that allow demand to be rescheduled in response to higher prices, by turning off lower priority circuits. When such technologies are installed on customer premises, higher response rates have been observed. Georgia Power and other utilities have found that *some* customers do respond significantly to real-time pricing, even though most customers do not respond at all. EPRI's StatsBank database contains the response estimates for about a thousand customers who have been on some type of real-time or time of use pricing. It provides ample evidence on observed customer response. The specific role of enabling technologies in boosting response is developed further in the Task 4 report.

SDG&E's proposal should be viewed as a transitional, rather than terminal arrangement where the ultimate goal is to facilitate customer choice among a menu of pricing products. As noted by SDG&E, "the possibilities are endless once interval meters are installed and a dynamic hybrid rate structure is implemented."

Pacific Gas & Electric Company (PG&E)'s proposal specifies four daily pricing schedules, all of which are fixed and known ahead of time. The off-peak schedule applies to holidays and weekends. The other three schedules-- called low, medium and high—feature 24 hourly prices that are designed to reflect market prices during

[26] Steve Braithwait and Ahmad Faruqui, "The Choice Not to Buy," **Public Utilities Fortnightly**, March 15, 2001.

progressively tighter demand-supply balances. PG&E will tell customers on a day-ahead basis which of the three schedules will in effect on the following day, and the customers will have an opportunity to modify their usage pattern. The rates embody a one-part design. There are limits on how many times each of the day types would be invoked.

PG&E's concept is similar to the approach used by EdF, in France for its residential customers. EdF is a winter-peaking utility, operating in a traditional, vertically integrated market. All residential customers have a one-way communication device in their homes, in the form of a red bulb. During peak conditions, the red bulb is activated, and the customer knows that electricity prices during the next day will be substantially higher than during normal days. There is a limit to how many days will be red bulb days.

Like SDG&E's proposal, PG&E's concept is a transitional step toward preparing customers for real-time pricing. In some ways, it is less dynamic than SDG&E's proposal, and is thus further removed from real-time pricing. Both utilities advocate the use of one-part designs rather than two-part designs, since they are concerned that the development of customer baseline loads (CBL) can be gamed by the customer. For example, the customer may choose to set the CBL at a higher than "normal" level, in order to avoid being exposed to really high real-time prices. However, a higher than normal CBL would also mean that the customer would not be able to benefit from lower than average prices. Since access to lower prices is the primary reason why a customer will choose to go onto a real-time price, SDG&E's concern about gaming may be misplaced. In addition, as discussed in Chapter 2, there is a national trend toward two-part designs.

What is noteworthy about these two proposals is that they deal with the commodity portion of the electricity rate, even though both utilities are pure utility distribution companies and are no longer in the commodity marketing business. The utilities are behaving as if they are power marketers. As an alternative, the UDCs would be limited to providing default service, where they simply resell the commodity at its real-time price, in the form of a one-part RTP. This would make them financially whole. Customers would then have the option to either (a) buy default service and pay for power on a real-time basis, or (b) hedge their price exposure by buying risk- management services from ESPs.

A research issue arises in this context:

- How should the state deal with the simultaneous existence of a variety of market-based load curtailment programs and real-time pricing? For example, one of the demand response programs currently being offered by the California Independent System Operator (ISO) pays customers a reservation payment of $20-kW/month and $500/MWh curtailed during system emergencies. Should customers who volunteer to be on this program also be allowed to receive service on a real-time basis? Would this constitute double dipping? Or would it be a cost-effective way of obtaining additional load shifting without having to make any additional investment in control technologies?

CHAPTER 2
SURVEY OF RTP PROGRAMS

2.1 INTRODUCTION

RTP programs have been around for over 15 years, and over 30 utilities have implemented some type of program, though many of these have been experimental. Despite the obvious benefits of RTP, and the experience with these programs, relatively few utilities have sizable RTP programs. To understand the major lessons learned from real-time pricing experience to date, we reviewed articles, conferences, and industry publications on RTP. We then supplemented our findings by interviewing staff at seven utilities with programs of interest.

This chapter begins with a discussion of the major lessons learned by utilities with experience in real-time pricing. These lessons address the following issues:

- Do customers respond to RTP? Are some types prone to responding more than others?
- Why do customers join real-time pricing programs?
- What do customers like and dislike about the programs?
- How do utilities feel about RTP programs?

The second section provides in-depth information on seven utility RTP programs. In particular, it provides background on each program, information on the rate structure offered in each program, and the major lessons learned by each utility. The seven utilities included in this section are BC Hydro, Duke, Georgia Power, TVA, PG&E, Edison, and UtiliCorp. Of these, PG&E was chosen both because it was the first utility to offer RTP, and because it is one of the major California utilities that still offer RTP. Edison was selected both because it is in California, and because it has a large RTP program. TVA, Duke, and Georgia Power were also selected because they have some of the largest real-time pricing programs. UtiliCorp was selected because we knew they had some innovative offerings. BC Hydro was included in the study because we knew that, at one time, customers were purchasing power on their RTP rate, and currently, there is little interest in the program. We wanted to know what had happened, and what lessons could be learned from this experience.

2.2 LESSONS LEARNED FROM RTP PROGRAM EXPERIENCE

Our survey found several reasons utilities offer real-time pricing programs. Most of the early programs were offered primarily to experiment with reducing peak load, (e.g., PG&E, Niagra Mohawk). By the early 1990s, utilities were beginning to offer RTP not only to gain a valuable load management resource, but also to increase their competitiveness, sell excess off-peak power, and encourage off-peak load growth. In the U.K., companies began offering customers access to half-hourly market prices at this time. More recently, U.S. utilities are offering RTP with the additional motivation of helping themselves and their customers learn about market-based prices.

Most of the early RTP programs—those offered in the 1980s—offered one-part RTP tariffs. More recently, the trend has been toward two-part tariffs. Our survey even found that some of the utilities that had originally offered one-part rates were later interested in adding two-part RTP.

Interestingly, we found that utilities learned similar lessons from their RTP experiences, regardless of their initial program goals, or of their rate structures. The major lessons learned are listed below, and explained in further detail in the rest of this section.

Major Lessons Learned from RTP Programs

- RTP programs can offer significant load shifting benefits, but most of the load response comes from relatively few customers.
- Certain types of customers are more likely to respond to RTP.
- A variety of customers can respond to prices.
- Customers join RTP to save money.
- Customers do not like unmitigated price volatility.
- RTP programs have revenue stability issues for utilities as well as customers.
- With two-part RTP rates, utilities and customers often prefer simpler CBLs.
- RTP programs have been successfully combined with interruptible programs.
- Education is key for successful RTP programs.

Lesson One: RTP programs can offer significant load shifting benefits, but most of the load response comes from relatively few customers

Most utilities report that customers on RTP programs pay attention to prices, and shift in response to price. For instance, one utility staff member we spoke with gave examples of peak load shifts of 15-20% or more (Duke), and most others spoke of "significant" load shifts. Detailed data on the magnitude of price responsiveness is available in "Electricity Customer Price Responsiveness—Literature Review of Customer Demand Modeling and Price Elasticities," prepared for the CEC by Christensen Associates, September 29, 2000.

Most utilities also report that most of their load shifting comes from a relatively small group of customers, and that many customers do not shift load at all. Midlands Electricity reported shifting by a "minority" of customers,[27] and Georgia Power and TVA representatives supported this in interviews. Duke found that it has roughly the same response this year with 59 customers as it did last year with over 100, because it was the

[27] King, Kathleen, "The Impact of Real-Time Pricing: Evidence from the British Experience," *Proceedings: 1994 Innovative Electricity Pricing*, EPRI TR-103629, 257-267. At the time of the study, all of the customers on Midlands Electricity's rate were 1 MW or larger.

non-price-responsive customers who dropped off the rate. At UtiliCorp, the representative we spoke with noted that only three of their 14 customers did any “significant” shifting. Some utilities found almost no customers were shifting. Edison’s representative reported that its customers had to be allowed to drop off their market-based RTP program after PX prices shot up, because the customers did not know how to shift BC Hydro had a similar response: with roughly 25 customers on the rate, only one ever really shifted load, and that customer could not sustain the shifting.

Studies at Midlands Electricity and Niagra Mohawk also find that, even among price responsive customers, response can vary significantly over time[28]. Presumably, customers have more scheduling flexibility at some times than at others.

Lesson Two: Certain types of customers are more likely to respond to RTP

Based on both our literature search and discussions with utility representatives, it appears that certain types of customers are more likely to respond to real-time pricing. Specifically, the following groups of customers have repeatedly been shown to be more responsive:

- Customers with on-site generation,
- Customers with noncontinuous (discrete) production processes, and
- Customers who have previously been on interruptible rates.

These customers groups have either previously displayed scheduling flexibility (as with interruptible customers), or have the means to adjust their electric needs in response to price. Among the customer types with these characteristics—who are also price responsive— are paper manufacturers, metals/steel customers, chemical companies, and universities.

Lesson Three: A variety of customers can respond to prices

Several of the utility representatives we surveyed said that customers with incentives to shift loads would find innovative ways to do so. Therefore, RTP programs should not exclude customers simply because they are not in the groups most likely to respond to prices. Our survey respondents mentioned that office buildings and grocery stores were among their price-responsive customers. One respondent even mentioned that a hospital was price responsive: this particular hospital changed its chiller use in response to hourly prices.

Lesson Four: Customers Join RTP to Save Money

One theme that clearly came through our survey was that customers join real-time pricing programs to save money. While it may seem obvious that customers with rate choices would choose rates in their best interests, it is also true that customers joining an RTP program have certain expectations about the rate-producing savings. This appears to be true even for customers who do not plan to shift load significantly in response to price

[28] Ibid.

variation. Thus, when the overall level of RTP prices (not just the price volatility) increases, customer satisfaction with the program decreases. In some cases, customers return to embedded cost-based rates in response to higher overall prices. For example, Duke had over 100 customers on their program last year and—after a period of high prices—now has 59. Similarly, all of BC Hydro's customers dropped off their RTP program within a year after market prices increased.

The finding that customers join RTP programs to save money, and are generally satisfied with the programs if they are saving enough, also holds true with residential customers. EDF in France has over 120,000 residential customers on a simplified RTP rate, and surveys there show that customers join the rate, and are satisfied with it, because of bill savings. (EDF has spent a significant amount of time finding customers "suitable" to the rate—e.g., those with the ability to shift and save money as well as offer peak reductions.) A survey of commercial and industrial customers at PG&E, Edison, Virginia Electric Power Company (Vepco), and Niagra Mohawk also indicated that bill savings, as well as the related "control over costs," was a major reason for joining RTP programs.[29]

While not as well documented, the implication that RTP programs have free riders, which join to save money, is also an issue. Edison brought forth this issue because its one-part rate was designed to be revenue neutral with its TOU rate. Since one-part rates are often designed to be revenue neutral for the class as a whole, they have "winners" and "losers"; e.g., customers who can switch to RTP and expect to save money without necessarily shifting load. Edison believes this happened with its rate, and cites that customers on its market-based rate did not seem to know how to respond to prices (because they had not planned to shift) when PX prices increased significantly. As a result, the utility ended up allowing customers to move back to the TOU rate, despite the fact that customers had a contractual obligation to remain on the RTP rate.

Even customers who can, and do, respond to prices become less satisfied when the overall level of prices increases. In Georgia, for example, when prices increased on average by one cent per kWh, customers went to the utility and the Commission requesting relief. The rate was modified slightly to lower hourly prices for these customers.

Lesson Five: Customers do not like unmitigated price volatility

Not surprisingly, studies find that customer satisfaction with RTP programs increases if they perceive limits on their price risks.[30] There are obvious reasons for this: greater price volatility can lead to higher bills. This is true even for price-responsive customers, because they may have periods when their response is constrained. For example, a manufacturer might not be able to postpone production because of the need to meet a large customer's schedule. Or the manufacturer might have already postponed for several

[29] Mak, Juliet C., and Bruce Chapman, "A Survey of Current Real-time Pricing Programs," *The Electricity Journal*, August/September 1993, page 62.
[30] Christensen Associates, *Real-Time Pricing QuickStart Guide*, published by EPRI, TR-105045, August 1995, page 24.

days in response to high RTP prices, and not be able to postpone further. To use a simple residential example, EDF notes that, while customers on the RTP rate generally postpone laundry and other domestic chores on high-priced days, if three high priced days come in a row, customers—especially those with young children—may have to do their laundry and other chores despite high prices.[31] Thus, if a summer has particularly high prices, even customers who generally shift may find few hours to shift to, and may experience high bills and a high level of dissatisfaction.

To protect against such situations, many utilities have integrated some type of risk mitigation into their RTP programs. For instance, Vepco's program (which had a menu-type RTP rate) had an upper limit on the number of high-priced days and a minimum number of low-priced days. Survey respondents said that this risk-mitigation feature increased the likelihood of their participation in the program..[32] A study at Long Island Lighting Company also found that limiting risk was likely to increase program participation.[33]

To limit price risk for its RTP customers, Southern California Edison limits their RTP-2 program's highest priced hour to $3.00 per kWh. In the U.K., customers can purchase contracts for differences that essentially provide them with fixed prices over a specific period of time.

In part to reduce customer exposure to extreme price volatility, most U.S. utilities developing recent RTP programs are developing two-part RTP rates. These rates allow a portion of customers' loads to be protected from price volatility. TVA, a federal utility that has had a one-part rate for 15 years, is now developing a two-part rate to offer its customers more risk protection. Some utilities with two-part RTP rates also offer risk-protection products similar to those offered in the U.K. These products are intended to provide customers with relief, in the event that high prices coincide with periods in which their ability to shift is limited. These products generally apply to a specific period of time, and the utilities that offer them still offer incentives to reduce load during high-cost hours.

Lesson Six: RTP programs have revenue stability issues for utilities as well as customers

Because RTP programs incent decreased usage during high-priced hours, utilities face the risk of under-collecting revenues from RTP programs. This is particularly true with one-part rates, which generally include fixed costs in the hourly energy price. According to two utility experts, "Experiences from some of the pilot (RTP) programs have shown that it is actually not hard for utilities to lose money on RTP." They go on to imply that

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[31] Cubille, J. and P. Valentin, "*tempo* Customers: Their Reaction to a New Tariff Option," presented at the Unipede Conference on Customers and Markets, Lisboa, June 1998, section 3.3.
[32] Mak, Juliet C., and Bruce Chapman, "A Survey of Current Real-time Pricing Programs," *The Electricity Journal*, August/September 1993, page 62.
[33] Takos, Yannis, Mitchel Horowitz, and Ellen Ford, "Gauging Customer Acceptance for Various Real-Time Pricing Configurations," *Proceedings: 1994 Innovative Electricity Pricing*, EPRI TR-103629, 138-144.

the reason most RTP programs are still "experimental"— and permanent ones often have very few customers on them— is partly due to revenue stability issues.[34]

Two of the utilities we spoke with, Duke and Georgia Power, both mentioned that they chose two-part RTP rates partly because they have lower risk of under-collecting fixed costs. Duke also chose to apply its "incentive margin," the adder to provide a contribution to fixed costs, only on net incremental (vs. decremental) energy to help avoid this problem. Other utilities with two-part rates, such as UtiliCorp and Public Service of Oklahoma, use variable adders, which tend to result in smaller adders being paid to customers for conservation than those paid by customers for incremental use. These adders address this revenue stability concern.

Lesson Seven: With two-part RTP rates, utilities and customers often prefer simpler CBLs

Both Georgia Power and Duke, which have some of the oldest and most successful two-part RTP programs in the country, began setting customer baseline usage with 8,760 hour load profiles. Both utilities have moved to simpler CBLs for most customers. The utilities report that they believe the simpler CBLs are appropriate for most customers, and that customers tend to find them less confusing.

Lesson Eight: RTP programs have been successfully combined with interruptible programs

Several utilities have successfully combined interruptible programs with RTP programs. In some cases, such as TVA, the utility's RTP rate applies only to interruptible power. While high prices alone would in theory incent customers to decrease load at critical times, the interruptible nature of the power ensures that TVA has a certain load-management resource. More typically, utilities allow interruptible customers on RTP programs, and require them to interrupt to the level of firm demand during interruptible periods. Customers not interrupting may have to pay a penalty for non-compliance in addition to purchasing energy at the hourly price. Some utilities offer customers an option to buy energy during interruption periods, but they reduce the size of the interruptible discount for customers choosing this option.

Typically, utilities offer interruptible customers RTP because these customers have demonstrated an ability to shift load, and may be able to provide valuable price response during periods of high prices that are outside interruptible periods. None of the utilities offering interruptible customers RTP felt that RTP negatively impacted response from the interruptible rate, or other similar rates. As one respondent explained , "the rates are so different; interruptions only occur a few times a year, [but customers can respond to prices every hour]."

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[34] Weisbrod, Glen, and Ellen Ford, "Market Segmentation and Targeting for Real-time Pricing," *Proceedings: 1996 EPRI Conferences on Innovative Approaches to Electricity Pricing*, EPRI, TR-106232, 14-1.

Lesson Nine: Education is key for successful RTP programs
Georgia Power's representative reported that the single most important lesson the utility learned from its almost decade-old RTP program is that customer education is the key to a successful program. Our source also reported that customers need to be educated repeatedly for a couple of reasons: First, there is turnover at companies, so the person best understanding the RTP program might not be there in the future. Second, customers tend to not focus on RTP when prices are low, and begin to pay attention again as prices increase. To address its educational needs, Georgia Power holds annual, statewide meetings with its RTP customers. The meetings are well attended, and the utility believes the education program has definitely paid off in terms of customer satisfaction.

2.3 FINDINGS ON SELECTED UTILITY PROGRAMS

This section summarizes our discussions with representatives of seven utilities about their RTP programs. The seven utilities were selected based on our review of literature, and reflect a variety of RTP program experiences. Two of the utilities, PG&E and Edison, were selected for two reasons; they are both major California utilities, and they were among the first utilities in the country to offer RTP. TVA, Duke, and Georgia Power were selected because of their sizable programs. BC Hydro was chosen because all its customers have dropped off its program, and we were interested in what lessons it had learned from its experience. UtiliCorp was selected because we knew it offered several innovative features in its program. All of these utilities have permanent RTP programs, except for PG&E, which has an experimental program.

Table 2-1 shows the utilities included in our survey. It provides information on their programs' start dates, the size and number of customers on their RTP rates, and the types of RTP rates they offer. In the section that follows, we provide background information on each utility's program, further information on its rate structure—including any specific risk mitigation features offered, or issues mentioned regarding the CBL—and the lessons learned by the utility from offering its RTP program. The utilities are discussed in alphabetical order.

Table 2-1
Background Information on Selected RTP Programs

Utility	Program Start Date	Customer Requirements	Number of Customers as of 8/01	Type of RTP Rate
BC Hydro	1996	Service at 69,000 + volts	0	Two-part
Duke	1993	1,000 kW +	59	Two-part
Georgia Power	1992	250 kW + for day ahead rate	Over 1,650	Two-part
PG&E	1985	500 kW +	20 - 25	One-part
SCE (Edison)	1987	500 kW + for main rates	100	One-part
TVA	1986	5 MW +	Over 350	One-part
UtiliCorp	1998	All customers	14	Two-part

BC Hydro

Program Background. In 1996, industrial customers at BC Hydro were paying 2 to 2.5 cents/kWh on standard tariffs. At this time, wholesale prices in the Northwestern U.S. were running 1 to 1.5 cents/kWh. In response to industrial customers' requests for access to this cheaper power, BC Hydro began a pilot RTP program that provided customers virtual access to the wholesale market. From BC Hydro's perspective, the value of the program was that it would give customers an understanding of the wholesale market, and also incent economic load shifting. In 1997, the RTP program became permanent.

At the peak of the RTP program, BC Hydro had roughly 25 customers on the rate. Then wholesale prices increased in 1999, making RTP rates greater than the tariff rates, and the bulk of the customers dropped off. By late 1999, all of the customers were off the program, and no customers have joined since that time.

Rate Structure. The BC Hydro RTP rate is a two-part rate with the real-time price based on the Dow Jones Mid-Columbia Index. Customers can select either the Mid-Columbia peak and off-peak price, or the mid-point of the next day's prescheduled price range. Thus, the program offers day-ahead variable pricing, but prices do not vary hourly.

The utility uses a two-part CBL based on the past three years of electricity use. The on peak period used is 6 am to 10 pm. As with other two-part RTP rates, customers using power above their baseline purchase this power at the real-time price. However, customers using between 75% and 100% of their CBL are credited back at their standard rate, rather than the RTP rate. When customers use less than 75% of baseline, they are credited at the RTP price. This move away from marginal cost based credits was the result of negotiations with customers. Though the utility explained that this clause would benefit customers only when wholesale prices were lower than tariffed rates "customers insisted that if they consumed less, they'd get credit at their original rate. They had a very short-term focus."[35]

Another non-standard feature of the BC Hydro two-part rate is that customers are allowed to purchase blocks of power in advance of use, at market prices, to replace a portion of their baseline usage. Customers are credited 80% of the real-time price for daily purchases of unused energy. Also in response to customer pressure to have greater access to real-time prices, the utility offered a load retention rate that allowed customers to have only 50% of their CBL billed at standard rates, and expose the other 50% to market prices. All of these non-standard features were the results of negotiations with customers.

Lessons Learned. BC Hydro learned that the major reason customers are willing to go onto a real-time rate is to save money, and that customers may not be willing to adjust usage to increase savings. BC Hydro did not see any demand response from their rate—neither load shifting nor load growth. (The representative we spoke with said that one customer tried to shift load, but could not sustain the shifting over time.) The customers

[35] From interview with Tony Chu, BC Hydro, August 2001.

on the rate represented BC Hydro's industrial base; they were pulp and paper, mining, and a few electrochemical companies.

The rate did achieve BC Hydro's goal of educating customers about the wholesale market. However, the representative said that, in retrospect, BC Hydro should have perhaps provided customers with more education about the rate before they went on it. BC Hydro's representative also said it can be difficult to determine how customers will respond to variable prices, because, in the utility's experience, the finance people are in favor of rescheduling production to save money, while the operations people oppose this.

Duke Power

Program Background. Duke started its real-time pricing program in 1993 with 12 customers. The program was developed to encourage new load when capacity was available, and to encourage load shifting in response to price. Last year, the program had over 100 commercial and industrial customers on it. However, prices were high for many hours last year, and a number of customers dropped off this rate and returned to the embedded cost-based TOU rate. Currently, they have 59 customers on the rate. The utility still sees about the same load response as they did last year, because most of the customers who dropped off the rate did not respond significantly to price.

Rate Structure. Duke offers a two-part RTP rate. Customers purchase their pre-determined baseline usage, (CBL), on standard rates. They then purchase or receive credits for energy above or below each hour's baseline. The hourly price includes hourly energy charges, which reflect marginal operating costs adjusted for line losses, and "rationing" charges, which consist of components that reflect heavy loading and reduced reliability of the transmission system and tight generation reserves. (The rationing charge is based on long-run marginal costs, and is zero in non-constrained hours.) In addition, customers pay an adder of 5 mills/kWh, called the incentive margin, on each kWh of net *incremental* load for the month. (For example, if a customer used 2,000 kWh above baseline in the off-peak period and 1,000 kWh less than baseline in the on-peak period, the incentive margin would be applied to the 1,000 kWh net increase in usage.) Duke designed the incentive adder in this manner because it was concerned about revenue erosion from load reductions. The other component in Duke's rate is an incremental demand charge. This nominal demand charge, which is intended to cover any needed increases in local distribution facility size, is applied only to the difference between the maximum demand during the month and the billing demand during the corresponding month of the CBL.

Developing the CBL. Duke's original rate design gave customers an 8,760 hour annual customer baseline. Today, they set the CBL using monthly average usage. Most of the customers joining the RTP rate were on the TOU rate before, so they have peak and off-peak levels for the CBL. The primary reason the utility simplified the CBL was it knew there was a significant amount of randomness in an hourly load profile, and therefore the 8,760 profile "did not seem all that meaningful."

Lessons Learned. The major lesson Duke learned from its RTP program is that a utility can get a large demand response with a small number of customers. Customers do pay attention to prices, and some customers respond to these prices. Last year, about 25 of the 100 customers on the Duke RTP rate shifted load in response to high prices, and Duke experienced peak load reductions of about 15-20% from the program. Because many customers who did not respond to prices have since left the program, Duke expects the percentage peak savings to be larger this year.

Duke found that customers who respond to price tend to be those with their own generation, or those with discrete production processes that could be rescheduled in response to high prices. Duke's representative noted that paper manufacturers, (with grinders that can shift), steel customers, (with arc furnaces), and universities, (with their own generation), are among the customers who respond to price. Duke found that most of the load shifting was within a day, but that some customers, for example those with on-site generation, shifted from one day to another.

Georgia Power

Program Background. Georgia law permits customers with 900 kW or more of connected load to put their load out to bid, and be served by any supplier in the state. In the late 1980s, Georgia Power was competing for these customers with almost 100 rural cooperatives and municipal utilities. In part to increase its competitiveness, Georgia Power began looking into real-time pricing. In 1992, it began a two-year controlled pilot, with the goals of increasing competitiveness; improving customer satisfaction, by giving customers more control over their bills; and curtailing load when needed. Georgia Power now has by far the largest RTP program in the country, with over 1,650 customers on hourly pricing.

Georgia Power was one of the first utilities in the country to develop a two-part RTP tariff, following the lead of Niagra Mohawk. They chose a two-part rather than a one-part rate for several reasons. First, the two-part rate allows the hourly price to more closely reflect the utility's true marginal cost. Second, the two-part rate best represents the "market price." Georgia Power believed a two-part rate would give it an opportunity to work with customers on price protection products. In addition, the utility was concerned about revenue stability; with a one-part rate, it would lose some of the contribution to fixed costs when customers curtailed in high priced hours. Georgia Power has expanded its RTP offerings since the 1992 pilot, but the basics of the program and tariff have remained relatively unchanged for almost a decade.

Rate Structure. Georgia Power has a two-part RTP tariff. Customers are billed for "baseline" use at their standard rate, and pay (or receive credits) for energy used above (or below) the baseline each hour at the hourly price. The hourly price is composed of a measure of marginal energy costs[36], line losses, a "risk recovery factor" (a fixed adder),

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[36] Originally, this measure of marginal cost was the system lambda. However, when the market opened up in Georgia, customers saw an increase of roughly one cent/kWh in real-time prices. Customers complained, and asked that the risk recovery factor (RRF) be lowered. In response, the Commission lowered the RRF,

and—near peaks—marginal transmission costs and outage cost estimates. (Marginal transmission costs are triggered by load and temperature. Outage costs estimates are based on loss of load probabilities, as well as customer surveys on the costs of having an outage.)

Georgia Power offers a "day-ahead" program, where customers are notified of price schedules by 4 pm the day before they go into effect, and an "hour-ahead" program, where customers are given an hour's notice on price. Currently, interruptible customers are served on the hour-ahead program. For these customers, their CBL drops to their firm contract level during periods of interruption. Customers who do not interrupt to their firm levels pay interruption penalties plus the hourly prices. The utility has filed to allow interruptible customers on the day-ahead rate as well. The other difference between the day and hour-ahead rates is that the risk-recovery factor for the day-ahead rate is greater than that for the hour-ahead rate, (4 mills/kWh versus 3 mills/kWh), since the utility bears a greater forecast risk.

Setting the Customer Baseline. When Georgia Power began its RTP program, it based a customer's baseline usage, or CBL, on an 8,760-point hourly load profile. However, customers often found this CBL confusing, and therefore frustrating. In response to these customers, Georgia Power now offers 360-point CBLs (with 24 average hourly weekday loads per month and six average 4-hour weekend day loads, for a total of 30 CBL points per month), and two-point CBLs. The two-point CBLs simply average usage levels during the peak and off-peak period.
The majority of customers, (basically, the high-load-factor customers), now select the two-point CBL. If the two-point CBL does not seem appropriate based on a customer's usage profile, Georgia Power will usually use a 360-point CBL. Only a very few unique loads" use the 8,760-point CBL today.[37]

Price Protection Products. Georgia Power offers customers a variety of products that allow customers to influence their exposure to RTP price risk. One product, the adjustable CBL, allows customers to temporarily adjust their CBLs. For example, if customers wants to lower their exposure to price volatility, they would increase CBLs. (Customers wanting to raise their CBLs must be on the RTP rate for a year, so that Georgia Power can determine how high the CBL can be raised.) Customers wanting to expose more loads to real-time prices—presumably because they believe it will be a cool summer—can lower their CBLs. Of the roughly 1,650 customers on RTP, 600 currently have adjustable CBLs. About 60% of the incremental energy sold on the RTP rate, i.e., usage above baseline, is now protected by this product.

Georgia Power also offers a variety of financial products to limit customers' exposure to RTP price volatility. These products include price caps, contracts for differences, collars,

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and also ordered that, in cases where Georgia Power's load was greater than that supplied by their own generation, hourly prices were to be based upon the average price of purchased power, rather than the cost of the marginal block of power.

[37] Our source noted that customers who can "really respond a lot" are typically on the higher point CBLs.

index swaps, and index caps.[38] Georgia Power has sold these Price Protection Products, or PPPs, for three years. It currently has 250 contracts with about 90 customers. (Customers have multiple contracts to cover different time periods.) Georgia Power believes that offering these products has probably not increased the number of customers on the RTP program, but it has increased customer satisfaction. The utility has examined whether offering the PPPs has dampened price responsiveness, and has found no evidence of this.

Lessons Learned. Our research shows that Georgia Power's experience highlights a number of lessons that have also been seen at other utilities. First, RTP can deliver substantial peak savings, despite the fact that many customers are not very responsive to price. When the hourly price reached $6.40/kWh, Georgia Power saw 850 MW of load reduction (out of 1,500 – 2,000 MW of incremental, or above-baseline load) from its RTP customers. Georgia Power also believes that customers have responded to the availability of low off-peak prices by expanding in Georgia.

The utility's experience also supports the finding that customers join RTP programs to have access to lower cost power. When hourly prices went up in response to changing market conditions, customers sought price relief, and were granted it by the Georgia Commission.

Georgia Power has also found that a small percentage of customers are willing to pay for limited protection against price volatility. In response to customer requests, they developed and now sell a variety of risk-management products.

Georgia Pacific has also found that intense manufacturers, such as chemical, and pulp and paper companies, are generally the most price responsive customers. It also learned that some commercial customers would respond to price. Office buildings, universities, grocery stores, and even a hospital (that changes chiller use based on hourly prices) are all responsive to real-time pricing.

Georgia Pacific states that the major lesson it has learned is that education is the key to a successful RTP program: Customers understand RTP the first time it is explained to them, but the utility needs to go back in a year or two and review the program with them. There are a couple of reasons for this: First, there is always turnover in staff. Second, customers tend to just "ride" the rate during a period of low prices, and then begin to pay attention to it again when prices increase. Georgia Power now holds annual, statewide meetings with RTP customers all to keep customers informed about the RTP program. The meetings are well attended, and the utility believes its education program has paid off in customer satisfaction.

[38] Georgia Power's price-cap product guarantees that average RTP prices over a specific time period will not go above the cap. Its contract for differences gives a fixed price guarantee on the average RTP price. The collar has a cap and floor on the average RTP price over a specific time period. The index swap is a financial agreement that ties the RTP price to a commodity price index. If the commodity price index increases, so does the RTP price. If it decreases, so does the RTP price. The index cap is a financial agreement that ties an RTP price cap to a commodity price index. As the commodity price increases or decreases, so does the price cap.

Pacific Gas & Electric (PG&E)

Program Background. PG&E was the first utility in North America to offer real-time pricing when it began its experimental program in 1985. The innovative RTP program grew out of PG&E's demand-side management programs, and was developed to provide customers with incentives to shift load from periods of high utility costs. The program, which began with four participants, was expanded to 15 customers in 1988. In 1992, the CPUC authorized further expansion of the experimental program, and capped the number of participants at 50. The program grew to roughly 50 customers, and PG&E was considering requesting a further expansion, based on customer requests, when restructuring began.

The onset of industry restructuring tabled the potential RTP program expansion. Because of the retail rate freeze, PG&E did not revise the RTP tariff, though it felt it was no longer compatible with the new, unbundled rate components. Currently, the program is closed to new customers, and serves 20-25 customers. The utility wants to stop offering the rate, because it believes there is no need for a program based on administratively determined prices—rather than market prices— in a restructured market.

Rate Structure. PG&E has a one-part RTP rate. The rate includes a customer charge and a nominal demand charge, through which the utility collects customers' non-time-differentiated costs. The bulk of charges are tied to the hourly energy rates. To calculate the energy charge in any hour, PG&E starts with a fixed base rate, adds a "gas adjustment multiplier" when a gas-fueled plant is on the margin, and multiplies this sum by the revenue reconciliation multiplier. It then adds factors to cover daily variations in T&D costs, and a generation capacity adder, called the Load Management Price Signal, or LMPS, during hours with a high probability of system constraints. To limit customer price risk, PG&E limits the number of hours per year the LMPS, which can exceed $1.00/kWh, can be applied to the energy charge.

Lessons Learned. PG&E says its RTP program worked well prior to restructuring; customers reduced demand significantly in response to high prices. The utility also learned that RTP is not necessarily only for large industrial customers. PG&E's representative mentioned that office buildings in particular "seemed to like the rate," indicating that—at least under certain conditions—commercial customers can also benefit from real-time pricing.

Southern California Edison (Edison)

Program Background. Edison began offering real-time pricing with a two-year experimental program in 1987. Currently, Edison has one of the larger RTP programs in the U.S., with about 100 large power, interruptible, and agricultural customers on real-time pricing. All of these customers are served under Edison's one-part RTP-2 rates. The utility also developed a two-part RTP rate four or five years ago. However, because the rate was approved just as restructuring was starting, the tariff did not receive much attention, and eventually the two-part RTP idea was abandoned.

More recently, Edison introduced RTP-3, which was intended to update and improve upon the RTP-2 rates, by using market, rather than administratively determined, prices. Since this rate was based on PX prices, (pushed up by a T&D capacity component), customers on RTP-3 were exposed to very high prices when California's capacity situation became tight. In general, customers did not shift load in response to the high prices, and their bills became so high that Edison felt it had to allow them to switch from RTP-3, even though their contracts did not allow this. Most customers were off the RTP-3 rate by the time the PX closed. In January, Edison officially closed the RTP-3 rate.

Rate Structure. Edison's RTP rates are one-part rates, with demand charges and hourly energy charges. Hourly energy charges reflect marginal energy costs and time-variant capacity costs. Multipliers are applied to hourly energy rates for revenue reconciliation purposes.

Edison's rates differ from many one-part rates, since they are based on a menu of day types. Edison uses nine day types,[39] and allocates costs to each hour of these day types. The hourly prices for each day type are predetermined; customers already know the hourly prices for a hot summer weekday, for example. The real-time component is that the utility sets the day type in "real-time" based on, for example, the maximum temperature in downtown L.A. on the prior day, as recorded by the national weather service. (The RTP-3 rate had a similar structure, except that only hourly T&D costs were obtained from the menu of day types, while the energy and generation capacity components were based on PX prices.) The interruptible version of the rate is similar, except it credits generation capacity costs to customers, as their standard interruptible rate does.

To mitigate customer exposure to high prices, Edison has limited the highest-priced hour in the RTP-2 rates to $3.00 per kWh. As revenue requirements increased over time, Edison placed the increases for the RTP rate in the shoulder periods, rather than the peak ones, to limit the top prices.

Lessons Learned. Edison's representative indicated a major lesson learned from its RTP experience: utilities developing RTP programs should seek out and market to customers who will shift load Edison believes that customers went on the RTP rate, which was designed to be revenue neutral with the TOU-8 rate, primarily because it saved them money, given their existing load profiles. As a result, these "free riders" did not respond even when prices (under RTP-3) became very high, and eventually dropped off the RTP-3 rate.

Tennessee Valley Authority (TVA)

[39] These day types are extremely hot summer weekday, very hot summer weekday, hot summer weekday, moderate summer weekday, mild summer weekday, high and low cost winter weekdays, and high and low cost weekends.

Program Background. TVA started its Economy Surplus Power, or ESP, program in 1986. It now has one of the country's largest programs, with over 350 customers purchasing hourly-priced energy. The program was designed to help TVA sell surplus power. To ensure that any incremental load would not be coincident with peak during constrained periods, the utility made ESP sales interruptible. This feature—that all RTP sales are for interruptible power—is one of the unique aspects of TVA's program. TVA included this feature because it wanted the ESP rate to be a load-management resource, and it knew that, while some customers would respond to high prices, others would not.

TVA is now phasing out its ESP program in favor of a similar RTP program called the Variable Price Interruptible, or VPI, program. The VPI has a rate design similar to the ESP, with the key difference being that the hourly price under the ESP is based on the price of the top 100 MW of system supply, while in the VPI rate, it is based on the top 1,000 MW of system supply.[40] This change was made because, as supply in the region tightened, the volatility of real-time prices increased significantly, and customer satisfaction with real-time pricing decreased. The VPI rate is designed to send an appropriate price signal, but expose customers to less price volatility. Customers purchasing ESP power will continue to do so until their contract period ends, at which time they can purchase VPI power.

To further mitigate price volatility, TVA is beginning to experiment with a two-part RTP rate. The two-part rate will also be interruptible, and the baseline usage will include the customer's firm and interruptible power, with each billed on the appropriate rate schedule.[41] The two-part RTP rate will be open to customers 20 MW and larger.

Rate Structure. Except for applying to interruptible power, the ESP and VPI rates are fairly standard one-part RTP rates. They have a demand charge that provides primarily for transmission cost recovery. The hourly price is based on the marginal cost of supply, (the top 100 MW of system supply for ESP and the top 1,000 MW for VPI), and has margins and markups for generation capacity, time-variant T&D capacity, etc. Thus, the RTP price includes energy and capacity charges, but the capacity charges are smaller than they would be in a firm rate, because of the interruptible nature of the service. Nevertheless, in certain periods, hourly prices can become quite high. TVA's customers contract for RTP interruptible power in addition to their contracts for firm power.

Lessons Learned: TVA's customers signed up for RTP as a way to save money. While most customers are still on the program to take advantage of these savings, their overall satisfaction with the program has decreased as price volatility has increased.

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[40] VPI also enhances the ESP rate by offering more options on curtailment priority. Both ESP and VPI rates are developed for different curtailment groups, with different priorities of interruption, and different notice periods prior to interruption.

[41] The TVA representative we spoke with noted that, so far, there had been a "mixed reaction" to the two-part rate, because some customers find the rate confusing. He surmised that this confusion was related to the way TVA is blending firm and interruptible power in the baseline.

Real-time pricing has been "very useful" to TVA. The utility found that some customers would provide significant load reductions in response to price, while others will not respond much. TVA has a wide variety of industrial customers on its rate. Based on this, TVA's representative suggested that the optimal way to apply RTP might be to a narrower group of customers.

UtiliCorp United

Program Background. UtiliCorp began offering RTP in 1998, and currently has 14 customers on its program. The program was started primarily to give customers "an inkling of choice," that is, a better idea of what a deregulated market can offer them. In addition, UtiliCorp offered the program to become more familiar internally with some of the concepts involved in the rate, and to gain experience in other market-based offerings that build from the RTP program.

Rate Structure. UtiliCorp has a two-part RTP rate, with the baseline (CBL) usage billed at the customer's standard rate, and incremental or decremental usage billed or credited with an hourly energy charge. The hourly energy rate is based on forecasts of short-run marginal costs, and includes costs for operating reserves, marginal costs of transmission (congestion charges), and line losses. Like other two-part rates, this hourly energy charge has an adder to contribute to the utility's fixed costs. However, unlike some other utilities' rates, UtiliCorp's adder is variable: the size of the adder in any hour depends on the level of marginal costs in that hour. When marginal costs are low, a larger adder is used. When marginal costs are high, a smaller adder is used.

UtiliCorp thinks that the use of a variable adder—rather than a comparably sized fixed adder—helps the benefits of the RTP program to be shared between customers and the utility. For instance, during high-cost hours—when customers are likely to conserve—the adder is smaller, so the utility pays customers a slightly lower credit for conserving than it would with a fixed adder. Nonetheless, customers still see a high price, which provides them with an incentive to reduce load, and a benefit from doing so. In hours where marginal costs are low, customers benefit from the low hourly price. The utility benefits more from this increased usage than it would have with a fixed adder, because the adder in those hours is higher than it would be with a fixed adder. UtiliCorp sees variable adder as a key difference between its RTP rate and some other two-part RTP rates, (e.g., Georgia Power's).

UtiliCorp offers RTP to customers with both firm and interruptible service. Interruptible customers have the option of receiving only 50% of their interruptible discount in exchange for being allowed to purchase power, (at the RTP price), above their firm power baseline during interruption periods.

UtiliCorp uses an 8,760-hour load profile to determine the CBL for its customers. ((UtiliCorp's representative said it takes about an hour to determine each customer's CBL.)

Products to Mitigate Risk from Price Volatility. UtiliCorp also offers customers products that can be used to decrease their risk from price volatility. With one product, customers expecting to temporarily increase energy use can purchase a block of power above their CBL at a fixed price. For instance, a customer anticipating increased power needs for a special job could purchase a block of power for three months. The other product UtiliCorp offers is the "get out of jail card," which provides customers with an opportunity to hedge a fixed quantity of power for a small period of time. This product was designed for customers who occasionally lack the flexibility to shift load during high-priced periods. The card consists of a contract quantity, an exercise (or strike) price, a period of time within which it may be exercised, a time period when the seller must be notified by the buyer of their intent to exercise, and a purchase price. For instance, a customer might purchase the right to pay no more than 15 cents/kWh for 1,000 kWh of usage in each hour during the peak period in August. Customers can purchase as many cards as they want. UtiliCorp has not yet had a customer purchase one of these products. UtiliCorp attributes this to insufficient marketing efforts , and to market conditions.[42]

Lessons Learned. UtiliCorp's experience indicates that customers join the RTP rate to gain access to less expensive power. While all of their RTP customers are interested in lower bills, only three of the 14 customers have shifted significant amounts of load. These customers, though, are quite price responsive; they have been able to save significant amounts, even during 1999, when hourly prices went as high as $1.00/kWh. Two of the price-responsive customers have back-up generators, and the third is a large farm operation. UtiliCorp's representative noted that one of the lessons learned from RTP is that, even if only a few customers select the RTP option, the offering is an important one in its developing portfolio of market-based products.

2.4 CONCLUSIONS

Utilities have learned a significant amount about customer response, participation, and satisfaction with RTP programs during the years they have offered such programs. Key findings include the fact that RTP programs can deliver significant peak savings, even though most of the savings come from a relatively small group of very price-responsive customers. These price-responsive customers are often large manufacturers with flexible production processes, but can also be universities, grocery stores, or other types of customers with less "production" flexibility. Customers join RTP rates to save money, and there is evidence that participation rates will be higher if utilities can limit the risk faced from price volatility.

[42] For instance, last summer UtiliCorp discussed the block purchase product with customers at a time when the market was quite volatile. Customers preferred to wait to see what would happen with the market before locking in a price. Eventually, prices started decreasing with cooler weather, significantly decreasing the need for the product. The get out of jail card was introduced last summer in mid-July, just about the time prices were falling for the season. Thus, each time the utility quoted a price, it was lower than the previous quote. This gave customers an incentive to postpone a decision to purchase the product, until eventually they did not need it. This summer, the utility staff has been too busy to seriously market the products. In addition, while absolute price levels have been quite high this summer, price volatility has been low. Therefore, customers have not observed the need for protection against price spikes this summer.

While most of the initial RTP programs offered one-part rates, the concern over utility revenue stability—as well as customer preference for some protection from price risk—has led most utilities introducing programs to offer two-part RTP rates. We found that two of the three utilities we surveyed—that had kept one-part RTP rates for well over a decade— had introduced, or were introducing two-part tariffs to supplement their one-part rates. Among utilities with two-part RTP rates, we also observed a tendency to simply the customer CBL, with some utilities offering customers CBLs with as few as two parts, an on- and off-peak usage level. We found that utilities often allowed interruptible customers to participate on the RTP rate, because these customers are believed to be potentially valuable as load management resources.

The other major lesson learned from utility RTP experience is that customer education is important in improving customer satisfaction with RTP rates. This lesson can be drawn from experience with successful RTP programs, as well as from less successful programs.

CHAPTER 3
BARRIERS TO REAL-TIME PRICING

3.1 INTRODUCTION

One of the original works on real-time pricing, by Professor Fred Schweppe and his colleagues, focused on demonstrating the economic efficiency that would result from this pricing methodology.[43] However, there was no discussion of barriers to the introduction of real-time pricing in this seminal work. The authors seem to have conjectured that if the various "publics" involved in real-time pricing could be convinced of its many benefits, implementation would flow automatically. California's inability to implement real-time pricing in the summer of 2001 shows that, in the real world, implementation can never be expected to flow automatically.

In the past, lack of metering was regarded as the most significant barrier to implementing real-time pricing. It was not clear who would pay for the cost of metering—the ratepayers or the stockholders. However, even when funds for metering were made available from the state's general revenue fund in spring 2001, real-time pricing failed to materialize. There were several reasons for this.

The CEC wanted to make real-time pricing mandatory, but the CPUC was reluctant to go along with that idea, fearing widespread customer opposition. This may have been due in part to the experience of San Diego in the summer of 2000, when all customers were suddenly exposed to unrestricted wholesale prices, and the resulting doubling and tripling of bills produced a political backlash. The utilities seemed to favor mandatory implementation, from the standpoint of ensuring revenue neutrality. However, they were also apprehensive about customer backlash. The CEC agreed to proceed with a voluntary implementation. However, even that failed to resolve the impasse, since disagreements now emerged on the major design issue: should it be one-part or two-part. As of this writing, these differences have not been resolved, and the CPUC has not ruled on real-time pricing.

The following chapter discusses several types of barriers to implementing real-time pricing in the real world. The barriers deal with the customer, the utility, regulators, and technology.

3.2 CUSTOMER BARRIERS

The vast majority of customers have a natural reluctance to participate in real-time pricing, since they equate higher price volatility with higher bills. They do not realize that higher price volatility often means that prices will be very high during a certain number of hours, but very low during a greater number of hours— ultimately resulting in

[43] Fred C. Schweppe, Michael C. Carmanis, Richard D. Tabors and Roger E. Bohn, *Spot Pricing of Electricity*, Kluwer Academic Publishing, 1988.

lower bills for the year as a whole. Of those that realize that higher price volatility may well translate into lower expected bills, a large number are risk averse, and therefore not inclined to “play the market”. And then there are some customers who think that real-time pricing is just another way for their electric utility to gouge them.

These perceptions are born out in a series of market research studies that have been conducted by EPRI over the past five years. Customers were interviewed about their preferences for a range of pricing options, based on their stated intent to buy or not buy one or more of these products. The studies are summarized in Table 3-1.

Table 3-1
Willingness to Pay for Alternative Pricing Options by Market Segment

Large C&I (8-utility study)	Flat v. 2-part RTP Flat v. 1-part RTP	.33 cents per kWh .74 cents per kWh
Medium C&I (7-utility study)	Seasonal v. TOU TOU v. Hourly with collar	.25 cents per kWh .92 cents per kWh
Small C&I (7-utility study)	Seasonal v. TOU	.92 cents per kWh
Large C&I (1-utilty study)	TOU v. 2-part RTP TOU v. 1-part RTP	.13 cents per kWh .29 cents per kWh
Small and Medium C&I (National sample)	Flat v. Seasonal Flat v. TOU Flat v. Hourly	.8 cents per kWh 1.4 cents per kWh 3.9 cents per kWh

Table 3-1 shows that customers are willing to pay real money to avoid being placed on a time-dependent rate structure, such as seasonal, time-of-use or real-time pricing. The willingness-to-pay estimates were based on data gathered through customer interviews. Customers ranked various pricing products, and the resulting rankings were subjected to conjoint analysis. One important caveat is that, in all but one interview, the data was derived from the standard logit model of customer choice, which enforces the same preference functions on all customers. Once that assumption is relaxed, by using the mixed logit model, important information on the variation in customer preferences within segments is revealed. On average, customers may display a preference away from real-time pricing, and be willing to pay a higher flat price than go on a real-time price. However, several customers within each segment may have a preference toward real-time pricing. The latter set of customers would form the target population for real-time pricing.

Several research questions arise in this regard:

- How valid are stated-intent studies of customer preferences for various pricing products? Are they confirmed with the choices customers actually make in the marketplace?

- What can be done to improve customer perceptions of the benefits of real-time pricing?

- Which types of customers are more likely to accept real-time pricing?

Utility experience with real-time pricing, surveyed in the previous chapter, provides evidence that several customers do participate in real-time pricing programs. However, with the exception of three utilities---Duke Power, Georgia Power and the Tennessee Valley Authority—most utilities only have a handful of customers on real-time pricing. And only one utility, Georgia Power, has been able to demonstrate a steady growth in the number of customers who have chosen real-time pricing. Research questions that arise include:

- Does the growth in Georgia Power's customers represent the pattern of growth exhibited by most new products and services, i.e., an S-shaped diffusion curve? Has it reached the inflection point?

- Why have other utilities not experienced a similar pattern of growth? Are there customers more risk averse (unlikely)? Or have they not devoted enough resources and budget to market real-time pricing (more likely)? Did the utilities not stand to benefit from real-time pricing?

Clearly, there are real and significant barriers to customer participation in real-time pricing. However, it should be possible to overcome them through successful program design. Examples from other industries indicate that customers do respond to the opportunity to lower costs by shifting their usage patterns (airlines) or by taking on time-varying products (adjustable rate mortgages).

Research questions that arise in this context include:

- Are customers not signing up for real-time pricing because they do not know how to lower costs by reducing usage during high cost hours and increasing usage during low cost hours?

- Or do lack customers lack the capability to shift load? This contention, often advanced by skeptics, has been negated by EPRI research, conducted over a number of years and over several geographical regions. EPRI finds that customers do shift load, but the magnitude of shifting varies across business types.

- What types of customers are likely to shift more load? EPRI finds that firms displaying the most amount of shifting have discrete processes of production that involve batch rather than continuous operations. Thus, firms in the warehouse, pipelines and municipal water businesses have the highest propensity to shift load in response to higher prices. Is this finding valid for California?

EPRI's *StatsBank* database contains the measured responses of about a thousand customers in the United States and the United Kingdom. Each of these customers has been on some form of a time-differentiated or real-time price for several years, and some of them have been on some type of curtailable or interruptible rate. Econometric methods were used to estimate the elasticity of substitution between hours. It was found that across all business segments, the estimated hour-to-hour elasticity of substitution within a day ranges from zero for some segments to values in excess of .30 for other segments.[44]

Within the manufacturing sector, EPRI has observed the highest elasticities for electrically-intensive customers (e.g., firms in the pulp and paper and primary metals industries) who have an average elasticity of .09. The lowest elasticities are observed for least-electrically intensive customers, who have an average elasticity of .04, such as firms in furniture manufacturing, and printing and publishing
This raises the following question:

- Is the pattern of customer response, as estimated by EPRI, a valid descriptor of California business?

The elasticities estimated by EPRI rise significantly if the customers have on-site generation. For example, the elasticity for electrically intensive customers with on-site generation is .15, compared with .09 for customers without on-site generation. The elasticity for the least electrically-intensive customers is .07, compared with .04 for customers without on-site generation. For firms in the pulp and paper industry, the presence of on-site generation doubles the elasticity from .15 to .30. A study of four industrial firms by Gupta and Danielsen also finds that self-generation significantly enhances customer responsiveness to real-time pricing.[45] These findings illustrates the role of enabling technologies, and leads to the following research question:

- Do customer responses increase change over time? In other words, as customers learn how to take advantage of real-time pricing, and invest in new enabling technologies, do they display increasing responses, suggesting that long-run elasticities of substitution would be higher than short-run elasticities?

3.3 UTILITY BARRIERS

Utilities have several concerns regarding real-time pricing. One of these concerns deals with revenue loss. Revenue loss can arise if the rates are offered on a voluntary basis, and customers who have inverse load shapes self-select themselves onto the real-time rate. The customers would lower their bills, without shifting any load from peak to off-peak hours. They would be better off, but the utility and non-participating customers would become worse off. There would be a loss of revenue to the utility, without any reduction in its costs—resulting in a loss of earnings. The lost earnings would then have to be made up by charging other customers a higher price.

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[44] For background on the various elasticity concepts, see Christensen Associates, "Electricity Customer Price Responsiveness—Literature Review of Customer Demand Modeling and Price Elasticities," prepared for the California Energy Commission, September 29, 2000.
[45] Nainish K. Gupta and Albert L. Danielsen, "Real-Time Pricing: Ready for the Meter? An Empirical Study of Customer Response," *Public Utilities Fortnightly*, November 1, 1998.

This concern can be addressed by making the rates mandatory. However, this often runs into a political barrier, as discussed in the previous section. The barrier may not be as formidable as it seems, since utilities have a long history of implementing mandatory time-of-use rates and curtailable and interruptible rates for their large power customers. A research issue that arises in this context is whether that experience can be transferred to real-time pricing. There are precedents from other industries, which might prove useful in this context. For example, long distance telephone rates were mandatory on a time-of-use basis for all customers before the industry was deregulated. Customers accepted this reality, and organized their calling pattern to follow the time-of-use pricing structure. Since there was no alternative, no one complained.

Real-time pricing requires the selection of a customer base load—which is an additional concern. There is a perception that customers will "game" the choice of CBL, so that it will minimize their exposure to high prices. One way to do this would be to set a CBL that exceeds their baseline usage. However, this would also preclude the customer from deriving any benefits from low prices. This leads to the following research question:

- Is there any empirical evidence that customers have gamed the selection of their CBLs? If so, can better educational programs offset this problem?

Another concern has to do with billing and settlement systems. Most existing systems are not capable of handling hourly bills. Modifications have to be made by the IT staff, which is often overburdened with other duties. The only practical solution is to outsource this capability, but that often comes burdened with a large price tag. Two research questions arise in this context:

- What is the cost of implementing billing and settlement systems that would enable real-time pricing?

- How can these costs be managed most effectively?

Finally, there is a perception that real-time pricing makes sense only during periods of high wholesale prices. Thus, if wholesale prices are low, as they have been during the past few months in the western states, then real-time pricing is not needed. What is often overlooked is that wholesale prices were high not too long ago, and that the sequential existence of low and high prices implies high price volatility. High price volatility is a hallmark of a competitive power market, and this phenomenon has been observed in the English and Wales market, the Australian and New Zealand market, and the Nordic market.[46]

Customers who sign up for real-time pricing will benefit when prices are low, and the existence of low prices during several hours of the year can be an inducement.. When a

[46] Frank A. Wolak, "Market Design and Price Behavior in Restructured Electricity Markets: An International Comparison," in Ahmad Faruqui and Kelly Eakin (editors), *Pricing in Competitive Electricity Markets*, Kluwer Academic Publishers, 2000.

utility has a large number of customers on real-time pricing, it creates flexibility for itself during high price periods, when it can transmit a high-price signal to the customers, and get customers to cut back on usage.

3.4 REGULATORY BARRIERS

The concept of real-time pricing is believed to have originated with William Vickrey in 1971 when he wrote a path-breaking article on "responsive pricing". Vickrey, who went on to win the Nobel Prize in Economics in the late nineties, noted that "the main difficulty with responsive pricing is likely to be not just mechanical or economic, but political." He felt that people shared the medieval notion of a just price as an ethical norm, and prices that varied according to the circumstances of the moment were intrinsically evil. He opined prophetically:

The free market has often enough been condemned as a snare and a delusion, but if indeed prices have failed to perform their function in the context of modern industrial society, it may be not because the free market will not work, but because it has not been effectively tried.

In a similar vein, Eric Hirst noted recently "the greatest barriers are legislative and regulatory, deriving from state efforts to protect retail customers from the vagaries of competitive markets."[47] One of the key barriers existing among several regulators is the misperception that customers cannot respond to real-time pricing, and would be forced into an awkward position if mandated to accept it. This misperception leads regulators to push for voluntary real-time pricing, which raises utility concerns about revenue loss and cross subsidization. The only way to solve this dilemma would be to convince the regulators that customers indeed have the capability to respond to well-designed real-time pricing. The following research issue relates to this barrier:

- What is the best way to convince regulators that customers can be trained to shift their loads from on-peak to off-peak hours? This may be accomplished through seminars and workshops, in which customer case studies are featured from other parts of the country where customers have shown an ability to respond.

A second barrier relates to fairness and distributional concerns. Not everyone would benefit equally from a switch to real-time pricing, and some customers would be made worse off. Those who consume large amounts of energy during peak times do made worse, since they would lose their subsidy from the other customers who consume smaller amounts of energy during peak times, and larger amounts during off-peak times. The only way to ensure that no one will be made worse off is to continue with traditional pricing, and continue the existing pattern of subsidy. A research issue arises in this context:

[47] Eric Hirst, "Price-Responsive Demand in Wholesale Markets: Why Is So Little Happening?" *The Electricity Journal*, May 2001.

- How should the competing demands of greater efficiency be balanced by the need to maintain the existing pattern of cross-subsidy between customers?

A third barrier has emerged recently in California. The state has bought large blocks of power at fixed price contracts. There appears to be no hourly variation in power prices under these contracts, but there is variation by pricing period. For example, blocks of peak power are much more expensive than blocks of off-peak power. Some have argued that real-time pricing is now irrelevant in California, since there is no hourly price variation in the wholesale price of power.

The argument that real-time pricing does not apply in this situation has two weaknesses: First, it ignores the fact that the existence of long-term contracts has not eliminated the wholesale spot market for power. According to some sources, during peak periods, as much as 30% to 40% of the power may be traded in this market. During such times, real-time pricing at the retail level would provide customers with the appropriate signal to conserve power usage. This would make the state better off, and if s can reduce peak load, it would make the participating customers also better off.

Second, it overlooks the fact that during times when the state has surplus power at long-term contracts, it is forced to dump this power on the wholesale market at lower-than-cost prices. If customers were on real-time pricing, they could be offered this power at the state's cost. This lower price may stimulate growth in customer usage during off- peak hours, especially if the customers have been trained in how to increase power usage by rescheduling operations. It would lead to even greater usage if customers have enabling technologies on their premises. The state would be better off, as would the customers and taxpayers.

The following research issue arises in this context:

- Is it possible to prove that real-time pricing can improve economic efficiency when the state has already brought large blocks of power at fixed price contracts? It may be possible to run numerical simulations with EPRI's Product Mix model to make this point transparent to policy makers.

A fourth barrier arises when either the independent system operator, or the state and federal commissions impose price caps in order to protect customers from price gouging by suppliers. Price caps have the unintended consequence of stifling customer and ESP interest in real-time pricing programs. As the California ISO's Market Surveillance Committee noted, "Price spikes provide the economic signals for retail customers to make the investment necessary to shift their demand in response to high prices."[48] In addition, improperly assessed price caps may discourage investment in new generation facilities.

The pertinent research question is:

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[48] Frank A. Wolak, Robert Nordhaus and Carl Shapiro, "An Analysis of the June 2000 Price Spikes in the California ISO's Energy and Ancillary Services Markets," September 6, 2000.

- Are customers better off if price caps are imposed in the wholesale market, or if they are placed on real-time pricing?

Finally, another disincentive to real-time pricing is created by the use of representative load profiles for customer billing. These profiles freeze the customers' load shapes, and provide no incentive for the customers to change their load shapes in response to real-time pricing.

3.5 TECHNOLOGICAL BARRIERS

Many technological barriers also impede the introduction and diffusion of real-time pricing. The barriers are not intrinsically technological, since the required technologies exist in the marketplace. However, the market penetration of these technologies has been very limited, due to their high capital costs (which in turn are due to their limited market penetration) and the barriers discussed in the previous sections.

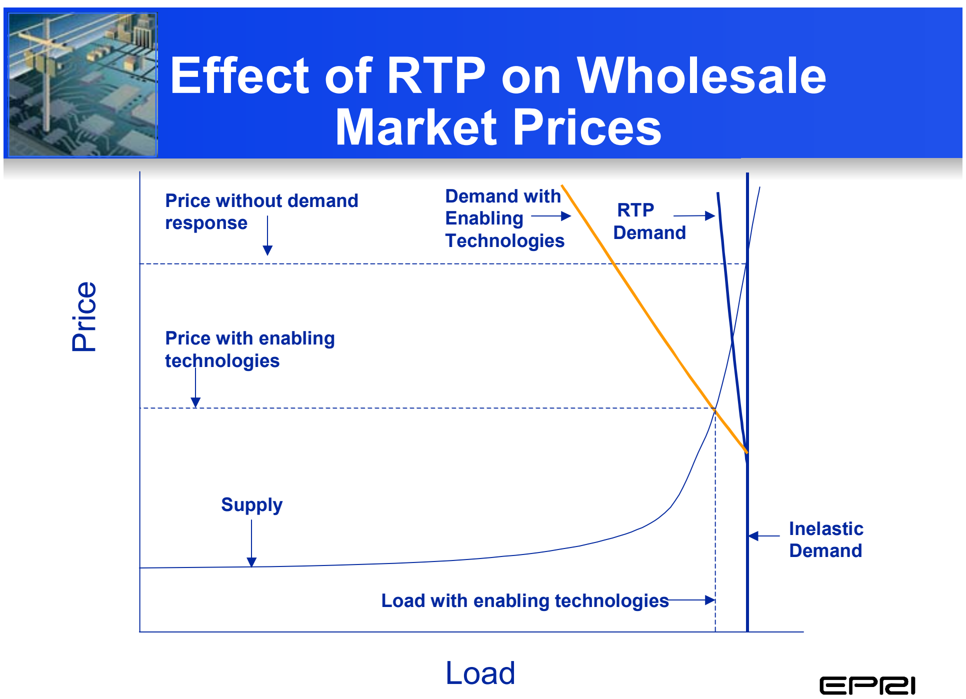
Technological barriers include the lack of hourly metering equipment; the lack of digital communication equipment to transmit hourly prices in real-time to customers; the limited penetration of sophisticated energy management and control systems; the even more limited penetration of time-flexible energy using equipment that allows the energy to be stored during off-peak periods and released during on-peak periods; and the small penetration of distribution energy resource systems. Each of these barriers is discussed further in the next chapter.

CHAPTER 4
ENABLING TECHNOLGIES

4.1 INTRODUCTION

Enabling technologies help customers make the most of the price incentives by lowering usage during high price periods and increasing usage during low price periods. They introduce higher elasticity in the customer's demand curve, and make possible further reductions in price volatility and average price levels. This benefit is shown in Figure 4-1.

Figure 4-1



This chapter deals with the key technical issues in the development, deployment, implementation and management of the technology infrastructure for enabling effective demand response through real-time pricing. The technologies behind such an infrastructure span several disciplines including communications, computing hardware and software, and advanced embedded controls in end-use equipment. These areas encompass a large number of technologies that have a high degree of technical complexity. The next section describes the overall scope of the RTP enabling systems and discusses how they may be integrated into a larger overall restructured industry communication framework.

4.2 A TAXONOMY OF ENABLING TECHNOLOGIES

The number of technology categories is high, since it spans all aspects of communications, networking and advanced information technology development, as well as several closely related topics, such as power engineering, software engineering, network management, data management, and security. Implementing real-time pricing in a restructured market involves potentially hundreds of business entities and millions of customers. We have developed a taxonomy of enabling technologies by drawing upon a recent paper authored by two, key CEC personnel,[49] and information coming out of several EPRI projects. The CEC paper recognizes that the technical functions necessary to achieve the desired customer response from real-time pricing include customer energy management systems and the dispatch of distributed generation. Moreover, this initial set of functional technology categories reveals the extent of the infrastructures required to support a full view of real-time pricing implementation.

The enabling technologies considered in this study are primarily directed at creating a system to establish, manage and implement the real-time pricing rate structures and invoke an automated customer response. They span a variety of overlapping physical domains, and their successful implementation will require the integration of equipment across these domains.

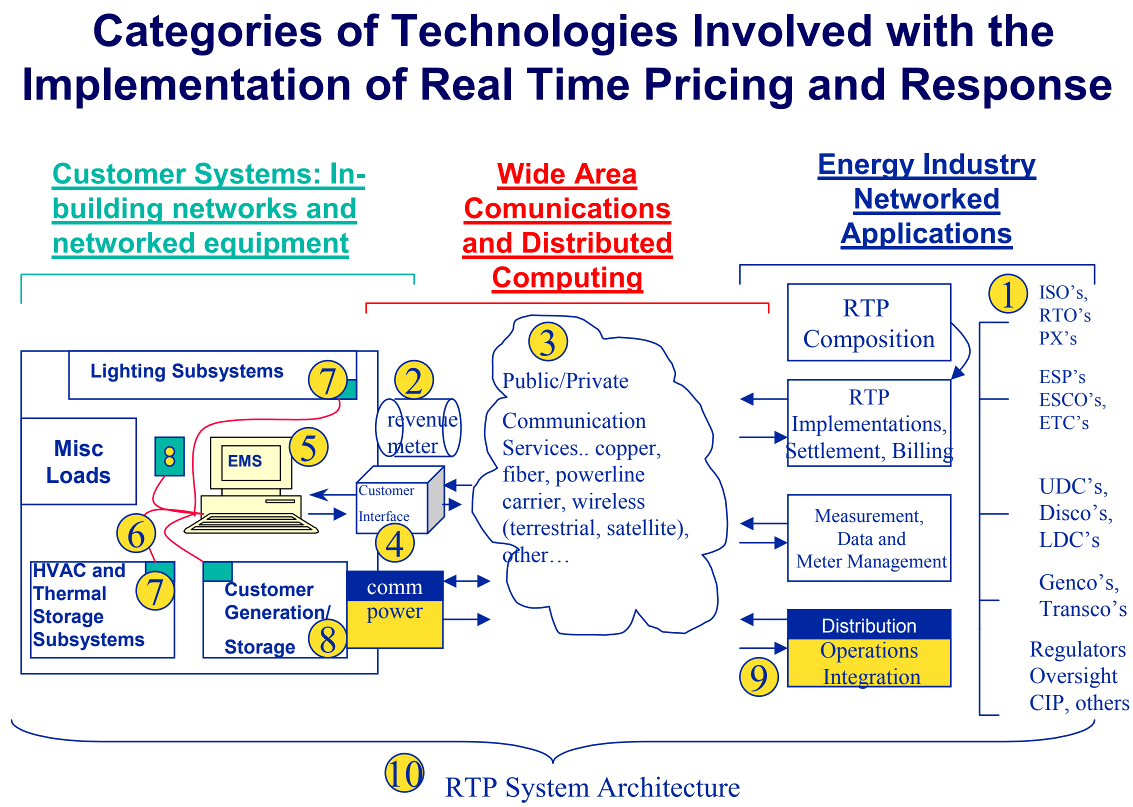
PHYSICAL DOMAINS OF ENABLING TECHNOLOGIES

Several technologies are traceable, in general terms, to physical components that make up the technology infrastructure. These technologies are easiest to visualize and describe in terms of their general function. Figure 4-2 contains a listing of 10 technology categories that are critical to the implementation of real-time pricing:

- Business-to-Business Information Systems
- Metering and Measurement of Customer Energy and Power
- Wide Area Access Networking Technology
- Customer Access “Gateway” Technologies
- Customer automated energy control system (AECS)
- In-building Networking Technologies
- Intelligent Networked Customer End-Use Equipment and Subsystems
- Integrated Distributed Generation and Storage
- Integrated Utility Field Operations
- Overall Technology Infrastructure

[49] M. R. Jaske and A. H. Rosenfeld, “Developing Demand Responsiveness in California’s Energy Markets” WEA, 76th Annual Conference, July 2001.

Figure 4-2



Currently, only a few of these technologies are available to assist in the implementation of real-time pricing, and they have not been integrated. In the future, new technologies will have to be developed and integrated. The application of real-time pricing would need to be overlaid with a systems management framework that is robust, secure and extensible. Additional information on these technologies is contained in Appendix D.

The enabling technologies include not just the basic physical components required for communications, metering, and networking, but also the sets of logical design guidelines that specify the underlying business and technical rules and policies. These guidelines will address such matters as the extent to which the enabling equipment will be expected to integrate key industry functions. One of the key issues in the development of the technical systems is the lack of business and policy guidelines upon which to build the enabling technologies. Issues such as security and a variety of restructuring administration functions are still being defined and this makes the job of building technology difficult since requirements can change and impact technical designs. It should be noted that technology should be designed and constructed to meet the business and industry needs and not vice versa.

4.3 ISSUES IN LARGE-SCALE DEPLOYMENT

Many of the R&D and implementation issues faced by the electricity industry are problems that stem from an inability to fully integrate and scale up to enterprise and industry-wide levels. The initial vision for the enabling technologies is that the general technology categories will become integrated, and will interoperate at a level that is still in the embryonic stage. The perspective of an overall architecture, category 10, is necessary because the industry has lacked a sufficiently broad perspective on integrating intelligent equipment and this has fragmented the development efforts. With the right approach, there will be ample opportunity for the vendor community to develop innovative products and services to serve the restructured energy system in California. The industry-wide technical architecture for rigorously and broadly implementing real-time pricing is not complete. This may sound puzzling, since a few utilities have extensive deployments of real-time pricing, as discussed in Chapter 2. Georgia Power Company has the largest dynamic pricing program in place with about 1,600 customers representing 5000MW of load.[50] This represents a substantial accomplishment with available technologies, such as standard box recorders; dialup modems; and both shared and leased-line telephone communications.[51] Georgia Power's accomplishments are indeed impressive. However, they are insufficient to meet the needs of large-scale deployment.

Large-scale deployment would involve several strategic technical challenges including:

- Moving up in scale by serving and managing hundreds of thousands of customers on real-time pricing
- Moving up in scope by adding and integrating more capabilities
- Integrating systems from different vendors and service providers
- Moving from a single vertically-integrated utility operation to operation in restructured markets with multiple energy service providers, utility distribution companies and independent system operators

The events of September 11, 2001 have brought forth another need: strengthening technology infrastructure systems, including those related to cyber security.

UTILITY INDUSTRY COMMUNICATIONS AND AUTOMATION

In the larger context of improving the efficiency of utility operations in a restructured market, the enabling technologies discussed here form a subset of the broader technology domain pertaining to utility automation and communications. As new strategies are developed for implementing a wide range of real-time pricing options, it would make

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[50] Richard Cowart, "Efficient Reliability: The Critical Role of Demand-Side Resources in Power Systems and Markets," The National Association of Regulatory Utility Commissioners , June 2001 NARUC
[51] Personal conversation with Georgia Power personnel

sense to seek out new economies of scope by bundling applications together. While enabling technologies can be implemented with a single purpose in mind, i.e., the implementation of real-time pricing, this can preclude the harvesting of synergies and economies of scope that can come from using the communications systems for other uses.

Potential synergies can come from integrating data from the customer site with the operation of the distribution system. For example, monitoring power quality can support improved system operations and also support new energy services offerings, such as premium power. The customer communications and data gathering capability required to implement real-time pricing can be a resource that can provide the utility distribution company with valuable operating data. While these additional applications are not directly a part of real-time pricing, they offer significant operational and public benefits. Thus, they should be considered in a strategic plan for the development of enabling technologies. One example of this synergy is the potential of using customer load profile data to study transformer and feeder loading, thus revealing new opportunities for distribution system operating and equipment efficiencies.

Industry restructuring has spawned a variety of new issues. For example, one has to deal with the requirements of direct access, such as switching energy service provider access to metering data. Some scenarios under restructuring may allow the customer to procure power from different suppliers within specific hours of the day. The real-time pricing communication "objects" described later in the chapter offer such an option. Some have argued that that the systems to implement real-time pricing can be easily migrated to a restructured environment. However, this is unlikely to be the case. Restructuring brings with it a host of new requirements, such as the ability to securely integrate the operation of systems, and achieve appropriate levels of interoperability between information systems deployed by a variety of organizations. This calls for a substantial upgrade from vertically integrated monopoly operations.

4.4 THE LIMITATIONS OF EXISTING TECHNOLOGIES

There is a substantial gap between what has been accomplished in the implementation of enabling technologies and what remains to be done. The surface has only been scratched in scope, scale and meeting technical requirements.

There are many technologies that are currently in use for metering, customer communications and early implementations of real-time pricing. Many of these systems use a combination of proprietary equipment combined with some level of standardization. These systems can and do work to provide for immediate "tactical" needs and are often used to focus on issues outside of the technology used for implementing them, such as customer feedback and response to rate structures. However, the technologies put to immediate use can have limitations in terms of system scaling and interoperation with other similar systems that can impair their ability to be scaled up to serve the entire industry. The development and ultimate implementation of enabling technologies to thousands of customers will require strategic elements for managing and appropriately securing the necessary communications and intelligent equipment systems. Often these needs do not surface in tests and pilots programs that are limited in scale. In addition, pilots and single-purpose implementations do not typically test the integration of systems built independently of each other. Yet, one of the key needs for the future is to be able to integrate equipment deployed by one company with equipment from another. When California experienced the need for integrating equipment across different energy service providers, it ran into classic integration problems[52].

Appendix A presents a series of questions to use in evaluating current implementations that may meet "tactical" needs against a system that includes "strategic" capabilities that will be necessary to serve an industry-wide infrastructure. Existing and planned CEC and other industry projects and programs related to real-time pricing may be evaluated against the attributes in this list. No existing system implements the full complement of strategic elements in this list. Strategic R&D can be planned to fill the gaps that current programs and implementations may exhibit. In addition, plans can be developed to migrate the industry to more strategic deployments of RTP technology. In particular, current implementations of RTP technology should be aware of potential shortcomings they may have that are related to interoperability, security and use of available and developing industry standards. The Commission should be wary of procuring proprietary technology that precludes integration with equipment or applications from other vendors or that otherwise "locks-in" technology.

Capital investments in enabling technology for real-time pricing are significant and will become even more significant as the scale of the systems increase. Careful attention to the development of strategic elements of the real-time pricing enabling system such as integration, interoperability, management and security are necessary to avoid the costs and inefficiencies that are likely to be incurred through "forklift upgrades" down the road.

Some have argued that the necessary equipment for implementing real-time pricing is already present in the marketplace and it is just a matter of having it installed. While it is true that a lot of technology is available, it has limitations in terms of interoperability between components and systems that could be supplied by a greater number of industry technology participants. While there has been a gradual migration to open systems in the marketplace, there still exist a substantial number of proprietary single-point solutions that cannot be easily integrated with products from other vendors. The strategic development of key, open standards can enable greater customer response than is now possible. It can also-improve effective vendor response to providing intelligent equipment that can participate in the infrastructure. For example, the ability of customers to respond to real-time pricing is currently limited to controls that are largely external to the end use equipment. Examples include relays that turn off the power or alternate thermostat set points. Implementing open standards for in-building networks can enable a more compete development of intelligent and sophisticated equipment by end-use equipment vendors, and thereby improve the price response by customers. In-building standards for communication with commercial building equipment enable the entire class

[52] Presentation by Mike Jaske of the California Energy Commission at a Stanford Workshop on Retail Markets, June 20-21, 2001

of networked intelligent equipment to develop. The lack of a widely established set of open standards, for example, has slowed the development and adoption of intelligent residential end-use equipment.

The necessary infrastructure for widespread implementation of real-time pricing is not yet complete. Free market forces, operating without any guidelines for interoperable systems development, will provide predominantly tactical and proprietary solutions. Thus, a key R&D issue is:

- Definition of the key networking communication interfaces that will be used to integrate equipment from different vendors. Technical approaches should be pursued that are vendor neutral and consistent with the state's regulatory policies.[53]

4.5 CUSTOMER RESPONSE TECHNOLOGIES

This set of technologies encompasses not only metering and meter communications, but also include integration of business processing with a wide variety of entities including those proposed for restructuring. The scope reaches into customer buildings and equipment, as well as the operation of the power delivery system. In response to real-time pricing, the customer can take actions in a variety of ways including those that are static and dynamic. Dynamic customer actions can include immediate actions such as throttling back, modulating or turning off equipment, and implementing on-site generation. In addition some technologies require several hours to implement, such as pre-cooling structures and cool storage technologies that can make use of "day ahead" pricing mechanisms. We focus on dynamic response mechanisms and the equipment required to stimulate the dynamic responses by customers.

First-generation technologies are available to assist customer response to real-time pricing where prices vary hourly if not more frequently. Four levels of technology can be distinguished to allow a more careful examination of the technical issues surrounding the customer network and end-use equipment integration. The levels range from a "manual" response to a mature set of sophisticated end-use subsystems that may employ optimization methods. Most of the first-generation technology falls into the first two levels that are tactical in nature, and cannot produce substantial customer response. Levels three and four require higher levels of integration and interoperability, and can produce substantial customer response. They are more strategic in nature, but also less mature in their development. However, it is in levels three and four where the full power of dynamic customer response manifests itself. These levels should be the focus of future R&D. Each of these levels is briefly described below.

LEVEL I: NONAUTOMATED CUSTOMER RESPONSE

[53] Initial regulatory Policies directed at technology and open systems development where part of the CPUC Decisions and workshops on Direct Access held in 1998, including the Permanent Standards Working Group

This level is a manual response where the customer may only receive a facsimile of RTP prices. No automation is involved. The facility managers may have developed sets of guidelines or rules that they would then proceed to implement. Or they may respond in an ad hoc fashion that would vary from day to day.

LEVEL II: SIMPLE AUTOMATED RESPONSE

This level involves the receipt of an RTP signal in a form that can be understood by an automated energy control system (AECS) that is installed on the customer's premises. However, at this level the AECS is limited to controlling the equipment through actions that are largely external to the equipment. Typically this is done by "unplugging" the equipment with a simple relay, adjusting a thermostat setting, or dimming the lighting level. These technologies can be put to use by customizing entire building controls and customer energy management systems. Relay modules that communicate over power line or wireless signals inside buildings are an example of such a system. A number of commercial versions of this retrofittable control technology are commercially available today. There is still some scope for additional R&D to address devices that the free market may not be adequately addressing. EPRI has done some initial development with a manufacturer on a combination circuit breaker/relay that can be applied to this level of customer response.

LEVEL III: SOPHISTICATED AUTOMATED CUSTOMER DEMAND RESPONSE

The sophisticated automated response requires the ability to communicate with the end-use equipment controls. This level of control must be embedded in the design of the end-use equipment or subsystem and should make use of one or more of the developing, open in-building standards. The main reason for open standards in this environment is the need to communicate with the large number and diversity of end use loads and subsystems within buildings. No load should be precluded from the opportunity to participate in a building energy-management implementation plan. This approach to end-use load control is far more encompassing than programs that target a single load. This is the main driver behind the more sophisticated in-building protocols such as BACnet™ or CEBus® Common Application Language. These protocols enable this strategic level of embedded control to be implemented. It should be noted that this opens up the vendor community to respond with more sophisticated designs for energy management. A control signal can be used to communicate the RTP prices directly to the equipment that can implement sophisticated optimization algorithms. Equipment for this level of control is just now starting to emerge for commercial buildings and vendors are beginning to make compliant products.

Several R&D issues surround the continued development of this level of control. These include:

- The development of implementation agreements and device models for generic equipment communications, developing interoperability test equipment, and developing the protocols to include RTP enabling capabilities. An example of RTP communications for this level of controls is shown in Appendix C.

Use of "common objects" for these device communications would greatly help to establish desired levels of interoperability across the industry. They should be refined through actual implementations and made available for standardization through standards development organizations such as IEEE, IEC and ASHRAE. ASHRAE has funded some work in this area but more needs to be done including R&D implementations to fully develop the concept through field implementations. This is an area with substantial potential for customer technology response development, and one in which the CEC could directly participate as a stakeholder. The General Services Administration participated in a trial of the BACnet protocol by implementing it in a federal building in San Francisco. This direct experience can help end-user communities better understand the technology and obtain a real, first-hand view of where the industry stands in the development of the technology.

LEVEL IV: SOPHISTICATED CUSTOMER AUTOMATED GENERATION RESPONSE

This level includes integration of customer equipment with the utility grid. This is the level required for the integration of distributed resources such as customer generation and storage technologies and injection of power into the grid. Several R&D issues surround this level of customer response including work to assist the standards required for power integration as well as communications and control integration. This level of response requires close work with existing and planned utility grid operation controls, or the customer equipment may interfere with "normal" utility operations. The level of customer response will require expanded thinking on the scope of communications infrastructure that includes utility communications and controls, in addition to potential integration with ISO/RTO operations.

4.6 OTHER VIEWS OF ENABLING TECHNOLOGIES

Figure 4.1 contained a view of enabling technologies that was based on the general physical location of each technology. However, this view is only one of many different perspectives that one can envision. For example, when one is seeking to understand the operation and architecture of a building, the external appearance only provides one dimension of understanding. Additional views are required to understand the plumbing system, electrical system, the heating and cooling system, etc. Likewise, to fully understand the set of enabling technologies associated with real-time pricing, one needs to envision other views that are not apparent from an external viewpoint alone. These additional views can contribute additional insights into R&D needs associated with enabling technologies. Two such views are discussed in this section.

THE OPEN SYSTEMS INTERCONNECTION BASIC REFERENCE MODEL VIEW (OSI BRM)

The OSI BRM view creates a frame of reference for the discussion of the technical R&D issues related to network communications and subsequent planning. The OSI BRM describes communications between intelligent equipment using layers to separate generic functions of different technologies. The layered view offered by this model provides a powerful method for building complex networks that can interoperate. The model is useful for discussing the relationship between many of the enabling technologies, as well as understanding how to develop a workable strategy for using the steady stream of new communications technologies that are coming from industry. The model enables a system designer to mix and match different technologies as necessary to match requirements as needed. A significant amount of technical work is focused on how to integrate protocols to meet desired industry needs. Appendix B provides additional discussion on this topic.

The OSI networking layers provides a basis for technical discussion of many remaining issues including integration of new physical media, sharing higher bandwidth communications among applications, securing networks and connected equipment and developing general guidelines for interoperability. For instance, standardization of a common "language" to be used by intelligent equipment can go a long way toward interoperability. This is an issue to be addressed in the "upper layers" of the networking model. The communication language can be carried across the different networks in a way that allows the physical communications media (at the bottom layer) to be independent. Using standardized RTP communications "objects," such as those described in Appendix C, can help to enable interoperability across the ten categories of technologies introduced above. This strategy is at the heart of several important industry initiatives related to infrastructure development.

THE SYSTEM MANAGEMENT VIEW

This third view of enabling technologies provides a distinction between the applications and the management equipment necessary to implement the real-time pricing applications. The distinction is similar to that between people who use desktop computers in an office (applications) and those who administer and maintain the computers and the networks around the office (system administration and management). There are R&D issues on the system management side as well as the applications side of the RTP enabling technologies. Management issues cut across all the domains and include such issues as system design, configuration and security. Management of the enabling technologies faces many technical challenges and several key R&D issues involve how to approach management of the RTP infrastructure. The management of the system poses some severe technical challenges that are greater than getting the applications in place.

4.5 HIGH PRIORITY R&D ISSUES

The technology infrastructure that ultimately enables real-time pricing has a high level of "public infrastructure" content that is analogous to other public infrastructure systems, such as roads, highways and air traffic control systems. The free market usually provides insufficient incentives for development of public infrastructure systems. It ends up developing and selling proprietary technologies, which have been shown to be socially suboptimal. In particular, the full development of several open systems standards is lacking. As a stakeholder with a significant number of buildings to manage, the State of California can play a key role in specifying a desired vision of interoperability to the vendor community, and by participating in some a few market trials of enabling technology.

Five high priority R&D issues relating to enabling technologies are described below.

1. Development of Direct Access System Architecture

The following two definitions describe the meaning of "Architecture" in the context of complex systems:

- An architecture is the highest level (essential, unifying) concept of a system in its environment[54]

- The structure of the components of a program/system, their interrelationships, and principles and guidelines governing their design and evolution over time

The highest priority work should involve the development of an industry architecture for real-time pricing. The architecture defines the overall substance, function, and management of the system. The lack of a completely defined open architecture for customer communications and real-time pricing in a restructured environment will be a major impediment to the full development of a robust, and cost-effective industry wide system. There are several issues that must be addressed for ultimately implementing a secure, extensible, and maintainable system. The strategic element questions posed in Appendix A identify several of the major issues and desirable characteristics of a robust strategic architecture. The architecture should include standardized industry notation and should build upon related work already underway by the power industry including standards initiatives underway within formally recognized standards-development organizations, such as ANSI, IEEE, ISO[55], and IEC. The work should also recognize the work within industry consortia such as the UCA™ Users group and the Object Management Group (OMG) utility task force. The work should address the concepts presented in the Architecture section of Appendix G. In addition to pricing applications development, the architecture should define the framework for overall system management, which includes a security management architecture.

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[54] The IEEE Architecture Working Group, 1995.
[55] This acronym refers to the International Organization for Standardization, ***not*** the California Independent System Operator.

2. Industry-wide security technology development and application for "RTP enabling" data communications and equipment

The power industry must take information technology security seriously, particularly when it involves applications related to the control of power and customer loads. This is a high priority item, in the aftermath of the events of September 11, 2001. Enabling technologies that integrate power system operations within customer facilities— and that are also connected to the utility power grid— means that vulnerabilities can lead to debilitating consequences to both customers and utilities alike. Simple protection methods that may have been viewed as adequate need to be revisited. The development of security policies should be consistent with industry initiatives that appropriately involve key stakeholding organizations and agencies, such as the NSA, DOE, EPRI, NIST and others. Policy development should be followed by a careful evaluation of both threats and vulnerabilities.

Several technologies are being developed that can "harden" information technologies against attack, and help stabilize and manage the systems when they are attacked. Hardening technologies include stronger forms of encryption, improved authentication methods and security management and administration. However, no amount of hardening will stop a sophisticated intruder, so additional technologies, such as intrusion detection and survivable networking technologies should be considered. Beyond the architecture of security management, this area of research should evaluate several practical implementation issues, such as encryption; trends in "server" protection for embedded systems; open systems and planned heterogeneity; and the application of emerging security technologies, such as IPsec, PKI, RBAC and others.

3. Development of an industry-wide set of functional and communications requirements

Adequately defined technical requirements for implementing RTP, Direct Access and Customer Communications for dynamic response do not exist. This area of research serves as a corollary to the architecture and security work proposed earlier. The requirements definition includes more detail on expected equipment and systems functions and behavior in a restructured environment. This task may be done in parallel with the above tasks since requirements can reveal necessary important elements of the architecture. In addition the requirements should rigorously identify and define the networking and interfaces between key components of the RTP enabling system. This approach should build upon work already underway in the industry.

4. Development of Interoperable and Interworkable Enabling Equipment

The development of elements and components that are built to open standards become the means by which the free market can contribute to the wide variety of equipment needed to implement real-time pricing. Strategic research and development work should include the implementation and refinement of open industry standards based on accredited standards organizations for key components. While many of the standards are in-place, they often do not have sufficient real-world implementations to surface technical issues and necessary refinements. The implementation of the standards for real applications becomes the proving ground for the robustness of the standards. Upon completion, the standard is field tested and more robust; it then seen as more mature (and "stable") by industry participants—improving the prospects for its acceptance by the various stakeholders in technology development and utilization.

Meeting standards conformance is often not enough to enable the independent development of desired levels of "plug and work" interoperability. The standards provide the vendor with a neutral approach for the development of key components of the RTP infrastructure, and they enable hundreds of companies to participate in contributing to the overall implementation of RTP—not just a select few. The desire for open systems development and integration must come from the end-users and researchers on behalf of the end-users. This is not development work that naturally comes from the vendor community, since vendors will typically develop, market and sell proprietary products. Ideally this development work is consistent with the architecture and security policies and requirements. The following components form an initial list of eligible equipment for this work:

- Meters and Meter Communications equipment
- Customer Communication Access devices and Central station clients
- Distributed Resources Communications and Controls Equipment

This equipment must be integrated with wide area access network technologies so the work should include an investigation into emerging available WAN systems, both public and private. Emphasis should be placed on developing interoperability, conformance to requirements and architectural principles. The work should also include refining and defining a common "vocabulary" or "language" that all the equipment can correctly interpret. This work should again leverage off industry work already underway in key standards initiatives. The industry needs to converge on a common language, instead of developing more solutions to the same problem. An emerging approach to the development of a common language for intelligent equipment is through the use of data and device models, using object-based approaches to device communications. Data and device models define the expected behavior of equipment. This is an approach that is being used under key standards initiatives such as at the IEEE, IEC and OMG. The in-building and intelligent customer equipment development will be stimulated by the presence of the real-time pricing rate structures. The free market will pursue the development of in-building technologies provided there are appropriate guidelines for key issues, such as how the customer equipment should be designed for security.

A second priority of work on interoperable equipment would include the following:

- Customer Automated Energy Management Control Systems
- Intelligent End-Use subsystem

- In-building communications development

Ideally customer in-building equipment subsystems can ultimately make use of the communication objects just as they come in from the utility system without having to reformat, interpret or otherwise alter them.

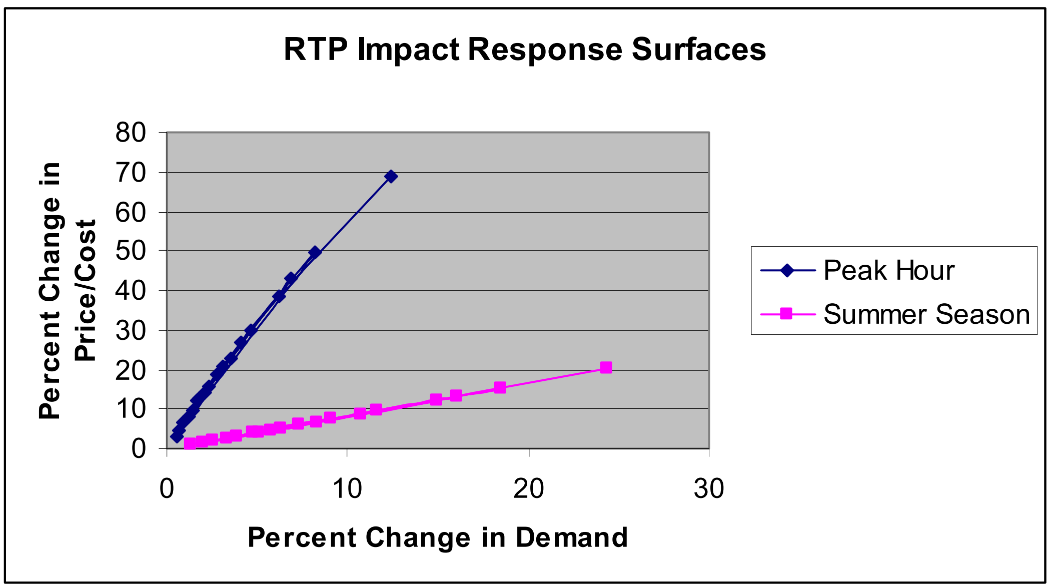
5. Equipment to Integrate Customer and Utility Distribution Operations

In the future, customer loads and generation injection may play a larger role in utility T&D operations. In addition, data from the customer's meter or from local power quality monitoring equipment may be used to help the utility distribution company (UDC) operate the distribution system. This research area would investigate the synergy between customer site data, such as load profiling and distribution system operations. Without developing this synergy, UDCs must install redundant additional equipment to monitor, plan, and control their systems, as well as offset central generation requirements. More system monitoring and integration with utility distribution automation operations is also an outgrowth of the deployment of distributed energy resources (DER) throughout the system. Without close coordination, DER systems operation can interfere with "normal" utility control and protection functions. These interactions suggest more sophisticated and standardized utility interconnection requirements for DER equipment, including both power engineering, and communications and control standards for DER interconnection.

CHAPTER 5
RESEARCH & DEVELOPMENT OPPORTUNITIES

Real-time pricing of electricity can provide substantial benefits to the citizens of California. It promotes economic efficiency in the consumption and production of electricity, by giving customers a strong incentive to lower usage when hourly prices are high, or to shift on-peak usage to off-peak hours. It gives participating customers greater control over their energy bills. In addition, by lowering price volatility and average price levels in the wholesale market, it benefits even those customers who choose not to buy power on a real-time price basis. EPRI has performed several simulations to quantify the benefits of real-time pricing. Both voluntary and mandatory modes of implementation were considered. During peak periods, real-time pricing was found to provide reductions in wholesale prices that, in percentage terms, were about five times the in-peak demand caused by real-time pricing. For the season as a whole, percentage price reductions were found to be equal to the percentage reductions in peak demand. Figure 5-1 lays out the two response surfaces that correspond to these cases.

Figure 5-1



The previous four chapters have identified a variety of research issues that pertain to real-time pricing. It is unlikely that the CEC's PIER program will have sufficient funds to pursue all the issues mentioned in these chapters. This chapter culls the "high priority" issues from the previous chapters, and presents them for the Commission's consideration. The high priority issues are grouped into four categories: customer issues, regulatory issues, utility issues and technological issues.

5.1 CUSTOMER ISSUES

The first issue relates to customer preferences for real-time pricing. Experience has shown that a very small number of customers have chosen real-time pricing. Customers are attracted to real-time pricing on the premise that it will save them money. However, when prices spiked in various markets during the past few summers, many customers dropped out. For example, Duke Energy had 100 customers, but now only has 59 on real-time pricing; BC Hydro had 25 customers, but now has none. To address the first issue, the CEC may want to initiate a project that addresses a group of interrelated research questions:

- If customers were offered real-time pricing on a voluntary basis, how many would take it? Are customers more likely to take a two-part design than a one-part design, because it provides a measure of price insurance? What types of customers are drawn toward real-time pricing? At what rate are customers willing to trade-off a lower expected value of price against a higher standard deviation of price? How many more customers would take real-time pricing if it were to be combined with some type of price protection product, such as a price cap or a price collar? What is the demand for other types of market-based pricing products, such as occasional real-time pricing?

The second issue relates to the load clipping or shifting that would be induced by real-time price. Experience has shown that only a few customers either reduce load or shift it from on-peak to off-peak periods. And of those that do respond to real-time pricing, there is considerable day-to-day variation in response patterns. The CEC may want to initiate a project designed to answer the following questions:

- How much load relief can be expected from real-time pricing? Is it greater or lesser with a one-part design versus a two-part design? What segments are likely to shift more load? Does the load shifting information contained in EPRI's StatsBank apply to California? Is load shifting information stable and reliable over time?

The third issue relates to implementation strategy. Some utilities have only a handful of customers on real-time pricing. How can better results be obtained? A project along the following lines might be worth considering:

- Should real-time pricing be offered on a voluntary or mandatory basis? Should a pilot program be conducted prior to full-scale implementation?
- What segments should be targeted? Research summarized in Chapter 2 indicates that customers with on-site generation, discrete production processes, and previous experience with interruptible tariffs are more likely to benefit from real-time pricing. Is this finding valid in California? What is the best recruitment strategy for signing up customers? How much education is needed to get customers acclimatized to the incentives provided by real-time pricing?

5.2 REGULATORY ISSUES

The first issue deals with the terms of the default service:

- Should default service be provided on a real-time basis? Is it infeasible to implement real-time pricing in a restructured power market, when the UDC is providing default service at a fixed price that is discounted off a historical value, thereby cannibalizing any new products that may be offered by ESPs?

The second issue relates to the simultaneous existence of market-based load curtailment programs and real-time pricing.

- Should customers who volunteer for a load curtailment program be excluded from receiving service on a real-time basis? Would this constitute double dipping? Or would it be a cost-effective way of obtaining additional load shifting without having to make any additional investment in control technologies?

The third issue relates to a perception that real-time pricing will seriously inconvenience customers, since they cannot reduce peak usage or shift load from on-peak to off-peak periods. This issue is related to the resolution of the issues discussed under Customer Issues.

- What is the best way to convince regulators that customers can indeed be trained to shift their loads from on-peak to off-peak hours? Would it be useful to conduct a series of seminars and workshops for regulators, utilities and prospective customers, in which customer case studies would be featured from other parts of the country?

A fourth issue arises from California's specific situation, in which the state has bought power under long-term contracts, thereby seemingly eliminating the need for real-time pricing.

- Is it possible to prove that real-time pricing can improve economic efficiency when the state has already brought large blocks of power at fixed price contracts? For example, would it be useful to run numerical simulations with EPRI's Product Mix model to make this point transparent to policy makers.

5.3 UTILITY ISSUES

The first issue deals with the potential for revenue loss. If customers volunteer for real-time pricing simply because they have an inverse load shape, utilities will lose revenue without gaining any reduction in costs. If customers volunteer because they can shift a major portion of their load to cheaper hours, that would also lead to revenue loss. The following project can address this issue:

- How serious is the potential revenue loss associated with real-time pricing? Can it be offset by following a two-part design?

The second issue relates to the potential for gaming associated with two-part designs that require the establishment of a customer base load (CBL). There is some anecdotal evidence that customers may have gamed the selection of their base load, when signing up for market-based load curtailment programs. A similar concern may also apply to two-part real-time pricing designs. This could be addressed through the following project:

- Is there any empirical evidence from other states that customers have gamed the selection of their CBLs? If so, can better educational programs offset this problem?

The third issue deals with billing and settlement systems. Most existing systems are not capable of handling hourly bills. Modifications have to be made by the IT staff, which is often overburdened with other duties. The only practical solution is to outsource this capability, but that often comes burdened with a large price tag.

- What is the cost of implementing billing and settlement systems that would enable real-time pricing? How can these costs be managed most effectively?

5.4 TECHNOLOGICAL ISSUES

The first issue deals with the development of direct access system architecture. The architecture defines the overall substance, function, and management of the system.

- There are several issues that must be addressed for implementing a secure, extensible, and maintainable system. This includes the development of standardized industry notation and definition of the framework for overall system management, and identification of security management systems.

The second issue deals with the development of security systems. Policy development needs to be followed by a careful evaluation of both threats and vulnerabilities.

- What technologies can be deployed to "harden" information technologies against attack, and help stabilize and manage the systems when they are attacked? Hardening technologies include stronger forms of encryption, improved authentication methods, and security management and administration. No amount of hardening however will stop a sophisticated intruder, so additional technologies such as intrusion detection and survivable networking technologies should be considered.

The third issue deals with the development of functional, nonfunctional, and communications requirements.

- What are the requirements for networking and interfacing key components of the RTP enabling system?

The fourth issue deals with the development of standards to facilitate interoperable and interworkable enabling equipment.

- How should existing industry standards be improved? Existing standards do not have sufficient real-world implementation to surface technical issues and necessary refinements. The new standards should deal with interoperability between the following classes of equipment: meters and meter communications equipment; customer communication access devices and central station clients; distributed resources communications and controls equipment; customer automated energy management control systems; intelligent end-use subsystem; and in-building communications equipment.

The fifth issue deals with equipment that integrates customer and utility distribution company operations.

- What is the synergy between customer site data such as load profiling and distribution system operations? Without developing this synergy, UDCs must install redundant additional equipment to monitor, plan and control their systems, as well as offsetting central generation requirements. More system monitoring and integration with utility distribution automation operations is also an outgrowth of the deployment of distributed energy resources (DER) throughout the system. Without close coordination, DER systems operation can interfere with “normal” utility control and protection functions.

CHAPTER 6
BIBLIOGRAPHY

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