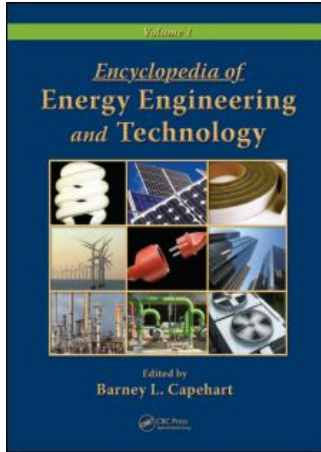


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Pricing Programs: Time-of-Use and Real Time

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Abstract

This article surveys numerous pricing designs for improving economic efficiency in all market segments. Electricity is a very capital-intensive industry characterized by a significant peak load problem. Expensive generating plants have to be installed to meet peak loads that are only encountered for a few hundred hours a year. This raises the cost of electricity to all consumers. Average cost pricing, the staple of the industry in which rates do not vary by time of use, compounds the problem by creating cross-subsidies. Customers with flatter load shapes subsidize those with peakier load shapes.

The problem can be alleviated by modifying electricity pricing practices to allow time-variation in costs. This would provide customers an incentive to lower peak usage, either by curtailing or shifting their activities. In addition, it would eliminate unfair and economically unjustified cross subsidies. But the potential benefits of time-varying pricing have yet to be fully realized. Many barriers stand in the way of reform, including economic, technological and political. Of all these barriers, the most formidable ones are the political ones. They have to be resolved by modifying the legal and regulatory framework through which electricity pricing is determined.

INTRODUCTION

Time-of-use (TOU) pricing and real time pricing (RTP) programs are designed to lower system costs for utilities and bring down customer bills by raising prices during expensive hours and lowering them during inexpensive hours. They differ in, that the former fixes the price and time periods in advance while the latter fixes neither the price nor the time period in advance. Thus, TOU rates can be considered static while RTP rates can be considered dynamic, even though before feature time-varying prices. Other rate designs bridge the gap between these two rate designs, as shown below.

Time-of-use pricing (TOU). This rate design features prices that vary by time period, and are higher in peak periods and lower in off-peak periods. The simplest rate involves just two pricing seasons, with prices being higher during the peaking season. A time-of-day rate is slightly more complex and involves two pricing periods within a day, a peak period and an off-peak period. More complex rates have one or more shoulder periods and seasonal variation.

Critical peak pricing (CPP). This rate design layers a very high price during a few critical hours of the year. It can also be combined with a TOU rate. Typically, a CPP rate is only used on 12–15 days a year. These days are called the day before or the day of the critical peak price.

Extreme day pricing (EDP). This rate design is similar to CPP, except that the higher price is in effect for all 24 h

for a maximum number of critical days, the timing of which is unknown until a day ahead.

Extreme day CPP (ED-CPP). This rate design is a variation of CPP in which the critical peak price applies to the critical peak hours on extreme days but there is no TOU pricing on other days.

Real time pricing (RTP). This rate design features prices that vary hourly or sub-hourly all year long, for some or all of a customer's load. Customers are notified of the rates on a day-ahead or hour-ahead basis.

Each of these rates exposes customers to varying amounts of price variance. Customers can lower their expected (average) price by taking more risks. For example, RTP rates are riskiest from the customer's viewpoint since they face wholesale prices that vary in real time, but they will most likely be associated with the lowest average price. Critical peak pricing rates carry less pricing uncertainty for customers, since customers know the prices ahead of time and the time for which these prices will be in effect is limited. However, the average price is likely to be higher than that for RTP rates. At the other end of the spectrum are rates that do not vary over the hours of the day and only vary seasonally. They provide the highest rate predictability to customers but are also likely to carry the highest average price.

TIME-OF-USE PRICING

Time-of-use pricing is commonplace in developed economies at all stages of market restructuring. Electricite de France (EDF) operates the most successful example of

Keywords: Electricity pricing; Rate design; Economic efficiency; Demand response.

TOU pricing. Currently, a third of its population of 30 million customers is estimated to be on TOU pricing. This pricing design was first introduced for residential customers in 1965 on a voluntary basis, having been first applied in the country to large industrial customers as the Green Tariff in 1956. The French model served for many years as a benchmark for many countries in Latin America. For example, in Brazil, it was introduced as the “Horosazonal” tariff, which divides the day into peak and off peak periods and the year into dry and wet seasons. The idea was to continue all the way to the residential customer (yellow tariff), but it never came to fruition.

Time-of-use rates have been mandatory in California for all customers above 500 kW since 1978, as a statewide policy response to the energy crisis of 1973. These rates are mandatory in several U.S. states but the size threshold varies by state.

Residential TOU rates are offered on a voluntary opt-in basis by utilities in all types of climates within the U.S., including Pepco in the Washington, DC area and the Salt River Project in the Phoenix area. The simplest variation involves two time periods. An example is the residential rate design offered by Pacific Gas & Electric Company (PG&E) in central and northern California. During the summer months, from noon to six P.M. on weekdays, electricity costs three times as much as during all other hours of the week. During the winter months, the price differential is smaller.

Another example is the project that was implemented by Puget Sound Energy (PSE) in the suburbs of Seattle. In May 2001, as a response to the power crisis in the Western states, PSE designed and implemented a TOU rate for its residential and small commercial customers. It involved four pricing periods. The morning and evening periods were the most expensive periods, followed by the mid-day period and the economy period. Unlike most TOU rates, which feature significant differentials between peak and off-peak prices, PSE’s TOU rate featured very modest price differentials between the peak and off-peak periods, reflecting the hydro-based system in the Northwest.

The peak price was about 15% higher than the average price customers had faced prior to being moved to the TOU rate and the off-peak price was about 15% lower. To keep the rate simple, there was no seasonal variation in prices.

Puget Sound Energy placed about 300,000 customers on the rate, but they could opt-out to the standard rate if they so desired. There was no additional charge to participate in the rate. During the first year of the program, less than half of one percent elected to opt-out of the rate. Customer satisfaction with the rate was high. In focus groups, customers identified several benefits of the TOU rate besides bill savings, including greater control over their energy use; choice about which rate to be on; social responsibility; and energy security. PSE also provided a

website to customers where they could review their load shapes for the past seven days.

Puget Sound Energy had a rate case settlement in June 2002. Under the terms of the settlement, the program became an opt-in program for new customers. The peak/off-peak rate differential of the TOU rate was reduced from 14 to 12 mils/kWh (A mil is a thousandth of a dollar). A monthly fee of \$1 a month, about 80% of the estimated variable cost of providing TOU meter reading, was levied on participating customers. Finally, each quarter PSE would notify customers of their savings (or losses) on the program, and it would switch all customers to the lower-cost rate (flat or TOU) in August 2003.

In October 2002, PSE sent customers their first quarterly report. For 94% of the customers, this report showed that they were paying an extra 80 cents/month by participating in the TOU pilot, comprised of the difference between 20 cents of power cost savings and a dollar of incremental meter reading costs. This was marked in contrast to the first year of the program when, prior to charging customers any part of the TOU meter reading costs, over 55% of residential customers experienced bill savings by being on the TOU rate.

Even though the report was for a single quarter, 10% of the participating customers chose to opt-out of the program between July 1 and October 31. At the same time, 1.8% of new customers opted into the program.

Media coverage was very negative and featured interviews with customers claiming that they had shifted almost half of their load from peak to off-peak periods, only to find out that they had lost money. PSE pulled the plug on a program that had become the most visible national symbol of a utility’s commitment to time-varying pricing, and agreed to refund the increased amounts to participating customers.

Lessons Learned From the PSE TOU Rate

Five lessons can be drawn from PSE’s TOU program.

- Customers do shift loads in response to a TOU price signal, even if the price signal is quite modest. According to an independent analysis, customers consistently lowered peak period usage by 5% per month over a 15-month period.
- It is important to manage customer expectations about bill savings.
- Customers should be educated on the magnitude of bill savings they can expect from specific load shifting activities.
- It is desirable to conduct a pilot program involving a few thousand customers before offering a rate to hundreds of thousands of customers.
- Finally, and most importantly, any program should make a majority of the customers better off, or it should not be offered.

Developing a TOU Rate

It is fairly straightforward to develop a TOU rate design. The following sidebar shows the steps involved in developing a “revenue-neutral” TOU rate. Such a rate would leave the average customer’s bill unchanged if that customer chose to make no adjustments in their pattern of usage. Of course, a customer who uses less power in the peak period than the average customer would be made better off (compared to his or her situation on the standard rate) by the rate even without responding to the rate and a customer who uses proportionately more power in the peak period than the average customer would be made worse off by the rate if he or she did not respond to the rate.

Sidebar 1 brings out the type of information that is needed to develop a TOU rate.

CRITICAL PEAK PRICING

Under this rate design, customers are on TOU prices for most hours of the year but additionally face a much higher price during a small number of critical hours when system reliability is threatened or very high prices are encountered in wholesale markets because of extreme weather conditions and similar factors. In 1993, EDF (France)

Sidebar 1 Developing a TOU rate involves several steps

Existing flat rate

Per-customer revenue requirement	\$100
Per-customer monthly usage	1000 kWh
Average price	\$0.10/kWh

Revenue neutral TOU rate

Estimate peak usage	200 kWh
Estimate off-peak usage	800 kWh
Set peak price = peak marginal cost	\$0.20/kWh
Set off-peak price = off-peak marginal cost	\$0.075 kWh

Given class revenue requirement	\$100
Given monthly usage	1000 kWh

TOU rate with load shifting

Estimate price elasticity	-0.2
Estimate new peak usage	160 kWh ^a
Estimate new off-peak usage	840 kWh
Estimate new monthly usage	1000 kWh
Estimate new per-customer monthly bill	\$95
Estimate bill savings = per-customer revenue loss	\$100 - \$95 = \$5

^aThese changes in usage for the peak and off-peak period are estimated by using the percent changes in peak and off-peak prices and the estimated price elasticity of demand.

introduced a new rate design, tempo, and now has over 120,000 residential customers on it. The program features two daily pricing periods and three types of days. The year is divided into three types of days, named after the colors of the French flag. The blue days are the most numerous (300) and least expensive; the white days are the next most numerous (43) and mid-range in price; and the red days are the least numerous (22) and the most expensive. The ratio of prices between the most expensive time period (red peak hours) and the least expensive time period (blue off-peak hours) is about 15–1, reflecting the corresponding ratio in marginal costs.

The tempo rate does not offer a fixed calendar of days, but customers can learn what color will take effect the next day by checking a variety of different sources:

- Consulting the Tempo Internet website: www.tempo.tm.fr
- Subscribing to an email service that alerts them of the colors to come
- Using Minitel (a data terminal particular to France, sometimes called a primitive form of Internet)
- Using a vocal system over the telephone
- Checking an electrical device (*Compteur Electronique*) provided by EDF that can be plugged into any electrical socket.

The tempo rate was preceded by a pilot program, in which prices were quite a bit higher than those that were ultimately implemented. The rates associated with the tempo program and with EDF’s standard TOU rate are shown in Fig. 1.

Critical Peak Pricing With Enabling Technologies

Recently, a number of utilities have experimented with dynamic pricing options, sometimes in conjunction with enabling technologies that automate customer response during high priced periods. As seen below, dynamic pricing, especially when combined with enabling technologies, can produce much larger reductions in peak demand than traditional TOU or non-technology enabled CPP rates.

Two utilities, GPU in Pennsylvania and American Electric Power in Ohio, conducted small-scale pilot programs in the 1980s using a two-way communication and control technology called TransText. The TransText device allows for the creation of a fourth critical price period in which the retail price of electricity rises to a much higher level (e.g., 50 cents/kWh in the GPU pilot). The number of hours during which this price can be charged is small (e.g., 100–200 h) and the customer knows what the critical price will be ahead of time, but does not know when the price may be called.

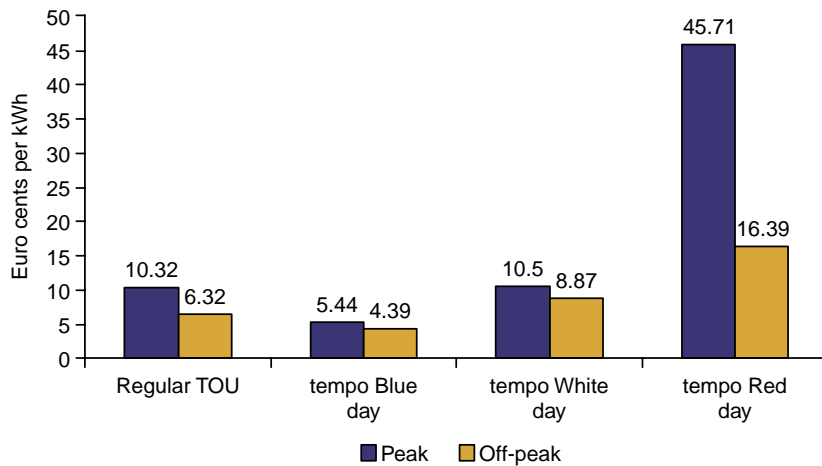


Fig. 1 EDF's tempo and standard TOU rates.

The TransText device incorporates an advanced communication feature that lets customers know that a critical period is approaching and it can be programmed so that the customer's thermostat is automatically adjusted when prices exceed a certain level. Using this technology, American Electric Power found significant load shifting, with estimated peak demand reductions of 2–3 kW per customer during on-peak periods and of 3.5–6.6 kW during critical peak periods. These critical peak reductions represented a drop of nearly 60% of a typical customer's peak load during the winter period.

The GPU experiment produced similar results, showing elasticities of substitution that ranged from -0.31 to -0.40 , significantly higher than the elasticities associated with traditional TOU rates, which have averaged -0.14 in a range of studies. These elasticities were estimated by comparing customer loads on days when control was being exercised with days when control was not being exercised.

Another example is provided by Gulf Power Company's *Good Cents Select* program in Florida. Like the GPU experiment, the Gulf Power program uses dynamic pricing to obtain additional benefits beyond traditional TOU pricing. Under this voluntary program, residential consumers face a three-part TOU rate for 99% of all hours in the year, where the peak period price of \$0.093/kWh is roughly 60% higher than the standard (flat) tariff price and approximately twice the intermediate (shoulder) price. For the remaining 1% of the hours, Gulf Power has the option of charging a critical period price equal to \$0.29/kWh, more than three times the value of the peak-period price. The timing of this much higher price is uncertain and it is called during the day when critical conditions are encountered. In conjunction with this rate, participating customers are provided with a programmable/controllable thermostat that automatically adjusts their heating and cooling loads and up to three additional control points in the home such as water heating and pool pumps. The devices can be programmed to modify usage when prices exceed a certain level.

Gulf Power is seeing results similar to those of the GPU experiment. Peak-period reductions in energy use over a 2-year period have equaled roughly 22% compared with a control group, while reductions during critical-peak periods have equaled almost 42%. Diversified coincident peak demand reductions have exceeded more than 2 kW per customer. This voluntary program has been in place for less than a year, and Gulf Power has already signed up more than 3000 high use customers. It hopes to attract 40,000 customers over the next 10 years, representing about 10% of the residential population. Participating customers pay roughly \$5/month to help offset the additional cost of the communication and control equipment. In a recent survey, the program received a 96% satisfaction rating.

The Gulf Power program is targeted at high use customers, just like the EDF program. Customer savings are large enough to offset the program costs. Both rates have significant peak to off-peak differentials as well. Because of these two factors, the programs have been successful. The PSE program failed in part because it had weak peak to off-peak differential and in part because it did not target the large customers.

California's Pricing Experiment

The state of California conducted a statewide pricing pilot (SPP) during the 2003–2005 timeframe to test customer response to a variety of pricing options, including TOU rates and CPP rates. In California, standard residential tariffs involve an "inverted tier" design in which the price of power rises with electricity usage. The typical residential customer pays an average price of about 13 cents/kWh. Within the SPP, customers on TOU and CPP rates pay a higher price during the five-hour peak period that lasts from 2 P.M. to 7 P.M. on weekdays and a lower price during the off-peak period, which applies during all other hours.

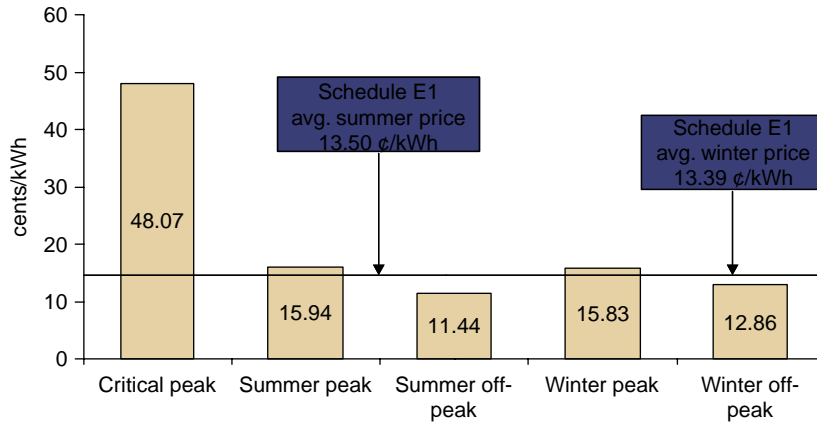


Fig. 2 Critical-peak pricing (CPP) tariff.

Each TOU and CPP rate involves two sets of peak/off-peak prices, to allow for precise estimation of the elasticities of demand. On average, customers on TOU rates are given a discount of 23% during the off-peak hours and are charged a price of around 10 cents. They are charged a price of 22 cents during the peak hours, which is 69% higher than their standard rate. Thus, with TOU rates, customers are given a strong incentive to curtail peak usage and to shift usage to off-peak periods. However, the incentive is much greater on selected days for customers on CPP rates, who are charged, on average, a price of 64 cents during the peak hours on 12 summer days, i.e., prices are nearly five times higher than the standard price. On the peak hours of other days and the off-peak hours of all days they face prices that are slightly lower than the prices faced by TOU customers during these periods. Fig. 2 shows the CPP tariffs that were used in the California experiment.

Analysis of data from the California experiment indicates that CPP rate customers face “rifle shot” price signals that can be very effective at reducing peak demand, thus dampening wholesale prices and obviating the need for building costly power plants that would run for only a

few hundred hours a year. Customers are likely to respond to higher peak prices by reducing peak usage, e.g., by reducing air conditioning usage, and perhaps by shifting some peak period usage associated with laundry, dishwashing and cooking activities to lower cost off-peak periods. They may also be raising off-peak use in response to lower off-peak rates by raising air conditioning usage, increasing lighting levels, and so on. Finally, since prices have changed in the peak and off-peak periods, the average price for electricity over the day may have changed for some customers as well. This would trigger additional changes in usage.

Fig. 3 shows the changes in customer load shapes caused by the CPP tariff in customers who were located in the San Diego Gas and Electric service area. The black line shows the usage of the control group of customers. The gray line shows the usage of customers who were equipped with a smart thermostat that received a communication signal from the utility during critical hours, which raised the set point of the thermostat. Their tariff was unchanged from that of the control group. The difference between the two lines is noticeable and suggests that remotely controlling the thermostat lowers peak usage. The white line shows the

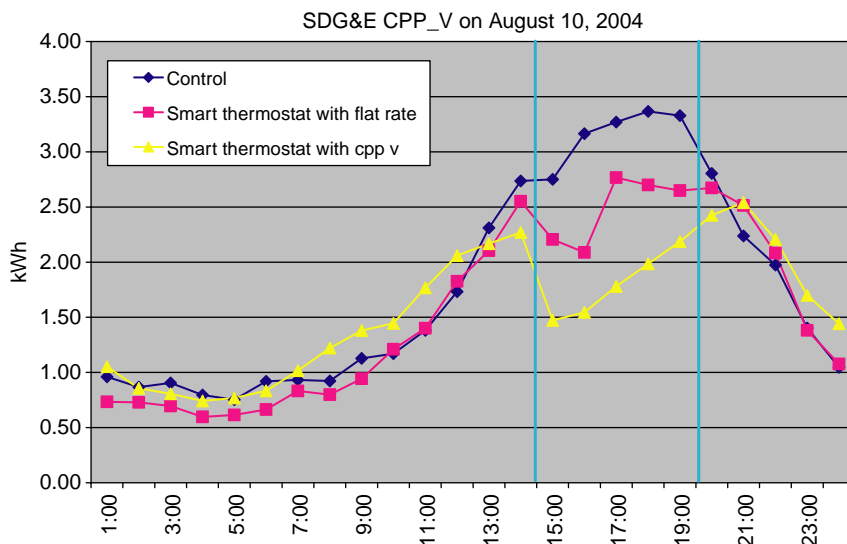


Fig. 3 Changes in customer load shapes.

usage of customers who were equipped with a smart thermostat and who also were placed on the CPP tariff. They show a greater drop than customers who had the smart thermostat but who were not placed on the CPP tariff.

REAL-TIME PRICING FOR RESIDENTIAL CUSTOMERS

The Chicago Community Energy Cooperative (Co-op) has implemented a market-based RTP pricing plan for residential customers, in conjunction with the local electric utility, CommEd. The utility provides the rate and the metering/billing system while the Co-op provides customer notification (via a web site, e-mail and telephone), education, and energy management tools (Fig. 4).

The pilot program is intended to model the bundled rate/market rate differential in the post-2006 market environment when the rate freeze is lifted. It involves RTP prices on a day-ahead basis for the generation portion of the rate. The prices are capped at 50 cents/kWh. The project is designed to estimate the magnitude of customer response to hourly energy pricing and understand the drivers of responsiveness. This is a 3-year experimental program that commenced in January 2003.

In the first year of the program, 750 customers were enrolled. Of these, 100 are in a control group. The summer of 2003 was mild in terms of both temperatures and prices. For example, the number of days with a maximum temperature higher than 90°C was 10 versus a historical average of 18. The maximum price was 12.39 cents/kWh, versus a price of 38.11 cents/kWh during the crisis years of 2000–2002.

Analysis of customer loads during the first year indicates that participants responded to the higher prices

they faced during the peak periods. A price elasticity of -0.042 was estimated over the full range of prices. Over half of all participants showed significant response to high price notifications. Aggregate demand reduction was as high as 25% during the notification period. Over 80% of the participants reported modifying their air conditioning usage, and over 70% reported modifying their clothes-washing patterns.

Multifamily households as a group were more price-responsive than single-family households. Households with window air conditioners maintained their price responsiveness better across multiple high-priced hours than single-family households, who started out strong but whose responsiveness tended to taper off during the high priced periods.

Customer satisfaction was very high with the program. The program was “quick and easy” for 82% of the participants and “time consuming and difficult” for 1%. Participants saved on average \$12/month or 20% of their monthly bill.

The project has shown that residential customers are a viable market for RTP. They represent a key target market, since residential load is a major contributor to system peak. And giving residential customers a choice of pricing options may be the only way to give them a meaningful choice in restructured power markets.

REAL-TIME PRICING FOR COMMERCIAL AND INDUSTRIAL CUSTOMERS

Utilities in the Southeastern U.S. have implemented RTP rates for about 2000 customers on a day-ahead or hour-ahead basis. These companies include Georgia Power,

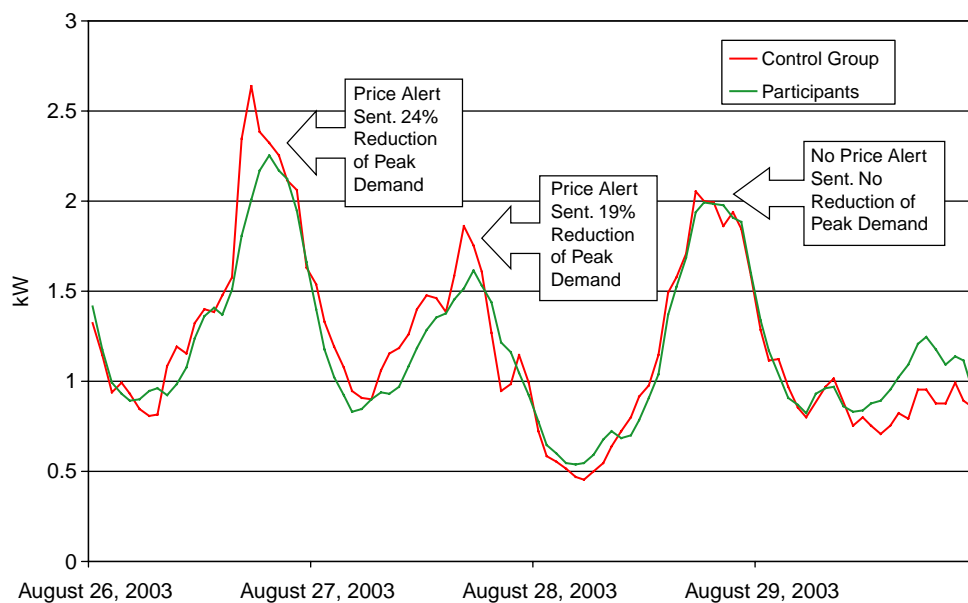


Fig. 4 Impact of real time pricing on Chicago Residences.

Duke Power and the Tennessee Valley Authority. The Georgia Power program is discussed in detail below.

Before describing the Georgia Power program, we note that RTP rates were probably first used by ESKOM, the state-owned utility in South Africa, for its largest customers, including the fabled gold mines. ESKOM has 1400 MW of load on day-ahead RTP. These customers drop their load by 350–400 MW for up to three consecutive hours when faced with high prices. While RTP is set up on a day-ahead basis, customer response is not used to optimize the dispatch of the power system. Electricity prices are based on the Pool Output Price, and do not change in response to changes in customer demand that may be induced by RTP. The utility is not aggressively marketing the program for this reason. It hopes that once a competitive energy market has been created, with a functioning Power Exchange, RTP will then be able to play its proper role in system operations.

If RTP had been implemented in California during the summer of 2000, much of the power crisis that developed in May 2000 would have abated within a month, rather than persisting for a year. If only a small proportion of the total customers had bought power on RTP, statewide peak demand would have dropped by 2.5%, or 1250 MW. During the peak hours, this would have lowered wholesale market prices by 20%. The state's power costs for the summer would have dropped by 6% (Faruqui, Ahmad, Hung-po Chao, Vic Niemeyer, Jeremy Platt and Karl Stahlkopf, "Getting out of the Dark," *Regulation*, Fall 2001, pp. 58–62).

RTP at Georgia Power

Georgia Power runs the world's largest and possibly the most successful RTP program. The company estimates that during emergency conditions, its customers drop demand by 17%, freeing up 800 MW of capacity. A load drop of this magnitude eliminates the need for several expensive power plants that would otherwise be needed for meeting the peak load.

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 RTP. In 1992, it began a 2-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 to balance supply and demand.

Georgia Power was one of the first utilities in the country to develop a two-part RTP tariff, following the lead of Niagara Mohawk in New York that had launched

an Hourly Pricing Program in the late 1980s. The utility 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. A discussion of price protection products is provided below. 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

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, line losses, a "risk recovery factor" for forecasting risk (a fixed adder), and—near peaks—marginal transmission costs and outage cost estimates. Marginal transmission costs are triggered by load and temperature. Outage cost 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 P.M. 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 customer baseline (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 a tariff with the Public Service Commission that would 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 mils/kWh versus 3 mils/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 8760-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 four-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 periods.

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 8760-point CBL today (Our source noted that customers who can "really respond a lot" are typically on the higher point CBLs).

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 want 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 1650 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, index swaps, and index caps (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). Georgia Power has sold these Price Protection Products, or PPPs, for 3 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 not probably 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

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 1500–2000 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 their facilities and business operations in Georgia. In other words, the rate has served to bring economic growth to the state and been a form of strategic electrification while also being a form of load management.

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 Public Services 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 Power has also found that manufacturers with highly energy-intensive processes, such as chemical and pulp and paper companies are generally the most price responsive customers. It is also learnt 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 Power states that the major lesson it has learnt is that education is the key to a successful RTP program. Georgia Power now holds annual, statewide meetings with all its customers to keep them informed about the RTP program. The utility believes its education program has paid off in customer satisfaction.

CONCLUSION

Electricity is a very capital-intensive industry characterized by a significant peak load problem. Expensive generating plants have to be installed to meet peak loads that are only encountered for a few hundred hours a year. This raises the cost of electricity to all consumers. Average cost pricing, the staple of the industry in which rates do not vary by time of use, compounds the problem by creating cross-subsidies. Customers with flatter load shapes subsidize those with peakier load shapes.

The problem can be alleviated by modifying electricity pricing practices to allow time-variation in costs. This

would provide customers an incentive to lower peak usage, either by curtailing or shifting their activities. In addition, it would eliminate unfair and economically unjustified cross subsidies. As surveyed in this article, there are numerous pricing designs for improving economic efficiency in all market segments. But the potential benefits of time-varying pricing have yet to be fully realized. Many barriers stand in the way of reform, including economic, technological and political. Of all these barriers, the most formidable ones are the political ones. They have to be resolved by modifying the legal and regulatory framework through which electricity pricing is determined.

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