

GAO

Report to the Chairman, Committee on
Governmental Affairs, U.S. Senate

August 2004

ELECTRICITY MARKETS

Consumers Could Benefit from Demand Programs, but Challenges Remain



G A O

Accountability * Integrity * Reliability



Highlights of [GAO-04-844](#), a report to the Chairman, Committee on Government Affairs, U.S. Senate

Why GAO Did This Study

The efficient and reliable functioning of the more than \$200 billion electric industry is vital to the lives of all Americans. As demonstrated in the 2003 black-out in the Northeast and the 2001 energy crisis in the West, changes in the cost and availability of electricity can have significant impacts on consumers and the national economy. The Federal Energy Regulatory Commission (FERC) supports using demand-response programs as part of its effort to develop and oversee competitive electricity markets.

GAO was asked to identify (1) the types of demand-response programs currently in use, (2) the benefits of these programs, (3) the barriers to their introduction and expansion, and (4) instances where barriers have been overcome. Additionally, GAO examined the federal government's participation in these programs through the General Services Administration (GSA).

What GAO Recommends

GAO recommends that (1) FERC consider demand-response in making decisions about wholesale markets and report to Congress on any impediments to doing so and (2) GSA make demand-response a key factor in its energy decision making.

www.gao.gov/cgi-bin/getrpt?GAO-04-844.

To view the full product, including the scope and methodology, click on the link above. For more information, contact Jim Wells at (202) 512-3841 or wellsj@gao.gov.

ELECTRICITY MARKETS

Consumers Could Benefit from Demand Programs, but Challenges Remain

What GAO Found

There are two general types of electricity demand-response programs in use: (1) market-based pricing programs enable customers to respond to changing electricity prices and (2) reliability-driven programs allow either the customer or the grid operator to adjust electricity usage when supplies are scarce or system reliability is a concern. The federal government's GSA participates in both types of programs.

Demand-response programs benefit customers by improving the functioning of markets and enhancing the reliability of the electricity system. Some recent studies show that demand-response programs have saved customers millions of dollars and could save billions of dollars more. The GSA—as only one example of federal involvement in these programs—has reported saving about \$1.9 million through the participation of only a few of its buildings in demand-response programs during the past 5 years. However, GAO estimates that GSA could potentially save millions of dollars more with broader participation in these programs.

While benefits from demand-response are potentially large, three main barriers limit their introduction and expansion: (1) state regulations that shield consumers from price fluctuations, (2) a lack of equipment at customers' locations, and (3) customers' limited awareness about the programs and their benefits. Regarding prices, customers do not respond to price fluctuations because the retail prices they see do not reflect market conditions but are generally set by state regulations or laws. In addition, in recent years, moderate weather conditions and other factors have kept overall electricity prices low, reducing the benefits of participating in these programs. According to GSA, its participation in demand-response programs has been limited because it lacks specific guidance on participation and tenants have little incentive to reduce their consumption since current leases do not provide a way to share in the savings that might occur.

Two demand-response programs that GAO reviewed illustrate how the barriers GAO identified were overcome and also point out lessons on how to cultivate new programs. Lessons learned include the necessity to provide sufficient incentives to make participation worthwhile, working with receptive state regulators and market participants to develop programs, and designing programs to include appropriate outreach materials, necessary equipment, and easy participation.

In commenting on the report, FERC and GSA agreed in general with the report's conclusions and recommendations, but GSA expressed concern about one recommendation to share potential savings with its tenants.

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Abbreviations

DOE	Department of Energy
FERC	Federal Energy Regulatory Commission
GSA	General Services Administration
ISO	Independent System Operator
NEDRI	New England Demand Response Initiative
NERC	North American Electric Reliability Council

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United States Government Accountability Office
Washington, D.C. 20548

August 13, 2004

The Honorable Susan M. Collins
Chairman, Committee on Governmental Affairs
United States Senate

Dear Chairman Collins:

The efficient and reliable functioning of the electric industry is vital to the nation's economy and central to the lives of all Americans. Annual expenditures on electricity amount to about \$224 billion, and electricity provides the power to produce billions of dollars more in revenue in other industries. As a result, changes in the price and availability of electricity can have substantial impacts on customers and the broader economy. In particular, two events have drawn attention to the need to examine the operation and direction of the industry. The August 14, 2003, blackout that affected New York and seven other states in the eastern section of the nation's electricity system—the largest blackout in U.S. history—caused losses in productivity and revenue estimated in the billions of dollars. Just a few years earlier, in 2000 and 2001, the energy crisis in the West boosted rates for customers, forced some utilities into bankruptcy, created additional uncertainty in electricity markets, led to rolling blackouts, and demonstrated that the electricity market was subject to price manipulation.

The federal government and some states are restructuring the electric industry with the goal to increase the amount of competition in wholesale and retail electricity markets, which is expected to lead to benefits for electricity consumers. As such, the industry is restructuring from one that is characterized by monopoly utilities that provided customers with electricity at regulated rates to a competitive industry in which prices are determined largely by supply and demand. Restructuring is already under way at the federal level for wholesale markets—markets in which power is bought and sold by utilities that are overseen by the Federal Energy Regulatory Commission (FERC). As part of this process, FERC is responsible for changes to wholesale market rules, including rules to allow new suppliers to enter wholesale markets and sell electricity. FERC is also responsible for making sure that prices in these markets are “just and reasonable” and does so by the promotion of competitive markets and issuing related market rules. Restructuring of retail markets—markets serving customers—is also under way in 17 states and the District of Columbia, while other states have either suspended or delayed previous plans or do not have plans to restructure their markets. Despite some state

initiatives to restructure, almost all retail prices continue to be set by regulation or state law and are not determined by supply and demand.

Whether subject to traditional regulation or the rules of a competitive market, the electric industry must manage a complex network of power plants and power lines. Since electricity travels at the speed of light and cannot be easily stored, the output of power plants must be matched precisely with demand for electricity to maintain the reliability of the network. Because of the need to precisely match supply and demand at all times, wholesale and retail markets are operationally joined. However, demand varies significantly with the time of day and year, generally reaching its highest levels on hot summer afternoons. As demand grows, utilities increase output from the power plants already supplying electricity and add a sequence of plants to meet the rising levels of demand. The last plants used to meet rising demand, so-called “peak demand” plants, are generally much more expensive to operate and generally operate the equivalent of only a few days per year. As a result, the costs of generating electricity can vary dramatically, becoming about 10 times more expensive during periods of peak demand than during periods of average demand.

In both regulated and restructured markets, the system continues to be balanced by changes in supply. Historically, grid operators maintain reliability by increasing or decreasing the amount of electricity available from power plants. The average prices customers pay are determined predominantly by the costs associated with these changes in supply. However, when prices are set by regulation or law and change infrequently, customers are largely insulated from frequent and short-term changes in the cost to generate electricity. Industry experts have long said that encouraging customers to change their demand for electricity in response to ongoing changes in its price may offer cost and operating advantages over relying solely upon changes in supply. Toward this end, some utilities and system operators have created a variety of electricity pricing and other programs that encourage customers to adjust their usage in response to changes in prices or market conditions affecting reliability of service. These programs are collectively referred to as “demand-response” programs.

According to FERC, demand-response is an important part of well-functioning electricity markets but largely missing from today’s markets. Further, there is general agreement among industry experts that the absence of retail demand-response contributes to problems in wholesale markets, allowing higher, more volatile prices and the exercise of market

power by electricity sellers. For example, FERC determined that the absence of consumer response to sharply higher prices in western wholesale electricity markets contributed to the financial and energy crisis there. FERC has approved proposals by several grid operators to incorporate demand-response into the wholesale markets that they oversee, but these efforts have met with limited success. As part of a broader effort to develop consistent rules for regional markets, referred to as its Standard Market Design proposed rule, FERC proposed an effort to encourage demand-response in wholesale markets. However, this broad effort was delayed because of resistance to certain aspects of the broader effort. Because its jurisdiction is largely limited to wholesale markets, FERC has said that states bear the primary responsibility for implementing demand-response in retail markets. Nonetheless, the wholesale and retail markets interact, affecting the supply and price of electricity in both.

In this context, you asked us to examine the current and potential role for demand-response programs. To address this issue, we identified (1) the types of demand-response programs currently in use; (2) the benefits of these programs; (3) the barriers to their introduction and expansion; and (4) where possible, instances in which these barriers have been overcome. In addition, we examined the federal government's participation in these programs through the General Services Administration (GSA)—a large operator of commercial office space throughout the country. GSA's involvement in these programs is discussed in answering the first three objectives.

To assess demand-response programs, their benefits, barriers to expansion, ways to overcome barriers, and the federal government's participation, we reviewed the literature, analyzed industry and participant data, and conducted interviews with state and federal officials (in FERC, the Department of Energy, and the GSA), industry experts, representatives from utilities, and customers. We examined four programs, two in states with restructured retail markets (California and New York) and two in states with traditionally regulated retail markets (Florida and Georgia). We selected these programs because they have operated for several years and experts consider them innovative and successful models. To determine GSA's participation in demand-response programs, we interviewed headquarters and regional staff and obtained information about electricity consumption and demand-response activities at 53 buildings where GSA is responsible for some or all of the electricity costs. These buildings incurred the highest electricity expenses of the about 1,400 GSA-operated buildings nationwide and represented about 40 percent of the agency's total

electricity expenses in 2003. We used data from GSA's Energy Usage Analysis System and, while we did not do a complete data reliability assessment, we reviewed the steps GSA has taken to ensure the data were reliable. Further, we did limited testing of the data by comparing it with information from our interviews with GSA regional energy managers at the 53 buildings and found no significant discrepancies. We concluded that the data were reliable for the purposes of this report. We obtained information on participation and the benefits of demand-response programs for a 5-year period—1999 through 2003. We conducted our work from March 2003 through July 2004 in accordance with generally accepted government auditing standards.

Results in Brief

Two types of demand-response programs are in limited use: “market-based pricing” and “reliability-driven” programs. Market-based pricing programs enable customers to adjust their use of electricity in response to changing prices. For example, in a Georgia program involving about 1,600 mostly business customers, prices varied hourly depending on supply and demand. According to customers we interviewed, they turned off specific electric equipment or operated their own on-site generation during periods when prices were higher and/or shifted activities such as manufacturing to times when prices were lower. Market-based pricing programs are only available on a limited basis with only a small share of overall demand subject to changing prices. Reliability programs enable grid operators to request that customers reduce electricity use when hot weather or system malfunctions mean that demand will probably exceed supply and cause a blackout. Customers told us that they can participate in these types of programs by reducing their demand on the grid by shutting down equipment or by generating their own electricity. For example, managers of a program in New York State have established agreements that allow the utility to reduce demand substantially, with short notice. Although reliability programs are more widely available than market-based pricing programs, their use is limited. The GSA reported that 33 of the 53 buildings with the largest electricity consumption are currently registered to participate in a variety of both market-based pricing and reliability programs across the country.

Demand-response programs, according to the literature we reviewed and experts we spoke with, can benefit customers in regulated and restructured markets by improving market functions and enhancing the reliability of the electricity system. First, markets function better when prices are more closely linked to the cost of supply. This linkage can lead to lower prices and significant savings because utilities have less need to use

expensive power plants to meet peak demand, price spikes caused by market conditions or by market manipulation are reduced, and industry has greater incentives for energy efficiency and other innovations. Recent studies show that demand-response programs have saved millions of dollars—including about \$13 million during a heat wave in New York State during 2001. A FERC-commissioned study reported that a moderate amount of demand-response could save about \$7.5 billion annually in 2010. The four programs we reviewed also produced significant savings. For example, household customers in a Florida program achieved average savings of 11 percent per year in 2002. Second, demand-response programs may enhance reliability because they afford greater flexibility to grid operators, who can change supply *or* demand to meet their needs. Such programs reduced the number of blackouts in California in 2000 and 2001. Regarding benefits to the federal government, GSA estimated that it saved about \$1.9 million from 13 of the 33 buildings that participated in demand-response programs from 1999 through 2003. The amount of these benefits has been limited to some extent because the agency has not actively participated in these programs. If GSA was able to achieve the level of participation reported to us at all of their large facilities, savings could reach \$12 million to \$114 million over a 5-year period, according to our analysis.

Although demand-response programs can provide benefits, they face three main barriers to their introduction and expansion: (1) state regulations that shield customers from short-term price fluctuations, (2) the absence of equipment installed at customers' sites required for participation, and (3) customers' limited awareness of programs and their potential benefits. First, customers do not respond to price fluctuations because the retail prices they see do not reflect market conditions but are generally set by state regulations or laws. This lack of response becomes important during periods of high demand, when actual costs are highest (because peak demand plants are used), but customers remain unaware of the higher costs and thus have no incentive to reduce their demand. Because retail consumers do not reduce their demand, they can also unknowingly harm wholesale markets by driving up prices higher than competitive levels. Second, most customers currently lack the necessary equipment, which includes meters for measuring when electricity is consumed and cell phones, pagers, or other mechanisms for communication with the utility. These items are not routinely required of customers, and neither customers nor energy companies are eager to pay for this equipment. Third, customers are not always aware of demand-response programs and their potential benefits. According to the operator of demand-response

programs in New York State, about half of the customers that it believed were well informed about electricity matters were unaware that these programs were available to them. In addition, several factors beyond the programs' control—including moderate weather, a slow national economy, and surplus generating capacity in some parts of the country—have combined to keep overall prices low in recent years, reducing the financial benefits for participating in these programs, according to industry experts. However, they also note that such programs may be urgently needed later, when supplies are limited and prices are high. According to GSA officials, the agency's participation in demand-response programs has been limited because it lacks specific internal guidance on participation, tenants have little incentive to reduce their consumption, and other factors such as mild weather conditions have further diminished participation.

Two demand-response programs that we reviewed illustrate how these barriers can be overcome and also point out three broader lessons on how to cultivate new programs. For example, to introduce a market-based pricing program in a regulated market, a Florida utility demonstrated to state regulators that its program could offer benefits, such as lower prices to participants, without increasing costs to nonparticipants. The utility also developed outreach materials (such as a video) and provided technology that automated consumer response to prices to simplify participation. In another instance, officials in New York State overcame the barriers of inadequate consumer awareness and infrastructure by educating consumers about a new reliability program during a time when supply shortages were expected and prices would likely rise. To promote this program, the grid operator developed brochures and other sources of information that described the problems to be addressed and the potential benefits to participants. It also provided equipment to communicate rapidly and effectively when supplies were short and reliability was in jeopardy (an automated telephone notification system). More broadly, these examples offer three important lessons for nurturing such programs. First, programs with sufficient incentives, such as a clear price difference between peak and off-peak consumption, make customers' participation worthwhile. In other areas, programs have been abandoned when this price difference was insufficient to attract participants or to induce participants to reduce their usage during critical periods. Second, programs have a higher chance of success if they are begun where state regulators and market participants are receptive to the potential benefits of demand-response programs in their areas. Third, to achieve these benefits and also increase the chances of success, the design of programs should include appropriate outreach, necessary equipment, and easy participation.

We are making recommendations that FERC consider additional actions to ensure that wholesale markets are not unnecessarily harmed by retail buyers, broadly review options to implement effective demand-response, and outreach with states, among other things. We also recommend that GSA make participation in demand-response a key factor in its energy decision making, identify programs for participation, educate building operators, and align incentives so that it can more fully benefit from these programs.

We provided FERC and GSA a draft of our report for review and comment. FERC endorsed our conclusions regarding the importance of demand-response to competitive energy markets and to electricity system reliability. FERC generally agreed with the report's recommendations. GSA also agreed with the report's conclusions regarding the importance of demand-response to an efficient and reliable electricity industry. GSA stated that it agreed with the majority of our recommendations, but expressed concerns about one recommendation for GSA to share savings with tenants for successful demand-response participation. GSA stated that such sharing would not be practical because the agency, under its current leases, would assume all the risks associated with electric costs, while sharing the benefits with its tenants. We revised the recommendation to reflect GSA's concerns about risk by adding that risk should also be shared between the agency and its tenants. As revised, we believe the recommendation provides sufficient flexibility for GSA to develop practical approaches in sharing financial incentives as well as penalties with its tenants without compromising tenant satisfaction.

Background

Demand and Supply in Regional Electricity Systems Must Be Continually Balanced and Adjusted

To avoid blackouts and other disruptions, the amount of electricity customers demand must be continually balanced with the amount of electricity power plants supply. This balance is essential because electricity cannot be economically stored. The operators of the electricity system, who oversee the complex network of thousands of power plants and power lines, collectively called the grid, coordinate this process. The continental United States is divided into three large regional electricity systems (East, West, and Texas). Changes in demand or supply within each of the three regions can affect the entire region, reinforcing the need for coordination.

Preserving this balance is challenging because customers use sharply different amounts of electricity through the course of the day and year. Typically, demand rises through the day and reaches its highest point—called the peak—in late afternoon. In some parts of the country, average hourly demand can be up to twice as high during late afternoon as it is during the middle of the night, when it is the lowest. In addition to the daily variation in demand, electricity demand varies seasonally, mainly because air conditioning accounts for a large share of overall electricity usage in many parts of the country during the summer. In some cases, peak usage can be nearly twice as high during the summer as it is in the winter.

Regardless of when electricity is used, the electricity network must have sufficient generating capacity to meet the highest levels of demand to avoid blackouts. A variety of power plants, ranging from “baseload” plants designed to operate nearly all the time to “peakers” that generally operate only a few hours per day in the summer, are used to meet demand through the day and year. Baseload plants are generally the most costly to build, but they generally have the lowest costs for generating electricity on an hourly basis. In contrast, peakers are much less costly to build but much more costly to operate.

The use of costly power plants that are seldom used results in higher electricity prices. In general, grid operators maximize the amount supplied by the baseload plants. However, as demand rises through the day and through the year, they must use plants that are more costly to operate. Because of this need to use more costly plants, the differences in the overall costs of meeting hour-to-hour demand are sometimes quite large. For example, the average cost of generation can rise tenfold from when demand is at its lowest at night to when it is at its highest in the late afternoon. Although the cost of generating electricity during peaks can be quite high, these periods are generally short and account for only a small percentage of the hours during a year. According to one expert, although the 100 highest priced hours of the year account for only about 1 percent of the hours in a year, they can account for 10 to 20 percent of the total electricity expenditures for the year. Regardless of how often or how long demand reaches its highest levels, power plants must be built to meet at least this level of demand to avoid blackouts. Because the cost of building and operating these seldom-used plants must be recovered through higher electricity prices, the need to build and use them adds directly to these prices.

Federal Restructuring of the Electricity Sector Has Expanded the Role of Competition and Markets, but States Remain Divided on Market Development

A combination of federal, state, and local governments, as well as a private entity oversee aspects of the electric industry. The federal government, through FERC, oversees the interstate transmission of electricity and the operation of wholesale markets—competitive markets in which power is bought and sold by utilities and other re-sellers. FERC has the statutory responsibility to assure that prices in these markets are “just and reasonable.” As noted, FERC has historically done this by approving rates to recover justifiable costs and providing for a regulated rate of return. FERC now seeks to meet its statutory obligation by establishing and maintaining competitive markets, believing that competitive markets will produce prices that are just and reasonable.

As part of this oversight, FERC has changed a number of rules to allow, for instance, new suppliers to enter competitive wholesale markets by granting them “market-based rate authority.” In essence, this authority permits suppliers to sell electricity in these markets at market-based prices. In contrast, FERC does not currently limit access of large buyers—including those who resell to retail buyers. To further competition, FERC also approves the creation of new regional entities to operate the electricity grid. In addition to overseeing the daily balancing of supply and demand, some of these grid operators also operate wholesale markets for electricity. States, through their public utility commissions or equivalent, oversee retail markets—markets directly serving customers. In this regulatory role, state commissions have historically approved utility plans for power plants, transmission lines, and other capital investments needed to supply electricity; they have also set rates to recover these costs and provide the utility with an approved profit margin. Under this arrangement, regulated electricity prices have historically been set as a single price, generally an average of the costs of serving a wide customer class, such as residential customers.¹ Thus most of today’s electricity system is a hybrid—competition setting wholesale prices and regulation largely setting retail prices. In addition, neither FERC nor the states generally have jurisdiction over electricity entities owned by cities, such as the Los Angeles Department of Water and Power, or utilities owned by their customers, such as rural electric cooperatives and local public utility districts; these entities account for about 25 percent of the wholesale market and are self-regulated by an elected board.

¹In some instances, state public utility commissions have allowed the use of time-of-use rates, or other time-differentiated pricing, but these cases are limited.

In addition to involvement by federal and state agencies, a private membership organization made up of large electricity providers in the United States—the North American Electric Reliability Council (NERC)—establishes technical and operational standards to maintain the reliable operation of the electricity networks. However, membership in NERC and adherence to its standards are currently voluntary, and it cannot penalize nonmembers who do not adhere to these standards. Among other NERC standards, utilities must maintain specific amounts of power in reserve in the event that demand rises to a higher level than expected or supply is interrupted, such as when a power plant has to shut down unexpectedly.

In addition to FERC's direct regulatory oversight, the federal government influences the electricity sector through the Department of Energy (DOE). Broadly, DOE formulates national energy policy, funding research and development on various energy-related technologies (e.g., energy-efficient air conditioners and refrigerators and other appliances); setting some standards for energy efficiency; analyzing energy issues; and disseminating information about energy issues to the states, industry, and the public. More specifically, DOE established the Office of Electric Transmission and Distribution in August 2003 "to lead a national effort to help modernize and expand America's electric delivery system to ensure a more reliable and robust electricity supply." This office worked jointly with FERC and the Canadian government to investigate the causes of the August 14, 2003, blackout in the northeastern United States and parts of Canada.

Both FERC and DOE Believe That Demand-Response Programs Could Address a Number of Problems

Over the past 20 years, experts have begun to recognize the potential advantages of allowing customers to see and respond to market conditions. Historically, grid operators have maintained reliable operations by increasing or decreasing the amount of electricity supplied that was needed to meet changes in demand. However, industry experts have long said that allowing customers to change their demand in response to ongoing changes in prices or limitations in supply may offer cost and operating advantages over relying solely upon changes in supply. Further, these experts generally believe that only a small amount of demand, in total, may be needed to bring about these advantages.

In this regard, FERC and DOE have said that demand-response is an important part of well-functioning electricity markets but is largely missing from today's markets. In 2001 FERC staff concluded that demand-response could reduce market power, reduce price spikes, and reduce electricity bills, among other things. Over the past several years FERC has identified

problems with some wholesale markets, such as periodic price spikes and efforts by some electricity suppliers to manipulate prices. Further, FERC has said that the absence of demand-response can worsen price spikes and allow suppliers to manipulate prices, both of which produce prices that are higher than its estimate of competitive prices. For example, in its 2002 proposed market design, FERC stated that if customers are allowed to respond to high prices, then price volatility and the ability of sellers to manipulate prices could be reduced. FERC has determined that several electricity sellers in the West manipulated prices during periods when supplies were scarce and that customers did not reduce demand in response to these high prices. Over the past several years, FERC has approved proposals by grid operators in New York State, New England, and California to incorporate demand-response into the wholesale markets they operate, but these efforts are unique to each grid operator and have not yet attracted significant participation. As part of a broader effort, referred to as Standard Market Design, to develop consistent rules for regional markets to promote more efficient and reliable electricity markets, FERC proposed a limited effort to encourage consistent demand-response in wholesale markets. However, this effort to implement demand-response was delayed because of resistance to certain aspects of the broad effort.

In 2000, a DOE team studying a series of electric power outages in the U.S. found that the ability of customers to manage their demand in response to market prices was key to ensuring reliable electric service and the efficient functioning of competitive electric markets. More recently, DOE's Office of Electric Transmission and Distribution believes that demand-response could help resolve price and reliability problems and plans a demand-response initiative as part of its strategy to help modernize the grid. Further, DOE's Federal Energy Management Program has promoted awareness of demand-response programs, pointing out opportunities for electricity users to receive payment for reducing use during specific periods of time.

The Federal Government and General Services Administration Are Large Electricity Users

The federal government is a large owner and user of commercial and other building space. As of September 30, 2000, the federal government owned about 3 billion square feet of office space and leased about an additional 350 million square feet.² While the Department of Defense is the largest user of building space (accounting for about two-thirds of the total owned building space), the General Services Administration (GSA) is the principal landlord for the federal government, operating buildings totaling about 330 million square feet and leasing the space to federal agency tenants; it owns about 55 percent of this space and leases the remaining space from private building owners. Nationally, GSA pays the energy bills for about 200 million square feet of office space, including about \$210 million for electricity used at its buildings. Almost half of this total was spent for electricity consumed in four states—California, Maryland, New York, and Texas—and the District of Columbia.

Market-Based and Reliability Programs Allow Demand to Respond to Changing Prices and Supply Shortages but Are in Limited Use

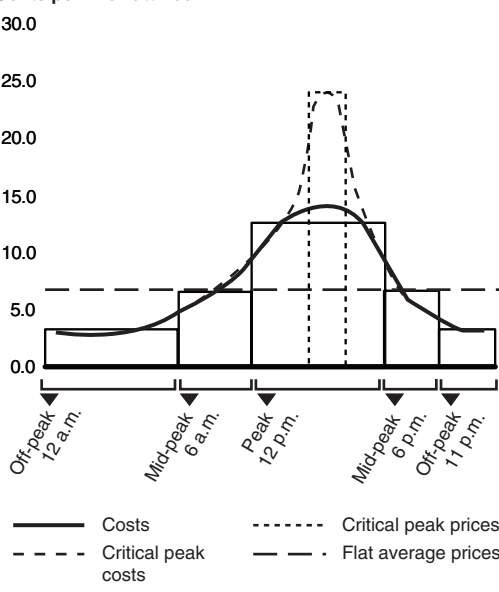
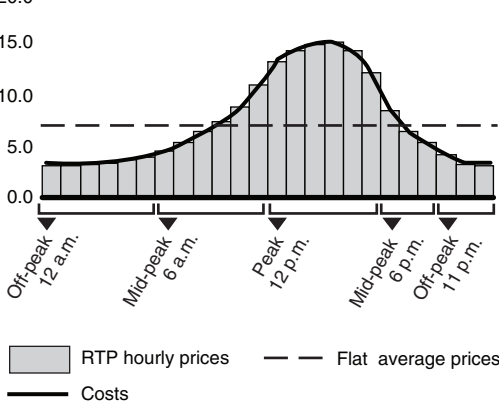
Two types of programs enable customers to respond to price variations or to supply shortages that may compromise reliable grid operations: market-based pricing and reliability-driven programs. Market-based pricing programs provide customers with information on prices that vary during the day based on the actual cost of supplying electricity so that customers can voluntarily reduce their use of electricity when prices are high. Overall, market-based programs are in relatively limited use with a small share of overall demand subject to market-based prices. Reliability-driven programs allow grid operators and utilities to avoid widespread blackouts when electricity supplies are tight by calling on participating customers to reduce demand. While reliability programs are more widely available, active participation remains somewhat limited. GSA reported that many of its larger facilities are currently registered to participate in both market-based pricing and reliability-driven programs across the country.

²U.S. General Services Administration, *Summary Report of Real Property Owned by the United States Throughout the World* (Washington, D.C.: June 2001). We have reported that the governmentwide real property data that GSA compiles—often referred to as the worldwide inventory—have been unreliable and of limited usefulness. However, these data provide the only available indication of the size and characteristics of the federal real property inventory. For more information, see U.S. General Accounting Office, *Federal Real Property: Better Governmentwide Data Needed for Strategic Decisionmaking*, [GAO-02-342](#) (Washington, D.C.: Apr. 16, 2002).

Market-Based Programs Transmit Information about Changing Prices, Allowing Customers to Adjust Demand, but Use Is Limited

Market-based pricing programs provide customers with prices that follow changes in electricity production costs throughout the day. We identified three general types of market-based pricing programs: time-of-use pricing, real-time pricing, and demand bidding. Two of these programs—time-of-use and real-time pricing—provide customers with retail prices that reflect the changes in the cost of electricity throughout the day, as shown in figure 1. A variation of time-of-use pricing, referred to as critical peak pricing, is also shown in figure 1. The third type of program, referred to as demand bidding, allows customers to sell back into wholesale markets electricity that they otherwise would have consumed. The prices offered by these programs differ sharply from the flat average prices that most customers face. Market-based prices can rise significantly when demand is high or supplies are short. As a result, they provide customers with incentives to reduce consumption during periods of peak demand when prices are highest.

Figure 1: Illustration of Variations in Market-Based Pricing Systems

Price plan	How prices vary during the day	How prices are determined	When prices change
<p>Time-of-use and time-of-use prices with critical peak pricing</p>	<p>Prices vary for set time blocks during the day, except when critical peak prices apply. Critical peak prices can be put into effect at any time but generally have a preset maximum number of hours per year.</p> <p>Cents per kilowatt hour</p>  <p>— Costs - - - - - Critical peak prices - - - - - Critical peak costs - . - . - Flat average prices</p>	<p>Average costs for each time block based on historical use patterns and forecasts of costs and usage. Critical peak prices preset at a significantly higher level to reflect when costs are higher than normal.</p>	<p>Seasonally, such as the beginning of summer.</p>
<p>Real-time prices</p>	<p>Price varies hourly, and hourly prices vary each day.</p> <p>Cents per kilowatt hour</p>  <p>■ RTP hourly prices - . - . - Flat average prices — Costs</p>	<p>Based on actual cost of electricity for each hour for each day.</p>	<p>One day or 1 hour ahead of actual consumption.</p>

Source: GAO.

With time-of-use pricing, different preestablished prices are in effect for predetermined parts of the day (e.g., off-peak, 11:00 p.m. to 6:00 a.m.; mid-peak, 6:00 a.m. to noon and 6:00 p.m. to 10:00 p.m.; peak, noon to 6:00 p.m.). The highest prices are established for periods such as the peak when demand and cost of supply are generally highest, based on historical cost and consumption information, and are designed to encourage consumers to reduce demand during those periods. We examined two time-of-use programs, one traditional program in California and a variation on that type of program in Florida. One industrial consumer operating a refrigerated warehouse, and participating in a traditional time of use program, explained how he adjusts his operations in response to these rates. By refrigerating some products at lower than normal temperatures during the night when prices are lower, he can turn the refrigeration equipment off during the middle of the day to avoid the higher daytime prices without temperatures rising above acceptable levels. While these responses can be useful, experts told us, traditional time-of-use prices are unable to reflect unforeseen events, such as increased demand because of extreme heat or a sudden supply shortage, which may occur if a power plant is unexpectedly shut down.

To modify time-of-use rates to accommodate these possibilities, the Florida program we reviewed operates a variation on time-of-use rates in a voluntary program for about 3,200 residential customers. Gulf Power presets prices for three periods per day (peak, off-peak, and mid-peak). However, with some advance notification, an additional price preset at a much higher level (called the critical peak price) can be put into effect at any time when supplies are tight or demand is high; however, this higher price cannot be in effect for more than 88 hours per year. An innovative control system, provided by the utility, enables customers to program the system to shut off as many as four electrical devices in response to preset price periods and notifies participants if the critical peak pricing period is in effect. The critical peak price was not used in 2003, but in 2002 the utility put the additional price into effect on 11 occasions for a total of 12 hours.

With respect to real-time pricing, prices generally vary for each hour of each day and are more closely linked to variations in the actual hourly cost of supply than time-of-use rates. There are several different ways of implementing real-time pricing programs. For example:

- Niagara Mohawk in New York State allows some of its large customers to participate in a program that prices electricity on an hourly basis, based on a forecast done the day before consumption is to occur (with

about 140 customers and accounting for about 8 percent of total electricity sales).

- Georgia Power, a regulated utility, offers a voluntary real-time pricing program (with 1,600 customers and about 5,000 megawatts³ (MW) of demand) that sets hourly prices 1 hour or 1 day before electricity use, at the choice of the participant. Under this program, participants are only allowed to pay real-time prices for the new electricity demand added since joining the program while paying their regulated rate on the rest of their demand. Officials told us that the program was designed this way to assure that customers participating in this program continued to pay for their share of the utility's existing network of power plants and transmission lines—like the rest of the utility's customers. Over time, a growing business could have a large portion of its demand priced as part of the real-time rate, which is generally lower than the regulated rate. As a result, competitors in the same business can have different electricity costs, a feature that recently has made the program highly sought after by customers. Indeed, some customers that had not experienced growth sought regulatory and/or court-ordered changes to increase the amount of their demand eligible for pricing under the real-time rate. According to one participating customer, he actively monitor prices through a Web-based system several times per day, monitors his demand, and reduces his demand if prices exceeded predetermined levels.

The third type of market-based pricing, referred to as demand-bidding programs, allows consumers to compete with traditional electricity suppliers, such as power plant owners and power marketers, in wholesale markets. While the other two types represent retail pricing efforts, demand bidding is a wholesale market effort. These programs, generally established by the grid operator or the local utility, enable mostly large customers to react to changing wholesale prices by offering bids to supply their large blocks of potential demand to the grid operator as if they were a power plant supplying electricity. We examined one such program operated by the New York grid operator, the New York ISO, and approved by FERC. In this program, customers who voluntarily sign up can bid amounts of demand reduction that they are willing to provide at prices that they determine.

³A watt is a measure of electrical power, or work. A kilowatt (KW) is 1,000 watts. A megawatt (MW) is 1,000,000 watts. One megawatt is equal to the demand of about 750 homes. A kilowatt used for 1 hour is equal to 1 kilowatt-hour (KWh). A megawatt used for 1 hour is equal to 1 megawatt-hour (MWh).

They are not penalized if they do not bid; however, they are penalized if their bid is accepted and they fail to provide the agreed-upon reduction. The New York grid operator told us demand bidding was a relatively small resource for reducing demand, accounting for 1,500 MWhs, for which 24 participants were paid \$100,000 or more in 2002. One participant told us that they were willing to bid when prices reach certain high levels, but they were reluctant to do so if prices were low because reducing demand generally reduced their production or otherwise hindered their business operations.

For demand-bidding programs to operate, the program operator must develop an estimate of participant demand for all hours of the year—called a baseline. According to experts, because individual consumer demand varies seasonally, in response to the economy, and for other reasons, it is often difficult to develop a baseline that accurately estimates demand. Further, because most of these customers have not agreed to purchase the electricity that they are offering to sell, some experts have questioned whether this lack of clear ownership of the electricity raises questions over property rights and opens the programs to manipulation.

Overall, the use of market-based pricing is relatively limited, generally affecting only certain types of customers and some areas and accounting for a small share of overall demand, with most customers still paying prices that are not market-based. Time-of-use pricing programs are available from many utilities, but participation is generally limited to some commercial and industrial customers. However, in some parts of the country some customers have been required to pay time-of-use rates. For example, the California Public Utility Commission requires large customers of the state's public utilities to be on time-of-use pricing plans. Real-time pricing programs are available in only a few locations, and the number of customers enrolled in these programs is generally small. With regard to demand bidding, these programs are relatively new and available only in a few locations. Even where they are available, active participation has been limited to times when wholesale prices are high.

Reliability Programs Allow Grid Operators to Reduce Demand in Response to Supply Shortages, but Use Is Limited

Reliability-driven programs allow the grid operator or utility to call on participating customers to reduce demand during periods of tight supply by shutting down equipment or by generating their own electricity. Grid operators and utilities activate these programs to avoid widespread blackouts during periods of extremely high demand or when a power plant or transmission line is shut down unexpectedly. Although enrollment in

these programs is typically voluntary, the contractual agreements may entail financial penalties if a participant does not reduce demand as required by the program. We identified three types of reliability-driven programs: interruptible rates, direct demand control, and voluntary demand reduction. Some programs, such as interruptible rates, are targeted at large users such as commercial and industrial customers, while others, such as direct demand control, include residential customers.

Interruptible rate programs provide participants with a discount on electricity prices during all hours in exchange for the right of the grid operator or utility to interrupt electricity supplies if needed. Typically, the grid operator or utility requests that the participant reduce demand by some preestablished amount. Under the terms of these agreements, interruptions are generally limited to a certain number of hours per year, and the customer is provided with advance notice that service will be interrupted. Although enrollment in these programs is generally voluntary, the participant can face significant financial penalties if it fails to reduce demand when directed to do so, such as paying market prices for electricity that they consume but had agreed to interrupt.

These programs are appropriate for customers that can curtail consumption for short periods with minimal impact on their overall operations. For example, an official with one commercial participant that operated cold storage facilities also participating in an interruptible rate program told us that his operation could reduce consumption within 30 minutes of a call for interruption by turning off refrigeration units and turning down air conditioning and lighting. He said his operation could sustain a shutdown for as long as 6 hours without a problem. These programs are not appropriate for all consumers, however. Because of supply shortages in some areas, such as California, some programs have been used more frequently, and some customers realized that they should not participate. For example, when Southern California Edison needed to call on its participants frequently during the electricity crisis in 2000 and 2001, it realized that some customers, such as hospitals and other facilities, should not have signed up for the programs. Many of these entities were unable to comply with requests to reduce demand and faced financial penalties, which were later waived. Because of this experience, the company said that they now more actively limit participation and routinely examine whether participants can reduce demand to the level that they agree.

Direct demand control programs compensate customers financially if the customers allow the utility or grid operator to remotely interrupt electricity use by one or more electrical devices, such as air conditioners. In some cases, electricity may be interrupted for an hour or more, in other cases, the operator may “cycle” the equipment, shutting it down for several short periods. Generally, these programs rely on a switch installed on the air conditioner or other device that the utility or grid operator can remotely activate. By controlling a large number of small devices, the utility can ensure that, at any given time, some of these devices are turned off, thus significantly reducing the peak demand. For example, Southern California Edison operates several demand-response programs and has developed infrastructure to support them including 250,000 remotely activated switches on electrical equipment. In total, in 2003 the company had about 20 years of experience with a program that has provided about 600 to 800 MW of potential reduction in peak demand.

Finally, voluntary reduction programs are geared to large commercial and industrial customers that must meet certain requirements, such as a minimum amount of demand reduction, to participate. In one program, the New York grid operator notifies participants when it needs to reduce system demand, allowing the participant to decide how much, if any, it wants to reduce consumption from an agreed-upon baseline level. Customers are paid for any actual reduction below the baseline level. Overall, these programs provide more flexibility for customers than interruptible programs because there is no penalty if the consumer is unable to reduce its demand. However, financial benefits can accrue only if the consumer is called on to reduce demand and actually reduces its consumption. In another program, participants have signed agreements with the New York grid operator that pay them for their willingness to reduce demand. These agreements are voluntary to enter into, but commit participants to reduce demand when asked, or face financial penalties. As a result of these agreements, the grid operator is able to achieve substantial reductions in demand with 2 hours notice. These programs also require communication links between the utility and customers, as well as advanced meters so that the utility can verify and measure the consumer’s actual response.

Customers told us that they reduce demand if their business situation and market prices warrant a reduction. For example, one manufacturer shuts down some processes to reduce demand and shifts workers to other tasks in the factory. In some cases, the manufacturer can compensate for the lost production by increasing output during normal work hours or during nights

and weekends. However, if the factory were operating at full capacity—three shifts per day, 7 days per week—the manufacturer would need to consider whether the value of lost production exceeded the expected compensation from the grid operator. Two participants told us that certain provisions of labor contracts limited their ability to shift work to night hours, or limited the profitability of doing so, because night hours required the payment of higher wages to employees.

Reliability-driven programs are more widely available than market-based pricing programs, but participation remains somewhat limited. Many utilities offer interruptible rate programs to large commercial and industrial customers. While offered for many years, these programs were generally used to provide lower prices for some selected customers, but electricity was rarely interrupted. As a result, program operators told us that some customers on these types of programs, such as hospitals and schools, would not be able to reduce demand if directed to do so, limiting the effectiveness of some of these programs. Direct demand control programs have been offered by utilities for many years. Many customers, including residential customers, currently participate in them, allowing their air conditioners, pool pumps or other devices to be remotely turned off. Voluntary reduction programs are relatively new and only available in a few locations. Although these programs may not be activated often, officials in California and New York State told us that the interruptible and voluntary demand reduction programs helped their states enhance reliability in recent years, providing the grid operator with an additional tool to avoid blackouts and other disruptions.

Some GSA Facilities Are Registered to Participate in Market-Based and Reliability Programs

Of the 53 GSA facilities we reviewed, 33 facilities in six states and the District of Columbia are registered to participate in either market-based pricing or reliability-driven programs, or both, according to GSA officials. These officials told us that the programs that they are signed up for are generally voluntary—they provide financial benefits when the buildings are able to reduce demand but do not include penalties if they do not respond to price changes or requests to reduce demand. Of the buildings that participate in a program, 21 facilities are registered for market-based programs such as time-of-use and real-time pricing, 7 for reliability-driven programs, and 5 are registered for both types.

Demand-Response Programs Have Saved Millions of Dollars and Can Improve the Reliability of the Electricity System

Demand-response programs have saved millions of dollars and could save billions of dollars more, as well as enhance reliability in both regulated and competitive markets, according to the literature we reviewed and experts we spoke with. For example, one market-based program in California saved \$16 million per year and one estimate of the potential benefit of demand-response was as high as \$10 to 15 billion. These actual and potential savings occur when consumers can respond to fluctuations in electricity prices, permitting markets to function more efficiently. In addition to improving the operation of electricity markets, demand-response can enhance the reliability of the electricity system if participants reduce their demand in response to higher prices, and they provide an additional tool to manage emergencies such as supply shortages or potential blackouts.

Market-Based Programs Have Saved Millions of Dollars and Have the Potential for Even Greater Savings

Over the past 25 years, many electricity market studies have reported on demand-response programs. Recent studies have reported that several programs have saved millions of dollars and demand-response could save billions of dollars if widely implemented in the future. These studies generally fall into two categories: (1) studies of actual benefits from programs already available and (2) studies identifying benefits that could be obtained if such programs had been available to ameliorate previous crises or potential future benefits of widespread implementation.

As shown in table 1, a number of studies of market-based pricing programs demonstrate that these programs have reduced demand and resulted in millions of dollars in customer savings.

Table 1: Studies of the Benefits of Existing Market-Based Pricing Programs for Regions and Specific Programs

Study title, author, date	Results/conclusions
"The Economics of Real-Time and Time-of-Use Pricing for Residential Consumers," King, June 2001	Pacific Gas and Electric has operated a time-of-use program since 1982, with about 85,000 participants as of 2001. Consumers have reduced their electricity usage during peak periods by 18%. As of the early 1990s, 80% of participants were saving \$240 per year through the program, or about \$16 million per year. The utility has also benefited from the shift in demand to off-peak.
"Evaluation of the Energy-Smart Pricing Plan: Final Report," Summit Blue Consulting for Community Energy Cooperative, Mar. 2004	Community Energy Cooperative of Chicago's demand-response program had 750 participating residential customers, representing a wide variety of neighborhoods and types of homes, in 2003, its first year of operation. Under day-ahead pricing, these customers saved an average of 19.6% on their energy bills, or more than \$10 per month in 2003, for modestly cutting back on consumption during approximately 30 hours of peak demand during the summer months.
"Industrial Response to Electricity Real-Time Prices: Short Run and Long Run," Schwarz, et al., Oct. 2002	Real-time pricing by Duke Power in the Carolinas induced demand reductions of about 70 MW, or approximately 8% of consumption during four summer months of peak demand. This translates into long-term savings of about \$2.7 million per year for the 110 industrial customers who participated during the period 1994 to 1999.
"Customer Response to Electricity Prices: Information to Support Wholesale Price Forecasting and Market Analysis," Braithwait for EPRI, Nov. 2001	Georgia Power's real-time pricing program, with about 1700 participants representing about 5,000 MW of demand, can count on a demand reduction of at least 750 MW when capacity is constrained and wholesale markets are tight. On a few days in summer 1999, Georgia Power's real-time prices reached levels as much as twice as high as those seen in previous years. Prices were moderately high on several days and spiked to an extremely high level on a few days. The very large industrial customers on hour-ahead rates reduced their purchases by about 30% from their normal rate on the moderately high-priced days and by nearly 60% during the two high-cost, capacity-constrained episodes.
"Analysis for 2002 GoodCents Select Program Critical Calls," Gulf Power, May 2003	Customers participating in Gulf Power's critical peak pricing program in 2002 on average consumed 50 percent less electricity during "critical periods"—when price was higher—than did a similar group of nonparticipating consumers. Participants also paid 11 percent less in total electricity bills because their total electricity expenditures rose slower than the similar group of nonparticipants.
"Demand Responsiveness in Electricity Markets," Lafferty, et al. for FERC, Jan. 2001	Residential customers in the Wisconsin Public Service Corporation's peak-load pricing program who faced a peak price that was double the off-peak price reduced their consumption during summer peak periods by about 12%, while those facing a peak price that was 8 times the off-peak price reduced their consumption by 15% to 20% during summer peak periods. At peak hours during heat waves, consumption was reduced by 31% relative to nonpeak noncritical days.
"Responsive Demand: The Opportunity in California," McKinsey and Company, Mar. 2002.	From July 1999 through August 2000, San Diego Gas and Electric Company charged residential customers electricity prices based on regional wholesale market prices. During this period, it provided customers with the electricity wholesale price index on their monthly statements. In June-August 2000, there was an unprecedented run-up in California wholesale electricity prices. As a result, the average customer's bill increased by 240% during these 3 months, compared with the same period in 1999. In response, during this period in 2000, customers reduced their usage by 5%.
"New York Independent System Operator (NYISO) Price-Responsive Load Program Evaluation: Final Report," Neenan Associates, Jan. 2002	The NYISO's demand bidding program provided over 25 MW of load reduction when summer peak prices were the highest in 2001. The program's scheduled load reductions are estimated to have reduced market prices by 0.3% to 0.9%. Total collateral benefits from reducing market prices are estimated to be \$1.5 million in 2001. The program is expected to reduce the frequency of system emergencies and lessen the need for reliability programs.
"Framing Paper #1: Price-Responsive Load (PRL) Programs," Goldman for NEDRI, Mar. 2002	The New England Independent System Operator's, New England Demand-response Initiative (NEDRI) was used on six occasions in 2001 when prices frequently reached \$1,000/MWh providing an average demand reduction of 17 MW.

Source: GAO.

As the table shows, these estimates of actual savings include savings to individual utilities and their customers as well as regional savings. For example:

- Individual programs operated by utilities located across the United States have seen reductions in demand of between 5 percent and 60 percent during high-priced hours, resulting in millions of dollars in customer savings and/or cost reductions. For example, according to a study of a long-running time-of-use program in California, in the early 1990s 80 percent of participants were saving \$240 per year (or about \$16 million per year in total for all participants) by cutting back on their consumption during the hours of peak demand. According to another study, Georgia Power staff could plan on participants reducing about 750 MW of power during high-priced hours, and they have seen reductions in peak demand of up to 17 percent on critical days. These savings reduce the amount of costly peak-generation equipment necessary, they said, and the program passes these savings along to its customers.
- Regional programs operating in the Northeast (New York and New England) have witnessed significant reductions in demand, which resulted in (1) millions of dollars in participant savings through price reductions and direct payments and (2) price reductions for nonparticipants amounting to millions of dollars more per year. For example, according to one study, the New York grid operator's demand bidding program reduced electricity prices by \$1.5 million in summer 2001.

Our discussions with individual participants also highlighted specific savings for them resulting from the availability and use of demand-response programs. For example:

- According to a manager at a rural textile mill participating in Georgia Power's real-time pricing program, the mill reduced its purchases from the utility by increasing the output of an on-site generator during periods of high prices, for a savings of about \$1 million per year. These savings allowed his mill to remain competitive while many others in the United States had shut down production and moved to other countries, in part because electricity prices were too high.
- In California, according to the manager at a three-building commercial office complex that participates in market-based and reliability

programs, the complex reduced its total electricity costs by 17 percent in 2003. To achieve these savings, the facility used advanced energy controls that allowed building operators to raise or lower building temperature and lighting, as well as a thermal storage cooling system that allowed it to chill water at night and use it during the day to cool the building and thereby avoid using air-conditioning during times when prices were high.

- One residential participant in Gulf Power's critical peak pricing program significantly reduced his demand during the most costly hours and saved nearly \$600 per year, or more than a third of his annual power costs, by shifting many activities from the most costly hours to off-peak hours.

As table 2 shows, retrospective studies of past crises in the West and other parts of the country that have experienced significant market problems estimate that these programs could have saved potentially billions of dollars had they been available and used in these areas. One study examined the electricity crisis of 2000 to 2001 in the West and estimated that, had market-based pricing been in place, the high prices seen in California during 2000 might have been reduced by 12 percent—resulting in a \$2.5 billion reduction in the state's electricity costs. Similarly, experts have prospectively estimated that the widespread implementation of these programs could result in significant reductions in electricity costs. For example, three separate studies concluded that widespread implementation of demand-response programs could result in savings ranging from \$5 billion to \$15 billion, depending on the extent of participation and the costs of implementation.

Table 2: Studies of Potential Benefits of Demand-Response

Study title, author, date	Results/conclusions
Retrospective	
“The Financial and Physical Insurance Benefits of Price-Responsive Demand,” Hirst, May 2002	If hourly pricing had been in place for 20% of California’s retail electricity demand in 1999 and there had been a moderate amount of price responsiveness, the state’s electricity costs would have been 4%, or \$220 million lower. In 2000, electricity prices were almost four times higher and also much more volatile than in 1999. Hourly pricing for 20% of retail demand in 2000 would have saved consumers about \$2.5 billion or 12 percent of the statewide power bill.
“Getting Out of the Dark: Market-based pricing could prevent future crises,” Faruqui, et al., fall 2001	In California, during the energy crisis in summer 2000, if demand-response to hourly market-based retail prices had been in place, Californians could have reduced their peak demand by 193 MW, thereby reducing prices from peak hourly levels of \$750 per MWh to \$517 per MWh. For the summer season as a whole, energy costs would have been reduced on high-priced days by \$81 million.
“Mitigating Price Spikes in Wholesale Markets through Market-Based Pricing in Retail Markets,” Caves, Eakin and Faruqui, Apr. 2000	In late July 1999 in the Midwest, wholesale electricity prices spiked to \$10,000 per MWh. If only 10% of the retail demand for electricity had faced real-time pricing and there had been a moderate amount of price responsiveness, electricity prices would have risen to only about \$2,700, 73% percent less than the price actually observed. Having just a small fraction of industry demand facing real-time prices would significantly dampen price spikes.
Prospective	
<i>Power System Economics: Designing Markets for Electricity</i> , Stoft, 2002	Evaluating power markets broadly, the net benefits of demand with real-time pricing would be about 2 percent of the total spent on electricity. For the United States in 2003, that would amount to about \$4.5 billion. This long-term estimate assumes that customers shift consumption from peak to off-peak periods, but that total consumption does not change. The estimate does not include potential benefits that accrue as a result of avoided blackouts or other service disruptions.
“Economic Assessment of RTO Policy,” ICF Consulting for FERC, Feb. 2002	The potential benefits for U.S. electricity customers from adopting real-time pricing, with conservative assumptions about customers’ magnitude of response and their ability for distributed generation, are estimated to be \$7.5 billion annually, compared with the status quo by 2010, the first year the effects would be fully in place.
“White Paper: The Benefits of Demand-Side Management and Dynamic Pricing Programs,” McKinsey and Company, May 2001	U.S. electricity customers could potentially realize benefits of \$10 billion to \$15 billion per year if they all participated in demand-response programs and, on average, shifted 5 percent to 8 percent of their consumption from peak to off-peak periods and curtailed consumption by another 4 percent to 7 percent. The switch to demand-response programs would avoid 250 peaking power plants at 125 MW each to handle peak demand, for a total of 31,250 MW of peak capacity (or \$16 billion to build plants used to handle peak demand). Also avoided would be 680 billion cubic feet of natural gas usage and 31,000 tons of nitrous oxide pollution per year.
“The Western States Power Crisis: Imperatives and Opportunities,” EPRI White Paper, June 2001	If adopted everywhere in the United States, demand-response programs could reduce demand for electricity by 45,000 MW or about 6 percent of forecasted peak baseline usage. In California, demand-response could reduce demand by 8.7% and offset the need for new capacity by eliminating 57% of the forecasted load growth during the next several years.
“The Choice Not to Buy: Energy Savings and Policy Alternatives for Demand Response,” Braithwait and Faruqui, Mar. 2001	Based on demand-response data from existing utility real-time pricing programs and actual California data for summer 2000, customer response to hourly market-based retail prices could generate demand reductions of 1,000 to 2,000 MW, reduce summer peak demand, retail prices by 6% to 19%, and produce energy cost savings ranging from \$0.3 to \$1.2 billion in California alone.
“The Feasibility of Implementing Dynamic Pricing,” California Energy Commission, Oct. 2003	California could reduce its peak energy demand by 5% to 24% within a decade by implementing dynamic pricing and installing advanced real-time meters for all nonagricultural energy customers.

Source: GAO.

In achieving these savings, demand-response programs promote greater efficiency in supplying electricity in two ways. First, they encourage greater reliance on more efficient plants producing electricity at a lower cost and correspondingly less reliance on the plants used to handle peak demand, producing electricity at a much higher cost. This increased reliance on more efficient power plants provides the immediate benefit of lowering the average cost of supplying electricity, according to the studies we examined. This lower average cost of supply is likely to reduce electricity prices for consumers in either regulated or restructured markets. Furthermore, the use of more efficient power plants results in less use of natural gas and other fuels, potentially lowering the prices of these fuels during parts of the year. In addition, by reducing the use of seldom-used peaking power plants, the industry will need to build and maintain fewer of them overall, which will improve the overall efficiency of the industry. Since 1,000 MW of peaking power plants currently cost about \$300 million to build, avoiding their construction can substantially reduce the amount of money the industry must commit to these little used plants.⁴

Second, such programs reduce the incidence of price spikes caused either by market conditions or by market manipulation. As part of its 2002 proposed market design, FERC determined that the absence of demand-response can result in periodic high prices in wholesale markets, exceeding the prices it would expect from competitive markets. Experts believe that these spikes are worsened, or in some cases may be caused, because consumer demand is determined in isolation from wholesale market conditions. Price spikes caused by natural changes in market conditions can be worsened by the lack of demand-response. For example, in late July 1999 the wholesale price of electricity reached the unprecedented level of about \$10,000 per MWh for a few transactions in the Midwest, instead of the usual summer day price of \$30 to \$50 per MWh. While FERC determined that hot weather led to high demand, it noted that the exceedingly high wholesale prices occurred principally because high wholesale prices were not passed through to retail customers. Consequently, customers did not face high retail prices—thus they received no signal that supply costs were extraordinarily high—and did not cut consumption, which would have reduced wholesale prices. Similarly, price

⁴According to industry data (Platts PowerDAT), from 1998 through 2003, power plants in the United States with a total generating capacity of between 84,000 MW and 134,000 MW operated 10% or less of the time. In 2003, these seldom used plants accounted for about 14% of the total installed capacity in the United States.

spikes caused by market manipulation, such as when a pivotal supplier withholds supplies in order to raise prices, can also be lessened if some consumers are able to see prices increase and reduce demand. Following the western electricity crisis, FERC determined some suppliers were able to increase wholesale prices by withholding supplies, contributing to a dramatic increase in electricity prices in California and other states. To limit the ability of producers to use their market power to raise prices and as a substitute for needed demand-response, FERC has approved various ways to control prices including price caps—collectively referred to as market power mitigation—but recognizes that these rules are imperfect solutions. Despite the presence of market power mitigation efforts, FERC has said that without demand-response prices can still exceed competitive levels. On the other hand, according to FERC officials, if there were sufficient demand-response in today's markets, the commission could significantly reduce its reliance on market power mitigation rules because markets would be more competitive. Whether high prices are caused by natural market events or market manipulation, experts believe that demand-response programs can serve to lessen the severity of price increases, if properly designed and implemented. Furthermore, experts believe that the ability to rely on more efficient plants and the ability to reduce price spikes, taken together, could significantly reduce market prices. For example, one expert estimated that a 5 percent reduction in peak demand could reduce prices by 50 percent.

In addition to immediate benefits, better aligning prices with costs offers long-range benefits because it provides the correct incentives for investments in energy efficiency and conservation or for other investments that allow consumers to reduce or avoid consuming energy during the most costly hours. These investments include thermostats to alter building temperatures during high-priced hours and equipment such as more efficient air conditioners or equipment that allows consumers to shift their demand from peak to off-peak, such as thermal or other energy storage devices. When electricity customers have more incentives to invest in such equipment, manufacturers of this equipment also have added incentive to develop and sell it. These improved incentives could result in the availability and use of more efficient energy-using equipment with substantial long-term benefits for consumers and society.

Demand-response may also result in environmental benefits in two key ways: reduced overall electricity supplied and reduced use of power plants with high pollution rates. First, to the extent that participants in market-based pricing programs reduce their consumption of electricity during

peak hours and do not increase their consumption during other hours, the amount of electricity supplied may be reduced in total. In such a scenario, emissions of air pollutants are reduced. Second, in some cases, participants in market-based pricing programs may reduce their demand during high-priced peak hours, but increase their demand during low-priced, off-peak hours. These participants allow the suppliers, or grid operators, to avoid using peakers to meet demand but increase the use of another power plant. Since there are regional variations in markets and power plants, depending on the area of the country, this shift may result in the use of power plants that are more or less polluting than the avoided peaking plants. Such offsetting effects make it difficult to determine the net environmental effect. Also complicating the determination of the potential environmental benefit, some demand-response participants may rely on backup generators to supply electricity periodically. Overall, experts we met with noted that there may be net environmental benefits from these programs, but the amount of the potential benefits was uncertain and was likely to vary by region.

Demand-Response Programs Can Improve the Reliability of the Electricity System, Reducing the Incidence of Costly Blackouts

Demand-response programs can lessen the likelihood of blackouts and other disruptions with their consequent financial losses, according to the literature we reviewed. An Electric Power Research Institute study of a “typical” year’s power outages and associated losses estimated that the annual cost of outages to some key sectors (industrial and information technology) of the U.S. economy ranges from \$104 billion to \$164 billion. In California—the state with the highest costs for outages—the costs range from \$12 billion to \$18 billion.⁵ Similarly, the August 14, 2003, blackout affected millions of people across eight northeastern and midwestern states, as well as areas in Canada, and lasted for several days in some areas. The U.S.-Canada Power System Outage Taskforce estimated that the blackout cost between \$6 billion and \$12 billion in lost goods and services.

Demand-response programs enhance reliability in two important ways: (1) market-based pricing tends to reduce demand as prices rise and (2) reliability-driven programs provide grid operators an additional tool to manage the last minute balancing of supply and demand needed to avoid blackouts. First, market-based pricing programs tend to reduce overall

⁵“The Cost of Power Disturbances to Industrial and Digital Economy Companies,” Consortium for Electric Infrastructure to Support a Digital Society, EPRI and the Electricity Innovation Institute (June 2001).

demand during times when electricity is scarce and costly, as individual customers choose not to purchase increasingly expensive supplies. This mechanism is especially useful when demand is slowly approaching the total available supply and customers have some advanced warning that electricity is becoming more costly. For example, higher real-time prices seen by retail customers would reflect, generally within 1 hour, a power plant or transmission line's unavailability. Seeing these prices, customers tend to reduce demand and hence the amount of electricity that must be generated from power plants during the next hour. This lower level of demand, in turn, makes it easier for the grid operator to add enough supplies to meet demand and perhaps reduces the cost of doing so. However, these programs may not be able to meet sudden needs or provide sufficient and predictable demand reductions to maintain reliability.

Second, reliability-driven programs provide additional flexibility by allowing grid operators to either increase supply or reduce demand to avoid blackouts or other disruptions. These types of mechanisms are especially useful in obtaining known amounts of demand reduction relatively quickly and sustaining demand reduction over some predictable period of time. For example, one expert told us that this type of program would be very useful if a large power plant had to suddenly shut down for safety reasons, and the grid operator found that available alternative supply sources were very costly or insufficient to meet their quantity and location needs. In this case, the grid operator might be able to maintain reliability at a lower cost by interrupting electricity service to interruptible customers for a short period of time, an interruption for which they would be paid. By this planned and compensated interruption of service for a few customers, utilities and other service providers are able to avoid unplanned service interruptions—or blackouts—for a much greater number of customers. For example:

- During California's energy crisis of 2000 and 2001, experts found that utility programs that could interrupt service were instrumental in avoiding blackouts on at least five occasions.⁶

⁶Goldman, et al., estimated that demand-response during this period avoided between 50 and 160 hours of rolling blackouts ("California Customer Load Reductions during the Electricity Crisis: Did They Help to Keep the Lights On?" LBL [May 2002]).

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- During a heat wave in 2001, one reliability program in New York State reduced electricity use by 425 MW on four occasions, or about 3 percent of total consumption, and achieved estimated benefits of about \$13 million in reduced market prices.⁷ In order to achieve these savings, the program paid selected customers \$4.2 million to forgo consumption. More recently, grid operators used demand-response capabilities to aid in the recovery from the 2003 Northeast blackout, interrupting participants in order to speed a return to normal electricity service for the state's grid.

However, because some of these reliability-based demand-response programs provide for periodic payments to participants, but are used infrequently, they can be costly to maintain and difficult to justify during years when they are not needed. Nonetheless, according to experts, these programs are very important for maintaining reliability during times when electricity supplies are inadequate or demand is higher than expected. Further, several experts and program operators noted that these programs are difficult and time consuming to start up when a crisis is expected, and it is better to have them in place before a crisis.

Opportunities Exist for GSA to Benefit Further from Demand-Response Programs

GSA has achieved some financial benefits from its limited participation in demand-response programs. Of the 53 buildings with the largest electricity expenses that we reviewed, 33 reported participating in a demand-response program, and 13 of these reported savings ranging from 0.1 percent to 10.8 percent, for a total of \$1.9 million from 1999 through 2003. About 72 percent of these benefits were from facilities participating in market-based pricing programs, 9 percent from facilities participating in reliability-driven programs, and 19 percent from facilities participating in both types of programs. However, while we received some estimates from GSA about its participation in market-based programs, total savings may be higher. Some building operators did not quantify the benefits of these programs and many building operators did not actively participate, even though their buildings were enrolled in them. For example, while large GSA buildings in California are registered for the time-of-use rate, as California requires, GSA staff told us that some building managers do not actively monitor price changes or take steps to adjust demand to respond to changing prices. As a result, some GSA buildings do not realize the additional

⁷In addition to these savings, the utility reduced its hedging costs by \$3.9 million, and all customers together saved \$20 to \$40 million from the lowered likelihood of blackouts.

savings that could result from reducing demand when prices are highest. In contrast, GSA building managers at facilities in Illinois that are enrolled in reliability-driven programs have actively participated by reducing their electricity demand, at the utility's request, in exchange for payment.

We estimate that GSA might be able to achieve substantial savings if it participated more actively in demand-response programs. Based on savings actually achieved from demand-response programs by 13 large GSA buildings (over 100,000 square feet in size) from 1999 through 2003, the median savings potentially achievable for these 13 buildings over the 5-year period, 2004 through 2008, is \$6.9 million and ranges from \$1.4 million to \$13.6 million, depending on how actively the buildings participate, weather conditions, and other factors, and assuming that at least time-of-use programs are available. If the other 40 GSA buildings of this size were to participate in demand-response programs that provided similar savings over this period, the median additional savings are estimated to be \$20.5 million with a range of \$4 million to \$40 million. If all 419 GSA-managed buildings over 100,000 square feet in size were to participate in demand-response programs that provided similar savings over this period, we estimated median GSA savings of \$58.2 million with a range of \$12 to \$114 million, according to our analysis.

Multiple Barriers Make It Difficult to Introduce and Expand Demand-Response Programs

Demand-response programs face three main barriers to their introduction and expansion: (1) regulations that shield customers from short-term price fluctuations, (2) the absence of needed equipment installed at customers' sites, and (3) customers' limited awareness of programs and their potential benefits. In addition, several external factors, such as moderate weather, have kept prices low in recent years in many parts of the country, thereby limiting the financial incentives for participation. Lack of specific guidance to the tenants in GSA buildings regarding participation and the tenants' lack of incentive to reduce consumption have also limited GSA's involvement in these programs.

State Regulations Promoting the Widespread Use of Fixed, Average Prices Impede the Development of Demand-Response Programs and Efficient Wholesale Markets

Whether subject to traditional regulation or restructured markets, the costs of supplying electricity are generally not reflected in the prices that consumers see in the retail markets where they buy electricity. Instead, these prices are generally prescribed by state law or regulation as a single average price for all purchases made over an extended period.⁸ Seeing no variation in retail prices, customers lack the information and the incentive to respond to the actual variation in supply conditions throughout the day and from season to season. This lack of consumer response becomes particularly important during periods of high demand for electricity, when the actual costs of its production are the highest, but customers remain unaware of the higher costs and thus have no incentive to reduce their demand. In turn, since consumers do not reduce their demand, they can unknowingly drive up the price for electricity in wholesale markets as their suppliers purchase electricity to meet their demand. This impact on wholesale prices ultimately increases the cost to consumers over time and may result in energy and/or financial crises similar to those experienced in the West. In short, the presence of such traditional retail pricing acts as an impediment to both the introduction and expansion of demand-response programs and to the efficient operation of wholesale markets.

Because retail prices remain subject to regulatory control in most cases, the introduction of market-based pricing arrangements that reflect the underlying costs of supply may not be possible without regulatory changes. In retail markets that remain subject to traditional regulation, local utilities cannot offer new pricing arrangements without first obtaining state approval. According to state utility commission staff, approval often requires demonstrating that the introduction of new pricing arrangements will benefit the participants while causing no price increases for nonparticipants. In restructured retail markets, competitive suppliers may be able to offer new arrangements that reflect costs without first obtaining regulatory approval, but the availability of flat average prices—as required

⁸U.S. General Accounting Office, *Lessons Learned from Electricity Restructuring: Transition to Competitive Markets Underway, but Full Benefits Will Take Time and Effort to Achieve*, GAO-03-271 (Washington, D.C.: Dec. 17, 2002). As noted earlier, only a small amount of demand, in total, may be needed to deliver the benefits of demand-response. Only a few customers need to be responsive to varying prices for there to be “adequate” levels of demand-response in markets. Customers would be free to choose between (1) paying varying prices, with varying monthly bills, and (2) paying slightly more, on average, in order to be guaranteed flat monthly prices reflecting the average cost of serving them over a longer period of time. Customers willing to respond to varying prices would not pay for a “flat price” guarantee.

by regulation or law—may continue to present a barrier to consumers switching to these rates. In addition, whether in regulated or restructured markets, because demand-response programs can reduce total electricity consumption—upon which owners and operators of the transmission system are paid—it may also be necessary to change how these entities are compensated.

Similarly, the introduction of reliability-driven programs may not be possible without regulatory and other actions by federal, state, and other entities. In general, reliability-driven programs are developed in a broader, regional context, where their success depends upon their integration with the flow of electricity throughout a region. Because electricity grids have become highly regional, with supply and demand in one part of the grid instantaneously affecting the grid across a wide geographic area, it is important for grid operators fully understand supply and demand conditions within these regional grids and to have sufficient authority to maintain reliability. Since introducing restructuring to wholesale electricity markets, FERC has approved the formation of eight grid operators across the United States that have different levels of authority and a variety of rules. Therefore, the effectiveness of reliability-based programs depends on the amount of the grid the operators control and the extent to which the operator's rules differ from the rules in a neighboring jurisdiction. As part of the changes needed to introduce reliability programs, it may not be possible to introduce several types without creating markets for them. For example, it may be necessary to make changes to allow companies to aggregate small individual demand-responses, such as residential air conditioners and water heaters, and provide a way to then sell the aggregated demand as a substitute for supply to the grid operator. To implement these changes, industry experts believe that FERC may need to change the rules used by grid operators so they can allow the creation of appropriate markets.⁹

⁹Because NERC establishes technical and operational standards, including the need to maintain certain levels of reserves, it may also be necessary to change rules to allow demand-response options to be counted in measuring whether grids are being operated reliably.

Lack of Some Equipment at Customers' Locations Limits Use of Demand-Response Programs

Most customers currently lack the necessary equipment—meters, communication devices, and special tools—for participating in demand-response programs. Although the needed technologies are commercially available, they are not present at most customers' homes and businesses. For example, the meters installed in most homes and businesses measure only total consumption, which is generally measured on a monthly basis for billing purposes. However, most demand-response programs require meters that are capable of measuring when electricity is consumed. These types of meters generally cost between \$100 and \$1000, according to experts we spoke with. Additionally, experts and program operators told us that the way in which some buildings are metered is inadequate to support effective participation in demand-response. For example, regulators, program operators, and others in New York State told us that the building code did not require that commercial and residential buildings be metered individually. They explained that in New York City, which has many large residential and commercial buildings, or multibuilding complexes, some of which may comprise hundreds to thousands of individual users, a single meter measures consumption. As a result, individual customers do not pay for the electricity that they consume; instead, they pay for a share of the total electricity consumed. In these circumstances, even if an appropriate meter were installed to replace the existing meter, individual customers would have only limited incentive to reduce their consumption, since the benefits of any individual reduction would be shared among all the other customers.

Most customers also do not have appropriate communications equipment for demand-response programs. Because most customers' electricity rates change infrequently, it has not been necessary to design or implement specific communications for this purpose. However, with most demand-response programs, more timely communication is important. According to operators of programs that we reviewed, they relied on some combination of e-mail, pagers, and telephones to provide timely communication.

Finally, some demand-response programs may require other equipment. For example, in market-based and reliability programs that allow the retail energy provider or grid operator to interrupt specific pieces of electricity-consuming equipment, participants need installed switches on their electrical equipment that can be activated remotely. Installing these technologies can be costly and raises questions about who should pay for them and how best to install them. Historically, local utilities paid for and installed the meters, recovering this cost through electricity rates over several years. However, because of uncertainties about the future of retail

restructuring and of the ability to recover these costs in competitive markets, utilities have been reluctant to pay for metering equipment unless cost recovery is guaranteed, which some regulators have been reluctant to do. Several experts told us that costs could be significantly reduced if the equipment were purchased and installed on a widespread basis. However, since not all customers participate in demand-response programs, it is not clear that such widespread installations are economical, even in light of the potential for reduced costs.

Customers' Limited Awareness of Demand-Response Programs and Their Potential Benefits Hinders Program Introduction and Expansion

In areas where demand-response programs are available, some customers are unaware of them or do not know how they could benefit from participation. For example, despite the widespread availability of demand-response programs in New York State, and of extensive outreach, many customers in New York State remain unaware of them, according to experts we spoke with. In a survey conducted for the operator of two programs in New York State, program operators learned that about half of the eligible customers it believed were well-informed about electricity matters were unaware of the demand-response programs. However, the same study found that the customers that were aware of the programs were highly likely to participate in them.

In some cases, the simultaneous availability of and solicitation for multiple programs can confuse potential participants. For example, California state officials told us that, in response to the 2000 and 2001 electricity crisis, many new programs were created in addition to a number of existing programs. According to one utility we spoke with, customers found it difficult to sort through the multiple options and were also confused by utility program complexities due to multiple programs and/or changing policies and requirements.

According to program operators and industry experts, customers often do not know the specific sources of their own demand (such as various production processes and air-conditioning), when their demand is the highest, and what options exist to reduce their demand without significantly affecting their commercial operations or household comfort. For example, customers participating in the Georgia Power real-time pricing program told us that the utility staff was indispensable in initially informing them about the existence of the program, about quantifying the potential savings, and in identifying ways to reduce demand during high-priced hours.

Several Outside Factors Have Also Served to Limit the Benefits of Participating in Available Demand-Response Programs in Recent Years

Several factors have also reduced the incentive to participate in demand-response programs over the past several years. These include (1) moderate weather across most of the country over the past couple of years that has limited overall and peak demand; (2) a slow national economy, which has limited overall demand; and (3) many new power plants in some parts of the country have increased supply and lowered costs in those areas. Consequently, prices have moved downward overall. However, experts note that these types of programs may be urgently needed when supplies are limited and prices are high.

According to participants that we met with, they hoped to benefit from their ability to reduce demand when prices were high and, in some cases, increase demand when prices were low. Participants told us that although they signed up for demand-response programs, they often would not actively participate unless prices were high enough to offset the costs of shutting down. Some businesses said they may not continue to participate unless they could demonstrate the financial benefits of doing so on a regular basis to senior managers, either through higher prices or through some ongoing payment for their willingness to reduce demand if needed. Recognizing this problem, program operators, grid operators, and others said that the persistence of low prices could imperil demand-response programs. For example, in the parts of the West where prices have historically been generally low, there was only limited demand-response capability outside of California. However, this capability became urgently needed during the crisis of 2000 and 2001. Because these programs are difficult to start up, particularly during a crisis, little additional demand-response was available.

GSA's Participation in Demand-Response Programs Has Been Limited

According to GSA officials, participation in demand-response programs has been limited for the following reasons:

- *GSA lacks specific guidance on how to participate.* While GSA provides guidance regarding participation in reliability-driven programs, information regarding market-based pricing programs is limited. For example, a regional energy manager we spoke with was not generally familiar with market-based pricing programs and thought that backup generation was required to participate. Another regional energy manager told us that he relied on information provided by the local utility and grid operator to provide the information he used to make decisions on whether to participate in these programs.

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- *Federal agency tenants have little incentive to reduce their consumption.* According to GSA officials, current leases require a fixed monthly payment from federal agency tenants, which does not provide a way to share any savings from demand reduction efforts or to pass on the higher costs to agencies creating higher demand during high cost periods. Therefore, tenants do not have incentives to seek opportunities for the electricity savings that could be realized from participation in demand-response programs.

In addition, the need to reduce demand has been limited in recent years. As with other customers, GSA officials have not seen high electricity prices because of such factors as moderate weather. Consequently, GSA officials told us that they have had difficulty maintaining interest in reliability-based programs among their clients or in recruiting new ones.

Certain Programs Show How Barriers Were Overcome and Provide Lessons on How to Cultivate New Programs

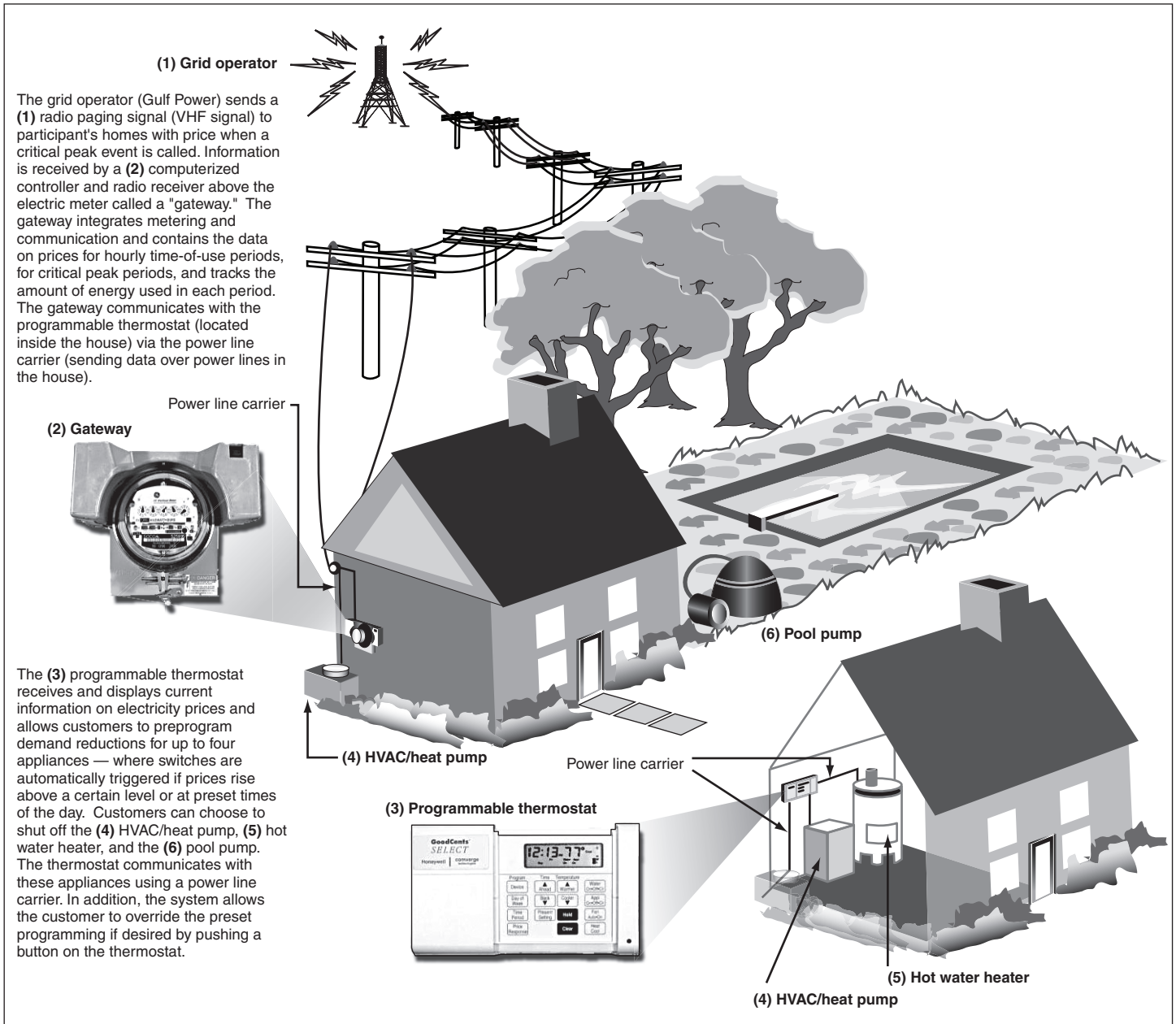
Certain demand-response programs that we reviewed illustrate how the barriers we identified were overcome and also point out three broader lessons on how to cultivate new programs.

Two Programs Illustrate How to Overcome Barriers

To overcome regulatory barriers, Gulf Power, a regulated utility in the panhandle of Florida, introduced its GoodCents Select market-based pricing program by receiving regulatory approval to offer it as a voluntary program. The utility demonstrated to state regulators that its program could offer benefits such as lower overall electricity costs and additional services to participants without raising prices for or otherwise harming nonparticipants. In general, state regulators told us that they review the impact of programs on the electricity rates of nonparticipants, which is referred to as the rate impact test. This test compares the avoided costs, including costs to construct power plants and transmission lines as well as costs to operate and maintain new facilities, with the costs of operating the program. In the case of the demand-response program that we reviewed, they approved the program proposed by the utility because of its benefits for both participants and nonparticipants.

Gulf Power also overcame the barrier of inadequate equipment by installing an innovative package of new technologies, including a computerized controller, called a “gateway” that integrates the metering, communication, and switches to control demand. Figure 2 illustrates this system. The programmable thermostat receives and displays information about the current electricity price period (e.g., peak prices) and allows customers to preprogram demand reductions for up to four appliances based on time-of-day or in response to changes in prices, or both. The switches are automatically triggered if the preprogrammed criteria are met such as if high critical peak prices are in effect. For example, customers can choose to shut off the heat pump, air conditioner, pool pump, or hot water heater if prices reach a certain point or other events occur. By automating demand reduction, this program allows customers to avoid consuming costly electricity, even if they are not actually present to monitor or turn off the equipment. However, this system also allows the consumer to override the preset programming if desired; for example to operate the air-conditioning if they are home during the day. The data on electricity usage is sent periodically via an integrated telephone line. Utility officials noted that installing meters and related equipment for their programs costs, on average, \$600 to \$700 per customer. In addition, because Gulf Power was able to demonstrate to regulators that the program provided benefits to nonparticipants, it was possible to have some of the cost of the equipment paid for by a state mechanism used to fund energy efficiency and other similar programs. The cost-sharing required participants to pay 60 percent and all ratepayers to pay 40 percent of the costs. These technologies had the added benefit of making participation easy, a consideration that was important to customers.

Figure 2: Gulf Power's Energy Control System for Residential Participants in GoodCents Select



Source: GAO analysis and illustration based on Gulf Power information; photos (2) and (3) Gulf Power.

Gulf Power also overcame the barrier of limited customer awareness through advertising and providing additional services that customers valued, such as whole house surge suppression and power outage notification, for a fee of \$4.95 per month. This charge also enables the utility to recoup some of its expenses. Gulf Power utilized mass marketing techniques to make consumers aware of the program and to provide basic information about the advantages available to participants. Further, the utility provided a detailed information package to interested customers and actively followed up with telephone and other contacts. Utility officials told us that customers require substantial education about the program's benefits, its basic features, and its ease of access to make the program successful. Residential customers, according to these officials, must be convinced that they will not be worse off financially and that they can achieve savings without substantially reducing their quality of life. In addition to the services provided by the innovative package of metering and other technologies, participants also received other services that they valued as part of their participation.

In New York State, the grid operator overcame barriers to establish both a market-based pricing program and a reliability-driven program primarily targeting commercial and industrial customers. In the summer of 2000, grid operators, utilities, and others expected supply shortages and quickly established these new programs to address these shortages.

The New York grid operator overcame the regulatory barriers by convincing the state regulators and FERC to make changes needed to establish the programs. These included the creation of an electronic trading marketplace so participants could offer their demand reductions to the grid operator at a certain price. State regulatory officials told us that they and FERC were open to considering the regulatory changes because there were no other options for quickly adding new power.

The New York grid operator overcame the barrier of inadequate equipment by identifying a state-funded entity to share the cost of installing the needed equipment. The program received financial support from the New York State Energy Research and Development Authority for installing needed equipment such as meters that can measure hourly consumption. This organization was allowed to provide as much as 70 percent of the cost of the meters, but it generally paid about 40 to 45 percent of the costs. The grid operator told us that the availability of this money made the customer's decision to participate easier because costs were lower. The ISO also developed an automated telephone notification system, introduced in 2003,

to replace the previous nonautomated process, which was described as time-consuming and inefficient. New York grid operators used the new system for the first time in August 2003 in conjunction with the blackout.

The grid operator overcame the barrier of inadequate customer awareness by starting the program during a time when supply shortages were expected and by widely publicizing the program's availability and its potential benefits. The grid operator provided brochures and other sources of information that identified the growing threat posed by the tight electricity supplies, the benefits of participating in the program, the role of participants, and the rules under which the program operated. In addition, state officials hosted a series of workshops that boosted awareness of the program and the need for demand-response. Enrollment in the program has grown substantially from its inception; in 2002 there were about 1,700 participants accounting for about 1,500 MW of demand. Industrial customers have also formed a trade association that has helped identify ways to improve the program.

Successful Demand-Response Programs Offer Three Important Lessons for Nurturing Further Programs

The demand-response programs that we reviewed offer important lessons for such programs to succeed. First, programs with sufficient incentives make customers' participation worthwhile. For example, Gulf Power's market-based pricing program provides a more than sevenfold difference between the lowest and the highest prices, depending on the time of day and season. Exposure to this great a difference in prices and the savings that result from adjusting demand accordingly provide a strong incentive for participation. In contrast, Puget Sound Energy began a somewhat similar program that was ultimately unsuccessful because the price differences with the regulated program were only about 20 percent different—too small to induce customers to change their consumption,¹⁰ according to studies we reviewed.

Second, programs are more likely to succeed if state regulators and market participants are receptive to the potential benefits of demand-response programs in their areas. In both Florida and New York State, certain market factors made demand-response especially appealing. In Florida, Gulf Power's customer base is predominantly residential and prone to sharp variation in daily and seasonal demand because of air-conditioning. In

¹⁰One study calculated that, if an average customer shifted all usage out of expensive periods and into the economy period, savings would amount to only \$4.65 per month.

presenting their case to state regulators, utility officials, demonstrated that the avoided costs of adding new capacity were greater than the costs of introducing a market-based pricing program. Similarly, in New York State, state officials recognized the potential for supply shortages, the difficulty of adding new capacity, and the benefits of developing a reliability-driven program as an alternative.

Third, to achieve these benefits and increase the chances of success, the design of programs should consider appropriate outreach, the introduction of necessary equipment, and the ease with which customers can participate. The programs discussed here have demonstrated that these factors are also critical to success.

Conclusion

The goal of restructuring the electricity industry is to increase the amount of competition in wholesale and retail electricity markets. While wholesale market prices are now largely determined by supply and demand in those markets, retail demand does not generally respond to market conditions because of key barriers discussed in this report, especially the presence of flat, average prices generally set by states. These prices serve to insulate consumers from market conditions and prevent them from potentially choosing to reduce demand when prices are rising dramatically or when grid reliability is a concern. As such, retail consumers—as was the case in California—can unknowingly drive up wholesale market prices because they continue to consume as much as or more electricity than normal even when demand could exceed available supplies. Thus, this hybrid system—competition setting wholesale prices and regulation setting retail prices—results in electricity markets that do not work as well as they could.

This hybrid system also makes it difficult for FERC to assure the public that wholesale prices are “just and reasonable.” While electricity markets are subject to divided jurisdiction, it is clear that these markets remain operationally joined; actions in one market affect the other. FERC has previously determined that actions in retail markets, particularly when consumers do not respond to market conditions, can cause prices in wholesale markets to exceed competitive levels. Such outcomes are not desirable or consistent with FERC’s responsibility for wholesale prices. Thus, FERC may have to take additional steps—within its jurisdictional boundaries—to ensure that competitive wholesale markets are not, unknowingly or unnecessarily, harmed by retail buyers.

It is clear that connecting wholesale and retail markets through demand response would help competitive electricity markets function better and enhance the reliability of the electric system, thus potentially delivering large benefits to consumers. Overcoming existing barriers will not be easy, however. Capturing these benefits will require leadership, collaboration, and action on the part of FERC, interested state regulatory commissions, and market participants in order to develop electricity markets that are truly competitive. Without these efforts to incorporate demand-response in today's markets, prices will be higher than they could be, the incidence of price spikes caused by either market conditions or by market manipulation will be greater, and industry will have less incentive for energy efficiency and other innovations, among other things.

To date, GSA has benefited from participation in demand-response programs, but clearly could do more. As a large customer with buildings located across the country, GSA is uniquely situated to benefit from demand-response programs and to provide a benefit to local electricity markets. While it has signed up for some programs, GSA could participate more actively by adjusting its energy consumption in response to prices and/or emergencies when asked—without compromising the operation of its buildings or tenants. To the extent that GSA does so, it could further reduce its annual electricity spending, possibly benefit the broader electricity market, and provide an opportunity for the federal government to lead by example.

Recommendations for Executive Action

We recommend that the Chairman of the Federal Energy Regulatory Commission take the following three actions:

- Because the lack of demand-response can result in wholesale prices that are not consistent with competitive outcomes and may not be “just and reasonable,” we recommend that the Chairman consider the presence or absence of demand-response programs when: (1) determining whether to approve new market designs or approve changes to existing market designs, (2) considering whether to grant market-based rate authority, and (3) determining whether to allow some buyers to participate in wholesale markets. As part of this process, FERC should consider its authority to use this information in making decisions on these matters. If there is inadequate demand responsiveness and FERC determines that it has authority, it should not approve these designs, authorities, or participation until such time as there is some combination of price and/or reliability based demand-response to assure that prices will be

just and reasonable. If FERC determines that its authority is not sufficient to take such action, it should seek this authority from Congress.

- In reporting to Congress, the Chairman should identify the options that may have potentially large benefits and are cost-effective for achieving consumer response, as well as statutory or other impediments to putting these options into practice.
- Because the development of demand-response programs depends upon there being markets where these services can be sold, the Chairman should encourage, where reasonable, equal consideration of supply and demand when approving or changing market designs.

In implementing these recommendations, it is important that the Commission continue working with system operators, regional entities, and interested state commissions, and market participants to develop compatible regional market rules and policies regarding demand-response. FERC should use these outreach efforts to identify regions of the country where demand-response programs are most urgently needed and where grid operators, state regulatory officials, and market participants are amenable to the collaborative introduction of regionwide demand-response programs. As part of its efforts, FERC should also engage the Department of Energy in its examination of demand-response options and involve the department in its outreach efforts, thus leveraging its expertise in identifying cost-effective technologies and its relationships with state, industry, and consumer groups.

Because demand-response programs offer potential financial benefits to the federal government and to demonstrate the federal government's commitment to improving the functioning of electricity markets, we recommend that, for locations where the General Services Administration has significant energy consumption, its Administrator take the following four actions:

- Require regional energy managers to identify what demand-response programs are available to them, require building operators to determine whether they could actively participate in the programs, and quantify the benefits of that participation.

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- Develop guidance that clearly articulates to the regional offices that participation in demand-response programs should be considered as part of the energy decisions that they make.
 - Require (1) guidance on specific measures that building operators can take to respond to market-based programs, similar to the guidance that they provide for responding to emergencies and (2) training on evaluating how to maximize benefits from participation in these programs.
 - Clarify the incentives for participation by defining how the GSA, its building operators, and its federal agency tenants will share the benefits and risks of participating in these programs through its leases.

Agency Comments and Our Evaluation

We provided FERC and GSA a draft of our report for review and comment. The Chairman of FERC endorsed our conclusions regarding the importance of demand-response to competitive energy markets and to electricity system reliability. The Chairman also generally agreed with the report's recommendations. In response to one recommendation, the Chairman agreed to consider conditioning market-based rate authority on the presence of sufficient demand-response, but noted FERC uncertainty as to whether it can require such a condition or that such conditioning would be workable, given current policy that separates wholesale and retail functions. Our recommendation, however, has a precedent in a similar state jurisdictional issue—that of the construction of new power plants. In this instance, FERC approved a mechanism, commonly known as “capacity markets,” that created an additional market for power plants and serves as a signal for when they are needed. In the same way, our recommendation, if properly implemented, could create such a market for demand-response as well as serve as a complementary signal for new capacity. FERC also provided several general and clarifying comments or suggestions that we incorporated as appropriate or address in appendix III.

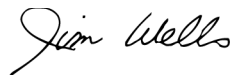
GSA agreed with the report's conclusions regarding the importance of demand-response to an efficient and reliable electricity industry. GSA also stated that it agreed with the majority of our recommendations, but it expressed some concern about one of them. Overall, its comments focused on concerns about risk, especially in the form of financial penalties that GSA may incur through participation in demand-response programs. GSA also commented on the broad risks regarding price stability and power reliability that pervade the transition from regulated to restructured

electricity markets. As such, GSA expressed concern about the fourth recommendation for GSA to define how benefits from successful demand-response participation will be shared with tenants. With this broad concern regarding risk to GSA in mind, GSA expressed the view that such sharing would not be practical because the agency would bear the risk while tenants reaped the rewards and because the savings to be shared are of a short-term nature. We revised the recommendation to reflect GSA's concern by adding that risk should be shared between the agency and its tenants. As revised, we believe the recommendation provides sufficient flexibility for GSA to develop practical approaches for sharing financial incentives as well as penalties with its tenants to encourage participation in demand-response programs. However, we note that as the electricity market places greater emphasis on competition, consumers such as GSA and the federal agencies that it serves will face greater price volatility. Consequently, efforts to manage this greater price volatility by developing demand-response capabilities will be an important element in managing GSA's operating costs.

As agreed with your office, unless you publicly announce the contents of this report earlier, we plan no further distribution until 30 days from the report date. At that time, we will send copies to other appropriate congressional committees; the Chairman of FERC; the Administrator of the General Services Administration; and other interested parties. We also will make copies available to others upon request. In addition, the report will be available at no charge on the GAO Web site at <http://www.gao.gov>.

If you or your staff have any questions about this report, please contact me at (202) 512- 3841. Key contributors to this report are listed in appendix V.

Sincerely yours,



Jim Wells
Director, Natural Resources
and Environment

Scope and Methodology

To assess demand-response programs, their benefits, barriers to expansion, ways to overcome barriers, and the federal government's participation, we conducted an extensive review of the literature; analyzed industry and participant data on the performance of the programs, where such data was available to us; and conducted interviews with state and federal officials (in the Federal Energy Regulatory Commission [FERC], the Department of Energy, and the General Services Administration [GSA]) and the Edison Electric Institute, a trade association representing large electricity providers.

To provide insights on the operation and experience of several current programs, we also examined programs in four states in greater detail: two in states with restructured retail markets (California and New York State) and two in states with traditionally regulated retail markets (Georgia and Florida). We selected these programs because they have operated for several years and experts consider them innovative and successful models. In particular, we examined the following programs:

- In California, we examined programs operated by one large electricity provider and several programs operated by others. We examined two programs operated by Southern California Edison: time-of-use rates for large customers, interruptible rates for large customers, and direct interruptions to the operation of specific electrical devices, such as air conditioners at customers' homes and/or businesses. In addition, we discussed a range of programs operated by the state grid operator (the California Independent System Operator [ISO]), and the state created in response to the electricity crisis in 2000 and 2001. We interviewed officials at Southern California Edison, the state public utility commission, the California ISO, the California Energy Commission, California Power Authority, and Pacific Gas and Electric. In addition, we met with four customers that participated in programs operated by Southern California Edison.
- In New York State, we examined programs operated by one large electricity provider and by the state grid operator. We examined a real-time pricing program implemented by Niagara Mohawk that provides day-ahead hourly prices against which actual consumption is billed. We also examined programs operated by the state grid operator (New York ISO)—one market-based pricing program and two reliability programs. We examined the New York ISO demand-bidding program (called the Day-Ahead Demand-Response Program). We examined one reliability program (called the Emergency Demand-Response Program) that pays

participants who reduce demand when reliability is at risk. We also examined a reliability program (called the Special Case Resources) that requires participants to sign agreements in advance to reduce demand whenever requested and pays them for doing so. In our report, we combine our discussion of these two reliability programs. We also interviewed staff from Niagara Mohawk, the New York ISO, the New York State Energy Research and Development Authority, the New York Public Service Commission, and a consultant who annually reviews the performance of programs run by the New York ISO. In addition, we met with four customers that participate in programs operated by the New York ISO and/or Niagara Mohawk.

- In Georgia, we examined a real-time pricing program operated by Georgia Power, a regulated utility. We also interviewed staff at Georgia Power, the Georgia Department of Natural Resources—Environmental Protection Division, and the Georgia Public Service Commission. In addition, we met with two customers that have participated in the Georgia Power program.
- In Florida, we examined a critical peak-pricing program (GoodCents Select) operated by Gulf Power, a regulated utility. We also interviewed staff at Gulf Power, the Florida Office of the Public Counsel, the Florida Energy Office, and the Florida Public Service Commission. In addition, we met with one residential participant in the program.

To determine GSA's participation in demand-response programs, we interviewed GSA staff located in the headquarters' Energy Center of Expertise and in GSA's 11 regional offices and obtained information about electricity consumption at about 1,400 facilities where GSA pays for electricity. In addition, we obtained information about demand-response activities at 53 large GSA buildings. These buildings incurred the highest electricity expenses of the about 1,400 GSA-operated buildings nationwide and represented about 40 percent of the agency's total electricity expenses in 2003. We obtained information on participation and the benefits of demand-response programs for a 5-year period—1999 through 2003. To estimate the potential benefits of GSA's more widespread and active participation in demand-response programs, we used information on GSA's participation and benefits from the 53 large buildings for 1999 through 2003 to estimate the potential benefits to large GSA-controlled buildings for 2004 through 2008. Specifically, we based our estimate of possible future GSA savings from demand-response programs on historical data on savings by GSA buildings participating in demand-response, the degree to which these

buildings participated, and weather conditions, which we obtained from GSA and other sources. To account for variations in the factors affecting benefits, a Monte Carlo simulation was performed. In this simulation, values were randomly drawn 1,500 times from probability distributions characterizing possible values for participation rates, degree of participation, and weather conditions. The simulation resulted in forecasts of possible future savings from demand-response program participation by GSA.

In developing our report we also met with 20 experts, who have extensive experience with demand-response programs. These individuals are listed in appendix II.

We conducted our work from March 2003 through July 2004 in accordance with generally accepted government auditing standards.

Selected Experts Interviewed

This appendix lists the 20 experts we interviewed on the issues surrounding demand-response programs. Their listing here does not indicate their agreement with the results of our work.

1. Severin Borenstein, University of California-Berkeley
2. Steve Braithwait, Christensen Associates
3. Richard Cowart, Regulatory Assistance Project
4. Larry DeWitt, Pace University School of Law
5. Ahmed Faruqui, Charles River Associates
6. Steve George, Charles River Associates
7. Joel Gilbert, Apogee Interactive
8. Charles Goldman, Lawrence Berkeley National Laboratory
9. Eric Hirst, Consulting in Electric-Industry Restructuring
10. Jerry Jackson, Jerry Jackson Associates Ltd.
11. Lynne Kiesling, Northwestern University
12. Chris King, E Meter Corporation
13. Roger Levy, Levy Associates
14. Amory Lovins, Rocky Mountain Institute
15. Bernie Neenan, Neenan Associates
16. Michael O'Sheasy, Christensen Associates
17. Steven Rosenstock, Edison Electric Institute
18. Larry Ruff, Charles River Associates
19. Vernon Smith, George Mason University
20. William Smith, Electric Power Research Institute

Comments from the Federal Energy Regulatory Commission

Note: GAO comments supplementing those in the report text appear at the end of this appendix.

FEDERAL ENERGY REGULATORY COMMISSION
WASHINGTON, DC 20426

OFFICE OF THE CHAIRMAN

July 7, 2004

Mr. Jim Wells
Director, Natural Resources and Environment
United States General Accounting Office
Room 2962
441 G Street, N.W.
Washington, D.C. 20548

Re: GAO Report Entitled *Electricity Markets: Consumers Could Benefit from Demand Programs, But Challenges Remain*

Dear Mr. Wells:

Thank you for your June 18, 2004 letter enclosing your draft report, *Electricity Markets: Consumers Could Benefit from Demand Programs, But Challenges Remain*. I congratulate you on this effort and appreciate the opportunity to comment.

I endorse and support GAO's conclusions that demand response would help competitive energy markets function better and enhance the reliability of the electric system. These goals underlie the Commission's own activities in developing and fostering demand response in wholesale electric markets. As this Commission has stated repeatedly, we cannot have a fully competitive and robust wholesale electric market unless customers have the ability to see and respond to electricity prices by modifying their demand for electricity.

Before I comment on the specific content within the draft report, I would like to offer three overall observations. First, the report correctly focuses on three main barriers to the introduction of demand response programs: (1) regulations that shield customers from short-term price fluctuations, (2) the absence of equipment installed at customers' sites required for participation, and (3) customers' limited awareness of programs and their potential benefits. The Commission recognizes these three barriers and has acted within our jurisdiction -- wholesale electric markets -- to lower or remove these barriers. Ultimately, however, these barriers were historically created and are today sustained at the state level, so the solution to these barriers lies in the states with retail electric regulators and policymakers. Our Strategic Plan commits to "work with states to support robust programs for customer demand-side participation in energy markets." The commission has been working to enhance and broaden wholesale

2

electric markets, to improve market transparency and participation to create more effective energy and capacity prices that give clear signals that serve both the demand and supply side. Where we see barriers in wholesale markets, we will work within our jurisdiction and authority to remove them.

Second, I generally support the report's recommendations to: (a) consider the presence or absence of demand-response programs as a factor in the approval of wholesale market designs, (b) identify demand response options in future reports to Congress, and (c) to encourage, where reasonable, equal consideration of supply and demand when approving or changing market design. I will ensure that the Commission continues its outreach and collaboration efforts with all parties on demand response (and its enabler, distributed generation), and our staff will continue their close cooperation with the Department of Energy on demand response and distributed generation issues. Examples of our close working relationship with the Department of Energy have included the joint sponsorship of the New England Demand Response Initiative stakeholder process and our current coordinated support of the International Energy Agency's Demand Response Resources project.

Third, we will consider your recommendation to condition a seller's market-based rate authority on having sufficient demand response capability. We do take market structure into account when granting market-based rate authority and approving market power mitigation policies. As a practical matter, it may not be possible to condition market-based rate authority of wholesale sellers on actions taken by their retail affiliates given current policy that separates wholesale merchant and retail functions. A wholesale seller cannot necessarily influence the policies of its retail affiliate, nor the state's retail regulations under which it operates – but we can certainly encourage state regulators to recognize the relationship between demand response and market power mitigation. It is unclear whether we can require wholesale suppliers to be subject to the existence of demand response programs as a condition of market-based rate authority in wholesale markets.

In addition to these overall comments in support of the report, I have several general and detailed comments on the contents of the report. These are discussed below.

General Comments

First, while the authors of the report recognize and understand the fundamental role of state policy and regulation in encouraging demand response, a clearer exposition of the role of federal and state regulation would strengthen the report. It would be helpful to include a brief review, early in the report, of federal

See comment 1.

and state regulation and relative jurisdictions as they relate to demand response. In addition, references to regulation throughout the report should clearly identify the responsible party (i.e., state versus federal). Without these clarifications, readers of the report may not fully comprehend that the success of demand response requires actions by both federal and state regulators, not just the federal government. This point would also be strengthened if your report offers recommendations targeted towards state policymakers to highlight the need for strong state impact on the success or failure of demand response and wholesale market price levels, regardless of whether the state's retail customers are served in a traditionally regulated or retail competitive environment.

Second, I disagree with the inference throughout the report that demand response is limited. For example, page 4, in "Results in Brief", states that, "Two types of demand-response programs are in limited use," and that, "Although reliability programs are more widely available than market based pricing programs, their use is limited." The report is correct that the amount of load currently participating in demand response programs is a small portion of peak load in most regions of the country. Nevertheless, the report leaves a negative impression about the potential of demand response and does not adequately highlight successes and recent significant improvements. New York is an example of a successful implementation of demand response -- the amount of demand response in NYISO's reliability-driven demand response is nearly equal to NYISO's typical 1,800 MW operating reserve, and the amount of demand response in NY is about 5% of peak system load. The most important lesson from New York is that the development of this level of demand response required the joint cooperation and support of multiple parties, i.e., NYISO, market participants, NYPSC and FERC -- a model for how demand response could be developed nationwide.

Third, in its criticism of the implementation of demand bidding programs, the draft report laments that demand bidding program participation is limited to high price periods (2nd full paragraph on page 17. "Even where they are available, active participation has been limited to times when wholesale prices are high."). This criticism is misplaced. This Commission recognizes that demand bidding programs provide the most benefit to the market and to participating customers when prices are high. During periods of low prices, the value to price-responsiveness to the market is low, and it is not profitable for customers to reduce demand and potentially modify or curtail production processes. Customers and LSEs will participate when it is "worth their while." Experience has shown that when prices are high, participation increases.

See comment 2.

Now on p. 17.

See comment 3.

See comment 4.

Fourth, the report does not adequately characterize the value and importance of existing ISO emergency programs that obligate load reductions through agreements and contracts. On page 19, the report categorizes all emergency programs as “voluntary reduction programs.” The report only briefly mentions the signed agreements in NYISO’s Special Case Resources (SCR) program that obligate participants to reduce demand when notified. The SCR program has proven to be an important program for reliability and reserves in New York, and the report downplays its importance within the NYISO and their value in other regions. The Commission supports these programs because they provide a guaranteed payment to customers willing to respond when asked, and can lead to greater customer interest and participation in other programs. I recommend that this section place greater emphasis on these programs, and recognize the similarity of these contractual programs to interruptible programs.

See comment 5.

Fifth, I strongly agree with the report’s concern on page 36 that low prices and oversupply “could imperil demand-response programs,” and that in the West during the crisis of 2000 and 2001 “because programs are difficult to start up, particularly during a crisis, little additional demand response was available.” This “boom-bust” problem affects both demand response programs and the availability of peaking supply units, so the Commission has been pursuing various policies to improve resource adequacy, provide incentives for infrastructure development, and enhance revenue and price stability. To address this problem as it relates to demand response, this Commission has encouraged and approved policies that provide capacity value for demand response and recognize the value of demand response as a callable resource option. Unfortunately, the report does not provide a targeted recommendation to resolve the “boom-bust” problem. The report’s recommendation to solve this fundamental problem and others is to recommend that FERC require demand response before it accepts various market designs. We would welcome any specific thoughts from the report’s authors to address this long-term resource adequacy problem, particularly in areas without ISOs or RTOs operating a competitive, organized wholesale electric market.

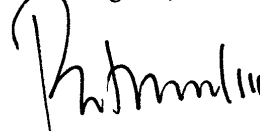
See comment 6.

Finally, while the report focuses on actions and policies that the Commission and the General Service Administration can undertake, it overlooks the potential role of other federal agencies. In particular, the Department of Energy (DOE) can play an important and critical role in developing the potential of demand response in the United States. DOE’s ongoing responsibilities to develop nationwide energy policy, fund energy research and development, and provide energy education can be utilized to foster greater demand response and awareness of demand response as a crucial resource. While the DOE has been active in promoting demand response, DOE could play an even larger role, and the GAO may have helpful recommendations for DOE’s role and responsibilities with respect to demand response.

On a matter of detail, on pages 3 and 11, the report states, “as part of a broader effort to develop consistent rules for regional markets, FERC proposed an effort to encourage demand response in wholesale markets.” It is not clear which Commission effort is being described. Our attempts to implement Standard Market Design did include demand response as a core characteristic, as does its successor, the Wholesale Market Platform. FERC continues to advocate an open wholesale platform for demand and supply resource to compete on an equal basis, and encourage states to “plug in” retail demand into this platform.

Thank you again for the valuable insights in your report.

Best regards,

A handwritten signature in black ink, appearing to read 'Pat Wood, III', written in a cursive style.

Pat Wood, III
Chairman

The following are GAO's comments on the Federal Energy Regulatory Commission's letter dated July 7, 2004.

GAO Comments

1. We agree with FERC that the divided jurisdiction over electricity markets poses a challenge for implementing demand-response. We have already mentioned this divided jurisdiction in the opening pages of our report and discussed it in greater detail in the background section. GAO, which works for Congress to evaluate federal agencies and recommend changes at those agencies, cannot make "recommendations" to state commissions. We agree, however, that state commissions are important to the success of demand-response. Toward that end, our recommendation states that FERC should work with state commissions to develop complementary policies regarding specific demand-response programs. Accordingly, we made no changes to our report for this comment.
2. We agree with FERC that demand-response programs have been implemented in some markets, such as the NYISO, as we discuss in our report. These programs provide examples of the importance and success of demand-response, particularly with regard to reliability. However, we continue to believe that the amount of load actively participating in such programs is "limited" when compared with peak load in most regions, as FERC notes. Our finding that demand-response programs are in limited use, when viewed from a regional or countrywide perspective, is not meant to leave a negative impression, as described by FERC, regarding the potential of demand-response. In fact, the second objective of our report discusses its overall benefits at some length and finds that it shows substantial potential. Our point in identifying the limited extent of demand-response is meant to clarify that in many parts of the country additional efforts are needed to assure that sufficient demand-response exists in all markets overseen by FERC. As such, we made no changes to our report.
3. The sentence referred to in this comment was not intended to criticize the implementation of demand bidding. Rather, we are clarifying the limited extent of demand bidding, which so far has been relevant only when prices reach very high levels, as FERC observes. We agree that demand bidding is meant to provide relief when prices are high. However, we also note that program operators expressed concern that there was little demand bidding in some markets even when prices were at levels where many customers would benefit from reducing

demand. These programs are generally subscribed to by customers with large demand, such as manufacturing. They are complex insofar as customers must develop baselines to reflect their expected consumption for all hours of the year, as we discuss in the report. We made no changes in response to this comment.

4. Our report intended to reflect the value and importance of voluntary and contractual ISO emergency programs. For both types of emergency programs, we noted that enrollment is typically voluntary. However, customers participating in contractual programs sign agreements that might entail financial penalties if a participant does not reduce demand as required by the program. We agree with FERC that these programs within the NYISO are important. In responding to our fourth objective, we discussed the reasons for the success of these programs, citing them as examples that might be applied in other areas. For these reasons, no changes in response to this comment were included in our report.
5. As FERC considers our recommendation to condition the granting of market-based rate authority upon the presence of sufficient demand-response, we are hopeful FERC will regard our recommendation as another way to dampen the ill effects of the “boom-bust” cycle. In this respect, we see our recommendation as a way help create a market for demand-response, which should benefit the development of these programs. In our view, the currently low electricity prices offer a perhaps short-lived opportunity to develop demand-response resources that may be urgently needed if demand intensifies in response to a stronger economy, weather events, fuel price increases, supply interruptions, or other events. With respect to actions to address resource adequacy, FERC may be in the position to limit the activities of energy sellers who are unwilling to develop or acquire adequate demand-response, even in markets without an organized ISO or RTO. It may be able to exercise this leverage when key participants in these markets seek FERC approval for market-based rate authority or for purchases from markets overseen by FERC. In view of these observations, we made no changes to our report.
6. While our report did not elaborate on DOE’s potential role in detail, we recognized its importance. In our report, we discuss DOE’s role in formulating national energy policy, researching technologies, and disseminating information to the public, among other things. In addition, in our recommendations to FERC, we suggested FERC should

also engage the Department of Energy's expertise in identifying cost-effective technologies and information dissemination capabilities, thus leveraging DOE's technology expertise and its relationships with state, industry, and consumer groups. As such, we did not add additional information in response to this comment.

Comments from the General Services Administration



GSA Administrator

July 15, 2004

The Honorable David M. Walker
Comptroller General
of the United States
General Accounting Office
Washington, DC 20548

Dear Mr. Walker:

The General Services Administration (GSA) appreciates this opportunity to submit agency comments on the U.S. General Accounting Office (GAO) "Draft Report to the Chairman, Senate Committee on Governmental Affairs, U.S. Senate, *Electricity Markets: Consumers Could Benefit through Demand Programs, But Challenges Remain*," GAO-04-844 (Draft Report).

GSA agrees with the majority of the recommendations and recognizes that the recommendations provide GSA with an ideal opportunity to advise and assist other Federal Agencies in implementing a more thorough demand response program across the Nation.

Specific comments on the Report and the Report's recommendations are enclosed. Questions regarding the Draft Report may be directed to Mr. Mark Ewing, Energy Subject Matter Expert, at (202) 708-9296 or mark.ewing@gsa.gov.

Sincerely,

A handwritten signature in black ink, appearing to read "Stephen A. Perry".

Stephen A. Perry
Administrator

Enclosure

U.S. General Services Administration
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Washington, DC 20405-0002
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**General Services Administration
Public Buildings Service
Energy Center of Expertise**

Response to

**Proposed Report: Electricity Markets: Consumers Could Benefit
through Demand Programs
(GAO-04-844)**

Participation in market-based demand response programs.

The Draft Report outlines various electricity demand response programs, generally described as either reliability or market-based. The Draft Report makes a specific case for increased participation in these programs by all retail customers, including GSA. In general, GSA agrees with the Report's conclusion that effective demand response is beneficial to the efficient and reliable functioning of the electricity industry. It is important to note that GSA's participation in reliability and market-based demand response programs may require significant investment and may pose financial risks to GSA in terms of penalties. Despite these challenges, GSA is cautiously increasing participation in market-based programs in order to maximize potential savings. The Draft Report states that, "To the extent that GSA does so, it could further reduce its annual electricity spending, possibly benefit the broader electricity market, and provide an opportunity for the federal government [sic] to lead by example." What the Report does not state is that by participating in market-based demand response programs, such as real-time pricing, GSA exposes itself to significantly greater risk should we not be able to reduce demand. The Draft Report quantifies the potential savings resulting from greater participation as \$12 to \$114 million, but it does not quantify potential penalties. Using the real-time pricing example above, if a GSA building was incapable of reducing demand according to price signals, GSA would incur significantly higher utility costs immediately. GSA would also face the dilemma of operating in excess of appropriations during the term of a given fiscal year. Exposing GSA to such potentially volatile market prices, when extrapolated to cover GSA's inventory nationwide, may present more risk than the budget planning process can accommodate.

Participation in reliability-driven demand response programs.

The Draft Report states, "However, when prices are set by regulation or law and change infrequently, customers are largely insulated from frequent and short-term changes in the cost to generate electricity." While regulation of the electricity industry did not provide for well-functioning electricity markets, regulation did provide better price

stability and power reliability than what currently exists. As states evolve toward a deregulated marketplace, many utilities are attempting to avoid stranded costs related to an efficient and reliable grid to better position their companies for competition. As a result, the grid is suffering in terms of both efficiency and reliability. Increasingly, retail consumers are not only paying more for electricity, but are also asked to pay the cost for electric reliability by investing in equipment that allows a building to change its electric consumption patterns, i.e., demand response. This investment requires careful planning so that investments are realized in the appropriate markets. Unfortunately, deregulation by states is not proceeding in any kind of predictable pace or general order. Often, consumer groups stop laws at the last minute or rules are changed within short time periods of three years or less. Given these constraints, combined with the limits of the Federal budget process, an accurate long-term strategy cannot be developed to permit widespread participation in response programs nationwide. While GSA has made progress, efforts are often focused specifically toward three states where the investment is considered to have the most predictable return on investment. Finally, it is not clear in the broadest sense whether or not this investment burden by retail customers, like GSA, is the most efficient process for correcting electricity industry problems.

Specific to the recommendations of the draft report, GSA offers the following comments:

Recommendation 1 - last line add "potential" before the word "benefits."

Recommendation 2 - GSA concurs

Recommendation 3 - GSA concurs

Recommendation 4 - GSA does not concur as it would not be practical for GSA to share savings with tenants for successful demand response participation as GSA assumes the rate/price/cost risk associated with electric costs during the core, on-peak hours of the day when it sets its rental rate. While GSA can offer incentives for its operations and maintenance contracts and GSA building managers can be rated based on energy performance, including demand response performance, it is not practical to share short-term savings with tenants in the form of interim rate reductions. However, informal tenant awareness events and the incorporation of tenant performance features into the lease can and do provide non-financial and quantifiable incentives to participants in GSA's demand response programs. Finally, if GSA were to offer tenants financial incentives to participate in demand response programs, they would include sharing penalties as well as savings, which could compromise customer satisfaction.

GAO Contacts and Staff Acknowledgments

GAO Contacts

Jim Wells (202) 512-3841
Dan Haas (202) 512-9828

Staff Acknowledgments

In addition to the individuals named above, Mary Acosta, Dennis Carroll, Randy Jones, Jon Ludwigson, Paul Pansini, Frank Rusco, Anne Stevens, Barbara Timmerman made key contributions to this report. Important contributions were also made by Kim Wheeler-Raheb and Carol Herrnstadt Shulman.

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