BARRIERS TO PRICE-RESPONSIVE DEMAND IN WHOLESALE ELECTRICITY MARKETS

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JUNE 2002

Preparation of this paper was supported in part by the Edison Electric Institute, Washington, DC; and the Regulatory Assistance Project, Montpelier, VT.

I thank Don Brundage, Harry Darnell, Ahmad Faruqui, David Lawrence, Michael O'Sheasy, Chris Seibens, and Rick Tempchin for their very helpful comments on a draft of this paper.

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JUNE 2002

1. INTRODUCTION

Virtually every state and federal government agency with an interest in energy issues has spoken out in favor of better integrating wholesale and retail electricity markets.[1] Recently, the U.S. Federal Energy Regulatory Commission (FERC) and the U.S. Department of Energy cosponsored a Conference on Demand Response; almost 400 people attended the conference.

Such improved integration requires that at least some retail consumers face dynamic prices that vary from hour to hour or participate in programs that provide an opportunity to reduce their electricity consumption when prices are very high. These price-responsive demand actions would improve economic efficiency, bulk-power reliability, and environmental quality.

In spite of all this enthusiasm, few retail customers face electricity prices that accurately reflect wholesale power costs. For example, the emergency and economic demand-reduction programs run by the PJM Interconnection (2001) signed up 220 MW of load reduction and achieved a maximum load reduction of 62 MW on August 9, 2001, just over 0.1 percent of PJM's typical summer peak load. At the other end of the spectrum, the Emergency Demand Response Program, run by the New York Independent System Operator (ISO), achieved an average load reduction of 355 MW during summer 2001, a savings of 1.1 percent (Neenan Associates 2002). These programs have achieved only modest results to date, in part because they are so new and in part because of the many obstacles that this paper discusses.

The rest of this paper focuses on various kinds of barriers that prevent greater retail participation in wholesale markets, including those related to retail customers (Section 2), government regulations (Section 3), tradition (Section 4), and technologies (Section 5). The final section suggests ways to overcome these barriers.

[1] See, as examples, recent statements from FERC (2001b), the Federal Trade Commission (2001), Western Governors' Association (2001), Vermont Public Service Board (2001), and New York Public Service Commission (2000).

2. CUSTOMER BARRIERS

Jaske and Rosenfeld (2001) note that consumers do not respond to dynamic prices for two reasons:

- They have no *motivation* to do so because, in most cases, the price they pay for electricity is time invariant.
- They have no *means* to do so because they are not informed of changes in wholesale electricity prices, and the meters that record their electricity use do not store data at the hourly level.

Both of these barriers relate to regulation and are discussed further in Section 3.

Even if customers had the opportunity to face dynamic prices and had interval meters and the necessary communications systems, they still might choose not to participate in such programs. Faruqui, Hughes, and Mauldin (2002) suggest that most consumers do not want to face volatile prices because they "equate price volatility with higher bills." Consumers generally do not recognize that the high prices during a few hours a year are more than offset by low prices during much of the year, resulting in a lower electricity bill for the year as a whole. In addition, consumers may not recognize the opportunities they have to shift consumption from high-priced to low-priced periods, further reducing their electricity bills.

These consumer perceptions highlight the critical need for customer education. Customers need information on how dynamic-pricing options work and how they might benefit from such programs before they will be willing to participate in such programs. At a more fundamental level, it might be worthwhile to educate consumers on how electrical systems operate and how wholesale electricity markets function. Such an understanding of operations and markets might help consumers understand that electricity consumption and production costs are quite volatile. As a consequence, a fixed price for electricity provides insurance to the consumer against both quantity and price risk, insurance for which customers must pay (Hirst 2002a).

Electricity consumers differ in ways that affect their interest in and ability to respond to time-varying electricity use. Some of the key characteristics include amount of electricity use, load shape (how load varies from hour to hour, from day to day, and from season to season), flexibility of operations (including the speed and ease with which consumers can modify loads), and the presence or possibility of automating control of some electricity-using equipment.

The greater the electricity use, the more likely the customer is to be willing to devote time and effort to understanding his options to reduce electricity costs. The hour-to-hour patterns of electricity consumption for different kinds of equipment and the correlations between these patterns and hourly prices affect the benefits of modifying consumption for those functions. For example, electricity use for air conditioning is highly correlated with hourly prices, while water-heating electricity use is largely uncorrelated with prices. This difference suggests that reductions in air-conditioning use are likely to yield larger dollar savings per kW of load reduction.

Where customers have considerable flexibility in operations, the cost of participating in demand-response programs is low. For example, municipal water-pumping systems typically have tanks, reservoirs, or lakes to store water for later distribution to consumers (Kueck 2002). These facilities permit the water-treatment system to interrupt pumping operations for up to a few hours at a time.[2] During such nonpumping periods, gravity will ensure sufficient water flow and the appropriate pressure to consumers. In aggregate, municipal water pumping accounts for approximately 3 percent to 4 percent of total U.S. electricity consumption.

If control of a particular process or piece of equipment can be automated, such that it does not require manual intervention to respond to time-varying prices, participation is likely to be much higher. For example, households are unlikely to participate in programs that require them to manually turn off their electric water heaters at certain times. However, many utilities operate direct-load-control programs that send a radio signal to the water heater to automatically turn it off and on.

Because of these differences in customer characteristics, retail providers should design different programs for different types of customers. Residential and small commercial customers might be best served with the traditional direct-load control and time-of-use programs utilities have run for years. Large commercial and industrial customers, on the other hand, might take advantage of more sophisticated program offerings, including the opportunity to sell short-

[2] The tanks for residential water heating represent an analogous storage opportunity that should make this end use a good candidate for dynamic-pricing options.

term load reductions as contingency reserves for reliability purposes and real-time pricing that varies from hour to hour.

Surveys of customers that participate in these programs show they prefer programs that are simple to understand and sign up for, permit aggregation of small loads, are announced well in advance of implementation, and provide a public-relations benefit to the customer (e.g., for helping to avert a regionwide blackout). Customers prefer programs that are voluntary, have no penalties for failure to reduce load when called upon to do so, provide ample advance notice of any consumer action that must be taken, and pay well for the load reductions achieved (Rosenstock 2001). Not all these customer preferences are internally consistent.[3]

Finally, with wholesale electricity prices currently low, consumers see little incentive to participate in these programs. On the other hand, when prices are high, it is too late to design and implement such programs.[4] One possible solution to this dilemma is for retail suppliers to accept some risk and guarantee a certain number of high-priced hours to participating customers. This guarantee would ensure both that customers received some benefit from the investment in meters and communications and that customers would not be faced with too much price volatility. In essence, the retail providers would act like long-term insurers.

[3] For example, the longer the advance notice required, the more convenient it is for customers to participate. However, longer notification periods lower the reliability value of the load reduction to system operators, therefore lowering the amount that can be paid for the load reduction.

[4] This situation is similar to the one facing a family whose roof leaks. When the sun shines, they have no incentive to repair the roof because it isn't leaking then. When it rains, they can't get on the roof to fix it. So, the problem continues unresolved.

3. REGULATORY BARRIERS

Government regulations at both the state and federal levels inhibit supplier offers and customer acceptance of demand-response programs and dynamic pricing. This section discusses several barriers related to state regulation (standard-offer service, metering and communications infrastructure, and load profiles), federal regulation, and bulk-power system operations (in which today's ISOs and tomorrow's regional transmission organizations [RTOs] set rules governing participation in wholesale energy markets).

A fundamental regulatory obstacle to greater use of demand-side resources is uncertainty on the part of market participants (both suppliers and consumers) about future government regulations and market design. Until the rules concerning definition, participation, and pricing for wholesale markets for energy, transmission congestion, and ancillary services are stable, suppliers and consumers will be unwilling to invest time and money to manage demand. Similarly, the rules concerning price caps and other forms of market-power mitigation must be stable before such programs can flourish. The California electricity crisis and the regulatory responses to those problems have made many market participants wary of long-term commitments to programs that may be abruptly modified or canceled. FERC's (2002) standard market design, if implemented, will help relieve these concerns.

STANDARD-OFFER SERVICE

The rules that state regulators have established governing retail competition are, perhaps inadvertently, limiting customer participation in dynamic-pricing programs. In such states, public utility commissions (PUCs) have mandated rate discounts, imposed rate freezes, and established predetermined load profiles as part of the transition to retail competition. Flaim (2000), Graves and Wharton (2001), and Jurewitz (2002) have written about the problems that standard-offer service cause. In particular, these standard offers typically require the distribution utility to offer all retail customers a discounted and time-invariant electricity price.

Flaim (2000) emphasizes the two elements of standard-offer service:

> … a physical supply function and a financial function. The former involves making sure that the kilowatt-hours are actually there to meet loads at given levels of reliability. The latter involves taking on the responsibility for incurring the costs associated with default supply, and for collecting those costs from default customers.

Flaim notes that the standard-offer service can be either hedged or unhedged. Unhedged service would most likely track the hourly spot market and its prices, which would be an efficient price. A standard-offer hedged product will "inevitably be an inefficient product design in that someone else has to decide in advance what types of supplies must be procured, at what cost, and for how long." Some competitive retail suppliers use a business model of gaming the default service and extracting its option value by switching customers back and forth depending on the relationship between the spot price and the default price.

These standard-offer services can block competition by (1) suppressing customer awareness of efficient price signals (they remain ignorant about the dynamics of pricing and never consider demand management), (2) hindering development of forward markets that would otherwise be used for customer hedging, (3) discouraging new retail providers from offering risk-management services as value-added products, (4) keeping utilities from becoming true wires companies, and (5) potentially threatening the financial viability of incumbent utilities (Graves and Wharton 2001).

Key to resolving these problems is explicit PUC recognition that the provision of fixed-price electricity includes an insurance policy as well as the electricity commodity (Hirst 2002a). These risk-management costs must be included in the rates customers face, and such costs must be reflected in the earnings that the provider of the standard-offer service receives for this service. PUCs should be sure the standard-offer service is a fair deal, for both customers and the provider, but not too good a deal for customers. A deal that is "too good to believe" today will have to be paid for later!

If PUCs impose rate caps on the local utilities, the utilities lose money if they run innovative load-reduction programs and pay for the associated metering and communication infrastructure. To the extent the utility recovers fixed transmission, distribution, and customer-service costs through a volumetric charge (i.e., on a ¢/kWh basis), its revenues and earnings will decline if customers reduce their electricity use. PUCs may want to modify their pricing policies to encourage such programs.

METERING AND BILLING INFRASTRUCTURE

PUC decisions on metering and related services (billing and access to meter data) are also critical to expanding price-responsive demand. Causey (1999) wrote:

> There is tremendous regulatory uncertainty about who eventually will own the meters and related equipment and the data generated from meter reading. Thus, utilities are justifiably fearful of making an investment today that might become a stranded asset tomorrow.

PUC indecision on these issues may slow the adoption of the infrastructure technologies necessary for dynamic pricing.

This lack of resolution inhibits utilities from installing these systems, for fear either that regulators will disallow these costs or that they might become stranded. Retail providers are unsure whether they are permitted to install such systems. If they do install these systems, how will they recover costs if customers switch to a different energy supplier? In the meantime, what entities have access to customer-meter data? Advanced metering can occur with either a regulated monopoly or a competitive market, but it will likely not occur until regulators decide on the framework for such metering and infrastructure issues.

Similar issues may apply to the computer systems required for billing and settlements. Obviously, more sophisticated software is required to bill customers with a time-varying price or for ad hoc load reductions than for electricity consumption at a time-invariant price. Unresolved issues—recovery of these software and computer development and implementation costs and whether these services should remain with the local utilities—may inhibit development of these systems.

Finally, PUCs need to decide who will pay for these infrastructure costs. The individual customers participating in dynamic-pricing programs could pay for the metering and communications costs associated with their facility. Alternatively, all retail customers could pay for these costs if these programs benefit all customers, not just those who participate in the programs.

Failure to resolve the pricing and technology issues discussed above places the local utility in a difficult position. Although it might recognize the benefits of more price-responsive demand, it might be reluctant to operate and market such programs. Utilities might worry that their investments in interval meters, communications systems, and enhanced billing systems might not be fully recovered through regulated rates, leading to stranded costs.

LOAD PROFILES

Utility rates today are based on customer-class load shapes. High-load-factor (e.g., large industrial) customers are the ones most likely to leave these rate classes to participate in price-responsive demand programs (a form of self-selection). The load shape of the remaining members of the rate class will then worsen. Absent a rate case, this change in load shape raises the utility's costs to serve the rate class with no corresponding increase in revenues.

The use of predetermined load profiles, rather than hourly metering, to bill customers further inhibits adoption of price-responsive demand. If customer meters are read only monthly, retail providers have no knowledge of the dynamics of electricity use and, therefore, no ability to either charge customers appropriately for their electricity use or mechanisms to reward them for changing the timing of their electricity use. In a similar fashion, customers have no incentive to respond to time-varying wholesale prices. State regulators should consider making interval meters a requirement for retail electric service, at least for larger users (e.g., greater than 20 kW).

PUCs can encourage adoption of these dynamic-pricing and voluntary load-reduction programs regardless of whether retail markets remain regulated or are open to competition. Indeed, many of the price-responsive demand programs are run by utilities under state regulation. A necessary prerequisite for these programs, however, is a competitive wholesale market with visible hourly prices.

FERC

At the federal level, FERC's acceptance and imposition of low price caps in the ISO markets it regulates will suppress customer participation in voluntary load-reduction programs. The limited program experience to date suggests that consumers will not participate in such programs unless the price exceeds about $250/MWh (Hirst and Kirby 2001). Indeed, the California ISO proposed a performance payment of $500/MWh plus a reservation payment of $20,000/MW-month for its summer 2001 Demand Relief Program, well above the $250/MWh cap in place at that time. The New York ISO's emergency demand response program paid participants an average of $514/MWh of load reductions during summer 2001 (Neenan Associates 2002). More generally, the greater the risk and magnitude of price spikes, the greater the incentives for price-responsive demand.

STATE/FEDERAL JURISDICTION

A critical issue is the potential conflict between state and federal regulation of price-responsive demand programs. Although FERC regulates wholesale markets and the ISOs that operate these markets, it has no jurisdiction over retail activities. The state PUCs, on the other hand, have authority over sales and service to retail customers but limited jurisdiction over wholesale markets.

The investor-owned utilities, regulated by both FERC and the states in which they operate, are caught in the middle. The ISOs, acting under FERC authority, might implement programs that impose costs on the utilities. Such costs can include those for metering, billing, program administration, and loss of revenues.[5] The latter can occur when fixed costs (e.g., for transmission and distribution systems, and for stranded costs) are recovered through volumetric charges, as they often are. In addition, the retail price caps under which many utilities operate provide gaming opportunities for customers, who can choose to face market prices when it is advantageous for them to do so and then regain the protection of the state-imposed price cap when that is the preferred option. Thus, utilities may be required by FERC to implement programs that increase their costs and reduce their revenue. These costs, however, can be recovered only with approval from the state regulator.

The solution here is not to ban ISO programs, but rather to ensure that the wholesale and retail efforts to better manage retail demand are coordinated. The goal should be to offer a comprehensive set of programs aimed at all customer classes with a minimum of duplication and confusion.

Finally, all retail-service providers should have the opportunity to offer such programs. And no providers (including the local utility) should be forced to incur costs that are not fully recovered. In particular, PUCs should permit regulated utilities to recover all reasonable program costs through rates.

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[5] FERC (2001a) briefly addressed these issues in its order approving the summer 2001 PJM demand-response programs.

INDEPENDENT SYSTEM OPERATORS

In some respects, the ISOs are logical candidates to promote demand-side participation in their markets. They run many of the day-ahead, hour-ahead, and real-time markets for energy and ancillary services. Because they are responsible for making these markets efficient and competitive, they are interested in expanding the range and diversity of resources participating in these markets. On the other hand, these markets are *wholesale*, and the issues this paper discusses concern *retail* customers. The ISOs are structured to deal with a few market participants, each of which is responsible for hundreds (or at least tens) of megawatts of demand or supply. The ISOs are not set up to interact with thousands (or millions) of customers. Perhaps the issue is whether the manager of wholesale markets has a responsibility to ensure easy access for retail customers and their providers.

As a practical matter, the existing ISOs have introduced pilot demand-side programs during the past few years. They operated small experimental demand-side programs for summer 2000, which they then refined and expanded in 2001.

At a minimum, the ISOs must ensure that customer loads are in no way prevented from participating in RTO markets. Just as the ISOs have developed many rules and procedures to deal with the idiosyncracies of different types of generation,[6] so must the RTOs develop rules that accommodate differences between the loads and generators (as well as among different types of loads) that might participate in their markets.

Consistent with the many rules that reflect and respect differences among generators, ISOs must accept differences among the loads that might participate in their markets. The ISOs cannot simply require that loads conform to the existing supply-side rules because those rules were developed with generators—and only generators—in mind. For example, some loads may be able to reduce their output very quickly and can therefore provide contingency reserves. However, some of these loads may not be able to return to their precontingency consumption level within the ISO-prescribed time, say ten minutes. Rather than prohibiting such loads from participating in reserve markets, the ISOs should examine the basis for the ten-minute restoration rule and decide whether a longer period of reduced load might be acceptable. (Resources must be restored to their pre-contingency levels when directed to do so

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6 As examples, generators differ in their ramp rate, speed with which they can change direction, minimum runtime, and ability to operate at less than full output. ISO scheduling and dispatch software recognizes and accommodates these and other generator characteristics.

by the ISO so they are ready to respond to the next contingency.) Perhaps a customer that cannot increase consumption for at least two hours after reducing its load in response to a contingency should be permitted to participate in contingency-reserve markets but get paid a lower price than resources that can return to their precontingency state within ten minutes.[7]

The ISOs must ensure that their resource scheduling and dispatching software can accept bids from customer loads as well as from supply resources. Not all the software used by today's ISOs can appropriately handle price-responsive load. In some cases, the number of retail loads that can be analyzed is limited. In other cases, demand bids are treated after the program optimizes across the supply bids, resulting in a situation in which the demand bids cannot set the market clearing price.

In addition, flaws in market design and implementation can yield prices that are economically inefficient and that discourage demand participation in wholesale energy markets. Patton (2001) analyzed New England market prices during high-load hours in summer 2001 and found many instances when prices were artificially low: "... New England market rules and/or actions of the ISO have artificially depressed market prices and created attendant economic distortions during periods of high demand this summer." These price distortions would have suppressed any demand response that might otherwise have occurred. The California ISO (2002) has experienced persistent problems with its intrahour market, leading to interval and hourly prices that often do not reflect actual operations.

The ISOs should review their metering and telecommunication requirements. The typical requirement is for metering and telecommunication of generator output to the ISO control center every four to six seconds. While obtaining data from large generating units so frequently may make sense, it may not be necessary for small loads. System operators monitor the output from large generators so frequently because the failure of any one unit must be compensated for immediately. Because almost all loads are tiny compared to generators, the statistical averaging across loads reduces greatly the need to monitor the consumption of individual loads. Also, it is inherently more reliable to turn something off (e.g., interrupt a load) than to turn something on (e.g., start a combustion turbine to provide contingency reserves).

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7 For example, the California Department of Water Resources has a pumping load that ranges from 1,000 MW to 2,600 MW. The Department can turn these pumps off almost instantaneously, but it cannot meet the ancillary-service requirements of the California ISO to restore the load within ten minutes of being directed to do so. The pumps must remain off for at least 30 minutes (analogous to the minimum runtimes of some generators) and can then be turned back on at the rate of 20 MW/minute (e.g., an hour to restore 1,200 MW of pumping load).

The ISOs need to be sure that the metering and telecommunications requirements they impose on participating loads are consistent with the RTO's reliability responsibilities. The California ISO (2000), in its effort to encourage load participation in its ancillary-service markets, relaxed the frequency with which individual loads must record and report their consumption from once every four seconds to once a minute. Because these loads are required to respond within ten minutes of an ISO request, it is hard to see why the ISO would need to know the consumption levels of these loads more often than once a minute. Although the ISO needs to be able to measure the performance of loads in delivering services to it, the ISO may not need to make these measurements in real time.

4. CULTURAL BARRIERS

A variety of traditional practices limits broad adoption of dynamic pricing and related competitive options. Perhaps the greatest barrier here is the belief that electricity costs and prices can and should remain time invariant. We emphasize again our view that consumers, suppliers, and regulators need to recognize the risk-management component of electricity pricing. A related barrier is the lack of experience with market-based prices that vary from hour to hour and with retail-customer programs that encourage economic responses to these price changes.

In addition, system operators (today's vertically integrated utilities and ISOs and tomorrow's RTOs) have traditionally focused on the supply side and ignored the demand side of the equation (by assuming, in essence, that demand is completely price inelastic). That is, they maintain reliability by managing generation and transmission assets to meet fixed customer demands. However, customer loads can participate in bulk-power operations to maintain reliability and participate in commercial markets (Hirst 2002b). System operators need to broaden their thinking to accommodate the unique characteristics of customer loads, just as they have done for the unique characteristics of individual generating units. Ancillary services need to be defined in terms of their functions, not with reference to the generators that traditionally provided the services. System operators should recognize the reliability benefits of using large numbers of small loads that can respond quickly.

The retail providers need to do additional market research to understand what customers want from their electricity supplier and how customers might respond to different products and services. More important, retail providers need to offer a variety of price and risk options. As discussed, customers differ substantially in the magnitude of their electricity consumption, load shape, storage capabilities, automation of electricity-using processes, and other factors that affect their interest in and ability to participate in dynamic-pricing programs. The retail providers and PUCs need to educate consumers about electricity, its production, costs, and alternative pricing and risk-management strategies.

Finally, not everyone benefits when loads respond to prices. In particular, generators lose money when customer demand drops in the face of high prices. Because generator earnings are very sensitive to price spikes, generator owners might object to RTO efforts to accommodate price-sensitive loads.[8]

[8] One observer of the Electric Reliability Council of Texas (ERCOT) believes that ERCOT has been slow to encourage demand-side participation in its markets because the owners of generation and the power marketers dominate the ERCOT board and committees. These market participants lose money if customers are more price responsive.

5. TECHNOLOGY BARRIERS

All the technical components necessary for dynamic-pricing and voluntary load-reduction programs exist and have been applied in various settings. As Faruqui, Hughes, and Mauldin (2002) note,

> The barriers are not intrinsically technological because the required technologies exist in the marketplace. However, the market penetration of these technologies has been very limited due to their high capital costs (which in turn are due to their limited market penetration) and the barriers … [related to customers, utilities, and regulators].

The technological barriers include: lack of interval meters, lack of digital communications systems, and limited use of sophisticated end-use energy management and control systems.[9]

Unfortunately, the industry has not evolved to the point that standardized (off-the-shelf) equipment and communication packages are readily available. It seems that every program custom designs its own infrastructure. To the extent that complete systems involve components from various manufacturers (e.g., meters, communication systems, and data-analysis software), the industry may need to develop standards to ensure that the various components can work well with each other, regardless of who manufactures what. Thus, large-scale deployment of price-responsive demand requires technologies that can manage hundreds of thousands of retail customers, encompass several functions, and integrate systems from different vendors and service providers.

Although the evidence on the capital and ongoing costs of these systems is sketchy, we believe there is substantial opportunity for cost reductions. In particular, as more utilities and retail providers offer such programs and the number of installations increases, the cost per customer should decline. Such

[9] Faruqui, Hughes, and Mauldin (2002), as an example, mention the use of customer energy storage to respond to dynamic pricing. Faced with day-ahead hourly prices, the energy management system for a large commercial building could automatically pre-cool the facility in the morning when electricity prices are low and then turn off the chillers during the afternoon when prices are high. The building management system would choose a specific operating strategy based on the day-ahead hourly prices and the anticipated weather during the operating day.

cost reductions will permit the cost-effective application of these programs to smaller and smaller electricity consumers. The metering, communications, and analysis tasks are not particularly challenging. Cell phones, pagers, and calculators perform more demanding duties. If the requirements for these services can be standardized, mass-produced electronics can in all likelihood dramatically reduce the cost and increase the performance of advanced metering. This would facilitate real-time market response for even the smallest load.

6. RECOMMENDATIONS

Although government regulators and energy-policy analysts encourage greater retail participation in wholesale electricity markets, the experience to date has been limited. (On the other hand, only a small fraction, probably no more than 10 percent to 15 percent, of retail load needs to be responsive to wholesale prices to improve greatly the efficiency of wholesale markets.) This paper discussed the many customer, regulatory, cultural, and technological barriers to greater use of dynamic pricing and other price-responsive demand programs.

Given the importance of increasing customer response to time-varying prices to improve economic efficiency, bulk-power reliability, and environmental quality, we offer the following recommendations for regulators and the electricity industry to consider. These suggestions raise difficult issues related to regulation, equity, and technology, which require further study.

- Regulators should recognize that traditional electricity pricing has two components: the electricity commodity and a risk premium that protects consumers from uncertainties about the timing and amount of their electricity use and the volatility of wholesale electricity prices.
- Because the traditional fixed-price electricity tariff includes critical risk-management services, regulators should define, at least conceptually, the default service for all retail customers as day-ahead hourly pricing. Because most residential and small commercial customers will not want to face prices that change from hour to hour, regulators should encourage retail providers to offer risk-management products to help customers deal with dynamic pricing.
- To implement dynamic pricing, regulators should require that interval meters be installed for larger customers. As the costs and performance of metering and communications systems improve, regulators can lower the minimum size (in kW) for mandatory interval meters.
- FERC should require ISOs and future RTOs to ensure that demand can participate fully in all energy, congestion management, and ancillary service markets.
- ISOs and RTOs need to recognize the unique characteristics of loads, just as they already do for generators (e.g., energy-limited hydro,

nondispatchable nuclear units, startup times and costs, minimum run times, and ramprate limits).

- FERC and the ISOs need to decide whether the current ISO load-reduction programs are transitional (i.e., intended to jump-start retail markets) or permanent.
- The electricity industry should conduct market research on customers to learn who can benefit from which types of demand-response programs and to learn how to best educate customers about these opportunities.
- Vendors should develop and implement technologies (automation) that make it simpler for customers to respond to dynamic pricing

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