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Harnessing the Power of Demand

How ISOs and RTOs Are Integrating Demand Response into Wholesale Electricity Markets

Markets Committee of the
ISO/RTO Council

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Executive Summary

Demand response empowers customers to reduce their electricity consumption in response to emergency, peak-load, and high-price conditions on the electricity grid. Policymakers at all levels of government have long recognized the benefits of demand response as part of a comprehensive solution to address rising electricity demand, increasing fuel prices, and concerns over global warming.[1] Ten regional grid operators—Independent System Operators (ISOs) and Regional Transmission Operators (RTOs)—representing 67% of electricity customers in the United States and more than half of the Canadian population, have been successful at encouraging demand response by implementing programs and market designs that encourage its development.[2]

This report shows how the organized wholesale electricity markets administered by ISOs and RTOs support the development and operation of demand response. These organizations are ideally suited to help fulfill the policy goal of reliably serving future electric demand in a low-cost and environmentally sound manner. The report also presents case studies describing actual events where demand response provided real value to the ISOs and RTOs and their customers.

ISOs and RTOs enable the realization of the full value of demand response by providing the following:

- Transparent market prices for a variety of products used by wholesale electricity markets (i.e., capacity, energy, and ancillary services). Transparent market prices make it easier for customers and demand-response providers to calculate the value of their demand-response capability.
- Diversity of participation with the entire range of participants, including individual customers, utilities, demand-response providers or aggregators, who are all able to participate in organized markets. ISOs and RTOs make it easier for all types of demand-response resources to participate in efficiently meeting load.
- Reduced barriers to market entry and lower transaction costs because of well-defined demand-response products, standardized rules, and common communication and meter data submission protocols.
- Large, liquid markets that can accommodate a significant amount and variety of demand-response resources.

Figure ES–1 summarizes the aggregate amount of demand-response resources available by market product (capacity, energy, and ancillary services) administered by the ISOs and RTOs.[3] It shows that the support provided by ISOs and RTOs for demand response has resulted in 23,129 megawatts (MW) of demand response participating in ISO and RTO markets as of spring 2007. This represents about 4.5% of

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[1] "These estimates do not include price-responsive load subject to dynamic retail prices (such as real-time or critical peak pricing) implemented and controlled by utilities or competitive suppliers."

[2] As of 2007, the North American ISOs and RTOs include the Alberta Electric System Operator (AESO); California Independent System Operator Corporation (CAISO); Electricity Reliability Council of Texas (ERCOT); Ontario's Independent Electricity System Operator (IESO); Midwest Independent System Operator (MISO), ISO New England (ISO-NE); New Brunswick System Operator (NBSO); New York Independent System Operator (NYISO); PJM Interconnection (PJM); and Southwest Power Pool (SPP).

[3] Capacity markets procure resources to maintain system reliability over the long term. Energy markets procure the power needed to run customer appliances and processes (e.g., lighting, motors, air conditioners, computers, etc.). Ancillary service markets procure reserves that can be called on with very short notice in the event that a large generator or transmission line suddenly fails.

the combined electricity demand of the ISOs and RTOs in North America. The percentage for each ISO or RTO would be higher if load that is subject to spot prices under utility- or competitive supplier-controlled programs is added.

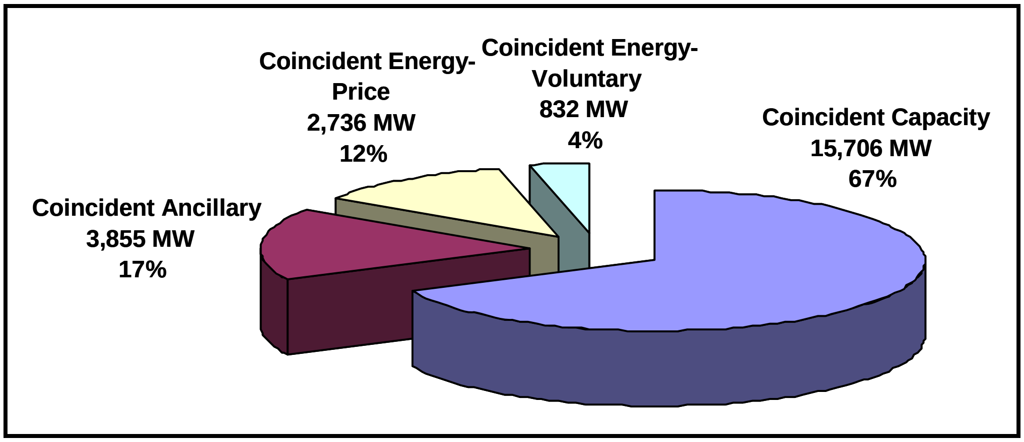

Figure ES–1: Demand resources by market product for ISOs and RTOs of the United States and Canada, as of spring 2007, totaling 23,129 MW.

Note: The term "coincident" represents the total amount of resources available at a given time and assumes that all enrolled customers respond to the extent to which they had committed.

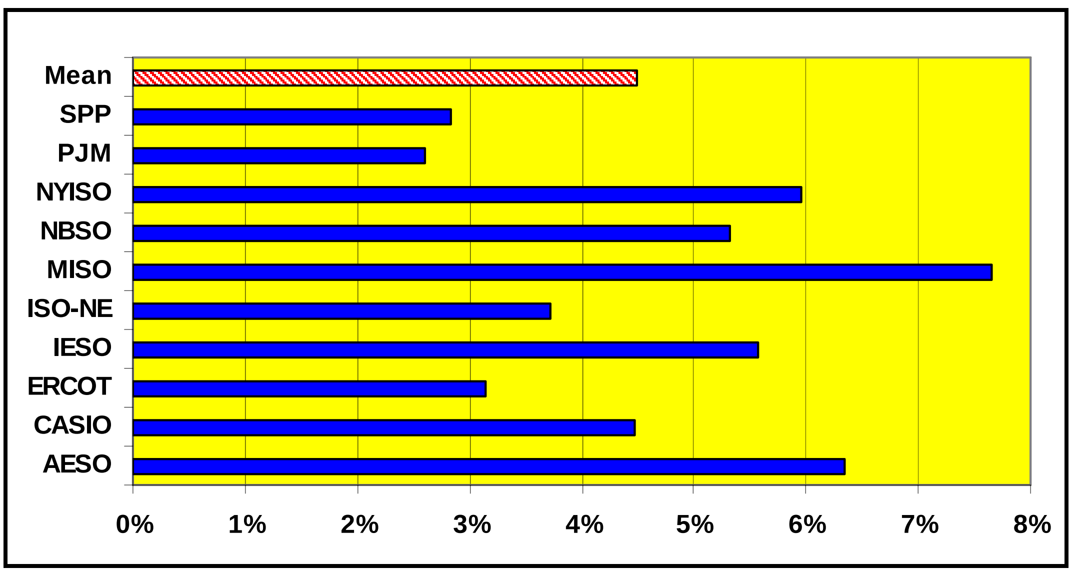

Figure ES–2: Demand response as percentage of system peak by ISO and RTO.

ISOs and RTOs support both the inclusion of demand-response initiatives in wholesale electricity markets by the ISO or RTO itself and by market participants serving customers within its footprint. Several ISOs and RTOs (for example Alberta, New England, New York, Ontario, PJM, and Texas) support demand response by enabling consumers or their representatives to directly participate in the markets by implementing demand-response programs. Other ISOs and RTOs support state/province-funded and utility-implemented demand-response programs (for example, California, Ontario, Midwest, Southwest, and New Brunswick).

In summary, ISO and RTO support of demand response helps ensure that electricity sector resources are used efficiently, the need for new generation resources is reduced, and system reliability is improved. As the wholesale electricity markets mature and technology improves, the markets administered by ISOs and RTOs can support significant growth in demand response.

The Role and Value of Demand Response in Wholesale Electricity Markets

Introduction

Policymakers at all levels of government have long recognized the benefits of demand response as part of a comprehensive solution to address rising electricity demand, increasing fuel prices, and concerns over global warming. Efforts to achieve more active participation of consumers in the electricity sector began in earnest in 1976 when the U.S. Congress enacted the Public Utility Regulatory Policy Act of 1976 (PURPA). PURPA directed state public service commissions and the utilities they regulate to consider the benefits of adopting retail rates that better reflect the highly variable nature of electricity supply costs. This action reflected a new sense of urgency to provide additional pricing and demand-response options that provide customers with incentives to use electricity more wisely.

In the most populous regions of the United States and Canada, 10 regional grid operators (ISOs and RTOs) have implemented programs or market designs, or a combination of both, that encourage the development of demand response. The markets these ISOs and RTOs administer, which represent approximately two-thirds of electricity demand across the United States and just over 40% in Canada, are playing an important and growing role in enabling demand response to reach its full potential. They provide visible price signals that will help consumers make rational decisions about expenditures on electricity in the same way they use market prices for deciding how to purchase other goods and services.

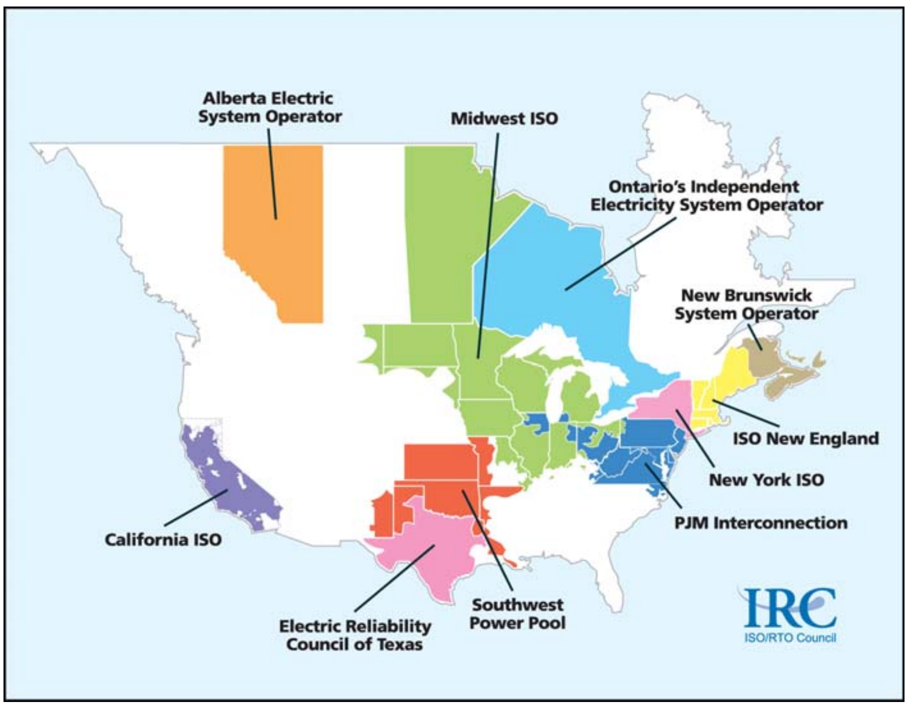

Figure 1: Footprint of the North American ISOs and RTOs.

Source: http:// www.iso-rto.org

Research suggests that substantial gains in wholesale market efficiency can be expected from a relatively small percentage of demand response.[4] Two factors drive the conclusion that small amounts of demand response can provide significant benefits. The first is that the supply curve is steep at high price levels, which means that a small reduction in demand can cause a large decrease in price. Second, increased use of air conditioning has resulted in the need for significant amounts of generation that is used for relatively few hours only during very hot weather. Lower demand during these few days can reduce capacity needs significantly. Based on analysis of existing supply curves and simulated case studies, demand response in the range of 5 %–15% of system peak load can provide substantial benefits in reducing the need for additional resources and lowering real-time electricity prices.

In most electricity markets, forces are being marshaled to increase demand response. In some, stakeholder and regulatory initiatives are directed at achieving specified targeted levels of demand response. ISOs and RTOs are prominent examples, but they are not acting alone. Many Northeast state agencies have promoted demand response through educational efforts and enabling technology proliferation programs. California is installing advanced meters to meet an established goal of achieving 5% price responsive load to complement the 3% of peak load reduction capability currently in place. Illinois has directed its utilities to make real-time pricing, a highly effective form of demand response that provides hourly prices on a day-ahead basis, available to all residential customers; [5] by doing so, the state's policymakers are looking to realize the full potential of demand response.

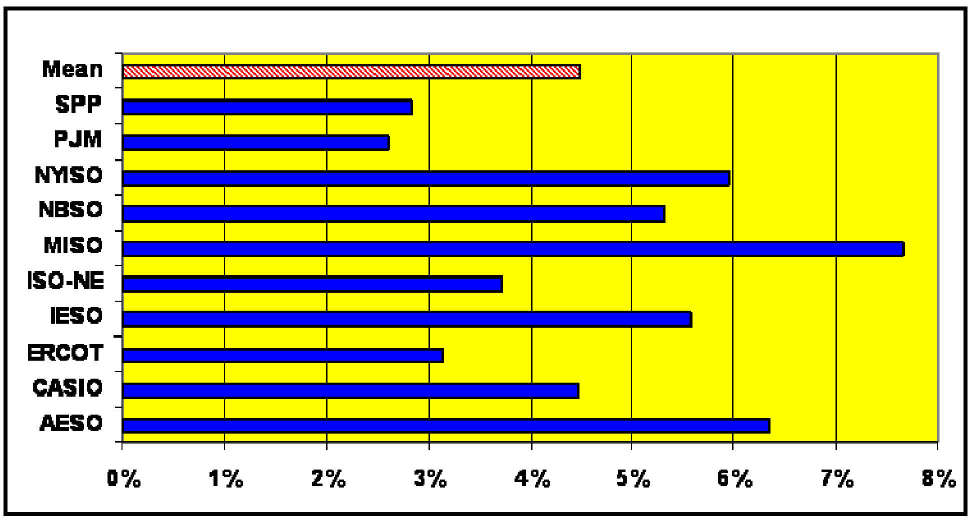

Figure 2: Demand response as percentage of system peak by ISO and RTO.

[4] Boisvert, R., Cappers, P., Neenan, B. April 2002. The Benefits of Customer Participation in Wholesale Electricity Markets. Electricity Journal, Vol. 15, No. 3, pp. 41-51. Elsevier Science Inc.: Brattle Group. January 29, 2007. Quantifying Demand Response Benefits in PJM. Prepared for PJM Interconnection and Mid-Atlantic Demand-Response Initiative.; Cappers, P. 2004. An Evaluation of New York State's Wholesale Electricity Markets. Thesis presented to Cornell University. Available at pcappers@yahoo.com; Caves, D., Eakin, K., Faruqui, A. April 2000. Mitigating Price Spikes in Wholesale Markets through Market-Based Pricing in Retail Markets. The Electricity Journal, Vol. 13, No. 3, pp. 13-23. Elsevier Science Inc.; B. Neenan, Cappers, P., Pratt, D., Anderson, J., December 2005. Improving Linkages between Wholesale and Retail Markets through Dynamic Retail Pricing: Report prepared for ISO New England. Available at: http://www.iso-ne.com: Rassenti, S., Smith, V., Wilson, B. December 2000. Controlling Market Power and Price Spikes in Electric Networks: Demand-Side Bidding. University of Arizona Economic Science Laboratory. Available at: rassanti@econlab.arizona.edu.

[5] Illinois Commerce Commission, December 20, 2006. Commonwealth Edison Proposed Revisions to Rate BES-h. Docket No. 06-0617.

Demand response is most effective when the way customers use electricity can be anticipated so that system dispatch can be optimized and the impact of demand response on overall electricity demand is considered. ISOs and RTOs are making a substantial contribution to fully integrating demand response into the wholesale electricity markets they manage. As of spring 2007, over 23,000 MW of demand-response resources, which represent on average about 4.5% of peak load, are enrolled in demand-response programs across the ISO and RTO markets. This percentage for ISOs and RTOs would be higher if loads that are exposed to spot prices under utility-or competitive supplier-controlled programs are added.

In the wholesale markets administered by ISOs and RTOs, demand-response resources can participate, and effectively compete against, generation resources. These opportunities include consumer participation in capacity, ancillary services, and electric energy markets in the following ways:

- As capacity or electric energy resources that compete directly with supply-side (generation) resources are dispatched to balance supply and demand
- As part of utility or competitive supplier-sponsored programs within the footprint of ISOs and RTOs, where customers curtail usage at the request of their retailer, who can gain from a lower load obligation
- By reducing electricity costs through a reduction of electricity consumption in response to the real-time price of electric energy, the most fundamental form of price response
- Through the provision of reserves and supplemental and emergency resources into markets administered by ISOs and RTOs.

The commitment by ISOs and RTOs to facilitate a wide variety of demand-response initiatives promotes efficiency and provides customers with choices in both the wholesale and retail sectors.

Wholesale energy markets have a number of important features that foster demand response. First, the price transparency that results from spot market energy prices (which are publicly posted by the ISOs and RTOs) provides consumers with a benchmark for measuring the cost of the electricity they presently use and will use in the future. Second, as described above, many ISOs and RTOs have successfully opened avenues for consumers to participate directly in wholesale markets; and others are moving in this direction. Third, ISO and RTO markets allow utilities and competitive retailers to devise retail pricing plans that make payments to customers that curtail demand when notified, and to set retail prices that properly and credibly reflect the marginal cost of supply. Historically, utility demand-response programs often have reflected costs already incurred. To be effective, however, consumers must have access to information about and be able to respond to prices that reflect real-time marginal costs (i.e., supply costs that otherwise would be incurred without demand response). Moreover, as more intermittent resources, such as wind power, are added to the grid, the need for more demand response resources and the balancing capabilities of regional grid operators will become even greater.

This report describes the role ISOs and RTOs play in fostering demand response in today's electricity markets. It is organized into two sections. The first describes the benefits of demand response, summarizes how demand response provides value to electricity consumers and all market stakeholders, and characterizes the level and types of demand response that currently participate in ISO and RTO markets. Finally, because there is more to do, it describes the critical next steps that ISOs and RTOs are undertaking to promote additional demand response in the organized electricity markets. The second section, a series of case studies that depict actual market situations or characterize the "insurance value" of demand response under low-likelihood, but high-impact circumstances, of these studies demonstrate how demand response provides value to all consumers.

The Benefits of Demand Response for Electricity Consumers

Electricity markets administered by ISOs and RTOs are providing a new and effective way to increase the role of consumers in the electricity markets and expand on existing demand-response resources. Potential benefits can be substantial and widespread. These benefits can be categorized by the sector to which they accrue, as follows:

- **Participants** in demand-response programs benefit because they receive an incentive payment to reduce electricity usage, or they lower their overall electricity bill by moving consumption from high-priced to lower-priced hours and by adopting conservation behaviors. It is widely indicated that many customers will elect to save money when offered the chance to do so by managing when and how they consume electricity. Many more will follow when new control technologies are more widespread and cost effective.
- **Other electricity consumers** benefit, even if they do not engage in demand response. Load curtailments by some customers set off a ripple effect that can result in lower wholesale electricity prices which translates into lower electricity costs for all consumers. Some of these savings are immediate, and others are enduring. In addition, demand response contributes to maintaining system reliability. Lower electric load when supply is especially tight reduces the likelihood of load shedding. Improvements in reliability mean that many circumstances that otherwise result in forced outages and rolling blackouts are averted, resulting in substantial financial savings and hard-to-quantify, but none-the-less important, health and safety benefits.
- **Society as a whole** benefits from demand response. Competitive pricing ensures that resources are used according to how they are valued by society. Demand response reduces the over consumption of electricity during high cost hours, which is an outcome of traditional average-cost pricing. By reducing consumption, scarce fuel, capital, and environmental resources are conserved. The reduction in peak demand also slows down the need to build costly additional transmission and generation infrastructure. When resources are redirected toward their highest societal value, which economists refer to as an increase in net societal welfare, all economic sectors and all consumers realize gains.
- **Communication and control technology firms** benefit because the greater the level of demand response and electricity control, and the greater the demand for enabling information and control technologies. Customers will be more inclined to adopt demand-response behaviors if they know the cost of what they are buying when they are making the purchase decision. Moreover, a variety of nonintrusive control technologies make it possible to centrally control key household appliances or devices. Technology companies that help customers increase their electricity usage flexibility will share in the benefits that result, which results in a ripple effect on the rest of the economy.

This groundswell of interest in fostering demand response among electricity consumers is rooted in the economic principle that markets can only perform well if supply and demand are both active participants in the market, which results in prices that reflect the value of consumption and the marginal cost of supply. ISO and RTO markets can accomplish this first by providing clear and transparent price signals that serve as a value benchmark for consumers to use as input in deciding when and how they use electricity. Additionally, some ISOs and RTOs enable customers and demand-response aggregators to directly access the market without having to go through local utilities that often have varying incentives and program requirements. ISOs and RTOs also provide a way for utilities that operate demand-response programs to more fully reflect not only the local but also regional value associated with them and thereby more easily encourage increased participation in demand-response initiatives. While much has been done, there is still a great deal of untapped potential for demand response. The ISOs and RTOs are working to realize that potential.

How ISOs and RTOs and Wholesale Markets Foster Demand Response

ISOs and RTOs have assumed a leadership role in developing demand response by creating opportunities for customers to offer their reliability-based demand-response capability into wholesale electricity markets. Along with developing and implementing demand-response programs, and in part through education and training, ISOs and RTOs have led initiatives to encourage load aggregators and customers to create demand-response products. They have joined with other agencies and institutions to expand the awareness of the value of demand response among a multiple of stakeholder audiences, worked with them to identify barriers to its growth, and championed improving market efficiencies through robust demand response.

In addition to providing leadership in developing demand-response programs, ISOs and RTOs serve a critical function in coordinating many of the utility-run programs in their footprints. In two examples in MISO and CAISO, the organized electricity markets provide key services critical to the success of demand response as follows,

- Significantly increasing the scope of the market for utility-based programs from the utility service area to the entire ISO and RTO region
- Providing additional value streams to evaluate the value of demand response resources, which are comparable with the full revenue stream earned by generation resources in the markets. If demand response can displace generation resources, they could earn that same revenue stream.
- Increasing the visibility and credibility of demand-response programs among end-use customers through enhancing awareness of the contribution of these programs to grid reliability

Direct Integration of Demand Response into ISO and RTO Electricity Product Markets

ISOs and RTOs have integrated demand-response resources and products directly into the various electricity markets in several ways:

- As a capacity resource in capacity markets. Customers that are willing to curtail load on demand, usually on short notice (e.g., within 30 minutes to two hours), augment the supply of capacity available to retailers seeking to fulfill their capacity obligation. For agreeing to curtail when called, load aggregators (and customers) receive payments as a capacity resource.
- As an emergency resource during system emergency events. Customers can also sign up to voluntarily provide load curtailments called for by the ISOs and RTOs during system emergencies to preserve system integrity. Customers that reduce load are paid for the kilowatt-hours (kWh) they curtail during the event, usually $0.30–0.50/kWh.
- As a resource actively participating in energy markets. Customers that have the flexibility to change their consumption patterns with very short notice can actively participate in ISO and RTO markets by offering to lower consumption at a specified price. In some markets, customers purchase supply in a day-ahead market and then reduce their consumption in response to high real-time prices. By doing so, they sell back their day-ahead position to the market and are therefore paid for doing so at the same market-clearing price that generators receive. Other markets, such as in Ontario, permit consumers to submit “bids to buy,” which the ISO’s dispatch algorithm uses in its five-minute dispatches the same as it uses generators to solve supply and demand imbalances or to manage transmission-interface loading levels.

- As ancillary services resources. Customers willing to reduce demand on very short notice—30 minutes or less—augment the supply of ancillary services available to those ISOs and RTOs that administer ancillary services markets. Customers that are scheduled to provide resources to the ancillary services markets are paid the corresponding market prices.
- For conservation of energy. Real-time pricing of electric energy may result in customers choosing to reduce some discretionary use of electricity. The response by some consumers to ISO and RTO programs indicates an overall reduction in energy usage, which results in an overall conservation of resources. The California pricing pilot appears to support conservation by smaller customers, like residential and smaller businesses, who forego discretionary usage when prices are high. Some larger customers in New York who pay prices linked to ISO prices exhibited shifting of electric energy use across hours of the day and some conservation behavior as well.

Coordination of Resources Enrolled in Utility and Other Retailer Programs

ISOs and RTOs, through their roles as reliability coordinators and as operators of spot markets for energy and other services, support the development of demand response through programs implemented by utilities and other retailers, as follows:

- Transparent day-ahead and real-time spot markets provide the means to implement dynamic default services by utilities in retail choice states. In New York, New Jersey, Maryland, and Pennsylvania, utilities fulfill their obligation to serve larger customers that do not select a competitive retailer by posting hourly electric energy prices that are linked directly to ISO and RTO day-ahead or real-time spot market prices. This encourages customers to carefully consider the benefits of responding to prices rather than paying a risk premium for hedged service.
- Vertically integrated utilities and competitive retailers are using spot market prices to rationalize and operate more effective pricing programs that offer participants ways to save money on electricity purchases and reduce the utility's overall supply cost, which benefits all its customers.
- Vertically integrated utility load-control programs, which pay participants according to the capacity costs that are avoided, can be more effectively dispatched by coordinating curtailment events with overall system supply and reliability conditions. ISOs and RTOs are working with the member utilities to devise protocols that allow utilities to synchronize load-curtailment events to correspond to conditions where the load reduction produces high value in terms of preserving system reliability.

Inventory of ISO and RTO Demand-Response Resources

ISOs and RTOs are at the industry forefront of encouraging demand response because they provide customers with opportunities to offer their demand-response capability into each of the ISO- and RTO-administered electricity markets, including capacity, electric energy, and ancillary services. The success to date is substantial, as evidenced by the amount of load enrolled in demand-response programs implemented or coordinated by ISOs and RTOs for summer 2007.

Demand-Response Resource Enrollment

The success of ISOs and RTOs in encouraging and supporting demand response is demonstrated by the 23,129 MW of demand-response resources either directly enrolled in ISO and RTO product markets or enrolled in utility programs that operate within the ISO and RTO markets (see Figure 3). This is about

4.5% of the summer-peak electricity demand of those markets. In Figure 3, demand-response resources are categorized by the market in which they participate for all 10 ISOs and RTOs.[6]

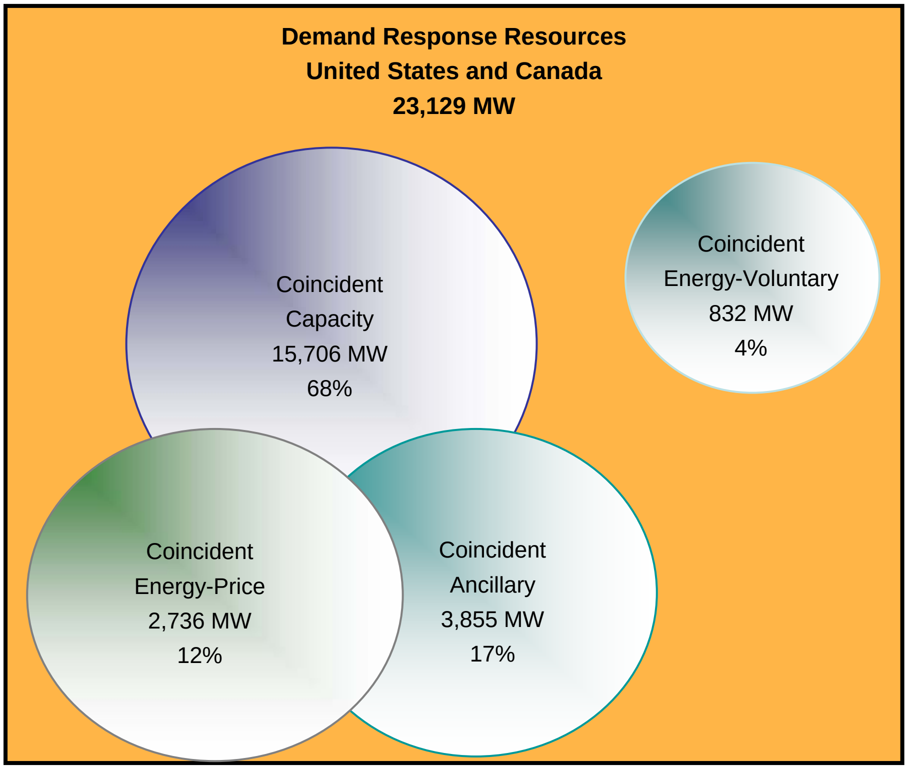

Figure 3: Distribution of ISO and RTO demand-response resources by market product.

Note: The term "coincident" represents the total amount of resources available at a given time and assumes that all enrolled customers respond to the extent to which they had committed.

Category Enrollment

Figure 4 provides additional information on demand-response resource categories by country of origin. The figure shows that 68% (15,706 MW) of total U.S. and Canadian resources are categorized as capacity, which corresponds to displacing as many as 30 commercial-size (500 MW) base-load generation units.

Ancillary services resources account for 17% of the total. Energy-Price resources (12%) also serve to supplement available generation capacity by reducing the energy they consume to make it available to other loads. The Energy-Voluntary category (4%) consists of customers that enroll to reduce load voluntarily for an energy payment when the ISOs and RTOs deem that additional energy resources are needed.

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[6] Like many of their generation counterparts, about 7% of the total coincident demand-response resources are enrolled in more than one product market, which provides diversity, as is the case with generation resources that can provide service in more than one way. To avoid double-counting of resources, however, only coincident resource amounts are reported herein.

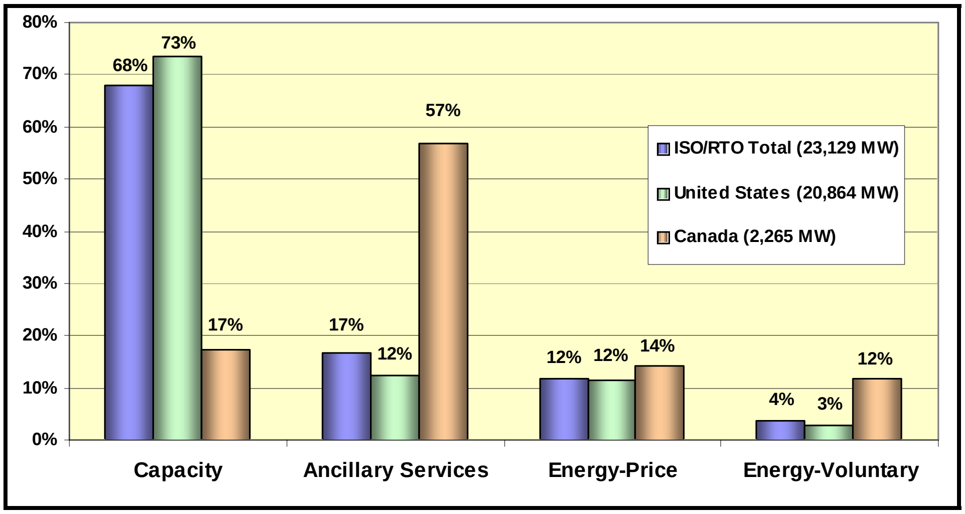

Figure 4: Distribution of ISO and RTO demand-response resources by category.

Figure 5 (Total) and Figure 6 (U.S. and Canada) show the distribution of coincident demand-response resources by country and by the ISOs and RTOs in which they are enrolled. A considerable degree of concentration exists in both countries. MISO (8,645 MW, 38% of U.S.) has the most coincident demand-response resources in the U.S., almost three times that of the next largest ISO and RTO enrollment, which is PJM (3,759 MW, 16% of U.S.). Most of MISO resources are originated through state-regulated utility programs. Among the Canadian ISOs and RTOs, the IESO accounts for over two-thirds of the available demand-response resources, with the balance provided by the AESO (27%) and the NBSO (7%). However, as noted earlier, coincident demand-response resources amount to 4.5% of peak demand on average for all ISOs and RTOs.

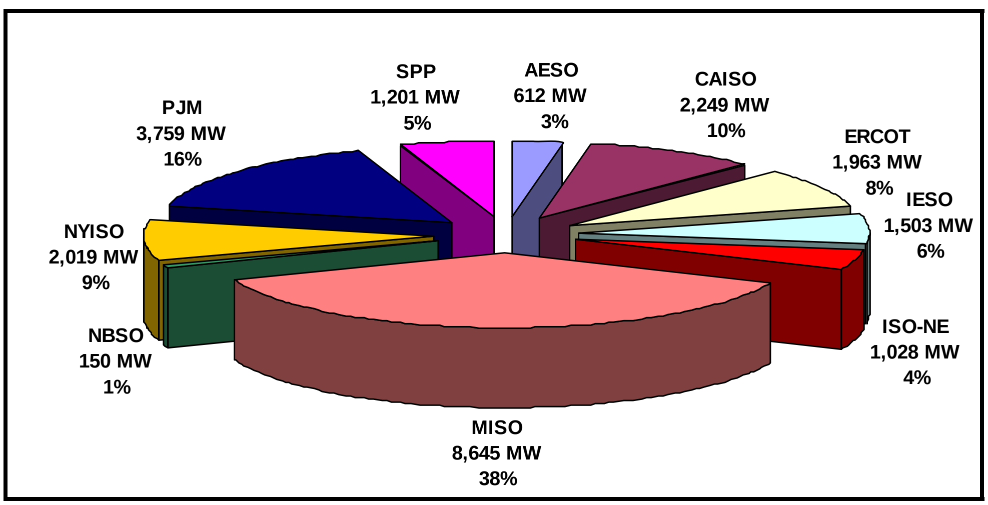

Figure 5: ISO and RTO total coincident demand-response resources.

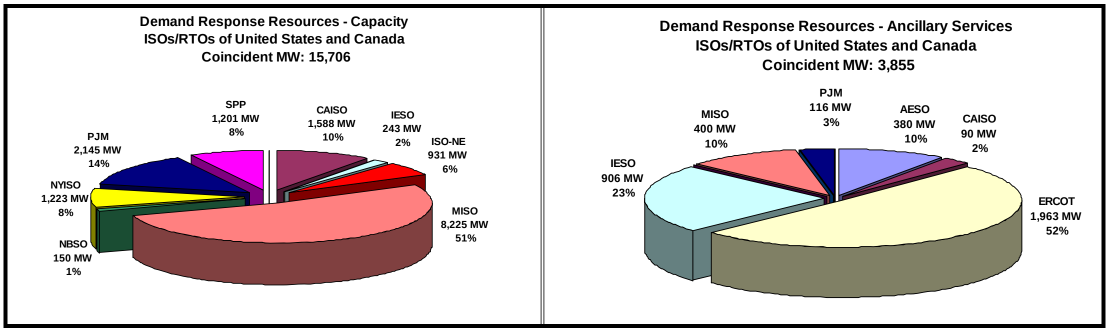

Figure 6: ISO and RTO capacity and ancillary service resources.

Category Concentration and Specialization

Different ISOs and RTOs concentrate on different categories of demand-response resources, as follows:

- Capacity (Figure 6). MISO's 8,225 MW constitutes over 51% of the capacity resources available from demand response.
- Ancillary Services (Figure 6). ERCOT reports 1,963 MW of the demand-response resources providing ancillary services, over half of all resources enrolled in that category. Two Canadian ISOs and RTOs (IESO with 23% and AESO with 10%) provide over one-third of total North American demand-response resources providing ancillary services.
- Energy-Price (Figure 8). PJM's energy-price resources (1,498 MW) account for 55% of the U.S. total, and over one-fifth of the remainder is in CAISO's market. AESO and IESO account for 11% of the total and all of such resources in Canada. These estimates would be much higher if they were added to estimate load under utility or competitive-supplier control and subject to spot prices.
- Energy-Voluntary **(**Figure 8**).** Only NYISO (566 MW) and IESO (266 MW) offer energy-voluntary products.

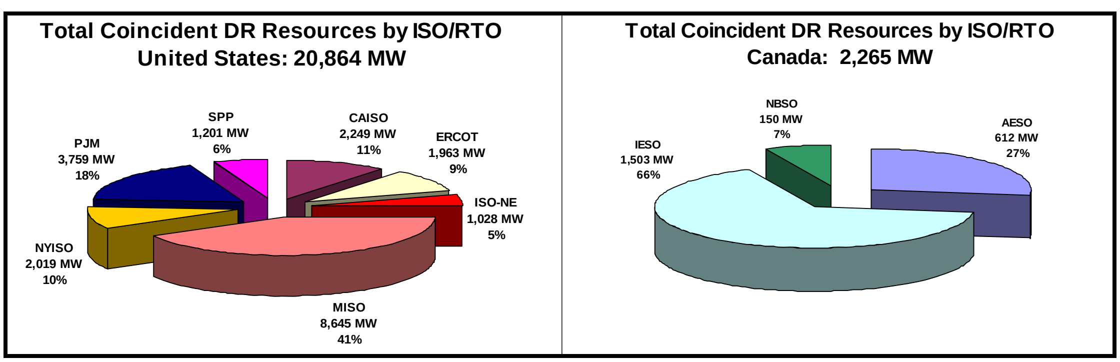

Figure 7: Demand response by category, U.S. and Canada.

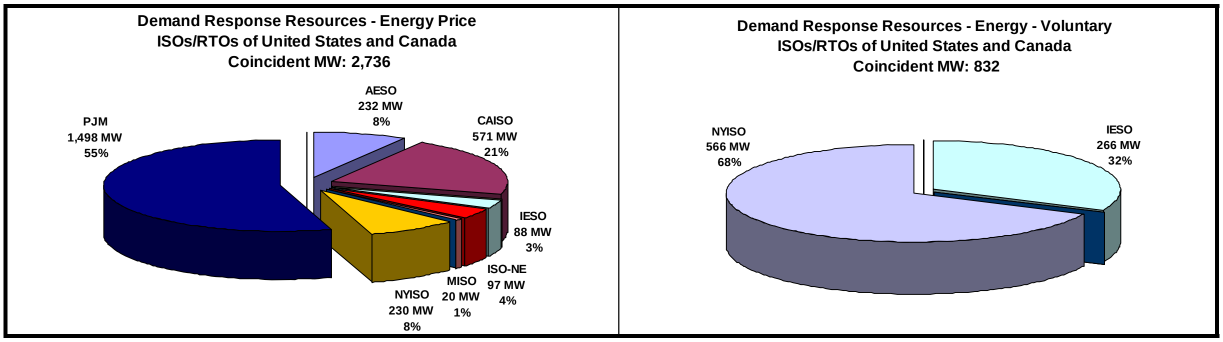

Figure 8: ISO and RTO price-responsive energy resources.

The relatively high degree of concentration in particular demand-response resource categories reflects regional market structure differences, differences in the prices paid for demand-response (and generation) resources, and customer characteristics.

For example, ERCOT currently has no centrally-administered capacity market. Instead, each retailer is obligated to self-provide sufficient capacity to meet its load's capacity obligation. Thus, in ERCOT's competitive retail market, demand-response can participate mainly by providing ancillary services.[7] ERCOT has built on the legacy of prior Texas utility programs that offered customer-rate discounts for load connected to an under-frequency relay. When system frequency drops past a specified set point, the relay closes and the customer's load is interrupted.

AESO and IESO also have cultivated substantial demand-response-based ancillary service resources. NBSO utilizes capacity resources enrolled by the provincial utility.

MISO's 8,225 MW of demand-response capacity is made available mostly through vertically-integrated utilities within the 15 Midwestern states that make up MISO. In many of these states, the utilities are the sole providers of retail service. MISO coordinates with the utilities to dispatch the resources to the benefit of the entire market.

CAISO relies on an estimated 1,500 MW of capacity resources administered by the state's investor-owned utilities, which is augmented by price-responsive program enrollments. SPP enjoys the benefit of over 1,200 MW of capacity resources available from member utilities.

PJM has the largest amount of the energy-price resource base, reporting almost 1,500 MW, which is 55% of the total available and more than any other single ISO or RTO. PJM offers customers two ways to participate within their energy markets; namely, by bidding prices on reduced loads associated with their day-ahead market or real-time market. PJM was among the first to provide such an opportunity to demand-response resources, and its market is characterized by a substantial industrial customer base; larger customers in many cases are better equipped and more inclined than other customers to adjust usage to price changes, especially very large customers or those customers whose electricity costs make up a substantial portion of their operating costs, or a combination of both types.

[7] Of the 10 ISOs and RTOs, CAISO, MISO, and SPP reported substantial demand-response resources provided by the utilities in their market footprint. This study did not identify any additional demand-response resources in the other ISOs or RTOs, such as stand-alone utility programs or programs administered by competitive retailers. ERCOT in particular believes that behind-the-meter, competitive retailer demand-response programs are quite prevalent and is undertaking to enumerate them.

The relatively larger amount of capacity-type demand-response resources in NYISO and ISO-NE are a result of concerted efforts by the ISOs and RTOs, in cooperation with state agencies, to develop a supplemental capacity resource base to avert the excessive price volatility and reliability problems of capacity shortages. NYISO and ISO-NE also have substantial resources registered in energy-price programs. ISO-NE branched out into ancillary services to fill a potential void, while NYISO has recruited over 500 MW of energy-voluntary load that it calls on to avert operating-reserve shortfalls.

In sum, demand-response resources of ISOs and RTOs are abundant and diversified. They constitute a critical element of the market in that they act as a counterbalance against supply and act to achieve efficient pricing and optimal scarce resource utilization. The market structure administered by each ISO and RTO has been a primary determinant of the kind of demand-response resources that have become available so far. But, through cross-fertilization, fueled in part by customers that have facilities in several markets and in part by cooperation among the ISOs and RTOs, concepts that work well are proliferating, and new opportunities are being explored.

Next Steps

ISOs and RTOs have been at the forefront in fostering demand response to improve the performance of both the wholesale markets they operate and the retail markets that rely critically on price transparency and resource coordination to achieve optimal resource utilization. They have developed vehicles permitting consumers to participate directly in wholesale markets, on terms equivalent to generation resources. In addition, they have worked with utilities and competitive retailers to ensure that demand-response initiatives serve customer needs and are aligned with how wholesale markets value resources. The result of ISO and RTO demand-response initiatives is a more vibrant and flexible wholesale market and infrastructure that benefits all consumers and all sectors of the economy.

Much has been accomplished but more must be done to ensure that the full force of customer demand for electricity is exerted consistently and in a sustainable manner on electricity markets, both at the wholesale and retail levels. Accordingly, ISOs and RTOs are continuing to work to increase demand participation in the market. They have identified key barriers to expanded demand response and are pursuing several initiatives to break them down.

The next steps to realizing the full potential of demand response fall into two categories.

Communication and Metering Standards and Infrastructure

The Barriers

The telemetry and communication requirements put in place by ISOs and RTOs for large generation resources providing ancillary services are likely to be cost-prohibitive for small and geographically-dispersed demand resources, which in the aggregate are a potentially large and valuable resource. In addition, the lack of standards in existing metering and associated information management systems for data exchange limits the scope and scale economies that are possible with demand response. Because utilities have built out their metering and consumption data retrieval systems independently and over different time spans and generations of technologies, the sector is characterized by devices and systems that cannot communicate with one another and are not readily amenable to communicating with new, more robust systems, such as those that are internet-based. In addition, ISOs and RTOs operate their own data-collection and communication systems. To fully integrate demand response into ISO and RTO market operations, inbound and outbound data retrieval is required, in some cases very frequently.

The lack of a standardized information network to measure and collect consumption data frustrates service providers and customers that operate in many jurisdictions. They cannot effectively integrate data from different customer sites to devise and carry out load-management plans across several sites. The lack of uniformity in metering and communication standards requires service providers and customers to develop different systems to participate in multiple markets. That raises the cost of business and reduces the amount of cost-effective demand response.

ISO and RTO Initiatives

The ISOs and RTOs are working together to develop standards for lower-cost open architecture technology for measuring demand response to enable more small demand-response resources to participate in ISO and RTO markets.

Standardization of Performance Validation Protocols and Terminology to Enhance the Nationwide Development of Demand Response

The Barriers

Demand response involves change in electricity usage over relatively short time periods, such as hours and in some cases minutes. Conventional metering only measures total consumption. Clearly, new technology is required. Even with the proper interval metering, protocols are required to measure demand response. Demand response is manifested by a reduction in usage during a specified time. What is metered and readily available is the consumer's actual usage after it has undertaken its demand-response actions. However, measuring the amount of load that was reduced requires ascertaining the level of energy usage the consumer would have otherwise consumed, often referred to as the customer baseline load (CBL). Currently, ISOs, RTOs, and utilities use somewhat varying CBL methodologies to measure and verify the load impacts of demand-response resources participating in wholesale markets (e.g., capacity, electric energy, ancillary services). As is the case with metering and communications, a lack of uniformity in CBL protocols stands in the way of realizing the scale and scope economies that characterize demand-response resources. A number of retail suppliers, curtailment service providers, and some large customers whose facilities or plants have a national or regional footprint (e.g., national chain accounts, very large industrial customers) have argued that more standardized methods to measure and verify the load impacts of demand-response resources would lower transaction costs and reduce barriers to participation by end users in wholesale markets. Moreover, the North American Energy Standards Board (NAESB) has embarked upon a process to develop wholesale (and retail) market standards for the measurement and verification (M&V) of the contributions of demand resources.[8] The Federal Energy Regulatory Commission (FERC) has been supportive of the NAESB effort.

Establishing common M&V standards as well as demand-response product specifications among the ISOs and RTOs would better enable third parties and load aggregators to serve multiple markets. It would enable firms that operate facilities in multiple markets and geographic locations to devise and carry out standardized demand-response behaviors. These efforts also would facilitate the full integration of demand-response transactions into ISO and RTO market systems, which will ensure that demand-response resources are paid promptly for the actual value they deliver.

ISO and RTO Initiatives

The ISOs and RTOs are working collaboratively with other stakeholders and NAESB to define more standardized M&V approaches that build on the body of existing experiences and recognize the diverse

[8] See http://www.naesb.org/dsm-ee.asp.

nature of demand-response resources and the consumers that provide them, with the goal of making demand response attractive to all electricity consumers.

ISOs and RTOs have transformed the electricity market by providing transparent and therefore credible and valuable information for the development of demand-response resources. Consumers finally have a contemporaneous way to link their consumption decisions to what electricity actually costs to supply. The advances in consumer technology along with transparent price signals can be a more powerful means to inform customers of the choices available for using electricity and how they can take control of their electric bill. As a result, consumers can participate in the more efficient use of the current stock of resources, and they can help make decision about how to use electricity in the future.

ISO and RTO Demand-Response Case Studies

Demand-response resources are integrated into ISO and RTO operations and provide a wide variety of valuable services to wholesale markets. To demonstrate how demand-response resources deliver a range of values, a case study was prepared for each ISO and RTO. Individually, they show how demand-response resources play an important role in the context of specific market circumstances. Collectively, by reducing costs, improving reliability, and ensuring that wholesale market prices reflect the value of electricity to consumers, they demonstrate the diversity that demand-response resources add to the electric system. Table 1 summarizes the ISO and RTO case studies.

Table 1
Case Studies in the Role and Value of Demand Response

ISOS/RTOS	Value Stream	Synopsis
AESO (Alberta)	Price response and ancillary services	Price response exerts its influence: Price-responsive demand lowered pool price in Alberta and provided additional generation to fill an operating-reserve shortfall.
CAISO (California)	Emergency services	Demand response is a key tool to manage unlikely but potential adverse conditions: A combination of voluntary and emergency demand-response programs resulted in a drop of 2,700 MW of load, which helped to avert involuntary load curtailment during the 2006 heat storm in the West.
ERCOT (Texas)	Ancillary services	Fast-responding demand-response operating reserves acted within 15 minutes to avert the potentially adverse consequences of the sudden and unexpected loss of over 500 MW of generation during winter 2006 in Texas.
IESO (Ontario)	Energy and ancillary services	Simulations were conducted to quantify the benefits of demand-response resources jointly dispatched as an energy and reserve resource. Savings to Ontario customers through lower prices were estimated at approximately C$7 million per year.
ISO-NE (New England)	Capacity deployment	New England's Forward Capacity Market allows a wide variety of demand-response resources, including energy efficiency, to participate in the capacity market and receive the same level of payment as supply resources.
MISO (Midwest)	Capacity deployment	Localized and precise use of demand-response resources during a winter cold spell in the Midwest adverted operating-reserve shortfalls
NBSO (New Brunswick)	Capacity deployment	Demand-response resources were deployed to restore reserves during capacity-shortage circumstances in New Brunswick.

ISOS/RTOS	Value Stream	Synopsis
NYISO (New York)	Capacity and emergency resource deployment	Flexibility of demand response demonstrated meeting localized needs in New York City during summer 2006. Demand response also played a key role in meeting regional needs with its ability to respond to operating protocols and free up generation to export 1,300 MW of emergency energy.
PJM (Mid-Atlantic and Midwest)	Price-response value	Simulations show that $300 million per year of benefits can accrue to all customers with as little as 3% of load reduction resulting from customer price response.
SPP (Southwest)	Price response	In Oklahoma, customers responding to elevated hourly prices provided the needed operating-reserve working margin when high temperatures and unit outages were pointing toward involuntary load drop.

How Price Response Improves the Efficiency of AESO's Wholesale Electricity Market

Summary

The Alberta Electric System Operator and its market stakeholders recognize the inherent value of price-responsive load. In October 2006, they had the opportunity to realize that value in their energy-only wholesale market structure. During a time of typical but significant "planned maintenance" outages, two additional, large coal-fired generation units that were scheduled to provide energy failed. As expected, the wholesale market price began to rise from $129/MWh to $419/MWh. The impact of the wholesale market price became apparent, however, in that prices then leveled off for a period. During that time, demand that had been forecast to increase by 125 MW, only ramped up by 57 MW. The higher prices did indeed have the effect of throttling back demand and controlling costs. Later that day, rising demand caused the AESO to invoke an Energy Emergency Alert 1, which resulted in the actual peak experienced being 204 MW less than forecast and obviating the need for any additional emergency measures.

Background

The Alberta wholesale electricity market is an "energy only" market. Supply and demand is balanced by dispatching generation units that have offered to provide energy. The system marginal price is determined every minute at the point of intersection of supply and demand on the system real-time offer curve. The price of the last generation resource selected during each minute sets the system marginal price for that minute, and all generators that provided energy during the hour are paid the average hourly price. Additionally, the AESO procures ancillary services, including active and standby operating reserves to maintain the integrity of the system and meet their obligations to the interconnected system. Operating reserves are fast-responding generation units that are held "at the ready" to be activated in response to the sudden loss of generation supply that may jeopardize the system operator's ability to match demand and supply as well as maintain overall system integrity.

For both the balancing energy and ancillary services markets, the AESO market price conveys important information about both current and future market conditions, as well as supply costs, to both buyers and sellers of electricity. Rising wholesale market prices provide an incentive for customers to reduce consumption. Customers that elect to forego hedged (and fixed) retail prices in favor of paying the real-time market clearing price can lower their cost of electricity by reducing load when prices are high and increasing electricity usage when they are low. Historically, the amount of price-responsive load in the province has been approximately 200 MW on a system that has a peak demand of about 10,000 MW. In Alberta, electricity demand peaks in the winter based on heating loads in the early morning and late evening hours. The coal-fired generation facilities in the province undergo regular maintenance throughout the year, however major maintenance outages are typically scheduled in the fall and early winter months because of historically low loads. The highest level of planned outages generally takes place in October, often with two to three large coal-fired units out of service. This was the case during October 2006. Three coal-fired units totaling 1,105 MW of capacity were off line, as were two major cogeneration facilities with a combined capability of 255 MW.

The peak-load forecast for October 4 called for 8,420 MW in the evening, as is typical at that time of year. During the prior afternoon's market closing, AESO schedulers evaluated day-ahead supply offers and concluded that the generation supply was ample and available to meet the next day's demand.

Case Study—Price Response Exerts its Influence

Things did not turn out as planned. Late on October 3, 2006, two coal-fired units, which were scheduled to provide 759 MW the next day, tripped off line. Combined with the planned outages, 1,874 MW (almost one-third of a total of 5,840 MW of coal-fired generation) was unavailable to serve load on October 4. Without customers cutting back or additional supply coming back to the market, insufficient supply for the day was a possibility. Moreover, the tight supply situation was conducive for seeing highly elevated and volatile wholesale market clearing prices.

During the early morning hours of the following day (October 4), the variation between the forecast and actual loads was slight. Prior to the normal morning ramp-up in load, the wholesale market price averaged $128.79/MWh, which was viewed as somewhat elevated but not dramatically so. Beginning about 8:00 a.m., however, the price more than tripled and reached $419.00/MWh (see Figure 9). Given the tight market conditions, as demand continued to rise, prices were expected to climb to even higher levels.

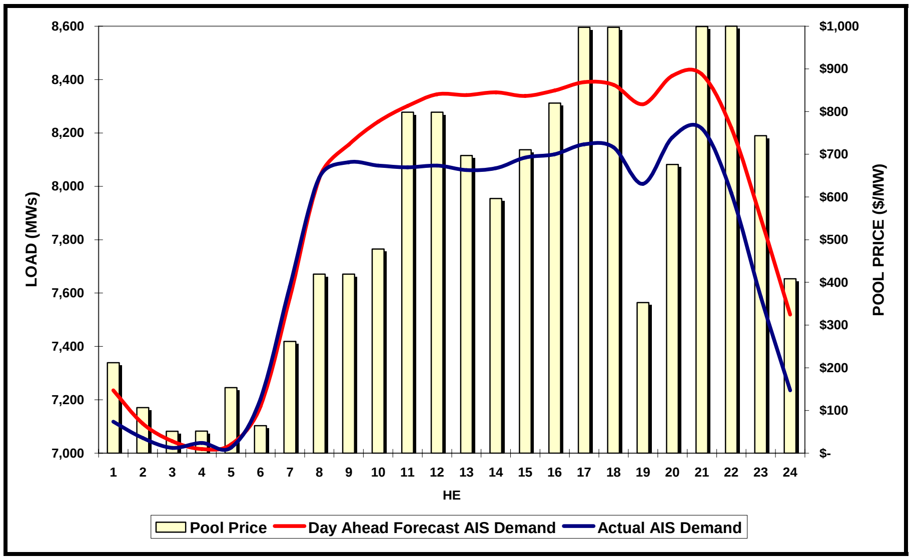

Figure 9: AESO load and prices on October 4, 2006.

One hour later, the manifestation of price response first became discernible. Instead of continuing to climb unabated, the market-clearing price remained about $419/MWh. How did AESO conclude that this price abatement was attributable to price response by customers and not other factors? The dynamics of their system load provided the answer: load increased by 57 MW between 8:00 and 9:00 p.m., as opposed to the forecast increase of 125 MW.

Thereafter, extremely tight supply conditions, combined with the full realization of the price-response potential, caused prices to rise even higher, eventually to the market price cap of $999.99/MWh. These very high prices served to keep the price-responsive load off line, which resulted in the realization of additional benefits, specifically in terms of increased system reliability.

Between 10:00 and 11:00 p.m. that evening, AESO declared an Energy Emergency Alert 1, signifying that all the generating capacity in merit order had been brought on line. However, sufficient operating reserves were being maintained, thus, while prices were high, the system was protected against adverse contingencies. The lower load, which was attributed to price response during the entire on-peak period, caused a significant divergence between the forecast and actual load. Whereas load had been forecast to peak at 8,420 MW, it actually peaked at 8,216 MW. In other words, the actual demand was 204 MW less than forecast, which enabled AESO to manage the system without invoking further emergency measures.

Conclusion

The events on October 3–4, 2006, in Alberta illustrate the importance of price response from two perspectives. First, the price increase due to the volume of generation that was off line was not as significant as could have been. The demand-response price impact that was observed benefited all consumers of power in Alberta through lower prices than what would have occurred if demand response did not occur. Second, the lower demand attributable to the customers' price response helped achieve system security during the coincident period of high prices and system capacity shortfalls.

How Demand Response Helped CAISO Meet 2006 Peak Electric Demand during the 2006 Heat Storm in California and the West

Summary

The July 2006 extended heat storm on the West Coast was literally one for the record books. As a result of the critical role of demand response, the California Independent System Operator Corporation met the record-breaking demand of 50,270 MW with sufficient operating reserves to avert a Stage Three Electrical Emergency that would have triggered involuntary curtailment of loads. Moreover, the deployment of demand-response resources of 1,200 MW was only about half the total demand resources available on this peak day. Other demand-response resources, such as controlled residential air conditioners, were available on very short notice if reserve margins had eroded further.

Background

Weather officials now agree that the triple-digit temperatures for 11 days in a row that gripped the western United States from July 17 to July 26, 2006, was a one-in-50-year heat storm. Cities throughout the West struggled to meet their electricity demand, drawing heavily on generation resources throughout the region. Figure 10 shows the daily high temperatures for selected western cities over that time span, with some cities recording temperatures over 110 degrees.

Although CAISO had prepared for months for what was anticipated to be a challenging summer, extraordinary demand meant the competition for megawatts throughout the West was intense.

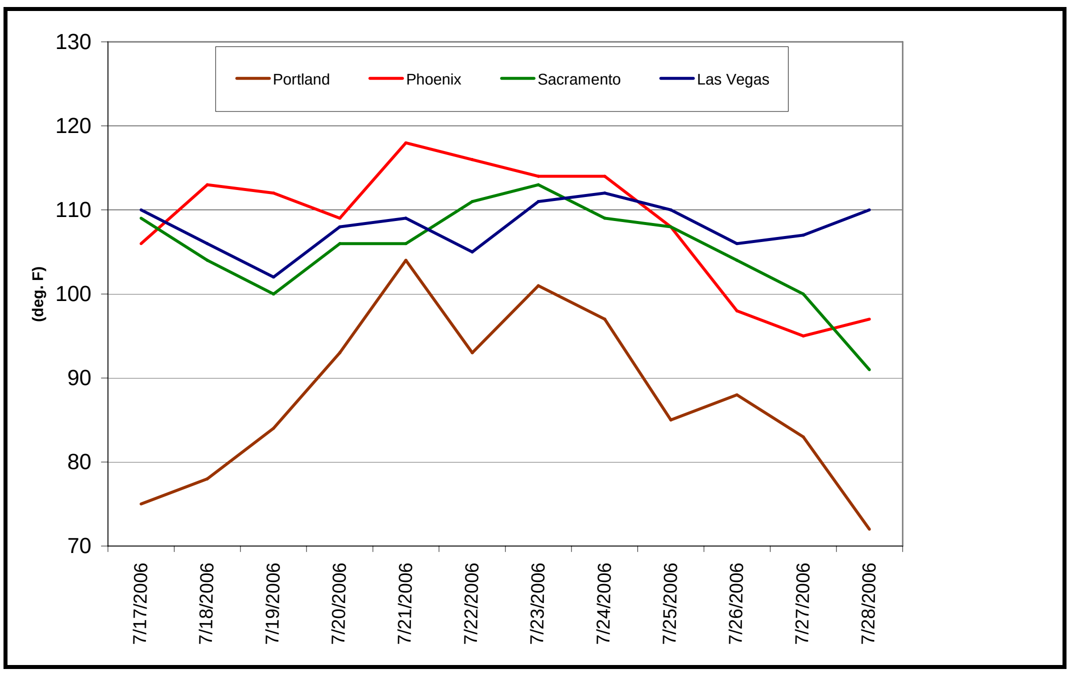

Figure 10: Daily maximum temperatures in western cities, July 17–28, 2006.

Case Study—Demand Response is a Tool to Manage Unlikely but Potentially Adverse Conditions

As the West heated up, demand (plus required reserves) began to surpass available generation capacity, even on the weekend. The CAISO and other western system operators worked together to utilize all available generation. In-state generation availability was at an all-time high, and imports into California were at record levels. However, the surging peak demand caused operating reserves[9] to drop to low levels. The CAISO invoked its emergency operating procedures in stages, as the potential for a supply/demand imbalance worsened.

- On July 21 to 23, the CAISO asked customers to undertake voluntary conservation measures to limit electricity demand during Stage One Electrical Emergencies declared when operating reserve levels dropped below 7%. Two pubic conservation programs helped reduce demand on the ISO grid during summer 2006. They were the Flex Your Power NOW! program and the Save A Watt Voluntary Load Reduction Program (targeting business customers). Partnering with media, for this programs, CAISO communicates the level of conservation, the duration of the conservation appeals, and the regions of the state where conservation is needed. Flex Alerts are usually issued 24 hours in advance of peak days. The Save a Watt program is communicated via a mass notification system and “shaves the peak” on hot days by asking businesses to reduce lighting, raise thermostats, or adjust other types of electrical usage.
- On July 24, after extending the Stage One Electrical Emergency, which resulted in voluntary conservation of 1,500 MW, the CAISO declared a Stage Two Electrical Emergency when operating reserves were forecast to fall under 5%. This triggered the utility interruptible programs. The result was approximately 1,200 MW of load reduction by program participants as seen in the load curve in Figure 11. As a result, CAISO met the record breaking demand of 50,270 MW with sufficient reserves and avoided declaring a Stage Three Emergency, which might have resulted in involuntary curtailment of customer loads. Moreover, an additional 1,200 MW of demand resources, such as controlled air conditioners, were held in reserve, ready to meet any contingency on the grid.

The Value of Demand-Response Resources in California

Quantifying the economic impact of involuntary load interruption is challenging, since it involves placing a price on an outcome, which is disconnecting customer loads at a time when electricity is most valuable. On the other hand, the unequivocal cost of an outage to residences and one of the largest economies in the world is not inconsequential. California utilities spend over $80 million per year to develop customers’ ability to adjust their consumption pattern and level to prevailing market conditions, either directly in response to the prices they pay for electricity, or by enrolling in a program that augments the stock of resources available to match supply and demand under most foreseeable circumstances. CAISO is working with the utilities and other stakeholders to ensure that demand response is flourishing, that it delivers value well in excess of the costs associates with its development, and that it is used to the maximum benefit of all Californians.

Conclusion

Record high temperatures in July 2006 provided a dramatic demonstration of how both dispatchable and voluntary demand resources helped meet record load levels. Demand-response resources proved to be a critical tool in planning for the unlikely but potential adverse conditions such as the summer 2006 heat storm in the West.

[9] Operating reserves of approximately 7% are required to be available for unexpected events, such as generation or transmission outages, or weather uncertainty.

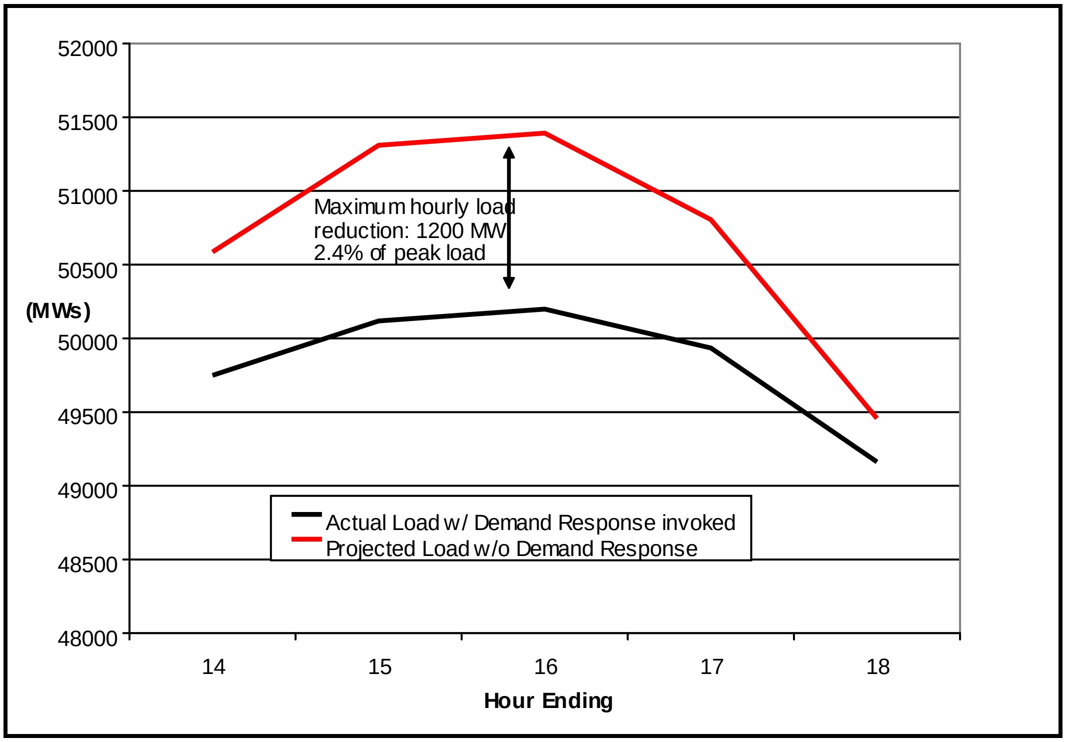

Figure 11: Demand response helps California grid during severe heat storm.

ERCOT'S Instantaneous Demand Response Proves Its Worth in Texas

Summary

ERCOT's market operations benefit from approximately 2,000 MW of large industrial and commercial load that is capable of providing ancillary services. These customers have the ability to disconnect designated load within a fraction of a second, if necessary, in response to sudden changes in conditions that result in supply/demand imbalances that can lead to electric grid instability. This capability proved its worth in December 2006 when load reductions enabled the ERCOT grid to recover almost instantaneously from the loss of nearly 1,300 MW of generation units. This resulted in a return to normal operating conditions within minutes of the system disturbances.

Background

ERCOT was among the first ISOs/RTOs to recognize the potentially substantial value of demand response as an ancillary service resource. Electric systems must respond instantaneously to changes in demand. This is achieved routinely and continuously by ERCOT dispatchers adjusting the output level of generation units that are on line in response to variations in electricity demand. Dispatchers also have additional resources available, called operating reserves, which are used to avert potential system emergencies that result when supply resources suddenly trip off line.

If a large generation unit suddenly trips, the available and uncommitted capacity of the remaining on-line units may be insufficient to meet demand or unable to respond in time to avoid a system disturbance. Operating reserves provide the first line of defense against such capacity shortfalls. They traditionally are generation units that can either be brought on line very rapidly (i.e., nonspinning reserves) or units already serving load that can increase their output quickly (spinning reserves) when fast action is required to maintain system integrity. Operating reserves are established to ensure that sufficient fast-acting resources are available to withstand what is referred to as a "first contingency"—defined as the sudden loss of the largest unit.

Ancillary services are integral to maintaining system integrity through all likely circumstances. ERCOT recognized that interruptible load—especially if it is capable of disconnecting instantaneously in an emergency—can serve as valuable ancillary service resources.

ERCOT allows curtailable loads to act as operating reserves provided that they meet stringent compliance criteria. These "Loads acting as Resources" (LaaRs) have been quite successful in providing responsive reserve services (RRSs) and are on-line resources, both generation-based as well as loads, which can rapidly respond to a major disturbance or other contingency event. To qualify to supply LaaRs, the customer must install equipment that prompts load reduction within 10 minutes of receiving a verbal dispatch Instruction.

In addition, LaaRs providing RRSs must be equipped with an under-frequency relay (UFR) device that immediately interrupts the load whenever the system frequency drops below a preset level. The ERCOT system operates at a frequency of 60 Hz. The UFR of one LaaRs is set to trip at 59.8 Hz; all others are set to trip at 59.7 Hz.

LaaRs may provide up to 50% of the total ERCOT hourly RRS requirement of 2,300 MW. That means that at any time, up to 1,150 MW of load can be providing RRS. In 2006, LaaRs provided 99.8% of their eligible capacity to the ERCOT Ancillary Services RRS Market.

Case Study—An Early Morning Surprise

In the early morning hours of December 22, 2006, at about 2:54 a.m., a generator east of Fort Worth supplying about 800 MW in the ERCOT grid control area tripped off line. As a result, the system frequency dropped to 59.78 Hz, which is well below acceptable operating limits.

One LaaR with the higher UFR set point tripped off line immediately, instantaneously reducing demand on the system by 168 MW and restoring frequency to close to an acceptable level. Less than one minute later, however, a second unit at the same site, generating about 500 MW, tripped off line. Frequency again dropped, even further than before, with many of the remaining LaaRs' UFRs dropping load. In less than a half-second, 48 LaaRs customer sites, representing 662 MW of load, were interrupted. As a result, system frequency was immediately restored to 59.85 Hz which was a drastic improvement but still not fully within acceptable operating levels.

Generator governors providing RRS regulation service also began to respond automatically by increasing output. ERCOT dispatched additional generation resources, and, as a result, system frequency improved to 59.95 Hz in four minutes; within five more minutes, the system returned to 60.0 Hz.

Frequency had been restored to near-normal levels so quickly that ERCOT's system operators did not immediately recognize that an incident had occurred. When they became aware that the majority of the LaaRs had tripped, at about 2:59 a.m., in keeping with ERCOT protocols and NERC standards, they issued a verbal dispatch instruction to the 52 remaining undeployed LaaRs providers. Less than 10 minutes later, at 03:09 a.m., an additional 375 MW of LaaR load had curtailed, fully stabilizing the ERCOT electric system and allowing the RRS capabilities provided by generation to be restored to their pre-event level of 1,150 MW. Returning the generation resources to standby status was critical because it then placed the system again in the position to withstand another contingency event.

In less than 15 minutes, a total of 1,250 MW of LaaR resources had been deployed, two-thirds of it virtually simultaneous with the frequency drop. Figure 12 shows a graphical presentation of the system frequency and LaaR response during this time period.

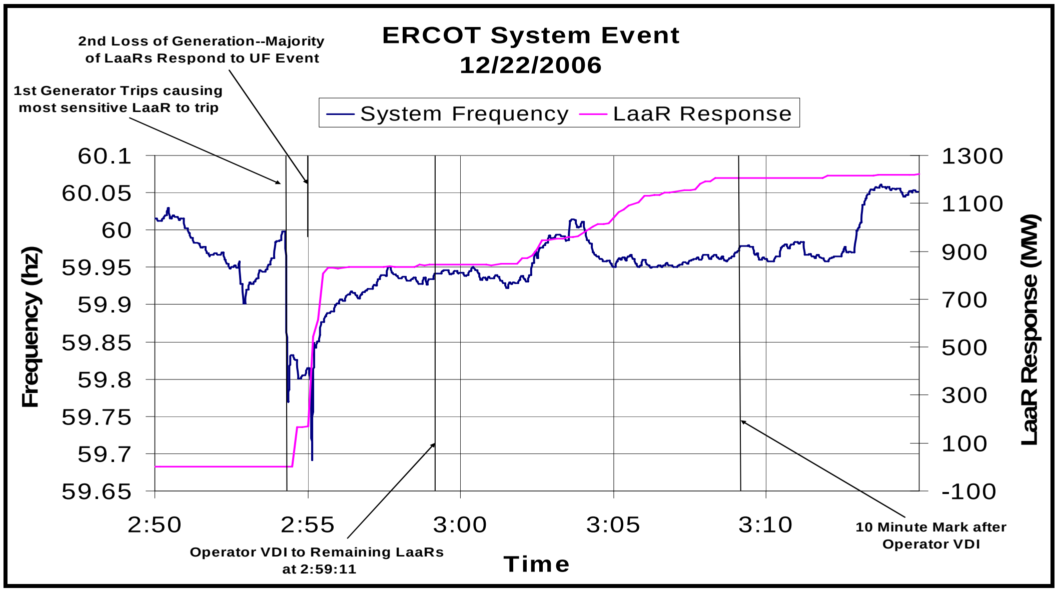

Figure 12: Chronology of ERCOT's December 22, 2006, event.

Conclusion

The December 22, 2006, event in the ERCOT region was triggered by the loss of an unusually large amount of generation during low-load conditions. LaaRs response to the event occurred in three stages: a 59.8 Hz UFR trip (168 MW); a 59.7 Hz UFR trip (662 MW); and manual dispatch (375 MW). The automated UFR trips contributed significantly toward successfully restoring the system's frequency. Measuring the benefits of what did not happen is always challenging. Estimating what would have been the economic and personal consequences of a forced outage on that December day in 2006 in the heavily populated areas of Texas is difficult. However, the case for attributing a significant monetary and nonmonetary value to the fast-responding demand-response resources is compelling.

Dispatchable Load Contributes to the Efficient Operation of the IESO's Electricity Market

Summary

The Ontario electricity market includes a feature referred to as "dispatchable load" that involves short-notice demand-response flexibility that consumers can use. This is accomplished by incorporating the ability for large industrial consumers to enter bids to buy electricity in real time. The IESO compares the incremental cost of generating additional electricity from a generator to the decremental value of the dispatchable consumer not consuming the additional electricity, and then instructs either the generator to increase (or decrease) its output or the consumer to decrease (or increase) its consumption. These industrial consumers have agreed to have the IESO dispatch their consumption on a 5-minute basis—effectively handing over to the IESO the right to use their bids and tell them how much to consume at any time. Given this flexibility, the dispatchable loads are able to compete with generators to sell operating reserve to the market and earn the same payments as generators for providing real-time reserves.

The IESO conducted a study that assessed the impact that demand-response resources have on the efficiency of the market. The study was built on 2006 actual market data and evaluated the respective market supply curves both "with" and "without" the participation of these real-time dispatchable loads in the operating-reserve market. The study quantified an efficiency improvement to the market of approximately C$7 million for the year.

Background

The IESO is responsible for operating the province's electricity system to maintain reliability and promote economic efficiency. It does so through the operation of a spot market to acquire resources that can be used to achieve two equally important outcomes: 1) balancing supply and demand every five minutes and 2) maintaining operating reserves in sufficient quantities to maintain system integrity if available generation resources drop below what is required to meet load.

The IESO's dispatch algorithm determines prices and schedules for both the energy and operating-reserve markets through a process known as "cooptimization." Generation suppliers submit their offer prices at which they will supply energy, and certain industrial customers provide their bid prices at which they will consume energy. In addition, both generators and consumers may submit offers that represent the price at which they will supply real-time operating reserves, which means alerting a generator that it is on stand-by status and may have to increase output to make up for a sudden shortfall following a contingency on the system, or in the case of a consumer, that it is also on standby and may have to decrease its consumption for the same reason. These reserves fall into three categories: 1) 10-minute synchronized reserves, 2) 10-minute nonsynchronized reserves, and 3) 30-minute reserves. Participants can provide offers to sell for each type. Cooptimization leads to the maximum benefit for all participants in the market because the desired level of reliability is realized for the lowest overall cost.

An Important Role for Demand-Response Resources

Dispatchable loads are the most active form of demand response in the Ontario electricity market. They can participate in the cooptimized energy market and nonsynchronized reserve markets and, as such, can be used in economic dispatch or to provide operating reserves or even to help solve congestion problems (out-of-merit dispatch) on the system.[10] Through market bids and offers, dispatchable loads indicate both a price at which they will supply operating reserves and a price at which they will curtail consumption and are viewed as equivalent to a conventional generation resource. Loads that are chosen as operating reserve providers receive stand-by payments for all megawatts scheduled; their payments are equal to the amount generation sources are paid for the equivalent service.

Dispatchable load participation in the IESO markets has grown by an order of magnitude since the option became available in 2002. Initially, two participants provided about 65 MW of dispatchable load. As of 2007, that number has grown to nine participants representing about 700 MW of dispatchable load. The increase in dispatchable load participation has provided improved dispatch opportunities and more efficient utilization of resources in both energy and reserve markets.

Case Study—Quantifying the Benefits; They Are Real and Substantial

To establish the efficiency benefits attributable to dispatchable loads providing operating reserve, the IESO conducted market simulations. The simulations estimated the overall production costs of supplying market demand under two different scenarios: one in which dispatchable loads offered operating reserve (the current state of the market) and one in which dispatchable loads did not offer operating reserves. The production costs under the two simulations were compared to determine the overall benefit (in the form of reduced production costs) attributable to having dispatchable loads provide operating reserves. The study was performed using 2006 historical market data.

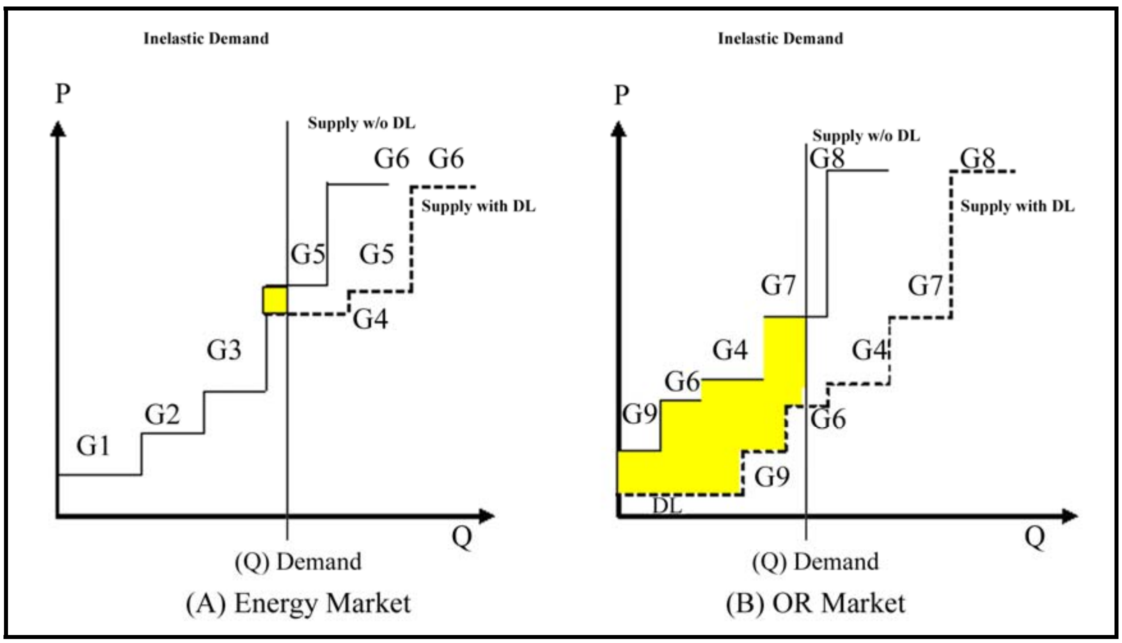

Figure 13: Impact of demand response on market prices for energy and operating reserves.

Figure 13 illustrates the framework for the simulation study. In the second simulation, the energy and reserve market supply "curves" were reconstituted as upward sloping, step functions indicated by the solid line; the energy market is represented by the left-hand panel and the operating reserves market on

[10] Participation by dispatchable loads in the synchronized reserve market is currently under review.

the right. Permitting dispatchable loads to provide operating reserves (OR) expands the supply of resources in both markets, indicated by the dotted line. The vertical lines (labeled [Q] demand) in each market represent the demand. The intersection of the supply step curve and demand yields the market clearing price in both markets. It also determines which resources are scheduled. By shifting the supply of resources via inclusion of the dispatchable-load operating-reserve offers, less expensive resources are scheduled, the market clearing price is reduced, and the overall production cost to meet demand is reduced. The shaded areas in each panel represent the estimated production cost savings attributable to dispatchable loads providing reserve. The bottom line is that for the 2006 study period, having dispatchable loads providing operating reserve resulted in an efficiency benefit in the form of reduced overall production cost that equated to Canadian $7 million per year.

ISO-NE's Forward Capacity Market Includes Energy Efficiency and Many Other Demand-Resource Types

Background

ISO New England, New England's electricity system operator and wholesale market administrator, is implementing a Forward Capacity Market (FCM) that will permit all demand resources to participate in the wholesale capacity market on a comparable basis with traditional generation resources. Demand resources, as defined by ISO-NE's market rules, includes energy efficiency, load management, real-time demand response, and distributed generation. Enabling demand resources to participate directly in the wholesale capacity market creates a predictable stream of revenue for the capacity savings produced by demand resources, gives demand-resource providers access to capital to finance projects, and enables the implementation of "all-cost-effective" demand resources. The response to this innovative development will create many "lessons-learned" opportunities for using demand resources as a capacity resource.

Developed through industry and regulatory consensus, the FCM provides an auction structure—called the Forward Capacity Auction (FCA)—through which capacity resources compete to obtain a market-priced capacity payment in exchange for a commitment to be available in the years ahead to meet the region's electricity needs. FERC approved detailed market rules implementing the FCM in a series of orders issued in April and June 2007. A pioneering element of the FCM is that demand resources can qualify as capacity resources along with conventional generation resources and be eligible to receive capacity payments.

Market Design Features

The objective of the FCM is to purchase sufficient capacity for reliable system operation over time. An annual Forward Capacity Auction will be held to procure capacity three years in advance of delivery.[11] This three-year window provides developers with sufficient time to construct and complete auction-clearing projects and to reduce the risk of developing new capacity. All capacity providers receive payments during the annual commitment period based on a single clearing price set in the FCA. This means that energy efficiency, load management, real-time demand response, and distributed generation resources receive the same price as fossil fuel, nuclear, hydropower, and renewable generation resources. The effect is to establish the economic value of demand-side initiatives and provide incentives for project developers.

In return, the providers commit to supplying capacity for the duration of the commitment period by producing power (if a generator) or by reducing demand (if a demand resource) during specific performance hours, which typically are peak load hours and shortage hours (i.e., hours in which reserves needed for reliable system operation are being depleted). The quantity of capacity purchased through the auction is called the Installed Capacity Requirement (ICR), which consists of the ISO's forecast of peak loads plus adjustments for reserves and other factors. Capacity projects that clear the auction but are not constructed on time or are otherwise not available during performance hours are subject to penalties.

[11] During the initial years of FCM implementation, FCAs will be held a little more frequently than once every 12 months and commitment periods for each FCA will commence in less than three years. However, once the process has matured, FCAs will occur once per year, and commitment periods will start three years after the FCA.

The first commitment period—the period within which capacity must be delivered to the New England electricity system—begins June 1, 2010. Capacity prices and quantities for the first commitment period will be based on the results of the first FCA, expected to be held in February 2008. Before the 2010 commitment period, during a transition period running from December 1, 2006, to May 31, 2010, capacity resources will be compensated for meeting demand requirements. During the transition period, qualified capacity in New England will receive negotiated payments that start at $3.05/kW-month and increase to $4.10/kW-month.

Strong Initial Response to the Forward Capacity Market from Demand Resources

To participate in the competitive FCA process, capacity resources must first complete a qualification process. Through this process, capacity resources must demonstrate that they can meet their commitment to provide capacity. Demand resources are required to demonstrate demand-reduction performance during specific operating hours in a manner that provides electrical capacity to the New England Control Area. To demonstrate a demand resource's demand-reduction value, the demand-resource project sponsor must have a Measurement and Verification (M&V) plan that complies with ISO-NE M&V standards. The measured and verified electrical energy reductions during performance hours form the basis of FCA payments to demand-resource project sponsors participating in the Forward Capacity Market. During the qualification process, ISO-NE would ensure that the applicant's proposal for reducing electricity use and their M&V Plan meet ISO-NE's M&V standards.

About 200 detailed qualification packages, representing approximately 2,500 MW of new energy efficiency, load management, real-time demand response, and distributed generation capacity, were approved by ISO-NE for participation in FCA #1 (see Table 2). These qualification packages were submitted by municipalities, government agencies, electric utilities, retail customers, and competitive energy suppliers. Approximately 80% of the new demand-resource capacity was proposed by nonutility, "merchant" providers, such as energy service companies, equipment vendors, competitive energy suppliers, and end-use customers, many of which have limited or no access to government funding for demand-resource projects. Several of the merchant providers are planning to greatly expand their operations in New England. To serve New England with this new demand-resource capacity, the interested providers still need to participate in and be selected through the auction and actually perform as promised to fulfill their capacity supply obligation. The contribution of demand resources selected through the FCA in meeting New England's capacity needs will signal an important milestone for the wholesale electricity markets.

Table 2
Approved Qualification Packages from New Demand Resources for FCA #1, Capacity Value by Load Zone and Demand-Resource Type, MW[(a)]

Load Zone	CRITICAL PEAK	ON-PEAK	REAL-TIME DEMAND RESPONSE	REAL-TIME EMERGENCY GENERATION	SEASONAL PEAK	GRAND TOTAL
CONNECTICUT	101.1	53.8	137.0	175.5	129.4	596.8
MAINE	23.3	27.8	148.8	37.0		236.9
NE MASSACHUSETTS	114.8	133.3	137.0	148.4	7.2	540.7
NEW HAMPSHIRE	13.6	32.2	34.7	48.7	3.4	132.6
RHODE ISLAND	7.7	39.5	56.2	93.7	1.6	198.7
SE MASSACHUSETTS	87.2	78.3	88.4	92.8	2.4	349.1
VERMONT	7.6	56.6	16.8	18.8	0.8	100.6
WC MASSACHUSETTS	36.5	68.1	117.8	99.0	15.0	336.4
Grand Total	**391.8**	**489.5**	**736.6**	**714.0**	**159.9**	**2491.8**

(a) Critical Peak-Demand Resources—designed for measures that can be "dispatched" s needed by the project sponsor (e.g., load management or distributed generation); On-Peak Demand Resources—designed for non-weather-sensitive measures, such as energy-efficient commercial lighting, that reduce demand across a fixed set of on-peak hours; Real-Time Demand-Response Resources—designed for measures that the ISO can dispatch as needed (e.g., load management or distributed generation); Real-Time Emergency-Generation Resources—designed for distributed generation measures whose state air-quality permits limit their operation to limited "emergency" conditions; and Seasonal Peak-Demand Resources—designed for weather-sensitive measures, such as energy-efficient air conditioning, that reduce load during high-demand conditions.

MISO’s Experience Demonstrates the Flexibility of Demand-Response Resources

Summary

MISO’s response to the events of February 2006 provides several key insights relative to the various roles and values associated with demand-response resources. First, demand-response resources can have an impact not only in response to summer season events but also to winter events. Second, demand-response resources are nimble and can be “ramped up” to match escalating constraints. Third, demand-response resources can be used to offset localized constraints associated with a given transmission line or area as well as across an entire system. Fourth, MISO (along with the involved balancing authorities and the load-serving entities and utilities and their demand-response participating customers) proved that with appropriate communication and coordination, demand response can be an effective resource within multi-state and multi-stakeholder environments.

Background

The Midwest Independent System Operator is responsible for the coordination and dispatch of generation in the 15-state area to ensure system reliability. Its system operators watch weather patterns closely for anticipating and preparing for cold weather conditions that are likely to put stress on generation resources and their associated reserves. Utilities in the region have enrolled substantial demand-response resources that they have historically dispatched to meet local reliability needs. MISO’s creation provided the means for coordinating the use of these resources so that they are even more valuable than previously demonstrated. A cold week in February of 2006 demonstrated the value of that coordination.

A Bitter Welcome to February

The first week of February 2006 was bitterly cold, even for hardy Midwesterners. Daily highs the first three days of the month were at or below 20°F in most cities, with a high of 0°F in Winnipeg. Overnight, temperatures plummeted to below zero; as low as -40°F in Winnipeg. Recognizing that loads would be high that week, MISO implemented procedures to prepare for contingencies that might threaten system security. It contacted utility system operators Sunday afternoon, February 4, to let them know that on the basis of projected load, reserve margins would be barely adequate and any deterioration of conditions—as a result of higher-than-anticipated load or unit outages—would require emergency procedures to be enacted.

These procedures are progressive, beginning with a warning to alert utility system operators to the possibility of the need to undertake actions to balance load. What transpired was that events indeed arose that required that emergency actions be undertaken. As a result of the availability of demand-response resources and through the coordinated actions of MISO and the utilities, conditions never reached the point that operating reserves needed to be used and were far from needing to shed load involuntarily during extreme cold weather conditions.

Case Study—Dispatching Demand Response in the Amount Needed and When Needed

Figure 18 illustrates how MISO managed the system through the extraordinary early February 2006 weather that resulted in peak loads. On Monday February 5, a Maximum Generating (Max Gen) warning was posted for the Western zone, where balancing supply and demand seemed to be at the most risk. Such a warning is a predecessor to invoking emergency procedures. By the early morning, a Max Gen event was declared to carry the system through the early morning load build up.[12] The event included invoking 300 MW of demand-response curtailments.

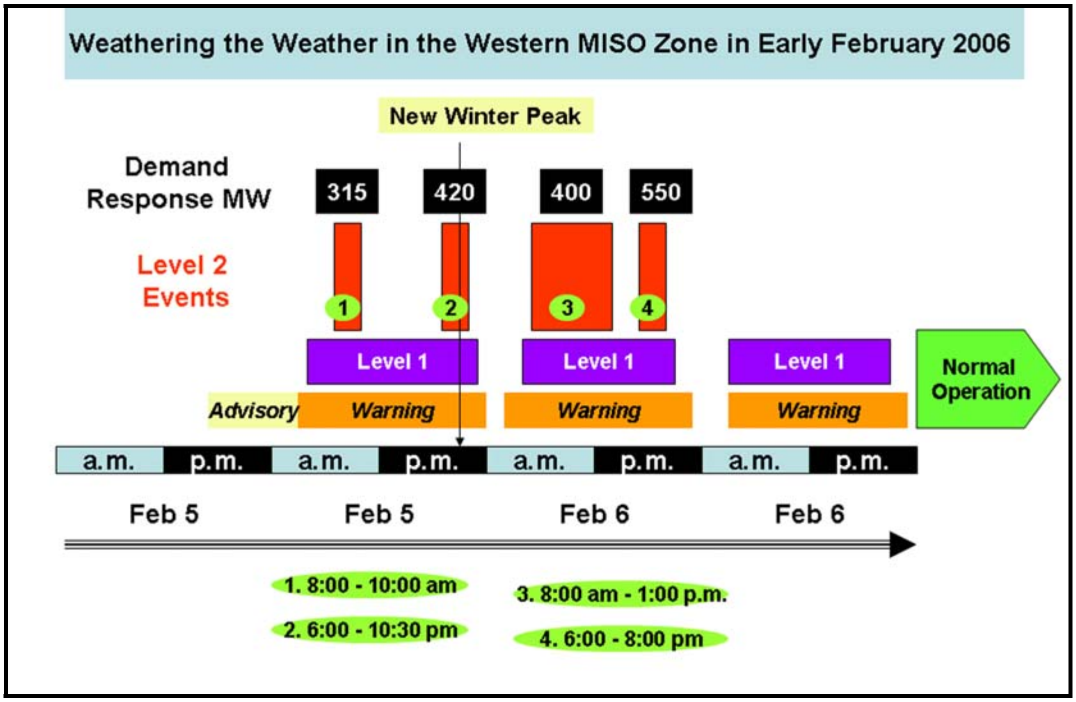

Figure 14: MISO event timeline.

This represented only about 30% of what was available in the MISO footprint. Dispatchers took advantage of the flexibility of demand-response resources to activate only what they felt was needed, keeping the rest in reserve. Later in the day, demand resources were again needed as another Max Gen event was declared. This time, over 400 MW were deployed to keep operating reserves at the required level and to meet the energy demands without shedding load involuntarily.

Tuesday, February 6, was almost as cold in the region, prompting MISO to ramp up their calls for demand-response resources as the day progressed. From 8:00 a.m. through the early afternoon, they garnered 400 MW, which was boosted to over 500 MW later in the day. And at least an additional 500 MW was held in abeyance in case a compounding contingency occurred.

Demand-Response Coordination and Flexibility Led to Delivered Results

The February 2006 events provided several key insights into the role and value of demand response in the MISO market. First, demand-response resources are available when they are needed, including in the dead of winter to manage high heating loads.

Second, demand-response resources are nimble and divisible, thereby providing valuable flexibility when matching demand response with identified grid-support constraints. MISO was able to realize the amount

[12] In NERC terminology, this is an EEA 2 event.

of supplemental operating reserves the situation called for, thereby preventing needless curtailments by customers. But only the amount required was dispatched, which allowed the system operators to use on-line generation units optimally.

Third, demand-response resources can be utilized locationally, when and where needed; in addition, in the absence of binding transmission constraints, they can be used across an entire market.

Fourth, MISO established that it can coordinate the implementation of demand response through communication and cooperation with existing balancing authorities, which have the responsibility for interacting with the load servers and utilities that have enrolled customers in their programs.

The Insurance Value of Demand Response in NBSO

Summary

New Brunswick's demand-response resources demonstrated their value as insurance against the adverse and potentially widespread consequences of the unexpected loss of an on-line generation unit. What is insightful is that while the conventional wisdom holds that the need for supplemental resources is often associated with high-load circumstances, New Brunswick's need arose under nonpeak conditions. The demand-response resources enrolled by NB Power to avoid building generation capacity to meet peak conditions paid off under nonpeak operating conditions, just like any good insurance policy. In addition, over 90% of the enrolled demand-response load performed well during the curtailments.

Background

The New Brunswick System Operator is responsible for coordinating the operation of the province's electricity system to provide reliable power on demand. An important element of that responsibility is to anticipate supply and demand imbalances and develop protocols to resolve them with the least possible adverse result to their electricity consumers.

Peak-demand conditions are considered to be the most challenging in terms of both balancing load and maintaining sufficient operating reserves to support the grid. When loads are the highest, most available supply resources already are committed to serve load or to provide operating reserves, leaving very little margin for dealing with adverse circumstances. But, sometimes things turn out not as expected, testing the system's resiliency.

New Brunswick's peak electricity demand of 3,300 MW typically occurs in January or February, primarily due to residential (and to some extent commercial) electric heating. Accordingly, the system is designed to maintain capacity to meet demand on the coldest winter days in the first two months of the year.

On December 15, 2005, which was only a seasonally cold winter's day, electricity demand was building normally, with an expected peak well below 2,800 MW. All indications pointed to it not being a peak-demand day with generation resources being ample…or so it seemed.

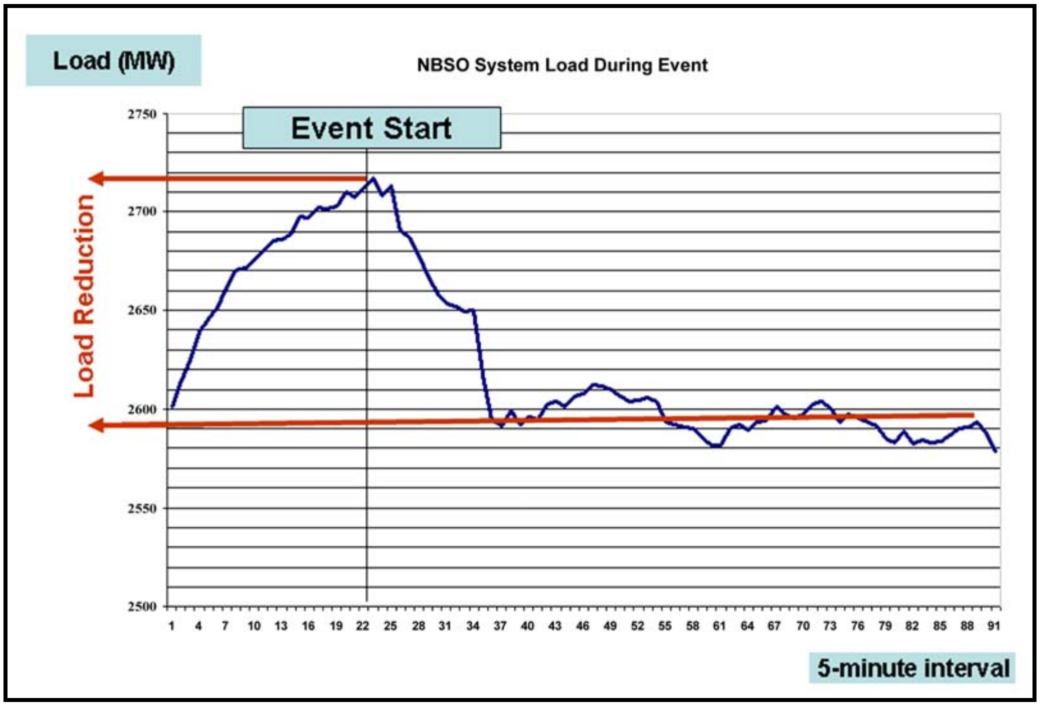

Figure 15: Demand response during NBSO reserve-shortfall event.

As load was approaching its peak for the day, 270 MW of generation suddenly and unexpectedly tripped off line. NBSO system operators moved quickly to dispatch uncommitted hydro and peaking units to avert a capacity shortfall that could quickly lead to a cascading system failure. They were only partially successful because 200 MW of peaking resources that were expected to be available were unable to respond. The result was a potentially dangerous capacity shortfall, with only emergency purchases from other nearby systems standing as the last backstop action before customers would be required to shed load to protect the system's integrity.

Case Study—Cashing In on Their Demand-Response Insurance

As a result of the availability of demand-response resources, neither of these actions was required. The local utility, NB Power, had anticipated that emergency capacity could provide a valuable service. It had enrolled 140 MW of nonfirm load, which customers had pledged to curtail on as little as 10 minutes notice under circumstances such as these. NBSO declared a curtailment event, which resulted in load reductions of 127 MW**,** equating to a response by more than 90% of enrolled resources. Figure 19 shows the rapid drop in total load that occurred following the issuance of instructions for load curtailments.

The combination of load reductions by demand-response customers and the curtailment of some export transactions allowed NBSO to safely balance their supply resources and the customers' demands on the system. Emergency actions, which are sometimes a prelude to forced outages of customer load, were averted.

NYISO Demand-Response Resource Performance during the August 2006 Heat Wave

Summary

New York's demand-response resources proved their worth during the early August 2006 heat storm that resulted in record temperatures and new peak electricity consumption throughout the East Coast. Demand-response resources provided reliability benefits for the New York grid, especially at the more localized level in the downstate New York metropolitan area. In addition, demand-response resources also indirectly contributed to the New York Independent System Operator's ability to comply with regional operating protocols to export 1,300 MW of emergency energy to their neighbor, ISO-NE.

NYISO Demand-Response Resources

The ICAP/SCR program allows customers to offer load curtailments as an alternative to generation to load-serving entities (LSEs), fulfilling their installed capacity requirements. These resources are dispatched with two-hours' notice when operating-reserve shortfalls are anticipated for an extended period. Participants are paid the market price (locational marginal price, LMP) for energy for the actual amount of curtailed load when dispatched, which augments the ICAP payment they receive for making themselves available to the program.

EDRP resources are load customers that have enrolled to undertake curtailments voluntarily when NYISO calls on them. They receive a payment equal to the market price (LMP), but at least $50/kWh, for curtailed loads.

Background

The first week of August brought sweltering heat to the entire East Coast. By Wednesday of that week, the collective effects of relentless heat and humidity placed a strain on the region's electric supply. While NYISO had sufficient resources to meet consumers' electricity demand, very few options were available to dispatchers at the power control center to deal with the failure of critical system resources. Simply put, there was little room for error. Neighboring systems were less sanguine about their ability to serve record forecasted loads.

Demand-Response Resources Help Manage the Peak Loads

On Wednesday, August 2, NYISO activated its two demand-response programs, the Emergency Demand Response Program (EDRP) and the Installed Capacity/Special Cases Resources (ICAP/SCR) program, in Zones J and K (the New York City area) from 1:00 p.m. to 7:00 p.m. In addition, demand-response resources in Zones A, B, and C (the western part of the state) were activated from 2:00 p.m. to 7:00 p.m. These resources were deployed to mitigate a combination of system conditions and regional needs.

An all-time system peak of 33,939 MW was reached between 1:00 and 2:00 p.m. that day, which is 33% above the peak load served just 10 years ago. Following established regional operating protocols, 1,300 MW of emergency energy was supplied from the New York Control Area to ISO-NE starting at 1:00 p.m. ISO-NE had already undertaken a 5% voltage reduction at the time to deal with potential capacity shortfalls. Without load reductions provided by the demand-response resources, the NYISO would not have been able to provide such emergency assistance. The NYISO's demand-response programs resulted in nearly 1,000 MW of load reduction for five hours that day. This reduced the state's peak load by about 3% and corresponds to the output of two medium-sized generating plants and the electricity needs of 300,000 to 400,000 households.

Figure 20 illustrates the impact that demand-response load reduction had over the August 2 peak period. It compares actual system demand with what the demand would have been without the demand response. The lower line on the graph shows the actual NY Control Area (NYCA) load, which peaked just when the demand-response resources were activated. The upper line shows what load would have been absent load curtailments by demand-response resources. The cumulative load reduction (over 7,000 MWh) from 12:25 p.m. to almost 7:00 p.m. had a profound impact on system reliability, as discussed below. While this day demonstrates the most dramatic impact of demand response resources, these resources are called upon on other occasions. Over the course of the 2006 summer, demand response provided nearly 16,500 MWh of load reduction—more than in any previous summer.

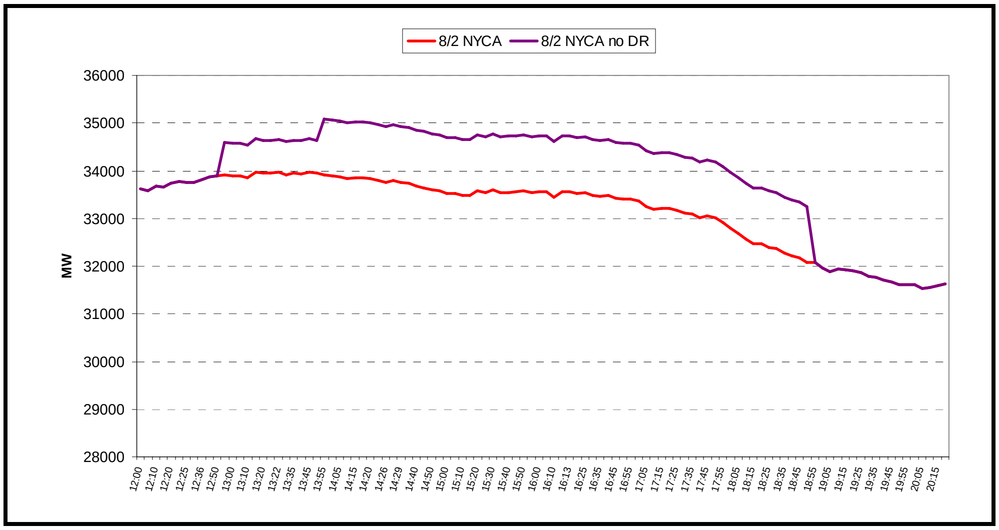

Figure 16: Impact of 1,000 MW of demand response on peak load.

Verifying the Impact

NYISO's demand-response resources are dispatched to avoid situations where the system becomes deficient in operating reserves. Maintaining reserve requirements is essential to avoid involuntary load shedding that can come about when critical transmission or generating facilities are lost during peak-load periods. On August 2, EDRP/SCR resources were required to maintain the required level of operating reserves in the eastern portion of the state for most intervals. Figure 17 plots the actual reserves (Eastern Reserves w/DR) and what the level of reserves would have been without the demand-response load reductions (Eastern Reserves w/o DR) on a one-minute real-time basis. The bottom line shows intervals when the reserves in the eastern portion of the state would have been below the eastern requirement of 1,000 MW. For much of the period shown, reserve levels would have been deficient. The upper line shows the actual reserve situation. From 2:00 p.m. on, demand-response resources were largely able to maintain reserves for the eastern portion of the state. Clearly, demand-response resources contributed to maintaining system security and reliability under conditions that exhausted the capabilities of conventional resources.

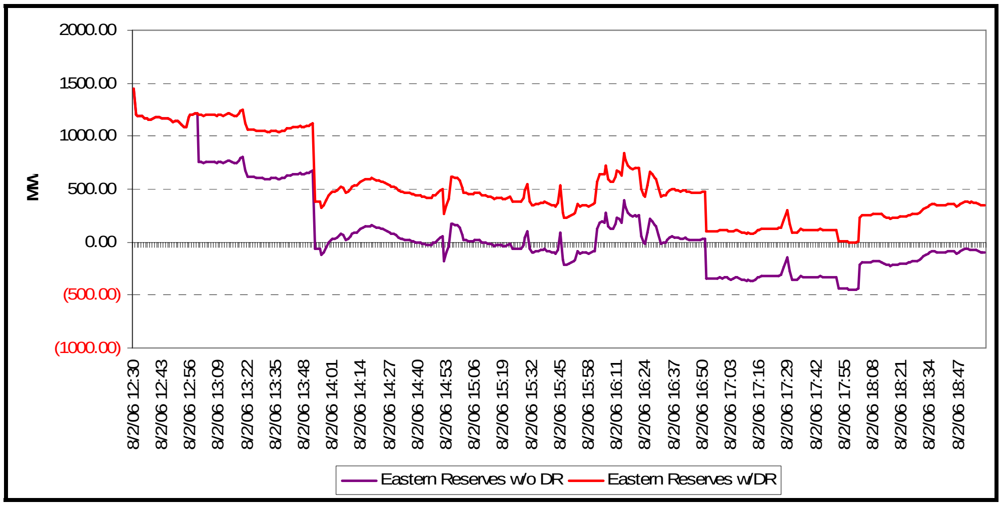

Figure 17: Eastern reserve status on August 2, 2006.

The Three-Percent Solution: PJM's Formula for Price Response

Summary

PJM, as part of a regional collaborative, conducted a study to estimate the potential level and distribution of benefits associated with price response, defined as customers paying prices linked to wholesale day-ahead and real-time prices. The PJM study demonstrates the power of demand response to reduce locational marginal prices (LMPs). The study modeled a modest 3% load reduction, which amounts to less than 1% of PJM's peak load, in the 100 highest LMP peak hours. It showed that a small decrease in load can deliver substantial energy and capacity market benefits to those customers who would respond to high prices. Collateral benefits also would accrue to all electricity consumers and society as a whole.

Background

PJM is constantly working with stakeholders to integrate demand-response resources into their market and system operations to realize demand response's full potential. A key element of that commitment is PJM's participation in the Mid-Atlantic Distributed Resources Initiative (MADRI), a coalition consisting of regional entities that include state regulators and utilities, federal and state agencies, consumer groups, and firms promoting technological solutions. MADRI seeks to identify and remedy retail barriers to the deployment of distributed generation, demand response, and energy efficiency in the Mid-Atlantic region.

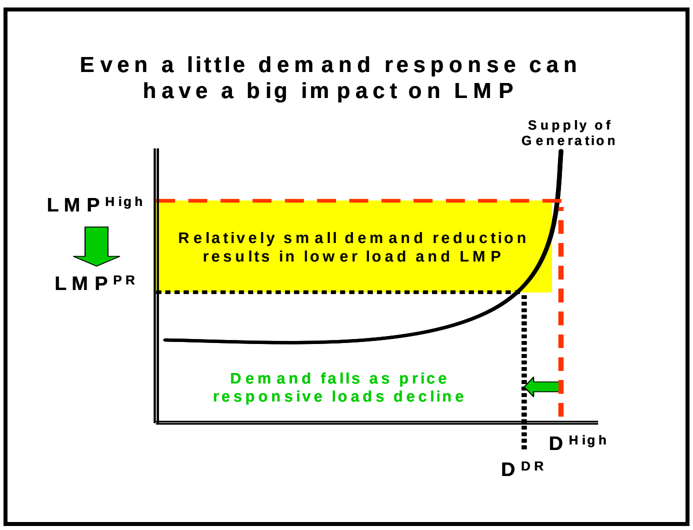

Figure 18: Benefits of price response.

A recurring theme in the MADRI deliberations is the need to quantify, in monetary terms, the benefits from linking customer's electricity usage decisions to wholesale LMPs, especially when LMPs are high. Establishing both the level of benefits attributable to demand response and its beneficiaries is critical to ensuring that economical and equitable solutions are implemented. PJM also desires a better understanding about how load changes affect LMPs; doing so will help them to anticipate the impacts of price-response initiatives and to refine the operation of their spot LMP markets accordingly.

Case Study—The Three-Percent Solution

PJM set out to answer a series of related questions. First, how does a reduction in a customer's usage translate into lower electricity costs? The premise is straightforward. When prices are high, they trigger reduced electricity usage and thus relieve the pressure on supply. As a result, LMPs fall. When electricity usage increases, more expensive generation units are dispatched, and LMPs increase since the LMP is set by the cost of the last unit dispatched. If customers were to respond to these prices by reducing usage, LMPs would drop. But, by how much would they drop? And who would reap the rewards?

Modeling a Three-Percent Solution

To answer these questions, in 2006, PJM and MADRI conducted a study to identify and monetize the potential benefits of LMP-based price response. A simulation model was used to recreate the actual 2005 market supply and demand conditions and then analyze how a 3% reduction in load in the highest priced hours would have affected LMPs for selected zones within the Mid-Atlantic region. The study was designed to test whether such a relatively inconsequential reduction in demand could have the predicted impact. The hypothesis holds that high LMPs are usually associated with supply conditions that are very sensitive to changes in demand, where even a small amount of demand response can have a significant impact under tight supply conditions (see Figure 18).

MADRI LMP Impact Study Scope

- Electricity peak load in DE, DC, MD, NJ, and PA was analyzed.
- The peak load of about 35,000 MW comprised 27% of the total PJM peak load.
- The study focused on the summer months of 2005 when LMPs were highest.
- LMP impacts were analyzed for a block of five afternoon hours on the 20 highest-priced days.
- LMPs on those days averaged from $118 to 212/MWh.

The LMP-impact simulation focused on the 20 days in 2005 when LMPs were highest and, for each day, the same five consecutive hours; this resulted in estimating LMP impacts for a total of 100 summer day hours. Based on the assumed 3% load reduction, the simulated LMPs were reduced by $85 to $234/MWh, which corresponds to a decline of 6 to 12%.

Quantifying the Modeled Benefits

The estimated financial rewards associated with the modeled demand response were substantial and would accrue to all electricity consumers in the PJM market, even though the load reductions modeled were limited to the Mid-Atlantic states. The adjacent sidebar summarizes those benefits, which can add up to almost $300 million per year. The results indicate that customers that undertook demand reductions under the simulated market conditions would realize up to $20 million in annual savings for themselves, while their load reductions would generate benefits two to three times larger for all other electricity consumers. Those savings extend to consumers outside the Mid-Atlantic states, demonstrating the inherent regional interdependencies between supply and demand in the PJM electricity market.

The 3% Demand-Response Solution Scorecard

- **$57–$185 million/year**—the annual savings that accrue to Mid-Atlantic customers other than those that respond to high LMPs
- **$9–$26 million/year—**bill savings by customers that respond to high LMPs
- **$73 million/year—**the resource savings from lower generation capacity requirements
- **$8–$12 million/year—**the spillover savings to other PJM customers outside the Middle Atlantic states

Preserving Reliability at the Local Level in SPP

Summary

Not all ISOs and RTOs have developed the same level of demand-response capabilities. For example, Southwest Power Pool recently launched its Energy Imbalance Services Market, which will incorporate demand-response resources. This supplements the programs established by the utilities within the SPP footprint. They have pre-established pricing and emergency-oriented demand-response programs, which will provide excellent platforms upon which to build. This case study highlights Public Service of Oklahoma's (PSO) experience with an August 2006 transmission line failure during a heat wave that was compounded by two generation units going off line. Both its real-time pricing (RTP) customers, as well as those in its curtailment program, were key to garnering over 50 MW of curtailed load over a work week.

Background

SPP established a market structure that meets the needs of its stakeholders. It is currently developing and testing protocols for the real-time balancing market it intends to implement in the near future and is evaluating how best to foster competition to ensure that sufficient and economical ancillary services are available and the system is reliable. Because the very foundation for the market is still embryonic, implementing a demand-response program is premature. However, SPP member utilities that provide service to retail customers in their franchise areas have been fostering demand response for years. This means that when SPP embraces and incorporates demand response into its market operations, experienced customers will be ready to provide these resources.

Case Study—Preserving Reliability at the Local Level

Public Service of Oklahoma serves over 4,100 MW of load in the state, which is known for its hot, humid summers. PSO builds capacity to serve that peak load reliably, but sometimes compounding circumstances circumvent even the best-laid plans.

In early August 2006, a transmission line feeding Tulsa unexpectedly went out of service, isolating the city, to a large extent, from the regional grid. Compounding the problem, generating units at two Tulsa-area power plants broke down on Sunday, August 6. The Riverside Station in Jenks and the Tulsa Power Station each shut down one of their units due to leaks in the steam boiler tubes. While thist is a fairly common issue to deal with for a single unit, the shutdown of two units during a time of peak demand resulted in the loss of more than 500 MW of capacity. This was complicated by the transmission outage, which meant a lack of import capability as a backup. With near-record demand for power due to the hot weather conditions, PSO would need to curb the supply of electricity to some commercial and industrial customers if overall system demand were not curtailed.

The Power of Price

PSO was an early adopter of real-time pricing (RTP) for its larger commercial and industrial customers. Under RTP, customers receive a new hourly price schedule every day applicable to energy usage the next day. The prices are derived from the marginal cost of supply as forecast by PSO schedulers, taking into account both local demand for electricity and regional supply and demand conditions. Over the past 12 years, RTP participants have consistently reduced usage when the price became elevated and made up their economic activity at another, lower-priced time. They would have done so in these circumstances except for bad timing. The plant outages occurred on Sunday after the RTP prices for Monday had been posted. The capacity shortfall therefore was not reflected in the RTP prices.

Seeing the need for load reductions to avert an operating-reserve shortfall, PSO appealed to the RTP customers to respond using a novel approach. It called customers and offered to pay the price above those posted if they curtailed load on Monday. The RTP customers responded by reducing load by over 60 MW during Monday's peak hours.

The Power of Public Appeal

On August 8, *Tulsa World* headlines read, "Consumers' voluntary cutbacks help; Threat of problems cited during triple-digit temperatures." On Monday, August 7, PSO asked customers to conserve electricity, despite the 100°F heat. It offered a list of ways to reduce electricity usage with a minimum of discomfort (see sidebar). While the amount of demand response realized is hard to quantify, PSO estimates it amounted to at least 10 MW on that Monday.

The impact was even more significant on Tuesday, August 8. One generation unit was back on line, so the supply outlook had improved. RTP prices were only moderately high, so price response was minimal. But customers took circumstances into their own hands and conserved. While a new peak demand for PSO was set, it likely would have been up to 30 MW higher without the customers' conservation actions. As a result, no curtailments were required.

Public Appeal Hot Weather Tips

- Set your thermostat no lower than 78 degrees. Use ceiling fans to circulate cool air.
- Move lamps and televisions away from thermostats. Use a programmable thermostat.
- Use a microwave instead of a conventional oven.
- Hang laundry outside to dry.
- Avoid using heat-producing appliances (ovens, clothes dryers) during the hottest times of day.
- Keep sunny windows covered with blinds or draperies.
- Install light-colored window shades to reflect heat.
- Place sun-control film on south-facing windows.
- Use fans to move air-conditioned air throughout your home.

This same pattern was repeated on Wednesday, August 9. Forecasted supply conditions resulted in only slightly elevated RTP prices and, as a result, very little RTP load reductions. The expectation of continuing voluntary conservation, which was realized, resulted in lower prices, allowing businesses vital to the Tulsa economy to continue normal operations. However, the weather forecast for the balance of the week called for the heat wave to continue; Tulsa was expected to stay at 100°F, and it did. By Thursday, the heat's cumulative effect raised PSO's electricity demand to new heights. These realities also were reflected in elevated RTP prices. As expected, RTP customers reduced their loads by over 50 MW. On

Friday, with the week winding down, so did the severity of the heat and related load. Still, RTP prices were high enough to induce a 40 MW load reduction.

Conclusion

Some ISOs and RTOs found demand response almost nonexistent when their markets opened and devised ways to allow customers to provide resources directly into market operations to supplement generation capacity. SPP enjoys an advantage in that some utilities within their footprint already offer retail pricing plans that link retail energy prices to exigent market circumstances. The participants have developed a level of experience and competence that allows the impacts to be predictable. As SPP moves forward, programs like this will help keep the lights on and shining brightly for consumers in the SPP market.

About the ISO/RTO Council

Founded in 2003, the ISO/RTO Council (IRC) is an industry organization comprised of 10 Independent System Operators (ISOs) and Regional Transmission Organizations (RTOs) in North America, responsible for delivering two-thirds of the electricity consumed in the United States and just over 40 % in Canada.

In addition to coordinating electric generation and transmission across a wide geographic area, ISOs and RTOs provide nondiscriminatory transmission access, facilitate competition among wholesale electricity suppliers, and conduct regional planning to ensure a reliable grid for the future.

The IRC works collaboratively to develop effective processes, tools, and methods for improving competitive electricity markets across North America. The IRC's goal is to balance reliability considerations with market practices, resulting in efficient, robust markets that provide competitive and reliable service to electricity users.

This report was compiled by the Markets Committee of the ISO/RTO Council.