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How to Get More Response from Demand Response

Despite all the rhetoric, demand response's contribution to meet peak load will remain elusive in the absence of enabling technology and standardized business protocols.

Scott Neumann, Fereidoon Sioshansi, Ali Vojdani and Gaymond Yee

I. Summer's Heat Wave shows DR's Potential

This past summer's heat wave engulfed most of the U.S. and stretched many utilities and system operators close to the limit. In California, the Independent System Operator (CAISO) had to declare several Stage 1 and Stage 2 alerts in July,[1] signaling that its reserve margin was precariously low. Similar episodes were repeated across the country in July and August as new peak load records were repeatedly set and broken (**Figure 1**). System operators, once again, were reminded of the real value of demand response programs.

When operators run out of generation capacity, the alternatives are either to resort to rolling blackouts – which nobody likes – or to plead to customers to drop discretionary loads. This practice, where customers are provided financial incentives to drop load during emergencies is known as demand response or DR.[2]

Currently, system operators have limited capabilities to engage in DR for a number of reasons. Most importantly, the protocols for sending the signal that capacity is tight and voluntary load shedding is needed is time-consuming, error-prone, and mostly manual. Since system

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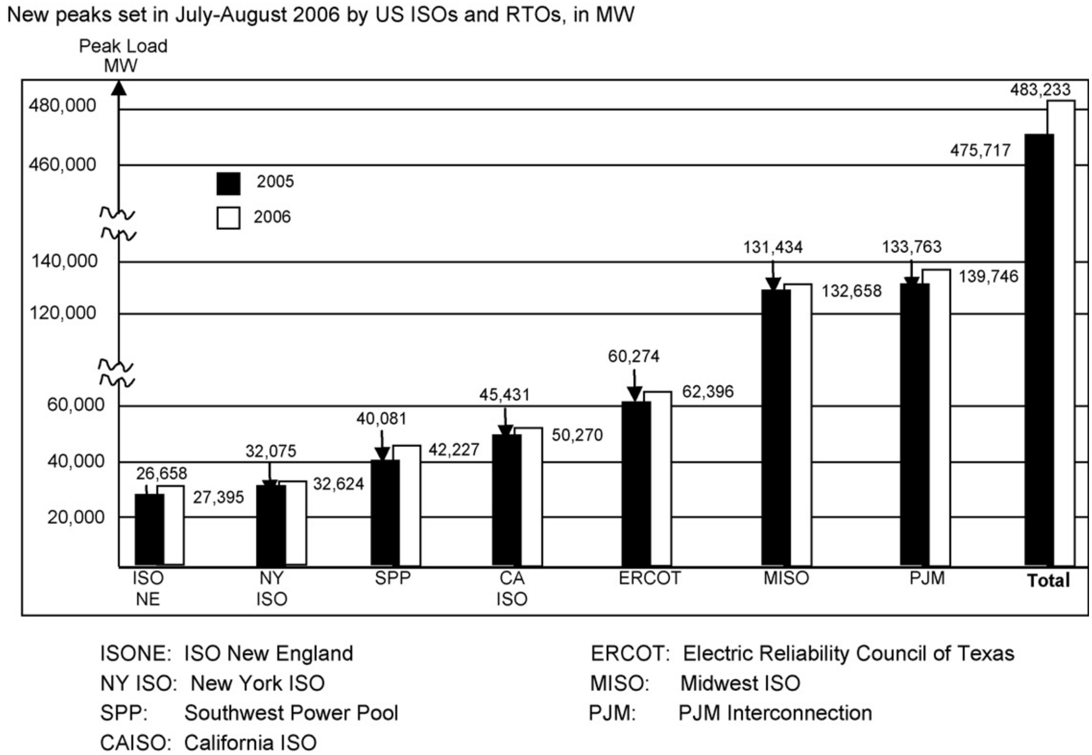

Figure 1: Killer Heat Wave, Record Peaks. **Source**: Various ISOs/RTOs

operators must balance load in real-time, any delays to get a signal out, get confirmation, and get tangible results must be fast, error-free and automatic – characteristics that are lacking in most current systems. This means that in many cases, the operator may resort to involuntary load shedding simply because of inherent delays and inefficiencies in implementing DR programs.

II. Is DR Cost-Effective?

A number of studies have confirmed the cost-effectiveness of DR relative to the alternatives, namely reliance on peaking units or rolling blackout. The former are expensive – as everyone recognizes – and the latter even more so.[3]

A recent report by the Federal Energy Regulatory Commission (FERC), for example, provides some evidence.[4] One study claims annual savings of $15 billion per year in the U.S. for shifting 5 to 8 percent of consumption from peak to off-peak hours and for depressing peak demand by 4 to 7 percent.[5] Another study looking at the New England ISO's service area claims annual savings of $580 million per year for reducing peak demand by as little as 5 percent.[6]

During the August heat wave, PJM Interconnection reported cost savings totaling $650 million attributed to DR programs.[7] On Aug. 2, 2006, alone, when PJM set a new peak load record of 144,796 MW, it reported DR savings of $230 million.[8] Similar testimonials are available from other ISOs and RTOs.

III. How Much DR is Really There?

Following the passage of the Energy Policy Act (EPAct) in August 2005, there has been renewed interest in smart meters, time-variable pricing, and demand response – the legs of a stool. EPAct's main contribution was two-fold: First, it codifies the significance of enabling technologies, which are prerequisites to wider implementation of DR. Second, it instructs both the Department of Energy (DOE) and FERC to establish baselines and goals for increased reliance on DR.

As a consequence, DOE published a report in February estimating DR's potential benefits, offering recommendations on how these benefits may be captured.[9] As a starting

Table 1: What is DR?

Price-Based Options	Incentive-Based Programs
• *Time-of-use* (*TOU*)*:* a rate with different unit prices for usage during different blocks of time, usually defined for a 24-hour day. TOU rates reflect the average cost of generating and delivering power during those time periods.	• *Direct load control:* a program by which the program operator remotely shuts down or cycles a customer's electrical equipment (e.g., air conditioner, water heater) on short notice. Direct load control programs are primarily offered to residential or small commercial customers.
• *Real-time pricing* (*RTP*)*:* a rate in which the price for electricity typically fluctuates hourly reflecting changes in the wholesale price of electricity. Customers are typically notified of RTP prices on a day-ahead or hour-ahead basis.	• *Interruptible/curtailable* (*I/C*) *service:* curtailment options integrated into retail tariffs that provide a rate discount or bill credit for agreeing to reduce load during system contingencies. Penalties may be assessed for failure to curtail. Interruptible programs have traditionally been offered only to the largest industrial (or commercial) customers.
• *Critical peak pricing* (*CPP*)*:* CPP rates are a hybrid of the TOU and RTP design. The basic rate structure is TOU. However, provision is made for replacing the normal peak price with a much higher CPP event price under specified trigger conditions (e.g., when system reliability is compromised or supply prices are very high).	• *Demand bidding/buyback programs:* customer offers bids to curtail based on wholesale electricity market prices or an equivalent. Mainly offered to large customers (e.g., 1 MW or over). • *Emergency demand response programs:* programs that provide incentive payments to customers for load reductions during periods when reserve shortfalls arise. • *Capacity market programs:* customers offer load curtailments as system capacity to replace conventional generation or delivery resources. Customers typically receive day-of notice of events. Incentives usually consist of up-front reservation payments, with penalties levied for failure to curtail when called upon to do so. • *Ancillary services market programs:* customer bid load curtailments in ISO/RTO markets as operating reserves. If their bids are accepted, they are paid the market price for committing to be on standby. If their load curtailments are needed, they are called by the ISO/RTO, and may be paid the spot market energy price.

Source: Benefits of DR in Electricity Markets and Recommendations for Achieving Them, US DOE, Feb. 06.

point, DOE divided DR programs into two basic categories, price- and incentive-based (**Table 1**), and identified various sub-categories under each. Following these definitions, the focus of the present article is on demand bidding/buyback and emergency demand response programs. These programs, broadly speaking, require the system operator to signal that there is an impending emergency and ask for customers to shed load in exchange for predetermined (the former case) or negotiated (the latter case) prices/incentives.

The DOE study estimated current (2004) U.S. DR capacity around 9,000 MW, roughly 1.3 percent of the U.S. peak load. It estimated DR's potential to be around 20,500 MW, or 3 percent of the peak load. Surprisingly, DOE found that DR capacity has actually declined from its peak in 1996, when more utilities engaged in such programs and had more load under control.

DOE offered a long list of recommendations under six major categories:

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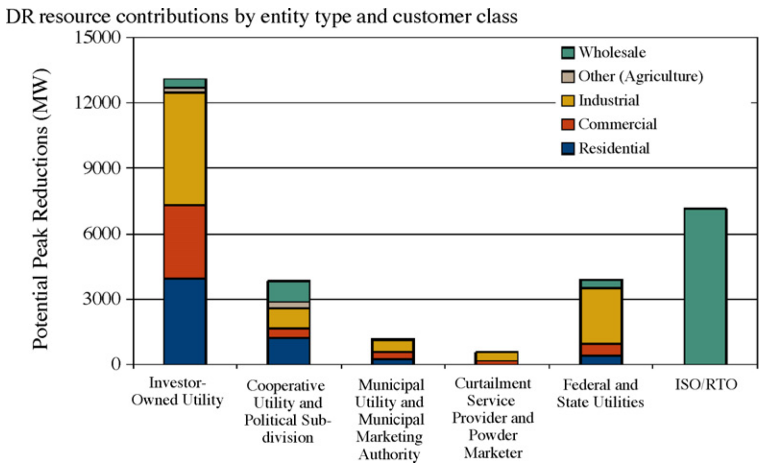

Figure 2: How Much Demand Response Is There? **Source**: Assessment of Demand Response and Advanced Metering, FERC, Aug. 8, 2006

- Fostering price-based DR,
- Improving incentive-based DR,
- Strengthening DR analysis and valuation,
- Integrating DR into resource planning,
- Adopting enabling technologies, and
- Further enhancing federal action.

In August, FERC also complied with the mandate of EPAct by releasing an assessment of the state of technology and demand response.[10] The FERC report provides a comprehensive survey of the penetration of enabling technologies and the prevalence – or rather lack thereof – of time-variable tariffs. Noting that less than 6 percent of electric meters are currently able to record or report interval usage, FERC, using rather diplomatic language, said, ''the use of DR (in the U.S. power industry) is not widespread.''

In terms of DR potential, FERC concluded, ''Nationally, the total potential DR resource contribution from existing programs is estimated to be about 37,500 MW,'' the lion's share among the investor-owned utilities, followed by the ISOs (**Figure 2**). FERC's main conclusions are that, ''The potential immediate reduction in peak electric demand that could be achieved from existing DR resources is between 3 and 7 percent of peak electric demand in most regions,'' but points out that the low penetration of enabling technologies limits what can be achieved in the immediate future. It is a classic chicken-and-egg problem. Without widespread penetration of smart meters and time-variable pricing there is little future for DR.

IV. What is the Holdup?

Given the significant size of the DR resource and its cost-effectiveness, why aren't we seeing more DR deployment when emergencies do occur? Most studies, including the two major reports by DOE and FERC, blame the problem on lack of *enabling technology* – which certainly is a major obstacle. Without affordable smart meters, reliable and inexpensive two-way communication and widespread use of time-variable tariffs, the true potential of DR will never be realized.

But there are two other highly critical aspects of enabling technology, which remain as serious obstacles to successful and cost-effective implementation of DR, namely:

- Fast, reliable, and automated communications among multiple players in the DR domain in real-time, and
- Standardized protocols for customer enrollment and notification, business processes and settlement.

Unless these two issues are successfully addressed, wide-scale implementation of DR shall remain limited and problematic, especially if there is interest to reach a significant number of small consumers.

Take the former. Currently, system operators have limited capabilities to engage in large-scale DR involving multiple players and large numbers of participating customers for a number of reasons. Most importantly, the protocols for sending the signal that capacity is tight and voluntary load shedding is needed is time-consuming, error-prone, and mostly manual. Since system operators must balance load in real time, any delays to get a signal out, get confirmation, and

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tangible results must be fast, error-free, and automatic – characteristics that are presently lacking. This means that in many cases, the operator may resort to involuntary load shedding simply because of inherent delays and time-consuming complications in implementing DR programs.

Currently when an emergency occurs, the system operator sends an alert to multiple utilities as well as others informing them of an impending crisis and requesting a response. This signal typically goes from the ISO to multiple utilities, who, in turn, pass it on internally and to participating customers using multiple means and channels (**Figure 3**). The process of sending and aggregating the responses from multiple parties is notoriously cumbersome and time-consuming, making it difficult to assess how many customers may participate within a short time frame and given a particular incentive offered. The ISO, faced with uncertainties of how many megawatts of load can actually be shed in real-time, may resort to involuntary but certain load shedding.

The problem becomes even more intractable if the system operator is engaged in real-time bidding, adjusting its incentives in response to how many customers volunteer to shed load. For such interactive schemes to work, a higher level of sophistication, automation, aggregation, and confirmation is needed.

The second problem may not be as obvious but is equally daunting. Since many customers and intermediaries are likely to participate in DR programs, keeping track of who did what and when and how much they are owed as a result of their contribution is currently a back-office nightmare (**Figure 4**). In many states, including California, there are multiple existing programs offered by different utilities to different customers with widely varied incentives, terms, and conditions.[11] Record keeping, invoicing, collecting and settlement processes become intractable with thousands or millions of customers and multiple intermediaries.

Both problems are going to grow in complexity and scale as more interval meters are installed and more customers participate in time-variable pricing schemes. California, for example, has decided to convert virtually all electrical meters in the state to the smart variety, able to handle time-variable pricing.[12] Other jurisdictions, including the Province of Ontario in Canada,[13] are moving in the same direction. In the absence of standardized protocols, the problem of managing multiple signals and commands, receiving confirmations, recording the response, and settling accounts to millions of customers will simply become unmanageable.

Everyone agrees that the participation of vast numbers of small commercial and residential users is critical if DR programs are to reach their full potential. Yet simple tasks such as attracting and handling the registration of residential users currently are labor-intensive and cumbersome manual processes. Each program offered by each utility to a seg-

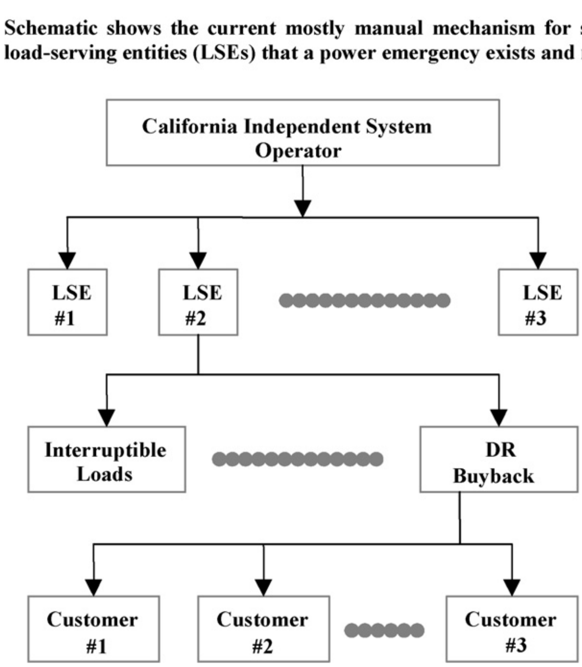

Figure 3: Schematic of the ''As-Is'' State in California

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Alternative state, where the system operator, using secure Internet protocols as the medium of communication, interacts with multiple utilities, intelligent agents, and thousands or millions of participating customers to implement DR

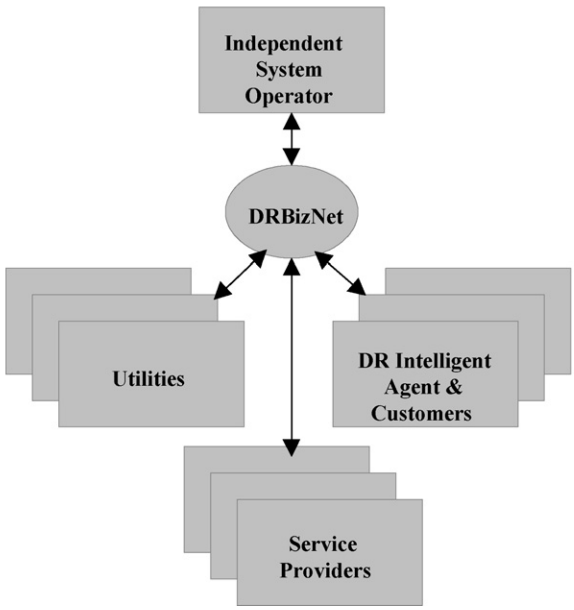

Figure 4: Schematic of the Alternative State

ment of the market uses a unique set of forms and protocols for customer enrollment. Likewise, the process of encouraging vast numbers of consumers to engage in DR in real-time during an emergency is time-consuming and cumbersome, reducing their contribution while increasing the implementation costs.

V. Potential Solutions

Many efforts are underway on how to tackle these key interface and logistical issues.[14] Among the promising solutions is the Demand Response Business Network (DRBizNet) offering a cost-effective approach to implementation of DR in real time.[15] This project, like several others, is focused on addressing one of the toughest challenges to widespread use of DR, namely allowing efficient real-time collaboration among multiple stakeholders, typically the grid operator, utilities, and their participating customers as well as other intelligent agents.[16]

The ultimate goal is to allow requests from the grid operator to curtail load to be transmitted flawlessly and instantaneously to hundreds, thousands, or millions of participating customers and their willingness to shed load immediately registered and aggregated. With such a facility at its disposal, the grid operator could receive acknowledgment of the amount of load reduction available in real time, enabling it to engage in DR rather than rolling blackouts.

Additionally, standardized business protocols allow a better way for utilities and the grid operator to manage their internal business processes including customer enrollment in DR programs, meter management, load shedding, and post-DR settlement processing.

The DRBizNet project has an ambitious goal to reduce the costs and increase the capabilities of DR business transactions a hundred times – reducing costs by an order of magnitude and increasing speed and functionality by similar magnitude.

According to Gaymond Yee, the project manger at California Institute for Energy and the Environment (CIEE), ''The recent field demonstration of DRBizNet proved the project's ambitious efficiency and cost-effectiveness goals, paving the way for great benefits to the people of California – and elsewhere – if the technology is widely adopted.''[17]

California's two regulatory and policy bodies, the California Public Utilities Commission (CPUC) and the California Energy Commission (CEC), respectively, are strong proponents of energy conservation, demand-side management (DSM), and DR. Over the years, CEC has aggressively maintained California's position as the state with the lowest per capita electricity consumption in the U.S. For its part, the CPUC has been a strong advocate of investment in advanced metering infrastructure (AMI) and has set ambitious goals for DR for the IOUs in California.[18] A number of other states, notably in the Northeast, are also considering similar initiatives to expand the

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penetration of DR. Likewise, FERC has been actively encouraging the various independent system operators (ISOs) and regional transmission operators (RTOs) to expand their DR programs.

VI. Not a Panacea

Realistically, however, DR is not a panacea for addressing all the problems associated with managing peak load during a crisis, whether they are caused by shortage of generation, transmission congestion, or unusual spikes in the load similar to those experienced during this past summer's heat wave. Hence, it is no substitute for resource planning, maintaining adequate reserve margins, effective price hedging on the part of loads, or having functional markets for ancillary services and alike.

But the experience of the past few years in competitive wholesale markets suggests that introducing relatively little elasticity in demand through time-variable prices – be it critical peak pricing or real-time pricing – or DR can make a big difference. These demand-side schemes essentially avoid the need to fire up that last, most expensive peaking unit or to engage in involuntary load shedding. At the peak of the 2000–2001 California electricity crisis (**Figure 5**), a fairly small reduction in load could have avoided the costly rolling blackouts[19] – with their significant economic and political ramifications.

Ali Vojdani, the project's lead investigator, is among those who are convinced that the

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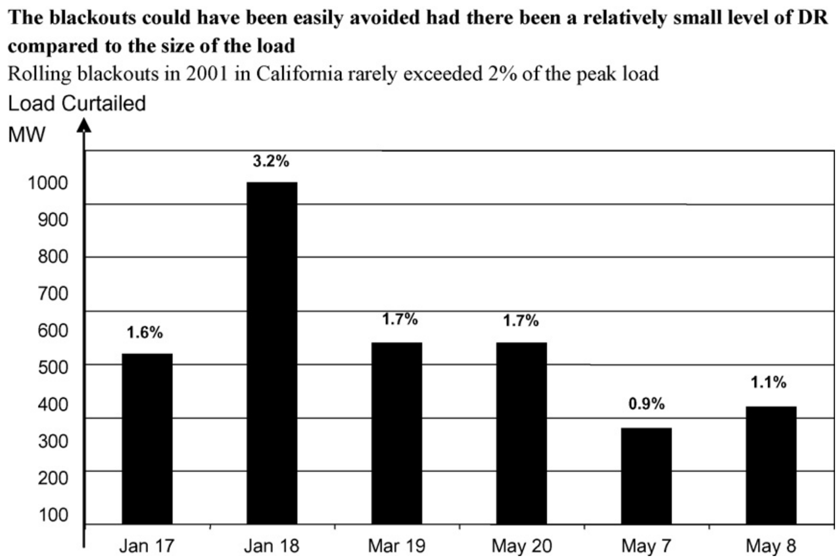

Figure 5: Rolling Blackouts during California's Electricity Crisis in 2001. **Source**: James L. Sweeney, The California Electricity Crisis, 2004, Hoover Press

industry needs *packaged solutions* such as DRBizNet for managing the demand-side of electricity far better than it has been possible up to now.[20] And that is important given the increasing demand for electricity, increasing fuel prices, and environmental concerns such as global warming.■

Endnotes:

1. Stage 1 Alert is called when operating reserves fall below 7 percent, prompting CAISO to issue a public alert and ask for voluntary conservation. Stage 2 Alert is called when operating reserves fall below 5 percent, at which point interruptible loads are curtailed and demand response programs are invoked. Stage 3 Alert is called when reserves fall below 1.5 percent, instituting involuntary load shedding.

2. Programs to shed load in a targeted fashion and with prior consent of customers come under a variety of plans including interruptible loads and air-conditioner cycling programs. Other programs provide incentives for customers to reduce usage during peak demand hours by shifting load to off peak hours, such a time-of-use (TOU) rates, critical peak pricing (CPP), and real-time pricing (RTP). Demand response (DR) is distinguished from these programs by virtue of its sophistication, where participating consumers are enticed to shed discretionary load in response to incentives offered – typically by the system operator.

3. There is a large body of evidence confirming the cost of maintaining an inventory of peaking units, which are only used infrequently. Similarly, a number of studies have documented the costs of service interruptions, which tend to be highly disruptive to customers.

4. *Assessment of Demand Response and Advanced Metering*, FERC, Aug. 8, 2006.

5. McKinsey Q., 2002

6. FERC, *supra* note 4.

7. PJM Press release dated Aug. 17, 2006.

8. ''These (DR) voluntary curtailments reduced wholesale energy prices by more than $300 per megawatt-hour during the highest usage hours,'' according to Andrew L. Ott, PJM vice president – markets. PJM press release dated Aug. 17, 2006.

9. *Benefits of DR in Electricity Markets and Recommendations for Achieving Them*, DOE, Feb. 2006.

10. FERC, *supra* note 4.

11. Examples include various types of interruptible loads, air-conditioner cycling programs, Flex-Your-Power, critical peak pricing (CPP), time-of-use (TOU) rates, and real-time pricing (RTP) options. Each utility offers a variety of programs targeted at different classes of customers.

12. On July 20, 2006, Pacific Gas & Electric Company (PG&E) received approval from the California Public Utilities Commission to convert its entire system – 5.1 million electric meters – by 2011 at a cost of $1.74 billion. CPUC wants the other two IOUs to follow a similar path within a similar time frame.

13. The Province of Ontario has proposed to convert all electric meters to digital variety by 2010.

14. For example, the State of California has established the Demand Response Research Center (DRRC) at the Lawrence Berkeley National Laboratory (LBNL) singly devoted to DR issues.

15. There are, of course, a myriad of other promising solutions, including one developed at DRRC called AutoDR.

16. The project was successfully demonstrated during a field demonstration at the California Energy Commission (CEC) in mid August with participation of CAISO and California's three IOUs.

17. DRBizNet Press Release, Aug. 11, 2006, available at www.DRBizNet.org.

18. California IOUs are currently required to develop and maintain DR programs to manage up to 5 percent of their peak demand, a percentage that is likely to be raised in the future.

19. James Sweeney in Electricity Market Reform: An International Perspective, F. Sioshansi and W. Pfaffenberger, Eds. (Oxford, England: Elsevier, 2006).

20. DRBizNet Press Release, Aug. 11, 2006, available at www.DRBizNet.org.