DEMAND RESPONSE SPECIAL SECTION

THE MISSING LINK

Everyone is in favor of more demand response, but little gets delivered when system operators need it the most.

With growing demand, rising electricity prices, and dwindling reserve margins, utilities and system operators around the country increasingly are focusing on bringing demand into the delicate real-time balancing of supply and demand. This elusive goal has preoccupied the industry for more than 30 years. Starting with relatively primitive and inflexible schemes, such as interruptible loads or time-of-use pricing (TOU),[1] the industry gradually has become more sophisticated.

Schemes such as time-variable pricing—also called real-time pricing (RTP)—and critical peak pricing (CPP) increasingly are being offered. In fact, the Energy Policy Act that Congress passed in August 2005 makes it mandatory to provide such tariffs to virtually any customer who wants it.[2]

At the same time, state regulatory commissions in a number of states, notably California, have decided that the time for a virtual switchover to interval smart meters with two-way communication capabilities has arrived, encouraging utilities to undertake massive investments in so-called advanced metering infrastructure (AMI).[3]

As more smart meters are installed and more utilities offer time-variable prices, more customers are expected to enroll in these programs, enhancing the system operators' ability to better manage the peak demand. Among the most promising concepts is the idea of demand response (DR), where customers volunteer to reduce electricity consumption during peak demand periods in exchange for financial incentives.

Voluntary shedding of discretionary load in response to real-time price signals—akin to the airlines' practice of getting a few passengers off an overbooked flight so the remaining passengers can get the service they need—is the industry's holy grail. Its key significance is that it is voluntary; customers are not denied service, but rather they choose to forgo service in exchange for incentives offered.[4]

When supplies are tight, customers with discretionary loads, like airline passengers with flexible schedules, agree to get off, and do so only when the incentives are sufficiently attractive. And just as the real-time auction that takes place at the boarding gate, where the rewards offered rises to get sufficient number of passengers to come forward, the system operator can adjust the incentives to get sufficient number of megawatts off the network.

The problem, as experienced during this past summer's heat wave, is that typical system operators do not have the necessary means to get anywhere near the full potential of DR. What they currently can get typically is the "tip of the iceberg," a mere fraction of the discretionary load that may be available. The consequence is that more expensive peaking units are brought on line to serve spiky loads—or in extreme cases—rolling blackouts are invoked to prevent the system from collapsing altogether. Both options are far more expensive than selective, targeted and voluntary DR.

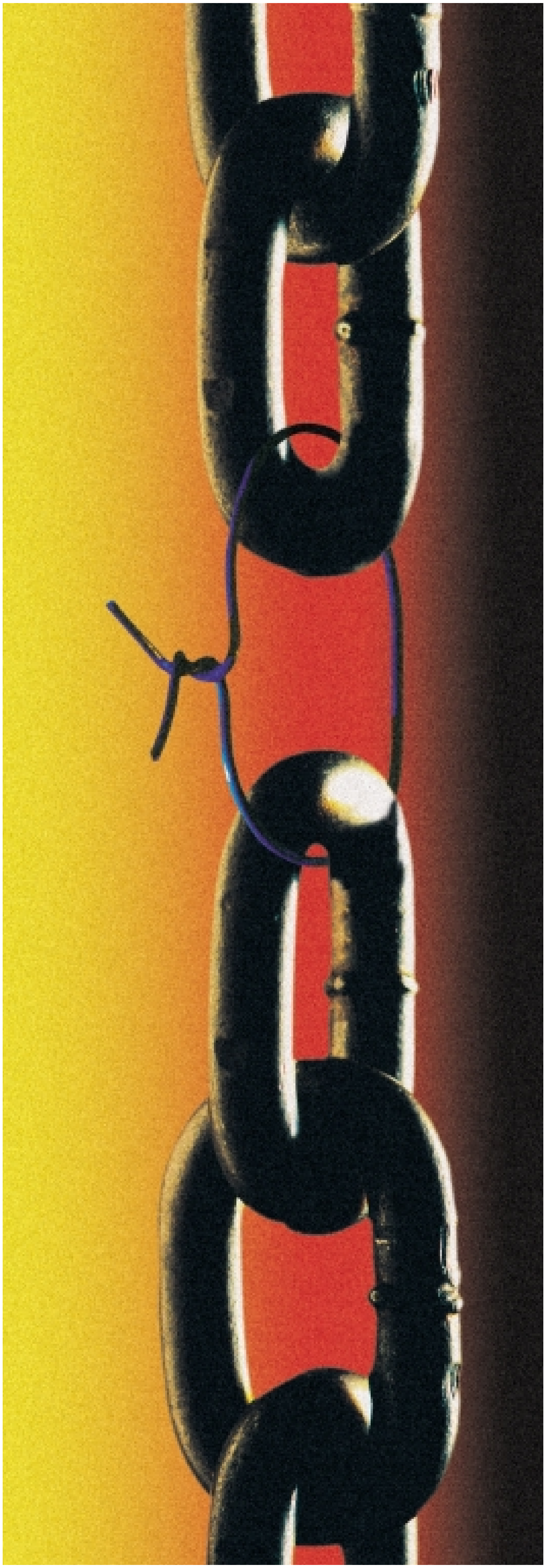
Returning to the airline analogy, the former would entail keeping extra empty planes (*i.e.*, peaking units) and crew on hand to fly a few overbooked passengers to their destination—even if many are willing to take a voucher and wait for the empty seats on the next flight, which is an expensive proposition. The latter would be tantamount to canceling the flight—denying service to a large number of passengers—just because a few could not be accommodated, a financially suicidal idea. No airline would dream of doing either of these, nor should any cost-conscious utility or system operator.

How Much DR Is There When You Really Need It?

Study after study has confirmed the presence and the cost-effectiveness of demand response (DR) as a resource option when capacity is tight. A recent report by the Federal Energy Regulatory Commission (FERC), for example, provides some evidence.[5] One study claims annual savings of $15 billion per

Illustration by Horia Stefanescu

BY SCOTT NEUMANN, FEREIDOON SIOSHANSI, ALI VOJDANI, AND GAYMOND YEE



year in the United States for shifting 5 to 8 percent of consumption from peak to off-peak hours and for depressing peak demand by 4 to 7 percent.[6] 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.[7]

But why bother with hypothetical studies when there is real-world empirical evidence? During the August 2006 heat wave, PJM Interconnection reported cost savings totaling $650 million attributed to DR programs.[8] On Aug. 2, 2006, alone, when PJM set a new peak-load record of 144,796 MW, it reported DR savings of $230 million—comparing the incentives paid to DR program participants versus the cost for acquiring peaking generation as determined by the market on that day.[9] Similar testimonials are available from other ISOs and RTOs around the country.

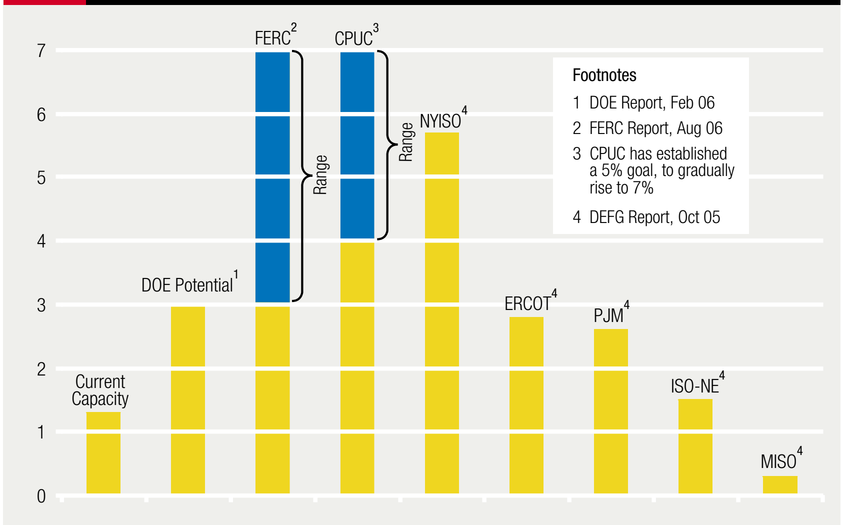
Likewise, a growing body of literature has documented the potential scale of DR as a resource (*see Fig. 1*). A U.S. Department of Energy study estimated current DR capacity around 9,000 MW, roughly 1.3 percent of the U.S. peak load, while putting the full potential around 20,500 MW or 3 percent of the peak load.[10] A more recent study by the Federal Energy Regulatory Commission (FERC) concluded: "Nationally, the total potential DR resource contribution from existing programs is estimated to be about 37,500 MW."[11] The same study puts "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.

Finally, empirical evidence from research conducted in a variety of settings involving different schemes and different segments of population has demonstrated that when confronted with time-variable pricing and empowered with enabling technology, such as smart thermostats, average consumers respond to signals in tangible and significant ways.

A major study in California, for example, reported that on average, residential consumers on CPP-type tariffs reduced peak-period energy consumption by 13 to 16 percent. The percentage load reduction increased to 27 percent for those with "smart" thermostats.[12] Another study of commercial and industrial consumers on RTP tariffs around the country found average peak-load reductions of 12 to 33 percent.[13] Consumers, in short, respond to price signals in highly predictable ways—whether it is electricity, gasoline, or use of congested roads. As economic theory would predict, there is no such thing as inelastic demand (*see sidebar, "There Is No Such Thing as Inelastic Demand," p. 54*).

With such overwhelming theoretical and empirical evi-

Fig. 1 **Potential for Reducing Peak Load From Demand Response**



Source: First 2 bars (from right) are from DOE study, 2006; third bar from FERC report, 2006; fourth bar is the current and future goals established by the California Public Utilities Commission (CPUC) for the three investor-owned utilities in California; all others are from an October 2005 study by Distributed Energy Financial Group titled A Critical Examination of DR Programs at the ISO Level.

dence, why aren't we seeing more DR when it is needed the most, during emergency periods? The answer is not as easy as one might like, but boils down to two major obstacles:

- Lack of enabling technology to administer time variable pricing; and equally important
- Lack of standardized transaction management practices and business protocols, which are critical if DR is to become more widespread among large numbers of customers.

The first obstacle is widely recognized and understood.[14] Time-variable pricing and DR cannot be administered without sophisticated metering. Moreover, for such schemes to work, participating consumers must be able to receive and respond to signals in real time. FERC's recent survey puts the current penetration of smart meters below 6 percent nationwide[15]—the glass is clearly not half full, it is 94 percent empty. Moreover, only 5 percent of U.S. consumers currently are on some form of time-based tariffs. FERC, which surveyed 3,366 entities and analyzed responses from 1,939, reported that only about 200 entities out of roughly 3,000 currently offer such programs in the United States. Clearly, there is plenty of room for improvement.

The second obstacle is less understood and, in our view, equally daunting. In simple terms, cost-effective implementation of DR requires:

- Fast, reliable, automated and secure communications between multiple players in the DR domain in real-time; and
- Standardized protocols for customer enrollment, DR

There Is No Such Thing as Inelastic Demand

As anyone who has taken Economics 101 can attest, one of the main tenants of economic theory is the law of supply and demand, a critical component of which is that consumers respond to rising prices by reducing consumption—to varying degrees. The reduction in consumption based on a rise in price, known as price elasticity of demand, varies depending on the item in question and whether there are reasonable substitutes. Price elasticity may be low if the good is a basic essential for which there are no substitutes—making demand relatively inelastic.

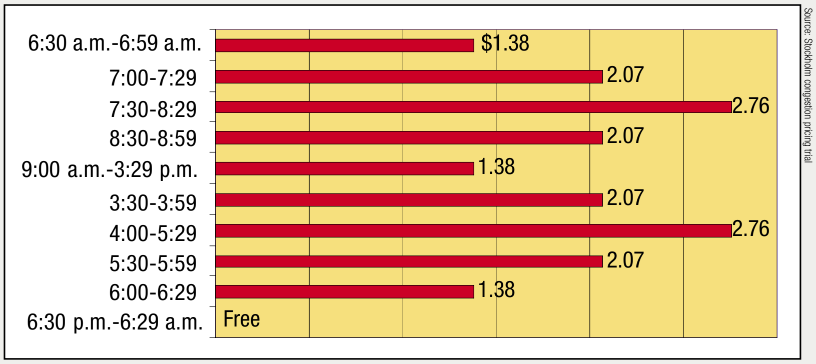
In practice, however, there virtually are no goods for which there are no substitutes, if one is willing to take a broad, longer-term view of the definition of "substitute." Take the case of gasoline. At first blush, one might say that there are no substitutes—and thus if price of gas at the pump goes up, drivers will continue to buy the same amount. But this clearly is not true. Walking, bicycling, car pooling, taking the bus or the metro, and telecommuting offer reasonable alternatives to driving. Hence, when prices rise, gasoline consumption drops, which in turn puts downward pressure on prices. But taking a longer-term view, there are even more substitutes including higher efficiency cars, hybrid vehicles, and converting to ethanol or compressed natural gas.

Nobel prize winning economist William Vickery has gone a step further, predicting that congested roads can be cleared off during rush hour through economic incentives, by charging those who make use of busy roads during peak driving hours. The same principle applies to sophisticated schemes used by modern day independent system operators (ISOs) to manage transmission congestion in electric networks.

In a big experiment involving the city

Road congestion pricing in practice – City of Stockholm, Sweden

Variable pricing scheme used in Stockholm during the experiment, April 05-06



of Stockholm, Sweden, between April 2005 and 2006, drivers were confronted with time-variable congestion pricing (see accompanying graph), similar to those used in RTP or CPP in electricity markets. Those who chose to use busy roads during heavy traffic periods had to pay a premium configured to correspond to their contribution to the traffic snarls. Those who drove during off-peak periods, after 6:30 p.m. and before 6:29 a.m., could use the network for free.

What happened is what can be expected to happen in electricity markets with time-variable pricing. Consumers adjust their behavior to avoid expensive periods. In the case of Stockholm, the use of public transit systems increased by 6 percent while inner city buses experienced a 9 percent increase in ridership. Traffic volumes during peak hours in some of the busiest access roads to downtown dropped anywhere from 9 percent to 26 percent—solid proof that there is no such thing as an inelastic demand.

If such schemes work and produce impressive results, why don't more cities adopt them? The answer has to do with the complexities and costs of implementation. Greater Stockholm, which has a population of less than 2 million, was a relative snap. The city center consists of several interconnected islands with 23 main entry points, where cameras and recording devices identify each passing car through a transponder, or by reading its license plate. Drivers would be billed via their banks or through the country's tax collection authority. Yet the scheme cost $525 million to set up. A similar system for bigger and more complex cities such as London, Los Angeles, or Bangkok would cost a bundle. ■

—***SN, FS, AV, & GY***

event notification, and customer participation followed by timely and accurate business processes for invoicing and settlement.

Unless these two issues are successfully addressed, wide-scale implementation of DR will remain limited, slow, and problematic, especially if there are large numbers of small consumers.

Currently, system operators have limited capabilities to implement DR for a number of reasons. Most important, the protocols for enrolling customers and communicating with them when an emergency occurs is time-consuming, error-prone, and mostly manual. Frequent delays to get a signal out, receive confirmation, and obtain tangible results are common. This means that, in many cases, the operator may resort to involuntary load shedding simply because of inherent delays or uncertainties in implementing DR programs.

Today, when an emergency occurs, the system operator must send an alert to multiple utilities informing them of an impending crisis and requesting a response. This signal typically goes from the ISO to several utilities that pass it on to participating customers using multiple channels. The process is notoriously cumbersome and time consuming. The ISO, faced with an emergency 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, as happens at the airport boarding gate, referring to the airline analogy. For such an interactive scheme to work, an even higher level of sophistication, automation, aggregation, and confirmation is needed. We are not aware of too many working examples of such schemes with multiple parties and large numbers of consumers successfully operating in real-time.

The second problem is principally one of handling multiple business transactions including accounting, billing, and settlement protocols. 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 to a DR emergency currently is a back-office nightmare. In most cases, utilities offer multiple programs to different customers with widely varied incentives, terms and conditions.[16] Record keeping, invoicing, collecting, and settlement processes become intractable with thousands or millions of customers.

Both problems are going to grow in complexity as more interval meters are installed and more customers participate in time-variable pricing programs. As already mentioned, California is about to convert virtually all electrical meters in the state to the smart variety.[17] Other jurisdictions, including the province of Ontario in Canada,[18] 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 simply will become unmanageable.

Participation of vast numbers of small commercial and residential users is considered critical if DR programs are to reach their full potential. Yet simple tasks such as attracting and enrollment of residential users currently is a labor-intensive and largely manual process. Each program offered by each utility to a segment of the market uses a unique set of forms and protocols for customer registration. Likewise, the process of enabling vast numbers of consumers to engage in DR in real-time during an emergency is time-consuming and haphazard.

The Way Forward?

Lack of enabling technology is widely recognized and is gradually being addressed through efforts to convert more consumers to interval meters as well as increasing the penetration of time-based rates. These efforts will take time and billions of dollars of investment to bear fruit. In the case of Pacific Gas & Electric Co., among the nation's largest privately held utilities, the cost of a complete rollover of 5.1 million electric and 4.2 million gas meters over a six-year time frame is estimated around $1.74 billion. Given the large number of meters and customers in the country, the size of the task is easy to grasp.

There are efforts now underway to tackle DR's key interface and logistical issues.[19] Among the promising solutions is Demand Response Business Network (DRBizNet), offering a cost-effective approach to implementation of DR in real time.[20] This project, briefly described in the sidebar (*"The Other Mundane but Critical Obstacle"*), is, like several others, focused on addressing the 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 DR service providers.[21]

Realistically, however, DR is not a substitute for resource planning, maintaining adequate reserve margins, effective price hedging on the part of loads, or having functional markets for ancillary services and the like. But the experience of the past few years in competitive wholesale markets around the country suggests that introducing relatively little elasticity in demand through time-variable prices—be it

The Other Mundane but Critical Obstacle:

Standardized Business Protocols

When operators face capacity shortages, the alternatives are either to resort to rolling blackouts, which no one likes, or to plead with customers to drop discretionary loads, usually with financial incentives.

For such a scheme to work in practice, the system operator needs a packaged solution that allows requests to curtail load to be transmitted flawlessly and instantaneously to hundreds, thousands, or millions of participating customers, with 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.

In addition, standardized business protocols are needed for DR schemes requiring multiple intermediaries (*e.g.*, utilities) and a large number of customers to work. Such transaction protocols are needed 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 Stockholm road congestion pricing analogy described on pp. 54-55 has obvious parallels to implementation of DR in the electric-power sector. The first requirement is to convert all customers to smart meters, which can record interval consumption data. Moreover, a two-way communication system is needed to send signals out and record their response, as was done with the car transponders. But that is not all. The system must record how each customer responded to the price signals, and it must calculate their monthly electricity bills based on how they responded during the emergencies. These mundane but important back-office business transactions among multiple parties are believed to be among the most daunting challenges facing wide-scale implementation of RTP and DR in the electric power sector.

The Demand Response Business Network (DRBizNet) project has an ambitious goal to 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.

The project that was demonstrated successfully in a live field demonstration in August 2006 in California 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.[1]

The California Energy Commission (CEC), a strong proponent of DR, funded the study through the Public Interest Energy Research Program. Other study participants included the California Independent System Operator, Pacific Gas & Electric Co., Southern California Edison Co., San Diego Gas & Electric Co., DR service provider Infotility, and a few representative commercial and residential customers. The demonstration was conducted by a team of consultants led by Utility Integration Solutions Inc. (UISOL). For information on DRBizNet, visit *www.DRBizNet.org*. ■

—***SN, FS, AV, & G Y***

Endnote

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

critical-peak pricing, real-time pricing, or DR—can make a big difference. Just as removing a few vehicles off busy roads during rush-hour traffic eases congestion, getting as little as 1 to 3 percent of the peak load off the network saves bundles of money, not to mention the menace of rolling blackouts.

We, like many others, are convinced that what the industry needs is packaged solutions for managing the demand-side of electricity far better than has been possible up to now.[22]

Scott Neumann is CTO of Utility Integration Solutions Inc., (UISOL), a consulting firm based in Lafayette, Calif. He can be reached at sneumann@uisol.com. Fereidoon (Perry) Sioshansi is president of Menlo Energy Economics, a consulting firm based in Walnut Creek, Calif., he can be reached at fpsioshansi@aol.com. Ali Vojdani is CEO of UISOL. He can be reached at avojdani@uisol.com. Gaymond Yee is a research coordinator at California Institute for Energy & Environment (CIEE), at Berkeley, Calif. He can be reached at gaymond.yee@ucop.edu.

Endnotes

1. The term "primitive" in this context is used to contrast unintelligent and involuntary schemes such as interruptible tariffs, where customers don't have an option to decline service interruptions, as opposed to more intelligent schemes where customers can decide if they wish to participate or opt out and pay a price premium.
2. Following the passage of the Energy Policy Act in August 2005, there has been increased interest in smart meters, time-variable pricing, and demand-response programs.
3. Following the 200-01 electricity crisis, the California Public Utilities Commission (CPUC) started a proceeding to persuade the investor-owned utilities in the state to explore the costs and cost-effectiveness of installing smart meters for all consumers and engaging in wide-scale RTP and DR programs.
4. This distinction is highly significant because customers who sign up for interruptible loads often drop out of these programs following emergencies when their service is repeatedly interrupted, as happened in California during the 2000-2001 electricity crisis.
5. *Assessment of Demand Response & Advanced Metering*, FERC, 8 Aug 06.
6. *McKinsey Quarterly*, 2002
7. *Assessment of Demand Response & Advanced Metering*, FERC, 8 Aug 06.
8. PJM Press release, 17 Aug 06.
9. "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 17 Aug 06.
10. *Benefits of DR in Electricity Markets & Recommendations for Achieving Them*, U.S. DOE Feb 06.
11. *Assessment of Demand Response & Advanced Metering*, 8 Aug 06, FERC.
12. *Impact Evaluation of the California Statewide Pricing Pilot,* CRA International, 2005.
13. *Real-Time Pricing as a Default or Optional Service for C&I Customers: A Comparative Analysis of Eight Case Studies*, Lawrence Berkeley National Laboratory, 2005.
14. Both DOE and FERC reports mention the lack of enabling technology and provide suggestions on how to overcome these barriers.
15. *Assessment of Demand Response & Advanced Metering*, FERC 8 Aug 06.
16. 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 *(Cont. on p. 66)*

CIOs Under Pressure

(Cont. from p. 39)

grown application that we make available to the constituents.

Fortnightly: What portion of BPA's budget goes to IT?

LB: Our expense budget for 2007 is $58 million for IT. For 2006, our total operation revenues were $3.4 billion. After expenses, our net operating revenues would be $872 million.

Fortnightly: If you had a blank check to change anything at your organization, what would you do?

LB: I think this enterprise GIS movement is the way I would answer that. GIS holds so much potential for us, and I think it is very appealing to IT folks because it's exciting. It's new and impressive technology. It gets that information into the hands of people in the field, and I think it will allow them to make better decisions and make better use of their time. In the long run, that should be good for the agency.

The other thing that's important to state is how important security is to us. If you look into the future and ask what concerns us the most, I'd have to say security is becoming more and more of an issue for us to keep our eyes on.

Because we're part of the government, protection of personally identifiable information is just critical to us. We have to make sure our systems comply with all of the requirements from the Department of Energy as well as the White House. It's not a small issue. Cyber-security, protection of our grip ops, SCADA security—that's the one thing I want to make sure we do a good job of in the future.

The leadership here supports this. We have a cyber-security group now within IT that reports up to me, and that group is being challenged to do more and more. Staffing in that group will increase in 2007.

The Green Effect

(Cont. from p. 45)

Wang and Joel Swisher, Rocky Mountain Institute, August 2006.

3. "Changing How People Think About Energy," Marjorie Isaacson, Larry Kotewa, and Anthony Star, Community Energy Cooperative and Michael Ozog, Summit Blue Consulting, August 2006.
4. Quantum Consulting, "Working Group 2 Demand Response Program Evaluation – Program Year 2004 Final Report," December 2004
5. "Direct Energy Feedback Technology Assessment for Southern California Edison Company," prepared by Lynn Fryer Stein and Nadav Enbar, EPRI Solutions, March 2006. It should also be noted that there is a risk of self-selection bias toward those more interested in conservation.
6. Sarah Darby, Oxford University, "Making It Obvious: Designing Feedback into Energy Consumption," in Energy Efficiency in Household Appliances and Lighting, edited by Bertoldi et. al., Springer, 2001. Also see "Advancing the Efficiency of Electricity Utilization: Prices to Devices," Background Paper for 2006 EPRI Summer Seminar.
7. Wang and Swisher, *op. cit.*
8. "A Survey of Time-Of-Use (TOU) Pricing and Demand-Response (DR) Programs" Energy and Environmental Economics Inc., for U.S. Environmental Protection Agency, July 2006.
9. "Analysis of NOx Emission Reduction Potential From Demand Side Resources" Art Diem, U.S. Environmental Protection Agency, presentation at Ozone Transport Commission, September 2006.

The Missing Link

(Cont. from p. 57)

utility offers a variety of programs targeted at different classes of customers.

17. On 20 July 2006, Pacific Gas & Electric Co. received approval from the CPUC 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.
18. Province of Ontario has proposed to convert all electric meters to digital variety by 2010.
19. 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.
20. There are, of course, a myriad of other promising solutions, including one developed at DRRC called AutoDR.
22. The project was successfully demonstrated during a field demonstration at the California Energy Commission (CEC) in mid August with participation of the California ISO and California's three IOUs.
22. DRBizNet Press Release, 11 Aug 2006 available at www.DRBizNet.org.

Advertising Index