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FEATURED ARTICLES

Making the Business Case for Demand Response

If you're an energy or facility manager, chances are you've heard of demand response (DR). If you have heard of demand response, chances are you have a slightly different definition of what it means and the upsides and downsides for your organization. To most customers, says Joel Gilbert, CEO of Apogee Interactive Inc. and founder of the Peak Load Management Alliance, the term demand response means, "We demand that you respond." No matter how one defines DR, there may be compelling financial and "good corporate citizen" reasons why participating in a DR program makes sense for your organization.

Defining Demand Response
Every independent system operator (ISO) and a great many utilities are designing programs that give them more options for reducing load in times of extremely high energy consumption. These programs are essentially agreements between the utility and energy users that grant reduced rates or rebates to customers who are willing to cooperate by reducing load at the utility's request. These agreements, which may be part of demand-response, curtailment, load management, or load-shedding programs, are designed to benefit the whole utility system. The underlying concept is that when each of many customers conserves a little, there will be enough power for everyone. Each type of program offers slightly different policies and terms. Some stipulate mandatory contract terms, some are completely voluntary, and others are intended to be used for frequent, even daily, energy management.

DR programs vary widely in complexity and technical requirements. Programs such as time-of-use rates, in which load management is more of a routine or daily activity, may not require advanced metering or control capability. More-sophisticated DR programs such as real-time-pricing and demand-bidding programs, which require advanced meters and more detailed and current energy-use information, may also require a dedicated human resource to monitor energy prices in near real time. In this article we focus on voluntary pay for performance programs.

There are two main types of pay for performance programs: price response and reliability (demand) response. **Table 1** below summarizes these types of DR programs that are currently being offered by the New England ISO.

Price-response programs typically involve low fixed (metering, controls) and variable (fuel, labor) costs. However, there is not a lot revenue potential unless you respond frequently. Most often these programs are purely voluntary ones where the participant decides when to participate and for what duration. The penalty for not responding is a higher energy price during peak times. Key issues that you will need to consider include balancing any technical and man-hour costs with the potential number of and duration of high-price periods and the associated potential penalty. Participants in price-response programs usually employ fairly low-tech opportunities to reduce load (turning things off, manual shutdowns, and the like)

Reliability programs are ones where a customer responds to system reliability conditions as determined by either the utility or the ISO. Basically, customers agree to make resources available when called upon by the program administrator. These programs are usually dispatched less often than price-driven programs and typically are the result of events such as unusually high temperatures during times of peak demand. These types of programs typically require more metering and data-transfer functionality—usually needing a data transfer in at least 5-minute intervals so that grid operators can monitor the reliability picture. Payments to participants are typically higher, but this can also be the case for the associated costs (such as advanced metering). Key questions you will want to

Table 1: ISO New England 2004 Demand-Response Programs

	Reliability based	Reliability based	Price based
Program name	Real Time Demand Response	Real Time Profile Response	Real Time Price Response
Customer type	Individual	Group	Individual
Minimum reduction	100 kW	200 kW	100 kW
Notification	Respond to ISO control room request	Respond to ISO control room request	Notified by ISO that wholesale prices are forecasted to exceed $0.10/kWh either the night before or the day of the event
Response time	Within 30 minutes or 2 hours of ISO request. Customer must elect option when applying.	Within 2 hours of ISO request	Voluntary. Customer decides when and for how long.
Energy payment rate and terms	Greater of real-time price or guaranteed minimum $0.50/kWh for 30-minute response and $0.35/kWh for 2-hour response.	Greater of real time price or guaranteed minimum $0.10/kWh	Greater of real time price or guaranteed minimum $0.10/kWh
Duration of demand-response event	Minimum 2-hour guaranteed interruption	Minimum 2-hour guaranteed interruption	Price-response “window” open as early as 7 a.m. and remains open until 6 p.m.
Monthly capacity payment ($/kW)	Yes	Yes	No
Metering requirement	5-minute data via internet-based communication system (IBCS)	Performance determined through statistical analysis	Hourly data submitted either daily or monthly

Note: ISO = independent system operator; kW = kilowatt; kWh = kilowatt-hour. Source: Platts; data from ISO New England ask include: How much load can your facility reduce with 30 minutes/two hours advance warning? Can this load be reduced manually or do you have the controls in place to automate things like reducing setpoints, shutting down processes, or activating on-site generation?

Making the Case

The decision to participate in a demand-response program is driven primarily by economics: whether the benefits are greater than costs. Bob Laurita, senior program administrator for ISO New England, explains that, first and foremost, customers are in it for the money. "There must be a significant value proposition and almost all prefer a voluntary option versus mandatory. Now they will go with a mandatory option—but there has to be even more money in it for them, because they are relinquishing some element of control inside their facility to someone else."

Financial benefits include the payments for participation and savings in energy and demand charges. Payments may vary widely and come from multiple sources including the energy service provider, the grid operator, and other intermediaries or government agencies. Costs may include those for equipment upgrades and modifications, electric usage metering and reporting, personnel costs, and potential reductions in product output.

It's important to note that for most organizations, the opportunities to reap huge sums of money on a regular basis for participating DR programs can vary widely. So basing a business case purely on demand-response financials won't necessarily get you to the top of the radar screen. "You're asking facilities to do things for a relatively short period of time. While they may be paid up to 50 cents per kilowatt-hour or higher for the energy that they save, there's not a lot of hours or days available," states Laurita. However, he also explains that when it comes to price-response programs—where the customers decides how much load they will reduce and when to reduce it—it's really up to them regarding how much revenue they will see. For instance, a fairly large pharmaceutical firm in the New England area participated in 30 separate price-response events (totaling 239 hours) in 2003. The firm's average demand reduction was 1.3 megawatts (MW) and it received an average payment of $0.104 per kilowatt-hour (kWh) for a total energy payment of $34,000.

There are also other things to consider when building the case for DR. Improving the shape of your load profile has several benefits and should be the cornerstone of your business case for participating in DR program. Improving your load shape reduces the risk the supplier has in serving your facility's load. Facilities that can demonstrate the ability to manage hourly usage or to respond to wholesale price spikes or reliability events reduce volatility for their suppliers and thus reduce retail prices. In states that allow a choice of retail electricity providers, a better load shape will significantly lower the facility's overall electricity rate. In regulated states, improving the load shape will reduce the facility's peak demand charges. These are savings you can enjoy throughout the year.

The Power of Load Profile Data
To increase participation in its peak load management program, Connecticut Light and Power (CL&P) got help from Predicate LLC and RLW, two energy service companies, to conduct a series of audits for industrial customers during the spring and summer of 2000. The preliminary assessment of the load profile data for a wire processing facility that CL&P served showed that its peak demand of 1,900 kilowatts (kW) occurred on only one day. The data also showed that the demand at the facility varied widely on weekdays, with several peaks and valleys occurring throughout each day. Further analysis showed that demand exceeded 1,360 kW only 5 percent of the time, and that if it could be kept under this level, the facility would save $31,000 per year.

To identify the source of the peak demand, the consultants installed temporary submeters at strategic points throughout the facility. The facility then agreed on a plan to install a 12-point energy management system (EMS) for $25,000. The EMS would enable the facility staff to continuously monitor the main and ancillary loads and keep the facility under the 1,360-kW demand cap. The savings of $31,000 per year meant a payback period for the EMS of only 10 months. The system also enabled the facility to better participate in CL&P's demand-response programs, providing additional energy cost savings.

In fact, improving your facility's load shape on an ongoing basis will generally result in much greater cost savings than participation in demand response programs alone. More detailed energy information will often reveal opportunities to improve energy efficiency.

Other things to consider include the "feel good" or "good corporate citizen" element in participating. Some DR participants state that they like the fact that they can tell their own customers they are helping to keep the lights on and maintain reliability for the community as a whole. Being able to go to senior management and say that your organization can help keep the power on over at the local hospital, police station, or fire station can be effective in helping make the case for participating in DR. Another way to pitch the benefits that DR can bring to a community as a whole is to emphasize mitigating rate increases. Roche Pharmaceutical in Palo Alto, California, sees the connection between it's participation in DR and the fact that City of Palo Alto Utilities has been able to maintain the lowest power rates in the area. The whole community avoids rate increases in part because of Roche's contribution to managing system peak demand.

Opportunities for Load Reduction

Once a facility decides to join a program, it must consider what curtailment actions to take. These actions can vary from event to event, but it makes sense to develop a specific curtailment plan that describes the range of options and how they will be implemented. Many utilities and energy service providers offer assistance in identifying opportunities and developing a curtailment plan. The plan can then be implemented during the curtailment event—either manually by the facility management staff, or automatically using an energy management system.

Common facility management practices include turning off specific lights or light circuits, changing thermostat settings on space-conditioning systems to reduce operating times, cycling or curbing ventilation fans, and shifting cleaning and maintenance crews to off-peak hours. These are relatively low-risk options.

The Power of Building Controls
During the summer of 2002, PETCO Animal Supplies Inc., a national pet supply chain, not only kept its California customers and their pets happy but also conserved energy and curtailed load during peak hours. Granted, a pet store may appear to have greater flexibility than fancy boutiques or other types of retailers to change lighting levels, temperatures, and other parameters without reducing customer satisfaction.
But PETCO's concern for the comfort, health, and safety of the animals, employees, and customers in its stores during load curtailment makes this experience an important early example from which other retailers can learn. Through an HVAC and lighting demand-response program, PETCO shaved nearly $65,000 off its monthly energy bills and saved California about 5.5 MW of curtailable load. Because of such results, in October 2002, PETCO was awarded the Peak Load Management Alliance 2002 Demand Response Achievement Award for an end user.

The larger opportunities and benefits, as well as the risks, come from changes to production processes, such as those described below. Some of these measures are appropriate for ongoing peak reduction/load leveling, while others measures are appropriate for more drastic and temporary load reduction, as in pay for performance demand-response programs. Medium-risk options include slowing down processes, taking advantage of storage capabilities through such means as refrigeration, and running standby equipment such as generators. Higher-risk options include stopping the processes and shifting production to earlier or later periods. However, even some of these more dramatic production changes can be accommodated readily with good planning and management.

The Power of Rebates and Incentives
The Lafarge Building Materials cement plant in Ravena, New York, recently installed a sophisticated power-monitoring system from Pegasus, including 65 submeters installed throughout the plant that measure and record energy usage and demand data. The submeters are electronic meters connected via Ethernet cables that measure kilowatt-hours and kilowatts, power factor, harmonics, voltage, and current on a per-phase basis, among other parameters. Through its participation in New York State Energy Research and Development Authority's Peak Load Reduction program, Lafarge received an incentive payment of more than $205,000 for the system, which was about 75 percent the total cost.

To reduce its load during peak demand periods experienced by the New York Independent System Operator, Lafarge temporarily shuts down the crushing mills (machines with loads up 3,300 kW) and instead uses stockpiled, previously crushed materials in its kiln operations. The power-monitoring system allows Lafarge to document the reductions in demand and consumption during the curtailment periods, enabling the company to receive payments for its curtailed usage. Lafarge also uses the power-monitoring system to measure and analyze the kW/ton of product being processed so that it can adjust operations to improve energy use and overall productivity. As Donald Britt, an electrical engineer at Lafarge told us, "Electricity is an important raw material for us, so it very important that we measure and manage it properly."

Ask Yourself the Right Questions

One of the first things you should do is determine what kind of resource your organization can provide. Do you simply want to be a resource that will participate in DR when wholesale prices are high? Under this scenario, the credits, payments, or settlements that you will reap will be fairly modest—usually you'll only receive the wholesale price or some guaranteed minimum payment. Probing a little deeper, ask yourself: Can you be a resource that can respond rapidly to a reliability problem? Chances are the payments you will be awarded can be substantially larger—you will be paid not only for the energy your facility did not use but also for agreeing to be a reliability resource in the form of a capacity payment.

Not all organizations are good candidates for DR. Prime candidates for demand response include facilities for which several of the following conditions apply. How many of the issues below apply to your facility or organization?

- Peak electric demands are high.
- There is exposure to fluctuating spot market electric prices.
- Interval meters are installed or can be readily installed.
- There is a champion for energy management and demand response at the facility.
- Options are available to reduce demand for a few hours (by such means as increasing production before and after the curtailment event or slowing down processes during the event).
- There is flexibility in scheduling of certain production processes.
- Backup generation capacity is available that is permitted to operate in nonemergency conditions.

The Communication Factor

It's also important to understand that demand response at its most basic is about information exchange. A customer reduces load at the agreed-upon time, and somehow this information must be measured and verified by program administrators. A critical part of evaluating a DR program is having a clear understanding of the technical and information exchange requirements involved. For instance, under the New England ISO Price Response program—where customers voluntarily agree to reduce load in response to wholesale market prices —all that is required for participation is hourly metered data either on a daily or monthly basis. On the other end of the spectrum are programs that require advanced meters, which can be costly in some cases.

Most utilities in the United States collect hourly usage data from their larger commercial and industrial customers, although the data are typically retrieved only once a month. If your facility does not have a meter capable of transmitting hourly usage data, check to see if one is offered as part of the program or if there are subsidies available from your local utility or ISO. Fees for the installation of basic and advanced meters can run from no cost or a monthly service fee up to a one-time installation fee of a couple hundred dollars.

For more information on demand-response programs in your area, contact your local utility or independent system operator.

Enterprise Systems: Different Perspectives, Different Needs, Same Goal

Information integration has a different meaning and value to electricity providers and users, but it's all about the enterprise. The phrase "enterprise system" has been around for several years. It refers to a fairly common dream of having one repository of data that's been gathered from many smaller systems and functions or from many company departments and locations. Enterprise systems are combinations of hardware and software that can collect, combine, store, and sort a mountain of data. What makes them "enterprise" in nature is that they are companywide and can both accept data from multiple sources and be tapped by multiple employees simultaneously.

Corporations of all types have been considering the possibilities of information integration since the advent of fast and affordable computing power. This article compares two roles of enterprise systems: enterprise energy management (from the perspective of an energy consumer) and enterprise integration (from the perspective of a utility). What's common to both is the imperative of viewing business processes from the top down. Enterprise energy management is about efficiency, synergy, and integration. For consumers, it enables corporate energy management rather than single-building control. For utilities, it means proactive multisystem management as opposed to reactive isolated departmental tasks.

Value for Energy Managers

The mission of an enterprise system is to extract value from raw information to improve a company's business process and positively affect its bottom line. From a consumer's perspective, enterprise energy management allows a corporate energy manager to compare his facilities on the basis of their kilowatt-hours consumed per square foot or per widget of production. He can then benchmark this metric against either the best-performing site or against a national average. Exception reports allow him to focus on nonperformance. Cost allocation reports allow him to assign responsibility for consumption to energy cost centers that may reside in several utility territories.

For an enterprise system to have value, it must be able to present information at the enterprise rather than the facility level. Unfortunately, utilities serve specific geographic areas and are not able to support the data needs of regional or nationwide corporations.

One of the goals of deregulation was to enable the possibility of having a single electricity or gas retail provider for multiple facilities, regardless of location. That retail provider would be able to convert an aggregated bill into benchmark and allocation reports for the whole corporation: one provider, one source of consumption data. But because that level of deregulation is still many years away, corporate energy managers are left to look for other ways to aggregate seemingly simple data sets.

Large commercial consumers, for example, said in a late 2002 survey that they think of their local utility first when considering sources for "utility accounting services"—reports that analyze energy consumption that a utility bills for. Yet they say local utilities are "too parochial" to provide enterprise-level information that is actionable at corporate headquarters. It's not uncommon for an energy manager to struggle to import data from utility bill–processing services, from weather-reporting services, from the corporate budget, and from multiple facility managers into a spreadsheet.

Multisite usage information can be a big deal. The 27 manufacturers that are members of the Electricity Consumers Resources Council collectively consume about 6 percent of all the electricity used in the United States. The U.S. federal government, with more than 500,000 buildings, is the largest single energy consumer in the nation, and the U.S. Department of Defense is developing a plan to monitor energy consumption at most of its facilities with advanced metering. For these customers, enterprise-level information from many utility territories will be necessary in order to better manage operational costs and to report on aggregated usage, savings, and emissions.

Got XML?

Utilities commonly use two data formats: MV-90 and electronic data interchange (EDI). MV-90, from Itron Inc. (Spokane, Wash), is the dominant meter-reading format. It has become a standard for collecting recorded consumption. EDI is the format most often used for bill-payment transactions. An energy manager could be forgiven for assuming that several utilities would cooperatively pump usage information in MV-90 or EDI format into a common spreadsheet or basic database. Both formats are expensive to set up and operate, and each is used for specific purposes that limit the functionality of its raw data.

What's needed is a common standard that is consumer-friendly. Extensible Markup Language (XML) is viewed by many to be the Holy Grail for enterprise systems. With XML, a piece of data is "tagged" as to its meaning. When that data is delivered into a system, the tag provides instruction about where it belongs or how it is to be treated. When two systems use the same tag, such as "first name" or "kWh," data can flow seamlessly between applications or systems.

Fernando Ramirez, VP of business development for Impact Facility Solutions (Glendale, California), says there hasn't been a true "energy portal" for enterprisewide management. Ramirez explains Impact's Enterprise Data Exchange (EDX) as "information technology meets building controls." The EDX portal is built on a Microsoft.Net structure with XML data coding. EDX integrates budget figures, energy usage from building control systems, and weather data at the simplest level to explain things such as variations in natural gas consumption.

Many companies offer enterprise energy management systems to corporate energy consumers. What's consistent about the offerings is their ability to report from a common database and to convert information into knowledge at the corporate level. Sometimes it can be difficult to collect data reliably from disparate sources, but the need for "the big picture" continues to drive energy managers toward their dream.

Value for Utilities

From the utility perspective, enterprise systems are seen as a collection of tools used across the corporation to increase efficiency and support better communication among departments. Here, too, enterprise systems collect data from multiple sources and convert the information into actionable reports through aggregation, sorting, slicing, and dicing.

Utilities are now examining the benefits of convergence: leveraging the hardware and software of automated meter reading systems for other operational or revenue programs. They're also starting to ask challenging questions about mixing customer information with usage information, system load management, outage restoration, and work orders. As an example, consider Itron's Mass Market Collection System Integration. The company offers it to utilities as a way to collect and mine billions of data bits for relevant answers to daily questions about their operations. "Departments collect different data in different ways. We provide a platform that allows the same data to be used to provide value to various departments or operations within a utility," explains Mima Scarpelli, Itron's VP of investor relations and corporate communications.

On the surface, enterprise application integration (EAI) should be straightforward. "The modern architecture of enterprise systems makes integration no big deal any more," says Allan Schurr, an Itron VP. Most large software systems have application programming interface (API) tools available that enable system integrators to build the software equivalents of merge lanes, off ramps, stoplights, and parking lots. In reality, the pathway from a customer's meter to a utility field crew or bill resolution desk can be hazardous and rough. Not only must the information technology department successfully connect systems, but the utility's business units must successfully connect people.

Lee County (Florida) Electric Cooperative (LCEC) has used Utility Center from Utility Automation Integrators (Huntsville, Alabama) to integrate its geographic information system (GIS) with its customer information system (CIS) and its automatic meter reading (AMR) system. As a result, the spatial tools that note the physical location of each meter and substation in its GIS can now be linked to the names, phone numbers, and addresses in CIS. What's more, LCEC's meters now can not only be read remotely for calculating a bill by its AMR system, they also can be "pinged" to determine if power was restored after an outage.

For LCEC's line workers, having the customer's address, the ID numbers of the connection devices, and a map all available on a rugged laptop computer in the service truck has been a major time saver. Part of the co-op's service territory is Cape Coral, where canals criss-cross the city. House numbers may seem reachable by ascending a street, but if may happen that the driver need to divert to a main highway and then back onto the street in order to find a particular service location. Now the location is pinpointed on screen, and the driver may avoid an otherwise meandering route.

The integration at LCEC has also made its customer service representatives (CSRs) more productive. While talking to a customer on the telephone, a CSR now can put data from both the CIS and the GIS on screen. Bob Tomlin, supervisor of planning and engineering graphics for the utility, explains the benefits as follows: "If the customer calls to report that a streetlight is not working, the CSR can look up the address visually on a map. She may ask the customer whether the streetlight is to the left or the right [as the customer is] looking out the front door. The CSR can then directly submit a work order with the correct device number. This [integration] adds a bit of technology to customer service, and since it's Web-based, there's a quick learning curve."

Back to Basics

As Itron's Schurr says, however, it's not about the data, it's about business processes. Customer usage data can feed load management. Customer enterprise energy management can be combined with interval metering for bill settlement in demand-response programs. "But very specific business cases have to be developed and carried out. The ideal is to think big, start smart, and scale fast."

When an energy company says it has gone "back to basics," what that usually means is "save money in operations, add new revenues, and increase customer satisfaction." But for companies in industries that are end users of energy, the three mantras are the same. Enterprise systems are powerful tools that must support all three goals.

In Brief:

California Energy Commission Launches Demand-Response Research Center (DRRC)

There has been significant interest in demand-response programs in California as a result of the power outages and price spikes in recent years. One positive outcome of these events has been the development of the Demand Response Research Center, an organization within the Lawrence Berkeley National Laboratory whose purpose is to build a knowledge base on demand-response issues. The nature of demand response requires that there is a close working relationship between all involved parties, especially researchers, policy-makers, and end users. The DRRC seeks to develop a roadmap for California that will guide research efforts by fostering cooperation and collaboration among research institutions using input and feedback from product engineers, facility managers, utility representatives, and academic researchers. This alliance will hopefully eliminate regulatory and compatibility problems that could arise if the different stakeholders in this field worked to develop solutions independently.

Some specific methods the DRRC will employ to facilitate market connection are to develop a newsletter and comprehensive Web site that keep all interested parties informed of the research status; organize an annual research conference and provide educational materials for utilities and end users. The research programs will examine all aspects of demand response, with emphasis placed on the integration of control technologies and building systems, the development of public policies and regulatory mandates, and the behavior of utilities and customers.

For more information, visit the Web site at http://drrc.lbl.gov/ or contact the center via e-mail at DRRC@lbl.gov

Multibuilding Internet Demand-Response Control System: The First Successful Test

In addition to founding the aforementioned Demand Response Research Center, Lawrence Berkeley National Laboratory has also tested a Web-based system for managing building loads during times when the power grid may become vulnerable. This test was the first successful integration of a completely automated system that operates independently without human controls. When the price of electricity reaches a specified threshold, a signal is sent via the Web to the buildings, which immediately begin to reduce their electrical loads, primarily lighting and air conditioning. Building managers have predetermined which loads to cut back on when the signal is sent, and multiple price threshold levels and responses have been successfully tested.

The funding for these tests was provided by the California Energy Commission's Public Interest Energy Research (PIER) Program, which is also responsible for developing the DRRC discussed above. The system was successfully tested on five different buildings with various control systems ranging from a supermarket to a library. One of the major accomplishments of the testing was the success of the XML (Extensible Markup Language) in communicating with a variety of different energy management and control systems in the respective buildings. This showed how one system could effectively control a number of different buildings with a standard signal, regardless of that location's control system. The test buildings all used commercially available control systems, so most existing businesses would require little or no capital investment in hardware in order to implement the demand-response system. The test results aid the campaign to introduce real-time pricing in California, because they successfully demonstrates a technology that will allow commercial buildings to engage in load shedding; with enough participation the possibility of blackouts would greatly diminish.

Further information can be found at www.lbl.gov/Science-Articles/Archive/EETD-demand-response.html or by contacting Allan Chen, tel 510-486-4210, e-mail a_chen@lbl.gov

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