Demand Response: An Introduction

Overview of programs, technologies, and lessons learned

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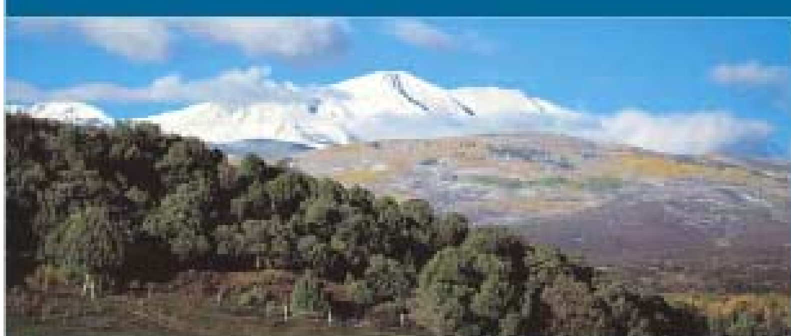

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Executive Summary

Demand Response (DR) is a class of demand-side management programs[1] in which utilities offer customers incentives to reduce their demand for electricity during periods of critical system conditions or periods of high market power costs. Interest in DR has increased during the past decade, although these programs have existed for nearly 25 years. Many utilities and independent system operators in deregulated markets have long recognized the benefits of DR. Utilities can purchase load demand from their customers for lower rates than they would pay to provide it, lowering the utility system's peak demand and help reduce peak wholesale power market prices. In addition, customers can also be asked to reduce load during non-peak periods to help maintain grid reliability, defer or eliminate generation capacity expansion, or defer or eliminate transmission/distribution capacity expansion.

However, realizing these benefits has not been as easy as hoped, and challenges remain in both wholesale and retail markets that complicate the use of DR as a capacity resource. This paper examines these challenges, chronicles some DR experiences to date, and illustrates how various barriers to successful DR programs can be overcome.

First, we present an overview of DR for the commercial sector, design components, end-use and facility targets for load reduction, and enabling technology options. Utility costs and system benefits, reasons why customers participate and barriers to participation are then discussed. Next follows some lessons learned and, based on successful programs around the country, and recommendations for the best practices in program design.

Additionally, this paper touches on energy efficiency as a second element of demand-side management, and explores the relationship between efficiency and demand response. While energy efficiency and demand-response programs are typically operated independently, these two demand-side resources are not mutually exclusive. When utilities couple demand response with efficiency programs, it is possible to flatten the utility's system load curve, and lower prices for power and gas considerably—results which benefit both the utility and its customers.

Categorization of Demand-Response Programs

DR programs, also known as load-management programs, can be broadly categorized along two dimensions (Table 1). The first dimension characterizes how and when utilities call on program participants to shed load. The second dimension shows the method by which utilities motivate their customers to participate.

Participants can be called upon for either emergency/reliability conditions or for economic purposes. Emergency programs offer customers payments for reducing their electricity demand during system contingencies such as generator or line failures. Economic programs offer customers incentives to reduce loads during non-emergency periods when utility cost of service exceeds some specified limit.

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[1]Demand-side management includes energy efficiency, demand response, and small-scale (<50 MW) generation on the customer side of the meter.

The second dimension concerns the methods by which utilities motivate their customers to shed load. Utilities may use straight communication signals (telephone, pager, Internet) to notify participants of reliability or economic events that merit load response in exchange for direct utility payment. Alternatively, they may use pricing signals to more accurately reflect the cost of providing power as a function of time. In price response, utilities structure their rates to go up during hours of either peak demand or supply constraint. Rates are kept lower at all other times (e.g., “off-peak” periods). In real-time pricing, utilities expose customers directly to the full and fluctuating range of wholesale power market prices.

Table 1. Categorization of demand response programs along trigger criteria and motivation dimensions

		Motivation Method	
		Load Response	**Price Response**
Trigger Criteria	**Reliability**	Direct Load Control Curtailable Load Interruptible Load	Critical Peak Pricing Demand Bidding
	Economic	Direct Load Control Curtailable Load	Time-of- Use Pricing Critical-Peak Pricing Real-Time Pricing Demand Bidding

Program Experience and Performance

Success with DR remains challenging, as most customers remain unfamiliar with load reduction options and are leery of compromising products and customers. For all DR programs, the amount of actual load reduction realized lags behind the amount committed upon enrollment.

A few of the largest programs in the country account for the majority of the demand-response capability. Within a DR program, the largest industrial and commercial customers typically account for the majority of reductions. Although utilities implement both load and price response programs with approximately similar frequency, load-reduction capacity from price-response programs lags behind that of load response programs.

Large commercial and industrial DR participants rely on process scheduling or backup generation for guaranteed load reductions, or else on manual strategies for flexing building loads. This is more difficult for most large facilities, which have more complex loads, compared to small commercial facilities. While some facilities may have energy management or energy information systems, facility personnel typically do not operate the existing technology optimally, and most are not equipped with automated response capability.

As such, utilities cannot accurately predict the amount of load that will be shed by large customers in price-response programs. For this reason, mass-market, direct load-control programs are attractive because utilities can install simple and low-cost technologies (e.g., control switches or smart thermostats) to control specific loads (e.g., air conditioning and/or water heating) in small commercial customers, with the guarantee that the load will be responsive when called.

Studies reporting benefit-cost (B/C) ratios of demand-response programs are few. Evaluation methodologies are inconsistent and reporting methods are mixed, making it difficult to compare projects. Based on available reports, however, studies show that small customer direct-load-control programs are generally cost effective. For large commercial reliability and economic programs, both the New York Independent System Operator (NYISO) and Pennsylvania-Jersey-Maryland Interconnection (PJM) reported that programs were cost effective, with B/C ratios of 2 and greater, when the incentives paid and the market price reductions were considered.

When first-year technology and infrastructure costs were included in the analysis, however, as was done by the ISO New England (NE ISO), reliability and economic demand response were not cost effective. However, higher market prices, lower customer incentives and accounting for future benefits from technology investments generally improved cost effectiveness of programs for NE ISO.

Lessons Learned from Successful DR Programs

Targeting the right end uses, and identifying the types of facilities best suited to benefit from DR can help achieve better results. At the same time, utilities or program sponsors must often assist customers in understanding their facility's loads and provide financial and technical assistance to help customers achieve their peak load reduction potential cost effectively.

Programs that recognize the diversity of customers and provide them with a limited portfolio of options are most successful at engaging and retaining participants. Although utilities traditionally targeted the largest commercial and industrial customers for DR, a number of successful programs have engaged small (<100 kW) and medium (<500 kW) customers.

Automated technologies can greatly enhance a facility's ability to shed load for DR, provide consistency in load shed capacity, and provide customers with ancillary benefits such as detailed energy consumption data. Customers can achieve per site reductions of 20 to 40 percent when automated technologies are used, compared to 10 and 15 percent using manual strategies or non-automated controls. Technologies with two-way communication capability further enhance the savings potential and reliability. They enable utilities to verify load reductions in near-real time and take measures if necessary to assist customers in shedding non-critical loads more effectively. Facilities with lighting and HVAC controls, EMS and EIS systems can use them for both DR and efficiency to achieve long-term energy cost savings while reducing peak demand charges when needed.

Utilities commonly operate energy efficiency and demand response programs independently and simultaneously. However, these two types of demand-side resources are not mutually exclusive. Given that DR and efficiency fulfill different but complementary power system objectives, utilities should couple demand response with efficiency programs to leverage the different strengths of each for an optimum resource plan. Implementing a coordinated efficiency and DR program portfolio can help flatten the utility's system load curve, lower prices for power and gas, and defer new plant construction. Combining EE and DR may be necessary to create an adequate value package for the customer. Efficient technology, for example, may be an effective means to mitigate customer comfort concerns about participating in DR.

1. Introduction: What is Demand Response?

DR focuses on reducing demand temporarily in response to a price signal or other type of incentive, particularly during the system's peak periods. End-user customers receive compensation (either through utility incentives or rate design) to reduce non-essential electricity use or to shift electric load to a different time, without necessarily reducing net usage. For example, a large customer may switch from grid-supplied electricity to backup generators, when called to do so by the utility.

DR is dispatchable in both space and time, providing the ability to stabilize transmission grids, reduce wholesale market price volatility, dilute market power of wholesale generators, and provide ancillary services. In this sense, DR is a distributed energy resource that utilities should consider an integral part of their resource portfolio.

Energy efficiency programs, on the other hand, aim to reduce overall energy consumption permanently, normally through technological change. For example, energy efficiency measures might include replacing inefficient motors, better control of lighting and HVAC systems, or retrofitting and insulating the building envelope.

Why Demand Response?

Demand response, also known as load management, has been practiced for nearly 25 years, although participation has waxed and waned as utility objectives shifted. Interest in DR recently has increased during that past decade, resulting primarily because two developments in the electricity industry.

The first development is the culmination of 25 years of legislative and regulatory efforts, beginning with PURPA in 1978, to open the business of electric generation, delivery, and service to greater competition. It was thought that competition among suppliers was sufficient to drive market efficiency and reduce electricity rates to customers. However, mixed performance from deregulated electricity markets revealed that market efficiency is more effectively achieved when the demand side also plays an active role.

The second development resulted from reduced rates of construction for new generation and transmission facilities in some regions, which created reliability issues in the electric system. Faced with capacity shortages, many utilities found it cheaper to pay customers for reducing their consumption.

Utility Learning Curve with Demand Response

Many utilities follow a fairly standard pathway in their involvement with DR. They start with simple and straightforward programs that can implemented for minimal cost, and then progress into more sophisticated programs that can be more exactly tailored to meet specific objectives. For a particular utility, experience with DR usually begins with an emergency or reliability program. Utilities work with customers to define rules under which reliability events are called, as well as to identify incentives and penalties for non-performance. However, reliability programs have a very narrow application because they are called few times during the course of a year (normally less than 5). Such programs can prove costly when utilities must pay incentives for participation whether or not any emergencies are experienced.

As both utilities and customers gain experience with DR, there is desire to call on customers more frequently—outside of emergency events—to serve other needs, such as reducing costly on-peak power purchases and diffusing market power of wholesale generators. Although economic programs cost more to administer than emergency programs (because customers are asked to shed load more frequently), utilities typically find the additional benefits worthwhile. To alleviate customer concerns, utilities often design into the program flexibility options to allow for relative degrees of customer participation (e.g., choice of curtailment hours per year, incentive levels, amount of load shed committed, and amount of advanced notification).

Economic programs using payments or pricing response typically add further costs since additional investments are required in metering, billing, and communications to handle the more complex performance verification and incentive payment transactions. However, if these programs are well-designed, cost savings to the utility should more than compensate for the additional investment costs. Customer-side load reductions reduce expensive power generation or purchases, help maintain grid reliability, defer or eliminate generation capacity expansion, and/or defer or eliminate transmission/distribution capacity expansion. The more frequently economic events are called at a given incentive level or price, and the greater amount of load customers shed, the more cost effective an economic program becomes.

2. Types of DR Programs

DR programs are broadly classified according to the customer motivation method (i.e., direct control or market price) and the criteria with which load reduction "events" are triggered or initiated (i.e., emergency or economic programs). Specific DR programs can be discussed in terms of these two dimensions as shown in Table 2.

When the utility offers customers payments for reduction of demand during specified periods, the program is called *load response*. Emergency DR is a form of load response used for system contingencies, as when customers reduce load to relieve generation and/or transmission or distribution capacity constraints.

When customers voluntarily reduce their demand in response to forward market prices, the program is called *price response*. Customers reduce load during those periods when the cost to reduce load is less than the cost to generate or buy the energy.

Table 2. Categorization of DR programs along the trigger criteria and notification dimensions

		Motivation Method	
		Load Response	**Price Response**
Trigger Criteria	**Reliability**	Direct Load Control Curtailable Load Interruptible Load	Critical Peak Pricing Demand Bidding
	Economic	Direct Load Control Curtailable Load	Time-of-Use Pricing Critical Peak Pricing Real-Time Pricing Demand Bidding

Program Design Components

DR programs are described in terms of design components such as participation, operations, and settlement criteria. Participation criteria indicate whether the program is voluntary or mandatory, and whether a particular segment or specific customer is eligible for participation. Operations criteria include the event trigger criteria (emergency or economic), which entity controls the load reductions (utility or customer), advanced notification (ranging from within the hour to 24 hours ahead), and eligible types of enabling technology. Settlement criteria include incentive and penalty structures, billing system changes, and the method of incentive or penalty disbursement.

The next two sections explain how each design component is defined according to DR program type. Additional information about customer participation rates and performance of CPP programs is provided in sections 4 and 5 of this report.

Load-Response Programs

In load-response programs, utilities offer customers payments for reducing their electricity demand for specified periods of time. Program participants can be considered “sellers,” since they provide load reductions in exchange for various economic incentives offered by the utility. Load-response programs can take a number of different forms, depending on the program objectives, targeted customers, and design components. Table 3 summarizes the characteristics of each type of load-response program.

Table 3. Load-response program overview

	Direct Load Control	Curtailable Load	Interruptible Load	Scheduled Load
Brief Definition	End-use loads turned off for limited periods of time	End-use loads reduced or turned off for limited periods of time	All or major portions of customer total load turned off for periods of time	Load reductions scheduled or planned ahead of time between utility and customer
Target Customer Size	<100 kW	>100 kW	>500 kW	All
Mandatory or Voluntary Load Reductions	Mandatory	Mandatory or Voluntary	Mandatory	Mandatory
Party Controlling Reduction	Provider/Utility	Provider/Utility or Customer	Provider/Utility or Customer	Customer
Incentive (examples)	$0.014 – 0.40/ton of cooling	$7-45/kW $0.15 -0.53/ kWh	$7-45/kW $0.15 -0.53/kWh	$0.10/kWh
Advance Notification	None	Minutes to hours	Minutes to hours	Months - contractual
Eligible Enabling Technology	Load switches, 2-way communication (optional)	Interval meters, automated controls, 2-way communication (optional)	Interval meters, backup generator (optional)	None necessary
Billing System Change?	No	No	No	No
Settlement	Fixed credit on monthly bill	Monthly bill adjustments, penalties for non-performance	Monthly bill adjustments, penalties for non-performance	Reflected on monthly bills, penalty for non-performance

Direct Load Control

Direct-load-control (DLC) programs are typically mass-market programs directed at small commercial (less than 100 kW peak demand) and residential customers. Utilities that operate small commercial DLC programs include Long-Island Power Authority (LIPAEdge), Utah Power (Cool Keeper), Florida Power and Light (Business On Call), and Southern California Edison (SCE) (Summer Discount Plan). Customers sign up for the program to allow the utility to control specific end uses at the customer site. The most frequently controlled end use is air conditioning (AC) loads, but lighting is also possible for commercial DLC programs. In some cases, water heating and pool pumps are targeted in residential DLC programs, too. Incentive structures for DLC programs typically include fixed monthly payments credited to the customer's utility bill, plus a one-time participation payment. Some utilities provide tiered payments based either on the size of the AC capacity committed or on the AC cycling strategy (15%, 25%, 50%, or 100% of the hour). Some utilities provide an additional payment when a load reduction event is called.

As part of the DLC program, the utility establishes agreements with customers that specify the maximum number of events per year (e.g. up to 30) and the maximum duration of any given event (between 2 and 8 hours, but typically 4). Because the utility controls the customer loads directly, very little advance notification is given prior to initiating an event (3 minutes or less). Most DLC programs allow the customer to override an event if they experience discomfort, but some programs impose penalties for overrides. These programs offer utilities assurance that loads can be curtailed when needed or called upon.

DLC programs are relatively simple and inexpensive to implement. Generally, they employ load control switches or "smart" thermostats linked to the utility to reduce loads (see also "Technology Options" section). Load switches cycle the AC compressor or completely shut off other loads such as lighting, water heating, and/or swimming pool pumps. Smart thermostats are programmable, communicating thermostats (PCTs) used to raise temperature setpoints and reduce customer load automatically during peak reduction events. Because these technologies are relatively inexpensive (around $70-$150 for a load switch and around $200-$400 for a smart thermostat), utilities typically pay upfront for the technologies and offer them to customers free of charge. These technologies are quite reliable, and capable of achieving up to 60 percent load reduction per site for small customers (RMI 2005, RMI 2006, Wright et al. 2003, Jerry et al. 2001).

Curtailable Load

Curtailable-load programs target medium (100-500 kW peak demand) to large customers and, like DLC programs, are relatively simple to implement. Participants agree to reduce or turn off specific loads for a period of time when notified by the utility. Customers can switch off loads or adjust settings manually or automatically, depending on the agreement and availability of control technologies. Utilities must notify customers before a curtailable load event. Advance notice is typically given minutes to hours ahead, but some programs notify participants up to a day ahead. Like direct-load-control programs, the utility must specify upfront,the maximum number of events and durations per year. Curtailable-load programs are operated in California, Colorado, Texas, Ohio, Illinois, and the Mid-Atlantic states.

The range of incentive structures varies widely among curtailable-load-response programs. These incentive structures can include a monthly capacity credit ($/kW), a monthly capacity credit plus a rate ($/kWh) reduction, an option payment with variable strike price[2], or a per event credit based on market pricing. Utilities may also choose to tier the monthly capacity credit

[2]See, for example, Cinergy's innovative incentive structure for its PowerShare price-response program, which is modeled after financial options. Cinergy negotiates a one-time payment with interested customers depending on the amount of load committed (e.g., the purchase cost of the option). Customers choose from a menu of $/MWh prices above which they are willing to reduce load, called the "Strike Price". When the day-ahead market prices are projected to be greater than the Strike Prices, Cinergy can call the option by notifying customers by 4 p.m. Customers are then paid the energy credit of the Strike Price for every MWh of load curtailed.

based on the amount of advanced notification a customer signs up to receive. Because of the size of loads committed by the large commercial customers in curtailable load programs, severe penalties are almost always imposed for non-performance.

Interruptible Load

Customers participating in interruptible-load programs agree to switch off major portions or even all of a facility's load for specified periods of time. Only a handful of the largest customers (>1 MW) have the loads and capability to participate in interruptible load programs.[3] In this scenario, the most common customer strategy is to use the facility's backup generators during an interruptible event. Some large commercial and industrial facilities install backup generation to supply power to critical loads in case of unexpected interruptions in power supplied from the electrical grid. Because backup generators are meant to be used only a limited number of hours per year (e.g., less than 50), customers install equipment such as diesel engines that have low capital costs but high operating costs. Some utilities, however, see interruptible load response using backup generators as a way to *preempt* probable interruptions in the electrical grid. In this case, utilities may choose to work with participants to comply with air emissions regulations or secure exemptions so that backup generators can operate for more hours of the year.

In exchange for their commitment to interrupt load, participants receive lower electricity bills during normal operation, as well as additional incentives (similar to curtailable program incentives) for each interruptible event. Because only the largest customers qualify, the program is implemented via bilateral agreements between a utility and a customer. These are binding contracts and severe penalties can be enforced for non-performance. As such, facilities are called upon only in dire emergencies, though contracts can obligate availability at any time. Advance notification is generally minutes to hours at a minimum, but can also be a day ahead. Utilities that operate interruptible load programs include San Diego Gas and Electric (SDG&E Base Interruptible program), Commonwealth Edison (ComEd Rider 26 Interruptible Service), and Southern California Edison (SCE I-6 Interruptible program).

Scheduled Load

Scheduled load reductions are pre-planned between the utility and customer. Participants receive bill reductions, as well as significant advance notification, since contractual agreements are set months ahead. The advantage of this program is that customers can plan to reduce load on pre-determined days. However, the disadvantage is that these dates may not coincide with actual utility system needs or unexpected emergencies.

This type of program is rather inflexible since utilities cannot call on customers to curtail load when needed on short (one day or less) notice, and is not commonly used for load or capacity shaving. However, three California utilities offer a scheduled load reduction more as energy efficiency programs, rather than as demand response programs: Pacific Gas & Electric, Southern California Edison, and San Diego Gas and Electric (SDG&E). Customers are offered incentives

[3] SDG&E uses an interruptible load program for smaller customers. SDG&E's Rolling Blackout Reduction program requires a minimum of just 50 kW, or 15% of peak demand reduction for participants.

and two options to reduce load, either 15% of their average monthly load or a minimum of 100 kW for at least four hours, one to three times a week, between June 1 and September 30. In the first option, customers reduce their monthly energy consumption on the whole, which is in essence an energy efficiency strategy. In the second option, customers commit to reducing load regularly and frequently during the summer season regardless of whether there is an emergency or economic need. This option thus resembles more an energy efficiency strategy rather than demand response.

Price-Response Programs

Table 4 summarizes the characteristics of each type of price-response program. These programs allow customers to voluntarily reduce their demand in response to economic signals. Programs vary by pricing structure and the amount of advance notification.

Table 4. Price-Response Program Overview

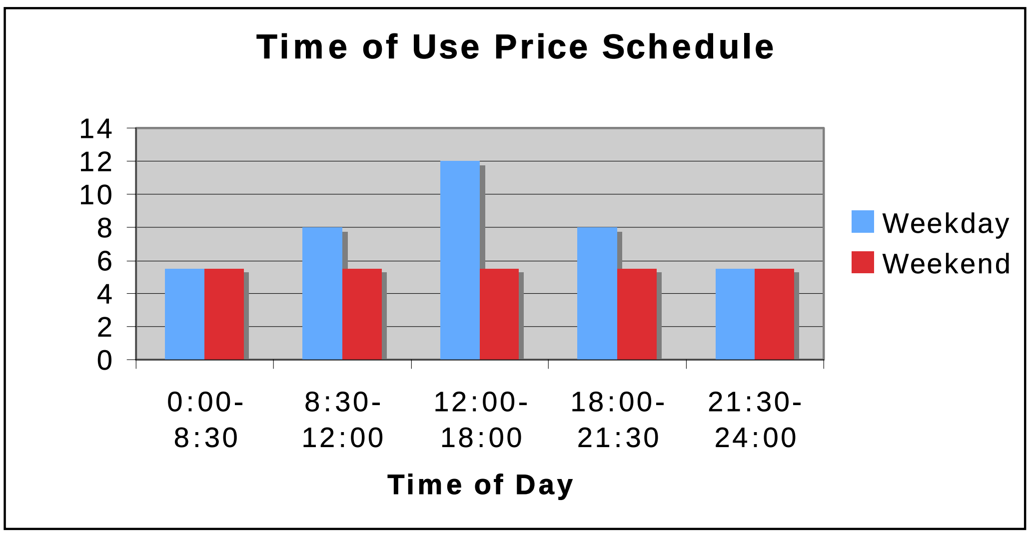
	Time-of-Use (TOU)	**Dynamic Pricing (Critical-Peak Pricing or Real-Time Pricing)**	**Demand Bidding**
Brief Definition	Load management based on stepped rate structure, including peak, off-peak, and sometimes shoulder peak rate	Load management based on dynamic tariff	Customers bid load reduction based on 1) provider proposed price, or 2) customer proposed price
Target Size	All	All	All
Mandatory or Voluntary	Mandatory or Voluntary	Voluntary	Voluntary
Party Controlling Reduction	Customer	Customer	Customer
Incentives (examples)	5% bill reduction premium + payment per event	Locational marginal price.	Locational marginal price. $0.15 – 0.50/ kWh
Advance Notification	None	Hours or day ahead	Hours or day ahead
Enabling Technology	TOU meters, real-time or prior-day energy information via Internet	Interval meters, 2-way communication, energy information via Internet	Interval meters, web-based trading/market, spot price information via Internet
Billing System Change?	Yes, new TOU rate	Yes, new CPP or RTP rate	No
Settlement	Monthly bill adjustments	Monthly bill adjustments	Separate payment based on bid price, additional reductions beyond bid paid, locational marginal price

Customers voluntarily "opt-in" to a price-response program, though an alternative option is to offer a default tariff structure in which customers can "opt out" if they choose not to participate. Because customer usage must be measured against time-varying electric rates, price- response programs require upfront technology investments such as interval meters.

Time-of-Use

Time-of-use (TOU) pricing programs are based on a stepped rate structure that includes a peak rate, an off-peak rate, and sometimes a shoulder-peak rate for pre-determined blocks of time set by the utility. An example rate schedule is illustrated in Figure 1. A TOU tariff might charge customers 5.5 cents per kilowatt-hour (kWh) consumed on weekends and weekdays from 9:30 PM to 8:30 AM, 8 cents/kWh on weekdays from 8:30 AM to noon, and 6:00 PM to 9:30 PM, and 12 cents/kWh on weekdays from noon to 6:00 PM. TOU rates do not recognize day-to-day volatility of supply costs, and are designed to reflect prices under expected, average market conditions. As such, TOU rates achieve only modest load shifting on a routine basis, ranging from 4 to 17 percent energy reduction per site (Faruqui 2002).

Figure 1. Generic time-of-use rate schedule



Critical Peak Pricing

Critical peak pricing (CPP) is a variation of TOU tariffs that tries to reflect the uncertainty and volatility of electricity supply costs. The CPP tariff adds a time-dependent rate several times higher than normal rate to either standard, or TOU rates, during peak periods. The utility can call a critical peak event anywhere from 24 hours to just minutes before when they are needed. Since the days when critical peak events will be called are unknown, the utility usually agrees to limit both the duration and number of events per year. For example, an agreement might specify that a critical peak rate of 24 cents per kWh can be imposed for 4 hours up to 30 days each year. Utilities then can base notification decisions on their forward-looking criteria related to the balance between supply and demand (e.g., weather or declining reserves).

The CPP rate can be added to either standard or TOU rates, and needs to be high enough to induce participant response (a minimum ratio of 2.5 to 1 between critical peak and peak price level is recommended). CPP programs are suitable for both small and large customers. Automated load control technologies are not required, but are desirable in CPP in order to maximize performance because customers may not be on-site when critical peak events are called. Gulf Power operates a full-scale critical peak-pricing program for residential and small commercial customers. The three California IOUs (PG&E, SCE, and SDG&E), as well as Sacramento Municipal Utility District (SMUD), have operated CPP pilots. Results of the California pilot reported that residential customers on the CPP rate without automated technology reduced load by only 5 to 17 percent, compared to customers with technology and the? CPP rate who reduced load by 20 to 60 percent (RMI 2006).

Real-Time Pricing

Real-time pricing (RTP) programs fully expose customers to the variability and volatility of costs in the wholesale power market. Rates charged for electricity reflect the actual supply costs to the utility for each hour of the day. The prices are provided to customers anywhere from an hour, to as much as 24 hours ahead of time. Facility managers are free to maintain operations as planned, or to adjust operations in response to higher or lower rates.

Implementing an RTP program requires significant technology investments, including automated interval metering, along with more complex price forecasting, communications and billing systems. In practice, only a small subset of the largest industrial and commercial customers (>1 MW) has a demand elasticity high enough to justify participation. These customers typically have backup generation or discrete production processes that can be rescheduled—the same strategies employed by customers who participate in curtailable or interruptible load response programs. Automated control technologies for customers are recommended to maximize performance and savings.

At this point, it is unclear whether RTP programs are more effective than curtailable load response at reducing end user demand on the utility system. However, they do provide customers with market-based information on which to base their energy use decisions and—combined with customer education programs— remain a strong tool for managing both load growth and peak demand.

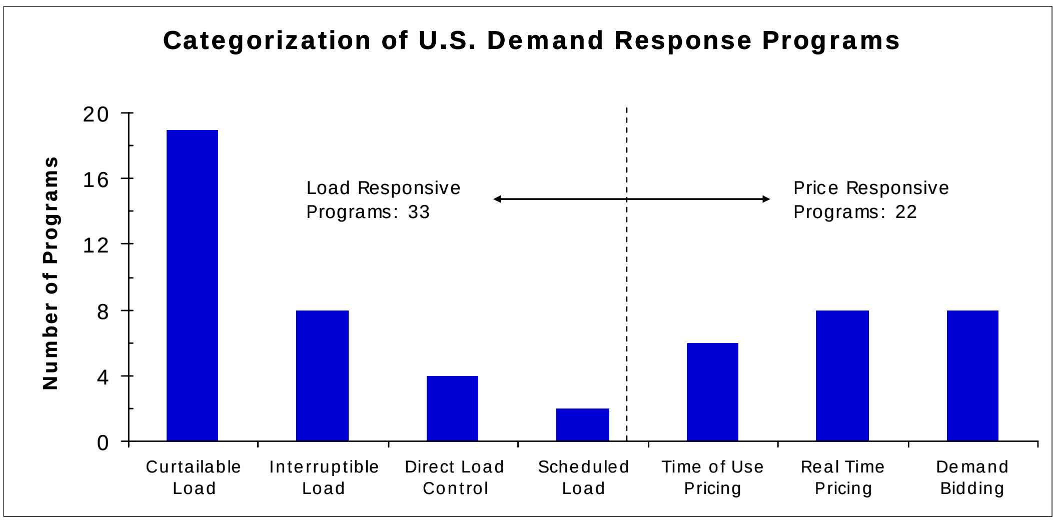
Demand Bidding

Demand bidding gives facility managers the opportunity to actively participate in market trading by offering to reduce loads for a price. In one type of bidding structure, participants name the price at which they are willing to sell their load reductions on the market. In other types of structures, the utility or independent system operator (ISO) determines the price they are willing to pay, and customers determine how much load reduction they are willing to provide. The utility or ISO then reviews the DR bids, along with those submitted by independent generators, and accepts bids in order of lowest price first until the demand is met.

In liberalized markets where demand bidding is used, the customers are most commonly large commercial and industrial customers have experience interacting directly with real-time power markets. They also have sophisticated load management tools and strategies. Smaller customers can participate via intermediaries such as aggregators or energy service providers, who aggregate small loads and package the total bid for submission. The New York Independent System Operator, PJM, Electrical Reliability Council of Texas, Pacific Gas and Electric, Southern California Edison, and San Diego Gas and Electric all have implemented successful demand bidding programs.

Figure 2 summarizes the results of a national survey on DR programs for commercial and industrial customers compiled by Rocky Mountain Institute. The chart shows the number of programs by program type. Based on the results of this survey, utilities do not appear to overwhelmingly prefer one class of DR programs over another, although load response programs are slightly more common than price response programs.

Figure 2. Categorization of U.S. Commercial and Industrial Programs



3. Customer Load Reduction Strategies

In order to participate in a DR program, customers must know how they will reduce their load. Commercial and industrial facilities employ several strategies for shedding load. These load shed strategies are more commonly implemented manually than via automated DR control technology (PLMA 2002, CEC 2004). Most industrial customers and some large commercial customers have generation equipment on site, either for emergency backup or supplemental power. As such, they can use on-site backup generation for DR. In addition, some industrial facilities such as pulp and paper manufacturing have discrete, independent production processes. These processes can be shifted to other times of day or to different days, if needed.

Load management technology or energy management systems (see “Technology Options”on page 12), are not usually equipped to respond automatically to signals sent by utilities. Thus, most customers require technical and financial assistance from the utility in order to install automated DR. Furthermore, once the DR equipment is installed, most customers require additional assistance in order to use the technology effectively. Facility demand response technology can be used to shut off non-essential building loads such as plug loads, process loads, refrigeration, motors, and elevators. Automated demand response technology is also used to flex major building loads such as lighting and HVAC systems.

Backup Generation

As previously stated, most industrial customers and some large commercial customers have generation equipment on site, either for emergency backup or supplemental power. Backup generators (BUGs) can be a simple and convenient strategy to shed load from the grid in exchange for utility payment. Industrial and commercial customers employ this strategy because it allows them to maintain their normal operations while gaining additional economic value from their equipment.

A big issue with use of backup generators for DR, however, involves pollutant emissions. Emissions permits for most emergency backup generators allow operation for a limited number of hours per year. Using backup generators for DR will require the generators to be operated more often than they otherwise would have. From the perspective of an air quality permitting agency, this can be a fairly complex issue. Agencies need to weigh the quantity and type of emissions from the backup generation, compared to the generation equipment that the utility would normally purchase the power from. This usually involves issues such as the type of equipment being used (e.g., engine vs. turbine), the fuel (e.g,. oil vs. gas), and the level of emission control.

The question may be further complicated by geography. For example, if the backup generation is located within a non-attainment zone (e.g., the downtown of a major city), but the utility generation equipment displaced is outside of that zone (e.g., the outskirts of the city), then the impact on air quality becomes critical. In general, without some relief from air permitting restrictions, it can be difficult to dispatch the backup generators outside of an emergency event. A few utilities are examining the issue of using backup generators for DR as a means of *preempting* emergency events, as an argument for air quality agencies to permit BUGs to operate outside of emergencies for DR. Alternatively, customers may be required to retrofit existing generators with additional emissions control technology.

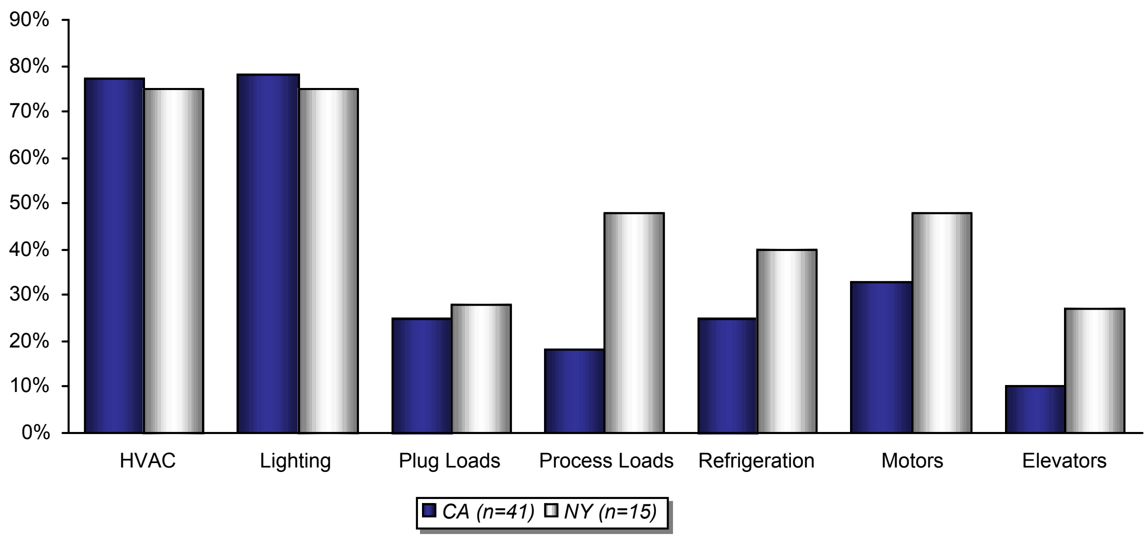
Additionally, utilities must assist DR program participants who use backup generation verify that their automatic transfer switches are in proper working condition to ensure smooth transition from grid-connected electricity to on-site backup generation. Many customers also need assistance in upgrading and maintaining the generator or retrofitting it with emissions control technology.

Increasing operating hours of on-site backup generators also may require additional noise and vibration controls, technical upgrades to the backup generator (particularly in switching from grid-connected to island mode), and greater maintenance and operation attention. Without utility assistance, these issues deter program participation by all but the most dedicated or sophisticated customers.

Load Flexing: End Use Targets

Customers without backup generation can consider “flexing” (modifying) facility loads. HVAC and lighting are the usual targets of a flexing strategy. Often, they are the largest two end-uses of a commercial facility as a portion of total building energy consumption and are *coincident* with utility system peak loads. For utilities whose annual peak occurs in the summer, commercial cooling and lighting contribute most significantly to that summer peak. For winter peaking utilities, lighting and electric heating are the prime end-use contributors. HVAC and lighting are also easy targets for curtailment, since slight adjustments do not critically impact operations. Temperature setpoints, for example, can be raised or lowered a few degrees with minimal impact on comfort, but usually only for a limited time (1-3 hours). HVAC and lighting controls are prevalent, and there are an abundance of proven solutions and experienced vendors to choose from for a wide range of facilities and applications.

Figure 3. Typical End-Use Targets for DR (Goldman 2002)



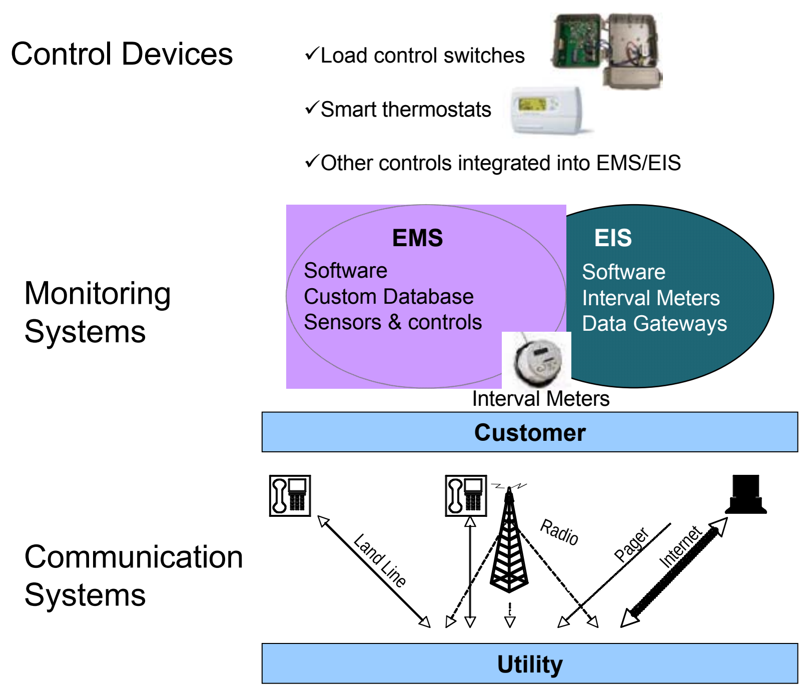
Miscellaneous loads are also good targets for DR--if turning them off does not critically impact normal operations. Examples include elevators, outdoor signage, and plug loads. Refrigeration equipment can be turned down or off for two hours or more because the insulation retards flow of heat into the cooled environment, while refrigerated contents provide capacitance for cooling energy storage. Figure 3 shows the targeted end use loads for flexing and the percentage of facilities that employ them for DR (Goldman 2002). The information is based on a Lawrence Berkeley National Laboratory survey of 85 and 23 participants, respectively, of the New York State Energy Research and Development Authority (NYSERDA) and California Energy Commission (CEC) programs utilizing automated technologies for price response. The data demonstrate the popularity of modifying lighting and HVAC loads by participants in price-response programs using enabling technologies. It also demonstrates that flexing of building loads other than lighting and HVAC are commonly employed as well.

Technology Options for Flexing Building Loads

Enhanced automation or use of load responsive technologies is recommended over manual strategies for program participation. Manual strategies are unlikely to produce as much or as consistent load reduction as automated load reduction strategies. Manual load reduction strategies require that the customer be on site during a load reduction event. Automated response technologies, on the other hand, enable enhanced control of a facility's energy consumption and peak load, as well as allowing for remote control. Further, the real time information and data collection capabilities of energy management and control systems allow greater understanding and appreciation of energy usage by facility management personnel. The load information and other relevant data provide a good basis for load reduction planning and strategy.

The set of automated technologies that enhance DR can be broken down into three broad categories: control devices, monitoring systems, and communication systems (Figure 4). The technologies that fall into these categories are described very briefly below.

Figure 4. Categories of DR Technologies



Control devices include technologies such as load control switches, smart thermostats, and lighting, HVAC, or other centralized end-use controls. Load control devices are either stand-alone or integrated into an energy management system for large or dispersed facilities. Load control switches remotely control specific end use loads such as compressors or motors. They are wired into the control circuitry of an appliance and can disconnect power to that controlled appliance once an activation signal is received from the utility. Smart thermostats make it possible to schedule fluctuations in temperatures settings. Smart thermostats modify loads by raising temperature setpoints. The utility, the customer, or both entities can control the devices remotely.

Thermostat set point control offers a “softer” control than on-off switching devices. On the other hand, load reduction performance using set point control degrades over time, as a building heats up and air conditioners cycle back on. Depending on the building construction, indoor temperatures may increase either slowly or quickly when setpoints are raised, and load reductions can be maintained for up to two hours before air conditioning kicks on at the new setpoint. Utilities sometimes try to compensate for “bounce back” demand on the system by deploying portions of a control population at different hours of a curtailment period, rather than the entire DR program population at the beginning of the event.

Monitoring systems include interval meters, energy management systems, and energy information systems. Interval meters measure and record energy usage at intervals ranging from 15 minutes to each hour, which is necessary for price-response and large commercial load-response programs. An energy management system (or EMS) consists of a series of hardware (sensors, switches, controls) and software that enables the customer to centrally monitor, analyze, and control building systems and equipment. An EMS is primarily intended to enhance building energy performance (i.e., save energy and/or reduce peak demand), but can be upgraded with automated demand response capabilities.

A facility installing a new EMS system cannot usually justify the costs based on cost savings from DR alone. Rather, permanent load reduction via energy efficiency must be (and typically is) the primary goal along with facility/process automation, with DR providing ancillary cost savings (Wood 2005). A valuable feature of EMS is centralized control of multiple buildings on a campus or geographically dispersed facilities. EMS is employed in many national chain retail stores (e.g., Blockbuster, Petsmart, Home Depot) as a means of aggregating small and medium-sized commercial facilities for DR within a utility’s service territory. A small fraction (about 15 percent) of facilities installing EMS use the technology for DR in parallel with energy efficiency or controls automation functions, according to a California Energy Commission commissioned study of Niagara Mohawk customers’ strategies for responding to real time pricing (Goldman et. al. 2005).

Energy Information Systems (or EIS) collect data and provide information about system-wide performance to end users and utilities, but can also be equipped with automated response capabilities. EIS can provide notification capability for end users to receive alerts regarding DR event, or provide both notification and analysis capability (e.g., monitoring and recording real time energy use data for analysis of building operations; and billing analysis and reporting to detect errors and aid in decision making). Limited load controls may be added to allow automated response to utility-requested events and to analyze the effects of operational changes made in response to an event cost effectively.

An EIS can operate independently from an EMS or serve as the gateway for two-way communication between a utility and existing EMS. Like EMS, facilities install EIS systems primarily for load management and energy information rather than for use in participating in DR specifically. However, the fraction of facilities using EIS for DR in conjunction with these other goals is slightly higher than facilities equipped with EMS, or about 23 percent according to a California Energy Commission commissioned study of Niagara Mohawk customers’ strategies for responding to real time pricing (Goldman et. al. 2005).

Communications systems between a utility and customers include telephone or facsimile transmission, radio media, the Internet, or wireless paging technologies. Load control devices and monitoring systems can be either load-response or price-response capable and are either one-way or two-way capable. Utilities use one-way communicating devices to alert program participants and/or the appliance directly regarding a DR event. Two-way communicating devices allow utilities to receive reply confirmations from customers and, in the case of meters, send measured event load response (in kWh) to utilities automatically.

One-way communication systems are extremely cost effective and simple to use. However, monitoring and verification of load impact is difficult and prone to error. For DLC programs, verification of load impact involves statistical sampling of participants. Estimated kW site reduction must be de-rated according to some assumed level of load diversity, e.g., the number of participating facilities actually using the air conditioner at the time an event is called.

Though not required for DR programs, two-way communication between the utility and customer control technology is desirable. Two-way systems help utilities monitor the number of facilities "on call" at the time of a DR event, and identify those facilities that override or "opt out" of participating in a specific event. They allow the utility to directly measure every customer's load reduction contribution during an event in (near) real time, lead to more accurate monitoring and verification of load impact, and facilitate settlement of billing or program incentive payments. As such, DR can provide ancillary services such as spinning reserve, frequency control, and voltage support. DR then becomes a valuable tool to use in concert with other resources and gives the utility another approach to managing intermittent generation on the grid. For customers, two-way communication also provides the added benefit of internal feedback for facility mangers to maintain acceptable operating ranges for equipment, or to manage multiple facilities.

Two-way devices are more expensive than one-way control devices; upfront costs can be twice as high. Though more expensive, the advantages offered by two-way systems can be cost effective for a targeted set of customers. For example, for higher consuming customers within a particular rate class, more sophisticated two-way technology helps achieve a greater load shed per event.

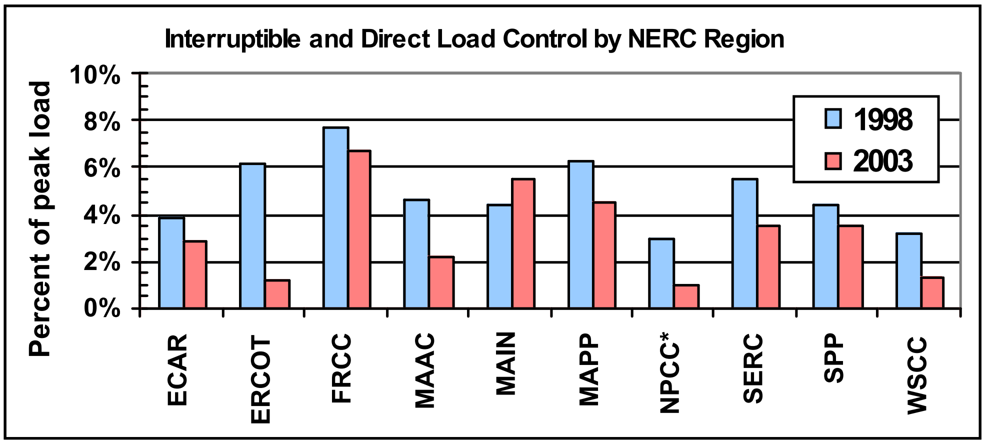
4. Customer Participation in DR Programs

Load-Response Programs Participation

Figure 5 shows the gross quantity of committed Interruptible/Curtailable and Direct Load Control resources by customers in 1998 and 2003 by NERC region. The top three regions with the most amount of customer capacity committed in 2003 are FRCC (Florida Reliability Council), MAIN (Mid-American Interconnected Network), and MAPP (Mid-continent Area Power Pool). These top three NERC regions achieve a minimum of 4 percent of peak capacity reductions available from load response, with FRCC reaching a high of 7 percent of peak capacity. Florida Power and Light (FPL) runs the largest and one of the oldest direct load control programs in the nation, with over 710,000 residential and commercial customers committing 1,000 MW of callable load reductions. The program has operated since 1988. Interruptible and curtailable load control programs commit an additional 1,450 MW of DR capacity.

WSCC (now the WECC or the Western Electricity Coordinating Council) is among the lowest in the nation in terms of customer loads committed for DR, at 1 percent of system peak demand. Of the six states in the Southwest region within the WECC, three states operate commercial DR programs: Utah, Colorado, and Wyoming.

Figure 5. Gross capacity enrollment in interruptible/curtailable and direct load control programs (Goldman and Levy 2005)



*NPCC data are for 1998 and 2002

PacifiCorp/Utah Power operates the Cool Keeper direct load control program for small commercial and residential customers, with 35 MW of gross committed capacity and 15 percent of eligible customers. Utah Power contracts the purchase of DR capacity from the turnkey contractor Comverge[4], who in turn implements the program on the utility's behalf. Comverge is responsible for all marketing, recruiting, and operation of the Cool Keeper Program and guarantees the load reduction provided to Utah Power. The contract period with Comverge is for 10 years, with an end goal of 90 MW of capacity enrollment by 2007. PacifiCorp also operates an Interruptible program and a demand bidding program called Energy Exchange for large customers in both Utah and Wyoming. Although both programs are open to all customers larger than 1 MW, actual participation has been limited to industrial facilities.

Xcel Energy Colorado started a new DR program June 1, 2005 for large commercial and industrial customers with at least 500 kW of curtailable load between noon and 8:00 p.m. The program has both emergency and economic callable events, along with additional design elements that make it more flexible than the company's interruptible program in Minnesota. Customers who sign up are subject to both emergency and economic DR events. For emergency events, customers are given a maximum 10 minutes advanced notice. The credit is calculated as the lesser of the contracted interruptible load, or the customer's peak load during the billing

[4]Other providers of turnkey program implementation for DR and aggregation of small customers include Honeywell, Cannon, Carrier, GoodCents Solutions, and Distribution Control Systems.

period. Customers must agree to curtail their load for a minimum of 4 hours. Non-compliance incurs a penalty of half the annual credit times the amount of load online exceeding the contracted interruptible load during the emergency event.

For economic events, Xcel Energy customers choose among 40 hour, 80 hour, 160 hour, or 200 hours of interruption and a choice of advanced notification periods of 10 minutes, 1 hour, or 8 hours for economic events. Customers must agree to curtail their load for a minimum of 4 hours in exchange for monthly credit on their bill. The penalty for non-performance is the maximum price Xcel Energy pays for power during the event plus any penalties the utility incurs (e.g. generator startup costs). Incentives are tiered-based on the number of hours customers opt to curtail and amount of advanced notification selected.

Colorado Springs Utilities began operating a direct load control pilot program for residential and small commercial customers in the summer of 2005. Customers receive a one-time payment of $25 for participating and the opportunity to keep the thermostat if they stay on for the three-year pilot period. The utility employs a few strategies, 50 percent cycling of customer AC or raising thermostat set points by 4 degrees, with no advanced notification. A total of eight events were scheduled for the 2005 summer, each with duration of 3 or 4 hours. During an event, the thermostat flashes the word "curtailment" on the read-out screen and also shows a countdown clock for how much time is left for the "curtailment" period. Override rates so far average 8.5 percent of participants overriding at least one hour of the curtailment event. Ninety-eight customers are currently participating in the pilot program, achieving an average of 1.5 kW load reduction per site per event.

Nevada Power Company (NPC) operated an interruptible program for one year in 2001 with just two customers, which was never used. On the other hand, NPC successfully operates a residential direct-load-control program targeting air conditioning loads using switches, with committed capacity of 20 MW as of summer 2005.

Price-Response Programs Participation

Participation in price response programs has been increasing in some parts of the country (Goldman and Levy 2005), although actual performance lags behind total enrollments (see "Customer Performance" on page 23). In the West, California had 540 MW of price response capacity in 2004, approximately 1 percent of system peak demand. The state's goal is to increase price responsive capacity for both emergency and economic dispatch to 5 percent by 2007. In the Southwest, Colorado Springs municipal utility operates a critical peak pricing program called Kilowatchers open to all customers 500 kW or larger. The super peak rate is set at $0.15/kwh with on-peak rate of $0.05/kWh and off-peak rate of $0.03/kWh. Total enrolled capacity information is not available, though 2 MW of demand reduction was achieved in 2003. Eleven large C&I customers are participating in the program for summer 2005.

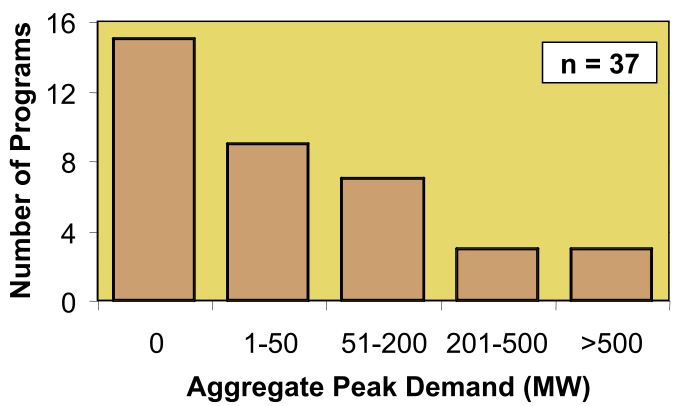
Table 5. Demand bidding program enrollment compared to other demand response programs

	California[5] (MW) committed	% of all programs, in MW	NYISO (MW) com-mitted	# of registered participants, NYISO
	2004		2004	
Interruptible/Curtailable	1095	59.5%	1523	2030
Demand Bidding	**152**	**8.2%**	**376.9**	**17**
Other Price Response	16	0.9%	0	0

Table 5 provides available participation information from California, NYISO, and PJM programs. Demand-bidding programs receive far fewer customers than other types of demand-response programs because of the need for large (>1 MW) load curtailments[6] and for greater time commitments to monitor prices and submit bids. Note that NYISO demand-bidding customers comprise less than one percent (<1%) of total participants in the program but make up almost 20% of subscribed load reductions in 2004. Customers are also deterred from demand-bidding programs when there are binding contracts for load reduction or penalties; they are generally averse to bidding in the energy market.

In California, the participation in demand response in general is concentrated in programs that have interruptible/curtailable load, with the demand-bidding programs contributing just 8.2 percent of the total capacity (MW) enrolled (Table 5). There were over 1100 more participants in NYISO's Emergency Demand Response Program (EDRP, which has no penalties) than the Day Ahead Demand Response Program (DADRP, which is a demand bidding program) in 2005, although the size of the committed load is comparable to the EDRP.

Figure 6. Real-time pricing program participation levels, 2003 (Goldman and Levy 2005)



[5]California Energy Commission. "Demand Response Hardware and Tariffs: California's Vision and Reality," ACEEE Summer Study, August 2004, "Demand Response Programs/Tariffs Investor Owned Utilities as of June 2004 MW Available" (Slide 11).

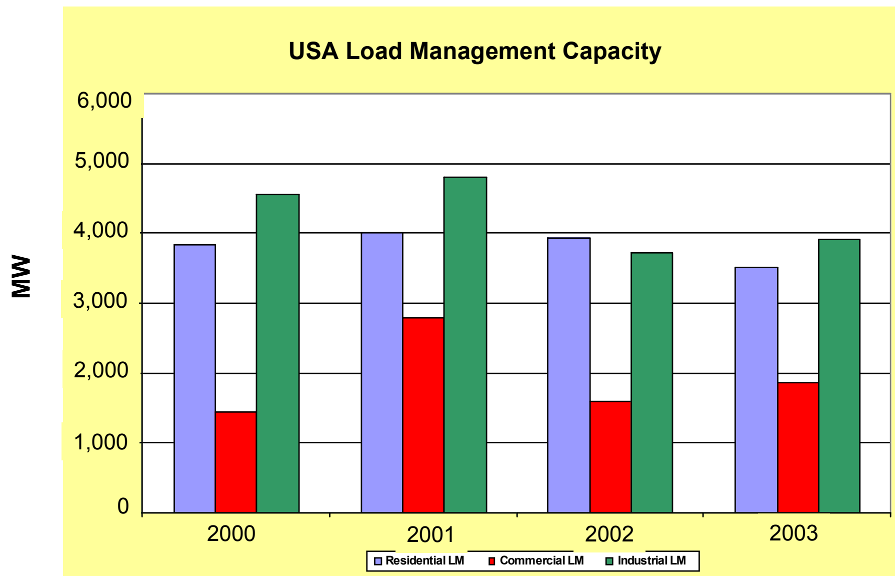
[6]An exception is SDG&E's demand bidding program, where customers with average monthly demands of just 20 kW and greater are eligible.

In 2003, approximately 2,700 non-residential customers and 11,000 MW were enrolled in RTP programs, in twenty-seven states across the country (see Figure 6). However, three of thirty-seven programs surveyed accounted for 80 percent of customers and 80 percent of gross load enrolled: Georgia Power, Tennessee Valley Authority, and Duke Power (Goldman and Levy 2005). RTP programs exist in the Mid-Atlantic region, Southeast, Midwest, and Western coastal states, but virtually none exist in the New England region or interior West.

Facility Types

Figure 7 shows the amount of registered capacity in all DR programs in the country by sector. The total capacity committed each year has declined from 2000-2003. Industrial and residential accounts make up the majority of total registered capacity. Industrial customers participate in both load and price response programs (except direct load control) while residential customers participate predominantly in DLC programs. On average, commercial facilities comprise between 15 and 20 percent of participating load reduction potential. Note that actual load reduction performance achieved is substantially less than the gross capacity committed, as discussed in the program performance section below.

Figure 7. Gross committed DR capacity by sector in the U.S. (Welch 2005)



It is more challenging to enlist commercial facilities in DR compared to industrial customers. Many facility owners and managers are rightly concerned about the comfort of their building occupants during a DR event, and require more marketing, education and assistance to enlist participation. Unlike industrial facilities, commercial facilities feel they have less flexibility in dropping or rescheduling loads (see discussion on customer reduction strategies above). The typical commercial facility lacks technologies that facilitate load shifting, and facility operators lack the knowledge to operate building control technologies for DR and to implement load management strategies.

Different commercial facilities also have different levels of operational risk when reducing air conditioning, lighting, or process loads. A hospital, for example, is usually reluctant to turn down air conditioning or lighting, since diminished? occupant comfort or disruption of care could harm patient health and staff performance. Nevertheless, hospitals do participate in DR programs by employing backup generation or thermal storage technology.

As an initial screen, facilities most suited to DR are those exhibiting high load consumption coincident with the utility's system peak. Some commercial facilities, such as offices (Figure 8) and retail stores, have a "peaky" load consumption pattern that reaches a maximum during the daytime hours and taper off in the evening and early morning. Other types of facilities, such as hotels (Figure 9), restaurants, hospitals, warehouses (non-refrigerated), and some manufacturing and industrial processes, consume energy more consistently throughout the day. As long as a facility has load available for reduction when a utility is experiencing peak demand on the system, the facility is candidate for DR.

Retail facilities can participate in DR relatively easily. Most retail stores are patronized predominantly by "buyers" (as opposed to "shoppers"), who spend less than half an hour in stores. These buyers are not on the store premises long enough to notice that the temperature indoors is a few degrees higher than usual, particularly if they just entered the building on a hot summer day (RMI 2002). With the exception of stocking shelves, which could create some temporary discomfort, physical activity by building employees is generally minimal. Employees in stores that have shoplifting issues may be concerned that decreases in lighting could exacerbate problems. "Big box" national retail chain stores have successfully participated in DR pilot programs. Companies such as Cost Plus, Petco, OfficeMax, and Sportmart (Gart) employ centralized control technologies to manage energy consumption for a population of geographically dispersed stores (see "Technology Options" section), in addition to participating in demand response (ICF 2004).

Figure 8. Typical summer day load curve for generic large office (EPRI 1998)

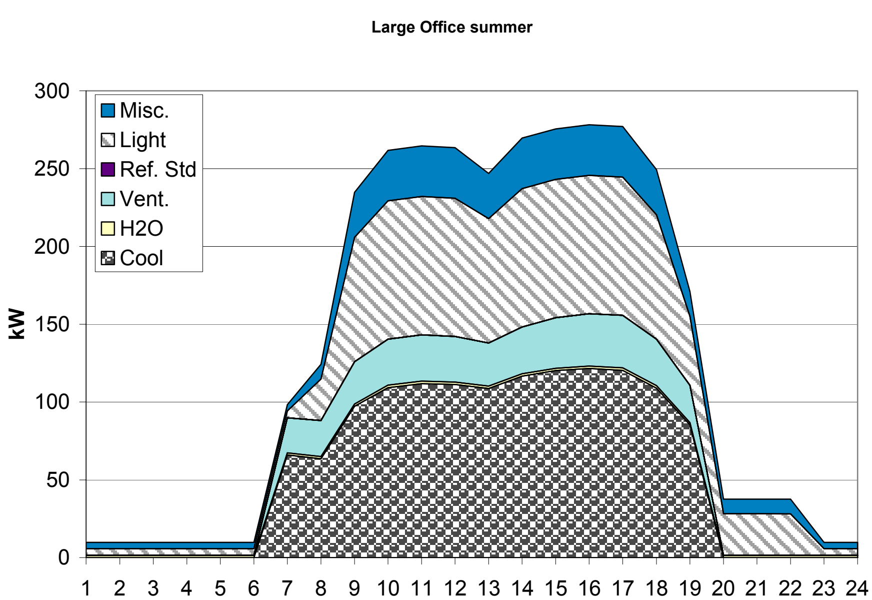
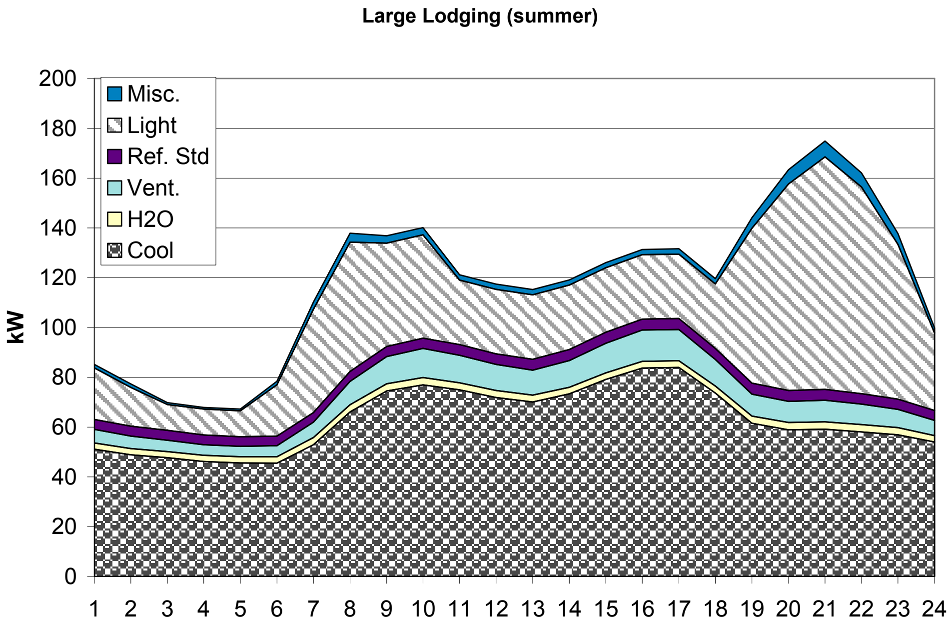


Figure 9. Typical summer day load curve for generic large hotel (EPRI 1998)



In areas of the country where tourism is a significant portion of the local economy, hotels, resorts, and casinos contribute a large portion of the system load. Their participation in DR creates significant benefits in terms of alleviating capacity constraints and helping other facilities maintain operations. Resort facilities in places such as Las Vegas, NV, Anaheim, CA, and Hawaii generate significant revenue for almost 24 hours a day during the high season. Closer examination, however, reveals that activity is concentrated in a few zones within the facility.

An effective DR strategy for large hotels and resorts is segmentation among business units to capture a greater portion of available potential. Unoccupied hotel rooms and ancillary areas are prime candidates, especially if controllable through a central energy management system[7]. Conference rooms or convention space and theaters are also good targets for DR. Energy managers can coordinate with booking and event scheduling to pre-cool meeting areas in anticipation of use if a load reduction event is needed that day. Lighting and HVAC in kitchen and dining areas can be turned down between peak meal hours, and use of appliances and specialized equipment such as heat lamps and microwaves can be modified. Miscellaneous loads in common areas can also be flexed, such as elevators or escalators, fountains, outdoor signage, exhibits lighting, pool lighting and pumps.

In spite of these options, however, only a few of the largest hotels have been willing to implement these load flexing strategies due to concerns for their patrons' comfort. Participating

[7] Depending on the hotel, guestrooms and service rooms (e.g., laundry, vending area) may already have conservation measures such as occupancy sensors or timers that turn off lighting when unoccupied, which reduces DR potential. Furthermore, some hotels are equipped with guestroom keys tied to the master switch for the room. On the other hand, guest room keys may not operate thermostat controls, which must be turned off manually by the building engineer or via an energy management system if left on when the guest vacates the room.

hotels have noted that patron comfort is not significantly compromised, and that guests willingly cooperate under emergency or extenuating circumstances. Two notable case studies include the Marriott Marquis in New York City and Doubletree Hotel in Sacramento. The Marriott leveraged its existing EMS system to participate in a pilot RTP program in 1997 with Consolidated Edison and EPRI. By linking its system to real-time hourly pricing information from the utility, the hotel was able to reduce load by 20 percent (Hirst and Kirby 2001). The Doubletree hotel in Sacramento, through its participation in California's Enhanced Automation campaign, installed new automated load controls to reduce its overall energy use by 11 percent, while also participating in Sacramento Municipal Utility District (SMUD) voluntary load curtailment program (CEC 2004).

Why Customers Participate

Customers express a variety of reasons for participating in DR programs, ranging from monetary savings, to the desire to help avoid blackouts, to a sense of corporate responsibility (PLMA [a], 2002). Successful DR programs increase customer awareness of the benefits of demand response and enhance their customer's ability to participate through use of control technologies like smart thermostats and energy information, resulting from technologies such as EIS. Enhanced automation and building energy management help customers manage loads optimally for demand response and save money through increased energy efficiency. Other customers recognize that participating in demand response programs could help avoid future blackouts, which are hugely disruptive to commerce and communities. Finally, some customers have expressed a desire to participate in demand response programs out of a sense of corporate responsibility. Helping the utility avoid or delay costly capital investments in additional central power plants, benefits both the community and environment.

Barriers to Customer Participation

Numerous concerns and uncertainties deter customers from participating in DR programs, but none is insurmountable. Potential customers may be uncertain about how much load is available for reduction during an event. They may have concerns about the financial viability of participating in a DR program and about maintaining occupant comfort during a DR event. They may also dislike the inherent uncertainty of price response programs and face high information search costs. Further, they may hesitate to participate if they do not perceive a utility emergency on the scale that warrants response. Utilities can address many of these concerns through smart program design and coordinated assistance.

Successful DR programs provide customers with a limited choice of programs and allow them to participate in more than one program (e.g., a pricing program and an emergency program). Too many options overwhelm customers and deter participation. No single DR program will fit all commercial and industrial customers. Even within an industry, different facilities have different technical, financial, and informational needs, and will be at different stages of decision-making.

Customers may also have widely varying technology needs. Some customers may already have EMS systems or other control technologies installed, but underutilize them. Others may have very little investment in building automation and controls. In both cases, customers often end up relying on manual strategies and therefore fail to fully achieve their DR potential. Manual load reduction strategies require that the customer be present on site at the time of a load reduction event and may incur high transaction costs. Properly employed control technologies, on the other hand, can relieve the customer of this burden and provide more consistent load reduction.

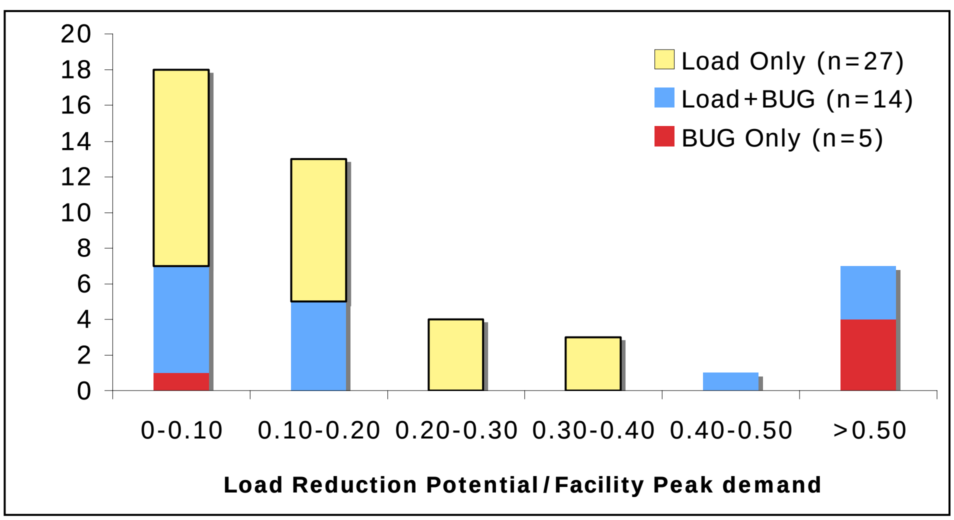
Utilities should provide an integrated package of services to move customers through various stages of program participation and technology adoption. The services must be coordinated to increase customer awareness about program and technology options and program incentives provide financial assistance for enabling technologies, and provide brokerage/mediation assistance such as locating and hiring contractors (CEC 2004). Small (<100 kW) and medium customers (100 – 500 kW), in particular, may not have established relationships with vendors. Customers will be more likely to participate if utilities work with them on designing and implementing DR programs.

Once customers are enrolled and participating in a DR program, they may drop out again if incentives are inadequate, if there are delays in receiving incentive payments, or if they are unable to shift loads within the required time frame. Thus, utilities should maintain contact with participants and help them realize positive outcomes.

5. Program Performance

On average, customers can achieve between 10 percent and 20 percent load reductions when called upon by the utility, and by using manual reduction strategies and simple controls. A higher percentage reduction is achievable by employing automated load control technologies. For commercial customers using more advanced demand response technologies including automated response, load reductions of 20 to 40 percent are possible. For participants who also use backup generation (BUG), load reductions of 50 percent or more are reported (Figure 10).

Figure 10. Customers' assessment of their achievable DR capability (Goldman et. al. 2002)



Note that these load reductions are for facilities that participate in DR events. In direct-load-control programs, actual participation rates? in events are typically 75 to 80 percent of total customers enrolled; with 20 to 25 percent non-participation from overrides and load diversity, though some utilities experience better performance (10 percent overrides or less) (RMI 2005). Customers must have load to curtail when they are asked to do so by the utility, and load diversity refers to customer loads that are not available or not operating at the time of an event.

There are a couple of ways to reduce overrides. Long Island Power Authority (LIPA) noticed that many direct load control participants were overriding without realizing they were in utility-called load reduction events. The utility sends a second curtailment signal to the customers' central AC unit one hour and again two hours into a curtailment event. This method reduced override rates to 7 percent. Another method is employed by NPC in their residential automated DR pilot program. The program utilizes an advanced, home energy control system that gives more control to its customers. Override rates in the pilot program are lower (11 to 20 percent) than in their direct load control program, where customers are not given control and utilities cycle AC units during curtailment events (20 to 30 percent override rate).

Actual load reduction performance of curtailable and interruptible programs for large commercial and industrial customers can comprise up to 40 percent of committed load enrolled in the programs. For price-response programs, actual load reductions are also less than the amount of enrolled commitments. Table 6 shows actual participation versus enrollments for load and price-response programs in three deregulated power markets where evaluation data are available: PJM, ISO New England, and the New York ISO. Different participants may respond during some events and not others, or during some hours of an event lasting many hours. Often, a load shed strategy for DR events is implemented by one key facility contact. With few exceptions, facilities participating in DR programs do not use automated load-response technology. If the key facility contact is absent or engaged in other commitments at the time of the notification, he/she may not be able to return to the facility control center in time to respond within the notification time frame (hours to minutes). Actual amount of load shed is also a function of the severity of penalties for program non-performance.

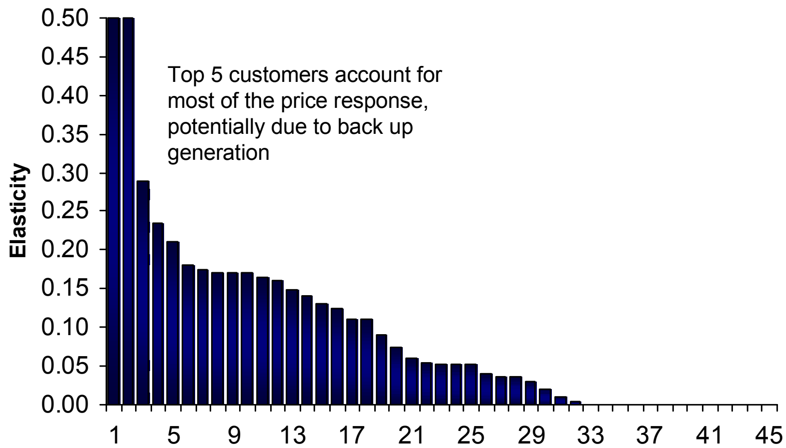
Table 6. Latest available event performance data versus enrollment of three DR programs

			PJM (2003)	**ISO NE (2003)**	**NY ISO (2003)**
Curtailable/ Interruptible	# Participants	Enrollment	168	87	1536
		Event performance	n/a	**53.1%**	n/a
	Load	Enrollment (MW)	659	204.2	1708
		Avg event performance	**7.1%***	**36.6%**	**41.0%**
		Max event performance	n/a	53.1%	n/a
Price Response	# Participants	Enrollment	245	175	17
		Event performance	n/a	**37.9%**	n/a
	Load	Enrollment (MW)	724	106.4	376.9***
		Avg event performance	**20.7%****	**79.9%****	n/a
		Max event performance	**123.6%**	n/a	n/a

*Only one emergency event was called by PJM in 2003, on August 15.
**Real time pricing programs
***Day ahead pricing program participation as of February 2005

For specific participants, various studies of how firms adjust electricity usage based on price changes converge upon a price elasticity range of -0.05 to -0.15 for large commercial and industrial customers (Neenan 2003). This indicates that a doubling of the price per MWh results in a 5 to 15 percent reduction in load. Price response participants seem to have a higher price elasticity on average than load response participants (Neenan 2003). A few of the largest participants generally account for the majority of the load shed performance, as the ISO-NE evaluation indicates in Table 6 and is supported by the Georgia Power study shown in Figure 11.

Figure 11. Georgia Power C&I real time pricing customer elasticity (Reiss 2004)



Empirical research further indicates that average load curtailments per participant achieved in practice are higher for reliability programs than for economic programs. In one survey, actual load curtailed for reliability programs was 50 percent of customer baseline load, but just 10 percent of customer baseline load for economic programs (Heffner 2002, NE ISO 2003). Possible explanations for this difference include:

- Programs where customers do not commit to a specified amount of reduction per event result in lower actual reductions during an event (Heffner 2002);
- Wholesale electricity prices are the primary incentive in economic-based programs and may not always be high enough to induce curtailment (Heffner 2002);
- Voluntary price-response programs are relatively new compared to load-response programs, meaning that most customers are still adjusting and learning how to respond. One survey of early industrial price elasticity revealed that the longer customers were subject to an RTP rate, the greater their price elasticity, indicating that customers adapt to price response with experience (Schwartz et. al. 2002).

Energy Savings, Efficiency, and DR

Net energy savings (measured in kilowatt hours, or kWh) from DR are small compared to the amount of load (measured in kilowatts, or kW) reduced or shifted, particularly in load-response programs where utilities call on customers to reduce load a very limited number of times per year (e.g., 10 times per year for a duration of 2 to 4 hours each). For example, a typical 30 MW small commercial program that is called 10 times per year for duration of 3 hours each, would reduce electricity at most by 900 MWh per year. A typical large commercial program consisting of a utility's 20 largest customers shedding 1 MW load per event for 10 events, lasting 3 hours each, saves 600 MWh per year at most. Furthermore, because DR shifts energy use in time or to a different source, some of this energy reduction is reversed during the remaining hours. The net result is small to negligible net energy savings for the year. Energy efficiency programs, on the other hand, can achieve several to tens of GWh per year in (permanent) savings on average[8].

While utilities commonly operate energy-efficiency and demand-response programs independently of one another, these two types of demand-side resources are not mutually exclusive. Efficiency and demand response fulfill different but complementary goals for utilities trying to serve customers cost effectively, while complying with environmental protection regulations. Demand response has an extremely valuable role to play in lowering peak power requirements, and in creating a price elastic response to future market manipulation by generators. It not only relieves generation capacity, but delivery capacity via a utility's transmission and distribution system during times of peak demand. Thus, the impact made by demand response is generally temporary, and takes place in the short term.

Efficiency, on the other hand, provides long-term energy reductions of a utility's overall system load, lowering energy costs for customers. Because existing electric generators effectively produce less energy when customers are more efficient, they also emit less environmental pollutants such as sulfur dioxide and nitrous oxides, which have local impacts. This is true also, for carbon dioxide, which contributes to global climate change. Thus, the benefits of energy efficiency occur over a longer-time horizon compared to DR,which is on the order of months and years.

Utilities should couple demand response with efficiency programs as part of a demand-side resource package to leverage the different strengths of each for an optimum resource plan. Implementing a coordinated efficiency and DR program portfolio can help flatten the utility's system load curve, lower prices for power and gas considerably, and defer new plant construction with subsequent benefits to both the utility and its customers. From the customers' perspective, combining EE and DR may be necessary to create an adequate value package (e.g,. efficient technology may be an effective means to mitigate customer comfort concerns about participating in DR efforts).

Facilities with lighting and HVAC controls, EMS and EIS systems can use them for both DR and efficiency, to reduce peak demand charges and achieve long term energy cost savings. Program participants better understand the nature of their energy use and the corresponding costs. Such knowledge can motivate customers to take further steps to reduce facility energy use and costs. There is anecdotal evidence, based on four large retail and department store chains (BJ's, Kohl's, Lowe's, and Wal-Mart) testimony in Georgia Power's 2004 rate case that, as a result of taking service on RTP, their companies installed a range of permanent measures to reduce peak electricity demand and to take advantage of low off-peak prices. These measures included: high efficiency air-conditioning and building envelope components; fuel switching (e.g., gas-driven desiccant cooling systems); and electric heating (Civic et. al. 2004).

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[8]Data based on national efficiency programs survey conducted by Rocky Mountain Institute, 2004.

6. Utility Costs and System Benefits

Technology investments to enable DR in customer facilities are a large part of a DR program, and utilities regularly help customers finance these costs. Technology investments are also needed at the utility end to facilitate the buying and settlement of load reductions from customers. Price responsive programs incur higher investment cost to utilities compared to load response programs. Data volume increases exponentially with the need to collect and record CPP- and RTP-based consumption. As a result, existing utility settlement systems need to be enhanced with more sophisticated database applications in order to handle the more complex rates and incentive payments to participants. Programs such as demand bidding, which necessitate customer interaction with utilities, require electronic interfaces to display asked prices and to verify and execute load reduction bids. Further, many utilities implement both load and price response programs simultaneously, and curtailable and interruptible load programs require utilities to keep track of customer-specific contracts used in billing major energy customers.

Though price response is more complex to implement, the cost of incentive payments in load-response programs can also be burdensome for utilities. Without a direct connection to electricity market costs, incentive structures for load-response programs are extremely difficult to get right; there is a delicate balance between paying enough to entice customers, while retaining some of the system value for utilities. Utilities pay customers for loads reduced relative to some baseline consumption in both load and price response programs. Baseline determinations are difficult to establish, since it is load that consumers would have consumed had the curtailment event not occurred. Consistent baseline estimation methods can encourage greater participation in DR. Various baseline calculation methods applied by utilities and ISO's aim to strike a balance between the following criteria:

- Simplicity and ease of use; transparency to utility and customer
- Verifiability
- Accuracy
- Minimization of participant gaming
- Weather sensitivity adjustments, and
- Low implementation costs

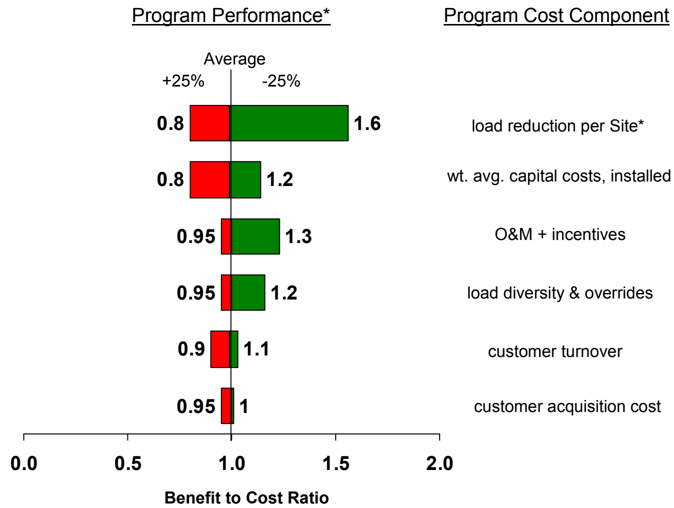
System benefits of DR include deferred or eliminated generation capacity expansion, deferred or eliminated transmission/distribution capacity expansion, and reduced plant-operating costs.[9] These benefits are measured in terms of the marginal generation and distribution capacity cost avoided, as well as marginal energy cost. The higher the avoided costs, the more attractive DR is to the utility or ISO. Additional benefits that are less frequently quantified include supplemental reserve value of verifiable, interruptible load and reduced need to purchase on-peak power, which leads to moderation of power market prices. Lowering demand by 5 percent of the system's maximum can reduce peak wholesale power market prices by 90 percent, as utilities and independent system operators reduce their need to purchase on-peak power (RMI 2002,

[9] More specifically, shifting of consumption away from peak hours to lower cost energy supply periods.

Wood 2005). The ability for utilities to stage deployment of DR programs[10] can be used as an option to manage the risk from future power market price spikes.

DR program economics are most sensitive to the amount of load curtailed per site and upfront technology costs (see Figure 12). Program incentive payments, operation and maintenance costs, churn (percent of customers who drop out of the program), and overrides also matter to the degree that they impact the amount of curtailed load per site. Other factors, such as customer acquisition costs and program administration, play a small to negligible role in determining program cost effectiveness.

Figure 12. Relative sensitivity of program value as measured by b/c ratio to program performance and various program costs



*Program performance key (+ or - 25%) applicable to all cost components except load reduction per site. Benefit-cost ratio increases when load reduction per site increases.

In terms of site load reductions, then, mass-market direct load-control programs for residential and small commercial customers are usually cost effective, because the technologies employed are simple and easily achieve load reductions of 1 kW or more[11]. For price responsive programs aimed at small customers using more sophisticated technologies such as two-way communicating thermostats or whole building EMS, load reductions of 2 kW or more must be achieved to realize cost effectiveness.

For medium-sized commercial customers (100kW-500 kW), utilizing technology to control lighting and HVAC, load response programs are cost effective when facilities can reduce load by about 25 kW or more. Price-responsive programs require greater load reductions per site to achieve program cost effectiveness, or a minimum of 30 kW or more per curtailment event.

[10] In other words, recruit and commit 10 MW the first year, 20 MW the second year, and so on. Thus, commitment is flexible and can be deployed in response to demand growth and market conditions. Once the load commitment is in place, "operation" of this demand-side resource is also quite flexible. Load reductions are reliably dispatched, and can be ramped up or down in response to system needs in order to compensate for loss of generation.

[11] Conclusions in these following paragraphs are based on RMI analyses.

Large commercial and industrial customers using automated lighting and HVAC control technology typically need about 50 kW or greater reductions in load response, or 300 kW reductions, for price-response programs to achieve program cost effectiveness. As mentioned above in the technology section, large customers installing facility-wide EMS systems generally cannot realize a positive return on their investment on load reductions alone, even in the presence of generous utility subsidies. EMS systems in large facilities are typically installed with the aim of managing energy consumption and improving facility reliability for the long term, with demand response participation as an incremental benefit.

Studies reporting benefit-cost ratios of demand-response programs are few. Evaluation methodologies are inconsistent and reporting methods for results are mixed, thus making it difficult to compare projects.

For small customer direct-load control programs, available reports merely state whether the benefits exceeded costs. Consolidated Edison Company of New York, Inc. (Con Edison), in cooperation with the New York State Public Service Commission (NYPSC) and other state agencies, operated a residential and small commercial load-response program with a two-way system for thermostat control. The program was reported as being cost effective, but quantitative economic evaluation was not available (Egan-Annechino et al. 2005). Similarly, Long Island Power Authority states that a total of four events are needed per year for its residential direct-load control program (LIPAEdge) for the program to be cost effective (Jackson 2005). Finally, an economic evaluation of a residential demand-response program using a two-way system for thermostat and pool control for Nevada Power Company found that the program was cost effective, with benefit-cost ratio close to 1.0 (RMI 2005).

For emergency and economic demand-response programs, three reports are available on cost benefit analysis from the NYISO, NE ISO, and PJM. The NYISO states that their demand-response programs are cost effective, with benefit-cost ratios of 2.7 to 3.0 for its emergency capacity and day-ahead demand-bidding programs from 2001-2004[12]. Benefit cost ratio estimated for the demand-bidding program in 2004 was less than 1.0, resulting from below average power market prices and lack of demand response events that year. PJM did not report benefit-cost ratios but stated that "the potential benefits of increasing demand side responsiveness in improving efficiency of the market are extremely large and certainly exceed the relatively small program costs by a wide margin." (PJM 2003). Furthermore, PJM continued "It was not necessary to [include calculation of reliability benefits] to demonstrate that there are substantial net benefits to the Economic Program."

Both the NYISO and PJM benefit-cost assessments, however, included only program costs such as program administration and incentives paid to customers in exchange for load reductions. The NYISO study also included annual maintenance costs for software development and support. Benefits were only assessed in terms of market price impacts (i.e., reduced market prices) and reliability benefits. This method may be too optimistic and thus overestimate program cost

[12] NYISO. 2004. *Seventh Bi-Annual Compliance Report on Demand Response Programs and the Addition of New Generation in Docket No. ER01-3001-00*. Prepared for Federal Energy Regulatory Commission. December 1. Retrieved March 23, 2006 from http://www.nyiso.com/public/products/demand_response/index.jsp.

effectiveness, as it does not consider any incremental costs for facility technology investments and any system capital costs relating to demand response.

The NE ISO economic evaluation reported benefit-cost ratio of 0.9 for both its emergency program and a ratio of 0.5 for its economic demand response program for 2002 (Townsley 2003). Unlike the NYISO and PJM evaluations, the NE ISO evaluation included first-year infrastructure costs along with customer incentive payments in its cost equation. These first-year infrastructure costs included:

- Purchase of the RETX demand bidding computer system,
- Incremental customer investments in load management technology,
- Incremental customer investments in self-generation technology, and
- Customer operational costs associated with load shifting or load reductions.

Additional utility costs included in the NE ISO economic evaluation were customer equipment rebates, program incentive payments, and direct ISO and utility costs relating to the programs.

Evaluation of NE ISO program benefits also differed in method from the NYISO and PJM evaluations. In addition to quantifying how much demand response reduced market clearing prices and improved reliability, NE ISO also included as part of program benefits valuation avoided capacity costs and avoided transmission and distribution cost.

The report explains that the low benefit-cost ratio was due to relatively high incentive payment costs and accounting of technology costs during first year only. The report states that the technology investments will likely generate additional benefits in the future and thus improve program cost effectiveness. For the economic demand-response program, the NE ISO study found that increasing the number of hours that customers are called upon to reduce load would improve benefit-cost ratio above 1.0.

Technology, Rates, or Both?

Automated technology enhances the responsiveness of a facility participating in a demand-response program by enabling the facility achieve a higher percentage of its load reduction potential. Program evaluation studies in California by Rocky Mountain Institute (RMI 2005, RMI 2006) indicate that technology appears to be an important driver in reducing load, especially super peak load, for higher consumption customers within a rate class. Automated technology can help produce consistent load reductions across the cooling season, even for consecutive event days.

Dynamic rates such as CPP or RTP have also proven to be effective in engendering load reduction from customers. In economic programs, industrial and large commercial customers exhibit the greatest price elasticities, but, without automation, they achieve these load reductions by using backup generation, shifting operations, or manually shutting off loads whenever possible (Goldman and Levy 2005). For lower-consumption customers within a rate class, RMI found that most of the observed load reductions appear to be due to rate effects (RMI 2005, RMI 2006).

RMI's findings from the residential demand-response program evaluations suggest that either automated technology or dynamic pricing can deliver significant DR for customers, but that the combination of both technology and dynamic pricing might not be necessary (RMI 2006). This insight also applies to small commercial customers. If a utility implements a load response program with technology, the utility and customer can work out a mutually beneficial arrangement to share the technology cost and the savings from the load reductions . The program accrues all of the benefit from load reductions, and cost effectiveness is a function of the relative cost of the technology installed.

On the other hand, the picture becomes slightly more complicated when a price-response program is implemented along with automated technology, because the rate effect would capture captures? some of the load reductions. As such, the incremental load impact attributable to the automated technology would be reduced. Whether or not the program using the technology is cost effective will depend on the incremental savings attributed to the technology, compared to the technology cost.

The technology cost, in turn, is a function of how much is already paid for in the system network set up to operate price response. Namely, the advanced metering and communications network that must already be in place for a price response program to operate. If the DR technology cost (smart thermostat, other automated load controls, and software) is small relative to the system cost, then it will be more likely that the incremental load impact and savings benefit will compensate for the technology cost, and therefore the price response program will more likely be cost effective. If the DR technology cost is large relative to the system cost, then it is less likely that the technology will capture enough incremental savings to compensate for its cost. As such, the program will probably not be cost effective.

7. Conclusions

Demand-response programs are experiencing renewed interest among utilities as a tool for tempering market power and volatility. Success in creating demand response as a viable energy resource, however, has been mixed. Utilities continue to struggle with both increasing and retaining customer enrollment, as well as motivating participation. Particularly for interruptible load and real-time pricing for large customers, a small minority (~1%) of participants contribute to the majority of load reductions during demand response events (about 20% or more of total load reduced per event). While many utilities around the country implement demand-response programs, only a handful of programs have achieved significant and stable capacity resources in the form of demand response.

In this report, we introduced the spectrum of demand-response programs and program technology options. In addition, we attempted to extract elements of successful programs that can help utilities increase their demand-response program performance. These elements are highlighted below.

- Programs that recognize the diversity of customers and provide them with a portfolio of program options are most successful at engaging and retaining participation. Those programs that also provide customers with a choice of participation levels and incentive payments--within the specific program option--achieve better retention than programs that do not give customers control over load reductions. At the same time, customers are typically unsure of the amount of peak load they have available for reduction and may lack the capability to reduce loads when called. Utilities or program sponsors often must assist customers in understanding their facility's loads, and provide financial and technical assistance, to help customers achieve peak load reduction potential cost effectively.

- Targeting the right end-uses and identifying the subset of facility types that are most suited to benefit from DR can help achieve greater peak load reductions. HVAC and lighting are the most common end uses targeted for DR, although non-critical loads such as certain plug loads, outdoor signage and motors can also be employed. Automated control technologies enhance DR capability and provide customers with ancillary benefits, such as detailed energy consumption data. Control technologies can be cost effective, but economics are highly sensitive to the amount of kW load reduction achieved per site, technology's capital and maintenance costs, and participation rates per callable event.

- Interruptible load response is targeted at large (>500 kW) commercial and industrial customers and is traditionally used for emergency programs only. However, emergency programs have a narrow application and because they are called a very limited number of times per year (less than 5), they can be costly if utilities pay incentives for participation whether or not any emergencies are called in a given year.

- Economic programs provide the ability to more broadly call on customer load reductions outside of emergencies to serve other purposes, such as reducing overall electric system costs and diffusing market power. Dynamic pricing or demand bidding can be practical for the largest customers (>1MW), as the programs require ongoing involvement or more sophisticated control technology. Large customers traditionally have relied on manual strategies for DR, such as shutting off or shifting loads, or else running backup generation. Automated control technology is often non-existent or underutilized.

- Automated DR technology often produces greater and more consistent load reductions over manual strategies, as well as allowing for remote customer control. Another advantage is that facility management personnel do not need to be present at the site during a DR event and can use technology to pre-program preferred responses to utility requests for curtailment. Two-way communication is recommended, as it allows the utility to directly measure customers' load reduction contribution during an event in (near) real time, leads to more accurate monitoring and verification of load impact, and facilitates settlement of billing or program incentive payments. Two-way communication allows customer loads to serve as capacity reserve and in essence operate fully as dispatchable capacity.

- Although large customers are often the primary targets of DR programs, load response and dynamic pricing can also work well for small and medium enterprises. For small to medium retail customers, automated technologies greatly enhance the responsiveness of a facility participating in DR. On the other hand, pricing signals appear to be an important driver for the lower consuming segment of the small customer sector. This suggests that either automated technology or dynamic pricing can deliver significant DR in low-consumption, small customers, but that the combination of both technology and dynamic pricing might not be necessary. Thus, the implementation of automated response technology among small customers requires careful marketing and consumer targeting to ensure performance and cost effectiveness.

The value of DR as a resource will continue to grow in the foreseeable future. The electricity system experiences increasing congestion in many parts of the country with new load growth and eroding reliability as new generation and transmission infrastructure struggle to keep up with the demand. Our hope is that the information contained in this report will help utilities and policy makers implement successful DR programs along with efficiency programs to provide affordable and reliable electricity services to the public.

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