Designing a Successful Demand Response Program: It's Not Your Grandfather's Load Control Program

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ABSTRACT

As demand response (DR) resources are increasingly becoming recognized as a cost-effective way to achieve reliable peak demand reductions, the question of how to design a successful program must be explored. Improved enabling technologies and the emergence of third-party DR providers for procuring DR resources affords the expansion from traditional industrial or residential peak load management programs to include significant demand reduction contributions from commercial and institutional buildings.

This paper discusses the DR program design elements that directly influence the success or failure of a commercial DR program and provides examples of both successful programs and barriers to DR program success. It is presented from the perspective of a DR provider (also known as a Curtailment Service Provider or Aggregator) with experience in working with utilities and ISOs to design and implement successful commercial, industrial, and institutional (C&I&I) DR programs throughout the United States and Canada. This paper covers key DR program design elements including the following: defining program goals and success factors, determining competitive program compensation and structure, measuring performance, selecting response timing and notification processes, defining program availability periods, determining appropriate program triggers, establishing penalty provisions, and deciding upon program administration.

Finally, this paper provides framework for planning DR programs that can be replicated to achieve significant cost-effective and reliable peak demand reductions in the C&I&I sectors.

Introduction

Demand response (DR) is the reduction in a customers' electric load during periods of peak demand or high market prices. Policy makers, utilities, and system operators have become increasingly interested in DR as a cost-effective, environmentally sensible means to meet system needs. The most basic DR programs are structured to avoid blackouts and brownouts. In recent years, however, DR has evolved into a more dynamic resource, providing price mitigation and ancillary services, in addition to improving system reliability.

Historically, utilities have typically made efforts to manage electricity demand by administering energy efficiency and load management programs. Until recently, load management programs have focused on small residential customers and large industrial customers through direct load control or interruptible rate programs, respectively. Through direct load control programs, utility or system operators can interrupt power supply to individual appliances or equipment in homes (e.g., air conditioning and pool pumps). In return, customers receive bill credits or other incentives. Similarly, industrial customers on interruptible tariffs pay lower electricity rates and, in exchange, the utility reserves the right to request a facility shut down during peak demand periods or other system emergencies (Kueck et al. 2001).

While utilities have had success developing large reserves of load management capacity, direct load control and interruptible rate programs have limitations.[1] First, utilities trigger load management events relatively infrequently, resulting in significant payments to customers for a limited resource to the utility. Second, utilities generally cannot observe quantifiable demand reductions during an event, making it difficult to rely on load management programs as dependable resources.

In the last five years, DR has evolved as a new type of load management resource available to utilities and system operators. The recent development of DR has arisen largely as a result of 1) the Internet; 2) improved hardware technology (e.g., metering, control equipment); 3) the increased need for utilities to manage peak demand in a time of rising infrastructure and resource costs; and 4) competitive demand response suppliers entering restructured electricity markets. Thus, forces both internal and external to the traditional utility planning model have converged to recognize the potential of DR to meet future electric system management challenges.

As outlined in Figure 1, DR is distinct from direct load control and interruptible rate programs for several reasons. First, DR programs enable the participation of commercial and light industrial customers, the customer classes that are typically excluded from traditional load management programs. Second, DR programs offer customers choices beyond full interruption or direct control of their end-uses. DR reduction processes can be tailored to meet specific end-user needs. For instance, customers have the option to curtail portions of their load while maintaining power to critical facilities; furthermore, reductions can be automated or manual depending on the sensitivity of the process and customer comfort. Third, DR programs have benefitted from advancements in enabling technologies, such as the Internet, improved advanced metering infrastructure and control equipment. These technologies enable two-way communications between the DR operator and the customer's meter, which provides for overall better management of load curtailments during a DR event. Some enabling technologies are proprietary and may require licensing or other investments; open source technologies can be used with a variety of platforms.

Figure 1. Comparison of Interruptible, DR, and Direct Load Control Program Characteristics

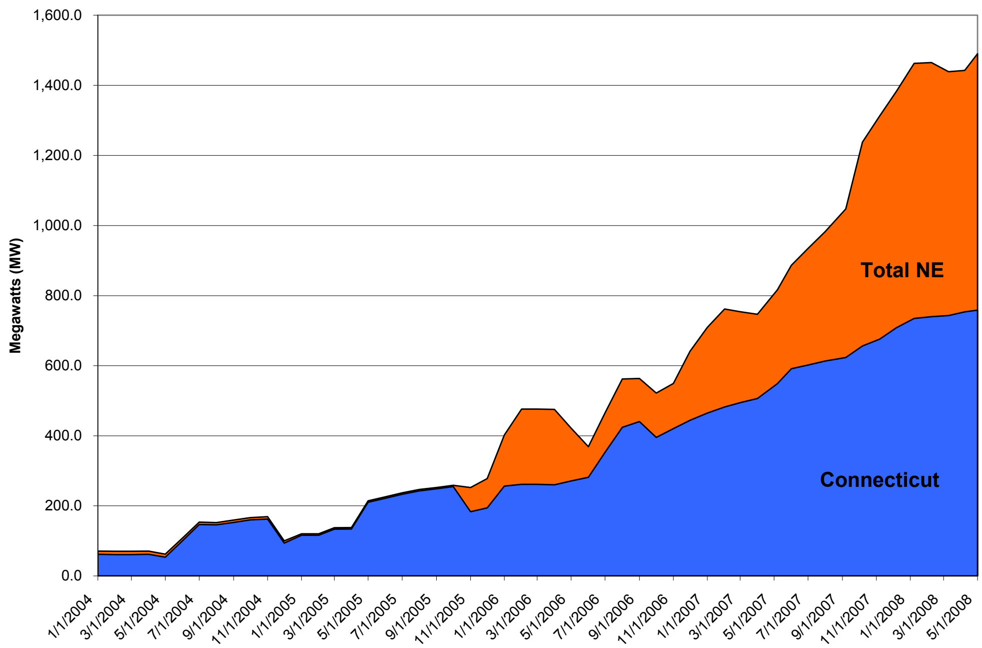
	Interruptible Tariff	***Demand Response***	***Direct Load Control***
Customer segment	Large Industrial	Light Industrial and Commercial	Residential
Capacity (per site)	1 MW and up	100 kW and up	1 - 2 kW
Incentive	Reduced rates	Capacity and Energy payments	Nominal bill credit
Resource profile	Idiosyncratic loads that require customized curtailment plan or full shutdown	Idiosyncratic loads that typically require customized curtailment plan	Common household applications (A/C, water heaters) with automatic utility control
Measurement	Utility interval meter	Interval metering via pulse outputs	Statistical sampling
Reliability	Varies	Can be very high	Varies

Source: EnerNOC, Inc.

[1] For example, in 1995, the Energy Information Administration (EIA) reports utilities had available 16 GW of load management capacity. See, http://www.eia.doe.gov/cneaf/electricity/epa/epat9p1.html.

Finally, the technology improvements realized during the electricity restructuring efforts undertaken in the late 1990s and early 2000s provided both means and ability for utilities and competitive third-party suppliers to begin to enable targeted customer load reductions. Competitive DR providers, also known as curtailment service providers and aggregators, arrived on the scene as a result of the independent system operator of New England (ISO-NE) and New York ISO (NYISO) need for capacity in highly constrained regions. For example, demand response in New England has grown considerably over the last three years. As of May 2008, "30-Minute Real-Time Demand Response" resources in ISO-NE exceeded 1,450 MW as shown in Figure 2. Notably, Connecticut has attracted over 758 MW of this resource, representing about ten percent of the total peak load in that state.[2] This level of DR penetration was previously unattainable with earlier forms of load management programs.

Figure 2. 30 Minute Real-Time Demand Response in New England



Source: EnerNOC, Inc.

How DR Resources Meet Electricity System Needs in the 21st Century

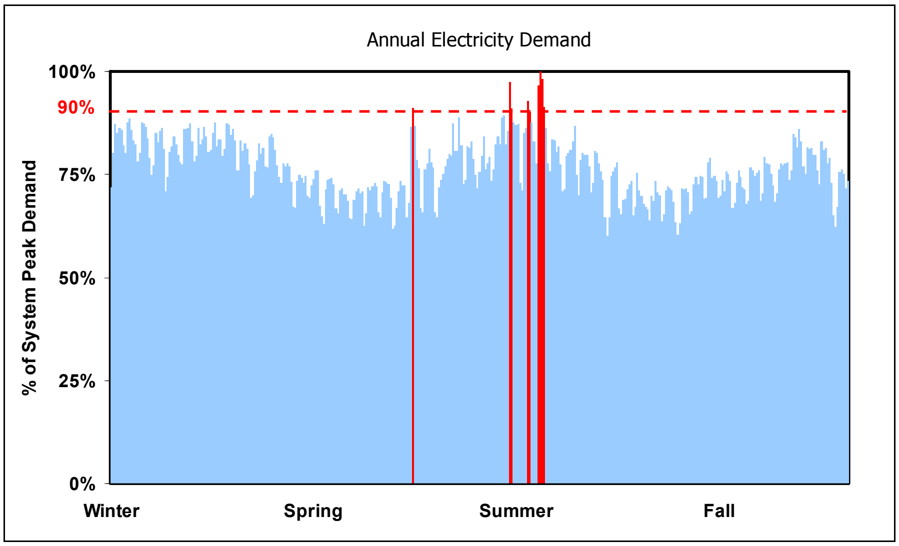
Today's DR resources can address many electricity system needs including improving system reliability, economic dispatch, wholesale price mitigation, and ancillary services. As such, DR can be employed to offset or defer the need for generation, transmission, and distribution infrastructure. This section reviews several of the key system services that can be provided by DR resources.

- System reliability: DR is a capacity resource that can be dispatched to meet many of the same needs as a peaking combustion turbine. Reliable DR is ideally suited to provide

[2] Connecticut's peak demand is 7,367 MW. See, ISO-NE 2006 SMD Hourly Data, http://www.iso-ne.com/markets/hstdata/znl_info/hourly/2006_smd_hourly.xls.

operating reserves during peak demand periods as it can be brought on- and off-line quickly for short periods of time throughout the year. In many systems throughout the United States, up to ten percent of system infrastructure is needed for less than one percent of the hours in the year. DR programs can provide demand reductions during the 50 to 100 hours of the year when demand is highest to relieve peak loading and improve system reliability.[3] Figure 3 shows a typical summer-peaking system where demand exceeds 90% of the system capacity during only a few periods in the late spring and early summer.

Figure 3. In Many Systems, Up to 10% of System Infrastructure is Needed for Less Than 1% of the Hours in the Year



Source: EnerNOC, Inc.[4]

- Economic dispatch: As with a combustion turbine, DR can be scheduled and dispatched by utilities or system operators as part of a resource "stack." A DR resource can set a strike price at which it is willing to respond when the price of energy exceeds that strike price. In this way, DR can effectively offset the need for market purchases or other higher-priced resources. DR can also help mitigate wholesale power prices, especially in congested regions where a few power marketers disproportionately influence energy prices. Since megawatt hour energy prices are largely determined by the price paid for the last megawatt hour produced (the marginal resource), small amounts of DR added to a system can have a significant deflating impact on energy prices. For example, one study showed that in five states in the Pennsylvania, New Jersey, Maryland (PJM) Interconnection, a three percent load reduction in the top 100 hours would yield annual economic benefits of $138-281 million (Brattle Group 2007).
- Ancillary services: In some markets, DR is eligible to provide ancillary services, including spinning reserves and regulation services. In the PJM Interconnection, DR resources are eligible to bid into the Synchronized Reserves and Regulation Markets. The

[3] Of the 8,760 hours in year, 50 hours equals 0.6% and 100 hours equals 1.1% of the total hours.
[4] Graph created using Federal Energy Regulatory Commission, Form 714 data

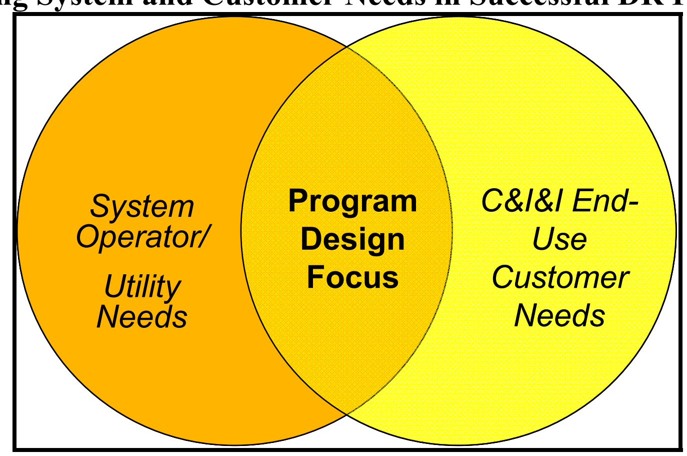
Electric Reliability Council of Texas (ERCOT) has in excess of one gigawatt of DR participating as Responsive Reserves.[5] Other regions are exploring the capabilities of DR as an ancillary service. A recent Federal Energy Regulatory Commission Notice of Proposed Rulemaking proposes that ISOs/Regional Transmission Organizations (RTOs) "…accept bids from demand response resources in their markets for certain ancillary services, comparable to any other resources (FERC 2007)."[6] End-users that can provide near instantaneous response to dispatch signals without a significant impact on business operations are effective ancillary services resources.

As DR resources are increasingly recognized as a reliable and cost-effective way to meet system resource needs, questions are arising among policy-makers, utilities, and system operators as to how to design a successful DR program to meet the specific objectives for each unique system. The remainder of this paper will provide a framework for dispatchable DR program design for C&I&I consumers, using successful DR programs as case studies.

Balancing DR Program Design Elements

Designing a successful DR program is a balancing act. Several key parameters must be adjusted to achieve the objectives of the utility or system operator while accommodating the capabilities and constraints of end-use customers. As Figure 4 below suggests, ideal DR program design considers the needs of the utility or system operator and the C&I&I customers to maximize the potential DR resource.

Figure 4. Balancing System and Customer Needs in Successful DR Program Design



Source: EnerNOC, Inc.

The following are the major program design elements to be balanced when creating a DR program. A successful DR program design will maximize the number of utility customers that are receptive to the program while meeting the needs of system planners and operators.

[5] This program is known as LaaR providing RRS, or Load Acting as a Resource providing Responsive Reserves Service.
[6] For example, ISO New England launched the Demand Response Reserves Pilot in the Fall of 2006 to test the ability for demand response to participate as an ancillary service in that system.

Key DR Program Design Elements

1. Program compensation. The success of a DR program will be influenced by the level and structure of compensation to C&I&I customers. In general, higher payments will elicit increased and more frequent customer demand reductions. Compensation can include capacity payments ($/kW-month), availability/reservations payments ($/kW-hour), and/or energy payments ($/kW-hour). Table 1 shows the different types of payments that are typically included as part of a DR program to compensate these three different products.

Table 1. Types of Demand Response Programs and Payments

	Capacity Payment ($/kW-month)	Energy Payment ($/kWh)	Availability Payment ($/kW-hour)
Capacity Market (Reliability Based Programs)	●	●	
Ancillary Services Market		●	●
Energy Market		●	

For example, in PJM, DR resources in the Emergency Load Response Program receive monthly capacity payments as well as energy payments during events; PJM's Synchronized Reserve Market pays users an hourly availability payment if reserved and an energy payment during reductions; PJM's Economic Load Response Program pays end users an adjusted locational marginal price (LMP) for reductions in the Real-Time or Day-Ahead Energy Markets.

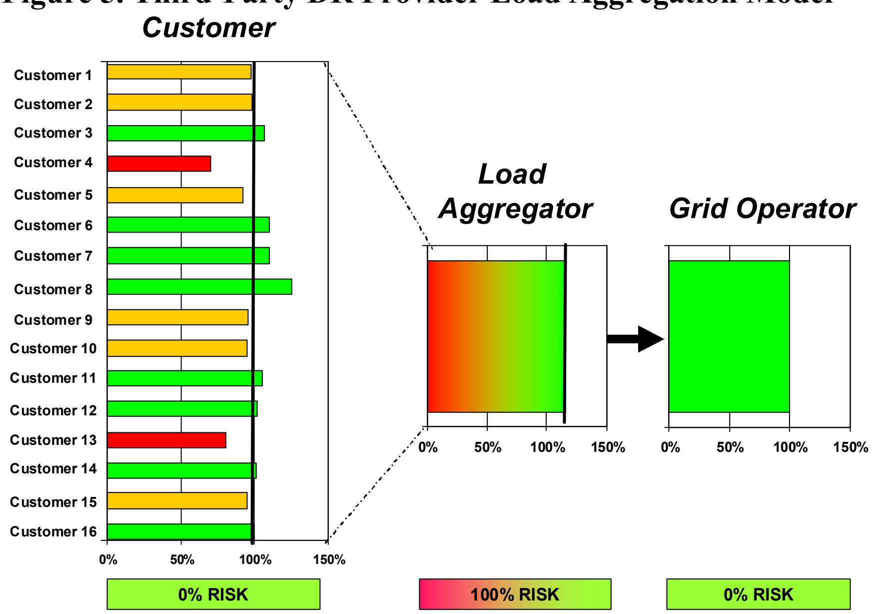
2. Performance measurement. Establishing an accurate and fair measurement and verification of performance for DR programs is critical for the success of DR as a trusted resource. The majority of today's DR programs are measured using some form of baseline methodology that relies on recent or historical data to determine what a customer's load would have been absent participation in a DR event. The most accurate baseline methodologies incorporate an adjustment factor based on the metered customer's load on the day of a DR event to capture the effects of weather or other conditions that influence a customer's demand. There have been a number of academic and consultant studies conducted to determine which baseline methodology provides the most accurate estimates of performance and minimizes systematic bias in either the positive or negative direction (Goldberg & Agnew 2003; Quantum Consulting 2004). Determining the best baseline methodology to use for a DR program should factor in the types of customers likely to be enrolled in the program as well as the level of complexity and timeliness of the baseline calculation. Customers with demand that correlates closely with outside temperatures will be more accurately measured using a baseline methodology that explicitly accounts for temperature (Coughlin et al. 2008). Other customers that have relatively stable electric demand may be just as accurately measured using a simple averaging baseline methodology. Ensuring that a customer is able to understand how their performance is being measured and receive feedback (and payment) on performance in a timely manner can contribute to the success of a DR program.
3. Resource response time. The Resource Response Time is the amount of time the DR resource has to curtail after being notified by the utility or system operator of a DR event. Programs can be categorized into either day-ahead or day-of notification. For day-of

programs, the response time can vary from several hours to minutes. DR programs designed for participation as ancillary services must be available within 10 minutes or less depending on the service provided. Many day-of programs provide response times within 30 minutes to 1 hour. In general, the shorter the response time, the fewer the number of customers who will be able to participate. Utility and system operators must balance their interest in having a quick-response resource with their objective of having widespread DR program participation.

4. Program availability. Utilities and system operators must decide when the DR resources will be available to respond to dispatch. Variations are by 1) season; 2) days of the week; 3) hours of the day; and 4) length of the event. DR programs that are designed to achieve peak load reductions for a summer-peaking utility may only be needed for five months of the year. Alternatively, a dual-peaking system may need DR to be available year-round to address all the critical system peak hours. Some DR programs operate only on weekdays and non-holidays; others operate seven days per week. Similarly, the window of availability of a DR program during a given day can be tailored to address the specific needs of a system. For example, DR resources might only be available from noon until 6pm or they might be available 24-hours per day. Finally, the period of time for which a program must operate when called upon can vary from minutes in the case of ancillary services to hours for reliability and economic DR programs. The selected periods of availability and operation can have significant implications for the overall cost and amount of DR resources available to the program.
5. Program triggers. DR programs can be dispatched based on a number of different system factors or "triggers." For example, triggers can include official "grid emergencies," reserve margins falling below a certain percentage, energy market prices at or above a certain level, voltage reductions, marginal generation heat rates, and local distribution emergencies. Some DR programs have limited triggers for which they can be dispatched whereas other DR programs can be dispatched at the full discretion of the utility or system operator.
6. Program penalties. Utilities and system operators are increasingly incorporating penalties for non-performance into DR contracts and programs to ensure the reliability of the resource. Alternatively, contracts and programs can have provisions that program payments are to be reduced or eliminated as a result of poor performance. Substantial non-performance penalties can provide strong incentives for reliable DR program performance. Penalties that are set excessively high can result in poor DR penetration, except in the cases where third-party DR providers shield participating customers from this risk by absorbing penalties.
7. Program administration. DR can be administered either by utilities directly or by third-party DR providers. Historically, utilities have administered load management programs directly with their customers. In recent years, new models have emerged to integrate DR into the resource mix. In the early 2000s, independent system operators in the eastern United States (ISO-NE, NYISO, PJM) constructed a new type of market participant to represent demand response resources in the market place. These entities are known by various terms including demand response provider, curtailment service provider, and responsible interface party. Today, some of the same entities that have successfully brought DR to deregulated regions have expanded throughout North America to provide outsourced DR programs to utilities. Utilities are increasingly contracting with third-

parties to compliment an existing demand side management portfolio with a targeted, dispatchable DR program. Figure 5 below portrays an illustrative load aggregation model employed by third-party DR providers, where the DR provider manages a portfolio of customers to provide the utility or grid operator with a specified level of DR capacity during DR events. In this model, the DR provider absorbs the program risk and shields the customer from potential non-performance penalties while providing the grid operator or utility the expected DR resource.

Figure 5. Third-Party DR Provider Load Aggregation Model



Source: EnerNOC, Inc.

Bringing it all Together – Designing a Successful DR Program

This section provides a framework for how to balance the key DR program design elements described above.

Step 1: Define Program Goals/Objectives

Given multiple design decisions, the first step in the development of any DR program should be to clearly define the goals of the program and the measures of success. For example, one utility might wish to develop a DR program exclusively for reliability purposes during peak summer months; a successful program would meet reserve obligations with DR while avoiding blackouts/brownouts. Alternatively, a second utility might develop a DR program to meet resource needs where DR is more economic than building or buying alternative supply-side resources; this program would be successful if it yields a more economically-efficient system through DR dispatch.

Step 2: Balance Key Program Design Elements to Best Achieve Goals/Objectives

Figure 6 shows the range of choices for DR program design elements and how the selection made can help or hinder the resource potential. The obvious example is program compensation: with higher incentive payments to customers, a DR program can attract more customers and better performance. Clearly, higher program compensation leads to higher program costs. Therefore, the DR program creator must adjust the other design parameters to create a high-value – and cost-effective – resource. Decisions surrounding many design elements should depend largely on the goals of the program. For example, if the goal of the program is to supply ancillary services, then a one to ten minute response time might be needed to achieve the goal; on the other hand, if the goal of the DR program is to improve the system reliability, then system operators might be able to effectively manage a resource with a two hour response time.

Figure 6. Range of Choices for DR Program Design Elements that Influence the Resource Penetration

Low — Resource Penetration — High

Low	**Program Compensation**	High
Simple but inaccurate	**Performance Measurement**	Uses recent historical interval data
Instant	**Notification Period**	Hours
24/7/365	**Availability**	Defined Window, Coincides with Business Operations
Unpredictable	**Dispatch Trigger**	Defined
High risk	**Underperformance Penalties**	Low risk
Utility / System Operator	**Program Administration**	Third-party

Source: EnerNOC, Inc.

Step 3: Consider Unintended Consequences

When designing a new DR program, it is important to consider how it will interact with existing DR programs. For example, if many of a utility's larger customers are on an existing interruptible tariff, then introducing a DR program that appeals to those same customers may simply result in a shift of DR resources rather than an expansion of the total pool of available DR. In essence, designers should avoid cannibalizing existing (and successful) programs and instead seek out non-participating customers through complimentary DR programs. If a new DR program has too many points of overlap for existing and successful programs, consider revising some of the key program elements to make the new program unique and targeted. Alternatively, the existing program could be updated with changes to program elements to expand its size or improve upon its proven success.

Step 4: Finalize Program

Once all the key program design elements have been determined, the remaining operational aspects of the program can be finalized. In Table 2, several DR program goals are listed across the top and the elements of design listed along the left-hand side. The ranges for the design elements suggest that even with the goal of the DR program identified, there is further room for refinement in design. It is important for the utility or grid operator to avoid "over-designing" a single DR program to try to capture all possible scenarios for which the DR resource may or may not be needed as this has the effect of reducing the program's ability to meet any of the scenarios. A better approach would be to design multiple DR programs, each with their own goals and success factors, which can be used as part of a targeted resource strategy.

Table 2. DR Program Design Goals and Elements

	System Reliability/Peak Management	Economic	Ancillary Services
Program Compensation	Capacity & Energy Payments ($/kW-month and $/kWh)	Energy Payments ($/kWh)	Availability & Energy Payments ($/kW-hour and $/kWh)
Performance Measurement	Difference between load-adjusted customer base line and actual load	Difference between load-adjusted customer base line and actual load	Difference between pre/post-event and event load
Response Time	20 – 240 minutes	Day-ahead or Day-of	Less than or equal to 10 minutes
Program Availability: Days	Business hours, working days	Markets are 24/7/365; resources bid in reductions	Markets are 24/7/365; resources bid in hours of availability
Program Availability: Hours per Year	10 – 100	10 - 100	50 – 100
Program Availability: Duration	1 - 8 hours	1 - 4 hours	10 - 60 minutes
Event Trigger(s)	Actual or forecasted operating reserves shortage or economic dispatch	Economic dispatch	System contingencies
Program Penalties	Loss of incentive payments and/or non-performance penalties below pre-determined threshold level	Loss of incentive payments	Loss of incentive payments and/or system tariff penalty payments
Program Administration	Utility or Third-Party DR Provider	Utility or Third-Party DR Provider	Third-Party DR Provider
Event Frequency	Low	At end-users discretion	High
Metering Requirements	Preferably 5-minute interval data (15 minute or 1-hour data can suffice)	Preferably 5-minute interval data (15 minute or 1-hour data can suffice)	1-minute or less
Communications Requirements	Ability to receive and confirm system operator requests, preferably with real-time performance transparency	Ability to receive day-ahead and real-time hourly energy prices	Ability to receive and confirm system operator requests, preferably with real-time performance transparency

Additional program finalization steps may include establishing expectations around the frequency of DR events; determining metering requirements communications protocols and requirements; and developing marketing and outreach strategies. Most programs will also require regulatory or board approval of the new program.

Step 5: Keep an Eye Out for Future Enhancement Opportunities

Just as previous generations of load management programs have evolved over the last several years, it is clear that today's programs will benefit from future technology innovations and changes in the electric market structure. For example, the effect of improved metering infrastructure will undoubtedly have an impact on the next generation of DR. Consideration of the positive environmental impact DR can have in future climate change mitigation efforts will need to be evaluated as part of DR program design.

One of the more immediate considerations for DR program designs is the potential for integration of DR and other demand-side resources such as energy efficiency and distributed generation. In both California and New York, policy-makers are evaluating the combined effect of DR and energy efficiency resources. California's recent draft Energy Efficiency Strategic Plan includes a vision statement that "[a]ll demand-side management programs are coordinated and, as appropriate, integrated to increase the penetration of energy efficiency and avoid lost opportunities" (CPUC Rulemaking 06-04-010). Another evaluation of the environmental benefits of DR and energy efficiency asserts that "…consumers rarely are interested in the distinctions among demand-side measures discussed in this article but rather in bottom-line results—lower power bills, rebates on new equipment, lessened risk and better environmental performance. Energy efficiency and DR advocates may well find that working together to promote overall demand-side management may yield political results that could not be achieved by either side alone (Nemtzow, Delurey & King 2007)."

Conclusion

DR has evolved significantly in the past five years as a result of improved enabling, metering and communication technologies, the increased need for utilities to manage peak demand in a time of rising infrastructure and resource costs, and the emergence of competitive demand response suppliers. For the first time, DR can effectively and efficiently be incorporated into electric system resource planning or grid management strategies as an alternative to new peaking capacity or transmission and distribution infrastructure. However, in order for DR resources to achieve these objectives, the programs need to continue to improve over time. This paper described several key DR program design elements to consider when planning a new DR program and provided a framework for developing successful DR programs that will ultimately be able to help address the many challenges of the electricity industry that lie ahead.

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