Demand Response in Organized Electric Markets
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A number of trends can be seen in new DR program designs and in the DR technologies being developed to support these programs. These trends will increase the value of DR in the future by improving the dispatchability and reliability of this resource. However, the benefits of these trends will be realized only with the ongoing and sustained support of regulatory bodies and market operators, i.e., there must be assurances that DR will mature and receive appropriate value in future electricity markets. At this time, DR is clearly providing value to markets but there are aspects of DR that remain untested in some markets that result in some uncertainty in the resource value of DR. These DR operational and response issues will be resolved as experience is gained and new technologies deployed.

DR values are generally based on avoided costs that include generation costs and transmission and distribution (T&D) costs where they can be identified. However, there are market-wide benefits that may, in the long run, be as significant. These include:

- Increasing the ability of demand to respond to changes in supply and the price of supply to help establish new market equilibria. DR initiatives that allow customers to respond to scarce supplies (directly to prices or to good proxies as part of DR programs) are critical to the industry. This increased ability to adjust demand in response to price will support:
  a. Efficient resource allocation in markets.
  b. Technology innovation – get technology companies and customers to invest in energy management technologies.
  c. Improved productivity in one of the most capital intensive industries.
- Managing what is scarce (peak electricity supplies) is best attained by allowing demand and supply to work together to achieve efficient market solutions.

Increases in capital costs of power plants, as well as increasing fuel prices combined with the needed expenditures on infrastructure (T&D as well as fuels transportation) makes it likely that traditional approaches to meeting future electricity demands will not work. Unlike the past, the industry may not be able to just build its way out of expected future supply issues. In this environment, the value of DR and its role in helping customers' demand adjust in response to supply and price is too great to not develop this resource.

TRENDS IN DEMAND RESPONSE PROGRAMS AND TECHNOLOGY

Recent trends in DR include:

1. Increased automation of a customer's load response.
2. Increased focus on firm reductions within DR programs.
3. Diversification in program participation.
4. Target marketing of DR to provide higher T&D benefits.
5. More accurate estimation of delivered load impacts.

Each of these trends is discussed below.

Trend 1. Increased automation of a customer's load response to signals from an aggregator or directly from a system operator.

Residential DLC loads are already automated and available within minutes after being called. A similar trend is occurring in the C&I sector. Discussions with aggregators of C&I loads have indicated that the fraction of load that is essentially automatically controlled through an energy management or building management system is increasing. Over the past two years, approximately 50% of the C&I response that select aggregators have been obtaining to meet firm contract requirements has used automated response that can be activated within 10 minutes. New load that is being enrolled in programs has an even higher fraction of load that responds automatically to a signal.[1] In addition, a substantial amount of industry research on DR is focused on "auto-DR" where much of the load response is automated. Still, most programs that have two or more hours of advance notice have some loads that are manually controlled and this can be expected to continue. Programs that have less than two-hour notification (e.g., 30-minute or 20-minute notification) are migrating to emergency generation options and towards the use of auto-DR concepts. Some programs are being designed that will allow a customer to have part of its load in a two-hour (or greater) notification program, and part of its designated load that can be called upon with 10-minute notification. In general, the auto-DR programs rely on buildings that have

[1] Interview with demand response aggregator.

energy management and control systems (EMCS) that can be used to control space conditioning, lighting, and other end-uses (chilled or heated water, refrigeration defrost cycles, or other equipment in the facility). Often, the load sheds are small and do not impact the building or facility significantly.

One implication of this trend is the increased cost-effectiveness of combining C&I DR programs with new construction or major building retrofit programs where load-responsive technologies can be installed while a building or facility is being built or undergoing a major retrofit. In addition, retro-commissioning of commercial buildings is a growing energy efficiency program type. These often involve working with or installing an energy management system. A collaboration between DR needs and the design of these traditional energy efficiency programs can help to install the equipment that is needed to deploy automation systems that allow customers to participate in fully-automated DR programs. These systems have been estimated to cost between $3,000 and $6,000 in most applications based on research conducted by the Demand Response Research Center (DRRC).[2] This DRRC effort on automated DR programs has encompassed a diverse set of building types including office buildings, retail chain stores, schools, museums, laboratory buildings, a museum, and a bakery.

Trend 2. Increased focus on firm reductions within DR programs.

There is an increased emphasis on DR programs that provide firm capacity that will allow DR to appropriately qualify for generation capacity deferrals and T&D deferrals. For programs offered directly by utilities to customers, this can involve financial penalties if specified load reductions are not met, or provisions where a customer's contribution is derated due to underperformance, and some customers have been dropped from DR programs. Most C&I aggregators seeking to provide high value load reductions are offering DR load reductions as firm load. This increased focus on DR programs as providing firm capacity has also resulted in operational protocols that call for the testing of DR program response (e.g., one or more test events each year) to accredit MW in a DR program.

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[2] Costs include EMCS programming, control hardware, and facility manager time. Some other labor costs may not be captured in these figures. This research is discussed in a number of DRRC reports including: M.A. Piette, D. Watson, N. Motegi, S. Kiliccote; Automated Critical Peak Pricing Field Tests: 2006 Pilot Program Description and Results, CEC PIER Demand Response Research Center, LBNL, August 2007 (LBNL Report 62218), p. 25. http://drrc.lbl.gov/pubs/62218.pdf. Other research indicates costs for DLC at commercial facilities of $14,000 for cooling and lighting end uses. See Quantec, LLC with Summit Blue Consulting and Nexant, Inc. for PacifiCorp. *Assessment of Long-Term System-Wide Potential for Demand-Side and Other Supplemental Resources.* June, 2007.

Trend 3. Diversification in program participation to reduce performance risks.

There are two considerations that can work in tandem to allow DR programs to provide firm capacity. First, if a sizeable fraction of a program's DR capability resides with just a few customers, then it is important to stay in touch with those customers to ensure that they can respond when needed. Having a program that provides firm capacity is not the same as having each customer provide a fixed kW reduction. Secondly, many C&I programs will still have a weather component, as the actions taken to reduce load will include HVAC actions that include global temperature controls, pre-cooling, chilled water, and hot water temperature adjustments. As a result, the impacts from customers that participate in a program will vary with weather conditions to some degree, and individual customers' kW reduction will depend on the amount of response strategies that are tied to HVAC actions.[3] Thus, having a reasonably large number of customers participate in a program offers diversity that can help maintain the level of load shed across called events. Managing the risk of underperformance in DR programs is improving dramatically as more aggregators are providing DR under contracts that require a target load reduction to be met.

Trend 4. Target marketing of DR to provide higher T&D benefits.

Utilities and planners are recognizing the locational benefits of DR programs and are working to design and market programs that can help defer T&D investments. For this to occur, adequate DR must be available on specific networks to reduce strain on local distribution lines when contingencies occur in that network, and to be available with notice provisions that will facilitate the potential deferral of T&D capacity investments. To defer capital investments in T&D, 10-minute notice may be needed by system operations. As a result, a subset of DR that can be made available on 10-minute notice should be developed and provided with higher incentives that reflect the value of these short-notice resources to the system.

[3] Some utilities have enough experience with and evaluation of their DR programs that they estimate the load reductions to be provided by a program as a function of outdoor temperatures projected for that day by 10:00 AM. This may seem complex, but the dispatcher simply looks up the relationship between weather and expected load reductions and uses the appropriate load reduction as the target for that program on that day.

***Trend 5. Increased accuracy in estimating program load impacts and customer baselines*.**

The calculation of overall program impacts and settlements for customers participating in DR programs is becoming more sophisticated. This includes the use of different baseline options available for the customer level and for estimating the program's overall impacts (which might be different than the sum of each customer's settlement load estimates). There is an increasing recognition that a single method for estimating impacts may not apply equally well to all customers. Several programs already take this into account by allowing customers to select between two baselines – one with a same-day adjustment to actual customer loads on that day and one that does not have a same day adjustment. Since the customers' actual loads on an event day are known, the key is estimating what the customer would have used had an event not been called. Traditionally, approaches for determining customer baselines have been limited. Often, the baseline calculation is based on that customer's load for 10 non-event weekdays preceding an event. Alternative methods are being used, in some cases, that include using the data from all the non-event days prior to an event for that season or testing of baselines for different customer segments within a program to see if different baseline methods work better for different customers, and there have been proposals to use both days preceding an event day along with several post-event days to help ensure a more accurate baseline. These calculation methods can be automated, and settlement provisions can be determined for participating customers that are accurate and understandable. In addition, system or resource planning may want estimates of program-wide load impacts that are as accurate as possible, and regression methods based on an entire season's data or all the data available up through an event day can be used.[4]

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[4] To facilitate prompt payments to customers, simpler calculations can be used to compensate customers for achieved load reductions to facilitate participation. However, it may be in the utility's interest to know with greater accuracy the program-wide load reductions, and different, more complex regression approaches are now being proposed for program-wide impact estimation. One such method would use whole-year, or whole season, data covering the period during which DR events took place, rather than just the 10 days prior to an individual event. Although this method cannot be used for prompt calculation of payments, it is perhaps a more reliable post-estimate of actual program impacts.