Calculating the Business Case for Demand Response

Whether for regional transmission systems, integrated utilities, or load serving retailers, there are many direct and indirect benefits – financial, regulatory, reliability, and customer satisfaction – that demand response can provide.

by Mark Triplett

FERC Chairman Jon Wellinghoff is known for saying “Demand response is clearly the 'killer application' for the smart grid”. Others have projected that AutoDR sites will increase five-fold in the next six years. No doubt in the big picture it seems obvious that demand side management is a must to reduce dependency on fossil fuels and meet growing energy demands on a physically antiquated grid infrastructure. But what are the quantifiable benefits that demand response (DR) brings to bear, and who in the energy value chain reaps the benefits? More importantly, how do they calculate the benefits to build a business case in order to move forward in implementing a DR program? The purpose of this paper is to examine who directly benefits from DR and how to measure results for a solid business case to justify funding and implementation.

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2 Navigant Research, Smart Grid: 10 Trends to Watch in 2013 and Beyond, Published 1Q 2013 Bob Lockhart, Neil Strother
Emergency Capacity

DR has been in use in some form for over 40 years, but it has not always been called DR. The primary use for load shedding has been for network reliability to protect against emergency situations when a generator trips off line, a transmission or distribution fault occurs, or in those few peak days when the capacity of the generation assets, or poles and wires infrastructure, are near or exceeding full capacity. In these network reliability situations, utilities would either call large industrial load customers and request load reduction, or they had some form of cooperative automated load shedding, such as a one-way pager system to contact thousands of water heaters. Or utilities might have been forced to do controlled load shedding at the meter level, rolling customers off line temporarily (rolling brownouts).

The root cause of a network reliability issue is usually that there is not enough reserve generation or network capacity to support emergency or extreme load situations. Both are very long lead-time and capital intensive problems to solve. Implementing DR in lieu of building peaking plants or adding transmission and distribution capacity for emergency conditions is a great alternative.

In this case, vertically integrated utilities, transmission operators, or distribution companies all can benefit from the use of DR in lieu of building additional infrastructure. Hawaiian Electric Company (HECO) was projected to have a generation reserve shortfall for emergency and peak load situations and was faced with building a new peaker plant or finding some other alternative. They chose to implement DR programs instead and reported to have saved $25.9M by deferring the construction of a 110 MW unit from 2006 to 2009, and is projected to save $250M in next 20 years by implementing more DR in lieu of building new generation capacity. This cost justification emerges from the financial comparison over a short and long term total cost of investing in and operating a new peaker plant or in implementing DR programs and technologies.

PJM manages one of the largest transmission networks in the world and was faced with a similar, but different dilemma. PJM needed either to build new transmission infrastructure to handle peak load throughputs to meet future load growth projections or implement more DR load management to compensate for the load growth. Two very large transmission projects were planned to support the projected growth, but as a result of PJM’s progressive DR programs, they were able to cancel the transmission projects, saving the region over $3.2 billion dollars. The cost

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3 HECO Presentation, Energy Solutions for Business, February 16, 2012
justification for PJM to implement its DR capacity program was the competitive cost of having a DR capacity program versus the infrastructure costs of traditional investment in generation and transmission to meet future forecasted load demand.

The net result was that DR is greener, cheaper, and faster to implement than implementing new generation and transmission infrastructure for emergency reliability purposes.

Deferring Capital Investment in Infrastructure

The second most common use of DR traditionally has been for postponing the upgrade of the transmission or distribution system; often such upgrades are required due to load growth in an area, as more homes and businesses come on line in different parts of the grid. In this case, there is a near-term need to solve and the solution is also capital intensive. Thus a utility may need to buy some time to do the actual upgrade, or, if it lacks the working capital to do the upgrade, it may need to push off the investment for some time.

As an example, recently we were working with a utility that has 30 distribution and transmissions substations that are currently not engineered to support the existing peak demand or are projected to be overloaded in the next two to three years. It does not have the current working capital to address upgrading all of these substations, so it was trying to determine which ones to upgrade and which ones to address with targeted DR programs at a fraction of the cost. The factor here in making these decisions is DR penetration potential – in some cases, if the projected load increase is over 20 percent in the next year or two, there is a risk of not getting the penetration from a DR program to cover that increase. On the other hand, if the load increase is under 15%, DR may be a very valid option. The beauty of the DR solution in this case is that it can be targeted at one region or even one substation to get the load reduction that’s needed.

The cost benefit analysis here is both a short and long term analysis of the cost of borrowing capital today, plus the depreciation of substation equipment and assets of the substation upgrade project, versus implementing a DR solution and its devices, cost of installation, and annual payments to customers for participating in the DR programs. It’s good to remember that a DR investment isn’t just a short term fix to buy time or defer capital but, rather, a long-term resource that may continue to be available in emergencies, as well as sold into energy markets or used to avoid paying peak energy prices as additional benefits.

Avoiding Peak Energy Prices

Two large transmission projects had been planned, but PJM’s progressive DR programs enabled it to cancel them, saving the region over $3.2 billion.
Load serving entities, also known as retailers, and even most integrated utilities buy energy and related services from independent power producers or other sources, especially during peak seasons when prices can become quite high. As an example, in Texas, where the ERCOT-wide load-weighted average real-time energy price was $28.33 per MWh in 2012\(^5\), during peak energy usage periods prices can spike to a price cap of $5000/MWh. That price cap will increase to $7000/MWh in 2014 and $9,000 in 2015\(^5\). In Australia it’s even worse—energy prices can spike up to $13,100/MWh. At or even near these prices, DR becomes a very attractive alternative to meet peak load demand. The potential economic energy benefit is calculated by taking the maximum number of hours that DR events can be called multiplied by the available DR being implemented compared to those same MWhs if the energy were purchased at the forecasted peak energy prices; one should consider

\[\text{Demand response can be a key component of a state’s or region’s renewable resource generating or overall resource program.}\]

\(^{5}\) 2012 STATE OF THE MARKET REPORT FOR THE ERCOT WHOLESALE ELECTRICITY MARKETS, POTOMAC ECONOMICS, LTD., Independent Market Monitor for the ERCOT Wholesale Market, June 2013

\(^{6}\) On October 25, 2012, the PUCT confirmed that “[t]he maximum wholesale rate will rise from $4,500 a megawatt hour now to $5,000 in June 2013, $7,000 in June 2014 and $9,000 in June 2015.” http://www.startelegram.com/2012/10/25/4365061/texas-regulators-vote-to-double.html.

avoided line losses, as well. Once under contract, DR capacity can be used or sold as reserve capacity or emergency services, or even sold as ancillary services if it’s in a region where there’s a market willing to pay for DR, as there is in PJM, ISO-NE, NYISO, CAISO, ERCOT, MISO and others.

**Reducing Demand Charges**

One other key area of potential benefit to energy distribution companies, retailers, and competitive energy service providers as well as their end load customers is the management of ‘Demand Charges,’ or ‘Power Charges,’ which is the pro rata share of the overall network capacity charges allocated to the user base. There are several different methods for calculating a customer’s demand charge; some are based on the system peak load (usually the highest four or five days and/or hours per year) and the coincident load of each of the participating loads during those exact same periods. Other demand charge calculations are based upon the single 15 minute peak load of each customer over a billing period, usually monthly. The demand charge can be 40 percent or more of a total electricity bill, so minimizing spikes or peaks can save significant money. Analyzing historic peak demand days and estimating the amount of load reduction possible with DR can be used to predict the impact of the allocated demand charge, which can be significant. The financial benefit is calculated by comparing
peak loads and the resulting demand charges with the adjusted -peak loads after implementing DR and determining the net demand charges after applying the DR.

**Spin versus Non-spin reserve**

Another excellent economic use of DR is to buy time to bring non-spinning reserve\(^7\) on line rather than paying for spinning reserve\(^8\) to be available. The cost of non-spinning reserves is much less than the cost of spinning reserve. Nevada Energy (NVE) utilizes DR for this purpose – in addition to peak shaving and capital deferment – thus avoiding the high cost of procuring energy, reducing emissions, and emergency reliability purposes. Figure 1 shows that NVE can drop over 120 MW in load in less than five minutes, because its portfolio of DR is responsive enough to buy time to bring online lower cost non-spinning reserves.\(^9\)

Calculating the financial benefit of spinning versus non-spinning reserves merely requires comparing the pricing of the services, taking the difference in terms of savings and multiplying by the hours and MW that DR can address this situation.

**Balancing Renewables**

Using DR to smooth the intermittency and unpredictability of renewable generation resources such as wind and solar is a fairly new application, but potentially a very valuable one. In this scenario, the renewable resource is forecasted for the next hour and DR is used to firm that forecast. As an example, if the wind

\(^7\) Non-spinning reserve or supplemental reserve is the extra generating capacity that is not currently connected to the system but can be brought online after a short delay. In isolated power systems, this typically equates to the power available from fast-start generators. Source: CAISO Settlements Guide; Spinning Reserve and Non-Spinning Reserve, California ISO, January 2006.

\(^8\) Spinning reserve is the extra generating capacity that is available by increasing the power output of generators that are already connected to the power system. For most generators, this increase in power output is achieved by increasing the torque applied to the turbine’s rotor. Source: CAISO Settlements Guide; Spinning Reserve and Non-Spinning Reserve, California ISO, January 2006.

\(^9\) “Building to Grid” Efforts at NV Energy, IEE - Building to Grid Integration Meeting June 27, 2013, Michael O. Brown, Manager, Demand Response & Distributed Energy Resources.
generation at a certain insertion point into the grid is forecasted to be 10 MW throughout the next hour, then that generation target is set and the combination of wind and DR are used to ensure that the net generation into the grid in that region is going to be 10MW. If the wind suddenly dies down and only 9MW is being generated, then near real-time automated direct load control, sometimes referred to as AutoDR, must kick into effect and reduce system load for that region by 1 MW. Conversely, if the wind picks up and 11MW is being generated, then DR can be used to increase load so that the net impact on the grid is 10MW of generation. Loads such as industrial irrigation pumping systems, large cold storage warehouses, paper pulping mills, water purification systems, and even residential hot water heaters can perform this function well. The benefit in this scenario is less use of expensive peaker generating assets to follow and augment the renewables generation. The cost benefit should therefore be calculated as a replacement for peaker plant costs to perform the same renewables generation smoothing functions.

**Other Uses and Benefits**

- **Reducing emissions.** –

In many regions fossil fuel type emissions are capped for business and any excess emissions result in fines, levies, or the business is required to cover their excess emissions by purchasing emissions capacity of others. Electricity generators are often impacted by such regulation. As a result entire “cap and trade” markets have been created to buy and sell emissions capacities. Another way of avoiding to pay for additional emissions

<table>
<thead>
<tr>
<th>Vertically Integrated Utility</th>
<th>Distribution Utility</th>
<th>Transmission System Operator</th>
<th>LSE Retailer</th>
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<tbody>
<tr>
<td>Increase Network Reliability</td>
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<td>Defer Capital Investment</td>
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<td>Avoid Peak Energy Prices</td>
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<td>Bld DR Capacity Into Wholesale Markets</td>
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<td>Reduce Demand Charges</td>
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<td>Use Non-spinning Reserves Instead of Spinning</td>
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<td>Reduce CO2 Emissions</td>
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<td>Balance Renewables</td>
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<tr>
<td>Meet EE or Renewable Goals/Mandates</td>
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<tr>
<td>Improve Customer Satisfaction</td>
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**Figure 2: Benefits from DR for different organizations.**

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9 There are active trading programs in several air pollutants. For greenhouse gases the largest is the European Union Emission Trading Scheme, whose purpose is to avoid climate change. In the United States there is a national market to reduce acid rain and several regional markets in nitrogen oxides. Markets for other pollutants tend to be smaller and more localized.
capacity is to simply reduce load through DR, thus reducing generation run time and overall emissions. Avoidance of paying for excess emissions charges should also be calculated as a benefit if this situation applies.

- **Meeting Renewables Portfolio Standards (RPS) Regulation Targets.**
  
  In many US states or regions around the world, targets are being set for reducing the reliance on fossil fuels through energy efficiency programs, renewable resource generation, or demand side management targets. Demand Response is often a key component of any such regulatory requirements and its value should be added when considering leveraging DR in the overall analysis. The value should be calculated as the cost of an alternative method of achieving the same target.

- **Increasing Customer Satisfaction.**
  
  Whether the benefit is fewer outages through higher network reliability and uptime as a result of having DR available, which increases SAIDI and SAIFI statistics and customer satisfaction; or as customers benefiting from being paid to be part of the solution, playing a role in better controlling their electricity bills and system reliability, customer satisfaction goes up. It should be noted that these are voluntary programs in which customers are paid to participate; the programs are usually not forced on participants. Customers can usually opt out of any event if the timing is inconvenient or if the customer is uncomfortable. Customers may also opt out of the entire program. Customer satisfaction is hard to quantify for a business case justification, but it is a significant consideration and benefit.

Whether an integrated utility, stand-alone distribution company, regional transmission system operator, or a load serving entity or retailer with a focus on using DR for network reliability, deferring capital investments, or avoiding the high cost of energy as the primary driver of implementing DR, there are many direct and indirect financial, regulatory, reliability, and customer satisfaction benefits to be considered in building the business case for implementing DR. The chart above provides a quick reference of the parties that benefit from implementing DR. It’s clear from the chart that vertically integrated utilities benefit from just about every direct and indirect value provided by DR.

It’s also clear that although there may be one key financial or other driver behind considering DR as a solution to a problem, in each case there are always other benefits to be considered as well.

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**Mark Triplett** is managing director of Alstom Grid’s Demand Response Management System (DRMS), following the acquisition of UISOL Software. Formerly president of UISOL Software, Mark is responsible for the DRMS activity, market strategy, commercial strategy, product direction, and global sales. He led the development and delivery of the demand response software in use by PJM Interconnection, MISO, CAISO and Transpower, the market operator in New Zealand, as well as by multiple distribution utilities in the US and abroad.