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Evolution and current status of demand response (DR) in electricity markets: Insights from PJM and NYISO

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ABSTRACT

In electricity markets, traditional demand side management programs are slowly getting replaced with demand response (DR) programs. These programs have evolved since the early pilot programs launched in late 1990s. With the changes in market rules the opportunities have generally increased for DR for participating in emergency, economic and ancillary service programs. In recent times, various regulators have suggested that DR can also be used as a solution to meet supply – demand fluctuations in scenarios with significant penetration of variable renewable sources in grid. This paper provides an overview of the evolution of the DR programs in PJM and NYISO markets as well as analyzes current opportunities. Although DR participation has grown, most of the current participation is in the reliability programs, which are designed to provide load curtailment during peak days. This suggests that there is a significant gap between perception of ability of DR to mitigate variability of renewables and reality of current participation. DR in future can be scaled to play a more dynamic role in electricity markets, but that would require changes both on technology as well as policy front. Advances in building technologies and energy storage combined with appropriate price signals can lead to enhanced DR participation.

1. Introduction

When electric demand is at or near its peak level, less efficient or higher cost generating units must be utilized to meet the higher peak demand. In some cases, electricity prices in wholesale markets could fluctuate from less than 5 cents per kWh to as much as 30 cents per kWh on a significant number of days per year. During capacity shortages, prices could increase to 50 cents per kWh or higher for a few hours, reflecting the price signals that are required to match available supply to meet the demand. Under these circumstances, even a small reduction in demand through demand response (DR) programs can result in an appreciable reduction in system marginal costs of production. In competitive electricity markets, where the marginal generating unit determines market clearing price for all load, a drop in wholesale peak prices also means that non-participants in demand response also share in the benefits, as prices for everyone are held in check. These peak costs, although short in duration, add to the average cost per kWh to the consumer and hence raise the average cost of a kWh of electricity.

The introduction of DR into constrained electricity networks can significantly reduce volatility in wholesale electricity prices and can potentially act as a check against the exercise of market power by generators [1–4]. DR is also valuable as a tool to improve reliability of the grid [5,6], as well as increasing available transfer capacity on transmission grid [7,8]. Recent research has also indicated that historically low participation in time-differentiated pricing programs, as well as the low short-run price elasticity of demand, can result in potentially large social welfare losses in deregulated markets. The welfare losses from low demand response levels could be significantly reduced by introducing administered DR programs in concert with centralized energy spot markets. [9] Studies have also identified the need for advanced metering infrastructure (AMI) and building automation controls for enabling the potential of DR and energy efficiency [10–12].

In last decade, various research groups have tried to quantify the social benefits of DR in US markets. [13–15] A 2001 study by McKinsey & Company [13] estimates that, $10–15 billion in annual benefits can be achieved from participation of all customers in dynamic pricing programs on a wide scale across U.S., with the majority of the potential, contrary to conventional wisdom, from residential sector DR efforts. The study estimated that the infrastructure needed for dynamic pricing can be brought to the mass market, with payback periods of 5–6 years. Based on a review of

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current utility programs, Electric Power Research Institute (EPRI) [15] estimated that DR has the potential to reduce current U.S. peak demand by 45,000 MW. The U.S. Federal Energy Regulatory Commission (FERC) [16] released a cost-benefit analysis in 2002 that showed a $60 billion savings over the next 20 years if DR is incorporated into RTO market design and operations.

2. Evolution of DR programs in PJM and NYISO

The ability of customers to respond to prices and reduce consumption during periods of system shortage has been a critical component of both the PJM and NYISO electricity markets since their start in 1997 and 1999 respectively. DR programs are designed to encourage consumers to modify their electric demand level and pattern of electricity usage. DR refers only to energy and load-shape modifying activities undertaken in response to economic or reliability signals provided by utilities or ISOs and not to load-shape changes arising from any normal operation. The Demand Response and Smart Grid Coalition (DRSG) defines DR as the reduction of customer energy usage at times of peak usage in order to help address system reliability, reflect market conditions and pricing, and support infrastructure optimization or deferral. Demand response programs may include dynamic pricing/tariffs, price-responsive demand bidding, contractually obligated and voluntary curtailment, and direct load control/cycling. Based on the type of signal used to activate the DR program, these programs can be categorized as either Emergency (or Reliability based) DR programs or Economic (Price based) DR programs or Demand Side Ancillary Service programs [17]. The emergency DR programs aim to provide cost-effective capacity resources to help avoid system outages in case of severe grid stress. On the other hand economic DR programs are developed to exert a downward pressure on electricity prices, by allowing demand side participation in electricity markets. Demand Side Ancillary Service programs allow DR to participate in ancillary service markets such as frequency regulation and operating reserves. Until recently some of the energy efficiency and load shaping programs, that were part of traditional DSM initiatives, were not considered as DR. As explained later in this paper, PJM introduced a new program in 2008–09, that provides capacity credits to qualified energy efficiency projects as part of DR program.

The PJM and NYISO markets have separate energy, capacity and ancillary services markets. Initially, both PJM and NYISO had mechanisms for inclusion of DR programs in the capacity markets through Emergency DR programs based on reliability criteria. This was accomplished through reducing a Load Serving Entity's (LSE) capacity obligation but limited integration into the energy markets. Partly in response to the very high price spikes experienced in 1998 and 1999 various stakeholders realized that there was a benefit to increase the ability of customers to respond to higher prices and reduce consumption. Since most customers at that time were on fixed pricing they did not have a direct incentive to reduce consumption during high priced periods. Additionally there was no capability to put in differing bidding parameters (such as the minimum commitment period for a load to reduce). Other issues included limited availability of interval metering required for monitoring and billing customers based on their actual usage.

Initially inclusion of DR in PJM's capacity markets was done through the Active Load Management (ALM) program. This program required customers, at that time typically through their LSE, to commit prior to the summer period (June 1–September 15) that they could reduce their power consumption during at least 10 days for a period of up to 6 h per day during the summer period. In exchange the customer (or their LSE) would receive a capacity credit for the entire year. The NYISO program, called Special Case Resources, was similar in that it reduced LSE's capacity obligation but unlike PJM included a separate summer and winter season as well as testing requirements on participants. In both the PJM and NYISO capacity programs, the response of the participating customers was mandatory and there were various penalties associated with non-compliance. The types of DR enrolled in these programs included residential load control devices (water heaters/air conditioners), commercial/industrial load reduction, and behind the meter generation. In practice these programs were called infrequently with 0–5 events per year being called as shown in Table 1.

Capacity prices in the first few years of the markets were relatively high and were the primary source of overall revenue paid to demand side response resources. However, as capacity markets started to go down in subsequent years and energy prices started to rise, there was a move to integrate DR resources more closely into the operation of the energy markets. For example, in PJM capacity prices were $34,799/MW-year in 2001 and fell to $2091/MW-year by 2006. Since then the introduction of locational capacity market and demand curve for capacity under Reliability Pricing Mechanism (RPM) has reversed the trend, particularly in capacity constrained zones, and capacity prices varied between $35,000 and $86,000/MW-year during 2009–2010 delivery year.

While many LSEs used the ability of their customers to reduce consumption during peak times for energy purposes (most often through interruptible rates), there was not an easy way to integrate these customers into the markets. In 2001 both PJM and NYISO started to develop mechanisms to allow customers to participate in the energy markets either directly through a Curtailment Service Provider (CSP) or through the customer's LSE. For a period of time the PJM and NYISO programs leapfrogged each other with one market rolling out a component of DR and the other adopting that and building off of it. The first add-on was an emergency energy program that both NYISO and PJM added allowing customers to get paid an energy payment if they would voluntarily reduce consumption during periods of emergency. These resources were called on very rarely and there was much debate about whether or not they should set price in energy market. NYISO opted to have them set the market clearing price and PJM chose not to.

In the NYISO the next DR market to be developed was the day ahead market with customers able to bid into the day ahead market in a similar manner to generators and through this process set price and be dispatched by the NYISO. In PJM both the day ahead and real time markets were opened up to DR resources. PJM initially promoted the participation in real time DR program as a voluntary effort, where customers did not face any penalties for non-compliance. It was initially believed that new customers will use the real time DR program to get familiar with the markets and then will gradually start participating in the Day Ahead DR program, where participants commit to mandatory load curtailment targets if their bid is accepted in the day ahead energy market. Even today, in PJM most of the DR participation is in the Real Time DR program, and very few customers participate in Day Ahead DR program.

Table 1
Summary of ISO/RTO initiated emergency DR events (source: PJM [18] & NYISO [19])

Year	Emergency events in PJM	Emergency events in NYISO
2000	2 (May 8 and 9)	
2001	4 (Jul 25, Aug 8–10)	4 (Aug 7–10)
2002	3 (Jul 3, 29, 30)	4 (Apr 17 and 18, Jul 30 and Aug 14)
2003	None	2 (Aug 15 and 16)
2004	None	None
2005	2 (Jul 27, Aug 4)	1 (Jul 27)
2006	2 (Aug 2, 3)	5 (Jul 17 and 18, Aug 1–3)
2007	1 (Aug 8)	2 (Jul 19 and Aug 3)