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Addressing Energy Demand through Demand Response: International Experiences and Practices

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List of Acronyms

AESO	Alberta Energy System Operator
AMI	advanced metering infrastructure
AMP	aggregator managed portfolio
Auto-DR	automated demand response
BRA	base residual auction
C&I	commercial and industrial
CAP	Climate Action Plan
CEC	California Energy Commission
CPP	critical peak pricing
CSPs	curtailment service providers
DECC	U.K. Department of Energy and Climate Change
DLC	direct load control
DOE	U.S. Department of Energy
DPCR5	distribution price control review
DR	demand response
DRAS	demand response automation server
DRRC	Demand Response Research Center
DSM	demand side management
EE	energy efficiency
EEPS	Energy Efficiency Portfolio Standard
EILS	emergency interruptible load service
EISA 2007	Energy Independence and Security Act of 2007
EMCS	energy management control systems
EPACT	The Energy Policy Act of 2005
ERCOT	Electric Reliability Council of Texas
FCM	forward capacity market
FERC	U.S. Federal Energy Regulatory Commission
FRCC	Florida Reliability Coordinating Council
HVAC	heating ventilation and air-conditioning
I/C	Interruptible/curtailable
IA	incremental auctions
IESO	independent electricity system operator
IOUs	investor-owned utilities
IT	information technology
LMP	locational marginal price
M&V	measurement and verification
MRO	Midwest Reliability Organization
NOCs	network operation centers

NPCC	Northeast Power Coordinating Council, Inc.
OPA	Ontario Power Authority
PG&E	California Pacific Gas and Electric
PPA	power purchase agreement
PTR	peak time rebates
RFC	ReliabilityFirst Corporation
RPM	reliability pricing model
RTDR	real time demand response
RTEG	real time emergency generation
RTO	regional transmission organization
RTP	real-time pricing
SCE	Southern California Edison
SERC	Southeastern Electric Reliability Council
SPP	Southwest Power Pool
SRM	synchronized reserve market
STOR	short term operating reserves
TOU	time-of-use
TVA	Tennessee Valley Authority
WECC	Western Electricity Coordinating Council
WEM	wholesale electricity market

1. INTRODUCTION

1.1. Definition of Demand Response

Demand response (DR) is a load management tool which provides a cost-effective alternative to traditional supply-side solutions to address the growing demand during times of peak electrical load. According to the US Department of Energy (DOE), demand response reflects “changes in electric usage by end-use customers from their normal consumption patterns in response to changes in the price of electricity over time, or to incentive payments designed to induce lower electricity use at times of high wholesale market prices or when system reliability is jeopardized.”¹ The California Energy Commission (CEC) defines DR as “a reduction in customers’ electricity consumption over a given time interval relative to what would otherwise occur in response to a price signal, other financial incentives, or a reliability signal.”² This latter definition is perhaps most reflective of how DR is understood and implemented today in countries such as the US, Canada, and Australia where DR is primarily a dispatchable resource responding to signals from utilities, grid operators, and/or load aggregators (or DR providers).

1.2. Benefits Brought by Demand Response

There are a variety of benefits brought by DR, ranging from the environmental to the economic.

Environmental benefits

By reducing electric demand to ensure the sufficiency of existing supply, rather than increasing supply to meet rising demand, DR avoids power plant operation and its associated emissions. Moreover, because DR capacity is distributed, there are added benefits due to the avoidance of electrical losses in the transmission and distribution lines typically experienced from centrally-generated utility power. The US-based energy consultancy Synapse Energy Economics addressed this issue in its study of DR and air emissions in the US market of ISO New England:

“...when DR operates it reduces system line losses relative to reference case system operation. This is because when energy is provided to customers from the grid it often comes from power plants a considerable distance from the point of end use, and energy is lost in transmission. Usually line losses are in the range of 5 to 10 percent, but they can be higher during periods when transmission lines are heavily loaded. In contrast, the DR resource – be it a load reduction or a generator – is located at the site of energy use, so no energy is lost in transmission.”
“Because DR avoids line losses, a DR resources of five MW is comparable to a grid-connected asset of slightly larger than five MW...For example, a five-MW DR resource might be credited as

¹ U.S. Department of Energy (February 2006), Benefits of Demand Response in Electricity Markets and Recommendations for Achieving Them: A Report to the United States Congress Pursuant to Section 1252 of The Energy Policy Act of 2005, pp. 11-12. (<http://eetd.lbl.gov/ea/ems/reports/congress-1252d.pdf>).

² http://www.energy.ca.gov/2011_energy_policy/documents/2011-07-06_workshop/background/Metrics_July_IEPR_DR_v1.pdf.

providing 5.5 MW of reserve capacity is average system line losses during DR events were determined to be roughly 10 percent.”³

In addition, because DR is often procured on a forward basis, it may not only offset the operation of power plants but also their very construction. In this manner, the environmental benefits of DR extend to the avoided emissions associated with the construction of the materials for the power plant itself (i.e. cement, steel, etc.), as well as the potential ecological impact that may have resulted should the unit have been constructed.

The use of DR for non- peak-shaving purposes such as for ancillary services, also comes with significant environmental benefits, despite the very short duration dispatches of such resources. In many systems, ancillary services (also known as reserves), are primarily provided by plants in running operating mode, as there may be an insufficient number of quick-start generating units able to start, synchronize, and export power to the grid in the requisite period of time. These plants tend to be fueled by diesel or oil, which add to local and regional pollution. Increased use of quick-response DR can reduce the need for power plants to run in operating mode, as well as potentially lead to a more efficient overall use of resources within the system.

Economic benefits

The economic benefits of DR oftentimes may be more significant than the environmental benefits. While there is a clear environmental benefit to avoiding or reducing power plant operation, the targeted usage of DR will not save the same amount of energy as permanent load reductions that come from energy efficiency measures. As peak periods are relatively infrequent, so too tends to be the use of DR. Yet, the infrequent spikes in demand have a significant economic impact: in many systems, 10% (or more) of costs are incurred to meet demands which occur less than 1% of the time.⁴ Reducing this peak demand through DR programs means that the capacity requirements which drive investments in generation, transmission, and distribution assets can also be proportionally reduced. The US-based energy consultancy the Brattle Group, in its 2007 paper “The Power of Five Percent,” found that a 5% reduction in peak demand would have resulted in avoided generation and T&D capacity costs of \$2.7 billion per year.⁵

In addition, the use of DR during peak periods can result in significant savings in terms of energy expenditure. In wholesale markets, spot energy prices during peak periods can skyrocket due to increased demand. Similarly, energy prices in vertically integrated, non-wholesale market systems can also increase during peak periods as less efficient units (i.e. with a higher heat rate) are utilized in order to meet the rising demand. As retail energy rates tend to not reflect the true cost of energy during peak periods, the expensive utilization of generation during these times is socialized among all customers. By reducing the need to purchase high-priced power, all customers in a system are positively impacted. The

³ Synapse Energy Economics, “Modeling Demand Response and Air Emissions in New England,” September 4, 2003. Page 16.

⁴ EnerNOC, Inc. Analysis of US and Australian Electricity System Data.; Brattle Group, “The Power of Five Percent,” May 16, 2007

⁵ Brattle Group, “The Power of Five Percent,” May 16, 2007.

aforementioned Brattle report also identified energy savings on the order of \$300 million per year from the same 5% reduction in the peak demand of the US as a whole. Figure 1 further illustrates the point that the avoided capacity costs far outweigh the avoided energy and avoided T&D costs.

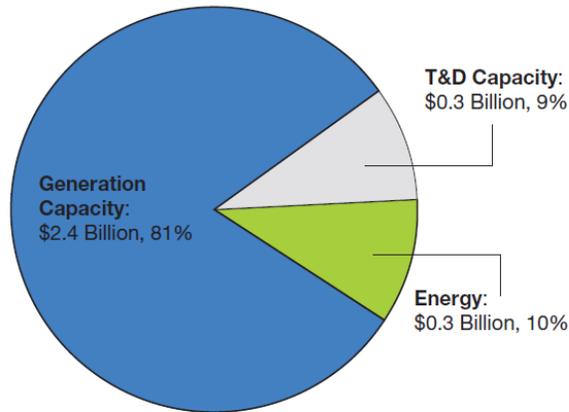


Figure 1: Annual Benefits of 5% Demand Response in the US⁶

Indeed, it is important to recognize the financial benefits participants in these programs receive, which are the sum of both the avoided energy costs (and demand charges) as well as the direct incentive payments for participation and successful performance.

⁶ Id.

2. DEMAND-SIDE MANAGEMENT AND THE ROLE OF DR

2.1. Overview of Demand Side Management

Demand-side management (DSM) consists of a broad range of planning, implementing and monitoring of activities designed to encourage end-users to modify their levels and patterns of electricity consumption. DSM programs and initiatives are typically implemented to achieve two basic objectives: energy efficiency (EE) and load management. EE is primarily achieved through programs that reduce overall energy consumption of specific end-use devices and systems by promoting high-efficiency equipment use and building design. Conversely, load management programs are designed to achieve reductions in consumption primarily during times of peak demand, rather than on a permanent or ongoing basis. Load management programs can include permanent-load shifting and peak-shaving activities traditionally associated with demand response. With improvements in technology, load management programs are also increasingly dispatched on a level playing field with supply-side resources.

Figure 2 presents the total peak load reduction through DSM from 1998 to 2009 in the US. Peak load reduction through energy efficiency programs increased from 13,591 MW in 1998 to 19,766 MW in 2009, but decreased from 13,640 MW to 11,916 MW during the same period by load management programs.⁷

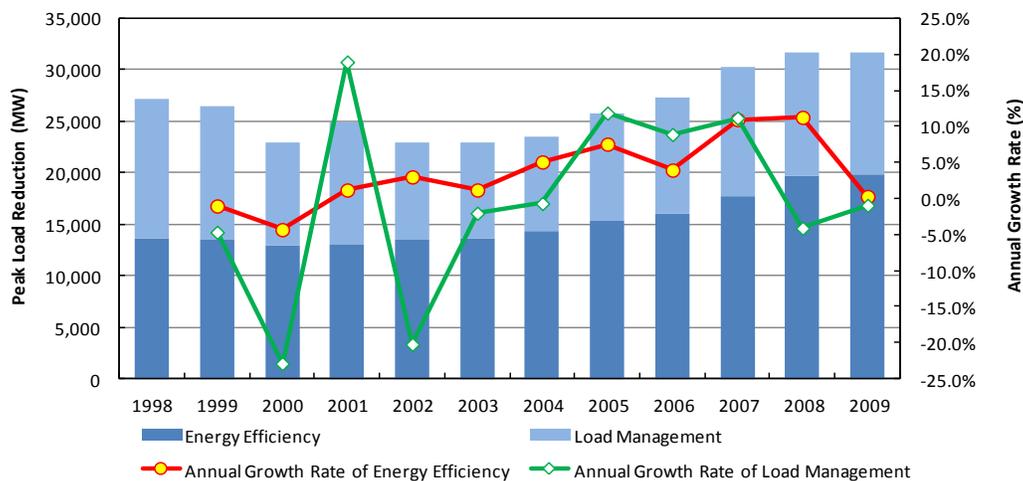


Figure 2: Peak Load Reductions from DSM Programs by Program Category⁸

⁷ U.S. Energy Information Administration (November 23, 2010), Demand-Side Management Actual Peak Load Reduction by Program Category. (<http://205.254.135.24/cneaf/electricity/epa/epat9p1.html>)

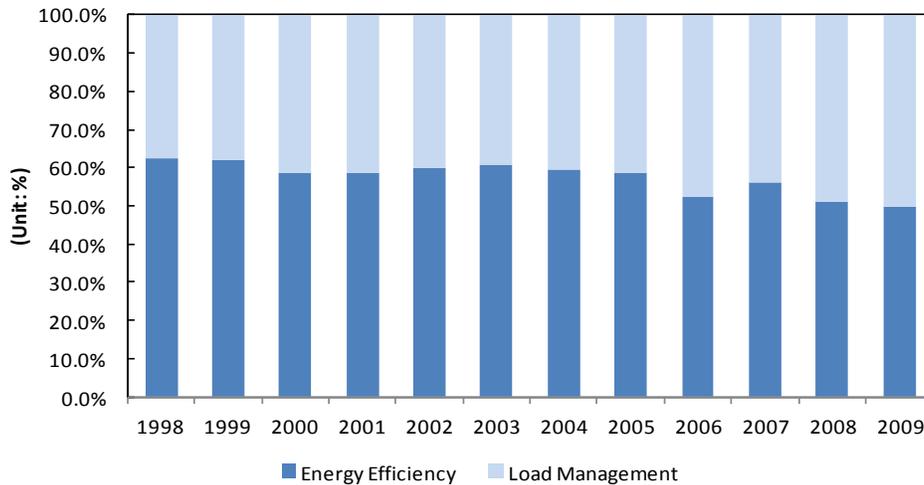
⁸ US Energy Information Agency. 2009.

2.2. Role of DR in Demand-Side Management

Demand Response is normally included as part of utility DSM program or a potential DSM program solution which helps make the electric grid much more efficient and balanced by assisting the electric grid's commercial and industrial customers in reducing their electric peak demands, and/or shifting the time period when they use their electricity, and/or prioritizes the way they use electricity, and in return reduces their overall energy costs.

A key difference between DR and EE is the energy reductions for DR are time-dependent, whereas reductions for EE are not. Demand response programs yield reductions in demand at critical times, which typically corresponds to time of peak power demand, while EE programs yield permanent energy savings. However, the two programs have overlapping effects: EE can permanently reduce demand including those occurred during the peak time while demand response with well-targeted control strategies can also produce energy savings.⁹

Up to 2003, EE programs in the US contributed to more than 60% of actual peak load reduction;¹⁰ however, its share dropped by almost 10% from 59.3% in 2004 to 49.9% in 2009. Meanwhile, contributions from load management had increased by about 12% from 37.6% to 50.1% during the same period (see Figure 3).



⁹ Goldman, Charles, M. Reid, R. Levy, and A. Silverstein (January 2010), *Coordination of Energy Efficiency and Demand Response*, Lawrence Berkeley National Laboratory, LBNL-3044E.

<http://eetd.lbl.gov/ea/ems/reports/lbnl-3044e.pdf>

¹⁰ Peak load reductions are categorized as potential or actual. Potential peak load reductions are the amount of load available for curtailment through load control programs such as direct load control, interruptible load control, other load management, or other DSM programs. Actual peak load reductions are the amount of reduction that is achieved from load control programs that are put into force at the same time as peak load and the amount of reductions that result from energy efficiency programs at the time of peak load.

Figure 3: Share of Total Actual Peak Load Reduction by Program Category¹¹

2.3. Coordination of Demand Response and Energy Efficiency

Demand response and energy efficiency programs could be coordinated at the customer level at least in the following four ways:¹²

- **Offering combined programs:** Although separating energy efficiency and demand response programs are quite common, customers could be presented with both opportunities at the same time. Furthermore, technologies that are commonly used for DR – such as energy monitoring, building automation systems and load control equipment – can also be leveraged to help inform about opportunities that would lead to energy efficiency improvements.
- **Coordinating program marketing and education:** Program sponsors could package and promote demand response and energy efficiency in a closely coordinated way. Because the two programs are quite complicated to customers, program sponsors could help customers addresses both topics under a broad DSM and management theme.
- **Market-driven coordination services:** Effective coordination can be done not only by utilities and Independent System Operators (a.k.a. ISO), but also by the initiative of private firms that find a market among customers who are interested in reducing their energy costs or receiving incentives.
- **Incorporating Building codes and appliance standards:** Building codes and appliance efficiency standards can incorporate demand response and energy efficiency functions into the design of buildings, infrastructure, and power-consuming appliances/equipments. Integrating those codes and standards can lead to significant reduction in the costs to customers of integrating demand response and energy efficiency strategies and measures.

¹¹ Id.

¹² Cappers, Peter, C. Goldman, and D. Kathan (2009), *Demand Response in U.S. Electricity Markets: Empirical Evidence*, Lawrence Berkeley National Laboratory, LBNL-2124E. (<http://eetd.lbl.gov/ea/ems/reports/lbnl-2124e.pdf>).

3. REGULATORY AND POLICY FRAMEWORKS THAT PROMOTE DEMAND RESPONSE

3.1. Demand Response Enabling Policies

DR, at least in a basic form, has been around for decades. In the US, load management and interruptible/curtailable tariffs were first introduced in the early 1970s. The primary interest in load management was driven in part by the increasing penetration of air conditioning which resulted in needle peaks and reduced load factor. These programs were effectively limited to the largest industrial customers in a given system, and in many cases never used. Deployed before the advent of the internet or the load aggregator business model, these programs were very manual and typically featured slow response times. With such limited capabilities, interruptible programs served less as an alternative to generation investments, and more as a load management tool that could theoretically be used in emergencies – in reality though, they were more often than not a customer retention tool allowing utilities to offer discounted service rates to customers large enough to fund the installation of their own generation assets.

This base of demand response was then further spurred by two important developments: Within traditionally-regulated, vertically-integrated utilities, the advent of integrated resource planning in the late 1970s and 1980s made utilities increasingly aware of the system cost impacts of meeting peak loads, and load management began to be viewed as a reliability resource. The results of this perspective were first evident in the rise of Direct Load Control (DLC) programs that cycled residential air conditioning units during peak periods. Even more significant, in the mid 1990s, policymakers and utilities interested in facilitating the development of regional, competitive wholesale markets primarily based on re-design and re-structure markets.

3.1.1 Wholesale Market Access

UNITED STATES

It is well-known to industry observers that the growth of the demand response industry in the United States can in many ways be traced to the opportunities in these wholesale power markets, particularly in the systems of ISO-New England¹³ and the PJM Interconnection¹⁴. According to the most recent government statistics, more than 31 GW of demand response was active in the US RTO/ISO markets in 2011¹⁵. While the opportunities for DR in California that emerged after the state's energy crisis in 2001 certainly contributed to the growth of the industry as well, the scale of the opportunities (and the realization of them) in the aforementioned wholesale markets has proven to be a stronger influence on the growth of the industry in the United States.

¹³ The current size of the ISO-New England system is approximately 26 GW.

¹⁴ The current size of the PJM system is approximately 165 GW.

¹⁵ Federal Energy Regulatory Commission (2011). "Assessment of Demand Response & Advanced Metering Staff Report." November 2011. Table 2.

The role of government policy in the establishment of these opportunities has been an essential driver to the growth of the DR industry in the US. The foundation of competitive power markets in the US can be traced to the Energy Policy Act of 1992 (EPAct) and Order 888 from the Federal Energy Regulatory Commission (FERC). EPAct began the process of electric industry deregulation and opened up the opportunity for independent power generators to participate in wholesale markets, which FERC Order 888 furthered by requiring fair access and market treatment to transmission systems. While the aforementioned legislation and Order were primarily focused on increasing competition among generators, the concepts laid the groundwork for demand response to enter wholesale markets when such resources could meet the same technical requirements as their supply-side counterparts. The Energy Policy Act of 2005 (EPACT) further codified that a key objective of US national energy policy was to eliminate unnecessary barriers to wholesale market demand response participation in energy, capacity, and ancillary services markets by customers and load aggregators,¹⁶ at either the retail or wholesale level.¹⁷

While demand response began participating at scale in wholesale power markets in the early 2000s – particularly in emergency capacity programs – many market barriers remained. Fortunately, in October 2008, FERC issued Order 719, which focused on the operation of the country’s wholesale electric markets. A major component of Order 719 was eliminating barriers to the participation of demand response in wholesale markets operated by wholesale market operators. Order 719 permitted load aggregators to bid demand response directly into organized markets, unless the relevant laws of the local electric retail regulatory authority prohibit such activity.

Demand response integration into US wholesale power markets was further bolstered with the March 2011 issuance of FERC Order 745. Order 745 requires that demand response resources are paid the Locational Marginal Price (LMP), or the wholesale market price for energy. By codifying the ability for DR to be compensated in the same fashion as generation resources for services provided to the energy markets, Order 745 advances the cause of equal treatment between generation and demand side resources.

In the US, DR is primarily seen in the wholesale capacity markets, most notably in the PJM Interconnection and ISO-New England. DR in these markets is procured in a competitive process that places demand side resources on equal footing with generation, creating an opportunity for cost-effective DR that can easily enter the market (should technical requirements be able to be met). In addition, in both markets, capacity DR is dispatched only during the very critical peak or emergency periods, making end-user participation relatively simple (compared to other markets to be profiled in this paper that are solely for balancing resources). Examples of both markets are provided below.

The PJM Interconnection

¹⁶ Load aggregation is the process by which individual energy users band together in an alliance to secure more competitive prices than they might otherwise receive working independently. Oftentimes, load aggregator companies are formed to represent the interests of these groups of customers.

¹⁷ Cappers, Peter, C. Goldman, and D. Kathan (2009).

PJM (Pennsylvania-New Jersey-Maryland) Interconnection is a regional transmission organization (RTO) that coordinates the movement of wholesale electricity in all or parts of Delaware, Illinois, Indiana, Kentucky, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, Tennessee, Virginia, West Virginia and the District of Columbia. PJM is the largest market in the US and allows DR to participate in all of its markets types – capacity, energy, and ancillary services. Today, more than 60 entities serve as Curtailment Service Providers (CSPs), or load aggregators, in the PJM system.

Like in most systems, the bulk of the DR in PJM participates in the capacity market. Capacity markets are particularly well-suited to peaking resources like DR which operate for relatively few hours a year and may have trouble accessing the proper price signals from an energy-only market. PJM's current capacity market, the Reliability Pricing Model (RPM), was instituted in 2007. In the RPM, those resources include not only generating stations, but also demand response actions and energy efficiency measures by consumers to reduce their demand for electricity. In this manner, demand side management is directly integrated into the wholesale capacity market structure.

Every year PJM conducts a Base Residual Auction (BRA) for delivery of capacity three years in the future. The BRA is held in May and the delivery year begins 3 years later on June 1st and ends on May 31st of the following year. In addition to the BRA, PJM conducts three Incremental Auctions (IA) that are held in advance of each corresponding delivery year. The purpose of the IA is to balance any changes in the load forecast and to allow suppliers of capacity resources to adjust their positions. In PJM's most recent Base Residual Auction in May 2011, the market procured 149,974 MW of capacity for the 2014/2015 delivery year. Of note, 14,118 MW of this capacity – or 9.4% of the total – came from demand response resources. Once cleared through the capacity market, these DR resources become participants in PJM's Emergency Load Response Program.

In PJM, qualifying DR resources can also participate in the wholesale energy market (both day-ahead and real-time) as well as various ancillary service markets (primarily, the synchronized reserve market). However, these markets are not the same drivers of DR growth that the capacity market is. The energy market does not feature capacity incentives, and therefore requires significantly more participation to garner the same financial opportunity. The Synchronized Reserve Market, on the other hand, requires full response within 10-minutes of a dispatch signal and generation-grade telemetry, limiting the pool of potential participants.

ISO New England (ISO-NE)

PJM's counterpart to the north, ISO New England, also operates a forward capacity market (FCM) in which DR can participate alongside generation, and which accounts for the majority of demand side participation within the New England system. Similar to PJM's BRA, the ISO-NE FCM also allows both dispatchable demand response and energy efficiency measures to participate in the market.

ISO-NE's use of demand response may be the clearest example of a resource designed specifically for reliability and/or emergency prevention purposes. While the ELRP in PJM is also designed for similar

purposes, the trigger for usage in ISO-NE is even more defined. ISO-NE treats DR provided by curtailment and on-site generation as distinct resources, labeling the former Real Time Demand Response (RTDR) and the latter Real Time Emergency Generation (RTEG). RTDR may be called by ISO-NE only when the system reaches an emergency level known as Operating Procedure 4 Action 9 (OP4 Action 9). RTEG, on the other hand, cannot be dispatched until a further level of emergency has been reached, OP4 Action 12. For customers that utilize both load curtailment and on-site generation to provide DR capacity, they (or their DR provider), must be able to call those distinct loads separately in order to comply with ISO-NE requirements. Today, approximately 2,000 MW, or 8% of the resources in the capacity market, are dispatchable demand response. This figure grows to 3,400 MW, or 10% of the ISO-NE system, in 2014/15.

Demand response resources can also provide energy to the ISO-NE market through the Real-Time Price Response and Day-Ahead Load Response Programs. As with energy market participation in PJM, these programs are relatively unpopular compared to the capacity market, as they require much more frequent participation and have comparatively lower economic benefit. In both markets, sites that participate in the energy programs tend to be among the most flexible participants in the capacity markets who are looking for an additional economic opportunity, rather than the energy program serving as the sole method of DR participation in the market. While ISO-NE formerly had a pilot program testing the ability for DR to provide ancillary services – the Demand Response Reserve Pilot (DRRP) – it no longer has an active mechanism for DR to provide operating or spinning reserves. DR participation in these markets is now under active consideration, in part due to the aforementioned FERC Order 719.

UNITED KINGDOM

National Grid Short Term Operating Reserves (STOR) Market

Demand response resources also enjoy wholesale market access in the United Kingdom, albeit in a much more limited context. Market-based opportunities for demand-side resources in the UK are currently restricted to ancillary service markets, primarily the Short Term Operating Reserves Market. While others exist, the parameters result in low levels of participation and or a small addressable market.¹⁸ DR cannot access the nation's wholesale energy market and unlike PJM and ISO-NE, there is no capacity market in the UK. That said, the government, spearheaded by the Department of Energy and Climate Change (DECC), is pushing forward legislation to launch one in the coming years and which will also allow for demand side participation.

STOR is essentially a supply and demand balancing service that meets the need of the grid as demand changes and as traditional power plants come online and ramp up and down, similar in many ways to the Synchronized Reserve Market (SRM) in the PJM Interconnection. While not a capacity market per se, cleared resource receive an availability payment for each hour they are in the market and available to be dispatched. Utilization (energy) payments are also given for the actual load reduction provided. Both features are also present in the aforementioned SRM. As a balancing market, STOR is called much more

¹⁸ For example, the Fast Reserves (FR) program has a 50 MW minimum requirement for participation.

frequently than the capacity programs in PJM and ISO-NE which are used primarily to address emergency conditions. STOR participants, on average, must be prepared to respond to a dispatch every week. Such frequent participation requires the employment of different curtailment strategies than those that are found in capacity programs designed to shave consumption only during infrequent, peak periods.

AUSTRALIA

Independent Market Operator – Wholesale Electricity Market (WEM)

Another successful example of DR participation in wholesale markets can be found in the South West Interconnected System of Western Australia, run by the Independent Market Operator (IMO). There are two wholesale markets in Australia; the Wholesale Electricity Market (WEM) in Western Australia, and the National Electricity Market (NEM) in the eastern states (except for the Northern Territory). The NEM is an energy-only market and has very low levels of DR participation for the reasons mentioned earlier, whereas the WEM is a capacity market similar in many ways to ISO-NE and PJM, and with a significant penetration of DR. In the most recent Reserve Capacity Cycle, more than 8% of the capacity procured came from demand-side resources.¹⁹

The IMO-administered WEM procures system resources through the Reserve Capacity Mechanism, in which capacity can be traded bilaterally to the IMO directly, or to retailers. Unlike in PJM and ISO-NE where capacity prices are the result of competitive offers, the IMO sets a price for all capacity based on the avoided cost of a marginal new peaking unit, specifically a 160 MW open cycle gas turbine. Auctions are only triggered if the bilateral trading mechanism secures insufficient capacity.²⁰ As in the previously discussed capacity markets of the US, DR and generation receives the same exact market payment.

As with PJM and ISO-NE, DR is assumed to have different levels of dispatch capability than traditional supply-side resources. The RCM has 4 Availability Classes; Generation must all list itself as Class 1, or available for more than 96 hours a year; DR meanwhile can offer at between 24-96 hours of dispatch.

One important distinction about DR in WA is that unlike PJM and ISO-NE; DR in the WEM can be dispatched when it is deemed to be economic and is not dependent on emergency conditions. The system operator is required to first utilize the plants of the former state-owned generation company, but afterwards all dispatch is determined by the market energy price offered by the resource.

Unlike its counterparts in the US, DR in WA is limited to participation in the wholesale capacity market. While a wholesale energy market also exists in WA, the STEM, DR resources do not have access to the market. Meanwhile, a competitive balancing market is only just now being designed, and access for DR is expected once the market is fully operational in the coming years.

¹⁹ The Reserve Capacity Cycle (RCC) is the process that is used in Australia to procure DR resources as part of the Reserve Capacity Mechanism.

²⁰ Note that to date this situation has never been experienced so no auctions have been called.

Capacity-based Programs in Energy-only Markets

Some wholesale market operators have taken a slightly different approach, creating DR-specific opportunities outside of the standard wholesale markets themselves. For the most part, these are energy-only markets, where the underlying structure is not as conducive to peaking resources like demand response, which operate for relatively few hours per year.

In the Canadian Province of Ontario, the Independent Electricity System Operator (IESO) and the Ontario Power Authority (OPA) launched a large scale DR program (DR3) in 2007 to provide additional capacity to the market due to planned retirement of coal-fired power plants in the province. DR3's inclusion of a capacity payment represented a departure from previous DR programs in Ontario that failed to gain traction, primarily due to incentives being limited to energy payments.

Another example is the Emergency Interruptible Load Service (EILS) program in the Texas market of ERCOT. EILS is essentially a standalone markets that exists alongside the wholesale markets open to generation resources in ERCOT. EILS is designed to provide reserve capacity to the energy-only ERCOT market, and is procured during four separate markets spaced evenly throughout the year. Unlike DR3, pricing in EILS is the result of offers made by DR providers, similar to how the capacity markets in PJM and ISO-NE work. A further similarity with PJM is that ERCOT allows EILS participating loads to provide operating reserves in the ERCOT ancillary service markets and receive the same payment as generation resources, similar to the SRM.

3.1.2 Bilateral Programs with Vertically Integrated Utilities and Network Operators

Access to existing wholesale markets are just one mechanism for creating and leveraging demand response resources. In recent years, much growth in the industry has been found in bilateral programs with vertically integrated utilities in traditionally regulated environments, and with network (T&D) operators located within a liberalized market structure. These bilateral programs are most often used as a way to avoid or defer investments in generation and/or T&D infrastructure, and tend to look similar in structure to a power purchase agreement (PPA) that a utility might sign with an independent power producer. These utility programs are likely better proxies for how the implementation of next-generation demand response could manifest itself in China, given the lack of a wholesale market.

There are a number of enabling policies that have encouraged the development of bilateral DR programs throughout North America, the UK and Australia. These policies include:

- Cost recovery and DSM funds
- Loading orders and similar regulations
- Peak demand mandates and energy efficiency portfolio standards

Cost Recovery and DSM Funds

Whether in the US, the UK, or Australia, vertically integrated utilities and distribution network operators are regulated monopolies whose revenues are dependent on government policy and regulation. As such,

it is essential to understand the regulatory environments in which these utilities operate in order to understand how regulatory policies have both contributed to, and hindered, the growth of demand response.

Perhaps the most basic and essential enabling policy is a cost-recovery mechanisms. Under a cost-recovery mechanism, a utility can recover prudently-incurred costs of DR and EE investments on a dollar-for-dollar basis, typically through a rider or customer surcharge. Cost recovery is designed to make a utility whole on its DR and EE investments. However, there are challenges with this approach. First, cost recovery alone will not address the lost margin revenue the utility will face due to reduced energy sales from DR and EE programs. Second, cost recovery does not factor in opportunity costs: DR and EE investments displace supply-side investments for which the utility can earn a profit. Given these opportunity costs, absent a statutory or regulatory mandate, program cost recovery alone will generally not attract utility interest in DR and EE programs. However, in some jurisdictions, utilities are authorized to recover additional costs associated with the lost revenue due to the energy efficiency measures. There are also provisions for earning a fair rate of return on the DSM investment, typically at levels that are equivalent to allowable returns on power generation assets.

Loading Orders and Similar Regulations

Loading orders are governmental proclamations that define the priority order in which resources are to be developed. To underscore the importance of energy efficiency and demand response in California's future energy picture, the state government developed the Energy Action Plan established a "loading order" of preferred resources, placing energy efficiency and demand response as the state's highest-priority procurement resource, and set aggressive long-term goals for energy efficiency and demand response resources. In addition, energy efficiency and demand response strategies were implemented to address greenhouse gas emission reduction targets specified by AB32, a law adopted in California to create regulatory policy mechanisms to combat global warming. As a result of these policies, California's energy efficiency and demand response efforts have proven to be very successful. California leads the nation in term of energy saved. The state invests nearly \$3 billion per year in energy efficiency and demand response programs that target electricity and natural gas customers to install high efficiency equipment, take measures to reduce their peak demands, and establish time-sensitive price structures that are more in line with the actual cost of providing the electricity. Resources such as renewable generation, distributed generation, and traditional generation are considered as the second and third priorities, respectively in the loading order, and should only be considered once all energy efficiency and demand response resources are exhausted.

In Massachusetts, a law known as the Green Communities Act was passed in 2008 and implemented shortly thereafter. The law requires the state's utilities to procure all available energy efficiency resources that cost less than traditional energy sources do. The law in effect prioritizes energy efficiency as being at the top of the loading order, ahead of renewable energy, and more traditional forms of generation. Among the major provisions is a requirement for utilities to invest in energy efficiency when it is less expensive than buying power. Previously companies purchased more power when demand

increased. The effect of the law is that the state is seeing significant investments in energy efficiency, leading toward the ultimate goal of reducing the state's use of fossil fuels in buildings by 10% and overall greenhouse gas emissions by 20% in the year 2020.

Peak Demand Mandates, Energy Efficiency Portfolio Standards

Peak demand mandates and energy efficiency portfolio standards have recently emerged as another mechanism to encourage DR outside of market-based opportunities. Perhaps most well known is a mandate in the state of Pennsylvania, the so-called Act 129 legislation, signed into law in October 2008, which requires all electric distribution companies to achieve peak demand reduction targets of 4.5% and energy efficiency reductions of 4% by 2015. While the legislation does not expressly encourage DR over other types of peak reduction such as energy efficiency and or solar PV, Pennsylvania utilities appear to have determined C&I DR was the most cost effective way to reach compliance and several large deals with aggregators have already been publicly announced.

Other states with peak demand mandates that are similar to Pennsylvania include New York, Colorado, Michigan and Ohio. In New York, the Public Service Commission established an Energy Efficiency Portfolio Standard (EEPS) which ordered the state's utilities to achieve a 15% reduction in forecast electricity usage by the year 2015. The state's utilities are implementing aggressive EE and DR programs in order to meet that goal, which specifies that each of the state's utilities realize specific MWh and peak MW reduction amounts by 2015. In Colorado, the Climate Action Plan (CAP) sets carbon reduction goals for the state and proclaims that energy efficiency programs are the most important responses to the carbon-reduction challenge. In response, the Colorado Public Utilities Commission has ordered the state's utilities to implement EE and DR programs to meet that goal. Michigan and Ohio have similar statutory mandates to lower energy usage and peak demand.

Parity of Treatment

Traditional utility regulation favors supply-side resources over DR and EE resources. First, utilities earn a rate of return on investments in generation, transmission and distribution infrastructure. The absence of a parallel incentive for DR and EE investments creates a bias against demand-side resources. This has been described in the economic literature as the "Averch-Johnson Effect." That is, where a firm's profits are linked to its capital investment, as is the case with utilities under traditional regulatory structures, there is an embedded incentive for the firm to increase its capital outlay in a manner that does not necessarily maximize producer and consumer surplus. Stated another way, traditional regulatory frameworks create a disincentive for utilities to meet resource needs using approaches that are less capital intensive. Thus, faced with otherwise equivalent alternatives of building a power plant that contributes to profitability or making investments in DR and EE that allow for cost-recovery only, a utility would generally prefer to build a power plant (or T&D).

The government of the United Kingdom recently recognized and addressed this very challenge. In the 2010-2015 Distribution Price Control Review 5 (DPCR5), Ofgem – the national electricity and gas regulator – instituted the so-called "Equalisation Incentive" which establishes parity in the treatment of

capital and operating expenditures by distribution utilities. Thus, any utility acting in its own rational economic interest will clearly pursue the most cost-effective way to meet network needs and reliability requirements, whether that is through traditional investments in infrastructure or through non-network alternatives like DSR. As a result of this new regulation, one local distribution network operator – Electricity North West – has already deployed a commercial scale DR program in which an aggregator is deploying DR on specific circuits in order to defer investments in substations. Other distribution network operators, such as UK Power Networks, are also conducting pilot projects using DR for distribution relief as they hope to prepare themselves to launch commercial-scale programs under this new regulatory framework.

Example Utility DR Programs

There are several examples of bilateral DR programs. In California, Pacific Gas and Electric (PG&E) implements the Aggregator Managed Portfolio (AMP) program. AMP is a non-tariff program that consists of bilateral contracts with aggregators to provide PG&E with price-responsive demand response. The program can be called at PG&E's discretion. Each aggregator is responsible for designing and implementing their own demand response program, including customer acquisition, marketing, sales, retention, support, event notification and payments. To participate, customers must enroll through a load aggregator. The customer in turn authorizes the aggregator to act on their behalf with respect to all aspects of AMP, including receipt of notification of an event, receipt of incentive payments and/or penalties. Southern California Edison (SCE) operates the Demand Response Contracts (DRC) program. SCE has contracted with several aggregator companies to provide SCE with price-responsive and/or demand response events that SCE may call at its discretion. Each aggregator designs their own programs, and offers demand response program structures and options that may not be directly available through SCE. Customers may select an aggregator with services that best meet their business needs.

More common are arrangements where a utility contracts with a single DR load aggregator for a program in their territory (or a single provider per customer class). For example, EnerNOC, a Boston-based load aggregator has a program in place with the Tennessee Valley Authority (TVA) in the southeastern US, the largest public power company in the country. TVA procured a long-term, 560 MW resource from EnerNOC which it is required to deliver in line with contract requirements over the 10-year contract length. There are many other load aggregator companies operating in the various electricity markets throughout North America. As with the aforementioned DR programs in California, the load aggregator is responsible for all roles from customer acquisition through resource dispatch and settlement.

As with similar DR programs, TVA has purchased a guaranteed firm resource. In addition to identifying and enabling DR capacity in line with contract milestones, the load aggregator must also meet performance standards when dispatched by TVA. Should the load aggregator fail to do either, financial penalties against the aggregator may be assessed. In this manner, TVA can depend on its DR-based "virtual power plant" in the same way its system planners and operators can trust a traditional generation resource. Figure 4 provides a summary of the TVA bi-lateral program parameters.

Program Size	Up to 560 MW
Advanced Notification	30 minutes
Dispatch Trigger	TVA's discretion
Availability Window	April – October: 12:00-20:00, Mon-Fri November – March: 5:00-13:00, Mon-Fri
Maximum Cumulative Dispatches	40 hours per annum
Term Length	10 years

Figure 4: TVA Bi-lateral DR Program Parameters

Other vertically-integrated utilities in the US that have implemented similar programs include: Arizona Public Service, Idaho Power, NV Energy, Public Service Company of New Mexico, Puget Sound Energy, Salt River Project, San Diego Gas & Electric, Tampa Electric, Tucson Electric Power, and Xcel Energy. Per the aforementioned “equalisation incentive” now in effect in the UK, distribution network operators (DNOs) in the country are also now deploying demand response programs to defer or avoid investments in network infrastructure. Electricity North West (ENW), one of the 14 regulated DNOs in the UK with a network that includes the Greater Manchester and Cumbria areas, has recently launched a DR program along with a third-party load aggregator. Under this program, DR is deployed within specified circuits in the network, allowing demand to be controlled on a geographically-targeted basis that will prevent the need to upgrade the substations on those portions of the network. The program, announced in May 2011, is set to last for five years. Such ‘network support’ contracts are also commonly found in Australia, particularly in New South Wales.

The same Distribution Price Control Review that launched the equalisation incentive, also included funds from Ofgem – the UK electric regulator – for Low Carbon Network (LCN) projects that will pilot new technologies and facilitate the development of an environmentally-friendly electricity system in the country. Many DNOs throughout the UK have successfully applied for LCN funding to pilot the use of DR in their networks, including UK Power Networks (UKPN) and Northern Powergrid (formerly CE Electric). ENW has also recently been awarded LCN funding from Ofgem to pilot the use of DR in new ways within their system that, if successful, would reduce the amount of network capacity DNOs would need to have in order to comply with reliability standards.

3.2. Encouraging End-User Participation: The Role of Incentives

The U.S. Department of Energy classifies demand response into two categories, i.e. price-based demand response and incentive-based demand response.²¹ Each category has its own subcategories. Pricing mechanisms vary on each subcategory as shown in Table 1.

- *Price-based demand response* refers to changes in usage by customers in response to changes in the prices they pay and include real-time pricing, critical-peak pricing, and time-of-use rates. If the price differentials between hours or time periods are significant, customers can respond to

²¹ U.S. Department of Energy (February 2006).

the price structure with significant changes in energy use, reducing their electricity bills if they adjust the timing of their electricity usage to take advantage of lower-priced periods and/or avoid consuming when prices are higher. Customers' load use modifications are entirely voluntary (Table 1)

- *Incentive-based demand response* programs are established by utilities, load-serving entities, or a regional grid operator. These programs give customers load-reduction incentives that are separate from, or additional to, their retail electricity rate, which may be fixed (based on average costs) or time-varying. The load reductions are needed and requested either when the grid operator thinks reliability conditions are compromised or when prices are too high. Most demand response programs specify a method for establishing customers' baseline energy consumption level, so observers can measure and verify the magnitude of their load response. Some demand response programs penalize customers that enroll but fail to respond or fulfill their contractual commitments when events are declared (Table 1).

Table 1: Demand Response Options and Related Pricing Mechanisms

Price-Based (Voluntary)	Incentive-Based (Contractually Mandatory)
<ul style="list-style-type: none"> • <i>Time-of-use (TOU)</i>: a rate with different unit price for usage during different blocks of time, usually defined for a 24 hour day. TOU rates reflect the average cost of generating and delivering power during those time periods. • <i>Real-time pricing (RTP)</i>: a rate in which the price for electricity typically fluctuates hourly reflecting changes in the wholesale price of electricity. Customers are typically notified of RTP prices on a day-ahead or hour-ahead basis. • <i>Critical Peak Pricing (CPP)</i>: CPP rates are a hybrid of the TOU and RTP design. The basic rate structure is TOU. However, provision is made for replacing the normal peak price with a much higher CPP event price under specified trigger conditions (e.g., when system reliability is compromised or supply prices are very high). 	<ul style="list-style-type: none"> • <i>Direct load control</i>: a program by which the program operator remotely shuts down or cycles a customer’s electrical equipment (e.g., air conditioner, water heater) on short notice. Direct load control programs are primarily offered to residential or small commercial customers. • <i>Interruptible/curtailable (I/C) service</i>: curtailment options integrated into retail tariffs that provide a rate discount or bill credit for agreeing to reduce load during system contingencies. Penalties may be assessed for failure to curtail. Interruptible programs have traditionally been offered only to the largest industrial (or commercial) customers. • <i>Demand Bidding/Buyback Program</i>: customers offer bids to curtail based on wholesale electricity market prices or an equivalent. Mainly offered to large customers (e.g., one megawatt [MW] and over). • <i>Emergency Demand Response Programs</i>: programs that provide incentive payments to customers for load reductions during periods when reserve shortfall arise. (e.g. ERCOT EILS) • <i>Capacity Market Programs</i>: customers offer load curtailments as system capacity to replace conventional generation or delivery resources. Customers typically receive day-of notice of events. Incentives usually consist of up-front reservation payments, and face penalties for failure to curtail when called upon to do so. (e.g. PJM ELRP, IMO WA) • <i>Ancillary Services Market Program</i>: customers bid load curtailments in ISO/RTO markets as operating reserves. If their bids are accepted, they paid the market price for committing to be on standby. If their load curtailments are needed, they are called by the ISO/RTO, and may be paid the spot market energy price. (e.g. PJM SRM, UK STOR)

Source: DOE (2006), p.12.

In addition to federal regulation as described in Section 3.1 and economic benefits described in Section 3.2, numbers of the U.S. utilities have taken action to expand their retail demand response programs. One incentive factor for many of them has been concern about peak load growth and rising energy prices.²²

²² U.S. Federal Energy Regulatory Commission (December 2008), *Assessment of Demand Response and Advanced Metering*, Washington D.C. (<http://www.ferc.gov/legal/staff-reports/12-08-demand-response.pdf>).

3.2.1. Lack of Sufficient Incentives from Standard and TOU Pricing: Experience with Interruptible Tariffs

Many utilities have offered a variety of traditional DR programs for many years. These legacy programs are typically referred to as load management programs. There are three types of legacy load management programs: direct load control (DLC), time-of-use (TOU) rates, and interruptible contracts. Each of these programs use some form of incentive to encourage customers to participate. However, the amount of the incentives or the nature of the incentives has not been sufficient to bring about meaningful levels of demand reductions.

DLC programs allow the utility to directly control customer end-uses during certain periods when the electrical system is under strain. The customer end-uses are directly controlled by the utility and when events are called, those loads are either shut down, cycled on and off, or moved to a lower consumption periods. Residential DLC programs often target air conditioners or electrical water heaters. Non-residential DLC programs include air conditioner systems, lighting and in some regions irrigation control. There are a number of challenges with DLC programs. First, customers tend to become frustrated with effects of the service interruptions and oftentimes will leave the program if they are called too frequently. Second, the incentives offered by the utilities have been insufficient to encourage their sustained participation.

TOU rates are tariff schedules that are typically offered to residential and small business customers on a voluntary basis and are mandatory for the largest commercial and industrial customers. The TOU rates are structured to charge lower rates during a utility's off-peak and partial-peak periods and higher rates during seasonal and daily peak demand periods. By charging more during the peak period, when incremental costs are highest, TOU rates send accurate marginal-cost price signals to customers. TOU rates encourage customers to shift energy use away from peak periods to partial-peak or off-peak periods and enable customers to lower their electricity bills. There are two common challenges with TOU rates. First, the utilities have often set the TOU peak periods to be for long periods at a time, thus limiting customers' abilities to shift their loads to the lower price off-peak periods. Second, the TOU rate programs tend to be static in nature in that the peak and off-peak prices do not change regardless of system conditions and the true costs required to deliver electricity to customers. Because of the static nature of the TOU rates, they cannot be counted on for meeting the peak demand needs of the utility.

In addition, the utilities often design these tariffs to be revenue neutral. That is, the price differentials between on-peak and off-peak are intended to not change the utility's overall revenue. This goal oftentimes is inconsistent with a goal of maximizing customer participation in order to have meaningful peak demand reductions as a result of the TOU tariff.

Interruptible tariffs are contractual arrangements set up between the utility and large non-residential customers. Customers agree to reduce their electrical consumption to a pre-specified level, or by a pre-specified amount, during system reliability problems in return for an incentive payment or a similar rate

discount. Customers are given the incentive regardless of whether reliability events are called. In the past, these programs were developed mostly for customer retention as the utilities assured customers that reliability events were so rare and would never be called. However, as reliability problems are becoming more acute, utilities are calling more interruptible events. As a result, many customers are opting to negotiate an exit to their contractual obligations for these programs as they cannot tolerate the volume interruptions to their businesses.

3.2.2. Cost and Risks—How Load Aggregators have Removed Traditional Barriers to DR Participation

Complicated tariff structures and insufficient incentives are just a few of the challenges utilities face when trying to garner customer interest in traditional, non-aggregator-based DR programs. Equally important are the costs and risks customers must bear in order to participate.

While the costs for metering and load control equipment may not always be borne by the customer in these situations, the exposure to performance penalties remains essentially a constant. Without an aggregator to guarantee the load response, utilities have no choice but to penalize customers if they don't fully comply with a dispatch in order to ensure proper response. However, C&I loads are inherently volatile – and customers may not always be able to participate – and consequently customers may need to be willing to face a strong likelihood of penalties if they seek to participate.

Using load aggregators is one proven approach to removing many of these traditional barriers to DR participation. It is typical that the load aggregator pays all costs for the installation of metering and load control equipment, making participation for the customer a no-cost proposition. More importantly, because load aggregators are measured on the total load reduction their entire portfolio of sites provides, and not on a site-by-site basis, they are able to pool resources in a way that ensures that contract performance requirements can be met. In the event that performance penalties are assessed on the aggregator, many will still refrain from passing these onto the customer. Figure 5 illustrates this concept.

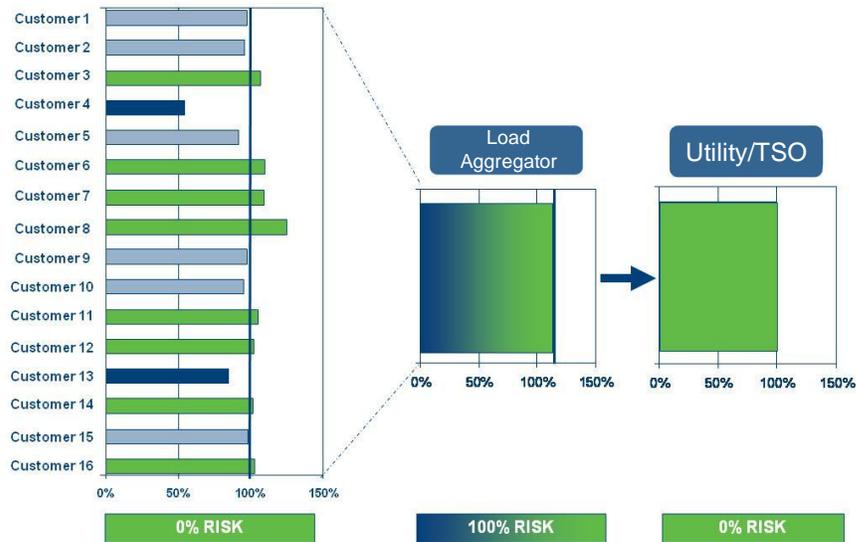


Figure 5: Aggregated Performance and Risk-Shielding

3.2.3. Avoid Energy Costs vs. Resource Payments

As is evident from the relative lack of uptake in energy-based demand response opportunities in wholesale markets (where prices are higher and more volatile than what customers face at a retail level), the economic benefit of avoided energy costs alone is likely to be an insufficient driver of customer participation. While dynamic pricing may impact this trend in some ways (as discussed in the next section), currently it is the ability to receive resource payments from DR participation that are driving customer involvement. In both wholesale market and bilateral programs, aggregators – or very large customers that qualify for direct participation – receive a payment from the entity purchasing the DR resources, either the system operator or the utility.

Whether determined through market pressures or a utility decision, these payments are almost always based on the avoided costs of providing the same functional service through a traditional supply-side resource. Aggregators then use a portion of this payment stream to cover their costs of customer acquisition, site enablement, dispatch and settlement; the remainder is used to pay the customer an incentive payment for their participation. These payments tend to exist in the same form as those the aggregator receives, namely energy and capacity. In wholesale markets where very large customers can participate directly, the customer would individually receive the full payment stream, but would be responsible for adhering to technical requirements and managing performance risk. For these reasons, many large customers continue to work with aggregators even when the market requirements don't make it a necessity.

3.2.4. Emerging Trends: Dynamic Pricing

Dynamic pricing refers to a category of rates that offer customers time-varying electricity prices on a day-ahead or real-time basis. Prices are higher during peak periods to reflect higher-than-average cost

of providing electricity during those times, and lower during off-peak periods, when it is cheaper to provide electricity. Dynamic pricing incentivizes customers to lower their usage during peak times, particularly during the most critical hours of the year when peak demands spike and the cost of acquiring electricity tends to be the highest. Dynamic pricing can take many forms. The most sophisticated form of dynamic pricing is real-time pricing (RTP). RTP programs are where prices are set by the utility in near real-time to match the market conditions for available power. Customers must be able to accommodate whatever price is given, which means that they take a significant risk that if prices spike they will either accept the higher price or be capable to rapidly reduce their consumption levels to avoid the high prices. Because of the complexities of RTP programs, most of the examples are in the pilot stages. Once sophisticated metering infrastructures are put into place and customers have the necessary building automation systems, it is likely that there will be more RTP programs coming on line in the future.

Critical peak pricing (CPP) is a less complex form of dynamic pricing. CPP programs are designed such that the prices for the top 60 to 100 hours are defined ahead of time, but the actual times in which these prices are in effect is not known until the day before the DR event or sometimes on the same day as the DR event. The price differentials are intended to be quite steep (oftentimes set at three to five-times the peak price) to encourage the customer to reduce or shift their loads during the critical peak times. CPP programs are offered to all customer types from residential to large commercial and industrial. A variant of CPP is peak time rebates (PTR). In PTR programs, a standard rate is applied during all hours but customers can earn a rebate if they reduce their consumption during the critical peak hours. PTR programs are most applicable to residential customers.

3.3. Summary/Comparative Analysis of Policy and Regulatory Frameworks

The global survey of demand response programs in this report illustrates a variety of regulatory constructs under which DR can thrive. Fundamentally, all of these regulations and policies in one way or another attempt to change the traditional paradigm that has historically lead to investments in additional supply-side infrastructure rather than load management.

Clearly, one method that has been incredibly successful in this regard is the wholesale capacity market. By removing the type of resource from the decision-making equation altogether and rather basing procurement decision on price alone, any resource that can meet the necessary market requirements can be purchased. With more 8-10%, or more, of system capacity met by DR in the PJM Interconnection, ISO New England, and the Western Australia Independent Market Operator, these markets have shown a clear ability to drive significant penetration of demand response.

Outside of the established liberalized markets where DR is present, there tend to be more fragmented regulatory efforts to mitigate – but not eliminate – the disparity in incentives between supply-side and demand-side investments by utilities. In fact, one could argue that these multitude of policies and initiatives are required because in most areas, the underlying financial drivers that encourage a supply-

side-focused perspective have not been modified: utility revenue is still tied to the amount of kWh sold, and the amount of capital they invest in generation and/or network infrastructure.

In many regions, utilities are only allowed to recover their DSM expenditures, but cannot earn a rate of return in the same manner as they would for supply-side investments. Because of this unequal treatment, some jurisdictions require their utilities to first pursue DSM programs before they can build generation assets to ensure solutions that may be cost-effective, but not financially beneficial, are considered. In other areas, utilities are mandated to reduce the peak demands (and energy consumption) or face penalties – such as in Pennsylvania – where there is no financial driver for the utility to do anything other than build more and more infrastructure.

It is within this environment that the UK's "equalisation incentive," is significant as it demonstrates a way to create true parity of treatment outside of a wholesale market context. While wholesale generation is competitive in the UK, distribution network operation is not – they are regulated monopolies in the same manner as vertically-integrated utilities in traditionally-regulated markets. Moreover, in traditionally regulated areas, such a mechanism could be applied to all investments so that generation (or alternatives to it) were also covered. In many ways, it is the concept of the "equalisation incentive" that is most important, and not its exact methodology. A multitude of regulatory mechanisms could likely be developed that would result in equal financial treatment between supply-side and demand-side investments, and it is important to not prescribe specific methodologies that may be better suited for one system than another.

This global survey demonstrates that good program designs are crucial to the success of demand response, perhaps more so than the existence of a formal market structures. Regardless of how DR programs or opportunities are engendered, programs must have the essential elements outlined in this paper in order to be sustainable, whether they are in liberalized markets or operated by vertically-integrated utilities.

In the wholesale capacity markets profiled in this paper, the programs found in the investor-owned utilities of California, as well as the program for the public utility TVA, clear similarities are evident. All such programs and markets are capacity-based, in which demand response resources are paid an ongoing payment for being available to provide capacity. In addition, all these examples are mainly targeted at the infrequent, yet expensive, top peak hours of the year. While there is indeed the ability for DR to provide more frequent response, such as in ancillary service markets, these general peak-shaving or emergency-prevention programs are suitable for the widest number of participants and can therefore lead to the highest levels of customer penetration.

Lastly, the inclusion of demand response load aggregators is another key recipe for success. In wholesale markets, often only the largest industrial customers can participate directly and aggregators are a mechanism for small and medium sized C&I customers to participate as well. Yet, even in such conditions, it is common for customers that could otherwise directly access the market do so instead through aggregators for the risk-mitigation benefits discussed in this paper. And in both the wholesale markets and among the regulated utility environments that are indeed more similar to the landscape in

China, we see aggregators play two other key roles that contribute to the success of DR. From the utility or system operator perspective is the ability to provide guaranteed capacity. Once reliability can be ensured, system planners and operators are subsequently able to depend on the DR resource and reduce the usage of, or construction of, supply-side infrastructure. Put another way, without these guarantees, there would be limited ability for investments in demand response that lead to opportunities for participation among end-users. Equally if not more important is the behind-the-meter expertise that aggregators offer. With specialized staff and technology able to implement repeatable curtailment strategies that do not negatively impact commercial business operations, aggregators can both identify and leverage more capacity, and achieve higher levels of customer participation.

4. Enabling Technology Solutions for Demand Response

Demand Response enabling technology solutions are dependent on the level of automation a particular facility participating in DR program is capable of. Understanding the functional capabilities of building control systems, including the underlying technologies and software capabilities as installed, is essential to identify and quantify a specific facility's potential to participate in Automated Demand Response (Auto-DR) and to maximize load reduction savings without affecting day-to-day business or operations. The three key ways a DR program can be implemented are:

- 1) **Manual DR:** This involves manually turning off or changing comfort set points, lights, or processes or each equipment, switch, or controller.
- 2) **Semi-Automated DR:** This involves automation of HVAC or one or several processes or systems within a facility using Energy Management Control Systems (EMCS) or centralized control system, with the remainder of the facility under manual operations.
- 3) **Fully Automated DR:** This involves automation of an entire facility, with integration of end use loads into an EMCS and centrally managed with no human intervention.

Regardless of the type, technology plays an important role in the reliable operation of demand response.

4.1. Metering and Control Solutions

Metering

Granular meter data is essential to the successful operation of a demand response program. First and foremost, it is the foundation of accurate measurement and verification (M&V), which is necessary for both proper measurement of the performance of the DR resource as well as financial settlement. Ensuring that DR performs as expected requires real-time data, so that the actual consumption of participating facilities can be compared to accurate forecasts of what their consumption would have been should a dispatch not have occurred. Furthermore, real-time metering and data presentment allows for performance monitoring during a dispatch. For aggregators, this enables them to ensure their entire portfolio is cumulatively delivering the load reduction required, and if not, allows them to utilize other resources to provide the proper level of curtailment. From an end-user perspective, particularly among larger sites responding with some level of manual action, real-time data also allows for them to ensure they have taken the proper steps necessary to comply with their intended response.

That said, it is important to differentiate between real-time meter data for DR and typically advanced metering infrastructure (AMI). First, while AMI can facilitate DR it is by no means a prerequisite for successful deployments. In fact, because AMI deployments are in their early stages, and often focused on the residential customer classes, most of the technology-enabled DR present today utilizes real-time meter data by the installation of additional technology. This typically includes directly accessing a utility meter through analog pulse or digital serial outputs, as well as metering/sub-metering specific loads such as a generator, and then transferring this information back to the DR aggregator using existing broadband and wireless infrastructure.

Even when and where AMI is present, it may be insufficient. Most smart meters and their supporting infrastructure are designed primarily with automated meter reading, and not DR in mind. As such, it is

common for these new “smart” meters to read data every half-hour or hour, and then backhaul the consumption data once a day. Such infrequent and delayed measurements, while appropriate for AMR purposes, do not provide the needed functionality for DR aggregators whom need to ensure delivery standards are met in real time. In this manner, the installation of additional or specialized metering equipment is likely required even where AMI is present.

Load Control

Load control hardware is another essential component of modern-day, technology-enabled DR deployments and is often part of the same advanced metering kit that is installed on customer premises. Many customer types require some level of automation in order to be able to respond to a dispatch signal. A grocery store, for example, will typically not have an energy or facilities manager on staff able to initiate curtailment measures. Even if personnel was present, without automation, they would likely be unable to manually enact common strategies for this customer segment, including HVAC cycling, partial lighting curtailment, and anti-sweat heater (condensation) control. In other situations, it is the program requirements that require load control in order to comply with the response time. Ancillary service programs, and some bilateral utility programs, can have response times of ten minutes, or less. In fact, frequency responsive DR programs can have even shorter response times. For example, the Alberta Energy System Operator (AESO) just launched a DR program with a 200-millisecond response time. With such requirements, automation and load control is an absolute necessity. Yet even in traditional peak management programs, remote load control is increasingly being utilized for customer convenience and enhanced resource reliability.

The aforementioned metering/gateway devices installed are often the foundation for initiating load control as they feature two-way communication. Such devices may toggle relays attached to specific circuits, send scripts to Building Energy Management Systems (BEMS) to begin pre-defined curtailment actions, or attach directly to industrial control equipment.

Dispatch, Monitoring and Management

In order to successfully leverage the metering and load control hardware described above, DR providers commonly deploy Network Operation Centers (NOCs) to utilize the aforementioned foundation technologies. It is from these NOCs that load aggregators can initiate automatic dispatch notifications to participating customers, remotely control customer loads and generation, monitor performance in order to ensure performance compliance, and coordinate technicians in the field.

Centralized control centers also allow DR to comply with telemetry requirements in a cost-effective way. Some grid operators require resource in some of their markets (e.g. PJM Synchronized Reserves, National Grid STOR) to be directly integrated into their respective control rooms with remote terminal units, or other similar equipment. Such generation-grade hardware is expensive, and would be cost-prohibitive to deploy at individual customer sites.

4.2. Auto-DR and OpenADR (with the AMI linkage)

Increasingly, Auto-DR activities in California and in pilots across the U.S. are carried out through Open communication technologies, namely the Open ADR technology developed by LBNL. Since 2010, OpenADR is being formally standardized within standard organizations and it is selected by the U.S. national Smart Grid activity coordinated by the National Institute of Standards and Technology (NIST) as the only standard to communicate price and reliability-based information.²³

In the *Open Automated Demand Response Communications Specification (Version 1.0)*,²⁴ OpenADR is defined as “a communications data model designed to facilitate sending and receiving DR signals from a utility or independent system operator to electric customers. The intention of the data model is to interact with building and industrial control systems that are pre-programmed to take action based on a DR signal, enabling a demand response event to be fully automated, with no manual intervention. The OpenADR specification is a highly flexible infrastructure design to facilitate common information exchange between a utility or regional transmission organization (RTO)/Independent System Operator (ISO) and their end-use participants. The concept of an open specification is intended to allow anyone to implement the signaling systems, providing the automation server or the automation clients.”²⁵

The specification also describes the scope of the OpenADR standard: “The Open Automated Demand Response Communications Specification defines the interface to the functions and features of a Demand Response Automation Server (DRAS) that is used to facilitate the automation of customer response to various Demand Response programs and dynamic pricing through a communicating client. This specification, referred to as OpenADR, also addresses how third parties such as utilities, ISOs, energy and facility managers, aggregators, and hardware and software manufacturers will interface to and utilize the functions of the DRAS in order to automate various aspects of demand response (DR) programs and dynamic pricing.” The OpenADR structure is illustrated in Figure 6, with the key features defined in Box 1.

²³ <http://collaborate.nist.gov/twiki-sggrid/bin/view/SmartGrid/OpenADR>.

²⁴ Piette, M.A., G. Ghatikar, S. Kiliccote, E. Koch, D. Hennage, P. Palensky, and C. McParland. 2009. Open Automated Demand Response Communications Specification (Version 1.0). California Energy Commission, PIER Program. CEC-500-2009-063 and LBNL-1779E.

²⁵ The OpenADR Primer, White paper by the OpenADR Alliance (<http://www.openadr.org/>).

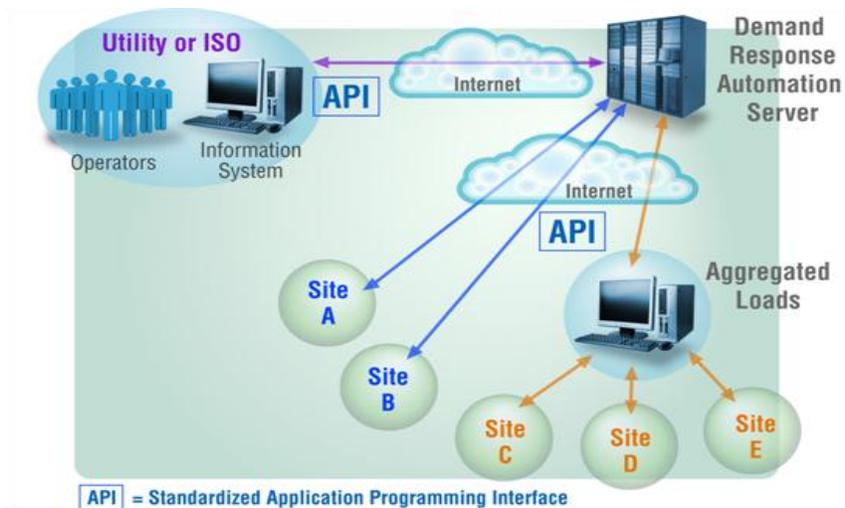


Figure 6: OpenADR Structure

Box 1: OpenADR Features

Continuous, Secure and Reliable – Provides continuous, secure, and reliable two-way communications infrastructures where the clients at the end-use site receive and acknowledge to the DR automation sever upon receiving the DR event signals.

Translation – Translates DR event information to continuous Internet signals to facilitate DR automation. These signals are designed to interoperate with Energy Management and Control Systems, lighting, or other end-use controls.

Automation – Receipt of the external signal is designed to initiate automation through the use of pre-programmed demand response strategies determined and controlled by the end-use participant.

Opt-Out – Provides opt-out or override function to participants for a DR event if the event comes at a time when reduction in end-use services is not desirable.

Complete Data Model – Describes a rich data model and architecture to communicate price, reliability, and other DR activation signals.

Scalable Architecture – Provides scalable communications architecture to different forms of DR programs, end-use buildings, and dynamic pricing.

Open Standards – Open standards-based technology such as Simple Object Access Protocol (SOAP) and Web services form the basis of the communications model.

During a Demand Response event, the utility or RTO/ISO provides information to the DRAS about what has changed and on what schedule, such as start and stop times. A typical change would specify one or more of the following:

- **Price signals:** This would include a price multiplier, a price relative, or an absolute price
- **Reliability signals:** This would include the load amount to be shed (difference, load level, or set-point that a load should go to).
- **Levels:** These are simple representations of the price and reliability signals such as NORMAL, MODERATE, and HIGH.

The standard also specifies considerable additional information that can be exchanged related to DR and Distributed Energy Resources (DER) events, including event name and identification, event status, operating mode, various enumerations (a fixed set of values characterizing the event), reliability and emergency signals, renewable generation status, market participation.

Widespread adoption of OpenADR will accelerate the successful implementation of DR programs and DER, thereby providing the following four major benefits for all stakeholders:

- *Lower Costs* – Standardization lowers development and support costs for vendors and, ultimately, their utility customers. Standardization also fosters technology innovation and competition, which expands product choices for both utilities and end users.
- *Assured Interoperability* – Electricity providers and consumers alike benefit from being able to choose from among a wide range of different products and services without concern for any incompatibility or inevitable obsolescence.
- *Greater Reliability* – Products based on robust standards function dependably under normal circumstances and are able to recover from any anticipated error conditions to deliver dependable operation.
- *Enhanced Flexibility* – OpenADR has been designed to work with existing DR equipment (so-called backwards compatibility), as well as with newer, more sophisticated systems offering advanced feature sets.

Commercial, industrial and residential customers, and energy aggregators, will all be able to reduce costs, time and risk in the selection and deployment of products and systems based on the OpenADR standard. Work being performed by the OpenADR Alliance²⁶ will educate these stakeholders about the benefits of DR, and will increase their confidence in the available solutions with rigorous testing and certification programs.

As a result, equipment vendors and systems integrators will be able to accelerate the time-to-market for, and lower the development costs of, innovative products and services, while electric utilities, ISOs and RTOs will gain faster access to the market, experience lower capital and operational expenditures, and achieve greater success with DR programs. Even regulatory agencies will benefit from knowing that the introduction of new pricing policies will not be undermined by incompatibilities or other end-to-end impediments in the marketplace.

4.3. Smart Meter and Advanced Metering Infrastructure (AMI) and OpenADR

As the use of OpenADR for commercial and industrial facilities has gained significant traction in California and other parts of the U.S., the Advanced Metering Infrastructure (AMI) and smart home technologies are currently being implemented on a large-scale basis in residences. The AMI system wide implementation in California residences by the utilities together with development of the supporting

²⁶ <http://www.openadr.org/>.

technologies has provided opportunity for wide range of system operation and customer management applications, including communicating DR information through the AMI communication channels. The AMI communication is not open and accessible outside the utility network. AMI infrastructure can include smart meter, which is a revenue-qualified device from which charges can be derived. Other means of measuring power may be used, but they would generally not be qualified for revenue use from the residence point-of-view, the advanced meter contains valuable information about current and past power usage. This advanced infrastructure is however, not needed in most DR programs. While the traditional electrical meters only measure total consumption and as such provide no information of when the energy is consumed, an interval meter can usually record consumption of electricity in intervals of an hour or less and communicate that information at least daily back to the utility for monitoring and billing purposes. In some DR programs, an interval meter is all that is needed for a customer to be qualified to participate.

LBNL is working with the utilities and other stakeholders to provide an external non-AMI based OpenADR interface to the residential technologies and home automation networks (HAN). These interfaces coexist with the AMI infrastructure that the utilities plan to use for their metering and billing purposes. Figure 7 shows these interfaces where OpenADR can be used as a means of communication directly with the residential gateway or the end-use devices such as the appliances:²⁷

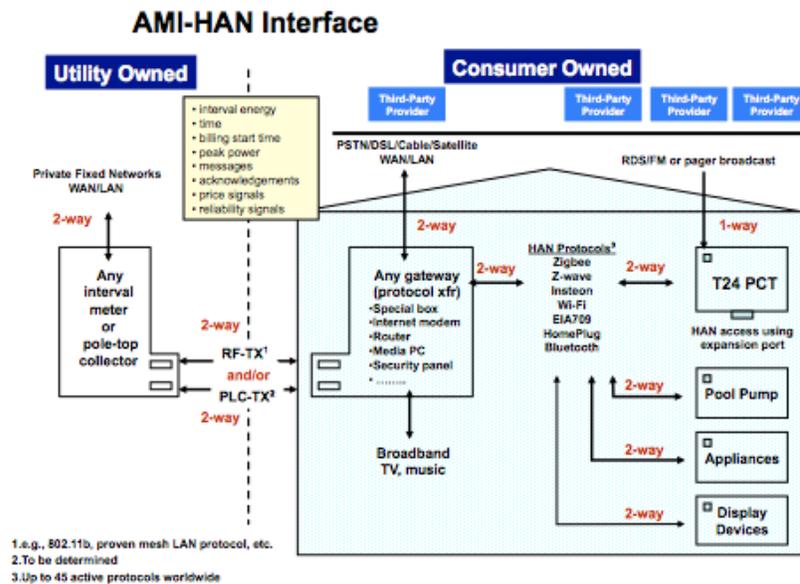


Figure 7: AMI-HAN Interface

Further details on the home automation technologies and its use within the DR context are available from previous LBNL studies.²⁸

²⁷ Figure courtesy: Ron Hoffman, California Energy Commission.

²⁸ McParland, Charles. Home Network Technologies and Automating Demand Response. LBNL, 2008. LBNL-3093E.

5. Best Practices and Results of DR Implementation

The DR implementation best practices vary from different types of buildings. For example, a certain set of Heating Ventilation and Air-Conditioning (HVAC) strategies for commercial buildings may not be so relevant for a water and wastewater or data center industry. These best practices need to be validated through the actual results. Some of the best practices developed by LBNL are the result of over 10 years of research through pilots and development of DR strategies that are commercially implemented.^{29 30} Since 2002, LBNL/Demand Response Research Center's (DRRC) research has been conducting research and development to advance DR technologies, policies, programs, strategies and practices. While most of these studies are focused on the commercial and industrial (C&I) sector, the DRRC has recently started research in residential sector.³¹

Over the years, DRRC has achieved significant success in accelerating the adoption of DR in various types of facilities and support DR program implementation successfully in California. As shown in Figure 8, this research includes development through field trials, standardization, and bringing technology to the market place.

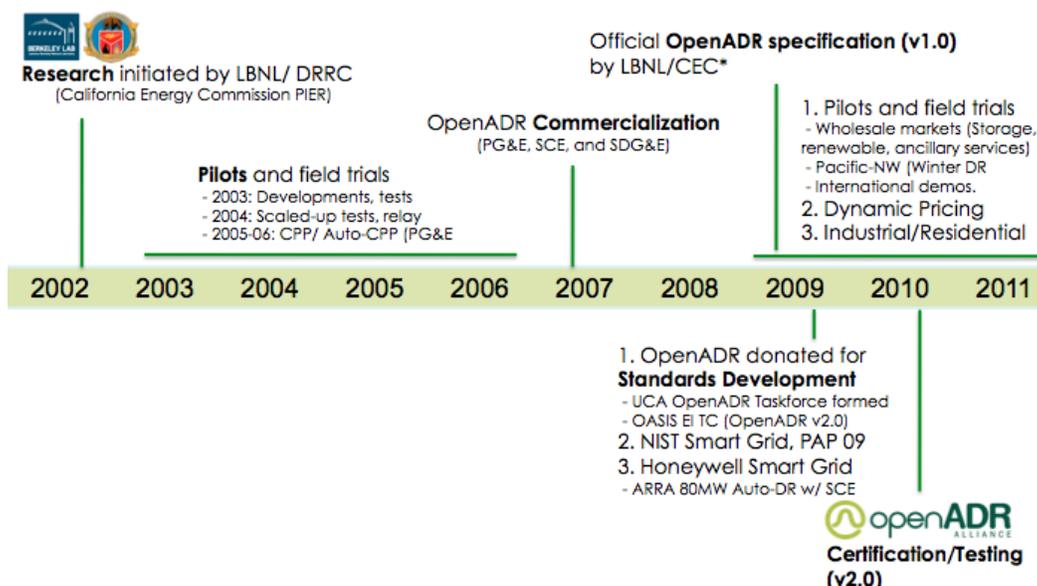


Figure 8: Roadmap of DR and AutoDR Research, Implementation and Commercialization

²⁹ S. Kiliccote, M.A. Piette, J. Mathieu, K. Parrish, Findings from Seven Years of Field Performance Data for Automated Demand Response in Commercial Buildings, Proceedings of the 2010 ACEEE Summer Study on Energy Efficiency in Buildings, Pacific Grove, CA, August 15-20, 2010, LBNL-3643E.

³⁰ Piette, M. A., G. Ghatikar, S. Kiliccote, D. Watson, E. Koch, and D. Hennage, "Design and Operation of an Open, Interoperable Automated Demand Response Infrastructure for Commercial Buildings", Journal of Computing Science and Information Engineering, vol. 9, issue 2, no. 2, 2009.

³¹ <http://drcc.lbl.gov/news/residential-energy-display-survey-reds-pilot>.

The impact of the LBNL research has extended well beyond the state of California. Auto-DR is used in many other states in the US and is being piloted for deployments in other countries.³² In this section, field experience, best practices and the achieved results from the research are provided.

Although, the primary goal of DR is to reduce electricity consumption during periods when wholesale price of electricity is high or when system reliability is jeopardized, the DR research has proven that DR has the capability of balancing the supply and demand at any time of the day.³³

As indicated in Section 4, DR can be implemented in a manual, semi-automated or fully automated fashion. Manual DR is labor intensive. Manual response can easily delay response or fail all together. Semi-automated DR means that the DR strategy is pre-programmed but requires a person to trigger it. 15% of the time people are not at the facility to respond to DR events.³⁴ Fully automated DR, or Auto-DR does not involve human intervention, and it is initiated by an EMCS in a facility through receipt of an external communications signal that triggers pre-programmed DR strategies. Automation helps improve the performance of DR by allowing the response to be more repeatable and reliable. Hence, whenever appropriate, Auto-DR may be a good practice moving forward.

5.1. DR Strategies in Commercial and Industrial Buildings

To provide reliable, repeatable DR, it is best to pre-program the strategy and fully automate the communication and controls to enable DR events without a human in the loop. This section discusses representative load reduction strategies and practices that can be used during DR events. These DR strategies work in well-tuned buildings when they are customized to sites' needs. In this section, we present DR strategies for commercial buildings and industrial facilities. Figure 9 identifies the typical end-uses that are in commercial and industrial buildings. It is from these end-uses that DR strategies are identified and acted upon.

³² Kiliccote, S., M. A. Piette, and J. H. Dudley, Northwest Open Automated Demand Response Technology Demonstration Project, 2010.

³³ Dave Watson, Mary Ann Piette, Nance Matson, Sila Kiliccote, Janie Page (Lawrence Berkeley National Laboratory); Karin Corfee, Betty Seto, Ralph Masiello, John Masiello, Lorin Molander, Samuel Golding, Kevin Sullivan, Walt Johnson, David Hawkins (KEMA). Automated Demand Response as a Grid Balancing Resource for the Integration of Renewables. Report for the California Energy Commission. In Press. 2011.

³⁴ Quantum Consulting Inc. and Summit Blue Consulting, LLC. Working Group 2 Demand Response Program Evaluation - Program Year 2004 Final Report. Prepared for Working Group 2 Measurement and Evaluation Committee. Berkeley CA and Boulder CO, December 2004.

Common End Use DR Loads		
Air handlers	Emergency generation	Motors
Anti-sweat heaters	Escalators	Outside signage
Chiller control	External lighting	Production Equipment
Chilled water systems	External water features	Processing lines
Cogeneration / CHP	HVAC systems	Pool pumps / heaters
Defrost Elements	Internal lighting	Refrigeration systems
Elevators	Irrigation pumps	Water heating

Figure 9: Common Examples of Commercial and Industrial End-Use Loads

5.1.1 DR Strategies for Commercial Buildings

Heating, ventilation, and air conditioning (HVAC) systems can be excellent resources for demand reduction. First, HVAC systems comprise a substantial portion of the electric load in commercial buildings. Second, the heat storage of building envelopes and internal thermal mass allows HVAC systems to be temporarily unloaded without immediate impact on the building occupants. Third, a person feels comfortable with the indoor thermal environment within an allowable range of temperature, humidity and air speed. As long as these limits are not exceeded or exceeded for short periods, the DR strategies may be acceptable. Fourth, it is common for HVAC systems in large commercial buildings to be at least partially automated with energy management and control systems (EMCS).

Along with strategies for HVAC and lighting systems, turning off unnecessary plug loads is also commonly deployed in commercial buildings. In the case of automated DR (Auto-DR), all these strategies are usually pre-programmed into the facility EMCS that automate HVAC load shed for DR events. Otherwise, these strategies could be implemented manually or in a semi-automated manner. Curtailable loads also include discretionary loads such as outside signage, elevators, escalators, fountains and water features.

5.1.2 DR Strategies for Industrial Facilities

Implementing DR in industrial sectors presents a number of challenges, both practical and perceived. Some of challenges are: the wide variation in loads and processes across sectors and even within sectors; resource-dependent loading patterns that are driven by outside factors such as customer orders or time-critical processing (e.g. tomato canning); the perceived lack of control; and aversion to risk, especially unscheduled downtime. However, experiences in industrial sector have proven that with careful planning and preparation, the industrial sectors hold significant promise and great opportunities for DR. Here, a few specific examples of DR strategies are briefly described.

5.1.3 DR Strategies in Water or Wastewater Facilities

Wastewater treatment facilities are energy-intensive and have significant electricity demand during peak periods. Most of the facilities have storage ponds, which make load-shifting strategy possible. Turning off the energy-intensive equipment such as effluent pumps and centrifuges can result in significant load reduction.³⁵

5.1.4 DR Strategies in Refrigerated Warehouse Facilities

Pre-cooling strategies, using the thermal mass in some of the refrigerated warehouses, enable load shifting from peak to off-peak periods. Shifting of batch process, shifting operation of equipment such as conveyors, pump systems, space conditioning, motors, process cooling, and storage can also be utilized. Another load shifting strategy is to defer forklift battery charging to off-peak hours.³⁶ Those load shifting strategies can be used in combination with load shedding strategies such as process shutdown; shutting down operation of equipment such as aerators, electrical, process air, shutting off air-handlers serving freezers, increasing set point on HVAC systems.

Refrigerated warehouses and cold storage facilities have also proven to be successful loads for the emerging field of bi-directional demand response. The ability to both increase and decrease end-user demand is becoming increasingly important with the rising penetration of intermittent renewable resources such as wind. For example, the Bonneville Power Administration (a large generation and transmission agency located in the Pacific Northwest region of the US) is currently operating a pilot program using loads for just this reason. The pilot program is using refrigerated warehouse and water pumping loads that can be altered in both directions for short periods of time, depending on the conditions of the wind system. If the wind is blowing during times of low system load, the loads in these facilities are increased. When the wind is not blowing, then the loads are decreased.

5.1.5 DR Strategies in Food Processing Facilities

Significant DR opportunities exist to both reduce and shift essential demand (i.e. manufacturing-related demand) and non-essential demand (e.g. office buildings, warehousing, etc.) in food processing facilities.³⁷ These strategies include adjusting operation schedules, adjusting raw material delivery, shutting off or adjusting setpoints of end-use applications, as well as adjusting lighting and HVAC systems. Various supply chain factors such as scheduling of raw material delivery, perishability, labor, logistics, shelf life, and product transport require the food processing sector in particular to carefully plan for curtailment or postponement.

³⁵ Thompson, Lisa; Lekov, Alex; McKane, Aimee; Piette, Mary Ann, Opportunities for Open Automated Demand Response in Wastewater Treatment Facilities in California – Phase II Report: San Luis Rey Wastewater Treatment Plant Case Study, LBNL-3889E, August 2010.

³⁶ A. Lekov, L. Thompson, A. McKane, A. Rockoff, M.A. Piette, Opportunities for Energy Efficiency and Automated Demand Response in Industrial Refrigerated Warehouses in California, LBNL-1991E, May 2009.

³⁷ Glen Lewis Group, Strategies to Increase California Food Processing Industry Demand Response Participation: A Scoping Study, LBNL-63668, November 2007.

5.1.6 DR Strategies in Data Centers

Data centers are another energy-intensive sector. Because data centers are highly automated, they are excellent candidates for Auto-DR. However, their sophisticated controls of environmental conditions, high level of technology implementation, and users' technical knowledge make data centers' participation in DR unique, especially in implementing Auto-DR strategies. "Non-mission-critical" data centers are the most likely candidates for early adoption of DR. The largest opportunity for DR or load reduction in data centers is in the use of software algorithms, server consolidation and virtualization to reduce Information Technology (IT) equipment energy use, which correspondingly reduces facility-cooling loads.³⁸ In the case of data center located in multiple regions, load migration may work well for DR events. DR strategies could also be deployed for data center lighting, and HVAC systems. This is an ongoing area of research for the DRRC.

End-use curtailment is just one manner of response for data centers. More common is the utilization of on-site generation. Data centers and other mission critical facilities (e.g. financial institutions) are fully-backed with standby generation to ensure business continuity in the event of a grid emergency. These facilities often regularly test these generation units to ensure readiness should a power loss occur. Instead of testing at random times, these facilities can shift site loads onto these generation assets during periods of grid need, and achieve the double-benefit of testing under load and providing a resource.

5.1.7 DR Strategies in Heavy Industry

Heavy industrial and manufacturing is another well-represented vertical within C&I demand response. While such facilities often have very specialized equipment, their energy-intensive operations can represent significant load reduction capability. For slow response (i.e. 4 or more hour notification), production lines can often be fully shut down, and perhaps rescheduled. On a more rapid basis, variable speed drives, balers, and even arc furnaces can be both curtailed and remotely controlled. Of course, many industrial facilities also have standby and cogeneration capacity which can be leveraged as well.

³⁸ Ghatikar, Girish, M.A. Piette, S. Fujita, A. T. McKane, J.Q. Han, A. Radspieler, K.C. Mares, D. Shroyer. Demand Response and Open Automated Demand Response Opportunities for Data Centers. California Energy Commission, PIER Program and Pacific Gas and Electric Company (PG&E), January 2010.

6. Recommendations and Key Principles for Designing and Implementing DR in China

Based on the experiences in the US and elsewhere in the world, we offer the following recommendations for designing and implementing DR in China.

Provide Capacity Payments

Regardless of market structure, the most successful demand response programs are those that utilize capacity or availability payments and compensate participants for being ready and able to reduce load when called upon to do so. Such payments create a visible revenue stream allowing customers to better assess the costs and benefits of participation, and for DR providers and aggregators to invest in the requisite technology to ensure reliable performance.

Enable Meter Access

Reliable demand response depends on access to granular meter data. Whether interval meters with pulse outputs, or advanced meters with RF communication abilities, it is essential to ensure timely meter data access to participating customers and demand response providers.

Facilitate Accurate and Transparent M&V

One of the most important elements of DR is the specification of measurement and verification (M&V) procedures. One of the most important aspects of DR M&V is the calculation of the baseline, reflecting the load that would have been in place had there not been a DR program on the particular DR event day. Baseline methods are very important in that they form the entire foundation for assessing both the capacity delivered and financial payments warranted. A poorly designed baseline can have unintended negative consequences that can render participation unattractive and negatively impact uptake in the program or market. Recommendations for a baseline measurement include:

- DR resources should receive credit for no more and no less than the curtailment they actually provide. A baseline methodology should use granular meter data to create an accurate forecast of what load would have been used in the absence of a demand response dispatch.
- Baseline methods should not include attributes that encourage or allow customers to distort their baseline through irregular consumption nor allow them to “game” the system.
- The baseline should be simple enough for all stakeholders to understand, calculate, and implement. In addition, it should be possible to determine the baseline measure in advance of, or, during demand response dispatches so that DR providers can use the baseline measure to assess performance in real-time in order to ensure that delivery targets are met.

Encourage Aggregation

In other markets, specialized demand response providers, known as load aggregators, have contributed significantly to the growth of the industry and level of available DR resources. More than 125 utilities

across the US are contracting with such outsourced DR specialists to implement C&I DR programs.³⁹ Achieving similar rates of growth and levels of success in China without load aggregators would likely be quite difficult. Load aggregators provide a variety of benefits that contribute to DR uptake:

- **Ability to match utility needs with customer capabilities.**
Across the various customer segments (e.g., residential, commercial, industrial), customers will have different capabilities to participate in a DR program. For example, some may be able to curtail their loads for as many as six hours at a time; others may be limited to shorter durations. In many cases, the capabilities of the specific C&I customers will not exactly match the needs of the utility. Load aggregators can pair together customer sites in various ways to ensure that a specified level of capacity is always available to a utility.
- **Core competency: Behind the meter expertise.**
There is significant potential to leverage the load reduction capabilities of large customers (e.g., commercial and industrial) as a capacity resource; however, in practice, realizing this potential requires a deep understanding of customer operations, since the “resource” is made up of dozens of decentralized assets. Unlike relatively homogenous residential loads, C&I loads vary widely across types of facilities. Effective load curtailment strategies must be customized to each organization’s specific operational requirements to avoid impacting operations or occupant comfort. While smart-grid developments may facilitate two-way communications between the utility and its C&I customers, enabling those customers to effectively respond to price or control signals requires the implementation and ongoing management of individualized demand reduction plans. Most load aggregators employ professional engineers who have a deep understanding of electricity use and load patterns across a broad range of facility types, along with the experience to assess and identify strategies to successfully and consistently deliver DR capacity.
- **Eliminates utility risk on performance.**
If demand response is considered to be part of a utility’s overall resource portfolio, it is essential that a DR program delivers the amount of capacity expected each time the program is dispatched. The value of a DR resource to a utility is closely tied to its reliability. Utilities that operate internally-focused C&I DR programs such as interruptible tariffs typically assess penalties on customers that fail to perform during an event, as a means of mitigating customer non-compliance. This dynamic can put the utility in an uncomfortable position if a valued customer underperforms, given that the utility relationship with that customer extends well beyond the DR program. By contrast, DR service providers such as load aggregators are uniquely positioned to guarantee a reliable DR resource to a utility. Much like an insurance company reduces its exposure by pooling risks across a number of policy holders, DR service providers are able to assemble a portfolio of DR customers in a way that mitigates the risk of non-performance for each of them. Notably, the larger the DR portfolio, the more reliable the resource will be.
- **Develop Open Standards.**

³⁹ Public Utilities Fortnightly, SPARK, “Outsourcing Negawatts,” January 2010.

OpenADR can be used to reduce the cost of DR programs and eliminate stranded assets. Creating an open, competitive market for controls vendors is an effective way to reduce the cost of DR equipment. Standards allow interoperability among systems. Open standards also facilitate the use of Auto-DR, which can be used to improve the performance of DR programs by allowing the response to be more repeatable and reliable. It is also essential when DR participates in ancillary services markets.

- **Create Opportunities for Training and Customer Education.**

It is critical that training and education opportunities be created to help the customer understand the value of DR, the strategies and technologies needed to properly deploy DR, and the policies and procedures put into place to enable further development of DR. Consumers need to be made aware of the time-varying value of electricity costs and take advantage of lower price periods.