DEMAND-SIDE BIDDING IN WHOLESALE ELECTRICITY MARKETS

Prepared for

The Australian Energy Market Commission

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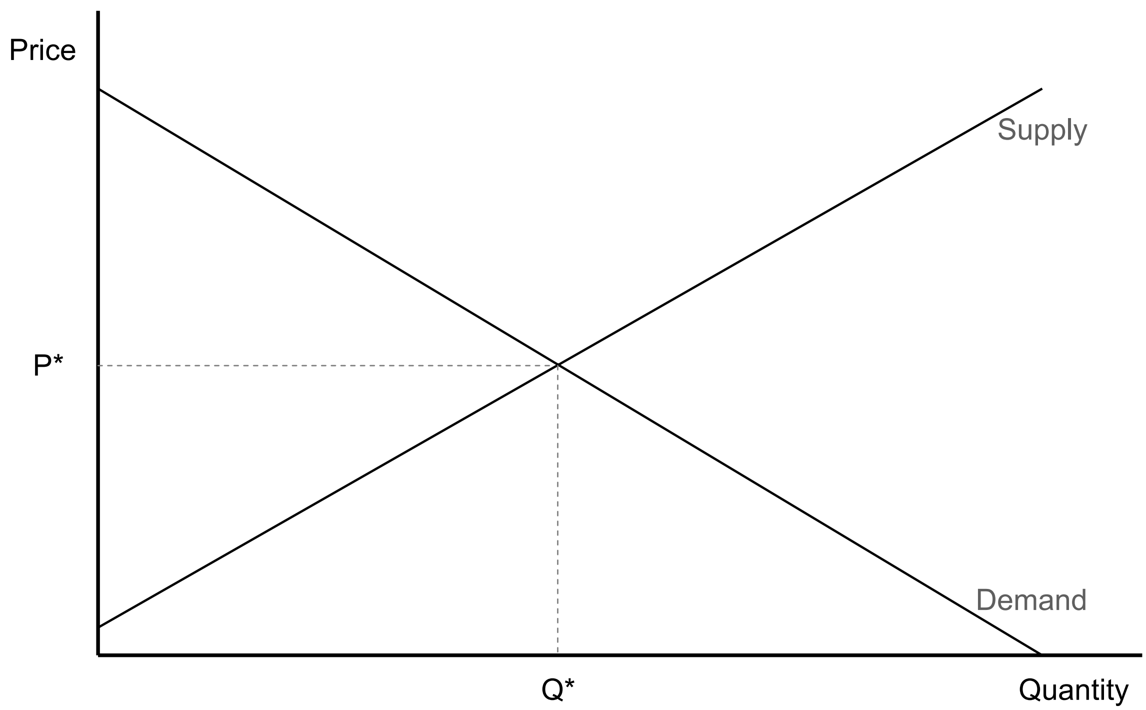
1. Introduction

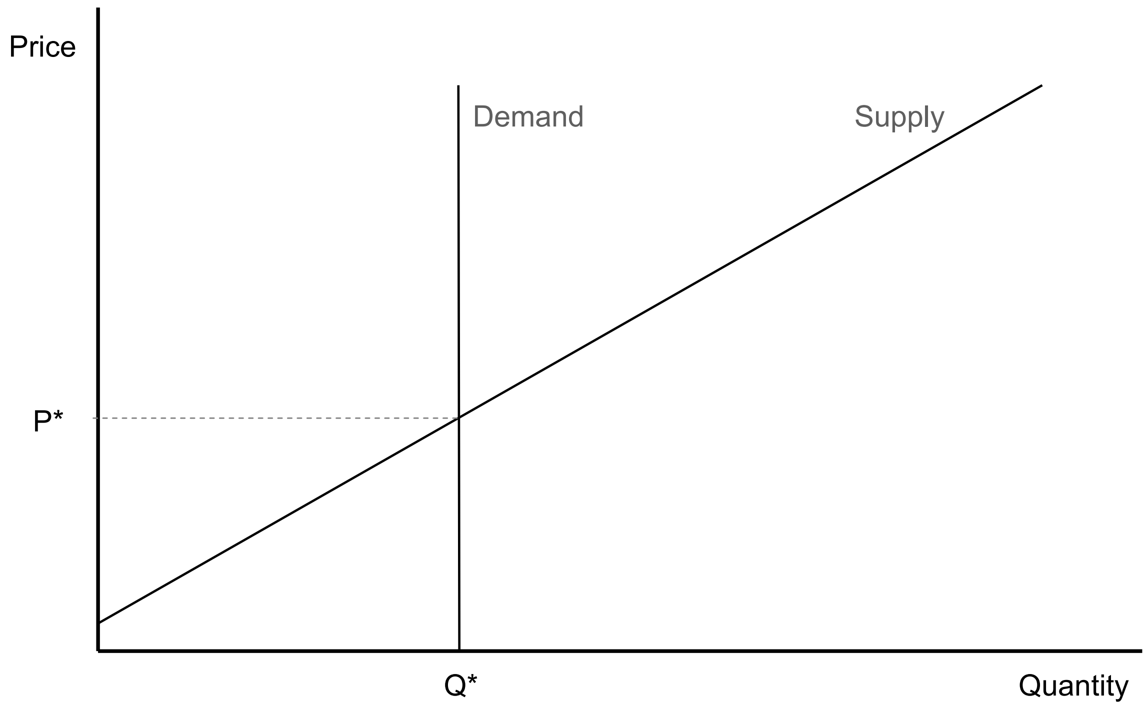
In most situations where money exchanges hands for the procurement of goods, prices and quantities are set by the interactions of buyers and sellers. A stylized representation of this process is shown in Figure 1.1. If the supply curve represents sellers' aggregate willingness to sell a given quantity at a given price, and the demand curve represents buyers' aggregate willingness to buy a given quantity at a given price, then the market clears where the supply and demand curves interest. The price set by the market is P* and the quantity sold in the market is Q*. An important matter to note about the figure is that the demand curve is downward sloping. That is, the demand curve exhibits elasticity with respect to price. The higher the price, the less is demanded. This assumption is standard for most economic analysis of markets.

Figure 1.1: Supply and Demand



Electricity, of course, is different. As a general matter, electric power is not storable and so production and consumption of electricity must occur simultaneously. Moreover, the tradition of an obligation to serve by the utility means that demand is generally taken as a given and not sensitive to prices in real-time. Because of these factors, wholesale markets for electricity in real-time[1] are often envisioned as in Figure 1.2 below. The demand curve is vertical or inelastic. No matter what the price is, the quantity demanded is assumed to be the same.

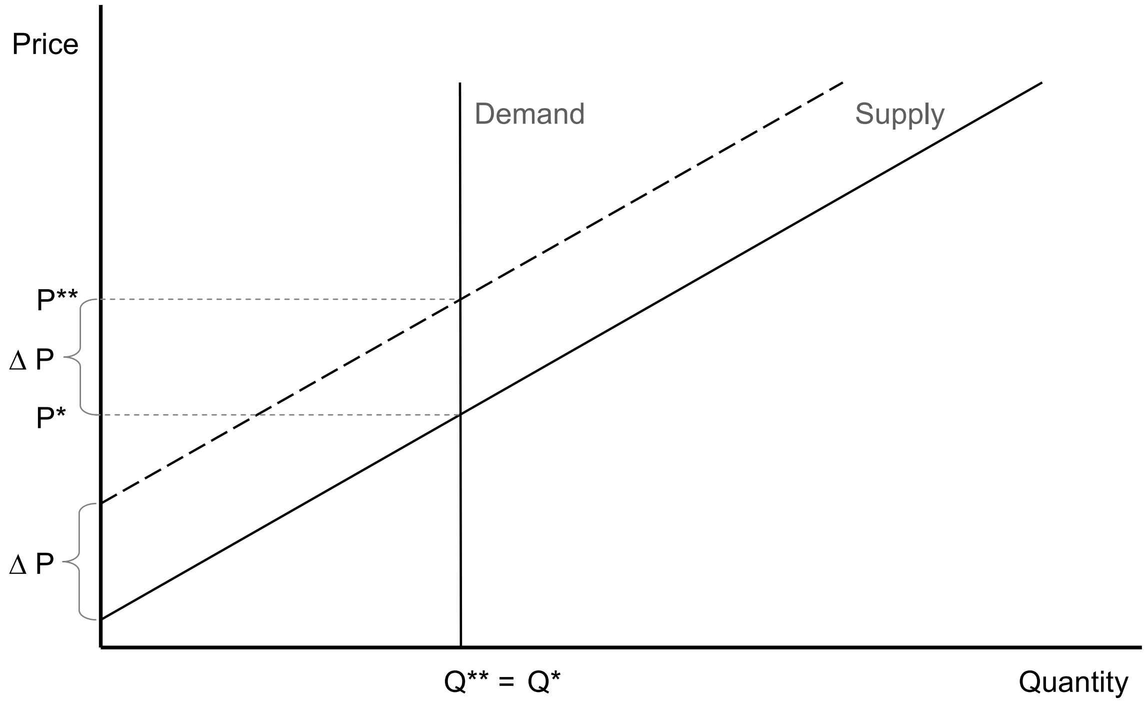
Figure 1.2: Inelastic Demand



As shown in Figure 1.3, if there is a shortage in supply, causing the supply curve to shift to the left and to raise the offered price by Δp, then the market clearing price will also go up by Δp.

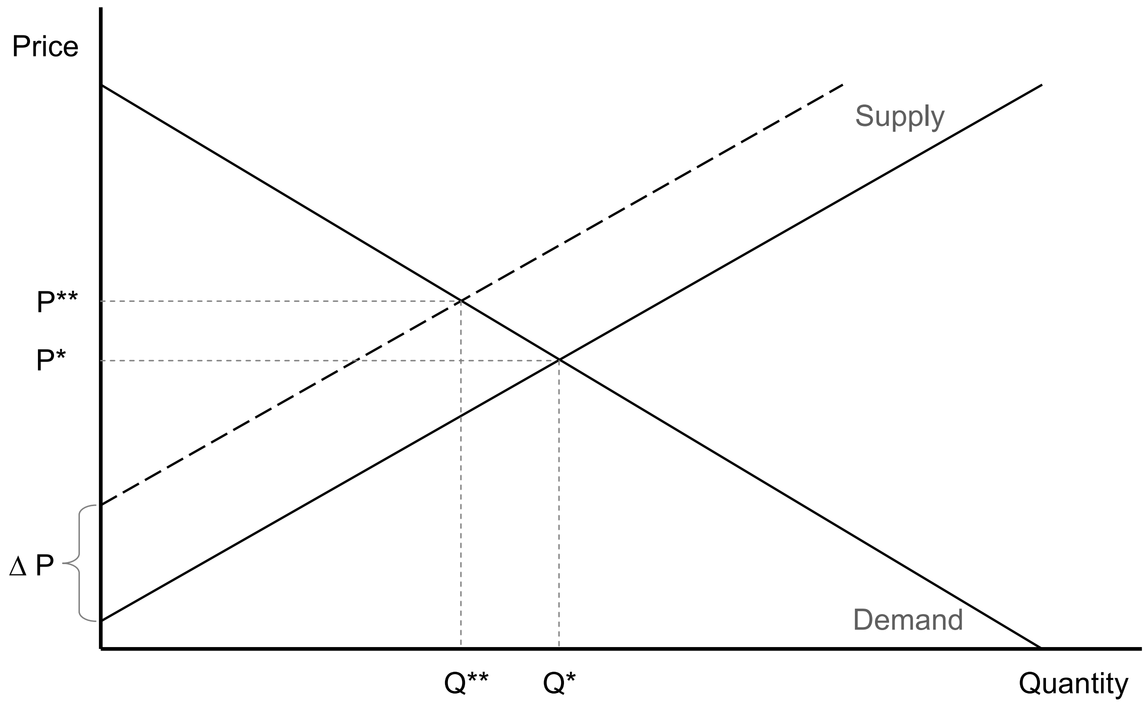
[1] By "real-time" we mean close to the time when power is consumed.

Figure 1.3: Inelastic Demand Exacerbates Price Volatility



By contrast in a market where the demand curve has some elasticity, if the price of supply goes up by Δp, the market clearing price will go up by something less than Δp, (P**-P*), as illustrated in Figure 1.4.

Figure 1.4: Demand-Side Bidding can Help Limit Price Volatility



This difference in outcomes when demand is elastic versus inelastic helps illustrate one of the reasons why demand-side bidding can be important in electricity markets. In the absence of demand-side bidding, the demand curve is usually just a vertical line. As a result, changes in the price of supply directly translate into equal changes in the market clearing price. With demand-side bidding, however, the demand curve becomes elastic and changes in the price of supply are mitigated by the fact that the demand curve is downward sloping. The market clearing prices are therefore less volatile than the supply prices. The lack of demand-side bidding is often cited as one of the causes of the California crisis in 2000 and 2001. Sellers, it is thought, were able to exercise market power to a greater extent because there was little reaction on the demand-side to high prices.[2]

The goals of this report are to examine how demand-side bidding works in various international wholesale markets and is intended to address the different drivers behind the integration of demand-side bidding, the different ways it has been integrated into wholesale electricity markets, the change processes and difficulties encountered, and the impacts on electricity systems. The report seeks to apply international lessons in these areas to the potential introduction of demand-side bidding into the NEM wholesale market taking into account both NEM's structure and the structure of other markets.

The remainder of this report is laid out as follows: Section 2 gives an overview of demand-side bidding in electricity markets. Section 3 gives a survey of demand-side bidding in selected markets in the United States as well as in the United Kingdom and Norway. Section 4 discusses key drivers of demand-side bidding in wholesale markets and impacts. The report concludes with Section 5 discussing the insights for NEM.

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[2] Ahmad Faruqui, Hung-po Chao, Vic Niemeyer, Jeremy Platt and Karl Stahlkopf, "Analyzing California's power crisis", *The Energy Journal*, October 2001.

2. Overview of Demand-Side Bidding

In most commodities markets, demand-side bidding takes place as a matter of course. Part of the difference goes back to the fact that other commodities have storability while electricity does not. Purchasers will buy and store the commodity to ride out price spikes.[3] Apparent demand elasticity at a given time in a commodity market can occur, then, in two ways. First, it can be reflected in the underlying demand elasticity of the commodity. As the price of a commodity rises, buyers purchase less because, for instance, they can substitute another good for the commodity. Another way demand elasticity can manifest itself is through buyers spreading out their purchases through time and avoiding purchases when the price seems too high.[4] In electricity there is little storage, but a similar phenomenon can be seen in two settlement markets. In these markets there is a day-ahead market and a real-time market. Buyers can choose from which market to purchase. When there is an ability to submit demand-side bids, buyers can shape their bid in the day-ahead market based on their expectations of what the real-time price will be. For example, a buyer with 1000 MW of load might buy 900 in a day-ahead market hoping that 100 MW might be bought more cheaply in real-time. This sort of "structurally induced" demand elasticity is a feature of two settlement markets that is now often actively encouraged in order to provide greater liquidity to the markets.[5] Traders often engage in buying in a day-ahead market and selling in a real-time market (or vice versa) in order to try to profit from the difference in prices. This practice is sometimes called intertemporal arbitrage.

The actual reduction of load in order to accommodate market prices or emergency conditions is called "demand response". Demand response takes many forms. It can consist of direct load control over air conditioners or pool pumps in residences. In this instance, a device is installed in the residence and the load is cycled by the utility when market prices or system conditions warrant. In the United States, aggregators such as EnerNOC, are building businesses around the ability to aggregate many end-use consumers through such devices and deliver demand response

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[3] Or, buyers will take advantage of the many financial tools that exist in order to hedge risk: forwards, options, etc.

[4] This is similar to stock traders who "dollar cost average" their position in a stock, by spreading their purchases over time to avoid buying at peak prices.

[5] For a study of structurally induced demand elasticity in the California market prior to the crisis, see Robert Earle, "Demand Elasticity in the California Day-Ahead Market", *The Electricity Journal*, October 2000.

to either utilities or directly to wholesale markets. Demand response can also take the form of businesses curtailing their business processes (such as at a smelter) or even dimming lighting in response to market or system conditions based on a signal from a utility or aggregator.

Another form of demand response is dynamic pricing.[6] Dynamic pricing is the use of time varying pricing where the varying of the price depends on the conditions in the market at the time. This differs from what is typically known as time-of-use pricing where the prices are set beforehand, typically through a ratemaking process. With time-of-use pricing, for instance, there may be an on-peak rate, say 12 cents/kWh, and an off-peak rate of 8 cents/kWh. The rates and the hours they apply to, that is the on-peak and off-peak hours, and the 12 cents/kWh and 8 cents/kWh are known well ahead of time. In contrast, dynamic pricing is dispatchable. Under some versions, such as critical peak pricing, the rates themselves are known, but when they apply will depend on market conditions and are announced at most 24 hours in advance. Under other versions of dynamic pricing, real-time prices are passed on to consumers. Because dynamic pricing is dispatchable, it is a key way of providing demand response. There can also be other forms of dynamic pricing that lead to demand response. For example, in Britain the network capacity charges that large consumers pay are determined on the basis of their demand levels during the highest three demand periods in a year. This has led to quite sizeable reductions in peak demand (of the order of 4-5 GW out of 60 GW) as large consumers deliberately reduce their consumption at times that may be counted as peaks.

In theory, a firm that buys power from a wholesale market and sells power to end-users (a load serving entity or "LSE") has an incentive to use demand response in order to earn greater profits. The way it would do this is similar to one of the ways that trading firms profit in other commodity markets. When the price is high in the wholesale market, the LSE would use demand response of its customers to reduce the load it has to serve and thereby either avoid having to purchase power at a high price in the wholesale market (or, perhaps be able to sell power it would otherwise use to supply its end-use customers). Some analysts of demand response claim that this is the only appropriate use of demand response and demand-side bidding

[6] Ahmad Faruqui, "Pricing Programs: Time-of-Use and Real Time," *Encyclopedia of Energy Engineering and Technology*, September 2007, pp. 1175-1183.

in wholesale markets. As of this writing, this is the approach that the Midwest Independent System Operator in the United States takes. It is also the approach taken in Norway (although LSEs are also allowed to provide ancillary services).

For a variety of reasons that go beyond the cost of implementing demand response programs amongst end-use customers, there appears to be less demand response and demand-side bidding in the United States than potential estimates seem to indicate is possible. These reasons include the disconnect between wholesale prices that are set by the market and retail rates that are approved by public utility commissions; wholesale prices that have price caps so that the ability to capture high prices through demand response is limited; as well as, the particular business rules in the wholesale market.

As a result, many feel that demand-side bidding should be treated as a generator and receive a *payment* for reduction of load as opposed to the LSE simply having to pay less because it was buying less on the market. In PJM, for instance, bids to curtail load in the day-ahead or real-time energy markets receive a payment to reduce load. These payments to curtailment service providers (in the parlance of PJM) are funded through an uplift on the LSEs. The reasoning is that the payment to demand response resources corrects a market imperfection and that the uplift payment is justified because the LSEs benefit from the reduction in load which results in a lowering of the wholesale market price. In other markets, payments to demand side bidders are treated no differently to other payments and can be recovered from all market participants, i.e. generators as well as LSEs. This is the case in Britain. An important issue that results from the payments for demand reductions in wholesale markets is the baseline against which the demand reduction is measured. This and other issues are covered in more depth in the sections that follow.

3. Survey of Demand-Side Bidding in Selected Markets

The practice of demand-side bidding in wholesale electricity varies across jurisdictions depending on the overall structure of the market and the regulatory context. This section reviews the practice of demand-side bidding in seven markets: five in the United States, the United Kingdom, and Norway. The markets in the United States are first treated together because of common regulatory history, political environment, and market development.

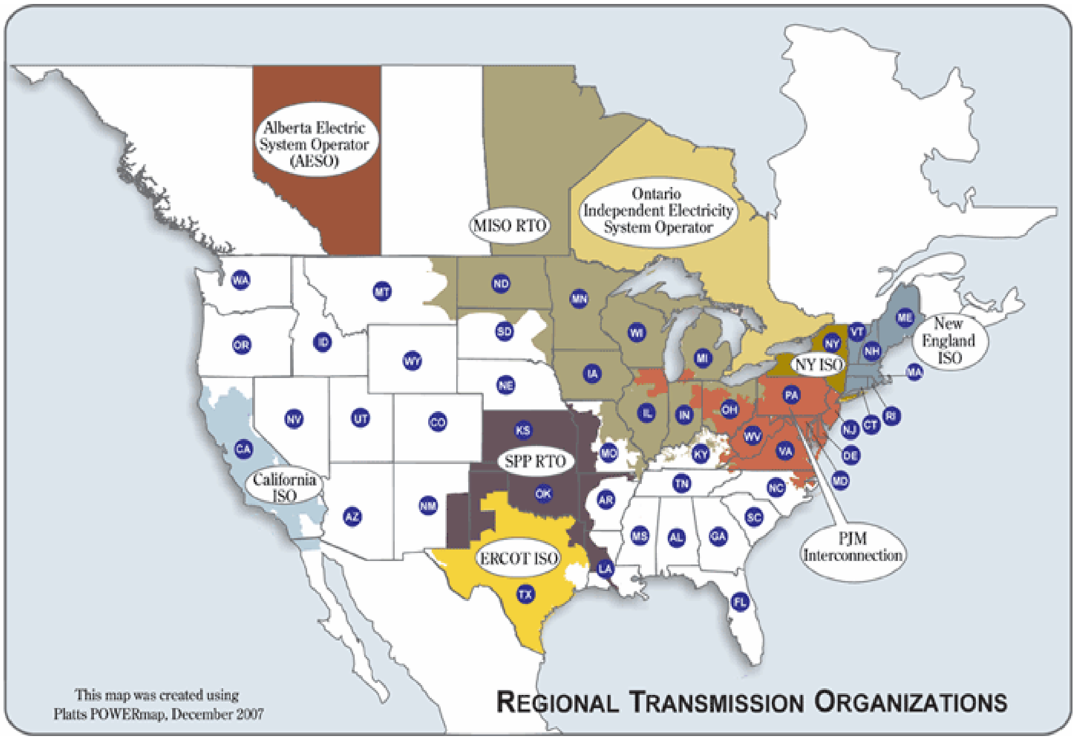
3.1 United States

Overview

This section provides an overview of existing demand-side bidding and demand response in centralized wholesale markets in the United States. It focuses on the regional transmission organizations (RTOs) in PJM, NYISO, ISO-NE, ERCOT, Midwest ISO, and CAISO[7], their demand response programs, and their impacts on peak load. Figure 3.1.1 shows a map of the RTOs in the United States.

[7] There are technical regulatory differences between Independent System Operators (ISOs) and RTOs which do not matter for the discussion in this paper. For ease of exposition we therefore refer to all of them simply as RTOs. PJM originally covered Pennsylvania, New Jersey, and Maryland but has extended into other regions. NYISO is the New York ISO. ISO-NE is the RTO covering most of the New England area. ERCOT is the Electric Reliability Council of Texas. Midwest ISO is the Midwest Independent System Operator. Finally, CAISO is the California ISO.

Figure 3.1.1 RTOs in the United States



Source: Federal Energy Regulatory Commission (http://www.ferc.gov/industries/electric/indus-act/rto/rto-map.asp)

The range of demand response programs offered and the opportunities to participate in wholesale markets varies significantly by RTO. Figure 3.1.2 below summarizes RTO-administered demand response programs and demand response participation in wholesale markets in six RTOs with significant demand response presence. These programs range from participation in the energy markets (both day-ahead and-real time), parts of the ancillary services markets, as well as specialized demand response programs centered around reaction to system emergencies.

Figure 3.1.2: Demand Response Programs and Participation in RTO Markets

Market Participation \ DR Program	PJM				NYISO			ERCOT		
	ELRP Full [1]	ELRP Energy Only [2]	ELRP Capacity Only [3]	Econ LRP [4]	EDRP [5]	ICAP/SCR [6]	DA DRP [7]	EILP [8]	BUL [9]	LAAR [10]
RT Energy Market				◆					◆	
DA Energy Market				◆			◆			
Emergency	◆	◆	◆		◆	◆		◇		
Capacity Market	◆		◆			◆				
Ancillary Services				◆			◇			◆

Key	Existing participation option ◆	Proposed or Not Yet Active ◇

Notes:
[1]: Emergency Load Response Program - Full Option
[2]: Emergency Load Response Program - Energy Only Option
[3]: Emergency Load Response Program - Capacity Only Option
Applies to ILR (Interruptible Load for Reliability) which receives capacity payments but does not bid into the capacity auction.
(PJM Manual 18: PJM Capacity Market; June 1, 2007; page 29 - 30)
[4]: Economic Load Response Program (Day-Ahead and Real-Time Energy Market)
[5]: Emergency Demand Response Program
[6]: Installed Capacity/Special Case Resource Program (reliability, capacity market)
[7]: Day-Ahead Demand Response Program (Day-Ahead Energy Market Only)
[8]: Emergency Interruptible Load Program (not yet active)
[9]: Balancing Up Load (Associated with balancing energy market)
[10]: Load Acting as a Resource (Associated with ancillary services)

Market Participation \ DR Program	ISO-NE					CAISO*			Midwest ISO*
	RT DRP [11]	RT PRP [12]	RT PrRP [13]	DA LRP [14]	Direct Participation [15]	VLRP [16]	PLP [17]	Direct Participation [18]	Direct Participation [19]
RT Energy Market			◆				◆		◆
DA Energy Market				◆					◆
Emergency	◆	◆				◆			◆
Capacity Market	◆	◆						◆	◆
Ancillary Services					◇		◆		◇

Key	Existing participation option ◆	Proposed or Not Yet Active ◇

[11]: Real Time Demand Response Program
[12]: Real Time Profiled Response Program
[13]: Real-Time Price Response Program
[14]: Day-Ahead Load Response Program
[15]: Currently as part of the Demand Response Reserve Pilot
[16]: Voluntary Load Reduction Program
[17]: Participating Load Program
* Current participation is by utilities only

Description of Demand Response Markets Mechanics

A feature of all the markets described for the United States is that they have a day-ahead as well as real-time market. As a general matter, bidding on the demand-side in day-ahead energy markets consists of the ability to submit a downward sloping bid (demand) curve. So, that as the price increases, less power would be purchased day-ahead. A typical scheme for demand-side bidding in a day-ahead energy market would be for buyers (demand) to submit their demand curves by noon the day before the operating day. For each operating hour and delivery location, a different demand curve might be submitted. Sellers would also have to submit their offer curves by that time as well. The bid curve submitted by buyers would typically consist of a sequence of price-quantity pairs that would represent the buyers' willingness to pay a certain amount for the quantity indicated. For instance, if a buyer was willing to pay $100/MWh for 1000 MW, but would only want 800 MW if the price rose to $120/MWh, the buyer would submit the price-quantity pairs: ($120/MWh, 800 MWh) and ($100/MWh, 1000 MW).

The bid curves submitted to the RTO would then be cleared with the offer curves. This would give the buyer a position that would be delivered the next day. In real-time, a net buyer could make an offer to change its position from its day-ahead position by submitting another demand curve. The difference in real-time is, however, that the buyer would need to be able to react in real-time to signals from the RTO. Whereas for day-ahead bidding, the buyer's position is set a day in advance and so would have much more time to take whatever measures were necessary in order to increase or decrease its load. Deviations in consumption from the day-ahead schedule for a buyer are typically settled at the real-time price. Sometimes penalties are applied if the deviations are large.

In contrast to the day-ahead and real-time energy programs, emergency programs are those used by RTOs only in the event of a pre-defined triggering event that is considered to be an emergency. These programs in some ways are very much like traditional load control programs (sometimes "DLC" for direct load control when the utility can directly control the load) in which a utility would call for reductions under certain conditions. In return, participants usually receive a fixed payment whether called or not, and sometimes receive a variable payment if called upon. Though emergency demand response programs are not really demand-side bidding, they are included here for completeness and because their size reflects the potential for demand-side bidding.

Ancillary service programs at RTOs range from those providing 10 minute reserve to those providing regulation. The RTOs vary across which ancillary services are open to demand-side bidding. This is further discussed below.

Finally, some markets in the U.S. have capacity requirements that are formalized through a centralized market for capacity in the RTO. In some of these jurisdictions, demand response can participate as a resource against generation.

Level of Demand Response

The total enrolled demand response MW can be found in Table 3.1.1. Both the MW in RTO programs as well as those in non-RTO programs are displayed. Economic and emergency enrollment levels are presented. As can be seen in the Table, emergency programs dominate in ISO-NE and NYISO,[8] while economic demand response is more prominent in PJM. In regions where the RTO offers a limited range of demand response programs (CAISO), or no programs at all (SPP, Midwest ISO) other than the ability to submit a downward sloping demand curve into the energy markets, demand response enrollment in non-RTO programs is prevalent. RTO programs provide a platform for both LSEs and CSPs (curtailment service providers) to sell load reductions that are treated like generation and not tied to load bids in the wholesale market. On the other hand, demand response that is managed by LSEs and are not part of RTO programs reduces an LSE's actual load and hence its load bid; such demand response operates much like demand-side bidding does as discussed in Section 2.[9]

The amount of load enrolled in DR programs differs from the load that actually participates in the market. As Table 3.1.1 shows, the ratio of enrolled load to participating load varies greatly among RTOs. California appears to be the most successful both in terms of reducing its peak

8 We do not have sufficient data to distinguish between non-RTO emergency and economic programs in ISO-NE, Midwest ISO, and SPP.

9 The RTO and non-RTO enrollment numbers in Table 4.1.1 may overlap. For example, it is unclear how demand response administered by an LSE but also enrolled in an RTO program is counted in the table.

load and mobilizing its enrolled demand response. As much as 78 percent of enrolled DR load responded on the peak day of 2006 in California. PJM has the most DR participation in energy markets, with 2915 MW enrolled in economic programs and 260 GWh annual deployment (corresponding to nearly 100 hours of deployment if most of the reductions came from economic demand response rather than emergency demand response). ERCOT's apparently very high GWh of load reduction seems unclear as demand response there provides primarily ancillary services.

Table 3.1.1: Enrolled and Realized DR in RTOs

	Program	Note	ISO-NE	NYISO	PJM	MISO	SPP	ERCOT	CAISO
	Note		*[1]*	*[2]*	*[3]*	*[4]*	*[5]*	*[6]*	*[7]*
Direct Enrollment in RTO Programs	RTO Emergency/Reliability (MW)	[A]	1,513	1,820	2,155	None	None	None	104 - 137
	RTO/ISO Economic (MW)	[B]	97	389	2,915			1,985 (all for A/S)	
	Number of Registrations	[C]	2,427	2,633	5,577	N/A	N/A	Approx. 92	6
Enrollment in LSE Programs	Non-RTO Emergency/Reliability (MW)	[D]	181		489	8,645	1,210		1,578
	Non-RTO Economic (MW)	[E]			2,703				964
Enrollment Total	Total Emergency/Reliability (MW)	[F]	1,513+	1,820	2,644	8,645	1,210		1,682 - 1,715
	Total Economic/Price Responsive (MW)	[G]	97+	389	5,618			1,985	964
Realized DR RTO Only (except MISO, SPP, CAISO)	Annual Demand Response Reduction (2006/2005, GWh)	[H]	53	7	260			4,637	
	Peak Hour Reduction (2006, MW)	[I]	597	948	2,050	2,651	70	DR not called on peak day	Approx. 2,066
	Reduction as a Percentage of Enrolled DR	[J]	37%	43%	40%	31%	6%	N/A	78%
	Reduction as a Percentage of Peak Load (2006)	[K]	2.1%	2.8%	1.4%	2.3%	Negligible % of peak	DR not called on peak day	4.1%

Sources and Notes:

[1A-B]: As of November 2007; ISO New England/NEPOOL Demand Resources Working Group Meeting, Demand Response Department, ISO New England, Inc., December 5, 2007.
[1C]: As of November 2007; ISO New England/NEPOOL Demand Resources Working Group Meeting, Demand Response Department, ISO New England, Inc., December 5, 2007, Pg 4.
[1D-E]: Includes "Other Demand Resources"; comprised of private, IOU, and state agency-sponsored distributed generation (wind and cogeneration) and energy efficiency projects.
[1F-G]: During the Show of Interest period for its Forward Capacity Auction, ISO NE received applications from New Demand Resource projects representing about 2,449 MW (Summer Demand Reduction Value)
Update on Demand Resource Participation in New England's Forward Capacity Market Demand Resources Working Group, Henry Yoshimura, ISO New England, November 7, 2007
[1H]: ISO-NE 2006 Annual Markets Report, ISO New England, Inc., June 11, 2007, Pg 113.
Economic DR plus emergency DR in energy market; all DR programs combined.
[1-7I]: FERC 2007 assessment of Demand Response and Advanced Metering, FigureII-1, Pg 5.
[1-7K]: FERC 2007 assessment of Demand Response and Advanced Metering, FigureII-1, Pg 5.
[2A-B]: October 2006 DR Registration, NYISO David Lawrence presentation on "Demand Response: What's New at the NYISO"
[2C]: October 2006 DR Registration, NYISO David Lawrence presentation on "Demand Response: What's New at the NYISO"
Sum of participants in EDRP, DADRP, and ICAP.
[2H]: FERC 2007 assessment of Demand Response and Advanced Metering, Pg 18.
Emergency DR data are from NYISO David Lawrence presentation on "Demand Response: What's New at the NYISO," Pg 7.
Economic DR plus emergency DR in energy market.
[3A-B]: As of 9/30/2007, PJM Load Activity Report January through September 2007 by Don Kujawski and Robert Jones, Pg2.
[3C]: As of 9/30/2007, PJM Load Activity Report January through September 2007 by Don Kujawski and Robert Jones, Pg2.
Sum of participants in emergency and economic programs as of September 2007.
[3D-E]: PJM 2006 State of the Market Report, Table 2-66. Emergency MW is calculated as total MW under DSR Programs Administrated by LSEs' in PJM Territory minus price sensitive DSR Distribution.
Economic MW is the sum of price sensitive DSR Distribution and Total MW with full and partial exposure to real time LMP.
[3F]: [3A] + [3D]
[3G]: [3B] + [3E]
[3H]: FERC 2007 assessment of Demand Response and Advanced Metering, Pg 18.
Economic DR plus emergency DR in energy market.
There was no activity in the Emergency Program during calendar year 2006. (PJM 2006 State of the Market Report, Vol. II, March 8, 2007, Pg 92)
[4D-E]: IRC Harnessing Power of Demand October 2007, Figure 5. MISO Emergency Demand Response Compensation Presentation 2006 reports 3,000 MW reduced the previous summer.
[5D-E]: IRC Harnessing Power of Demand October 2007, Figure 5.
[6A]: 2005 State of the Market Report for the ERCOT Wholesale Electricity Markets, Potomac Economics, Ltd. Pg 104.
2006 State of the Market Report for the ERCOT Wholesale Electricity Markets, Potomac Economics, Ltd. Pg 86.
There were no Balancing Up Loads (BULs) registered with ERCOT in 2005 or 2006.
[6B]: 2006 State of the Market Report for the ERCOT Wholesale Electricity Markets, Potomac Economics, Ltd. Pg xxiv and Pg 86.
MW numbers are as of December 2006.
[6C]: 2005 State of the Market Report for the ERCOT Wholesale Electricity Markets, Potomac Economics, Ltd. Pg xix and Pg 104.
Number of resources is as of December 2005.
[6H]: FERC 2006 assessment of Demand Response and Advanced Metering Footnote, Pg 84.
DR providing ancillary services.
[7A, D, E]: IOU July 2006 DR Numbers: CAISO Glen Perez's presentation "Demand Response Where We Are Now."
[7C]: CAISO Congestion Revenue Rights, Source and Sink Names; December 6, 2006
Mostly pumping load of pump storage units (ex. Helms), and California DWR SWP (State Water Project).
[7F]: [7A] + [7D]
[7G]: [7B] + [7E]

Different approaches to achieving demand response

As one looks at the future, it is apparent that in the United States, state regulatory policy and RTO policy can work together under three distinct approaches for demand response: (1) dynamic pricing at the end-user level; (2) Load serving entity (LSE) based load reduction programs; and (3) curtailment service provider (CSP) provision of load reductions.

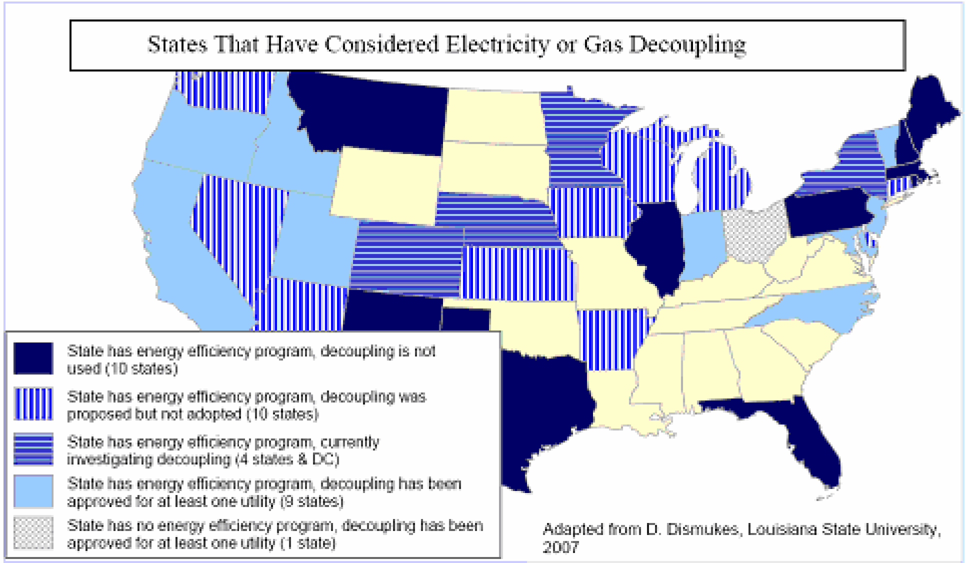
1) **Dynamic pricing at end-user level** involves customers paying more for the energy they consume when spot prices are higher, that is, through real-time pricing or critical peak pricing programs (in both cases, there are ways for customers to largely hedge their exposure to prolonged high prices). This is the classical economic approach that has been the motivation behind much of electric power restructuring in the United States. However, because of the reluctance of regulators to pass through costs, this approach has gained little ground except for large industrial and commercial users. It is, however, theoretically the most efficient and the simplest model for demand response. This is the commodity model for demand response described above.

2) **LSE-based load reduction programs** primarily involve interruptible retail rates and/or direct control of some customers' loads by the LSE (and possibly some dynamic pricing). The LSEs get credit for the load reductions, but in effect they simply reduce the net amount of energy and/or capacity purchased. The advantage of this model is that it prevents the RTO from having to accommodate CSPs, although similar difficulties in measuring and compensating customers for their load reductions may still have to be dealt with at the LSE level. The main disadvantage is that it is unlikely to develop demand response to its full potential because many LSEs have neither the financial incentive to reduce their customers' loads nor the expertise to marketing and implementing DR as effectively as CSPs can.

   Traditionally, of course, implementation of demand response (or energy efficiency measures) has been against the financial interests of vertically integrated utilities. A decrease in sales volumes (MW or MWh) results in a decrease in revenues leading to a decrease in profits. In order to encourage utilities to invest in energy efficiency and demand response programs, some states enacted tariffs whereby the utilities that are in effect held harmless from decreases in sales volumes due to demand response or energy efficiency efforts. Rates in several states are “decoupled” from the effects of demand response programs, hence encouraging utilities to invest in demand response. Figure 3.1.3 below shows the status of energy efficiency and decoupling across the states in the lower continental United States. States that have enacted decoupling indicate a propensity for demand response compared with other states. As can be seen, both the Midwest ISO and PJM are a patchwork of implementation of decoupling.

The second approach probably works the best in states that have enacted decoupling, such as California. In California, CSPs have no direct access to CAISO wholesale markets, but they have collaborated with utilities in developing many of the LSE-based DR programs on a fee-for-service basis.

Figure 3.1.3 Status of Decoupling in the United States



3) **Curtailment service providers (CSPs)** work directly with end-users to reduce peak loads through a combination of direct load control and communications protocols. They aggregate their customers' load reduction capabilities into long positions, which they bid directly into the RTO's capacity and/or energy markets. They receive compensation from the ISO, which they share with their customers (typically taking much of the capacity value while giving the customer most of the energy value). The advantage of CSPs is they provide innovative technical and marketing expertise, and they lack the disincentives that many utilities have for implementing DR. CSPs have produced a large amount, if not the majority, of new DR in PJM, NYISO, and ISO-NE, where both the RTOs and the states have enacted CSP-enabling policies. The disadvantage of accommodating CSPs is that it introduces considerable complexity into the ISO's business practices. The RTO must define customers' baseline usage from which reductions are measured, it has to be able to dispatch and validate participation, and it must establish an uplift mechanism to fund the compensation for DR. The uplift issue is discussed in greater detail below.

An important question is the fairness of the uplift payments that other customers have to make in order to compensate DR under this model. Uplift payments are needed because enabling CSPs requires that DR be treated as a generation-like resource that is disconnected from load bids. Therefore, because LSEs and their customers pay only for their actual usage, some claim that selling load reductions is basically reselling something that neither the customer nor their LSE has bought. In the second approach, the LSE can bid a gross load of 1000 MWh, and if 100 MWh of DR gets deployed, the LSE is in effect charged for 900 MWh. In the third approach, the LSE is charged for the gross and credited for the DR, whereas the LSE is charged only for the net. As a result, in the third approach there are insufficient funds to pay for the DR without uplift.

The fairness of such uplift payments depends on the value that non-DR customers receive from DR in the form of reduced prices and increased reliability. These benefits are more difficult to quantify than the direct benefit of reduced energy and capacity requirements that accrue to DR participants. A *Brattle* study conducted for PJM and MADRI last year showed non-participant benefits from lower prices that far exceeded the energy payments to DR participants, based on an analysis conducted with a short-run equilibrium model. However, as the study states, lower energy prices can raise capacity prices commensurately; and to the extent that DR reduces the amount of installed generation capacity (and the type) online, energy prices can eventually increase toward their original levels.[10] In the long-term, energy and capacity prices will change as a result of DR, but perhaps not as much as a short-run equilibrium model indicates. Actual benefits might be far greater under extreme conditions or in places where there are barriers to entry of generation compared to areas where such barriers do not exist. If uplift is the only way to get CSPs into the market, and hence the only way to develop a lot more DR, it may be a good idea.

[10] Sam Newell and Frank Felder, "Quantifying Demand Response Benefits in PJM," Prepared for PJM Interconnection, LLC and the Mid-Atlantic Distributed Resources Initiative (MADRI), *The Brattle Group*, January 29, 2007 ("PJM-MADRI Demand Response Study"). Also see, "The Power of Five Percent", Ahmad Faruqui, Ryan Hledik, Sam Newell, and Johannes Pfeifenberger, The Electricity Journal, October 2007.

Comments from FERC and the RTOs, publicly available data on CSPs, and our interviews with the three large CSPs indicate that CSPs contribute a large fraction, if not the majority, of DR in PJM, NYISO, and ISO-NE. In NYISO for example, CSPs account for 91% of participation in ICAP/SCR capacity programs and 53% of all demand response reductions.[11] In particular, Energy Curtailment Specialists (ECS) provides 786 MW, or 70% of demand response participating in the ICAP/SCR program providing capacity in the NYISO capacity market. Another aggregator, EnerNOC provides 623 MW demand response (8.3% state peak) in Connecticut and 170 MW demand response (8.4% state peak) in Maine. Comverge provides 1,500 MW demand response total, but approximately 700 MW of that is from fee-for-service contracts with utilities. Finally, there is approximately 800-900 MW of CSP-based demand response from Enerwise acquisition and in PJM programs.[12] CSPs can provide expertise, technology, and a willingness to take risk that utilities often lack. LSEs and aggregators, however, are not necessarily in competition with each other.

A proposal was recently made by the FERC to obligate RTOs to permit aggregators of retail customers participate in the RTO's organized markets except where state regulations would not allow it.[13] In reaction, it has been suggested that not only should LSEs and aggregators have equal access to RTO markets, but individual customers (e.g., large industrial facilities) should be able to bid into the wholesale markets directly.

11 FERC 2007 Assessment of Demand Response and Advanced Metering, page 20.
12 Interviews with CSP personnel.
13 February 22, 2008, Notice of Proposed Rulemaking, 122 FERC ¶ 61,167

3.2 United Kingdom

The original two settlement system

From 1990 to 2001, there was effectively a mandatory two settlement system in England and Wales[14], with a day-ahead Pool after which the Transmission System Operator (TSO) took control of the system and could adjust the accepted Pool offers and use ancillary service contracts to achieve a balanced system. Demand-side bidding into the Pool was allowed from the end of 1993 onwards but initially (until 1998) only 30 demand-side bidders (DSBs) were allowed to participate. Each DSB had to be able to deliver at least 10 MW of demand reduction in any settlement period and 50 GWh of demand reduction over the course of a year. DSBs had to specify the price at which they were prepared to reduce their demand (the same price curve for all 48 settlement periods in a day) and the level of demand reduction they could deliver in each settlement period. DSBs were not paid for any energy they were scheduled not to consume but they did receive an availability payment when they were available to reduce demand but not scheduled to do so.

Current single settlement system

From 2001 onwards, the original two settlement system was replaced by a single settlement system. Bilateral trading (over the counter or via power exchanges) continues until an hour before the start of each settlement period when a real-time market (the Balancing Mechanism) opens. In principle, there is nothing to stop the demand-side participating in bilateral trading but no information is available on whether this occurs. However, DSB occurs in the Balancing Mechanism, which was specifically designed from the outset to allow this to occur – DSB have to provide information on their intended level of consumption during the settlement period and the price and extent to which they are prepared to move away from this level. If their offer is accepted, i.e., they are requested to reduce their demand, they are paid their offer price for the energy they do not consume.

[14] The much smaller markets in Scotland and Northern Ireland were each effectively single settlement markets.

Measurement issues are less of a problem than is often the case because of the way that the settlement system functions. This is because demand-side participants are exposed to imbalance charges for any difference between the demand they notify to the settlement administrator when the real time market opens (their final physical notification or "FPN") and the volume of contracts they have signed to cover that demand. If DSBs have an offer accepted, their FPN is adjusted to reflect the demand they are deemed not to have taken. Consequently, if a DSB were to submit an artificially inflated FPN so as to provide headroom for delivering an offer without taking any action, it would have either to accept exposure to imbalance prices (if its contract volume matched its intended actual demand) or to pay under contract for power it did not need (if its contract volume matched its FPN). Neither of these options is likely to make financial sense. (Note that the settlement system does not directly generate an "uplift payments" since the net imbalance cash flow - the difference between the payments made by participants for being short and the payments made to participants for being long - is smeared back across all parties in proportion to their metered volumes.)

In addition, the demand-side can provide a number of different ancillary services, irrespective of whether or not they chose to participate in the Balancing Mechanism. Table 3.2.1 below summarizes the current participation of the demand-side in the delivery of ancillary services. Note that it is possible for large loads to individually contract with the system operator, provided that they can deliver a demand reduction of at least 3 MW, or to have their demand reduction submitted jointly with that of other loads via an aggregator (there are currently three aggregators active in the market).

Table 3.2.1: Demand-side participation in the United Kingdom

	Demand side involvement	**Demand involvement in 2005/06**	
Service	(MW)	% of service provided	% of total demand
Short term operating reserve - firm	1800-2000 MW	32%	>1%
Short term operating reserve - flexible	250-400 MW		
Fast reserve	Possible, but volume unknown	6%	<1%
Frequency response	450 MW	36%	~1%
Constraint management	Possible, but none so far	Possible, but none so far	N.A.

In terms of the services listed above:

- Short-term operating reserve has to be delivered within 240 minutes and, once called upon, must be capable of a sustained delivery of at least 2 hours. Once having provided reserve, Firm reserve has to be made available in all the service windows in a season (there are six seasons in a year and up to four windows per day) whereas flexible reserve only has to be made available a week at a time. An availability (per MW per hr) payment is made for being in a state to provide the reserve plus an utilization payment (per MWh) if the service is actually invoked.
- Fast reserve has to be delivered (at a fast rate) within 2 minutes and generally has to provide more than 50 MW of reserve. Domestic load control via teleswitching has been used to provide fast reserve.
- Frequency response is delivered via automatic low frequency relays, which are typically activated around 20 times a year.

While the British regulator has always been supportive of the involvement of the demand-side in the wholesale market, e.g., by designing the real-time market to allow its participation, a key driver of the development of demand-side ancillary services has been the financial incentives to which the system operator is exposed. These are of the "sliding scale" variety whereby the system operator gets to keep a proportion of any reductions in its balancing costs below a target level and has to pay a proportion of any increase in its balancing costs above that target level. The demand-side can bring additional competition to the delivery of ancillary services, particularly fast reserve, which can enhance the ability of the system operator to control its costs. This, in turn, delivers benefits to consumers through lower system costs.

3.3 Norway

Norway is part of Nord Pool, which organizes futures, forwards and day-ahead markets across the Nordic region (Norway, Sweden, Denmark and Finland). Norway organizes its own (regulating) reserve market although the other countries involved in NordPool (plus Germany) participate in a joint reserve market (Elbas[15]). However, the Nordic TSOs coordinate in balancing the overall system, with the main role being taken by the Swedish and Norwegian TSOs.

<u>Day-ahead market (Elspot)</u>

Participation in the day-ahead market is optional. Having taken account of any obligations under their physical bilateral contracts, Elspot market participants submit generation offers and demand bids in the form of a price/volume curve for each hour of the following day. Nord Pool sets hourly ex-ante prices at the intersection of the aggregate supply and demand curves. By 13:30 on the day-ahead, Nord Pool informs each participant of its generation or purchase commitments in the spot market and allows participants 30 minutes to check that their net trading position is in accordance with their bids and offers. Once confirmed, accepted bid and offer quantities become firm contracts for physical delivery. Participants have no opportunity to revise their bids and/or offers. Since market participants provide demand curves as well as supply curves, provision is made for price responsive demand to participate in the market. Over 20% of Norwegian demand is considered to be potentially demand responsive.[16] However, according to the Norwegian system operator (Statnett), the economic incentives for the demand-side to participate in the day-ahead (or futures/forwards) markets are limited.[17] On the other hand, given that the Norwegian market is dominated by hydropower (it accounts for more than 99% of Norwegian capacity and around 50% of NordPool capacity), there may be significant incentives in years when there is little precipitation.

[15] Elbas enables the continuous trading of single hour blocks up to 2 hours prior to delivery.
[16] "Load Control in the Norwegian Balance Market", Statnett.
[17] "Demand Response Resources, Electricity Market Impacts: A brief overview of DR in Norway from the TSO perspective", April 2005.

Real-time markets

Due to the ready availability of balancing services from hydropower plants, the opportunities for demand-side participation in the real-time markets are limited. Thus far, it is only in providing fast reserve and constraint management that opportunities for the demand-side have been developed. In the future, it is anticipated that opportunities to provide frequency response may be developed.

A separate reserve options market has been in existence in Norway since winter 2000. Its purpose is to ensure that an adequate level of regulating reserve offers are submitted during the winter months (when there is most need for reserve). Over 2,000 MW of option contracts are required to supplement the regulating reserve that is normally available. Weekly auctions are held for the option contracts and successful bidders receive an option fee, in return for which they are obliged to offer reserve in the regulating reserve market although they are free to choose the price at which they do so. When the TSO schedules reserve, the marginal price is paid for all reserve provided i.e. the price of the most expensive accepted offer for upward regulation and the price of the cheapest accepted bid for downward regulation.

Contracts are offered for a minimum of 25 MW, reserve must be made available between 06:00 and 22:00 hours on business days with the potential for delivery within 15 minutes for a period of not less than 1 hour (and at least 10 hours of reserve delivery per week must be possible). The obligation on demand-side participants with option contracts to offer reserve is reduced (or removed) if they reduce their consumption in the Elspot market in response to high prices. However, in these circumstances, their option fees are reduced correspondingly.

The reserve options market has proved popular with consumers, with up to 1,200 MW of the contracts signed with the demand-side. At times, this has represented almost 70% of the contracts signed (although a much smaller proportion of the total available reserve – the total annual level of regulating power is around 8 TWh). Participation has mostly been from large industrial facilities (metals and paper production). However, Statnett has also been working to encourage medium-sized consumers (electric boilers and back-up generation) to participate in the options market and, indeed, in the day-ahead market. Its aim was to have 200 MW of reserve option contracts from medium-sized consumption by the end of 2005/06 plus 60 MW of demand responsive participation in Elspot (note that peak Nordic demand is around 67 GW).

Some studies have also been carried out to explore the extent to which smaller loads (including domestic customers) could also be involved in the market. These involve the introduction of smart metering (to allow consumers to respond to price signals) and automatic load shedding controls. While these showed that there was the potential for greater demand-side involvement, they also highlighted the technological and cost-related challenges that would need to be overcome to encourage participation.

4. Key Drivers of the Integration of the Demand-Side Bidding

Key Drivers of the Integration of Demand-Side Bidding in Wholesale Markets

There are a number of key drivers of the integration of demand-side bidding in wholesale markets. First, regulators, RTOs, and consumers often see demand response as a method to decrease high prices. By making demand price sensitive, wholesale prices should come down. As a result, all consumers benefit from the reduction in the market clearing price in wholesale markets. One study showed that a 5% reduction in peak usage in the United States would result in a $3 billion annual savings simply from avoided capacity and energy costs. Additional benefits would flow from reductions in wholesale prices.[18] Second, demand response is also seen as a way to mitigate market power. The more elastic demand is, the harder it is for sellers to exercise market power. Third, many LSEs, CSPs, aggregators, and large consumers see potential profit opportunities in demand response. As a result, the inclusion of demand-side bidding and integration of demand response in wholesale markets has been driven by regulators, RTOs, large consumers, and aggregators. Utilities and generators have tended to be less enthusiastic.

With these key drivers there are a number of factors that influence the level of demand-side participation in wholesale markets when the capability for demand to bid in these markets exists. These include external factors to the wholesale market such as geographical and economic context of the wholesale market in question, and internal factors to the wholesale market such as bidding and settlement rules.

External Factors in Demand Response Availability

While regulatory policy and RTO business practices are critical for enabling demand response, the economic potential for demand response depends on factors largely beyond the RTOs' and regulators' immediate control: the geographical and economic context and electricity supply and demand conditions.

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18 Faruqui, Ahmad, Ryan Hledik, Sam Newell, and Hannes Pfeifenberger, "The Power of Five Percent", *The Electricity Journal,* October 2007.

Electricity Supply and Demand Conditions

In the United States, RTOs and state regulators have some influence over supply and demand conditions, but at any point in time the amount of resources and the level of demand must be taken as given. The value of demand response depends on the cost of supply. Demand response is particularly critical in regions with scarce supply, and it has less value in markets with surplus capacity. PJM has seen a recent rise in demand response in locations where the market is becoming tight (after years of surplus). In ISO-NE most new demand response was created in Southwest Connecticut, where supply shortages compounded by a weak transmission system that could support limited imports and no new generation interconnections.[19] Similarly, in PJM's capacity auctions, proportionally more new demand response was added in the Eastern and Southwestern MAAC Locational Delivery Areas as a percentage of peak load.[20] (These RTOs also undertook actions to encourage DR in these areas, which will be addressed in the next section). It was also the case in Norway where a tightening supply-demand gap led to the first movements towards including demand-side bidding in the ancillary services market.

The overall level of current or recent reserve margins in each RTO in the United States is shown below:

- Midwest ISO: 19.9%; (Midwest ISO 2006 SOM Report, Table 1, Page 18)
- PJM: 18% (PJM 2006 Load Forecast Report; PJM 2006 SOM Report, Pt I, Page 27, Table 1-5) adjusted to include imports
- ISO-NE: 21% (2007 CELT, Page 1) adjusted to include imports;
- NYISO: 18.1% (2006 and 2007 Load and Capacity Reports; Review of NYISO Summer Peak Models – 2000 to 2006, NYISO Resource & Load Adequacy, January 22, 2007) adjusted to include imports.

In the future, these numbers are expected to decline, as demand continues to grow at a faster rate than supply. In addition, just as with generation, DR needs sufficient and stable enough prices in capacity markets in order for the incentive provided by capacity markets to be sufficient to induce entry. For example, some analysts and market participants claimed that the clearing price in ISO-NE's recent Forward Capacity Auction were not sufficient to support large upfront

19 ISO New England, 2007 Regional System Plan
20 2009/2010 and 2010/2011 RPM Base Residual Auction Results, PJM

investments in new DR.[21] Note, however, that this does not mean that demand response will not develop in the absence of a capacity market as experience in Great Britain, Norway, and ERCOT (neither of whom have a capacity market) shows.

<u>Economic and Geographic Factors</u>

The geographical and economic context of the wholesale market is an important factor over which the market participants have no control. Geography can be an important influence because of the underlying weather patterns and hence the usage and penetration of technologies like air conditioning. For example, the Midwest Census Region where most of the Midwest ISO's footprint lies has residential air conditioning penetration of approximately 83 percent while California has residential air conditioning penetration of approximately 48 percent.[22] Clearly, the ability to obtain DR via direct load control of air conditioning has, at the face of it, more potential in the Midwest ISO than in CAISO.[23] Likewise, the underlying economic background of the RTO region will influence the type and amount of DR that is available. For example, ERCOT has a very successful DR program in large part due to the size of the industrial base in its territory.[24] Without that underlying industrial base, ERCOT's DR program would probably be much smaller.

The economic and geographic context of the RTO can be a key determinant in the amount of DR available. Figure 4.1 shows the relative level of large industrial load. As can be seen from the figure, industrial load represents 30 percent of total load in the West South Central census division, which is roughly the same as in Texas. This relatively large industrial load is reflected in the size of ERCOT's industrial DR programs. By contrast, industrial load represents less than a fifth of total load in New England, and therefore, the potential of such loads to provide DR is likely much lower.

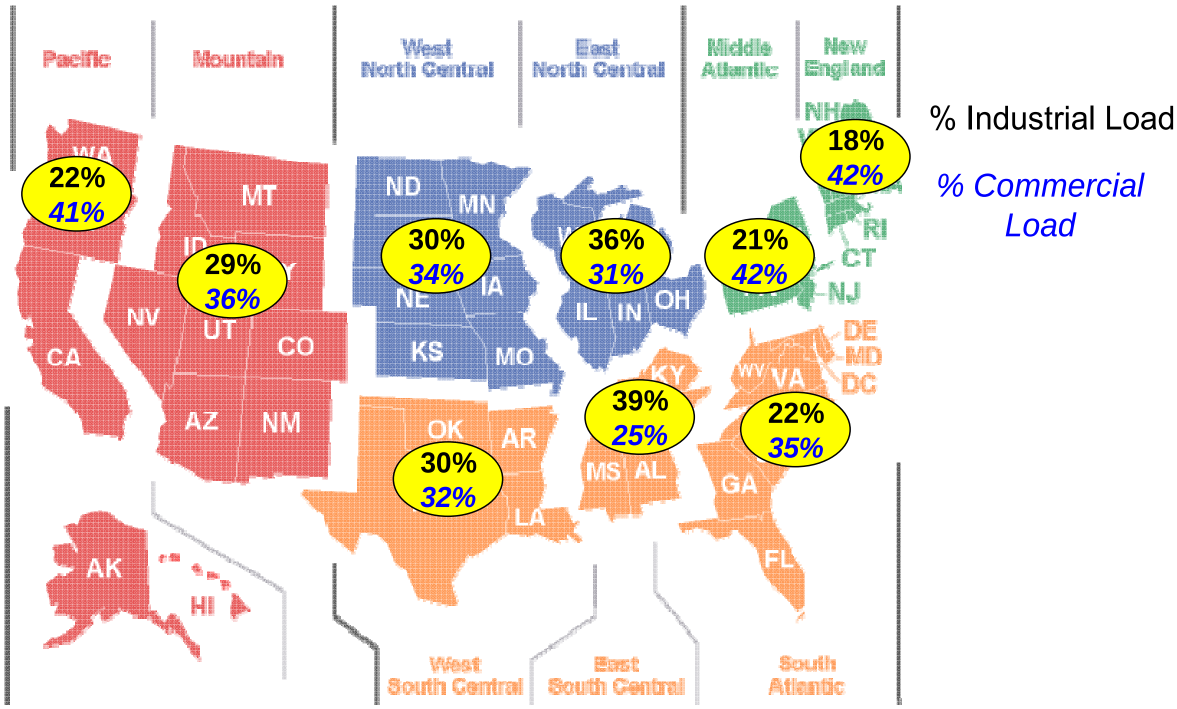
21 The market clearing price of capacity in ISO-NE's recent Forward Capacity Auction for 2010/2011 was equal to the floor price of $4.50/kW-month.

22 Based on EIA's 2001 Residential Energy Consumption Survey (RECS), Form EIA-457A

23 Clearly, the amount of air conditioning on direct load control is influenced by a variety of factors beyond the sheer amount of air conditioning penetration in a particular ISO. However, the amount of air conditioning penetration gives the "market size" for air conditioning direct load control.

24 Robert Earle and Ahmad Faruqui, "Demand Response and the Role of Regional Transmission Operators", *2006 Demand Response Application Service*, Electric Power Research Institute, 2006.

Figure 4.1: Industrial Load as a Percentage of Total Load by Census Division

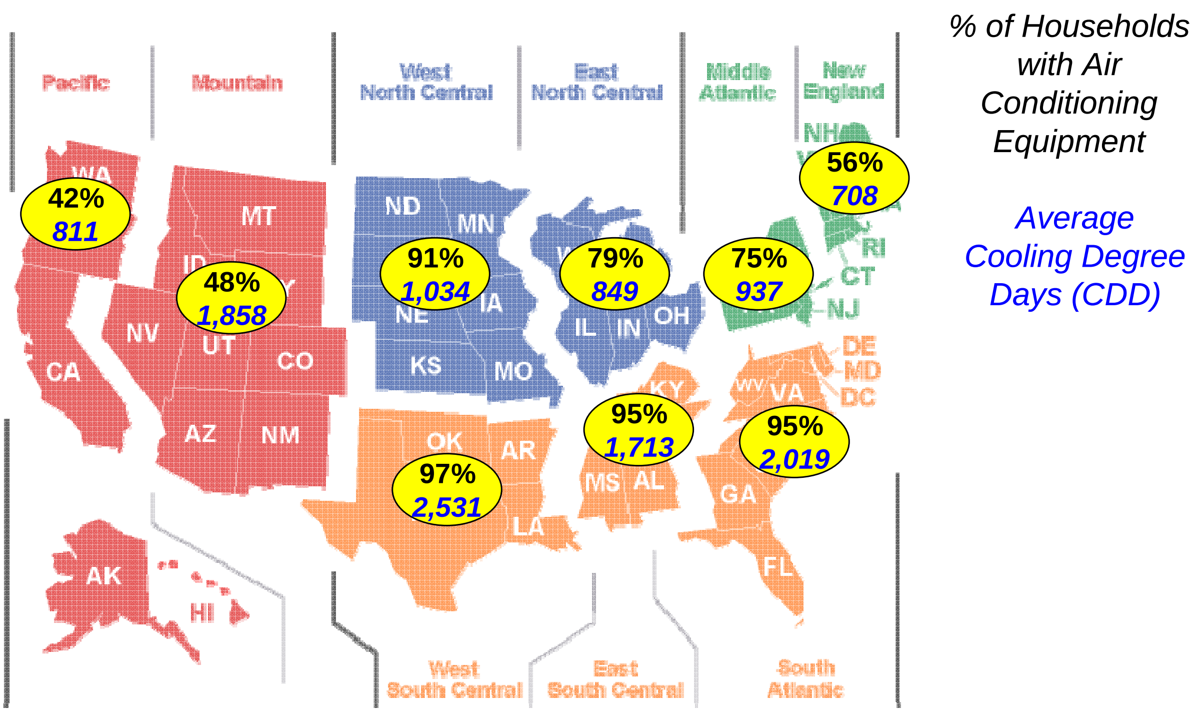


Source: Census regions and divisions defined by EIA; See http://www.eia.doe.gov/emeu/reps/maps/us_census.html. Supplemental Tables to the Annual Energy Outlook 2007, Tables 1-9; http://www.eia.doe.gov/oiaf/aeo/supplement/index.html

Residential A/C penetration is depicted in Figure 4.2 below.[25] As the figure shows, the Midwest has a much higher A/C penetration and higher A/C loads (based on cooling-degree-days), and hence a greater potential for demand response from A/C load, than for example CAISO or ISO-NE.

[25] ***Source***: Census regions and divisions defined by EIA; See http://www.eia.doe.gov/emeu/reps/maps/us_census.html. Air conditioning saturation based on survey data in 2001 Residential Energy Consumption Survey; Form EIA-457A (2001)--Household Questionnaire; OMB No.: 1905-0092, February 29, 2004.

Figure 4.2 Residential Air-conditioning Saturation by Census Division



Source: Census regions and divisions defined by EIA; See http://www.eia.doe.gov/emeu/reps/maps/us_census.html. Air conditioning saturation based on survey data in 2001 Residential Energy Consumption Survey; Form EIA-457A (2001)--Household Questionnaire; OMB No.: 1905-0092, Expiring February 29, 2004.

<u>Internal factors influencing the level of demand-side participation in markets</u>

Although demand response development depends largely on the regulatory environment and economic factors described above, wholesale market business rules shape the ease with which demand response can participate in the wholesale markets and payments that demand response resources receive. The most important business rules address:

- The role of CSPs;
- The presence of resource adequacy requirements and organized capacity markets to facilitate meeting such requirements;
- Qualification requirements for participating in organized capacity, energy, and A/S markets that can provide barriers to participation;
- Bidding and settlement rules that can either ease or hinder DR participation as well as affect the earnings of DR providers;
- Measurement and verification that may affect the willingness of DR to participate in markets and may create opportunities for gaming and/or for load

reductions that occur for reasons other than responding to conditions of scarce electricity;

- Penalties that act as a barrier to DR;

This section of the report treats each of these issues in turn by doing a cross-comparison across a number of wholesale markets.

The role of CSPs

In the Midwest ISO and CAISO, demand response can only be provided by LSEs currently, and not by third-party aggregators. CAISO rules do not allow for a customer to have two Scheduling Coordinators. Wholesale market business rules can also limit aggregator participation in subtle ways. For example, some wholesale market data reporting rules require aggregators to submit recent load data, enabling LSEs to create barriers to CSPs by limiting access to customer data.

In Britain, demand response in the wholesale market can be provided either directly by consumers who have chosen to participate in the wholesale market and by third-party aggregators. The situation is similar in Norway except that it appears that the RTO acts as the aggregator.

Resource Adequacy Requirements and Capacity Markets

Anecdotal evidence, including interviews with DR providers, suggests that capacity payments (United States) or availability fees (Europe) are a major factor in attracting demand response load in the United States. End-use customers seem to prefer the certainty of capacity payments to the possibility of high energy payments to be received only in the relatively rare instances of system shortages. Apparently, the certainty of capacity payments helps DR customers or aggregators to justify the investment they make in DR.

All RTOs in the U.S., except ERCOT, have a resource adequacy requirement. Given the apparent attractiveness of capacity payments for demand response, it may seem surprising that ERCOT has a relatively large amount of DR participation. As already explained, however, ERCOT has a large industrial base that can readily participate in ERCOT's ancillary services markets on a regular basis and so the need for a steady income stream from capacity payments may be less important there. In addition, ERCOT's Load Acting as a Resource (LaaR) program, which allows DR to participate in the ancillary services market, is perceived as particularly "load friendly."[26]

Among the RTOs that do have a resource adequacy requirement, PJM, ISO-NE, and NYISO have organized capacity markets (in addition to bilateral trading), while the Midwest ISO and CAISO currently rely on bilateral trading only.[27] Bilateral trading provides for capacity payments to DR similarly to organized markets. However, organized markets administered by RTOs are often thought to foster standardization of capacity products leading to greater market liquidity and lower transaction costs as well as greater transparency of market prices. Some market participants argue that the transparency of pricing is particularly valuable for demonstrating the value of DR to state regulators.

While forward capacity markets can provide incentives for demand resources to emerge within a wholesale market, just as with generators, making forward commitments to deliver demand response is implicitly risky due to uncertainty surrounding customer participation, the ability of new technologies to deliver, as well as regulatory uncertainty (for regulated utilities).[28]

On balance, it appears that capacity markets are helpful (but not essential) for encouraging the entry and participation of demand response resources.

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[26] Grayson E. Hefner et al., Loads Providing Ancillary Services: Review of International Experience, Ernest Orlando Lawrence Berkeley National Laboratory, LBNL –62701, May 2007

[27] CAISO is currently considering implementing a capacity market of its own.

[28] On the other hand, demand response resources are typically scaleable in a way that traditional generation is not, which can be highly valuable for planning purposes. It can also be sited in load pockets where new generation might not be possible.

Qualification Requirements

Table 4.1 below gives an overview of demand response participation in meeting resource adequacy requirements across wholesale markets. A fact to note here is that demand response that participates only in economic programs and does not commit to being callable by the wholesale market in emergencies generally does not count toward resource adequacy requirements. This is often cited as being unfair treatment by demand response resources relative to generators. However, generators are generally required to bid their available capacity into the day-ahead energy market lest they be accused of physical withholding.[29] Demand response as a resource differs from generation in this respect and is not subject to such daily must-offer requirements.

The seasonal nature of air conditioning-based demand response can present qualification challenges. ISO-NE admits only annual resources into its forward capacity market. Seasonal resources, such as air-condition-based demand response, can participate only by combining their offers with other resources whose winter capabilities are greater than their summer capabilities, which may unnecessarily increase the overall cost of capacity procurement. The difficulty of developing joint offers is compounded by the fact that ISO-NE requires aggregated resources to be located within the same load zone.

[29] This is the case in RTOs with organized capacity markets, i.e. PJM, ISO-NE, and NYISO

Table 4.1 – Overview of Demand Response Participation in Meeting a Resource Adequacy Requirement

		Midwest ISO	PJM	ISO New England	New York ISO	California ISO	Southwest Power Pool
Does a centralized forward capacity market exist?		No	Yes: Reliability Planning Model	Yes: Installed Capacity Market	Yes: Forward Capacity Market	No	No
Participation Requirements	Minimum Size	100 kW	100 kW	100 kW	100 kW	No limit	LSE DR program-specific
	Maximum Size	No limit	No limit	No limit	No limit	No limit	
	Callable by RTO?	Yes, DR must be available during emergencies	Yes	Yes, must be callable by the RTO during emergencies, except DR outside RTO programs	Yes	Not all DR is directly callable by the RTO	
	Interruptibility	Up to 5 times during the peak load season	Up to 10 times a year, for up to 6 hours per interruption	No explicit limit on the frequency or duration of each event	No explicit limit on the frequency or the duration of each called event, but DR performance is mandatory only for 4 hours per event	Must be available at least 48 hours each summer season.	
	DR outside RTO programs eligible?	Yes	No, must be in PJM's Emergency Demand Response Program	Yes	No, must participate in NYISO's Special Case Resources (SCR) program	Yes	
	Energy Efficiency Eligible?	No	No	Yes	No	No	
What DR, if any, is added back to the peak forecast for establishing resource adequacy requirements?		Load reductions associated with DR that counts as capacity	Load reductions associated with DR that counts as capacity	Load reductions associated with DR that counts as capacity	Load reductions associated with emergency DR and SCR during the peak hours	Load reduction associated with dispatchable DR over which LSEs have control	

Most RTO programs require demand response to meet a minimum size requirement, typically 100 kW. Aggregation of smaller loads is usually allowed, although some programs, such as CAISO's Participating Load Program, currently accommodate only large demand response resources. Setting a reasonably low minimum threshold and allowing the aggregation of retail loads to meet the minimum required size is an obvious strategy to increase demand response participation. Note, however, that minimum size requirements for certain aspects of demand response can be much larger. For example, demand response must be capable of providing at least 3 MW in order to be eligible to tender for ancillary services in Great Britain.

Some market participants have also suggested that current financial assurance requirements (e.g. in ISO-NE) may act as a significant barrier for smaller aggregators, although it does not seem to be a problem for larger demand response providers.

<u>Bidding and Settlement Rules</u>

Some wholesale markets (e.g. PJM, NYISO) have integrated demand response into their wholesale energy markets more effectively than others. The effectiveness of integration depends largely on having bidding and settlement rules that ease demand response participation and provide fair compensation. This section discusses four key elements of bidding and settlement:

(1) bidding protocols; bid mitigation; (2) the ability of demand response to set market prices; and (3) settlement timing.

Bidding Protocols

The Midwest ISO's bidding and settlement systems cannot currently accommodate two market participants at the same commercial pricing node (CPN). This limitation excludes curtailment service providers from offering load reductions from end-use customers, because the customers' LSEs already have claim to their loads' CPN. CAISO similarly excludes CSPs through its rule that there can be only one "scheduling coordinator" per end-use customer. These limitations should be changed if CSPs are to be admitted into the wholesale market.

PJM has the most advanced bidding protocols for demand response. The user interface for entering demand response bids (via eLoadResponse) is different from that for entering generation bids (via eMkt). The special interface accommodates differences in bid parameters, although the dispatch, market clearing, and settlement treats demand response the same as generation bids. Developing eLoadResponse required substantial investment; with eLoadResponse in place, the dispatch, market, and settlement systems required only minor tweaks.

These issues appear to be much less problematic in Britain and Norway, in part because neither market has locational marginal pricing. Thus, for example, demand response curves in the day-ahead market in Norway only have to be provided by region rather than by node.

Bid Mitigation

The Midwest ISO has a relatively high maximum offer price of $1000/MWh for demand response, compared to $500 in NYISO, and $1000 in ISO-NE. The Midwest ISO also has the highest caps on A/S offers (e.g., $500/MWh for regulation vs. $100/MWh in PJM). However, PJM has no maximum on demand response's energy price offers. Having a high or unlimited cap serves two purposes: first, it encourages demand response; and second, it allows for scarcity pricing. Toward that end, FERC's NOPR has proposed the following:

- Raise the current bid caps for all bidders in periods of tight supply
- Raise the current bid caps only for demand response bids and allow them to set the market price
- Require a demand curve for operating reserves during emergencies
- Set the market-clearing price at the payment received by demand response participating in emergency demand response programs

The Ability of Demand Response to Set Energy Market Prices

In some wholesale markets (*e.g.* ISO-NE), demand response that is activated only during system emergencies ("emergency demand response") cannot set the market price. Therefore, the activation of emergency demand response may dampen market prices despite the fact that the system is in an emergency. If emergency demand response cannot set the market price, energy price signals may be distorted during emergencies. "Scarcity pricing" is typically dampened by this shortcoming compounded with market power mitigation. In contrast to ISO-NE, emergency demand response can set the market price in PJM, and hence price signals do accurately reflect shortage conditions during emergencies.[30]

Even "economic demand response", i.e., that which is called based on bids into the energy market, cannot set the price in all RTOs. Due to limitations in its market software, economic demand response in ISO-NE is called after the generation-based market clears, and it is compensated at the generation-based clearing price. This prevents demand response from being able to mitigate peak prices. On the other hand, PJM has economic demand response completely integrated into its market software, leading to more efficient outcomes.[31]

Settlement Timing

Having a short time interval between curtailment events and settlement appears to be important to some CSPs. As shown in table 4.3, the Midwest ISO has by far the shortest settlement period for demand response in its energy markets. However, the experience of other RTOs shows that

30 Note that DR must have real-time telemetry in order to set the PJM market price. Not all customers participating in the real-time DR programs have the necessary telemetry, but we have not been able to determine how many customers do have it.

31 PJM's software integration required considerable investment in a bidding interface designed specifically to take the special characteristics of DR resources as user-input and transmit the data into the market software.

accommodating CSPs requires a measurement and verification methodology that tends to make the settlement process longer.

Table 4.3: Maximum Number of Days to Settlement for Demand Response in Energy Markets[32]

	Program		Load Reduction Date	Metered Data Submittal	Baseline and Performance Calculation	Payment Received
MISO	Economic Day-Ahead DDR	[1]	T	T + 6 Days	T + 7 Days	T + 17 Days
MISO	Economic Real-Time DDR	[2]	T	T + 6 Days	T + 7 Days	T + 17 Days
NEISO	Load Response Programs	[3]	T	Preliminary: T + 2.5 Days Updates: T + Max 51 Days	Preliminary: T + Max 38 Days Updates: T + Max 58 Days	T + Max 77 Days
NYISO	DADRP	[4]	T	T + Max 45 Days	T + 45 Max Days	Earliest: T + Max 52 Days Latest: T + Max 83 Days
NYISO	EDRP	[5]	T	T + Max 45 Days	T + 45 Max Days	Earliest: T + Max 52 Days Latest: T + Max 83 Days
NYISO	Special Case Resource Program	[6]	T	T + Max 60 Days	T + 60 Max Days	Earliest: T + Max 52 Days Latest: T + Max 83 Days
PJM	Economic Load Response Program	[7]	T	Preliminary: T + 60 Days Updates: T + 72 Days	Preliminary: T + 60 Days Updates: T + 72 Days	Earliest: T + Max 50 Days Latest: T + Max 111 Days
PJM	Emergency Load Response Program	[8]	T	Preliminary: T + 60 Days Updates: T + 72 Days	Preliminary: T + 60 Days Updates: T + 72 Days	Earliest: T + 50 Days Latest: T + Max 111 Days

Sources and Notes:

Resettlement days not included in Payment Received Date.

[1]: MISO Economic Day-Ahead DDR - Based on information from sections 2.6 and 3.0 in MISO BPM 005 - Market Settlements.

[2]: MISO Economic Real-Time DDR - Based on information from sections 2.6 and 3.0 in MISO BPM 005 - Market Settlements.

[3]: NEISO LRP - Based on information from sections 4.4, 4.5.4, and 4.8 of the ISO-NE Load Response Program Manual; Revision 11; July 31, 2007.

[4]: NYISO (DADRP) - Metered Data Submittal days assumed same as EDRP. Metered Data Submittal Resttlement Update days based on information from Section 6.4 of the NYISO Day-Ahead Demand Response Program Manual; July 2003. Baseline and Performance Calculation and Payment Received days are assumed to be the same as the respective parameters specified in the EDRP.

[5]: NYISO (EDRP) - Based on information from Section 6.2.2, Section 6.4.1, and Section 6.6 of the NYISO Emergency Demand Response Program Manual; Revision 5.0; April 5, 2004.

[6]: NYISO (Special Case Resource Program) - Metered Data Submittal and Payment Received days are assumed to be the same as the respective parameters specified in the EDRP. Baseline and Performance Calculation days based on data from Section 4.4.7 of the NYISO Installed Capacity Manual; Version 6.3; July 2007.

[7]: PJM (Economic LRP) - Based on information from Page 11 of PJM Load Response Programs – Business Rules; June 1, 2006; Pages 103-104 of PJM Manual 11: Scheduling Operations; Revision 32; September 28, 2007; Slide 177 of PJM Demand Side Response; April 19, 2007; Page 11 of PJM Manual 29: Billing; Revision 17; June 1, 2007.

[8]: PJM (Emergency LRP) - Based on information from Page 11 of PJM Load Response Programs – Business Rules; June 1, 2006; Pages 103-104 of PJM Manual 11: Scheduling Operations; Revision 32; September 28, 2007; Slide 177 of PJM Demand Side Response; April 19, 2007; Page 11 of PJM Manual 29: Billing; Revision 17; June 1, 2007.

32 Payment date is a function of actions taken by DR providers (e.g. submitting load data to aggregators), as well as the RTO. Table 4.3 shows the range of days after the load reduction within which DR normally receives the payment from the RTO.

Measurement & Verification (M&V)

M&V refers to the set of tools and methods used to measure and verify load reductions in order to estimate the impact of demand response. M&V concerns the RTO only in the case of load reductions that are bid as a positive resource, as opposed to a reduction from a demand bid. Measurement and verification protocols may affect the willingness of demand response to participate in energy markets and may create opportunities for gaming and/or for load reductions that occur for reasons other than responding to conditions of scarce electricity. This section will discuss (1) simplicity vs. accuracy of M&V; (2) baseline definition and gaming; and (3) equipment requirements.

It is important to balance the accuracy of performance measurement with the simplicity of calculations. Determination of compliance with a dispatch instruction must be transparent and relatively simple. Complex or unclear rules may discourage participation by demand response. For example, ERCOT's Balancing Up Load (BUL) program, in which demand response can bid to provide balancing energy, failed to enroll any load since its inception in 2003. The Public Utilities Commission of Texas (PUCT) attributed the complicated load impact estimation methodology as one factor behind this failure.[33]

Another issue is whether M&V is performed on an individual resource or a CSP/LSE portfolio basis. Demand response incentives to participate are weaker if performance is measured on a portfolio basis, because individual efforts to reduce load are less likely to be rewarded.

A combination of economic conditions and RTO business rules can give rise to gaming opportunities. For example, in ISO New England's Day-Ahead Load Response Program (DALRP), days when a demand response offer clears in the day-ahead energy market are excluded from the calculation of the baseline for the demand response customer.[34] In addition, demand response is subject to a $50/MWh minimum offer requirement (originally intended to restrict demand response participation to peak hours). The recent rise in fuel prices resulted in market conditions when market prices exceed this threshold most of the time, hence increasing the likelihood that demand response bids above the minimum threshold clear as well. A recent

33 PUCT DR Workshop presentation, December 8, 2006

34 ISO-NE ISO New England Load Response Program Manual, Section 4.2.2

ISO-NE analysis showed that, by making offers every day DALRP participants are able to engage in strategic behavior that overstates their respective customer baselines and receive compensation for load reductions that do not in fact occur. For instance, a baseline based on summer days may create an unrealistically high baseline level for the winter period. The solution to this problem is to include only recent days (e.g., at most the 15 most recent days) in the baseline calculations ("revolving baseline"). Baseline definition is one of the most difficult and contentious market design issues surrounding demand response.

Applying the same metering standards to demand response as to generators may be prohibitive for demand response. For example, the 1-minute interval metering requirement in PJM's ancillary services market can exclude most loads, since most advanced meters are hourly or quarter-hourly. Statistical measures could be used to measure the performance of demand response that is under direct load control by the ISO, utility, or CSP.

Some wholesale markets (e.g. ISO-NE and NYISO) have addressed these barriers created by metering requirements by providing grants and rebates to demand response that wants to participate in a program.

Penalties that Act as a Barrier to Demand Response

In its June 22, 2007 Advance Notice of Proposed Rulemaking, FERC requested comments on the issue of eliminating uplift charges (resulting from make-whole payments to suppliers with fixed costs that are not covered by market revenues) to demand response that deviate from their day-ahead schedule in real-time due to curtailment during a system emergency. This methodology can disproportionately penalize demand response because load reductions are more difficult to predict day-ahead than a generator's scheduled output. FERC is concerned about the implications of such penalties. FERC also requested comments on eliminating charges related to deviations between day-ahead schedules and real-time consumption/curtailment for demand response, realizing that these charges cover real costs.

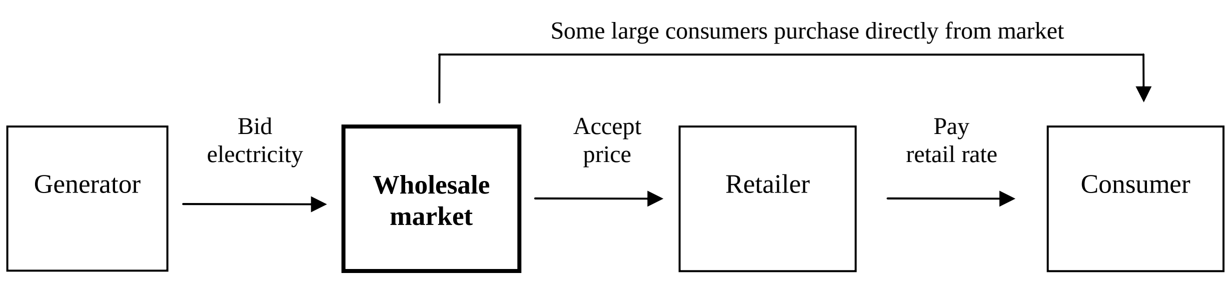
5. Impacts of Demand-Side Bidding

Existing studies of demand-side bidding impacts are largely high-level theoretical analyses based on experiments and simulations. The literature includes little empirical analysis of the historical market effects of full-scale program implementation. However, these studies can still serve as a valuable benchmark against which to compare the arguments and findings presented earlier in this report. Specifically, the existing literature on demand-side bidding can be used to gain insight into the impacts in the following general areas, as they affect generators, retailers, and consumers.

- Load impacts
- Avoided capacity costs
- Avoided fuel costs
- Market power and price mitigation

These impacts are all interrelated. In a market without demand-side bidding, generators have the potential to exercise market power under certain conditions, because the ability for retailers and end-use consumers to respond to changes in the wholesale market price is limited. This general relationship between the various market participants in the absence of demand-side bidding is illustrated in Figure 5.1.[35]

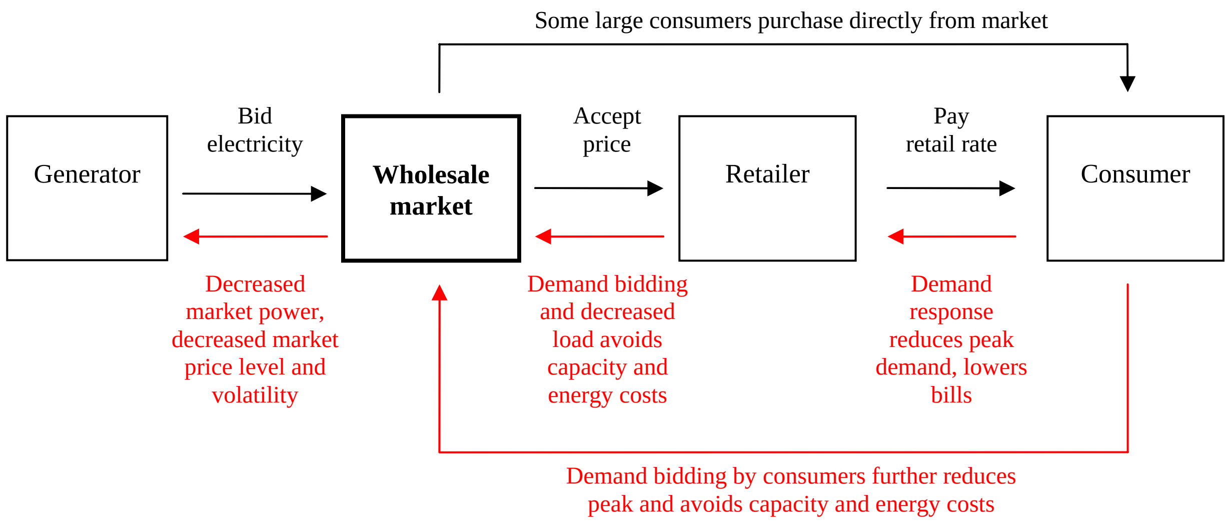
Figure 5.1: Relationship between Market Participants in Absence of Demand-Side Bidding



[35] For simplification purposes, this illustration of the electricity supply chain ignores the role of third party aggregators and retail competition.

The integration of demand-side bidding into the wholesale market changes the dynamics throughout the electricity supply chain. These impacts generally serve to create a market that is more favorable to the retailers and consumers than a market without demand-side bidding. The impacts of demand-side bidding on the market participants are illustrated in red in Figure 5.2.

Figure 5.2: Relationship of Market Participants with Demand-Side Bidding



In the remainder of this section, the best available studies and research available on demand-side bidding impacts are used to describe in detail the relationships illustrated above and the specific effects of implementing demand-side bidding in the wholesale market.

<u>Impacts on Consumption</u>

In the previous sections of this report, it has been suggested that demand-side bidding can lead to decreased consumption in response to price increases. This happens at both the retailer and the consumer level, although the extent to which a retailer's consumption is affected is driven partly by the demand curve of the retailer's customers.[36] The consumer's demand curve is made apparent to the retailer through the customer's own consumption patterns, which are determined by the customer's price elasticity. Consumers can further exhibit their price-responsiveness to

[36] It is also a function of the price of electricity available to the retailer outside of the wholesale market.

retailers through demand response programs such as dynamic pricing, direct load control, or other forms of load management.

At the consumer level, a study on the Norwegian electricity market has produced some qualitative findings regarding the impacts of demand-side bidding on consumption.[37] The study finds that, while consumers who purchase directly from the spot market are able to adjust their consumption in response to changes in the spot price, customers purchasing electricity under long-term fixed contracts cannot participate and thus do not have incentive to adjust demand. However, as these customers are allowed to participate in the market through demand-side bids, they respond to the spot price by selling lower-priced contracted electricity for a profit and reducing consumption (or substituting with electricity from an alternate source). Generally, large commercial and industrial customers have the most flexibility in terms of adapting their demand to changes in the spot price. These customers consume most of their electricity during daytime hours on weekdays, and as a result the demand for electricity is the most elastic during these times. This is supported by interviews with employees of the Norwegian market operator (Nord Pool), who have found that demand is most elastic during periods of higher demand.

There is significant empirical evidence regarding the price elasticities of electricity consumers across sectors in various regions. This information is not specific to the impacts of demand-side bidding on consumer consumption, but can provide useful insights to general consumer responsiveness to the price of electricity and, indirectly, how access to demand-side bidding might enable this price responsiveness. A recent RAND study found that the short-run price elasticities of residential, commercial, and industrial customers could range from -0.05 to -0.32, depending on the region in which they were located.[38] In other words, this suggests that a 100 percent increase in price could result in a decrease in consumption ranging from five percent to 32 percent. These estimates are generally supported by short-run elasticity estimates summarized in an upcoming EPRI paper.[39] Figure 5.3 below summarizes these findings.[40]

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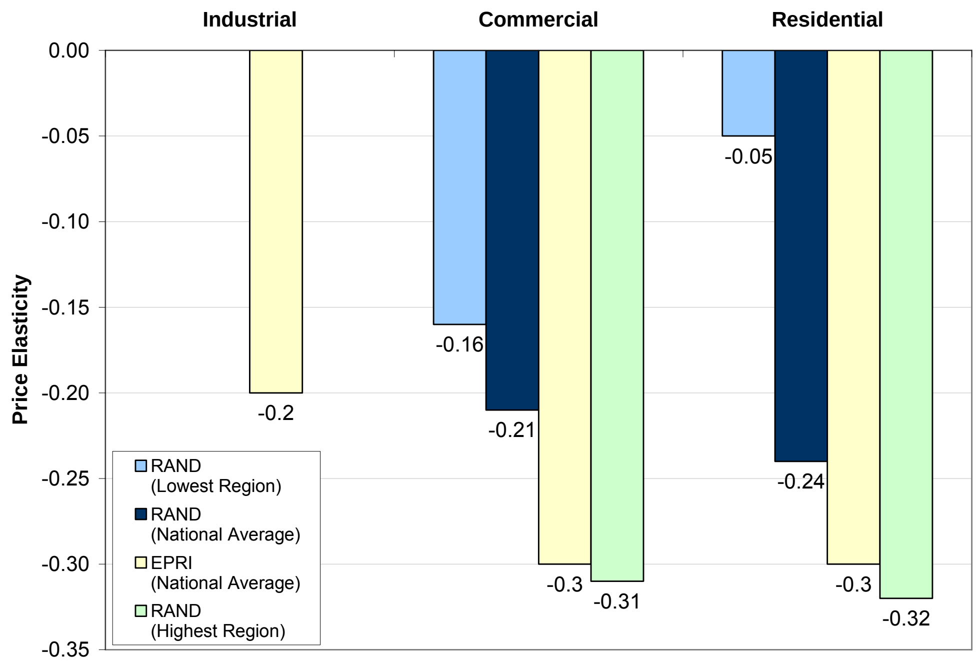
37 Tor Arnt Johansen, Shashi Kant Verma, and Catherine Wolfram, "Zonal Pricing and Demand-Side Bidding in the Norwegian Electricity Market," September 14, 1999.

38 Mark Bernstein and James Griffin, "Regional Differences in the Price-Elasticity of Demand for Energy," RAND Corporation, 2005.

39 Electric Power Research Institute, "Price Elasticity of Demand for Electricity: A Primer and Synthesis," January 2008, 1016264.

Customer price responsiveness has also been measured and found to be significant in several recent dynamic pricing pilots.[41]

Figure 5.3: Summary of Price Elasticities by Sector



It is important to recognize that, at the consumer level, these elasticities do not necessarily translate into load reductions that would be bid into the market. This is because of the disconnect that exists between non-time varying retail electricity rates and wholesale spot electricity prices. However, the introduction of demand-side bidding into wholesale markets would likely encourage retailers to promote demand response programs, which would in turn provide consumers with a means for acting on these price elasticities. Additionally, some larger commercial and industrial consumers purchase directly from the spot market. Demand-side bidding would provide these customers with further means for responding to changes in the price of electricity.

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40 For additional information, a summary of recent studies on consumer price elasticities can be found on the EIA website at http://www.eia.doe.gov/oiaf/analysispaper/elasticity/table2.html.

41 See, for example, Ahmad Faruqui and Sanem Sergici, "The Power of Experimentation," A Discussion Paper, *The Brattle Group*, May 2008. Can be downloaded from http://papers.ssrn.com/sol3/papers.cfm?abstract_id=1134132.

Avoided Capacity and Energy Costs

To the extent that demand-side bidding enables price responsiveness, it is likely to produce reductions in consumption during times of system peak demand when prices are much higher than average, as described above. Reductions in system peak demand reduce the need to install both peaking generation capacity as well as transmission and distribution capacity. This can amount to significant financial savings from a system perspective. As discussed above, these savings were recently estimated in a study to quantify the financial benefits of a five percent decrease in peak demand in the United States.[42] This study found that, at a national level, $2.4 billion dollars per year in generation capacity costs could be avoided. An additional $0.3 billion per year could be saved in T&D costs. Avoided generation capacity costs often represent the large majority of supply-side savings in such analyses. Similar research has also been conducted at the state level. A *Brattle* study for the California Energy Commission found that California could save $200 million per year in avoided generation capacity costs and an additional $20 million annually in T&D capacity costs.[43]

Both studies also found that there would be financial value associated with avoided energy costs. The decreased consumption during peak periods would require that retailers purchase less electricity during these times. However, a study on the competitiveness of demand-side bidding found that its implementation would not necessarily lead to energy savings.[44] The study finds that while a reduction in consumption might occur during high-priced periods, there would be the opposite effect during low-priced periods and periods immediately before and after the load reduction. In other words, demand-side bidding would result in the shifting of load from peak to off-peak and shoulder periods, rather than overall energy conservation.

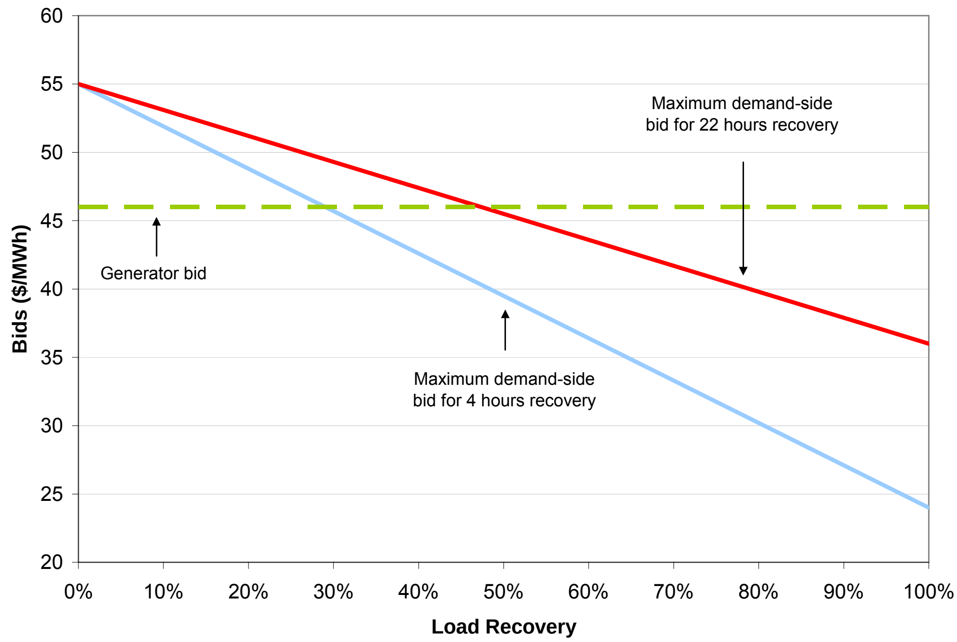
42 Ahmad Faruqui, Ryan Hledik, Johannes Pfeifenberger, Sam Newell, "The Power of Five Percent," *The Electricity Journal*, October 2007.

43 Ahmad Faruqui and Ryan Hledik, "The Next Generation of Load Management Standards," prepared for the California Energy Commission, May 2007.

44 Goran Strbac and Daniel Kirschen, "Assessing the Competitiveness of Demand-Side Bidding," *IEEE Transactions on Power Systems*, February 1999.

To illustrate the effect of load shifting on the competitiveness of demand-side bidding with supply-side resources in a wholesale electricity market, the study simulated the incremental cost of equivalent demand-side and supply-side bids. Figure 4.4 below illustrates this simulation.[45]

Figure 4.4: Incremental Costs of Equivalent Generation vs. Demand-Side Bids



In Figure 4.4, the x-axis represents the amount of demand-side bidding-induced load reduction that would be recovered during other hours of the day. In other words, if demand-side bidding produced a 100 MWh reduction on a given day during the peak period, 20 percent load recovery would mean that an additional 20 MWh of consumption would occur outside of the peak hours. The y-axis represents the price of the demand-side bid that would allow it to be competitive with a peak-time supply-side bid from a system-cost perspective. Additionally, two different types of demand-side bids are shown. One bid would recover the load reduction over a four hour period immediately before and after the period of reduction, while the other would spread this load recovery over 22 hours of the day. The figure shows that, under the specific costs and market

[45] Reproduced from "Assessing the Competitiveness of Demand-Side Bidding."

conditions assumed in the study, the effect of load recovery serves to significantly decrease the price at which a demand-side bid is competitive. This suggests that avoided energy costs are potentially negligible relative to the financial benefits of avoided capacity costs.

Ultimately, the effect of avoided supply-side costs through demand-side bidding is to decrease the cost of electricity to consumers, both through lower retail electricity rates and through direct purchases to the wholesale market. A review of the literature does not produce a direct translation of avoided costs to retail rate reductions, as this could differ dramatically by region depending on the political climate and process through which rates are approved. Thus, the sharing of the benefits of cost avoidance between retailers and consumers is highly variable.

Market Power and Price Mitigation

In addition to the avoidance of capacity and energy costs, demand-side bidding can also lead to a reduction in the wholesale price of electricity. Studies have shown that this price reduction is driven by both a reduction in the generators' market power and through a more economically efficient use of the existing generation resources.

A recent experimental study tested the potential effects of demand-side bidding both in markets without concentrated market power and in markets with concentrated market power. [46] In the scenario without concentrated market power, the simulation suggested that the actual market price would still be above the strictly competitive market price in the absence of demand-side bidding. This was due to collusive behavior on the part of the suppliers participating in the experiment. However, the study found that the introduction of demand-side bidding into this market would effectively reduce the surplus that the generators were achieving through this behavior by half during the shoulder time periods, decreasing the market price by between 10 and 15 percent. The same impacts applied to a smaller extent in the peak and off peak periods.

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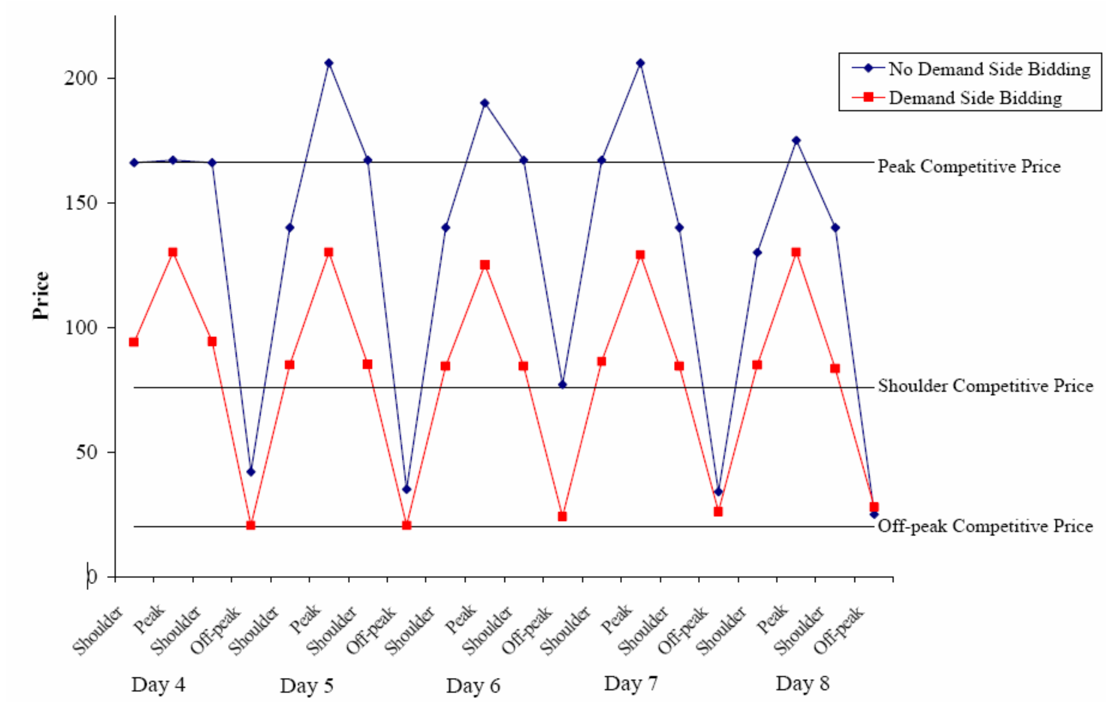
[46] Stephen J. Rassenti, Vernon L. Smith, and Bart J. Wilson, "Demand-Side Bidding will Control Market Power and Decrease the Level and Volatility of Prices," Economic Science Laboratory, University of Arizona, February 2001. See also "Controlling Market Power and Price Spikes in Electricity Networks: Demand-Side Bidding," by the same authors, *Proceedings of the National Academy of Sciences*, December 2002.

In the scenario with concentrated market power, the effect of demand-side bidding was to virtually neutralize the effects of market power. Before demand-side bidding, the simulation estimated that market power would produce shoulder period market prices approximately 50 percent above the price level in the absence of market power. Similar price differences were seen in the off peak periods on a percentage basis. There was no significant increase in peak prices. With demand-side biding, prices were consistently brought down to within the range of competitive prices across all periods. It was also found that the volatility in the price of electricity drastically reduced after the introduction of demand-side bidding. Figure 5.5 shows the comparison of simulated prices before and after demand-side bidding. [47]

Figure 5.5: Impact of Demand-Side Bidding in a Market with Concentrated Market Power



In contrast, the study of the Norwegian market found that demand-side bidding did not totally mitigate market power. In the off peak hours of one particular region, the study found that electricity prices were 15 percent higher than the expected competitive level, despite the

[47] Adapted from “Demand-Side Bidding will Control Market Power and Decrease the Level and Volatility of Prices.”

integration of demand-side bidding in the market. This difference in prices was attributed to the less elastic demand in that market during off peak hours.

The effect of a peak load reduction on market prices has also recently been quantified in a study of the benefits of demand response in the PJM Interconnection in the United States.[48] The study used a simulation-based approach to quantify the market impacts of a three percent peak load reduction in select PJM zones. The study found that a three percent reduction in load during roughly the top 100 peak hours in these zones could produce a reduction in the average market energy price of between five and eight percent. The resulting system-wide benefit of this drop in the cost of energy would have amounted to between $150 million and $300 million in 2005 in PJM. It is important to note that these impacts, unlike the reduction from mitigated market power, are short term impacts. After demand-side bidding, supply and demand would equilibrate and this price effect would be phased out in the long term.

48 Sam Newell and Frank Felder, "Quantifying Demand Response Benefits in PJM," Study Report Prepared for PJM Interconnection, LLC, and the Mid-Atlantic Distributed Resources Initiative (MADRI), January 29, 2007.

6. Insights for NEM and Needed Change Processes

A number of insights can be gleaned from international experience with demand-side bidding that may apply to NEM. The degree of their applicability to NEM and the change processes that would be necessary in order to obtain similar results varies. A fundamental insight from international experience is that demand-side bidding provides benefits through:

- Better provision of price signals
- The reduction of market power
- The reduction of market prices, and
- The avoidance of new capacity builds

These gains in efficiency are important to keep in mind as overall benefits. NEM appears to be in a good position to benefit overall from demand-side participation in its markets. There are a relatively large number of contestable end-user customers which would allow for LSEs to compete for their business by implementing demand response based offerings. Moreover, it appears that there is a reasonable amount of demand elasticity in the electric power sector in Australia so that demand response could be elicited and therefore turned into demand-side bids.[49] With the addition of a possible rollout of smart metering in Australia the potential for demand-side bidding in NEM is substantial.[50]

<u>Lessons for NEM</u>

Given NEM's current situation as a one-settlement market, lessons from day-ahead markets may not have much relevance for NEM unless there are plans to move to a two settlement system. Some of benefits of a two-settlement system have been discussed above. With respect to demand-side bidding, a two settlement system would facilitate demand response that requires day ahead notification to be integrated into the market. In this regard, surveys of the demand response potential in NEM should be done so as to distinguish between the potential from demand response that requires day-ahead notification from that which can be done the day of, or

[49] *Load Forecasting White Paper*, Power Systems Planning and Development, NEMMCO, 2005 cites an elasticity of -.38 for industrial customers.

[50] Council of Australian Governments Meeting Communique, February 10, 2006.

in real time. While clearly not necessary for demand-side bidding in wholesale markets, two-settlement systems facilitate demand-side participation.

Likewise, experiences with ancillary services bidding in the United States are not likely to be directly applicable to NEM because of the difference in definitions of ancillary services in NEMS versus markets in North America. In general, because of the structure of the transmission network in NEM, ancillary services require much faster reaction time. The ability to attract load to participate may therefore differ than in the United States.

Though there is no one particular jurisdiction that directly provides lessons for NEM on the introduction of demand-side bidding into its markets, from the discussion in the previous chapters, there are a number of lessons that can be learned from international experience that are applicable to NEM:

- The availability of technology such as interval meters makes a large difference in the amount of response that can be garnered.[51] In this respect, the smart metering mandate is important.
- Along with smart meters, enabling technology is important to getting the highest degree of demand response, and therefore, demand-side bidding. Enabling technology that allows for automatic shut down of air conditioning equipment when the consumer is not at home, for instance, allows for day-of and real-time demand response programs. This is particularly important in the absence of a day-ahead market.
- To the degree that customers are not contestable and price signals cannot be passed to consumers, demand response will likely be less than if competitors can offer programs that reflect market prices.
- Subsidies and uplift payments to encourage demand response may result in greater demand-side bidding, but come with problems of measurement and verification along with equity issues of who pays for the uplift payments. Subsidies and uplift payments may not be necessary in conditions under which price signals can be passed to consumers and consumers have the ability to react to them.

[51] See, for instance, Ahmad Faruqui and Lisa Wood, "Quantifying the Benefits of Dynamic Pricing in the Mass Market", *The Brattle Group, Inc. and Edison Electric Institute*, January 2008.

- As was seen in Chapter 4, demand-side bidding has been most successfully integrated into markets where:
    - Relatively small loads can easily participate
    - Demand can set the market-clearing price
    - Metering for demand is not required to have the same level of technology as that for generation
    - Penalties for deviations do not unfairly penalize demand
    - Settlement timing does not disadvantage demand-side resources versus generation

Change Processes

There are a number of change processes that would likely be needed in order to incorporate demand-side bidding into NEM. Change processes will need to address business rules, software, and communications. These change processes will need to address new issues as well change existing infrastructure and rules to incorporate demand-side bidding. For instance, rules detailing how demand-side bids are formulated will be needed. In addition, there may be existing areas in which changes will need to be made to accommodate changes needed for demand-side bidding. An example of this is market participation requirements. Because new rules will be needed to be created for demand-side participants, parallel changes may be requested by generators in the interest of parity with demand-side participants. In other words, it will not just be the new demand related features of the market that will be added, but areas on which demand related issues touch may have to be reexamined for generation as well.

Change processes will need to address at least the following areas:

- Market participation requirements
- Metering requirements
- Scheduling
- Market clearing process
- Treatment of deviations
- Settlements process