Monitoring Analytics

Barriers to Demand Side Response in PJM

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The Independent Market Monitor for PJM

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Introduction

The Federal Energy Regulatory Commission (FERC) issued a Final Rule in Order 719 on October 17, 2008 which required that each RTO and ISO assess and report on any "remaining barriers to comparable treatment of demand response resources that are within the Commission's jurisdiction, and to submit its findings and any proposed solutions along with a timeline for implementation within six months of the Final Rule's publication in the Federal Register."[1] The Commission further adopted "the requirement that each RTO's and ISO's Independent Market Monitor must submit a report describing its views on these issues to the Commission." This is the report of the Independent Market Monitor for PJM pursuant to the Commission's direction. In a subsequent order, the Commission directed that the PJM Market Monitoring Unit file its report by July 1, 2009.[2]

Barriers to Demand Response

In economic theory, a perfectly competitive market requires that a number of conditions be met, including complete knowledge by customers and producers of relevant economic and technological data and free entry and exit. While these conditions are not often completely met in real markets, they provide a guide to the requirements for competitive markets.

Complete knowledge by customers and producers would mean, at a minimum, that customers and producers know the actual price of the product, when they purchase it. Free entry means that firms can enter a market when there is an expectation of economic profits. When barriers to entry exist, less entry will occur and prices will be higher than under conditions of free entry, all else equal. Free exit means that capital is not invested in assets with unique applicability to the single market and can be withdrawn from an industry at no cost.

Barriers to entry can be grouped into two categories: structural and strategic.[3] Structural barriers to entry can be the result of the technological features of a market, including capital requirements and economies of scale, or the result of the actual operation of the

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1 125 FERC ¶ 61,071 (2008).

2 Notice of Extension of Time, Docket No. ER09-1063-000, -001 (May 20, 2009).

3 William G. Shepherd, *The Economics of Industrial Organization*, (Prentice Hall, 1997). Jean Tirole, *The Theory of Industrial Organization*, (Cambridge: The MIT Press, 1988), 305-307. Richard J. Gilbert, "Mobility Barriers and the Value of Incumbency," *Handbook of Industrial Organization*, Volume 1, (Elsevier, 1989), 475-535.

market, including access to information, and can include governmental or regulatory actions that limit entry. Strategic barriers to entry result from the actions of incumbent firms and can include limit pricing, creation of excess capacity, taking efforts to increase the costs of competitors and limiting access to information.

The fact that regulation continues to play a very significant role in wholesale and retail power markets means that an analysis of the barriers to entry for full demand side participation must recognize existing and potential regulatory actions. The relevant regulatory authorities include the Commission and the state public utility commissions. The RTOs/ISOs play a quasi regulatory role. PJM's rules, which are approved by the Commission when included in the tariff but generally not when in manuals, define the markets in detail.

This report addresses barriers to the participation of the demand side in PJM wholesale markets. Barriers to entry are usually defined relative to potential supply. The issue of access to markets by the demand side is somewhat unusual given the voluntary nature of most markets. However, power is a necessity, demand for power is correspondingly price inelastic and the price of power is subject to detailed regulatory control at both the wholesale and the retail level.

One of the central preconditions for complete markets does not yet exist for power markets. Customers, as a general matter, do not know and do not pay the market price of wholesale power. The market price for wholesale power is the LMP in organized markets and more specifically the price that reflects actual supply and demand conditions at the specific location and time that power is purchased. This is the fundamental barrier to the development of the demand side of wholesale power markets. This barrier has led to the creation of demand side "programs" designed to work around the absence of price information rather than to the direct provision of price information. Potential and current providers of services under these programs face barriers to entry.

The Issues

The demand side of wholesale power markets is underdeveloped. Wholesale power markets will be more efficient when the demand side of the electricity market becomes fully functional. A precondition for a functional demand side of a market is that there be an organized market. Organized wholesale power markets like those in the current RTOs/ISOs are required in order to develop market price signals before they can be passed directly to the customer.

A fully functional demand side of the electricity market means that end use customers or their designated intermediaries will have the ability to see real time energy price signals in real time, will have the ability to react to real time prices in real time, and will have the ability to receive the direct benefits or costs of changes in real time energy use.

In addition, customers or their designated intermediaries will have the ability to see current capacity prices, will have the ability to react to capacity prices and will have the ability to receive the direct benefits or costs of changes in the demand for capacity. When these conditions are met, customers can and will make decisions about how much power to use, including investments in demand side management technologies, based on their own evaluations of the tradeoffs among the price of power, the value of particular activities and the costs of those technologies.

Today, most end use customers do not face the market price of energy, that is the locational marginal price of energy (LMP), or the market price of capacity, the locational capacity market clearing price. This results in a market failure because when customers do not know the market price and do not pay the market price, the behavior of those customers is inconsistent with the market value of electricity. The transition to a more functional demand side requires that the default energy price for all customers be the day ahead or real time hourly locational marginal price (LMP) and the locational clearing price of capacity. When the default price for customers is the hourly locational price of energy and the locational price of capacity, customers will have the ability to enter into contracts with intermediaries for fixed price contracts under which the intermediaries take the risks of volatile prices. The intermediaries would then have the incentive to respond to price signals and to incent the customers to respond to price signals.

The most basic barrier to a fully functional demand side of the market is that not all customers are exposed to the actual incremental cost of energy and capacity.

Demand side programs are generally designed to work around this market failure rather than to address it directly. PJM's Economic Load Response Program is designed to work around this market failure by attempting to replicate the price signal to customers that would exist if customers were exposed to the real time wholesale price of energy and by providing settlement services to facilitate the participation of third party Curtailment Service Providers (CSPs) in the market. The design of PJM's Load Management (LM) Program in the RPM market also attempts to replicate the price signal to customers that would exist if customers were exposed to the locational market price of capacity.

The term "demand side resource" is the willingness of customers to respond to prices by reducing usage when the price of power, including energy and capacity, exceeds the value to the customer. This willingness can take the form of an agreement to reduce usage when the price (energy or capacity) is above a certain level or an agreement to reduce usage when the customer wants to respond to price.

PJM's demand side programs are designed to address barriers to the full development of a demand side of the wholesale power markets. Ultimately, those barriers must be addressed directly. The integration of demand resources into PJM markets through PJM's demand side programs should be understood as one relatively small part of the transition to a fully functional demand side for PJM markets. The complete transition to a fully functional demand side will require explicit agreement and coordination among the Commission, state public utility commissions and RTOs/ISOs.

When customers directly face market prices and have the ability to respond to such prices and to directly receive the benefits of their choices, there will be only a limited need for demand side programs. There will be a need for clear market rules governing the participation of demand side resources in energy, capacity and ancillary services markets, but there will be a sharply reduced need for elaborate measurement and verification programs. Customers will choose to consume or not consume energy based on the price. The metered usage and the bill will reflect that choice, and the assessment of that choice will belong to the customer. In the capacity market, a fully functional demand side will require that customers who wish to avoid paying for capacity provide an enforceable commitment to be interruptible by the RTO above a defined level of capacity, based on a clear and transparent market signal.

Price Signals

A fully functional demand side of the power market means that customers or their designated intermediaries will have the ability to see real time price signals in real time, will have the ability to react to real time prices in real time, and will have the ability to receive the direct benefits or costs of changes in real time energy use.

The energy market price signals must be transparent and must occur in real time so that customers can react. Customers must receive a benefit or pay a cost as a result of their response, which is determined by real time energy prices. If customers continue to consume at times of high prices, they would pay those prices and if customers reduce consumption at times of high prices, they would benefit by not paying those prices. Receiving the benefit or paying the cost also depends on the availability of adequate metering.

The price signals in the capacity market in PJM are established in a forward market. In the capacity market, customers have the option to choose to purchase capacity at a specified level and at a specified threshold price. If customers choose to purchase only such a specified level of capacity, they must also be willing to have any energy purchases above that level interrupted when the system needs the capacity to serve those who paid for it.

Given the preconditions for a fully functional demand side of the market, the absence of a transparent, real time energy price signal to the end use customer and the absence of a transparent, locational capacity price signal to the end use customer are significant structural barriers to entry.

The technology for communicating prices to the end use customer must also be specified.

Control Technologies

A fully functional demand side of the electricity market means that customers or their designated intermediaries will have the ability to see real time price signals in real time, will have the ability to react to real time prices in real time, and will have the ability to receive the direct benefits or costs of changes in real time energy use, which is determined by real time energy prices.

The reaction to price signals in real time can be based on manual interventions, on preprogrammed interventions or on automated interventions in energy use. If customers have the ability to engage in any of these actions, the ability to react to price signals is present. An example of a manual intervention would be turning off electricity using applications when prices rise, using a switch or a signal. An example of a preprogrammed intervention would be shifting the operation of electricity using applications from periods of expected high prices to periods of expected low prices. An example of an automated intervention would be building energy management systems that are programmed to modify energy usage in response to actual prices. Any of these interventions could be made by individual customers or by CSPs acting for multiple customers.

This report does not evaluate the availability of cost effective methods for automated interventions in energy use. The absence of cost effective methods for automated reactions to price signals could be considered a barrier to full demand side participation.

Metering Infrastructure

In order to receive the benefit or pay the costs associated with responding to real time prices, customers must have the appropriate meters, referred to as advanced meters, as part of an Advanced Metering Infrastructure (AMI). Advanced meters are capable of measuring, recording and communicating usage at the hourly level or more frequently. Advanced meters can provide data to any service provider, using frequent data transmittal of measurements over a communication network to a central collection point that is easily accessed by the customer. [4]

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[4] The Commission defines Advanced Metering Infrastructure as "a metering system that records customer consumption (and possibly other parameters) hourly or more frequently and provides for daily or frequent transmittal of measurements over a communication network to a central collection point." Federal Energy Regulatory Committee (FERC), "2008

Most end use customers in the PJM footprint do not have advanced metering technology. In the 2008 Assessment of Demand Response and Advanced Metering, the Commission reports that while AMI has increased significantly since 2006, penetration in the Reliability*First* Corporation (RFC) reliability region is approximately 5.1 percent and penetration in the state of Virginia is approximately 0.2 percent.[5]

The absence of adequate meter technology, associated data communication infrastructure and clear standards constitutes a barrier both to the development of the demand side of wholesale power markets and to the entry of CSPs who wish to participate in PJM's demand side programs. In addition, when utilities have AMI installed, there must be clear standards governing the timely access of customers and their CSPs to the meter data.

Meter installations, meter readings and metered data are request services provided by local utilities. There are virtually no consistent standards applied across state and local utilities and municipalities that define the terms of timely access to meter data and timely installation of metering equipment.

PJM addressed meter standards issues in the Demand Side Response (DSR) settlement process with the creation of a Metering Issue Subcommittee (MIS). This committee made several recommendations to improve protocols dealing with data access, Meter Data Service Provider (MDSP) certification, communications protocols, database capabilities and settlements. Further, the PJM Meter Task Force (MTF) developed revisions to the PJM Scheduling Manual that clarify meter data and equipment standards, as well as the role of the CSP in meeting these standards.[6]

Progress made by both the MIS and MTF will improve efficiencies in PJM markets by eliminating the administrative burden of reconciling settlement submittals based on customer meters with "billing quality" meter data. However, these actions do not address the barrier that the current metering infrastructure is inadequate to facilitate widespread demand response. The burden of acquiring adequate meter data is on the customer and/or on the CSP. In addition, an end user or CSP may be hesitant to invest in these AMI technologies, if it is possible that the local utility will eventually upgrade.

Assessment of Demand Response and Advanced Metering," (December, 2008) http://www.ferc.gov/legal/staff-reports/12-08-demand-response.pdf

5 Federal Energy Regulatory Committee (FERC), "2008 Assessment of Demand Response and Advanced Metering," (December, 2008) http://www.ferc.gov/legal/staff-reports/12-08-demand-response.pdf

6 PJM Manual 11: Scheduling Operations, Section 10, pages 118-119, effective October 1, 2009

The cost effectiveness of AMI technologies may depend on the scale of implementation. While it is clear that widespread implementation of AMI will likely require coordination of initiatives of federal, state retail authorities as well as RTOs such as PJM, there is not yet a coordination of federal, state and local initiatives to integrate AMI on a wide scale and to apply consistent metering standards for all end use electricity customers.

Advanced Metering

Metering equipment that provides integrated hourly kWh values on an electric distribution company (EDC) account basis is a precondition for participation in PJM's demand side Program.[7] In many cases, the utility provided metering equipment is not adequate to facilitate the sale of demand resources from retail customers in PJM Markets. The customer and/or Curtailment Service Provider (CSP) bears the costs of installation including the necessary hardware and a site visit from a utility field service technician.

Most end use customers in the PJM footprint have meters that record gross kilowatt usage, such as an electromechanical meter or an Automatic Meter Reading (AMR) system.[8] These meters do not timestamp usage and, as a result, such meters cannot be used in DR applications. These meters provide total consumption data at two points in time. The difference between the data points is used for billing purposes. The time interval is determined by the times at which the meter is read. In order to be usable for DR applications, when such meters are in place, the customer and/or CSP must purchase a device, called a meter module, to record and store meter data at regular intervals. The installation of a meter module on a utility owned meter requires a site visit from a utility field service technician.

An electromechanical meter or an AMR system with a module that can timestamp and temporarily store hourly integrated meter data is the minimal metering requirement needed for demand resources to participate in PJM Markets. However, without

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[7] Section 1.5A.4 (Economic Load Response) and Section 10 Sheet No. 417 (Emergency Load Response) of the tariff.. While hourly interval metering equipment is a requirement in the Emergency Load Response Programs, a pilot program effective June 1, 2009, allows CSPs to propose an alternative method of measuring load reduction subject to PJM approval (Sheet No. 421A). See PJM Manual 11: Scheduling Operations, Section 10, pages 118-119, for more information on metering requirements.

[8] In the *2008 Assessment of Demand Response and Advanced Metering*, the Commission found that 5.1 percent of customers in RFC and 0.2 percent in Virginia utilize advanced meters (page 11-12). The breakdown between AMR and electromagnetic metering is not known for this region, however, in 2007, the Commission estimated that approximately 85 million of the 145 million meters in North America were electromechanical in 2007 (see page 15).

enhanced communication technologies, the storage device will only provide meter data as frequently as it is physically obtained and downloaded, similar to a data storage disk. The customer or CSP will not see hourly integrated load data in real time, and will not see the impact of load reducing actions taken in real-time.

AMI is required for a customer or CSP to be able to measure/monitor reductions in load associated with deliberate actions in real time. Once hourly integrated data is collected and stored in a digital format, it must be transmitted to a central storage point which can be accessed by the end user customer in real time. This requires a meter module with data communication capabilities. There are several types of systems available to transmit this data, including broadband, Power Line Communication (PLC), fixed Radio Frequency (RF), or existing public networks, such as wireless internet or telephone lines.[9]

Some utilities have begun widespread implementation of more advanced AMR systems which enable hourly integrated data storage and retrieval. If the customer has real time access to this meter data, this constitutes an advanced metering system. No capital expenditure is required of the customer and CSP. However, the majority of retail customers in PJM do not have access to AMI and for them to implement AMI would require a significant capital expenditure.[10]

The purchase and installation of a meter module to collect hourly integrated meter data compliant with metering accuracy requirements satisfies the minimal metering requirements for participation in PJM demand side programs, and it requires the lowest capital cost. However, for a fully developed demand side, customers must be able to see hourly usage and hourly price data in real time. AMI equipped with comprehensive communication capabilities is the next step necessary to develop a price responsive demand side, as it allows customers to observe changes in usage in real time. The optimal AMI will allow for easy integration of real time price data as well. While there may be added efficiency for wide scale deployment with a central data storage and communication function, the end use customer must have seamless, real time access to the usage and price data.

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9 Federal Energy Regulatory Committee (FERC), "Assessment of Demand Response and Advanced Metering," (March, 2006) http://www.ferc.gov/legal/staff-reports/demand-response.pdf

10 Electric sub-metering equipment that meets ANSI C12 standards generally costs between $200 and $500. Units with more sophisticated communication technologies, for example web enabled pulse recorders, may cost more.

Measurement and Verification

There would be no measurement and verification issues if demand side response relied on real time price signals and adequate metering. Customers would pay for their hourly metered usage based on hourly prices and such payments would reflect the choices made by customers. It is only in the transition to a fully functional demand side that measurement and verification issues arise. Measurement and verification issues arise because under most demand side programs, payments are based on a counter factual estimate of the power that would have been used in the absence of the program. This is a purely hypothetical construct and it is not possible to know what usage would have been without the program. Attempting to estimate this value creates incentive issues and the need for a complex oversight function.

Given the structure of demand side programs, measurement and verification rules determine measured savings, revenues and profitability. Unclear and inadequate measurement and verification rules are an impediment to the further development of demand side programs. A lack of clarity in the measurement and verification rules and a lack of confidence that these rules result in an accurate measure of actual demand response leads to uncertainty for CSPs, to a reluctance of customers to participate and to objections from state public utility commissions.

Issues

In the PJM Economic Load Response Program, the goal is to pay participants based upon the reductions in MWh usage that can be attributed to demand side actions. Participants in the Economic Program measure their reductions by comparing metered load against an estimate of what metered load would have been absent the reduction.

Since the beginning of the program, there have been significant issues with this approach to measuring demand side response. In the *2008 State of the Market Report for PJM*, the Market Monitoring Unit (MMU) analyzed settlement activity to evaluate the effectiveness of the revised CBL in modeling customer load patterns.[11] The MMU concluded that the modifications to the CBL calculations and the new review process are significant improvements to the Economic Program, but the review process is not yet adequate to ensure that other customers are receiving the benefit of actual load reducing actions taken in response to price. In addition, the MMU made recommendations to improve measurement and verification standards.

[11] See the *2008 State of the Market Report*, Section 1 – Energy Market, Part 1, (pages 108-110)

Customer Baseline Load (CBL) for economic load response

PJM has made significant efforts in the area of measurement and verification. In the April 2009 filing regarding barriers to comparable treatment of demand response resources, PJM referred to the work of the CBL subcommittee in evaluating four CBL methodologies, according to empirical performance, simplicity, propensity to eliminate gaming/free ridership and costs of implementation and administration.[12] The methodology with the second highest empirical performance won the majority of member support. The Subcommittee proposed changes to both the Tariff and the Operating Agreement, which were endorsed by the PJM Members Committee (MC), filed by PJM in April of 2008[13] and approved effective June 13, 2008.[14]

In addition to CBL revisions, PJM began an activity review process for settlements in the Economic Program effective November 3, 2008.[15] The activity review process includes four daily settlement screens applied to all incoming settlements to identify and deny settlements showing low economic value or a low level of deliberation. The review process also includes a "normal operations" screen, which requires more in depth verification from highly active participants. The threshold for normal operations is the submittal of settlements for 70 percent (or 21 days) of available days in a rolling 30 weekday period.

The CBL revisions have significantly improved the CBL calculation as a basis for quantifying load reduction and the PJM Settlement Review Process has improved the measurement and verification of load reductions. Prior to these changes, CBLs were frequently based on load data from several weeks or months prior due to a long look back window and there were virtually no daily settlement screens in place. The CBL revisions and settlement review process provide for more recent data to be included in CBL calculations which has made them more accurate and less prone to bias.

However, the program is not yet at a point where market participants can be confident in the demand reductions that are paid and the CBL calculation is not yet sufficient to capture end use customer operations in all cases in a manner that prevents demand

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12 *PJM Interconnection, L.L.C.,* Docket No. ER09-1063-000

13 *PJM Interconnection, LLC.*, Tariff Amendments, Docket No. ER08-824-000 (April 14, 2008)

14 123 FERC ¶ 61,257 (2008).

15 PJM Activity Review Process was presented to DSR Steering Committee on October 31, 2008: http://www.pjm.com/~/media/committees-groups/committees/drsc/20081031-item-04-dsr-activity-review-proc.ashx

response payments for load levels that would have occurred regardless of PJM's market opportunities. PJM does not evaluate daily settlements to assess responsiveness to price or accuracy of the CBL. Insufficient methods for measurement and verification of load reductions remain an impediment to further development of the demand side program approach to the creation of a fully functional demand side of the market.

Competition with Utilities or Load Serving Entities

CSPs providing demand side services to end use customers are in direct competition with the local utility because the local utility earns revenues from the sale of each KWh. The result is that the utility does not have an incentive to cooperate with such CSPs. CSPs have to coordinate with utilities in order to participate in PJM Demand Response Programs. A third party CSP may have to request services from a local utility, such as the purchase and installation of a meter upgrade or pulsing equipment. While it may be generally more cost effective to retrofit the existing utility provided meter by installing a meter module, this requires the utility's consent and installation service, and there are no rules governing the response time. There are no rules governing the response time when a CSP requests meter data. This does not mean that utilities engage in anti competitive behavior, but it is important to recognize the structural incentives resulting from the design of markets and regulations. It is a reason to ensure that there are explicit regulations governing the interactions of utilities and CSPs.

In addition, many utilities offer curtailment services in PJM in direct competition with third party CSPs. Utilities or their affiliates account for 29.0 percent of MW registered in the Economic Program and 42.2 percent of MW registered in the Emergency Program. Table 1 and Table 2 show the number of customers and MW registered to a CSP that also acts as or is directly affiliated with the customer's Load Serving Entity (LSE) or Electricity Distribution Company (EDC) for the Economic Program as of June 1, 2009 and for the Emergency Program as of June 24, 2009.

Table 1 Registered Sites and MW in the Economic Program by CSP type as of June 1, 2009

	Registered Sites	Percent of Total	Registered MW	Percent of Total
Third Party CSPs	792	87.1%	1,508.0	71.0%
Local Utility (Customer EDC or LSE)	117	12.9%	616.4	29.0%
Total	909	100.0%	2,124.4	100.0%

Table 2 Registered Sites and MW in the Emergency Program by CSP type as of June 24, 2009

	Registered Sites	Percent of Total	Registered MW	Percent of Total
Third Party CSPs	5,749	77.5%	4,218.5	57.8%
Local Utility (Customer EDC or LSE)	1,671	22.5%	3,076.4	42.2%
Total	7,420	100.0%	7,294.9	100.0%

Utilities acting as CSPs may have a cost advantage compared to third party CSPs, depending on the regulatory treatment of the overhead and direct costs associated with providing the CSP services. Utilities may also have an advantage in identifying potential customers because they have access to retail meter data.

LSE role in Settlement Process

Prior to the settlement review process beginning November 2008, the potential for LSEs to construct strategic barriers was inherent to the settlement process. Settlements in the Economic Load Response Program were submitted to the customer's LSE for verification and approval of the metered load data and the CBL calculation. However the LSE had the authority to dispute settlements for any reason. During this period, PJM was not screening daily settlements and there was a value to the critical review provided by the LSEs. However, as LSEs may have a financial interest in denying settlements, providing LSEs with the power to deny settlements creates a potential for the creation of strategic barriers to entry. While there is no evidence that LSEs acted in an anti competitive manner, this was a design flaw that has been rectified.

Since the implementation of the settlement review process on November 3, 2008, this issue has been nearly eliminated. The process explicitly states the criteria for which an LSE can deny a settlement, dealing primarily with data integrity.[16]

Demand Response in RPM

A demand resource in the capacity market results when an end use customer agrees to limit its use of capacity to a pre specified level and to interrupt its use of energy above that level when called on to do so by PJM. When a customer makes such a commitment, PJM does not have to procure capacity to meet the defined interruptible load. Demand resources have been eligible for capacity payments in the PJM capacity market since the implementation of the Reliability Pricing Model (RPM) on June 1, 2007, under the Load Management (LM) Program. The LM program was comprised of two types of resources: Interruptible Load for Reliability (ILR) and Demand Response (DR). DR had to offer in to the RPM auction and be certified in the year of the auction, while ILR did not have to commit or be certified until three months prior to the delivery year.

On December 12, 2008, PJM filed several tariff changes governing the sale of demand resources in RPM, which resulted in more consistent treatment of demand resources and generation resources, including: the elimination of the ILR option, mandatory capacity testing for demand resources absent an emergency event, the revision of the penalty

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16 LSEs can deny settlements if they are aware of an outage or holiday being submitted as a load reduction. All other criteria deal with data integrity.

structure for DR/ILR compliance, and the integration of Demand Response in Incremental Auctions.[17] These changes were conditionally approved March 26, 2009.[18]

Program Design

With few exceptions, customers do not know and do not pay the market price of the capacity component of wholesale power. The market price for the capacity component of wholesale power is the clearing price in the capacity market and more specifically the price that reflects actual supply and demand conditions at the specific location that capacity is purchased. As in the energy market, this is the fundamental barrier to the development of the demand side of wholesale power markets.

Demand side programs are generally designed to work around this market failure rather than to address it directly. The design of PJM's Load Management Program attempts to replicate the price signal to customers that would exist if customers were exposed to the locational market price of capacity. While it is not the purpose of this report to analyze the detailed design of the Load Management Program, it is not clear that the required hours of interruption required under the LM Program are adequate, given the actual pattern of high loads on the PJM system.

The goal for integrating demand response into RPM is to allow demand resources to make decisions about capacity needs based on the price of capacity, and to allow demand resources to save the capacity price for any decrease in capacity needs.

Customers on a retail tariff may pay a fixed rate for capacity that does not reflect the market price of capacity. The costs or savings that result from a change in demand for capacity is a function of the tariff price. This results in a market failure because when customers do not pay the market price for capacity, the behavior of those customers is inconsistent with the market value of capacity. In addition, capacity charges in retail tariffs may be based on customer class consumption rather than customer specific consumption. They may be rolled into the generation portion of a retail rate. This lack of transparency prevents customers from making informed decisions on how much peak period energy to buy (capacity) and from seeing the impact of changes in the demand for capacity.

The RPM provides a work around mechanism for loads to receive the capacity price for any decrease in capacity consumption. A demand resource can register to provide capacity up to its peak load contribution (PLC) from the prior year and receive the price

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[17] *PJM Interconnection, L.L.C.*, Tariff Amendments, Docket No. ER09-412-000 (December 12,2008)

[18] 126 FERC ¶ 61,257 (2009).

for that capacity. The demand side program in the capacity market, like that in the energy market, is a complex process designed to provide a price signal directly to customers. Participants in the demand side program in the capacity market are not providing resources, they are responding to the capacity market price by reducing consumption. Participants in the demand side program in the capacity market are not being paid to provide resources, they are receiving the savings associated with not consuming capacity.

The combination of a forward capacity market and the determination of customer peak loads using historical data substantially attenuates the link between usage and the payment of the price of capacity. The PLC represents the customer's capacity obligation, and is determined by averaging the customer's metered load during the five highest load hours in the RTO.[19] If a customer reduces load during the five highest load hours, the following year's PLC will be reduced but the value of the reduced peak load usage will not be received for four years following the reduction.

Mitigation of Demand Resources in RPM

The mitigation of existing demand resources in RPM Auctions can be a barrier to the entry of existing demand resources by creating a risk that such resources will be committed at a capacity market price less than their incremental cost. Under current rules, existing sellers of demand resources, if they would otherwise affect the clearing price, are subject to an offer cap of $0 per MW-day.[20] Existing generators are subject to an offer cap equal to their avoidable cost rate (ACR) less projected PJM Market Net Revenues. The effect is that demand resource sellers may be committed at a capacity price below the incremental cost of providing price responsive demand side capacity in the delivery year.

The policy logic reflected in the RPM settlement was that, based on the number, size and heterogeneity of loads providing demand side offers in the capacity market, it would be virtually impossible to calculate the incremental cost of providing demand reductions. It was also assumed that capacity market clearing prices would be greater than such incremental costs. The effect of the zero offer price requirement was to make demand side offers price takers.

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19 See PJM Manual 19: Load Forecasting and Analysis, p. 21 for more information

20 Attachment DD, Section 6.5, (b) of the PJM tariff: "When the Market Structure Test is failed, any Sell Offers of existing Demand Resources shall not be considered in determining the Capacity resource Clearing Price in any auction for the market for which such test was failed."

Given that the offers of generating units, with appropriate market power mitigation measures, will determine the price in RPM auctions and that demand side participation can only decrease that price, it is appropriate to remove the market power mitigation provisions of the tariff applicable to demand side resources. This is appropriate if the market structure test is applied only to the generating units, excluding demand side participation, and if the MMU continues to have the authority to monitor the competitive behavior of demand side providers.

PJM, based on widespread agreement of its members, will file such a change with the Commission in September.

Regulatory Process

The creation of a fully functional demand side of the wholesale power market will require significant cooperation by all regulatory authorities. The creation of a fully functional demand side requires a shared view of the desired end state across regulatory authorities. The demand side of the market is the customers. Customers pay retail rates subject to the jurisdiction of state public utility commissions. Wholesale prices are formed in the wholesale markets subject to the jurisdiction of the Commission. A fully functional demand side of the market requires that customers pay the real time wholesale market prices because these reflect the locational value of power at the time of consumption. A fully functional demand side of the market requires that customers see real time price signals in real time, have the ability to react to real time prices in real time, and have the ability to receive the direct benefits or costs of changes in real time energy use. Given that jurisdictional boundaries must be crossed in order to achieve the goal of full demand side integration, the goal will not be achieved without a coordinated effort by the Commission and state public utility commissions, with appropriate respect for jurisdictional limits to the regulatory authority of each.[21] [22]

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21 An important step was the establishment of the Mid-Atlantic Demand Response Initiative (MADRI). MADRI was established in 2004 by the public utility commissions of Delaware, District of Columbia, Maryland, New Jersey and Pennsylvania, along with the U.S. Department of Energy, U.S. Environmental Protection Agency, the FERC and PJM, for the purpose of educating stakeholders, especially state officials, on distributed resource opportunities, barriers, and solutions, developing alternative distributed resource solutions for states and others to implement, and pursuing regional consensus on preferred solutions. In addition to the founding jurisdictions, MADRI also reports on developments in Illinois and Ohio.

22 *See*, *e.g.*, Hon. Jon Wellinghoff and David L. Morenoff, *Recognizing the Importance of Demand Response: The Second Half of the Wholesale Electric Market Equation*, ENERGY L. J. v. 28, No. 2 at 396–412 (2007).

In addition to the rules governing pricing, meters and access to meter data, regulatory certainty creates a neutral framework for investment and can reduce inefficient barriers to entry. Regulatory uncertainty reduces the incentives of end users and CSPs to offer demand resources into PJM wholesale power markets. The regulation of public utilities by the Commission and state commissions and the development of market rules by PJM has, in some cases, created uncertainty for those market participants offering demand resources into the wholesale power markets administered by PJM.[23] However, the system of regulation and the design of market rules in PJM can work to establish a stable framework that will encourage economic investments in demand side assets.

Kentucky, Indiana and Ohio have taken actions that could constitute barriers to the ability of suppliers to offer demand resources into PJM wholesale markets. PJM reports that Virginia, West Virginia, North Carolina, Kentucky, Tennessee, Ohio and Indiana indicated, in response to PJM's canvassing in 2007, an intent to regulate in some manner the availability of demand resources and distributed resources to PJM's wholesale power markets.[24]

Table 3 shows the number of sites and MW in the Emergency Program and the Economic Program by state as of June 24, 2009.

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23 Some of the recently enacted rule changes implemented and proposed by PJM have been directed towards removing obstacles to offering demand-side resources into PJM markets. *See, e.g.*, PJM's filing to clarify its obligations relative to state actions concerning retail customer participation in PJM's Economic and Emergency Load Response Programs, Docket No. ER09-701, filed February 9, 2009 ("DSR Participation Filing"). By letter dated June 2, 2009, PJM requested that the Commission suspend action on the DSR Participation Filing until it has resolved related issues pending rehearing of Order No. 719.

24 *PJM Interconnection, L.L.C.*, FERC Status Report: Integrating Efficiency into the Capacity Market and Forum for Identifying and Resolving Impediments to Demand Response at 14, Docket No. ER05-1410-000, et al. (September 24, 2007).

Table 3 Registered sites and MW in the Emergency Program and the Economic Program by state as of June 24, 2009

	Emergency Program		Economic Program	
State	Sites	MW	Sites	MW
DC	105	39.9	8	3.6
DE	110	128.1	48	122.2
IL	1,331	1,343.7	76	152.3
IN	59	327.4	1	80.0
KY	0	0.0	0	0.0
MD	872	818.0	169	599.1
MI	6	3.1	0	0.0
NC	3	101.2	0	0.0
NJ	1,138	524.6	155	174.0
OH	543	1,132.8	11	30.7
PA	2,342	1,760.0	466	729.4
TN	3	14.8		
VA	657	614.9	91	313.2
WV	251	486.6	12	158.7
Total	7,420	7,294.9	1,037	2,363.2

In Kentucky, the Commission approved a settlement that integrated AEP Kentucky into PJM including a stipulation that reads:

> Any PJM-offered demand side response or load interruption programs will be made available to Kentucky Power for its retail customers at Kentucky Power's election. No such program will be made available by PJM directly to a retail customer of Kentucky Power. Kentucky Power may, at its election, offer demand side response programs to its retail customers. Any such programs would be subject to the applicable rules of the Commission and Kentucky law.[25]

In Indiana, the Indiana Utilities Regulatory Commission (IURC) has begun an investigation into "any and all matters relating to participation by Indiana end use customers in demand response programs offered by the Midwest IS0 and PJM Interconnection." Hearings convened in April 2009, in which PJM staff actively

25 Offer of Settlement filed in Docket No. ER03-262 on June 1, 2009, Appendix A at 3–4 (Agreed Stipulation filed in KPSC Case No. 2002-00475 on April 19, 2004). *See also New PJM Companies and PJM Interconnection, L.L.C.*, 107 FERC ¶61,272 at P 8 (2004).

participated,[26] and a decision currently is pending. In the meantime, the IURC has continued to allow the registration of certain end users by third party CSPs on a case by case basis. Certain CSPs and end users have complained that the legal costs and delays resulting from involvement in these proceedings constitute barriers to entry in PJM programs, and some of these are on record in Commission proceedings.[27]

At the request of AEP-Ohio,[28] the Ohio Public Utility Commission (PUC) has agreed to consider whether to prohibit the offering of demand resources in PJM markets in a future proceeding, but has determined to permit such participation in the meantime.[29] Earlier, the Ohio PUC had approved certain special retail service contracts which contain a provision that prohibits the customer from participating in PJM demand response programs other than through AEP (at AEP's election). In approving contracts containing this provision, the Ohio PUC did not discuss this provision. However, Ohio Consumers Council ("OCC") specifically objected to the inclusion of this provision,[30] and the order of the Ohio PUC made a point of indicating that approval of the contract does not constitute state action for the purpose of the antitrust laws."[31]

In Order No. 719, the Commission permits Relevant Retail Regulatory Authorities ("RERRAs") to affirmatively opt out of wholesale demand response by law or regulation. In other words, Order No. 719 can be interpreted to require that a RERRA either reject participation by all demand resources or accept participation by all demand

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26 *See* Pre-Filed Direct Testimony of Paul M. Sotkiewicz, Ph.D., IURC Cause No. 43566 (March 5, 2009); Reply Testimony of Peter L. Langbein, IURC Cause No. 43566 (April 13, 2009).

27 *See* PJM Response dated April 28, 2009 to the Commission's Deficiency Notice issued April 10, 2009, Docket No. ER09-701 ("PJM's April 28th Response"), Attachment A (Affidavits of Thomas Rutigliano and Richard S. Kalmas).

28 Columbus Southern Power Company and Ohio Power Company, both d/b/a AEP Power.

29 *See In the Matter of the Application of Columbus Southern Power Company for Approval of an Electric Security Plan; an Amendment to its Corporate Separation Plan; and the Sale or Transfer of Certain Generating Assets, et al.*, OPUC Case No. 08-917-EL-SSO, et al. (March 18, 2009). AEP has pending a request for rehearing on the interim treatment of demand resources.

30 *See* Motion to Intervene, Motion for Hearing and Objections by the Office of the Ohio Consumers' Counsel, OPUC Case No. 08-883-EL-AEC (July 30, 2008).

31 *In the Matter of the Application for Approval of a Contract for Electric Service Between Columbus Southern Power Company and Solsil, Inc., et al.*, OPUC Case No. 08-883-EL-AEC, et al. at 5 (July 31, 2008).

resources. This interpretation conflicts with the state provisions that limit customer participation from a single utility in PJM demand programs.

This approach may prove to permit more significant barriers to entry to demand resources in PJM than has been appreciated. In addition to state regulatory commissions, RERRAs include at least some and probably most of the municipal utilities in the PJM Region. At the state level, only Kentucky has opted out, but PJM reports that it has received numerous opt outs from municipal entities. To date, PJM informs us that municipal utilities have opted out in Indiana, North Carolina, Ohio, Pennsylvania and Virginia and attempted to opt out in Maryland.

PJM's requirement that CSPs register the resources included in their portfolio with PJM is a reasonable step to ensure the integrity of demand resources. The registration of demand resources is a step comparable to those taken by PJM to accurately determine for other resources the quantity and quality of energy, installed capacity and ancillary services sold into its markets. PJM has encountered problems with sellers of demand resources seeking payment for products that were not what they purported to be. PJM has taken significant steps to improve its process for verifying demand resources, and registration is a continuing part of ensuring that PJM's customers receive the value of their payments to demand resources. Registration is designed to ensure that the relationship between the CSP and its resource is legitimate and to verify that the resource is physically and contractually available to perform in the manner required by PJM.

It may be possible for RERRAs of all types to rely on the PJM registration process to address their legitimate concerns about resources purchased by entities located in their jurisdiction. Progress in this area would seem to require additional coordinated effort on the part of the regulatory authorities to craft solutions that ensure the integrity of demand response products.

More generally, it is difficult to see how the demand side of the PJM wholesale power markets can function without the participation of customers in all the states in the PJM footprint. An opt out provision constitutes a barrier to entry. Regardless of the appropriate jurisdictional lines, which must be respected, the demand side of the market will be fully developed only if all regulators share this as a goal and implement a common approach to the issues.

DR Market Rules

On May 21, 2009, the MMU convened a meeting of the Market Monitoring Unit Advisory Committee in order to formally solicit the views of stakeholders on barriers to entry. One of the salient issues raised was that the PJM market rules and the process by which they are modified and promulgated constitute a barrier to entry to demand resources. This problem is significant for the end use customers that constitute demand resources because end use customers are not in the power supply business. Part of the role of CSPs is to bridge this gap, but CSPs still need to be able to provide clear explanations about the obligations and opportunities associated with demand response programs. There is no reason, however, why the existing rules and the processes by which they are modified and communicated cannot be reformed for clarity, consistency and comprehensiveness.

The demand response rules should be revised to meet these objectives. The rules governing demand response programs should all be in one place, to the extent possible. The documentation should be clear and unambiguous. There should be clearly specified timelines for implementation of any changes to the rules. The PJM settlement review process and any further settlement screening criteria should be fully described and clearly documented in either the PJM tariff or in the PJM Manuals.

Compensation for Economic Load Response

In December 2005, PJM filed tariff revisions with the FERC which established the Economic Load Response Program as a permanent feature in PJM, as well as provided for the expiration of the Economic Demand Response Incentive on December 31, 2007.[32] PJM stakeholders "deferred consideration of incentive/subsidy payment until mid-2007 in order to gain experience with expanded demand response market opportunities."[33] The stakeholders let the incentive/subsidy payments lapse effective December 31, 2007 and there has been no agreement on a new design.

No proposal on incentives to date has achieved the required amount of stakeholder support to move forward. There are currently four proposals in contention undergoing the stakeholder process. Major distinctions between proposals include: (1) which end use sites are eligible for incentive payments, based on rate contract, (2) the time period for incentive eligibility, (3) price/operations threshold above which incentive compensation is applicable, (4) allocation of incentive payments and (5) various methods and degrees for measuring and verifying load reductions, including built in risk associated with uneconomic behavior.

Terry Boston, President and CEO of PJM, made a statement on behalf of the PJM Board of Managers, dated June 26, 2009, on the topic of incentives. Mr. Boston indicated that

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32 *PJM Interconnection, L.L.C.*, Tariff Amendments, Docket No. ER06-406-000 (December 28, 2005)

33 *PJM Interconnection, L.L.C.*, "FERC Status Report: Integrating Energy Efficiency into the Capacity Market and Forum for Identifying and Resolving Impediments to Demand Response", Docket Nos. ER05-1410-000,-001 & EL05-148-000,001 (September 24, 2007).

the PJM Board of Managers, "has approved the reintroduction of incentive payments as an interim measure to enhance progress toward the long term solution." This was part of a longer statement that addressed the appropriate long term approach to the demand response issues.

The purpose of PJM's demand side Economic Program is, or should be, to address a specific market failure, which is that many end use customers do not pay the market price, or LMP. The current compensation structure is consistent with the purpose of the demand side program, in that the hourly LMP replaces only the generation component of retail rates in order to provide the appropriate wholesale market price signal to customers, so for any reduction in the program, customers receive LMP less the generation component of the applicable retail rate and, any compensation in excess of that is a subsidy.

A question that requires further investigation is the actual definition of the generation component of retail rates. The generation component of retail rates is subtracted from LMP because it is assumed to represent the tariff-based price paid by customers for energy usage. Since the goal is to expose customers to LMP, that is accomplished by reducing customer bills by the amount that LMP exceeds the price of energy they are already paying under the tariff. However, the generation component of retail rates is not clearly defined. In theory, the generation component of retail rates could include energy and capacity payments. If it does, the full generation component should not be subtracted from LMP, but only the energy component. Subtracting the capacity payments from the energy charge would result in too low a price to the demand side resources.

The term subsidy is not a pejorative to an economist. There is nothing wrong with providing a subsidy when the subsidy is designed to address a clearly defined market failure and the level of the subsidy is designed to be the amount required to address that market failure. Determining the need for and/or the optimal level of a subsidy in the Economic Program is a difficult task. It is nearly impossible to quantify the extent to which current structural barriers to selling demand resources in PJM Markets affects net revenues for demand response technologies.

Eligibility

Customers who pay the hourly LMP in their retail rate are already exposed to the real time market price of electricity, and they have the ability to make decisions about levels of power consumption based both on the value of the uses of the power and on the actual cost of that power. They receive direct savings when they reduce consumption in response to real time price. Any additional payment made to these customers in addition to the direct savings results in a subsidy that is not aligned with the objective of the program. Customers who pay the real time LMP should not be eligible for payments under the PJM Economic Load Response Program. This subsidy is not necessary as the market failure in question does not exist for these customers. This recommendation does not apply to payments under the Load Management Program, related to the capacity market.

Participation Levels

In the Economic Load Response Program, settlement MWh and credits decreased significantly in 2008 compared to 2007, and have further decreased through March of 2009. Other indications of participation, such as registrations, submitted settlement days and active customers, showed some level of stability and even moderate growth for the full calendar year following the elimination of the incentive program, but most of these indicators have shown decreases from December 2008 through March 2009.

While the removal of the incentive program, effective November 2007, may have reduced participation, the exact role of the elimination of the incentive program is not known because there were changes in other key factors which directly impact participation, including a tightening of measurement standards and lower energy market prices.[34] The evidence does not support the claim that the removal of the incentive program resulted in a reduction of activity in the Economic Program.

Participation in the Load Management (LM) Program has increased significantly since implementation for the 2007/2008 delivery year. Participation in this program is a function of prices in the capacity market and of the rules governing the participation of demand resources in the capacity market. Participation in the LM program is not related to the referenced incentive program, which applied only to the Economic Program.

Economic Program

In the Economic Program, total MWh reductions and credits to CSPs decreased in 2008 compared to 2007. In 2007, there were 714,100 MWh of reduction accounting for $49.0 million in total credits including incentive payments, $31.6 million in credits, not including incentive payments. In 2008, there were 458,300 MWh of reduction accounting for $27.3 million in credits. Total MWh reductions decreased 35.8 percent and total credits decreased 13.6 percent. MWh reductions and credits continued to decline through March of 2009. Figure 1 shows monthly credits for 2007, excluding incentive payments, through March of 2009.

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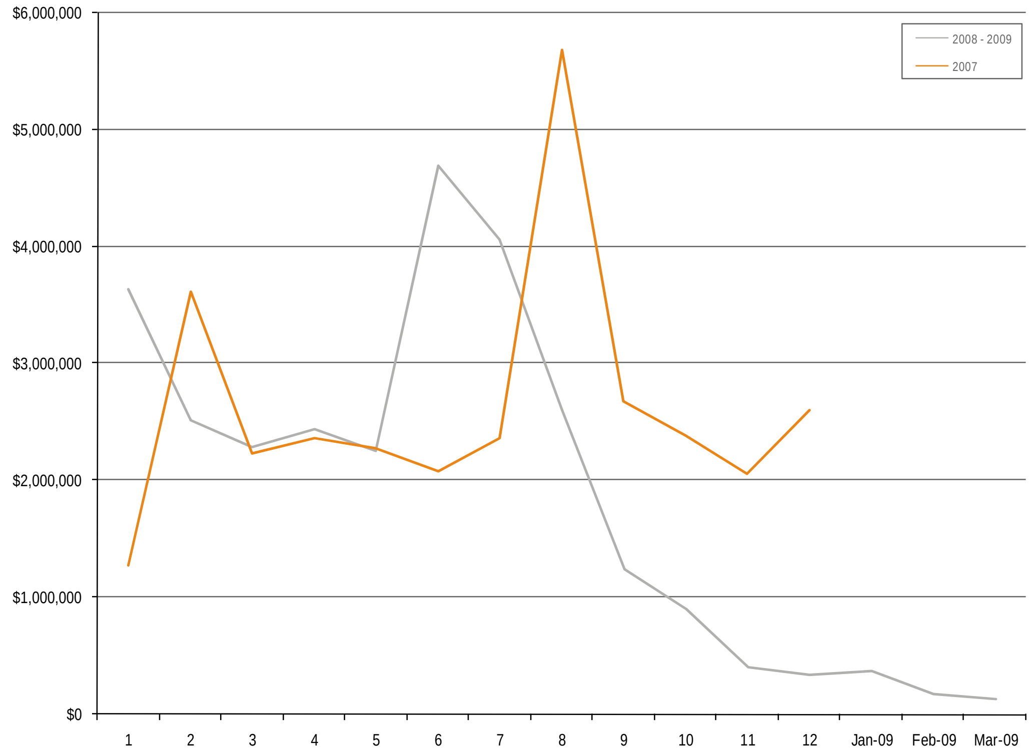
[34] In 2006 and 2007, when LMP was greater than, or equal to, $75 per MWh, customers were paid the full LMP and the amount not paid by the LSE, equal to the generation and transmission components of the applicable retail rate, was charged to all LSEs in the zone of the load reductions. As of December 31, 2007, the incentive payments totaled $17,391,099, which exceeded the specified cap. As a result, incentive credits paid in November and December were retracted.

Figure 1 Economic Program Payments: Monthly from January 2007 through March 2009 (without incentive payments) and 2008



PJM improved the review process for payments claimed under the Economic Program by revising CBL and by improving the verification process. The CBL revisions effective June 12, 2008 significantly improved CBL calculations by reducing the upward bias in measured savings that resulted from the use of stale or non representative load data. The implementation of the revised CBL likely resulted in a decrease in both MWh reductions and the credits associated with these reductions. The implementation of the PJM settlement review process on November 3, 2008 improved the verification process for the Economic Program. The tightening of the verification process likely resulted in a decrease in both MWh reductions and the credits associated with these reductions. Average PJM price levels from October 2008 through March 2009 were lower than for the same periods in 2007 and 2008. Lower average price levels likely reduced the number of hours in which it was economic to reduce load.

Other indicators of participation levels, such as active registrations and settlement submissions, remained stable or increased through 2008, but decreased in 2009. Table 4 shows the number of registered sites and total MW associated with these sites for the last day of the month for January 2007 through May 2009.[35] From November 2007 to March 2009, the number of registered sites remained relatively stable, while the registered MW increased from 2007 values. Registrations did not decline over the 16 months following the elimination of the incentive program in November of 2007. However, the number of registered sites decreased in April and May 2009 and the amount of registered MW decreased in May 2009.

Table 4 Registered sites and MW on the last day of each month for January, 2007 through May, 2009

	2007		2008		2009	
Month	Registered Sites	Registered MW	Registered Sites	Registered MW	Registered Sites	Registered MW
Jan	508	1,530	4,906	2,959	4,862	3,303
Feb	953	1,567	4,902	2,961	4,869	3,219
Mar	959	1,578	4,972	3,012	4,867	3,227
Apr	980	1,648	5,016	3,197	2,582	3,242
May	996	3,674	5,069	3,588	1,250	2,860
Jun	2,490	2,168	3,112	3,014		
Jul	2,872	2,459	4,542	3,165		
Aug	2,911	2,582	4,815	3,232		
Sep	4,868	2,915	4,836	3,263		
Oct	4,873	2,880	4,846	3,266		
Nov	4,897	2,948	4,851	3,271		
Dec	4,898	2,944	4,851	3,290		
Avg.	2,684	2,408	4,727	3,185	3,686	3,170

Table 5 shows the number of CSPs and customers who submitted at least one settlement per month from January 2007 through April 2009. The number of CSPs actively submitting settlements is generally slightly higher in each month of 2008 than in 2007. The number of CSPs declined in March and April 2009. The number of customers actively submitting settlements remained relatively stable from June 2007 through January 2009. Through calendar year 2008, there were 20 distinct CSPs that submitted at least one daily settlement, and 494 distinct customers that submitted at least one daily settlement, compared to 17 CSPs and 384 customers in the calendar year 2007. However, there has been a decrease in active customers since February 2009.

[35] The site count and registered MW associated with May 2007 are for May 9, 2007. Several new sites registered in May of 2007 overstated their MW capability, and it remains overstated in PJM data.

Table 5 Distinct Active CSPs and customers by month and year for calendar years 2007 and 2008 and year to date 2009

	2007		2008		2009	
Month	Active CSPs	Active Customers	Active CSPs	Active Customers	Active CSPs	Active Customers
Jan	10	68	11	260	13	234
Feb	8	83	10	241	11	128
Mar	8	82	10	216	9	143
Apr	9	92	11	204	5	67
May	10	103	9	227		
Jun	10	163	14	276		
Jul	13	227	14	255		
Aug	15	285	15	270		
Sep	13	280	14	276		
Oct	9	240	10	222		
Nov	8	202	11	205		
Dec	9	241	10	192		
Total Distinct	17	384	20	494	13	271

Table 6 shows total settlement days submitted by month in 2007 and 2008. Total settlement days submitted increased by 22.3 percent from 26,423 in 2007 to 32,316 in 2008. Total monthly settlement days began to decrease in October 2008 and the trend continued through April 2009.

Table 6 Total settlement days submitted by month for calendar years 2007 and 2008

Month	2007	2008	2009
Jan	887	2,894	1,224
Feb	1,099	2,785	630
Mar	1,185	2,802	542
Apr	1,468	3,386	318
May	1,609	3,309	
Jun	1,731	3,072	
Jul	2,421	3,209	
Aug	3,783	3,732	
Sep	3,320	3,179	
Oct	3,446	1,947	
Nov	2,819	1,068	
Dec	2,655	933	
Total	26,423	32,316	2,396

Load Management (LM)

The level of demand side capacity resources under the Load Management (LM) Program has increased significantly since the implementation of the modified capacity market effective June 1, 2007. Table 7 shows available MW in the LM Program on June 16 from 2007 through 2009.[36] Total MW in the LM Program have increased by 2,796.7 MW, or 62.2 percent, from delivery years 2008 to 2009.

Table 7 Available MW in the Load Management Program: 2007 through 2009

Year	Total DR MW	Total ILR MW	Total LM MW
2007	560.7	1,584.6	2,145.3
2008	1,017.7	3,480.5	4,498.2
2009	1,021.1	6,273.8	7,294.9

The ILR option in the LM Program was eliminated effective March 26, 2009. There was a corresponding significant increase in the amount of DR offered into the 2012/2013 Base Residual Auction (BRA). Table 8 shows the amount of offered and cleared DR in each BRA since the implementation of the RPM. There were 9,535.4 MW of DR offered into the 2012/2013 BRA, of which, 4,077.9 MW were planned DR.

Table 8 Offered and cleared DR in BRA: Delivery years 2007 through 2012

Planning Year	DR Offered in BRA	DR Cleared in BRA
2007/2008	123.5	123.5
2008/2009	691.9	536.2
2009/2010	906.9	856.2
2010/2011	935.6	908.1
2011/2012	1,597.3	1,319.5
2012/2013	9,535.4	6,824.1

Ancillary Services

The PJM tariff provides that demand side resources may participate in the ancillary services markets. There has been no demand side participation in the regulation market to date. There has been substantial participation in the synchronized reserve market by demand side resources.[37] For example, demand side resources accounted for all cleared Tier 2 synchronized reserves in 27 percent of hours when a synchronized reserve market was cleared.

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36 LM registration data is retrieved for June 16 of the applicable delivery year. June 15 is the final day for DR emergency registrations.

37 See the *2008 State of the Market Report*, Volume II, Section 6, "Ancillary Service Market."

The PJM market design permits demand side resources to participate directly in the ancillary services markets and to receive the market clearing price. Resources have the ability to decide whether payments for participation exceed the costs of participation, including required metering.

While there are clear requirements for participation in the ancillary services markets, there are no significant barriers to entry for demand side resources.

Conclusion

The demand side of wholesale electricity markets is underdeveloped. Wholesale electricity markets will be more efficient when the demand side of the electricity market becomes fully functional. A precondition for a functional demand side of a market is that there be a market. Organized wholesale power markets like those in the current RTOs/ISOs are required in order to develop market price signals before they can be passed directly to the customer.

A fully functional demand side of the electricity market means that customers or their designated intermediaries will have the ability to see real time price signals in real time, will have the ability to react to real time prices in real time, and will have the ability to receive the direct benefits or costs of changes in real time energy use. In addition, customers or their designated intermediaries will have the ability to see current capacity prices, will have the ability to react to capacity prices and will have the ability to receive the direct benefits or costs of changes in the demand for capacity. When these conditions are met, customers can and will make decisions about how much power to use, including investments in demand side management technologies, based on their own evaluations of the tradeoffs among the price of power, the value of particular activities and the costs of those technologies.

One of the central preconditions for competitive markets does not yet exist for power markets. Customers, as a general matter, do not know and do not pay the market price of wholesale power. The market price for wholesale power is the LMP in organized markets and more specifically the price that reflects actual supply and demand conditions at the specific location and time that power is purchased. This is the fundamental barrier to the development of the demand side of wholesale power markets. This barrier has led to the creation of demand side "programs" designed to work around the absence of price information rather than to the direct provision of price information. The providers of services under these programs face barriers to entry.

Demand side programs are generally designed to work around this market failure rather than to address it directly. PJM's Economic Load Response Program is designed to work around this market failure by attempting to replicate the price signal to customers that would exist if customers were exposed to the real time wholesale price of energy and by providing settlement services to facilitate the participation of third party Curtailment

Service Providers (CSPs) in the market. The design of PJM's Load Management (LM) Program in the RPM market also attempts to replicate the price signal to customers that would exist if customers were exposed to the locational market price of capacity.

When customers directly face market prices and have the ability to respond to such prices and to directly receive the benefits of their choices, there will be only a limited need for demand side programs. There will be a need for clear market rules governing the participation of demand side resources in energy, capacity and ancillary services markets, but there will be a sharply reduced need for elaborate measurement and verification programs. Customers will choose to consume or not consume energy based on the price. The metered usage and the bill will reflect that choice, and the assessment of that choice will belong to the customer. In the capacity market, a fully functional demand side will require that customers who wish to avoid paying for capacity provide an enforceable commitment to be interruptible by the RTO above a defined level of capacity, based on a clear and transparent market signal.

There are barriers to sellers providing demand response under PJM demand response programs. The principal barriers are the absence of an adequate meter infrastructure, lack of clarity among the regulatory authorities with jurisdiction over parts of the demand side, structural disadvantages compared to local utilities and a lack of clarity in the business rules and the process for promulgating the business rules.

The integration of demand resources into PJM Markets via the demand response programs via the demand response programs should be understood as one relatively small part of the transition to a fully functional demand side for PJM energy markets. The issue of real time pricing is complicated by restrictions imposed and overlaid by state and local retail ratemaking authorities. The large scale transition to a fully function demand side will require coordination between federal agencies and state and local ratemaking authorities, along with RTOs/ISOs.