Demand-Side Response (DSR)

Markets require both a supply side and a demand side to function effectively. The demand side of wholesale electricity markets is underdeveloped. Wholesale power markets will be more efficient when the demand side of the electricity market becomes fully functional.

Overview

- **Demand-Side Response Activity.** In calendar year 2011, the total MWh of load reduction under the Economic Load Response Program decreased by 57,288 MWh compared to the same period in 2010, from 74,070 MWh in 2010 to 16,782 MWh in 2011, a 77 percent decrease. Total payments under the Economic Program decreased by $1,080,438, from $3,088,049 in 2010 to $2,007,612 in 2011, a 35 percent decrease.

  Settled MWh and credits were lower in 2011 compared to 2010, and there were generally fewer settlements submitted compared to the same period in 2010. Participation levels since 2008 have generally been lower compared to prior years due to a number of factors, including lower price levels, lower load levels and improved measurement and verification. On the peak load day for 2011 (July 21, 2011), there were 2,041.5 MW registered in the Economic Load Response Program.

  Since the implementation of the RPM design on June 1, 2007, the capacity market has become the primary source of revenue to participants in PJM demand side programs. In 2011, Load Management (LM) Program revenues decreased by $25.2 million or 4.9 percent, from $512 million to $487 million. Through calendar year 2011, Synchronized Reserve credits for demand side resources increased by $4.1 million compared to the same period in 2010, from $5.3 million in 2010 to $9.4 million in 2011.

- **Locational Dispatch of Demand-Side Resources.** PJM dispatches demand-side resources on a subzonal basis when appropriate. The disconnect created by the fact that CSPs are still permitted to aggregate customers on a zonal basis is being addressed through the stakeholder process. More locational deployment of demand-side resources improves efficiency in a nodal market where demand side resources should be dispatched consistent with transmission constraints.

Conclusions

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. A functional demand side of these markets means that customers will 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.

Most end use customers pay a fixed retail rate with no direct relationship to the hourly wholesale market LMP. End use customers pay load serving entities (LSEs) an annual amount designed to recover, among other things, the total cost of wholesale power for the year.[1] End use customers paying fixed retail rates do not face even the hourly zonal average LMP. Thus, it would be a substantial step forward for customers to face the hourly zonal average price. But the actual market price of energy and the appropriate price signal for end use customers is the nodal locational marginal price. Within a zone, the actual costs of serving load, as reflected in the nodal hourly LMP, can vary substantially as a result of transmission constraints. A customer on the high price side of a constraint would have a strong incentive to add demand side resources if they faced the nodal price while that customer currently has an incentive to use more energy than is efficient, under either a flat retail rate or a rate linked to average zonal LMP. The nodal price provides a price signal with the actual locational marginal value of energy. In order to achieve the full benefits of nodal pricing on the supply and the demand side, load should ultimately pay nodal prices. However,

1 In PJM, load pays the average zonal LMP, which is the weighted average of the actual nodal locational marginal price. While individual customers have the option to pay nodal LMP, very few customers do so.

a transition to nodal pricing could have substantial impacts and therefore must be managed carefully.

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. Most end use customers pay a fixed retail rate with no direct relationship to the hourly wholesale market LMP, either on an average zonal or on a nodal basis. 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. This market failure does not imply that PJM markets have failed. This market failure means that customers do not pay the actual hourly locational cost of energy as a result of the disconnect between wholesale markets and retail pricing. When customers pay a price less than the market price, customers will tend to consume more than if they faced the market price and when customers pay a price greater than the market price, customers will tend to consume less than they would if they faced the market price. This market failure is relevant to the wholesale power market because the actual hourly locational price of power used by customers is determined by the wholesale power market, regardless of the average price actually paid by customers. 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. While the initial default energy price could be the average LMP, the transition to nodal LMP pricing should begin.

PJM's Economic Load Response Program (ELRP) is designed to address this market failure by attempting to replicate the price signal to customers that would exist if customers were exposed to the real-time wholesale zonal price of energy and by providing settlement services to facilitate the participation of third party Curtailment Service Providers (CSPs) in the market.[2] In PJM's Economic Load Response Program, participants have the option to receive credits for load reductions based on a more locationally defined pricing point than the zonal LMP. However, less than one percent of participants have taken this option while almost all participants received credits based on the zonal average LMP. PJM's proposed PRD program does incorporate some aspects of nodal pricing, although the link between the nodal wholesale price and the retail price is extremely attenuated.

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 PJM market design also creates the opportunity for demand resources to participate in ancillary services markets.[3]

PJM's demand side programs, by design, provide a work around for end use customers that are not otherwise exposed to the incremental, locational costs of energy and capacity. They should be understood as one relatively small part of a transition to a fully functional demand side for its 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.

If retail markets reflected hourly wholesale prices and customers received direct savings associated with reducing consumption in response to real-time prices, there would not be a need for a PJM Economic Load Response Program, or for extensive measurement and verification protocols. In the transition to that point, however, there is a need for robust measurement and verification techniques to ensure that transitional programs incent the desired behavior. The baseline methods used in PJM programs today, particularly in the Emergency Program which consists entirely of capacity resources, are not adequate to determine and quantify deliberate actions taken to reduce consumption.

Detailed Recommendations

- The MMU recommends elimination of the Limited and Extended Summer Demand Response products from the capacity market. All products competing in the capacity market should be required to be available to perform when called for every hour of the year.

2 While the primary purpose of the ELRP is to replicate the hourly zonal price signal to customers on fixed retail rate contracts, customers with zonal or nodal hourly LMP contracts are currently eligible to participate in the DA scheduling and the PJM dispatch options of the Program.

3 See the *2011 State of the Market Report for PJM*, Volume II, Section 9, "Ancillary Service Markets."

Table 5-1 Overview of Demand Side Programs

Emergency Load Response Program			Economic Load Response Program
Load Management (LM)			
Capacity Only	Capacity and Energy	Energy Only	Energy Only
Registered ILR only	DR cleared in RPM; Registered ILR	Not included in RPM	Not included in RPM
Mandatory Curtailment	Mandatory Curtailment	Voluntary Curtailment	Voluntary Curtailment
RPM event or test compliance penalties	RPM event or test compliance penalties	NA	NA
Capacity payments based on RPM clearing price	Capacity payments based on RPM price	NA	NA
No energy payment	Energy payment based on submitted higher of "minimum dispatch price" and LMP. Energy payment during PJM declared Emergency Event mandatory curtailments.	Energy payment based on submitted higher of "minimum dispatch price" and LMP. Energy payment only for voluntary curtailments.	Energy payment based on LMP less generation and transmission component of retail rate. Energy payment for hours of voluntary curtailment.

The MMU recommends that PJM continue to implement subzonal dispatch for Demand Response products and develop a plan to implement nodal dispatch for all demand resources.

- The MMU recommends that changes be made to simplify and improve the Emergency Demand Response (DR) program. The MMU recommends that the option to specify a minimum dispatch price under the Emergency Program Full option be eliminated and that participating resources receive the hourly real-time LMP less any generation component of their retail rate. The MMU also recommends that the Emergency Program Energy Only option be eliminated because the opportunity to receive the appropriate energy market incentive is already provided in the Economic Program.
- The MMU recommends that there be improvement in measurement and verification methods implemented in order to ensure the credibility of PJM demand-side programs. These could take the form of improvements in the CBL calculation and/or improvements in the verification and customer documentation of load reducing activities. PJM has implemented or plans to implement changes to the CBL calculation that should improve measurement and verification for many customers.
  - The MMU recommends that the testing program be modified to require verification of test methods and results. Load Management test results are submitted by CSPs directly to PJM. The test results consist of metered load data provided by the CSP which are compared to some baseline consumption level or firm service level determined by LM participation type. PJM screens the data for unreasonable test results, but relies on the CSP to submit accurate metered load data for the testing period with no physical or technical oversight or verification, although EDC's can request additional test data from the CSP. In order for PJM or the MMU to assess the accuracy of the CBL for a particular customer or for the Program in general, more hourly load data is required than is currently received by PJM. The MMU recommends that all available metered load data should be submitted to PJM and the MMU in order to verify accurate testing and measurement of customer loads.
  - The MMU recommends that any baseline approach that attempts to estimate unrestricted load consumption based on a comparable day or a comparable set of days be adjusted for ambient conditions and other variables impacting load for all participants, and be limited to the days closest to the event.
  - The MMU recommends that any settlement submitted with a consecutive 24 hour period of CBL greater than metered load should trigger a CBL review by PJM and that a customer should be required to provide documentation of load reduction actions taken, prior to acceptance of such settlements.

PJM Demand Side Programs

All load response programs in PJM can be grouped into the Economic and the Emergency Programs. Table 5-1 provides an overview of the key features of PJM load response programs.[4]

4 For more detail on the historical development of PJM Load Response Programs see the *2010 State of the Market Report for PJM*, Volume II, Section 2, "Energy Market, Part 1." <http://www.monitoringanalytics.com/reports/PJM_State_of_the_Market/2010.shtml>.

Demand Side in the Energy Market: Economic Load Response

In the Economic Load Response Program (ELRP, or the Economic Program), all hours are eligible and all participation is voluntary. The ELRP Program is designed to facilitate the participation of demand response in PJM Energy Markets. Participation in the ELRP takes three forms: submitting a sell offer into the Day-Ahead Market that clears; submitting a sell offer into the Real-Time Market that is dispatched; and self scheduling load reductions while providing notification to PJM. In the first two methods, a load reduction offer is submitted to PJM through the eMkt system specifying the minimum reduction price, including any associated shutdown costs, and the minimum duration of the load reduction.

The fundamental purpose of PJM's Economic Load Response Program is, or should be, to address a specific market failure, which is that many retail customers do not pay the market price or LMP. Based on this purpose, the design goal of the Economic Program incentives should be to replicate the price signal to customers that would exist if customers were exposed to the real-time wholesale price. The real-time hourly nodal LMP is the appropriate price signal as it reflects the incremental value of each MWh consumed.[5]

Retail customers pay retail rates including components that reflect the cost of generation (or power purchased from the wholesale market), the cost of transmission and the cost of distribution. Under a rate design consistent with the purpose of the demand-side program, the hourly LMP would replace only the generation component of retail rates in order to provide the appropriate wholesale market price signal to customers. Accordingly, the appropriate compensation for load reductions in the Economic Program is LMP less the generation component of the applicable retail rate per MWh. Nonetheless, it would be a reasonable approach to the policy objective of increasing demand side participation to pay the full LMP to retail customers who pay flat retail rates, for accurately measured load reductions. But it would not be reasonable to pay full LMP to customers who already pay LMP directly rather than a flat retail rate. In that case, the market failure that the program is designed to address does not exist. Payment of full LMP to customers already paying LMP would be paying the customer twice for the same action.

The PJM Economic Load-Response Program is a PJM-managed accounting mechanism that provides for payment of the savings that result from load reductions to the load-reducing customer. Such a mechanism is required because of the complex interaction between the wholesale market and the retail incentives and regulatory structures faced by both LSEs and customers. The broader goal of the Economic Program is a transition to a structure where customers do not require mandated payments, but where customers see and react to market prices or enter into contracts with intermediaries to provide that service. Even as currently structured, however, and even with the reintroduction of the defined subsidies, if they exclude previously identified inappropriate components, the Economic Program represents a minimal and relatively efficient intervention into the market. However, implementation of the Economic Load-Response Program changes on April 1, 2012, will change the nature of the program and may cause additional concerns.

Economic Incentive Payments: Order No. 745

On March 15, 2011, the Commission issued Order No. 745, in which the Commission ordered RTOs and ISOs to pay demand resources that are capable of balancing supply and demand full LMP.[6] In this order, demand resources that are cost-effective as determined by a "Net Benefits Test" (NBT) will be eligible to receive the full LMP rather than LMP less the generation and transmission charges. This approach recognizes that dispatching demand resources may result in a net increase in cost to non-demand response loads, and requires the NBT as mitigation. Each RTO and ISO was directed to develop a mechanism that would determine the price level at which the dispatch of demand resources would be cost effective.

5 This does not mean that every retail customer should be required to pay the real-time nodal LMP, regardless of their risk preferences. However, it would provide the appropriate price signal if every retail customer were required to pay the real-time nodal LMP as a default. That risk could be hedged via a contract with an intermediary. The transition to full nodal pricing from average zonal LMP should be implemented gradually because it can be expected to have significant impacts on some customers.

6 *Demand Response Compensation in Organized Wholesale Energy Markets*, Order No. 745, FERC Stats. & Regs. ¶31,322 (2011); *order on reh'g*, Order No. 745-A, 137 FERC ¶61,215 (2011); *order on reh'g*, Order No. 745-B, 138 FERC 61,148 (2012).

By order issued December 15, 2011, the Commission conditionally accepted PJM's compliance filing with Order No. 745.[7] The Commission directed PJM to continue to pay LMP less generation and transmission when a demand response resource is not cost-effective under the NBT.[8] The Commission also directed PJM to provide guidelines in its tariff governing "PJM's unilateral right to set a CBL when a variable load and PJM cannot reach an agreement."[9] The Commission further directed that PJM propose "an alternative data submission method for the minority of residential and small commercial participants who may have trouble meeting the data requirements."[10] Finally, the Commission ordered PJM to provide for the allocation of costs to areas where the load-weighted average LMP equals or exceeds the price determined under the NBT.[11]

The December 15th Order accepted PJM's requirement that demand resources must be dispatchable by PJM operators, although it did not include a must offer requirement for demand resources.[12] Self-scheduled resources will be ineligible to set LMP, as per their inability to offer flexibility to PJM dispatch. However, demand resources will be able to change offers up to three hours before the operating hour, giving three hour notice to PJM dispatchers in order to handle these resources.

The December 15th Order also approved PJM's clarification, as the Commission stated it, "that meter data from an on-site generator may be used as evidence of a load reduction only to the extent the on-site generator is operated to facilitate its demand reduction."[13] The December 15th Order approved setting the NBT on the basis of a single monthly price for PJM as a whole.[14]

This approach to compensating demand response, effective April 1, 2012, may increase participation in the Economic Load Response Program. This change will also allow double compensation for entities already paying LMP, as these entities will now receive the LMP in addition to the avoided cost of paying that LMP.[15]

7 137 FERC ¶ 61,216.
8 *Id.* at P 16.
9 *Id.* at P 63.
10 *Id.* at P 67.
11 *Id.* at P 78.
12 *Id.* at PP 31–35.
13 *Id.* at P 90.
14 *Id.* at P 43.
15 Comments of the Independent Market Monitor for PJM, Docket No. RM10-17-000 (May 13, 2010), at 2.

Order No. 745 treats demand resources differently than generation resources on several dimensions. Demand resources will not be subject to a must-offer requirement in the Day-Ahead market. Demand resources will be able to alter their schedule up to three hours before the operating hour, including the ability to withdraw the offer to curtail. Behind-the-meter resources will also have a substantial advantage compared to metered generation resources, in that they will have the ability to not offer, and not have to comply with the requirements imposed by PJM rules on metered generation resources.

The NBT uses a single monthly price for PJM. The NBT price threshold will not reflect the price separation in the Real-Time and Day-Ahead markets that results from binding transmission constraints or hourly fluctuations in LMP. The Commission directed PJM to study the inclusion of the NBT in its dispatch algorithm, but this will not be implemented as of April 1, 2012.

Demand Side in the Capacity Market: Emergency Load Response

Load Management generally refers to the integration of load response resources into RPM and thus encompasses both Emergency Load Response Options pertaining to capacity: Full and Capacity Only. In the 2011/2012 delivery year, all participants in the Emergency Program were capacity resources, integrated into RPM through the Load Management Program.

As a result of Reliability Pricing Model (RPM) implementation on June 1, 2007, the Load Management (LM) Program was introduced as the mechanism for Emergency Program customers and other DR providers to participate in RPM. Customers in the Emergency-Full and Emergency-Capacity Only options of the Emergency Program are committed capacity resources, which receive RPM capacity payments and which are subject to RPM penalties for noncompliance during emergency events. Emergency-Full customers are also eligible for energy payments for reductions during emergency events.[16]

The Load Management (LM) program was, from its inception in June 2007, comprised of two types of resources: Interruptible Load for Reliability (ILR)

16 For additional information on RPM provisions for customers in the Emergency Load Response Program, see PJM, "Manual 18: PJM Capacity Market," Revision 10 (June 1, 2010).

resources and Demand Resources (DR).[17] Customers offering DR resources submit a capacity sell bid into an RPM Auction and are paid the clearing price. Interruptible load for reliability (ILR) resources must be certified at least three months prior to the delivery year and are paid the final zonal ILR price. The ILR option was eliminated on March 26, 2009 for the delivery year beginning June 1, 2012.[18] A DR resource must be registered in the Emergency Full option or the Capacity Only option.

The purpose of the Load Management Program is to provide a mechanism for end-use customers to avoid paying the capacity market clearing price in return for agreeing to not use capacity when it is needed by customers who have paid for capacity. The fact that customers in the Load Management Program only have to agree to interrupt ten times per year for a maximum duration of six hours per interruption represents a flaw in the design of the program. There is no reason to believe that the customers who pay for capacity will need the capacity used by participating LM customers only ten times per year. In fact, it can be expected that the probability of needing that capacity will increase with the amount of MW that participating LM customers clear in the RPM auctions.

In the Emergency Load Response Program, only hours in which PJM has declared an Emergency Event are eligible. Participation may be voluntary or mandatory, and payments may include energy payments, capacity payments or both.

There are three options for Emergency Load Response registration and participation: energy only; capacity only; and capacity plus energy (full emergency option).

Energy Only

In the Energy Only option, participants submit a minimum dispatch price for load reductions during emergency events, which include shutdown costs and a minimum duration. All participation is voluntary. This option of the Emergency Program is similar to the Economic Program in that it provides only energy payments and all participation is voluntary. However, compensation differs significantly between the two programs as Energy Only participants in the Emergency Program receive the greater of LMP or the value of the submitted minimum dispatch price, including shutdown, for the duration of the emergency reduction.

Capacity Only

In the Capacity Only Program option, participants are considered a capacity resource, and are obligated to reduce load during emergency events. Participation during an emergency event or capacity testing is mandatory and failure to reduce will result in a compliance test failure charge. The participant receives capacity payments, however, no energy offers are submitted and no energy payments during emergency events are applicable. This option exists to accommodate registrations in which the Curtailment Service Provider may only provide capacity related services or situations in which the customer is participating in the Economic Program or in Ancillary Service markets when managed by another CSP.

Capacity plus Energy (Full Emergency Option)

Similar to the Energy Only option, participants in the Full Emergency option submit minimum dispatch prices associated with reductions during emergency events. In addition, they are considered committed capacity resources and receive capacity payments. Participation during an emergency event or capacity testing is mandatory and failure to reduce will result in a compliance test failure charge.

Minimum Dispatch Price

During an emergency event, participants registered in the Full Emergency option and the Emergency Energy Only option will be paid the higher of the submitted minimum strike price or the zonal real-time LMP for emergency reductions. The minimum dispatch price, which is submitted by the participant, acts as a floor for energy compensation during an emergency event. Given the current program rules, market participants have an incentive to submit a minimum dispatch price at the maximum threshold for energy bids of $1,000/MWh. For the 2011/2012 delivery year, approximately 73 percent of registered sites representing 64 percent of registered MW in the Emergency Full Capacity option submitted a minimum dispatch price of either $999 or $1,000 per MWh.

17 As part of the transition to RPM, effective June 1, 2007, the PJM active load management (ALM) program was changed to the load management (LM) program.

18 126 FERC ¶ 61,275 (2009).

There is no economic reason to compensate load reductions up to $1,000/MWh during an emergency event regardless of the hourly LMP. Compensation in the Emergency Program should be directly aligned with the RPM market clearing price. The appropriate energy market price signal for load reduction in any hour is the hourly LMP. This means that the appropriate compensation in any PJM Program is the LMP less the generation component of a fixed retail rate, which is already made available through participation in the Economic Program. There is no need for energy payments through the Emergency Program. The current design of the Emergency Program incents resources to seek overcompensation through Emergency Energy payments equal to the greater of LMP or a submitted minimum dispatch price, which, in most cases is set at $1,000/MWh.

There is no relationship between the minimum dispatch price and the locational price of energy or the participant's costs associated with not consuming energy. The minimum dispatch price is also not a meaningful signal from the participant about its willingness to curtail. In the Emergency Full option, end use participants are already contractually obligated to curtail during an emergency event because they are capacity resources and receive capacity payments. Thus, the ability to submit a minimum dispatch price is a guarantee of an energy payment for resources that are already required to curtail, regardless of their minimum dispatch price. The appropriate energy payment for a load reduction during an emergency event is the hourly LMP less any generation component of their retail rate. For customers on a real-time LMP contract, no energy payment is necessary because the customer saves the hourly LMP by not consuming during an emergency event. Any energy payment to customers on a flat retail rate in excess of the real-time LMP net of generation costs results in a subsidy, subject to the caveat that such a subsidy may be an appropriate policy for a limited transition period.[19]

In the Economic Program, customers also have the opportunity to submit a minimum price at which they will curtail. However, customers in the Economic Program will be dispatched economically and paid the real-time LMP less the generation and transmission component of their fixed retail rate only if they are dispatched.[20] Under the Emergency Energy Only option and the Emergency Full option, participants are made whole to a minimum strike price offer regardless of the hourly LMP. There is no economic reason to compensate load reductions up to $1,000/MWh during an emergency event regardless of the hourly LMP.

The MMU recommends that the option to specify a minimum dispatch price under the Emergency Program Full option be eliminated and that participating resources receive the hourly real-time LMP less any generation component of their retail rate. The MMU also recommends that the Emergency Program Energy Only option be eliminated because the opportunity to receive the appropriate energy market incentive is already provided in the Economic Program.

Double Counting

PJM procures capacity for load-serving entities (LSEs) through the Reliability Pricing Model (RPM). LSEs use customers' Peak Load Contribution or PLC to allocate capacity obligations and the cost of capacity among their customers.[21] Use of PLC as a basis for allocating capacity obligations and capacity costs predates the establishment of PJM's current capacity market, the Reliability Pricing Model (RPM); emergency demand response programs; and even the organized wholesale electricity markets. Large, sophisticated customers have also managed their PLCs for many years to achieve a lower PLC and, as a result, reduce their obligation to purchase capacity and reduce their payments for capacity. (Such customers are termed self managing.)

Prior to the introduction of demand response programs it was reasonable to assume that customers managing their PLC would continue to manage their PLC going forward in order to continue to reduce their obligation to purchase capacity. It was not deemed necessary to formalize a managed PLC as an obligation to reduce customer load during times of system peak load because continued management of the PLC resulted in reduced loads on high load days. Prior to the introduction of RPM and DR programs, the incentives to manage PLC

19 Energy Only participants are also paid the higher of the real-time LMP and the submitted minimum dispatch price. However, there are currently no participants registered under this option.

20 OA Schedule 1 § 3.3A.4(a).

21 The peak load contribution (PLC) is measured by a customer's consumption during the five coincident peak hours in the prior year.

and the resultant actions were consistent with economic signals and generally resulted in a match between reduced peak loads and reduced capacity payments. PLC management was and continues to be, in effect, a market based demand side management program.

The PJM Emergency Demand Response program provides customers an alternative to managing PLC as a way to reduce the obligation to purchase capacity. A customer can register as a capacity resource in the Program and receive credit for the amount of capacity it is willing to curtail in a given delivery year. The amount that can be nominated in the Program is limited to the customer's current PLC.[22] In return for not paying for the capacity associated with that curtailed load, the customer agrees to reduce load by that amount when customers who are paying for the capacity need it. A party that manages PLC avoids paying for capacity, but also assumes responsibility for determining when to curtail. Participants in PJM's Emergency Load Response Program curtail when called by PJM.

Self managed customers who elect the Guaranteed Load Drop (GLD) measurement and verification option will show substantial apparent measured over compliance during an Emergency LM event. The over compliance results from the fact that the GLD option measures compliance as the reduction in real time consumption from a baseline established by actual recent consumption. This baseline consumption reflects full load rather than managed load and thus will reflect consumption above a customer's PLC. The reduction observed for compliance will show the full reduction capability of the customer, including the load that the customer already reduced to manage its PLC. The measured reduction may be significantly higher than the amount nominated in the LM Program, which may not exceed the PLC. This results in double counting of the savings.

Double counting takes two forms. Double counting may exist at an individual customer level or at a CSP portfolio level.

At the level of an individual customer, when a customer that previously managed its PLC shows measured over compliance based on GLD, the result is a disconnect between the amount of capacity that a customer did not pay for based on its availability to be curtailed, and the amount offered by the customer in the delivery year as a reduction. In the same delivery year, due to the lag between PLC management and associated savings, the customer pays for capacity equal to the lower PLC and, if consumption is greater than PLC, may request and receive credit for not using capacity that was not paid for under one interpretation of the rules, which was accepted in 2011. That credit constitutes double counting. This double counting at an individual customer level occurs when the PJM rules limiting nominations to the PLC are interpreted as permitting a reduction from peak load by the amount of the PLC rather than permitting only a reduction below the PLC level. Only the second is a logical interpretation and consistent with the fundamental economics and appropriate incentives.

At the portfolio level, the double counting issue is exacerbated when customers with managed PLCs are included in a portfolio managed by a Curtailment Service Provider (CSP). Although a GLD customer that has managed its PLC cannot claim a capacity benefit greater than its nomination, the netting rules permit a CSP to use measured over compliance from such customers in its portfolio to offset underperforming resources in its portfolio, under one interpretation of the rules. Netting is not the issue. The use of apparent overcompliance as the basis for netting creates the double counting issue at the portfolio level.

It is double counting because the self managing customer is incurring a capacity obligation only equal to its PLC and therefore paying for capacity only equal to its PLC, but the CSP is being paid for reducing load from peak to PLC. The customer, through the CSP, is selling back to PJM capacity that it did not purchase.

Netting is appropriate when it recognizes additional reductions below PLC in excess of nominated levels. However, the rules should explicitly prohibit CSPs from crediting apparent over compliance against underperforming parts of its portfolio when such over compliance is attributable to reductions which occur at MW levels greater than PLC.

The data on customer compliance show that some LM participants that selected the GLD method for measurement and verification claimed load reductions in excess of their PLCs, and that the load reductions

22 OATT Attachment DD-1 § J.

associated with these participants account for a significant portion of overall compliance. Table 5-17 shows that, in 2011, of the total load reductions submitted for the July 22 Load Management event by customers using the GLD measurement and verification approach, 51 percent of the MW of submitted load reductions were in excess of customers' PLCs and that 29 percent of such MW were in excess of 150 percent of customers' PLCs. This is strong evidence that double counting remained a significant issue in 2011.

The issue is further complicated by the disconnect between the load reduction value used to measure compliance and the addback process, which is part of determining the customer's capacity obligation for the following year. When an LM customer, which does not directly manage PLC, reduces load during an Emergency event, that reduction will generally reduce the customer's PLC and therefore its obligation to purchase and pay for capacity in the following year.[23] If the customer appropriately participates in the LM program, it is paid for its reductions from its PLC. The addback means that the reduction is added back to the customer's load in order to ensure that its peak load and therefore PLC are correctly calculated for the next year. The addback prevents the PLC for such a customer from being inappropriately reduced as a result of participation in the LM program. The addback ensures that in the following year, the customer's load obligation reflects unmanaged levels and thus the customer will be able to nominate up to its full reduction in that year. The problem arises because the addback is limited to the amount nominated in the current delivery year. Thus, when a customer shows measured overcompliance in excess of its nomination, the addback is limited to the nomination. As a result, the customer's PLC is understated for the next year, which means that the customer's capacity obligation is understated and creates the potential for an additional double counting issue for the customer.[24]

By order issued November 4, 2011, the Commission conditionally accepted revisions to the tariff proposed by PJM to clarify the rules and correct the double counting issue.[25] The clarified provisions specify that a GLD customer's load drop would "only be recognized if the metered load multiplied by the loss factor is less than the current Delivery Year peak load contribution."

The November 4th order directed PJM to submit a compliance filing that allows for an interim mitigation measure that will apply to the 2012/2013 through 2014/15 Delivery Years and protect the reasonable reliance expectations of DR suppliers through that period.[26] On January 4, 2012, PJM filed a compliance filing to the Commission. This filing clarified issues regarding aggregation and compensation for reductions below PLC, as well as dealing with the "reasonable reliance expectations" of DR suppliers for Delivery Years in which BRAs have been held. As interim mitigation measures, PJM offered two possibilities to deal with "reasonable reliance expectations."

To deal with other possible reliance expectations, "PJM further proposes to allow any qualified DR provider to demonstrate that it has unavoidable contractual obligations to end-use customers during the transition delivery years which the purchase of replacement capacity in the Incremental Auctions will not mitigate." Specifically, this provision would deal with any contractual commitments for CSPs that were signed before April 7, 2011, the date of PJM's original filing.

In an order issued February 24, 2012, the Commission conditionally accepted PJM's compliance filing.[27] While the Commission accepted the majority of PJM's filing, PJM was directed to explain how CSPs will be compensated for unavoidable losses resulting from contracts signed prior to April 7, 2011. PJM's compliance filing is due by March 10, 2012.

New Demand Response Capacity Products

On December 2, 2010, PJM proposed, and by order issued January 31, 2011, the Commission approved, an unlimited demand-side capacity product, which it terms "Annual DR."[28] PJM also proposed and the Commission accepted the continued use of "Limited DR" and another new product, "Extended Summer DR." Limited DR simply continues the current limited product. Extended Summer DR includes more obligations than Limited DR but fewer

23 If the event coincides with one of the five coincident peak hours.

24 For more information including a detailed example, see the IMM/PJM joint statement regarding double counting: <http://www.MonitoringAnalytics.com/reports/Market_Messages/Messages/PJM_IMM_Joint_Statement_DR_Double_Counting_20110204.pdf>.

25 137 FERC ¶ 61,108 at P 64 (2011).

26 *Id.* at P 81.

27 138 FERC ¶ 61,138 (2012).

28 PJM filing in Docket No. ER11-2288-000; 134 FERC ¶ 61,066 (2011).

than Annual DR. PJM provided testimony explaining how Limited DR is flawed and poses an increasing reliability risk, but did not propose to eliminate it.[29]

Limited products are inferior to unlimited products and permitting the limited products to replace the unlimited demand side product or the unlimited generation product distorts capacity market outcomes. A single unlimited demand-side capacity product is all that the PJM capacity market needs, and such a product could provide maximum flexibility for participants whatever their particular operational characteristics or preexisting investment. Given that Curtailment Service Providers (CSPs) can and do aggregate participants into portfolios eligible to serve as DR, the market design can accommodate participation by any customer. CSPs are better situated than PJM to play the role of aggregator, and providing CSPs with an incentive to do so will sustain the growth of demand-side participation in PJM markets.

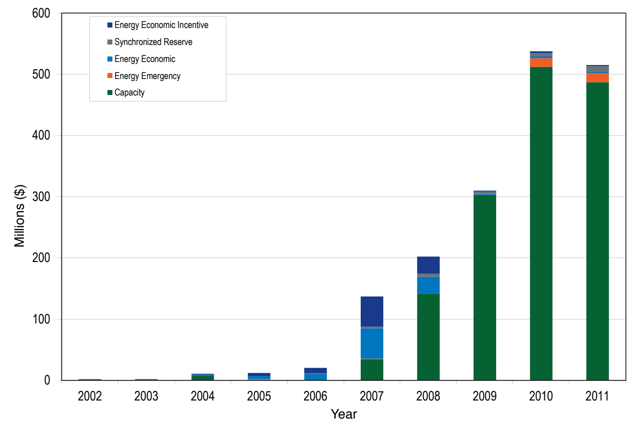
Participation in Demand Side Programs

In 2011, in the Economic Program, participation became more concentrated by site compared to 2001. There were fewer settlements submitted and active registrations in 2011 compared to 2010, and settled MWh and credits decreased. The number of sites registered decreased more significantly than the level of registered MW.

In 2011, LM Program participation increased compared to 2010. For the 2011/2012 delivery year, there were 11,522.7 MW registered in the LM Program, compared to 9,052.4 MW registered in the 2010/2011 delivery year.

Figure 5-1 shows all revenue from PJM Demand Side Response Programs by market for the period 2002 through 2011. Since the implementation of the RPM design on June 1, 2007, the capacity market has become the primary source of revenue to demand side participants. In 2011, Economic Program revenue decreased by $1.1 million or 35.0 percent, from $3.1 million to $2.0 million. Capacity revenue decreased by $25 million or 8.3 percent, from $512 million to $487 million. Synchronized Reserve credits increased by $4.1 million, from approximately $5.3 million to $9.4 million from 2010 to 2011. Emergency energy payments are made to resources through the Emergency Program for reductions during PJM-declared Load Management Events. In 2010, there were six Load Management Events resulting in $13.8 million in emergency energy revenues, and in 2011, there were three Load Management event-days, resulting in $14.6 million in emergency energy revenues, an increase of 6.3 percent.

Figure 5-1 Demand Response revenue by market: Calendar years 2002 through 2011



Economic Program

Table 5-2 shows the number of registered sites and MW per peak load day for calendar years 2002 through 2011.[30] On July 21, 2011, there were 2,041.8 MW registered in the Economic Program compared to the 1,725.7 MW on July 6, 2010, an 18.3 percent increase in peak load day capability. Program totals are subject to monthly and seasonal variation, as registrations begin, expire and renew. Table 5-3 shows registered sites and MW for the last day of each month for the period calendar years 2008 through 2011.[31] Registered MW declined in June but increased in August, which is likely the result of expirations and renewals. Registration in the Economic Program means that customers have been signed up and can participate if they choose. Thus, registrations represent the maximum level of potential participation.

29 PJM filing in Docket No. ER11-2288-000, Attachments A (Affidavit of Thomas A. Falin on Behalf of PJM Interconnection, L.L.C.) & B (Affidavit of Michael E. Bryson on Behalf of PJM Interconnection, L.L.C.).(December 2, 2011).

30 Table 5-2 and Table 5-3 reflect distinct registration counts. They do not reflect the number of distinct sites registered for the Economic Program, as multiple sites may be aggregated within a single registration.

31 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 5-2 Economic Program registration on peak load days: Calendar years 2002 to 2011

	Registrations	Peak-Day, Registered MW
14-Aug-02	96	335.4
22-Aug-03	240	650.6
3-Aug-04	782	875.6
26-Jul-05	2,548	2,210.2
2-Aug-06	253	1,100.7
8-Aug-07	2,897	2,498.0
9-Jun-08	956	2,294.7
10-Aug-09	1,321	2,486.6
6-Jul-10	899	1,725.7
21-Jul-11	1,237	2,041.8

Table 5-3 Economic Program registrations on the last day of the month: 2008 through 2011

	2008		2009		2010		2011	
Month	Registrations	Registered MW	Registrations	Registered MW	Registrations	Registered MW	Registrations	Registered MW
Jan	4,906	2,959	4,862	3,303	1,841	2,623	1,609	2,432
Feb	4,902	2,961	4,869	3,219	1,842	2,624	1,612	2,435
Mar	4,972	3,012	4,867	3,227	1,845	2,623	1,612	2,519
Apr	5,016	3,197	2,582	3,242	1,849	2,587	1,611	2,534
May	5,069	3,588	1,250	2,860	1,875	2,819	1,687	3,166
Jun	3,112	3,014	1,265	2,461	813	1,608	1,143	1,912
Jul	4,542	3,165	1,265	2,445	1,192	2,159	1,228	2,062
Aug	4,815	3,232	1,653	2,650	1,616	2,398	1,987	2,194
Sep	4,836	3,263	1,879	2,727	1,609	2,447	1,962	2,183
Oct	4,846	3,266	1,875	2,730	1,606	2,444	1,954	2,179
Nov	4,851	3,271	1,874	2,730	1,605	2,444	1,954	2,179
Dec	4,851	3,290	1,853	2,627	1,598	2,439	1,992	2,259
Avg.	4,727	3,185	2,508	2,852	1,608	2,435	1,696	2,338

Table 5-4 shows the zonal distribution of capability in the Economic Program on July 21, 2011. The PECO Control Zone includes 310 sites and 142.2 MW, 18 percent of sites and 7 percent of registered MW in the Economic Program. The BGE Control Zone includes 59 sites and 588.7 MW, 3.5 percent of sites and 29 percent of registered MW in the Economic Program.

Table 5-4 Distinct registrations and sites in the Economic Program: July 21, 2011[32]

	Registrations	Sites	MW
AECO	30	33	15.2
AEP	53	104	102.8
AP	132	211	102.3
ATSI	6	6	75.5
BGE	50	59	588.7
ComEd	72	100	92.1
DAY	6	16	7.9
DLCO	33	38	59.7
Dominion	89	93	197.1
DPL	33	39	63.4
JCPL	25	33	120.8
Met-Ed	72	80	84.5
PECO	249	310	142.2
PENELEC	138	169	103.4
Pepco	18	22	14.6
PPL	140	223	225.6
PSEG	90	152	45.8
RECO	1	1	0.3
Total	1,237	1,689	2,041.8

32 The second column of Table 5-4 reflects the number of registered end-user sites, including sites that are aggregated to a single registration.

Total Payments in Table 5-5 exclude incentive payments in the Economic Program for the years 2006 and 2007. The economic incentive program expired in December of 2007.[33]

Table 5-5 Performance of PJM Economic Program participants without incentive payments: Calendar years 2002 through 2011

	Total MWh	Total Payments	$/MWh	Total MWh per Peak-Day, Registered MW
2002	6,727	$801,119	$119	20.1
2003	19,518	$833,530	$43	30.0
2004	58,352	$1,917,202	$33	66.6
2005	157,421	$13,036,482	$83	71.2
2006	258,468	$10,213,828	$40	234.8
2007	714,148	$31,600,046	$44	285.9
2008	452,222	$27,087,495	$60	197.1
2009	57,157	$1,389,136	$24	23.0
2010	74,070	$3,088,049	$42	42.9
2011	16,782	$2,007,612	$120	8.2

Figure 5-2 shows monthly economic program payments, excluding incentive payments, for 2007 through 2010. Economic Program credits declined from June 2008 through 2009. In 2009, payments were down significantly in every month compared to the same time period in 2007 and 2008.[34] Lower energy prices and growth in the capacity market program were the biggest factors. Energy prices declined significantly in 2008 and again in 2009.[35] In 2011, credits were down compared to 2010, except the months of May and June 2011.

Figure 5-2 Economic Program payments by month: Calendar years 2007[36] through 2011

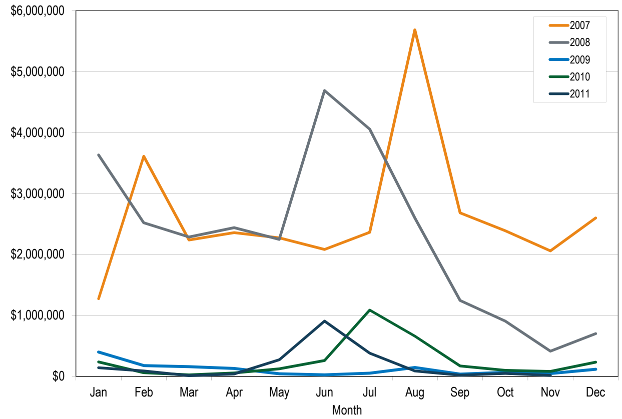


Table 5-6 shows 2011 performance in the Economic Program by control zone and participation type. The total number of curtailed hours for the Economic Program was 16,782 and the total payment amount was $2,007,612.[37] Overall, approximately 98.6 percent of the MWh reductions, 99.6 percent of payments and 98.7 percent of curtailed hours resulted from the real-time option of the Economic Program. Approximately 1.4 percent of the MWh reductions, 0.4 percent of payments and 1.2 percent of curtailed hours resulted from the day-ahead option. The Dominion Control Zone accounted for $1,062,900 or 53 percent of all Economic Program credits, associated with 11,330.1 or 68 percent of total program MWh reductions.

Table 5-7 shows total settlements submitted by month for calendar years 2007 through 2011. For January through July of 2008, total monthly settlements were higher than the monthly totals for 2007, despite the recent expiration of the incentive program. In October of 2008, settlement submissions dropped significantly from the prior month and from the same month in 2007, a trend that continued through early 2009. This drop in participation corresponds with the implementation of the PJM daily review process, as well as the lower overall price levels in PJM. April of 2009 showed the lowest level of settlements submitted in the three year period, after which, settlements began to show steady

33 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 (recoverable charges), was charged to all LSEs in the zone of the load reduction. As of December 31, 2007, the incentive payments totaled $17,391,099, an increase of 108 percent from calendar year 2006. No incentive credits were paid in November and December 2007 because the total exceeded the specified cap.

34 December credits are likely understated due to the lag associated with the submittal and processing of settlements. Settlements may be submitted up to 60 days following an event day. EDC/LSEs have up to 10 business days to approve which could account for a maximum lag of approximately 74 calendar days.

35 The reduction was also the result in part of the revisions to the Customer Baseline Load (CBL) calculation effective June 12, 2008 and the newly implemented activity review process effective November 3, 2008.

36 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 retail rate, was charged to all LSEs. Economic Program payments for 2007 shown in Figure 5-2 do not include these incentive payments.

37 If two different retail customers curtail the same hour in the same zone, it is counted as two curtailed hours.

Table 5-6 PJM Economic Program participation by zone: Calendar year 2010 and 2011

	Credits			MWh Reductions		
	2010	2011	Percent Change	2010	2011	Percent Change
AECO	$5,026	$0	(100%)	86.7	0.0	(100%)
AEP	$56	$24,279	43,293%	7.0	310.0	4,315%
AP	$130,576	$17,988	(86%)	4,459.9	372.2	(92%)
ATSI	$0	$1,829	NA	0.0	19.4	NA
BGE	$445,908	$730,278	64%	3,679.3	2,294.5	(38%)
ComEd	$39,894	$2,420	(94%)	2,298.1	197.4	(91%)
DAY	$1,173	$13,435	1,046%	11.2	18.8	68%
DLCO	$0	$534	NA	0.0	12.9	NA
Dominion	$1,598,117	$1,062,900	(33%)	29,103.1	11,330.1	(61%)
DPL	$248	$59	(76%)	0.9	0.4	(63%)
JCPL	$20,539	$1,075	(95%)	235.5	3.3	(99%)
Met-Ed	$1,359	$17,429	1,182%	32.7	183.9	463%
PECO	$824,400	$78,346	(90%)	33,493.1	1,698.2	(95%)
PENELEC	$918	$3,376	268%	42.5	80.8	90%
Pepco	$3,106	$2,637	(15%)	58.2	38.0	(35%)
PPL	$15,249	$46,041	202%	499.6	188.1	(62%)
PSEG	$1,458	$4,986	242%	61.5	33.9	(45%)
RECO	$24	$0	(100%)	0.4	0.0	(100%)
Total	$3,088,049	$2,007,612	(35%)	74,069.6	16,781.7	(77%)

growth. Settlements dropped off significantly after the summer period in 2009, and January through May of 2010 were generally lower than historical levels while summer of 2010 showed a moderate increase, consistent with 2009. December of 2011 showed the lowest level of settlements in the five year period, and 2011 overall showed a substantial decrease in the number of settlements submitted compared to previous years.

Table 5-7 Settlement days submitted by month in the Economic Program: Calendar years 2007 through 2011

Month	2007	2008	2009	2010	2011
Jan	937	2,916	1,264	1,415	562
Feb	1,170	2,811	654	546	148
Mar	1,255	2,818	574	411	82
Apr	1,540	3,406	337	338	102
May	1,649	3,336	918	673	298
Jun	1,856	3,184	2,727	1,221	743
Jul	2,534	3,339	2,879	3,007	1,411
Aug	3,962	3,848	3,760	2,158	790
Sep	3,388	3,264	2,570	660	294
Oct	3,508	1,977	2,361	699	66
Nov	2,842	1,105	2,321	672	51
Dec	2,675	986	1,240	894	40
Total	26,423	32,990	21,605	12,694	4,587

Table 5-8 shows the number of distinct Curtailment Service Providers (CSPs) and distinct customers actively submitting settlements by month for the period 2008 through 2011. The number of active customers per month decreased in early 2009, reaching a three year low in April. Since then, monthly customer counts vary significantly. In 2011, monthly customers appear to follow seasonal trends, high in the summer period and lower in shoulder months, however, the number of active customers in calendar year 2011 increased 172, or 39 percent, over calendar year 2010.

Table 5-9 shows a frequency distribution of MWh reductions and credits at each hour for calendar year 2011. The period from hour ending 0800 EPT to 2300 EPT accounts for 94 percent of MWh reductions and 96 percent of credits.

Table 5-10 shows the frequency distribution of Economic Program MWh reductions and credits by real-time zonal, load-weighted, average LMP in various price ranges. Reductions occurred at all price levels. Approximately 40 percent of MWh reductions and 82 percent of program credits are associated with hours when the applicable zonal LMP was greater than or equal to $150.

Table 5-8 Distinct customers and CSPs submitting settlements in the Economic Program by month: Calendar years 2008 through 2011

	2008		2009		2010		2011	
Month	Active CSPs	Active Customers	Active CSPs	Active Customers	Active CSPs	Active Customers	Active CSPs	Active Customers
Jan	13	261	17	257	11	162	5	40
Feb	13	243	12	129	9	92	6	29
Mar	11	216	11	149	7	124	3	15
Apr	12	208	9	76	5	77	3	15
May	12	233	9	201	6	140	6	144
Jun	17	317	20	231	11	152	10	304
Jul	16	295	21	183	18	243	15	214
Aug	17	306	15	400	14	302	14	186
Sep	17	312	11	181	11	97	7	47
Oct	13	226	11	93	8	37	3	9
Nov	14	208	9	143	7	40	3	13
Dec	13	193	10	160	7	46	5	12
Total Distinct Active	24	522	25	747	24	438	20	610

Table 5-9 Hourly frequency distribution of Economic Program MWh reductions and credits: Calendar year 2011

	MWh Reductions				Program Credits			
Hour Ending (EPT)	MWh Reductions	Percent	Cumulative MWh	Cumulative Percent	Credits	Percent	Cumulative Credits	Cumulative Percent
1	6	0.03%	6	0.03%	$105	0.01%	$105	0.01%
2	6	0.04%	12	0.07%	$193	0.01%	$298	0.01%
3	12	0.07%	24	0.14%	$619	0.03%	$917	0.05%
4	4	0.02%	28	0.17%	$61	0.00%	$978	0.05%
5	8	0.05%	36	0.22%	$51	0.00%	$1,028	0.05%
6	36	0.21%	72	0.43%	$725	0.04%	$1,754	0.09%
7	956	5.69%	1,028	6.12%	$71,402	3.56%	$73,156	3.64%
8	1,340	7.98%	2,367	14.11%	$124,197	6.19%	$197,353	9.83%
9	570	3.40%	2,937	17.50%	$37,435	1.86%	$234,788	11.69%
10	191	1.14%	3,128	18.64%	$9,052	0.45%	$243,840	12.15%
11	169	1.01%	3,297	19.65%	$4,688	0.23%	$248,529	12.38%
12	260	1.55%	3,557	21.20%	$12,390	0.62%	$260,919	13.00%
13	428	2.55%	3,985	23.75%	$33,834	1.69%	$294,753	14.68%
14	678	4.04%	4,663	27.78%	$69,954	3.48%	$364,707	18.17%
15	1,809	10.78%	6,471	38.56%	$334,304	16.65%	$699,012	34.82%
16	2,482	14.79%	8,953	53.35%	$404,561	20.15%	$1,103,573	54.97%
17	2,972	17.71%	11,925	71.06%	$449,552	22.39%	$1,553,125	77.36%
18	2,593	15.45%	14,519	86.52%	$323,419	16.11%	$1,876,543	93.47%
19	1,448	8.63%	15,966	95.14%	$101,101	5.04%	$1,977,645	98.51%
20	507	3.02%	16,473	98.16%	$19,977	1.00%	$1,997,622	99.50%
21	167	1.00%	16,640	99.16%	$5,560	0.28%	$2,003,182	99.78%
22	72	0.43%	16,712	99.58%	$4,051	0.20%	$2,007,233	99.98%
23	49	0.29%	16,761	99.88%	$323	0.02%	$2,007,555	100.00%
24	21	0.12%	16,782	100.00%	$56	0.00%	$2,007,612	100.00%

Table 5-10 Frequency distribution of Economic Program zonal, load-weighted, average LMP (By hours): Calendar year 2011

	MWh Reductions				Program Credits			
LMP	MWh Reductions	Percent	Cumulative MWh	Cumulative Percent	Credits	Percent	Cumulative Credits	Cumulative Percent
$0 to $25	18	0.11%	18	0.11%	$508	0.03%	$508	0.03%
$25 to $50	2,028	12.09%	2,047	12.19%	$10,230	0.51%	$10,738	0.53%
$50 to $75	3,208	19.12%	5,255	31.31%	$57,601	2.87%	$68,339	3.40%
$75 to $100	1,775	10.57%	7,029	41.89%	$71,362	3.55%	$139,701	6.96%
$100 to $125	1,605	9.56%	8,634	51.45%	$99,603	4.96%	$239,304	11.92%
$125 to $150	1,376	8.20%	10,010	59.65%	$122,436	6.10%	$361,741	18.02%
$150 to $200	2,040	12.16%	12,050	71.81%	$248,723	12.39%	$610,464	30.41%
$200 to $250	1,262	7.52%	13,313	79.33%	$210,393	10.48%	$820,857	40.89%
$250 to $300	962	5.73%	14,274	85.06%	$208,525	10.39%	$1,029,382	51.27%
> $300	2,507	14.94%	16,782	100.00%	$978,230	48.73%	$2,007,612	100.00%

Emergency Program

The zonal distribution of DSR capability in the Emergency Program option is shown in Table 5-11 by program option. On July 21, 2011, the peak-load day for the year, there were no available resources in the Emergency-Energy Only option of the Emergency Program. There were 10,132 sites accounting for 10,334.3 MW registered in the Emergency Full option and 819 sites accounting for 1,188.4 MW registered in Emergency Capacity Only option. The ComEd Control Zone showed the highest number of registered sites in Emergency-Full option at 1,178 or 12 percent, while the AEP Control Zone showed the highest MW capability with 1,623.1 MW registered, or 16 percent of MW registered in the option. The ComEd Control Zone showed the highest participation in the Capacity Only option of the Emergency Program with 496 sites, or 61 percent of total sites, and 479.6 MW, or 40 percent of total MW registered in the option. Total peak-load day registrations in the Emergency Program increased by 39 percent, from 7,881 in 2010 to 10,951 in 2011, and total peak day registered MW increased by 27 percent, from 9,052.4 MW in 2010 to 11,522.7 in 2011.

Table 5-11 Registered sites and MW in the Emergency Program[38] (By zone and option): July 22, 2011

	Energy Only		Full		Capacity Only	
	Sites	MW	Sites	MW	Sites	MW
AECO	0	0.0	173	79.6	2	12.7
AEP	0	0.0	1,028	1,623.1	79	384.4
APS	0	0.0	952	896.5	14	23.0
ATSI	0	0.0	487	1,238.4	0	0.0
BGE	0	0.0	619	891.4	7	79.8
ComEd	0	0.0	1,178	1,185.4	496	479.6
DAY	0	0.0	174	172.9	16	46.4
DLCO	0	0.0	722	1,055.8	3	5.6
Dominion	0	0.0	289	192.7	8	27.6
DPL	0	0.0	264	211.4	0	0.0
JCPL	0	0.0	324	210.4	0	0.0
Met-Ed	0	0.0	315	244.6	14	3.9
PECO	0	0.0	958	479.2	137	106.7
PENELEC	0	0.0	494	390.1	4	3.3
Pepco	0	0.0	452	309.0	5	3.3
PPL	0	0.0	944	735.2	28	10.5
PSEG	0	0.0	745	412.3	6	1.8
RECO	0	0.0	14	6.4	0	0.0
Total	0	0.0	10,132	10,334.3	819	1,188.4

Load Management Program

The increase in registrations in the Emergency Program for peak periods in 2010 compared to 2009 is due to increased participation in the Load Management (LM) Program, that is, increased load response participation in RPM. Table 5-12 shows registered MW in the Load Management Program by program type for delivery years 2007/2008 through 2011/2012.

Table 5-12 Registered MW in the Load Management Program by program type: Delivery years 2007 through 2011

Delivery Year	Total DR MW	Total ILR MW	Total LM MW
2007/2008	560.7	1,584.6	2,145.3
2008/2009	1,017.7	3,480.5	4,498.2
2009/2010	1,020.5	6,273.8	7,294.3
2010/2011	1,070.0	7,982.4	9,052.4
2011/2012	2,792.1	8,730.5	11,522.7

Table 5-13 shows zonal monthly capacity credits that were paid during the calendar year 2010 to ILR and DR resources. Capacity revenue decreased by $25 million or 4.9 percent, from $512 million in 2010 to $487 million in 2010. Credits from January to May are associated with participation in the 2010/2011 RPM delivery year, while credits from June to December are associated with participation in the 2011/2012 RPM delivery year. The decrease in capacity credits after May is the result of a decrease in RPM clearing prices.

Load Management Event Compliance

In calendar year 2011, PJM declared five Load Management events. The first and second events, declared on May 26, 2011 and May 31, 2011, affected resources committed in the 2010/2011 Delivery Year, as it occurred prior to June 1, 2011. However, since it fell outside of the summer compliance period of June through September, curtailment was not required and no compliance penalties were assessed for this event.[39] Participants that did curtail were eligible to receive emergency energy credits. The three following events were called on the same day, July 22, 2011, but as separate events. These events affected resources committed in the 2011/2012 Delivery Year. Since each of these events occurred within the summer compliance

38 Table 5-11 shows registered sites and MW in the Emergency Program as of July 22, 2011, the peak load day of 2011. As all resources are registered in either the Capacity Only or Full options, all resources in the Emergency Program are considered RPM Resources participating in the Load Management (LM) Program and Table 5-12 reflects the same participation. Registered sites and MW remain constant in the LM Program through delivery years.

39 See RAA, Schedule 6 § L.

Table 5-13 Zonal monthly capacity credits: Calendar year 2011

Zone	January	February	March	April	May	June	July	August	September	October	November	December	Total
AECO	$515,251	$465,388	$515,251	$498,630	$515,251	$332,740	$343,831	$343,831	$332,740	$343,831	$332,740	$343,831	$4,883,314
AEP	$7,718,744	$6,971,769	$7,718,744	$7,469,752	$7,718,744	$5,220,226	$5,394,234	$5,394,234	$5,220,226	$5,390,887	$5,216,988	$5,390,887	$74,825,436
APS	$4,272,819	$3,859,321	$4,272,819	$4,134,986	$4,272,819	$3,300,774	$3,410,799	$3,410,799	$3,300,774	$3,410,799	$3,300,774	$3,410,799	$44,358,284
ATSI	$0	$0	$0	$0	$0	$4,665	$4,821	$4,821	$4,665	$4,821	$4,665	$4,821	$33,277
BGE	$5,039,828	$4,552,103	$5,039,828	$4,877,253	$5,039,828	$3,513,455	$3,630,571	$3,630,571	$3,513,455	$3,630,571	$3,513,455	$3,630,571	$49,611,487
ComEd	$8,156,971	$7,367,587	$8,156,971	$7,893,843	$8,156,971	$5,965,794	$6,180,266	$6,180,266	$5,980,903	$6,180,266	$5,980,903	$6,180,266	$82,381,008
DAY	$1,151,545	$1,040,105	$1,151,545	$1,114,399	$1,151,545	$797,889	$824,485	$824,485	$797,889	$824,485	$797,889	$824,485	$11,300,748
DLCO	$1,118,544	$1,010,298	$1,118,544	$1,082,462	$1,118,544	$2,340	$2,418	$2,418	$2,340	$3,977,804	$3,849,488	$3,977,804	$17,263,005
Dominion	$5,447,494	$4,920,317	$5,447,494	$5,271,768	$5,447,494	$3,851,851	$3,980,247	$3,980,247	$3,851,851	$817,336	$790,970	$817,336	$44,624,406
DPL	$1,088,233	$982,920	$1,088,233	$1,053,128	$1,088,233	$790,970	$817,336	$817,336	$790,970	$2,418	$2,340	$2,418	$8,524,536
JCPL	$1,301,034	$1,175,128	$1,301,034	$1,259,066	$1,301,034	$854,729	$883,220	$883,220	$854,729	$883,220	$854,729	$883,220	$12,434,362
Met-Ed	$1,205,089	$1,088,468	$1,205,089	$1,166,215	$1,205,089	$880,176	$909,516	$909,516	$880,176	$909,516	$880,176	$909,516	$12,148,541
PECO	$2,826,229	$2,552,723	$2,826,229	$2,735,060	$2,826,229	$2,300,272	$2,376,947	$2,376,947	$2,300,272	$2,375,286	$2,298,664	$2,375,286	$30,170,144
PENELEC	$1,827,610	$1,650,744	$1,827,610	$1,768,654	$1,827,610	$1,335,716	$1,380,240	$1,380,240	$1,335,716	$1,380,240	$1,335,716	$1,380,240	$18,430,336
Pepco	$1,307,359	$1,180,840	$1,307,359	$1,265,186	$1,307,359	$1,137,037	$1,174,938	$1,174,938	$1,137,037	$1,174,938	$1,137,037	$1,174,938	$14,478,965
PPL	$4,115,164	$3,716,922	$4,115,164	$3,982,417	$4,115,164	$2,651,235	$2,739,610	$2,739,610	$2,651,235	$2,739,610	$2,651,235	$2,739,610	$38,956,977
PSEG	$2,536,813	$2,291,315	$2,536,813	$2,454,980	$2,536,813	$1,431,581	$1,479,301	$1,479,301	$1,431,581	$1,468,327	$1,420,962	$1,468,327	$22,536,115
RECO	$9,266	$8,369	$9,266	$8,967	$9,266	$21,799	$22,526	$22,526	$21,799	$22,526	$21,799	$22,526	$200,634
Total	$49,637,993	$44,834,317	$49,637,993	$48,036,767	$49,637,993	$34,393,250	$35,555,305	$35,555,305	$34,408,359	$35,536,881	$34,390,530	$35,536,881	$487,161,575

Table 5-14 PJM declared Load Management Events: Calendar year 2011

Event Date	Event Times	Delivery Year	Geographical area
26-May-11	HE 1500 - 1900	2010/2011	Norfolk portion of Dominion
31-May-11	HE 1600 - 2000	2010/2011	AECO, BGE, Dominion, DPL, JCPL, Met-Ed PECO, Pepco, PENELEC, PSEG, RECO
22-Jul-11	HE 1300 - 1800	2011/2012	BGE (Short Lead Time)
22-Jul-11	HE 1300 - 1800	2011/2012	BGE (Long Lead Time)
22-Jul-11	HE 1400 - 2000	2011/2012	DLCO, DPL, JCPL, Met-Ed, PECO

period, each was considered in compliance assessment. Table 5-14 lists Load Management Events declared by PJM in calendar year 2011.

For all events listed in Table 5-14, except for a specific deployment of short lead time resource in BGE on July 22, 2011, PJM deployed only long lead time resources, which are those that require between one to two hours notification. As a result, the nominal ICAP stated in event compliance tables in this section may not equal total nominal ICAP for the zone. For the July 22 Event, PJM deployed short lead time resources for BGE in addition to long lead time resources. Short lead time resources are those which require no more than an hour notification. Approximately 95.5 percent of registrations, accounting for 83.2 percent of registered MW, are designated as long lead time resources.

The event on May 26 was the second time in the history of PJM Load Response Programs that PJM deployed emergency demand side resources subzonally. While all PJM Emergency Actions, including Load Management Events, may be issued for part of a zone, the only locational requirement for the aggregation of multiple end use customers to a single registration is that they reside in the same control zone. Similarly, compliance for testing and for zonal Emergency Events, is aggregated for each CSP to a zonal portfolio. Some market participants were not prepared to deploy resources on a subzonal level, and they submitted event compliance data for all resources within the Dominion Zone.

That PJM may require subzonal Load Management events while CSPs may aggregate customers on a zonal basis and, in some cases, are assessed compliance on a zonal basis, is a broader issue that needs to be addressed. More precise locational deployment of Load Management improves efficiency while reducing the ability of a CSP to aggregate customers. A requirement to identify the subzonal location of demand resources would be a positive step towards nodal pricing and the ability of PJM to deploy demand resources in a manner more consistent with the nodal deployment of generation and more consistent with nodal pricing. Without the ability to dispatch resources nodally, demand resources may be called where they are not needed. The Norfolk subzone of Dominion illustrated the need for subzonal dispatch, as weather events caused DR to be needed only within the Norfolk subzone, and outside this subzone any emergency response was unnecessary.

Table 5-15 Load Management event performance: July 22, 2011

Zone	Nominal ICAP	Committed MW	Load Reduction Observed	Over/Under Compliance	Percent Compliance	Percent of Nominal ICAP
BGE	1,001.7	956.8	962.1	5.3	100.6%	96.0%
BGE Short Lead	521.1	517.6	521.0	3.5	100.7%	100.0%
BGE Long Lead	480.6	439.3	441.1	1.8	100.4%	91.8%
DLCO	205.4	182.0	162.9	(19.1)	89.5%	79.3%
DPL	171.7	167.2	128.5	(38.7)	76.8%	74.8%
JCPL	183.0	177.4	141.1	(36.3)	79.5%	77.1%
Met-Ed	244.6	239.7	205.9	(33.8)	85.9%	84.2%
PECO	590.7	572.6	497.1	(75.4)	86.8%	84.2%
Total	2,397.0	2,295.7	2,097.6	(198.1)	91.4%	87.5%

Table 5-16 Distribution of participant event days across ranges of performance levels across the event in the 2011/2012 Delivery Year compliance period

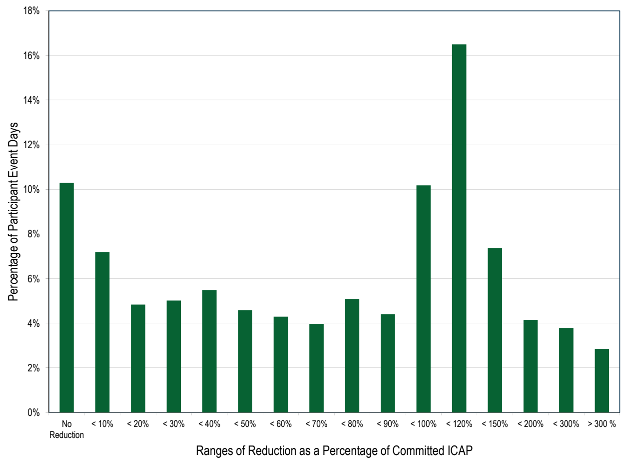
Ranges of performance as a percentage of committed MW	Number of participant event days	Proportion of participant event days	Cumulative Proportion
0% or no load reduction	285	10%	10%
0% -10%	199	7%	17%
10% - 20%	134	5%	22%
20% - 30%	139	5%	27%
30% - 40%	152	5%	33%
40% - 50%	127	5%	37%
50% - 60%	119	4%	42%
60% - 70%	110	4%	46%
70% - 80%	141	5%	51%
80% - 90%	122	4%	55%
90% - 100%	282	10%	65%
100% - 120%	457	16%	82%
120% - 150%	204	7%	89%
150% - 200%	115	4%	93%
200% - 300%	105	4%	97%
> 300%	79	3%	100%
Total	2,770	100%	

Table 5-15 shows performance for the July 22 event. The first column shows the nominal value which represents the reduction capability indicated by the participant at registration. The second column shows Load Management MW commitments, which are used to assess RPM compliance. Differences between these two columns may reflect differences between MW offered and cleared for any partially cleared DR resource. In addition, RPM commitments consider any RPM transactions, such as capacity replacement sales or purchases for Demand Resources, while the nominal ICAP does not. Overall, the performance was 87.5 percent, or 2,097.6 MW out of 2,296.1 MW committed. BGE showed the highest MW reduction with 962.1 MW in observed load reduction or 46 percent of total observed load reduction, as well as the highest aggregated performance percentage of 100.6 percent.

Performance for specific customers varied significantly. Table 5-16 shows the distribution of participant event days across various levels of performance for the event in the 2011/2012 compliance period. For this event, approximately 17 percent of participants showed little or no reduction. Approximately 37 percent of participants did not meet half of their committed MW. The majority of participants, approximately 65 percent, showed less than 100 percent reduction to their commitment. Figure 5-3 shows the data in Table 5-16.[40] The distribution appears bimodal, with high frequencies of both low performing and over performing registrations. The large disparity in performance and the proportion of underperforming assets are indicative of over compliance offsetting underperforming resources, and consistent with double counting.

40 Participant event days, shown in , Figure 5-3, and Table 5-17, are defined as distinct event performances by registration. If a registration was deployed for multiple events, each event constitutes a single participant even day. In addition, the load reduction values associated do not reflect actual MWh curtailments, but average curtailments in each event, summed for all events in the period.

Figure 5-3 Distribution of participant event days across ranges of performance levels across the event in the 2011/2012 Delivery Year compliance period



It is difficult to determine whether Guaranteed Load Drop (GLD) customers have managed their PLCs without more load data than is provided for compliance settlements. However, one way to evaluate the likelihood that a customer has managed their PLC is to compare the PLC to the observed load reduction in real time. For customers that did not manage PLC in prior years, the PLC should reflect unrestricted usage during system peak conditions. It is unlikely that these customers would be able to show a reduction in real time greater than their PLC unless their PLC represented a managed consumption level. Table 5-17 shows the distribution of GLD participant event days and observed load reductions across ranges of load reduction as a percentage of PLC for all events in the 2011/2012 Delivery Year.

About 77 percent of GLD participants submitting event compliance data show reductions in real time which are less than or equal to 75 percent of their PLC. These GLD participants account for 456 MW of event day reductions, which is 40 percent of GLD event day reductions and 22 percent of total event day reductions. Observed reductions for these customers account for 75 percent or less of their purchased capacity, which is based on historical peak usage levels.

About 14 percent of GLD participants submitting event compliance data show reductions in real time which are greater than or equal to 100 percent of their PLC. These GLD participants account for 584 MW of event day reductions, which is 51 percent of GLD reductions and 28 percent of total reductions. It is reasonable to conclude that such GLD customers, showing a reduction greater than or equal to PLC, did manage their PLCs in the prior year. Reductions from customers with reductions equal to from 150 percent to 300 percent or more of their PLC accounted for 29 percent of total GLD reductions. The results in Table 5-17 show the extent to which customers with managed PLCs are participating under the GLD option of the Load Management Program, and are consistent with double counting.

Emergency Energy Payments

For any PJM declared Load Management event in calendar year 2011, participants registered under the "Full" option of the Emergency Load Response Program that were deployed and that demonstrated a load reduction were eligible to receive emergency energy payments, which is equal to the higher of hourly zonal LMP or an energy offer made by the participant, including a dollar per MWh minimum dispatch price and an associated shutdown cost. In other words, participants are paid their emergency offer, regardless of the zonal LMP. Table 5-18 shows the distribution of registrations and associated MW in the Emergency Full Option across ranges of minimum dispatch prices. The majority of participants, about 73 percent, have a minimum dispatch price of $999/MWh or higher. Energy offers are further increased by shutdown costs submitted, which, in the 2011/2012 Delivery Year, range from $0 to more than $10,000. Depending on the size of the registration, the shutdown costs can significantly increase the effective $/MWh energy offer.

Table 5-19 shows emergency credits and make whole payments for each event in calendar year 2011. The emergency credit is market value of the load reductions observed during the event, based on applicable zonal LMPs. Make whole payments represent the difference between the market valuation of the load reduction, based on zonal LMP, and the submitted energy offer.

Table 5-17 Distribution of GLD participant event days and observed load reductions across ranges of load reduction as a percentage of Peak Load Contribution (PLC) for the events in the 2011/2012 Delivery Year

Ranges of load reduction as a percentage of PLC	Number of GLD participant event days	Proportion of total GLD participant event days	Cumulative Proportion	Observed reductions (MW)	Proportion of total GLD observed reductions	Cumulative Proportion
0% - 25%	1,017	50%	50%	157.7	14%	14%
25% - 50%	323	16%	66%	153.6	13%	27%
50% - 75%	234	11%	77%	144.7	13%	40%
75% - 100%	172	8%	86%	112.1	10%	49%
100% - 150%	183	9%	95%	249.4	22%	71%
150% - 200%	40	2%	97%	214.0	19%	90%
200% - 300%	36	2%	98%	24.7	2%	92%
300% or greater	35	2%	100%	95.8	8%	100%
Total	2,040	100%		1,152.0	100%	

Table 5-18 Distribution of registrations and associated MW in the Emergency Full Option across ranges of Minimum Dispatch Prices effective for the 2010/2011 Delivery Year

Ranges of Strike Prices ($/MWh)	Registrations	Percent of Total	Nominated MW (ICAP)	Percent of Total
$0 - $1	2,130	19.5%	3,407.2	29.6%
$1.01 - $200	90	0.8%	100.0	0.9%
$200 - $500	734	6.7%	503.8	4.4%
$500 - $998	39	0.4%	130.5	1.1%
$999+	7,958	72.7%	7,381.2	64.1%
Total	10,951	100.0%	11,522.7	100.0%

Table 5-19 Emergency credits and make whole payments by event: Calendar Year 2011

Event	Emergency Credits	Emergency Make Whole Payments	Total
31-May-11	$1,686,049	$2,332,381	$4,018,430
22-Jul-11	$4,259,202	$6,348,960	$10,608,162
Total	$5,945,250	$8,681,341	$14,626,592

Energy payments in the Emergency Program differ significantly from energy payments in the Economic Program and even capacity payments through the Load Management Program in that they are not based on or tied to any market price signal; they are simply guaranteed offers which are subject to no documentation or justification. In fact, their value should be aligned with the Economic Program, since it is designed to compensate for energy reductions and higher incentives would naturally occur as emergency events approach through higher energy market prices. However, because the two programs are not aligned and because the emergency credits are significantly more attractive to participants than Economic Program payments, there is an incentive for participants to delay any economic load reductions on days when an emergency event may be called.

In addition, the measurement protocol used to determine emergency energy payments is misaligned with other Load Response Programs. All emergency energy payments are based on the "same day" method, which is the difference between usage for one hour prior to the event and usage throughout the event. If a customer opts for a different method in performance calculations, the same event and same load reducing activities will be associated with two different load reduction values, one for emergency energy settlements, another for performance calculations.

Load Management Testing

In the 2007/2008 and the 2008/2009 delivery years, Load Management (LM) compliance was assessed only for actual PJM declared events. If no event was declared, no capacity testing was required. PJM filed amendments to the tariff providing for LM testing if no emergency event is called by August 15 of the delivery year which became effective in the 2009/2010 delivery year. All of a provider's committed DR and certified ILR resources in the same zone are required to test at the same time for a one hour period between 12:00 PM EPT to 8:00 PM EPT on a non-holiday weekday between June 1 and September 30. The resource provider must notify PJM of the intent to test 48 hours in advance.[41]

Depending on initial test results, multiple tests may be conducted. If a Curtailment Service Provider (CSP) shows greater than or equal to 75 percent test compliance across a portfolio of resources, all noncompliant resources are eligible for retesting. However, if the initial test shows less than 75 percent compliance, no associated resources are eligible for a retest.

41 For more information, see PJM, "Manual 18, PJM Capacity Market", Revision 10 (June 1, 2010), Section 8.6.

Table 5-20 Load Management test results and compliance by zone for the 2011/2012 delivery year

Zone	Nominal ICAP	Committed MW	Load Reduction Test Results	Over/Under Compliance	Percent Test Compliance	Percent of Nominal ICAP
AECO	92.6	89.9	89.6	(0.3)	100%	97%
AEP	2,091.1	2,012.5	2,152.7	140.2	107%	103%
AP	931.8	920.2	944.0	23.8	103%	101%
ATSI	1,304.4	1,169.6	1,239.8	70.2	106%	95%
ComEd	1,665.0	1,633.0	1,730.3	97.3	106%	104%
DAY	222.7	222.2	246.5	24.3	111%	111%
DLCO	6.0	5.9	7.5	1.6	127%	125%
Dominion	1,152.5	1,106.7	1,089.8	(16.9)	98%	95%
DPL	48.7	48.6	48.7	0.1	100%	100%
JCPL	54.4	54.4	51.2	(3.2)	94%	94%
Met-Ed	3.9	3.9	5.3	1.4	136%	136%
PECO	1.4	1.4	1.2	(0.2)	86%	86%
PENELEC	401.3	400.8	434.3	33.5	108%	108%
Pepco	320.7	268.3	259.2	(9.1)	97%	81%
PPL	771.8	760.4	819.2	58.9	108%	106%
PSEG	419.9	404.0	437.7	33.7	108%	104%
RECO	6.4	6.4	4.6	(1.8)	72%	72%
Total	9,401.9	9,018.3	9,472.0	453.7	105%	101%

There were 9,018 MW of Committed ICAP not deployed in an event during the compliance period for the 2011/2012 Delivery year and thus required to perform testing. Load Management testing results are shown in Table 5-20. Overall, test results showed 453.7 MW available over RPM commitments, or 105 percent test compliance. The Met-Ed control zone showed the highest percentage of compliance, with load reductions at 136 percent of RPM Commitments, while the AEP control zone showed the highest level of MW reduction in testing, with load reductions at 2,152.7 MW, or 140.2 MW over RPM commitments.

Load Management test results are submitted by CSPs directly to PJM. The test results consist of metered load data provided by the CSP which are compared to some baseline consumption level or firm service level determined by LM participation type. There is no physical or technical oversight or verification by PJM or by the relevant LSE of actual testing. PJM screens the data for unreasonable test results, but relies on the CSP to submit accurate metered load data for the testing period with no verification.

This form of testing is not an adequate measurement and verification protocol to ensure that demand side capacity resources can reliably reduce during a system emergency. The MMU recommends that the testing program be modified to require verification of test methods and results.

Measurement and Verification

Traditionally, there have been two approaches to measurement and verification of demand side resources. The less common is specifying a firm MW level to which usage will be reduced. This method is limited to capacity based demand side products. In PJM's Load Management Program, this measurement and verification option is called Firm Service Level (FSL).

The more common approach for both economic and capacity demand side products is to establish a base line usage level by analyzing prior usage levels for a set of days that are intended to be representative of or similar to the day of the reduction. Similar can be defined by day of the week, peak or off peak, and, in more complicated scenarios, weather conditions. In the Economic Program, the baseline method is the default approach, and the standard baseline is referred to as Customer Baseline Load (CBL). In the Load Management Program, this measurement and verification option is called Guaranteed Load Drop (GLD) and there are several baseline methods to choose from. The extent to which the DSR Program can accurately quantify and compensate actual load reductions is dependent on the Program's ability to establish what a customer's metered load would have been absent any load reduction. This is a very difficult task and the methods used to date have been flawed, resulting in payments for reductions in usage that did not occur.

Baseline Pilot Study

On April 20, 2011 PJM issued a report from KEMA, which focused on potential improvements to the CBL methodology.[42] KEMA recommended the PJM economic CBL with a same day additive adjustment. KEMA concluded that same day additive adjustments perform better than an unadjusted or weather adjusted CBL. Some other CBLs were similar in accuracy, but required additional data or administrative burden in comparison to the PJM economic CBL. KEMA also recommended that rules be established to identify and mitigate any possible manipulation of CBLs.

Economic Program

In PJM's Economic Load Response Program, the primary tool used to establish what unrestricted load would have been is the standard CBL. The modifications to the CBL calculations currently occurring represent 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 demand reductions when payments are made under the program.

The definition of the standard or default CBL should continue to be refined to ensure that it reflects the actual normal use of individual customers including normal daily and hourly fluctuations in usage and usage that is a function of measurable weather conditions.

Participants in the Economic Program are paid based on the reductions in MWh usage that can be attributed to demand side actions. Most participants in the Economic Program measure their reductions by comparing metered load against a Customer Baseline Load (CBL), or an estimate of what metered load would have been absent the reduction.[43] The default CBL employed for approximately 85 percent of Economic Program Participants is the simple average usage over the highest four of the last five similar days.

Customer Base Line (CBL) – History

Since the beginning of the program, there have been significant issues with the approach to measuring demand-side response MW. An inaccurate or unrepresentative CBL can lead to payments when the customer has taken no action to respond to market prices. Substantial improvement in measurement and verification methods must be implemented in order to ensure the credibility of PJM demand-side programs. These could take the form of improvements in the CBL calculation and/or improvements in the verification and customer documentation of load reducing activities. The goal should be to treat the measurement of demand-side resources like the measurement of any other resource in the wholesale power market, including generation and load, that is paid by other participants or makes payments to other participants. PJM has made changes to improve the settlement review process, but more needs to be done.[44]

The current weekday CBL methodology includes the highest four of most recent five weekdays, with a maximum lag on eligible days set at 45. Low usage days (load less than 75 percent of the average) and event days (days with curtailment events or demand reductions) are eliminated and replaced with prior days, unless there are not enough eligible days in the last 45 weekdays. Saturdays are considered separately, as are Sundays and holidays. The elimination of event days means that CBL measurements are not limited to the most recent five weekdays and can include weekdays from as far back as 45 days.

CBL Issues

The CBL is a generic formula applied to nearly every customer's usage and is not adequate to serve as the sole or primary basis for determining if an intentional load reduction took place. There are no mandatory CBL enhancements for customers with highly volatile load patterns. If a customer normally has lower load on one particular weekday, that day will appear as a reduction eligible for payment under the current CBL methodology although no deliberate load reducing actions were taken in response to real time price signals. There are no mandatory adjustments to the standard CBL for load levels that are a function of weather. In a mild week following a week of extreme temperatures and high load levels, a customer can submit settlements without taking any load reducing action and it will appear as a reduction eligible for payment because metered load is

42 See "PJM Empirical Analysis of Demand Response Baseline Methods" <http://www.pjm.com/~/media/markets-ops/dsr/pjm-analysis-of-dr-baseline-methods-full-report.ashx>.

43 On-site generation meter data is the other method used to determine the load reduction, if used only for economic load reduction.

44 123 FERC ¶ 61,257 (2008).

below CBL. A customer's CBL calculation is only reviewed in the Economic Program registration process and the review criteria are unclear. In the registration process, an alternative CBL may be proposed by the CSP or the relevant LSE/EDC, though following Order 745 changes, CBLs must undergo a Relative Root Mean Squared Error (RRMSE) test to determine the most accurate method.[45] PJM has developed thirteen alternative CBL calculations, three of which include a weather sensitivity adjustment.

Determining the accuracy of a CBL is difficult. More data are required than the metered load associated with settlement and the CBL used to determine the reduction amount. However, those are the only data currently available to PJM at the time of settlement review. Complete historical data is required in order to determine whether the CBL is representative of normal load patterns.

In the future, retail markets will reflect hourly wholesale prices and customers will receive direct savings associated with reducing consumption in response to real-time prices. There will not be a need for a PJM Economic Load Response Program, or for an extensive measurement and verification protocol. In the transition to that point, there is a need for robust measurement and verification techniques to ensure that transitional programs are incenting the desired behavior. These techniques are designed to estimate what consumption would have been, absent any load reducing activities.

Analysis of Settlements

PJM and the MMU only have access to meter data submitted as part of a settlement day. Neither PJM nor the MMU have sufficient data to determine if hours submitted for settlement represent deliberate actions taken or normal load fluctuations due to other variables.

The MMU has reported that a large number of consecutive hours showing a metered load less than CBL may be an indication that the CBL is not an adequate method to determine load reductions.[46] If a CBL is accurately modeling load patterns, then a CBL greater than real time load indicates load reducing actions are taking place. If, for any settlement, the number of consecutive hours showing load reduction is beyond a reasonable window for load reducing actions in response to price, it should trigger a CBL review and warrant further substantiation from the customer and CSP.

The occurrence of 24 hour settlement submissions and therefore the frequency of 24 consecutive hours where the CBL is greater than metered load have decreased significantly every year since 2008. However, this does not indicate that the CBL is more accurate and there are still instances of requests for settlements passing the daily activity review screen that include 24 consecutive hours of reduction. These settlements are paid without any documentation of load reducing activities in response to real time price signals.

It is extremely implausible that any customer would take load reduction actions for 24 consecutive hours in response to real time price signals. It is also extremely implausible that an accurate CBL would result in metered load less than base line load for every hour of the day. It is more likely that the CBL is biased upward because it is based on usage from prior days with higher load. Under these circumstances, it is impossible to determine whether the customer took any load reducing actions, from the settlement data.

The MMU recommends that any settlement submitted with a consecutive 24 hour period of CBL greater than metered load should trigger a CBL review by PJM and that a customer should be required to provide documentation of load reduction actions taken, prior to acceptance of such settlements. Further, in order for PJM or the MMU to assess the accuracy of the CBL for a particular customer or for the Program in general, more hourly load data is required than is currently captured by PJM.

Load Management Program

There are three measurement and verification protocols in the Load Management (LM) Program: (1) Direct Load Control (DLC), (2) Firm Service Level (FSL), and (3) Guaranteed Load Drop (GLD). The DLC method is used for 8 percent of registered MW in the LM Program, while the FSL method is used for 32 percent and the GLD method is used for 60 percent.[47]

45 If, however, agreement cannot be reached, then PJM will determine the alternative CBL.

46 A similar and more extensive analysis of settlements also appears in the *2008 State of the Market Report for PJM*, Volume II, Section 2, "Energy Market, Part 1", p. 108.

47 Of the 56 percent of registered MW nominated as Guaranteed Load Drop, seven percent elect the behind the meter generation option for measurement and verification.

For DLC customers, a CSP will interface directly with customer equipment, sending a communication to reduce when PJM has declared an event. Load reductions are estimated through PJM reported or site surveyed impact studies. While customers are required to provide documentation of technical capabilities to enroll in this option, no telemetry or load data are required for verification of actual event performance. Rather, the CSP submits to PJM the time at which the equipment is deployed. There is no way for PJM or the MMU to determine if any load reduction took place in an emergency event.

GLD customers establish a baseline of unrestricted consumption absent the emergency event, similar to the measurement and verification procedure in the Economic Program. The load reduction for GLD customers is the reduction of committed MW when an event is called. There are several techniques for estimation available to participants. The comparable day option determines reductions based on consumption on similar day experience. Another option determines reduction as differences from hourly load immediately prior to or following an event. A third option is the standard CBL calculation used in the Economic Program. Other options include regression analysis and load profile modeling.

FSL customers establish a firm consumption level which they must reach during an emergency event and the difference between that firm service level and the Peak Load Contribution (PLC) is the amount nominated in the LM Program. FSL customers are contractually obligated to reduce load to a nominal value. The measurement and verification of load reductions under FSL option for purposes of event compliance is relatively straightforward.

The shortfalls of the standard CBL calculation used in the Economic Program have been identified, including the potential for an upward bias based on prior days with warmer temperatures. The potential for an upward bias during an actual Emergency Event is more limited, since Emergency Events coincide with peak load conditions in PJM which are highly correlated with peak temperatures. However, this design flaw is an issue when applied to Load Management testing as participants have discretion as to when testing will take place. Currently, GLD customers can test on any day in the summer period, and choose any other day in that period to serve as the baseline consumption for estimating load reductions. There are no objective criteria to establish comparability between the baseline day and test day.

The MMU recommends that any baseline approach designed to estimate unrestricted load consumption based on a comparable day or a comparable set of days be adjusted for ambient conditions and other variables impacting load for all participants.

While the introduction of Load Management testing for any delivery year without an emergency event is an improvement to the Program, the current state of testing does not constitute an adequate measurement and verification protocol to ensure that demand side capacity resources can reliably reduce during a system emergency. The MMU recommends that the testing program be modified to require verification of test methods and results. In addition, the MMU recommends refinement of the baseline methods used to calculate compliance in Load Management for GLD customers. The baseline pilot study conducted by KEMA indicated that the CBL used by the PJM Economic Program is an improvement, and consequently should be used by the GLD option in the Load Management Program.