Demand Response

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 without depending on special programs as a proxy for full participation.

Overview

- **Demand Response Jurisdiction.** In a panel decision issued May 23, 2014, the U.S. Court of Appeals for the District of Columbia Circuit vacated Order No. 745, which provided for payment of demand-side resources at full LMP.[1] The court found that the FERC lacked jurisdiction to issue Order No. 745 because the "rule entails direct regulation of the retail market - a matter exclusively within state control."[2] On January 25, 2016, the Supreme Court voted 6-2 to reverse the decision of the lower court.[3] The result is that FERC retains jurisdiction over demand-side programs.
- **Demand Response Activity.** Demand response includes the economic program and the emergency program. The economic program includes the response to energy prices in the energy market. The emergency program is the capacity market program which includes both capacity payments and associated energy revenues when the capacity is called on to respond. The emergency program accounted for 98.4 percent of all revenue received by demand response providers, the economic program for 1.0 percent and synchronized reserve for 0.6 percent. In 2015, total emergency revenue increased by $136.4 million, or 20.2 percent, from $675.7 million in 2014 to $812.2 in 2015. Capacity market revenue increased by $178.9 million, or 28.3 percent, from $632.8 million in 2014 to $811.7 million 2015.[4] Emergency energy revenue decreased by $42.5 million, from $43.0 million in 2014 to $0.5 million in 2015. Economic program revenue decreased by $9.5 million, from $17.8 million in 2014 to $8.3 million in 2015, a 53.2 percent decrease.[5] Synchronized reserve revenue increased by $43.3 thousand, a 0.6 percent increase. Total demand response revenue in 2015 increased by 18.2 percent from $675.7 million 2014 to $825.6 million in 2015. Not all DR activities in 2015 have been reported to PJM at the time of this report.

  All demand response energy payments are uplift. LMP does not cover demand response energy payments although emergency demand response can and does set LMP. Emergency demand response energy costs are paid by PJM market participants in proportion to their net purchases in the real-time market. Economic demand response energy costs are paid by real-time exports from the PJM Region and real-time loads in each zone for which the load-weighted average real-time LMP for the hour during which the reduction occurred is greater than the single system price determined under the net benefits test for that month.[6]
- **Demand Response Market Concentration.** The ownership of economic demand response was highly concentrated in 2014 and 2015. The HHI for economic demand response reductions increased from 7713 in 2014 to 7862 in 2015. The ownership of emergency demand response was moderately concentrated in 2015. The HHI for emergency demand response registrations was 1760 for the 2014/2015 Delivery Year and 1497 for the 2015/2016 Delivery Year. In 2015, the four largest companies contributed 65.3 percent of all registered emergency demand response resources.
- **Locational Dispatch of Demand Resources.** Beginning with the 2014/2015 Delivery Year, demand resources are dispatchable for mandatory reduction on a subzonal basis, defined by zip codes, only if the subzone is defined at least one day before it is dispatched. More locational dispatch of demand resources in a nodal market improves market efficiency. The goal should be nodal dispatch of demand resources with no advance notice required as is the case for generation resources.

1 Electric Power Supply Association v. FERC, No. 11-1486, petition for en banc review denied; see 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).

2 *Id.*

3 FERC v. Electric Power Supply Association, Slip Op. No. 14-840.

4 The total credits and MWh numbers for demand resources were calculated as of February 27, 2015 and may change as a result of continued PJM billing updates.

5 Economic credits are synonymous with revenue received for reductions under the economic load response program.

6 PJM: "Manual 28: Operating Agreement Accounting," Revision 64 (April 11, 2014), p 70.

Recommendations

The MMU recognizes that PJM has incorporated some of these recommendations in the Capacity Performance filing. The status of each recommendation reflects the status at December 31, 2015.

- The MMU recommends, as a preferred alternative to having PJM demand side programs, that demand response be on the demand side of the markets and that customers be able to avoid capacity and energy charges by not using capacity and energy at their discretion and that customer payments be determined only by metered load. (Priority: High. First reported 2014. Status: Not adopted.)
- The MMU recommends that there be only one demand response product, with an obligation to respond when called for all hours of the year, and that the demand response be on the demand side of the capacity market. (Priority: High. First reported 2011. Status: Partially Adopted.[7])
- The MMU recommends that the option to specify a minimum dispatch price under the Emergency and Pre-Emergency Program Full option be eliminated and that participating resources receive the hourly real-time LMP less any generation component of their retail rate. (Priority: Medium. First reported 2010. Status: Not adopted.)
- The MMU recommends that the emergency load response program be classified as an economic program, responding to economic price signals and not an emergency program responding only after an emergency is called and not triggering the definition of a PJM emergency. (Priority: High. First reported 2012. Status: Not adopted.)
- The MMU 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. (Priority: Low. First reported 2010. Status: Not adopted.)
- The MMU recommends that a daily energy market must offer requirement apply to demand resources, comparable to the rule applicable to generation capacity resources.[8] (Priority: High. First reported 2013. Status: Not adopted.)
- The MMU recommends that the lead times for demand resources be shortened to 30 minutes with an hour minimum dispatch for all resources. (Priority: Medium. First reported 2013. Status: Partially adopted.)
- The MMU recommends that demand resources be required to provide their nodal location, comparable to generation resources. (Priority: High. First reported 2011. Status: Not adopted.)
- The MMU recommends that PJM require nodal dispatch of demand resources with no advance notice required or, if nodal location is not required, subzonal dispatch of demand resources with no advance notice required. (Priority: High. First reported 2015. Status: Not adopted.)
- The MMU recommends that PJM eliminate the measurement of compliance across zones within a compliance aggregation area (CAA). The multiple zone approach is less locational than the zonal and subzonal approach and creates larger mismatches between the locational need for the resources and the actual response. (Priority: High. First reported 2015. Status: Not adopted.)
- The MMU recommends capping the baseline for measuring compliance under GLD, for the limited summer product, at the customers' PLC. (Priority: High. First reported 2010. Status: Adopted.)
- The MMU recommends capping the baseline for measuring capacity compliance under winter compliance at the customers' PLC, similar to GLD, to avoid double counting. (Priority: High. First reported 2010. Status: Partially adopted.)
- The MMU recommends that measurement and verification methods for demand resources be modified to reflect compliance more accurately. (Priority: Medium. First reported 2009. Status: Not adopted.)
- The MMU recommends that compliance rules be revised to include submittal of all necessary hourly load data, and that negative values be included when calculating event compliance across hours

7 PJM's Capacity Performance proposal includes this change. See "Reforms to the Reliability Pricing Market ("RPM") and Related Rules in the PJM Open Access Transmission Tariff ("Tariff") and Reliability Assurance Agreement Among Load Serving Entities ("RAA")," Docket No. ER15-632-000 and "PJM Interconnection, L.L.C." Docket No. EL15-29-000.

8 See "Complaint and Motion to Consolidate of the Independent Market Monitor for PJM," Docket No. EL14-20-000 (January 27, 2014) at 1.

and registrations. (Priority: Medium. First reported 2012. Status: Not adopted.)

- The MMU recommends that PJM adopt the ISO-NE five-minute metering requirements in order to ensure that dispatchers have the necessary information for reliability and that market payments to demand resources be calculated based on interval meter data at the site of the demand reductions.[9] (Priority: Medium. First reported 2013. Status: Not adopted.)
- The MMU recommends that demand response event compliance be calculated for each hour and the penalty structure reflect hourly compliance for the base and capacity performance products. (Priority: Medium. First reported 2013. Status: Not adopted.)
- The MMU recommends that demand resources whose load drop method is designated as "Other" explicitly record the method of load drop. (Priority: Low. First reported 2013. Status: Adopted Q2, 2014.)
- The MMU recommends that load management testing be initiated by PJM with limited warning to CSPs in order to more accurately represent the conditions of an emergency event. (Priority: Low. First reported 2012. Status: Not adopted.)
- The MMU recommends that shutdown cost be defined as the cost to curtail load for a given period that does not vary with the measured reduction or, for behind the meter generators, be the start cost defined in Manual 15 for generators. (Priority: Low. First reported 2012. Status: Not adopted.)
- The MMU recommends that the Net Benefits Test be eliminated and that demand response resources be paid LMP less any generation component of the applicable retail rate. (Priority: Low. New Recommendation. Status: Not adopted.)
- The MMU recommends that the tariff rules for demand response clarify that a resource and its CSP, if any, must notify PJM of material changes affecting the capability of the resource to perform as registered and to terminate registrations that are no longer capable of responding to PJM dispatch directives because load has been reduced or eliminated, such as in the case of bankrupt and/or out of service facilities. (Priority: Medium. First reported Q2, 2015. Status: Not adopted.)

Conclusion

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 in the same year in which demand for capacity changes. 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.

In the energy market, if there is to be a demand side program, demand resources should be paid the value of energy, which is LMP less any generation component of the applicable retail rate. There is no reason to have the net benefits test. The necessity for the net benefits test is an illustration of the illogical approach to demand side compensation embodied in paying full LMP to demand resources. The benefit of demand side resources is not that they suppress market prices, but that customers can choose not to consume at the current price of power, that individual customers benefit from their choices and that the choices of all customers are reflected in market prices. If customers face the market price, customers should have the ability to not purchase power and the market impact of that choice does not require a test for appropriateness.

If demand resources are to continue competing directly with generation capacity resources in the PJM Capacity Market, the product must be defined such that it can actually serve as a substitute for generation. This is a prerequisite to a functional market design.

In order to be a substitute for generation, demand resources should be defined in PJM rules as an economic resource, as generation is defined. Demand resources

9 See ISO-NE Tariff, Section III, Market Rule 1, Appendix E1 and Appendix E2, "Demand Response," <http://www.iso-ne.com/regulatory/tariff/sect_3/mr1_append-e.pdf>. (Accessed February 17, 2015) ISO-NE requires that DR have an interval meter with five minute data reported to the ISO and each behind the meter generator is required to have a separate interval meter. After June 1, 2017, demand response resources in ISO-NE must also be registered at a single node.

should be required to offer in the Day-Ahead Energy Market and should be called when the resources are required and prior to the declaration of an emergency. Demand resources should be available for every hour of the year and not be limited to a small number of hours.

In order to be a substitute for generation, demand resources should be subject to robust measurement and verification techniques to ensure that transitional DR programs incent the desired behavior. The methods used in PJM programs today are not adequate to determine and quantify deliberate actions taken to reduce consumption.

In order to be a substitute for generation, demand resources should provide a nodal location and should be dispatched nodally to enhance the effectiveness of demand resources and to permit the efficient functioning of the energy market. Both subzonal and multi-zone compliance should be eliminated because they are inconsistent with an efficient nodal market.

In order to be a substitute for generation, compliance by demand resources to PJM dispatch instructions should include both increases and decreases in load. The current method applied by PJM simply ignores increases in load and thus artificially overstates compliance.

In order to be a substitute for generation, reductions should be calculated hourly for dispatched DR. The current rules use the average reduction for the duration of an event. The average reduction across multiple hours does not provide an accurate metric for each hour of the event and is inconsistent with the measurement of generation resources. Measuring compliance hourly would provide accurate information to the PJM system. Under the new CP rules, the performance of demand response during Performance Assessment Hours will be measured on an hourly basis. Overall demand response compliance is still measured by performance across the entire event.[10]

In order to be a substitute for generation, any demand resource and its Curtailment Service Provider (CSP), should be required to notify PJM of material changes affecting the capability of the resource to perform as registered and to terminate registrations that are no longer capable of responding to PJM dispatch directives, such as in the case of bankrupt and out of service facilities. Generation resources are required to inform PJM of any change in availability status, including outages and shutdown status.

As a preferred alternative, demand response should be on the demand side of the capacity market rather than on the supply side. Rather than complex demand response programs with their attendant complex and difficult to administer rules, customers would be able to avoid capacity and energy charges by not using capacity and energy at their discretion.

The long term appropriate end state for demand resources in the PJM markets should be comparable to the demand side of any market. Customers should use energy as they wish and that usage will determine the amount of capacity and energy for which each customer pays. There would be no counterfactual measurement and verification.

Under this approach, customers that wish to avoid capacity payments would reduce their load during expected high load hours. Capacity costs would be assigned to LSEs and by LSEs to customers, based on actual load on the system during these critical hours. Customers wishing to avoid high energy prices would reduce their load during high price hours. Customers would pay for what they actually use, as measured by meters, rather than relying on flawed measurement and verification methods. No M&V estimates are required. No promises of future reductions which can only be verified by M&V are required. To the extent that customers enter into contracts with CSPs or LSEs to manage their payments, M&V can be negotiated as part of a bilateral commercial contract between a customer and its CSP or LSE.

This approach provides more flexibility to customers to limit usage at their discretion. There is no requirement to be available year round or every hour of every day. There is no 30 minute notice requirement. There is no requirement to offer energy into the day-ahead market. All decisions about interrupting are up to the customers only and they may enter into bilateral commercial arrangements with CSPs at their sole discretion. Customers would pay for capacity and energy depending solely on metered load.

10 PJM "Manual 18: Capacity Market," Revision 29 (October 16, 2015), p 148.

A transition to this end state should be defined in order to ensure that appropriate levels of demand side response are incorporated in PJM's load forecasts and thus in the demand curve in the capacity market for the next three years. That transition should be defined by the PRD rules, modified as proposed by the Market Monitor.

This approach would work under the current RPM design and this approach would work under the CP design. This approach is entirely consistent with the Supreme Court decision in EPSA as it does not depend on whether FERC has jurisdiction over the demand side. This approach will allow FERC to more fully realize its overriding policy objective to create competitive and efficient wholesale energy markets. The decision of the Supreme Court addressed jurisdictional issues and did not address the merits of FERC's approach. The Supreme Court's decision has removed the uncertainty surrounding the jurisdictional issues and created the opportunity for FERC to revisit its approach to demand side.

PJM Demand Response Programs

All demand response programs in PJM can be grouped into economic, emergency and pre-emergency programs.[11] Pre-emergency demand response is defined to be dispatchable before an emergency event is declared.[12] Table 6-1 provides an overview of the key features of PJM demand response programs. Demand response program is used here to refer to pre-emergency, emergency and economic programs. Demand Resources is used here to refer to emergency and pre-emergency load response, which participate in the capacity market, and Economic Resources refer to economic load response, which participates solely in the energy market. All Demand Resources must register as pre-emergency unless the participant relies on behind the meter generation or the resource has environmental restrictions that limit the resource's ability to operate only in emergency conditions.[13] In all demand response programs, CSPs are companies that seek to sign up end-use customers, participants, that have the ability to reduce load. After a demand response event occurs, PJM compensate CSPs for their participants' load reductions and CSPs in turn compensates their participants. Only CSPs are eligible to participate in the PJM demand response program, but a participant can register as a PJM special member and become a CSP without any additional cost.

11 Throughout this document, emergency demand response refers to both emergency and pre emergency demand response.
12 147 FERC ¶ 61,103 (2014).
13 OATT Attachment K Appendix Section 8.5

Table 6-1 Overview of demand response programs

	Emergency and Pre-Emergency Load Response Program			Economic Load Response Program
	Load Management (LM)			
Market	Capacity Only	Capacity and Energy	Energy Only	Energy Only
Capacity Market	DR cleared in RPM	DR cleared in RPM	Not included in RPM	Not included in RPM
Dispatch Requirement	Mandatory Curtailment	Mandatory Curtailment	Voluntary Curtailment	Dispatched Curtailment
Penalties	RPM event or test compliance penalties	RPM event or test compliance penalties	NA	NA
Capacity Payments	Capacity payments based on RPM clearing price	Capacity payments based on RPM clearing price	NA	NA
Energy Payments	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 full LMP. Energy payment for hours of dispatched curtailment.

In a panel decision issued May 23, 2014, the U.S. Court of Appeals for the District of Columbia Circuit vacated Order No. 745, which provided for payment of demand-side resources at full LMP.[14] The court found that the FERC lacked jurisdiction to issue Order No. 745 because the "rule entails direct regulation of the retail market - a matter exclusively within state control."[15] On January 25, 2016, the Supreme Court voted 6-2 to reverse the decision of the lower court.[16] The result is that FERC retains jurisdiction over demand-side programs.

Participation in Demand Response Programs

On April 1, 2012, FERC Order No. 745 was implemented in the PJM economic program, requiring payment of full LMP for dispatched demand resources when a net benefit test (NBT) price threshold is exceeded. This approach replaced the payment of LMP minus the charges for wholesale power and transmission already included in customers' tariff rates.

Figure 6-1 shows all revenue from PJM demand response programs by market for each year for the period 2008 through 2015. Since the implementation of the RPM Capacity Market on June 1, 2007, demand response that participated through the capacity market, which includes emergency energy revenue, has been the primary source of revenue to demand response participants.[17]

In 2015, emergency and pre-emergency revenue, which includes capacity and emergency energy revenue, accounted for 98.4 percent of all revenue received by demand response providers, credits from the economic program were 1.0 percent and revenue from synchronized reserve was 0.6 percent.

Total emergency and pre-emergency revenue increased by $136.4 million, or 20.2 percent, from $675.7 million in 2014 to $812.2 in 2015. Of the total emergency revenue, capacity market revenue increased by $178.9 million, or 28.3 percent, from $632.8 million in 2014 to $811.7 million in 2015, due to higher clearing prices and volumes in the Capacity Market for the 2014/2015 and 2015/2016 delivery years. The weighted average RPM price increased 26.6 percent from $126.40 per MW-day in the 2014/2015 Delivery Year to $160.01 per MW-day in the 2015/2016 Delivery Year.[18] Emergency energy revenue decreased by $42.5 million, from $43.0 million in 2014 to $0.5 million in 2015. Total demand response revenue in 2015 increased by 18.2 percent from $698.4 million in 2014 to $825.4 million in 2015. Total demand response revenue includes economic, pre-emergency, emergency and synchronized reserve revenue.

Total revenue under the economic program decreased by $9.4 million from $17.8 million in 2014 to $8.3 million in 2015, a 53.2 percent decrease.

14 Electric Power Supply Association v. FERC, No. 11-1486, *petition for en banc review denied; see 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).

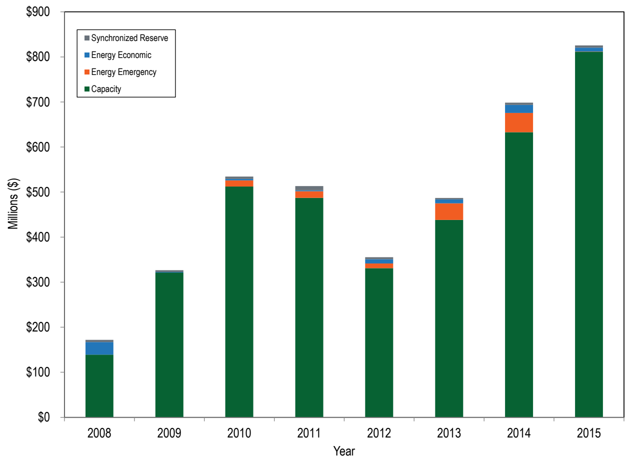
15 *Id.*

16 FERC v. Electric Power Supply Association, Slip Op. No. 14-840.

17 This includes both capacity market revenue and emergency energy revenue for capacity resources.

18 *2015 State of the Market Report for PJM: January through September*, Section 5: Capacity, Figure 5-6.

Figure 6-1 Demand response revenue by market: 2008 through 2015



Economic Program

Table 6-2 shows registered sites and MW for the last day of each month for the period January 2010 through December 2015. Registration is a prerequisite for CSPs to participate in the economic program. Both the average number of registrations for economic demand response and the average registered MW decreased in 2015 compared to 2014. The average number of monthly registrations decreased by 123 from 1,066 in 2014 to 943 in 2015. The average monthly registered MW for 2015 decreased by 56 MW, or 2.0 percent, from 2,787 MW in 2014 to 2,732 MW in 2015.

Several demand response resources are registered for both the economic and emergency demand response programs. There were 266 registrations and 1,363 nominated MW in the emergency program that were also registered in the economic program during 2015.

The registered MW in the economic load response program are not a good measure of the MW available for dispatch in the energy market. Economic resources can dispatch more, less or the same amount of MW as registered in the program. Table 6-3 shows the sum of maximum economic MW dispatched by registration each month for January 2010 through December 2015. The monthly maximum is the sum of each registration's monthly noncoincident peak dispatched MW and annual maximum is the sum of each registration's noncoincident peak dispatched MW during the year. This aggregated maximum dispatched MW for all economic demand response registered resources in 2015 increased by 105 MW, from 1,743 MW in 2014 to 1,848 MW in 2015.[19]

Table 6-2 Economic program registrations on the last day of the month: January 2010 through December 2015

	2010		2011		2012		2013		2014		2015	
Month	Registrations	Registered MW	Registrations	Registered MW	Registrations	Registered MW	Registrations	Registered MW	Registrations	Registered MW	Registrations	Registered MW
Jan	1,841	2,623	1,609	2,432	1,993	2,385	841	2,314	1,180	2,325	1,078	2,960
Feb	1,842	2,624	1,612	2,435	1,995	2,384	843	2,327	1,174	2,330	1,076	2,956
Mar	1,845	2,623	1,612	2,519	1,996	2,356	788	2,284	1,185	2,692	1,075	2,949
Apr	1,849	2,587	1,611	2,534	189	1,318	970	2,346	1,194	2,827	1,076	2,938
May	1,875	2,819	1,687	3,166	371	1,669	1,375	2,414	745	2,511	980	2,846
Jun	813	1,608	1,143	1,912	803	2,347	1,302	2,144	928	2,943	871	2,614
Jul	1,192	2,159	1,228	2,062	942	2,323	1,315	2,443	1,036	3,006	870	2,609
Aug	1,616	2,398	1,987	2,194	1,013	2,373	1,299	2,527	1,080	3,033	869	2,609
Sep	1,609	2,447	1,962	2,183	1,052	2,421	1,280	2,475	1,077	2,919	867	2,608
Oct	1,606	2,444	1,954	2,179	828	2,269	1,210	2,335	1,060	2,943	858	2,568
Nov	1,605	2,444	1,988	2,255	824	2,267	1,192	2,307	1,063	2,995	851	2,566
Dec	1,598	2,439	1,992	2,259	846	2,283	1,192	2,311	1,071	2,923	850	2,566
Avg.	1,608	2,435	1,699	2,344	1,071	2,200	1,134	2,352	1,066	2,787	943	2,732

19 As a result of the 60 day data lag from event date to settlement, not all settlements for December 2015 are incorporated in this report.

Table 6-3 Sum of peak MW reductions for all registrations per month: 2010 through 2015

	Sum of Peak MW Reductions for all Registrations per Month					
Month	2010	2011	2012	2013	2014	2015
Jan	183	132	110	193	450	169
Feb	121	89	101	119	307	336
Mar	115	81	72	127	369	198
Apr	111	80	108	133	146	143
May	172	98	143	192	151	161
Jun	209	561	954	433	483	833
Jul	999	561	1,631	1,091	665	1,362
Aug	794	161	952	497	358	272
Sep	276	84	451	549	795	816
Oct	118	81	242	168	214	136
Nov	111	86	165	155	166	127
Dec	114	88	98	168	155	122
Annual	1,209	841	1,947	1,490	1,743	1,858

All demand response energy payments are uplift rather than market payments. Economic demand response energy costs are assigned to real-time exports from the PJM Region and real-time loads in each zone for which the load-weighted average real-time LMP for the hour during which the reduction occurred is greater than the price determined under the net benefits test for that month.[20] The zonal allocation is shown in Table 6-13.

Table 6-4 shows the total MW reductions made by participants in the economic program and the total credits paid for these reductions in 2010 through 2015. The average credits per MWh paid in 2015 decreased by $50.35 per MWh, or 42.3 percent, from $119.15 per MWh in 2014 to $68.80 per MWh dispatched in 2015. The average real-time load weighted PJM LMP in 2015 decreased by $16.98 per MWh, or 31.2 percent, from $53.14 per MWh in 2014 to $36.16 per MWh in 2015. Curtailed energy for the economic program was 121,338 MWh in 2015 and the total payments were $8,347,755.[21] Total credits paid for economic DR in 2015 decreased by $9.5 million or 53.2 percent, compared to 2014.

Table 6-4 Credits paid to the PJM economic program participants: 2010 through 2015

Year	Total MWh	Total Credits	$/MWh
2010	72,757	$4,728,660	$64.99
2011	17,398	$2,052,996	$118.00
2012	145,019	$9,284,118	$64.02
2013	133,963	$8,711,873	$65.03
2014	149,246	$17,704,828	$118.63
2015	121,338	$8,347,755	$68.80

Economic demand response resources that are dispatched in both the economic and emergency programs at the same time are settled under emergency rules. For example, assume a demand resource has an economic strike price of $100 per MWh and an emergency strike price of $1,800 per MWh. If this resource were scheduled to reduce in the Day-Ahead Energy Market, the demand resource would receive $100 per MWh, but if an emergency event were called during the economic dispatch, the demand resource would receive its emergency strike price of $1,800 per MWh instead. The rationale for this rule is not clear. All other resources that clear in the day-ahead market are financially firm at that clearing price.

Figure 6-2 shows monthly economic demand response credits and MWh, from January 2010 through December 2015. Higher energy prices and FERC Order No. 745 increased incentives to participate starting in April 2012. The $9.5 million decrease in credits paid to economic DR resources in 2015 when compared to 2014 can largely be attributed to lower energy market prices in the first three months of 2015.

Figure 6-2 Economic program credits and MWh by month: January 2010 through December 2015

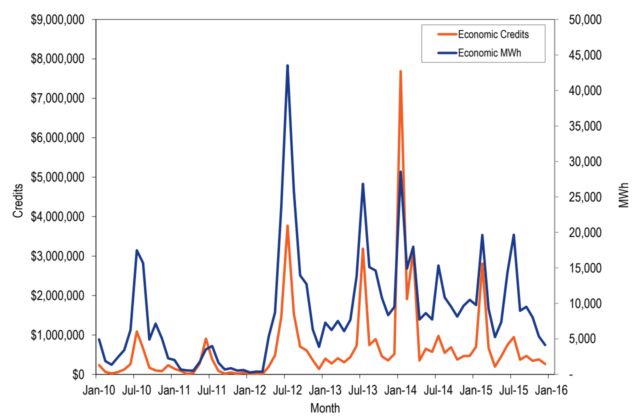


Table 6-5 shows performance for 2014 and 2015 in the economic program by control zone and participation type. Total economic program reductions decreased 19.4 percent from 149,560 MW in 2014 to 121,338 MW in 2015. The economic credits decreased by 54.2 percent from $17,819,607 in 2014, to $8,374,755 in 2015.

20 PJM: "Manual 28: Operating Agreement Accounting," Revision 64 (April 11, 2014), p 70.

21 The total MWh and Total Credits values in this table are the most up to date at the time of this report. Succeeding tables that report on charges paid for economic demand response may vary slightly from these numbers due to the timing of PJM settlement database updates.

Table 6-5 PJM economic program participation by zone: 2014 and 2015[22]

	Credits			MWh Reductions			Credits per MWh Reduction		
Zones	2014	2015	Percent Change	2014	2015	Percent Change	2014	2015	Percent Change
AECO, JCPL, PECO, Pepco, RECO	$2,429,613	$535,534	(78.0%)	9,639	4,824	(50.0%)	$252.06	$111.03	(56.0%)
AEP, AP	$323,274	$151,753	(53.1%)	3,629	2,223	(38.8%)	$89.08	$68.28	(23.4%)
ATSI, ComEd, DAY, DEOK, DLCO, EKPC	$1,073,497	$814,821	(24.1%)	11,308	18,695	65.3%	$94.93	$43.59	(54.1%)
BGE, DPL, Met-Ed, PENELEC	$1,280,545	$1,105,865	(13.6%)	13,734	20,527	49.5%	$93.24	$53.87	(42.2%)
Dominion	$9,951,828	$4,799,160	(51.8%)	89,396	59,432	(33.5%)	$111.32	$80.75	(27.5%)
PPL, PSEG	$2,760,850	$940,622	(65.9%)	21,853	15,638	(28.4%)	$126.34	$60.15	(52.4%)
Total	$17,819,607	$8,347,755	(53.2%)	149,560	121,338	(18.9%)	$119.15	$68.80	(42.3%)

Table 6-6 shows total settlements submitted for 2009 through 2015. A settlement is counted for every day on which a registration is dispatched in the economic program.

Table 6-6 Settlements submitted by year in the economic program: 2009 through 2015

Year	2009	2010	2011	2012	2013	2014	2015
Number of Settlements	2,227	3,781	732	4,554	2,357	2,356	1,697

Table 6-7 shows the number of CSPs, and the number of participants in their portfolios, submitting settlements by year from 2009 through 2015. There were 48 fewer active participants in 2015 than in 2014. All participants must be included in a CSP.

Table 6-7 Participants and CSPs submitting settlements in the economic program by year: 2009 through 2015

2009		2010		2011		2012		2013		2014		2015	
Active CSPs	Active Participants	Active CSPs	Active Participants	Active CSPs	Active Participants	Active CSPs	Active Participants	Active CSPs	Active Participants	Active CSPs	Active Participants	Active CSPs	Active Participants
15	212	16	258	15	203	22	428	20	276	18	165	18	116

The ownership of economic demand response was highly concentrated in both 2014 and 2015.[23] Table 6-8 shows the monthly HHI and the HHI for 2015. The table also lists the share of reductions provided by, and the share of credits claimed by the four largest parent companies in each year. In 2015, 79.7 percent of all economic DR reductions and 92.7 percent of economic DR revenue were attributable to the four largest parent companies. The HHI for economic demand response increased 111 points, from 7713 in 2014 to 7824 in 2015.

Table 6-8 HHI and market concentration in the economic program: 2014 and 2015

	HHI			Top Four Companies Share of Reduction			Top Four Companies Share of Credit		
Month	2014	2015	Percent Change	2014	2015	Percent Change	2014	2015	Percent Change
Jan	7018	8081	15.1%	88.0%	96.8%	8.8%	84.2%	98.6%	14.4%
Feb	6547	7358	12.4%	84.1%	91.4%	7.4%	77.5%	87.8%	10.3%
Mar	7646	7539	(1.4%)	87.7%	89.1%	1.4%	88.5%	84.4%	(4.2%)
Apr	8343	7216	(13.5%)	100.0%	97.8%	(2.2%)	100.0%	97.8%	(2.2%)
May	8090	7779	(3.9%)	98.8%	98.9%	0.1%	99.1%	99.4%	0.3%
Jun	8141	7971	(2.1%)	91.5%	96.8%	5.3%	87.9%	95.6%	7.6%
Jul	8357	7731	(7.5%)	88.1%	83.1%	(5.0%)	85.6%	78.2%	(7.4%)
Aug	8327	8397	0.8%	97.8%	94.9%	(2.9%)	96.7%	94.0%	(2.7%)
Sep	8632	8024	(7.0%)	89.7%	92.7%	3.0%	87.4%	91.6%	4.2%
Oct	7285	7585	4.1%	91.8%	99.4%	7.6%	92.8%	98.9%	6.0%
Nov	7699	7869	2.2%	100.0%	94.3%	(5.7%)	100.0%	97.0%	(3.0%)
Dec	7712	8480	10.0%	99.5%	97.5%	(2.0%)	99.3%	97.8%	(1.5%)
Total	7713	7824	1.4%	79.8%	79.7%	(0.1%)	87.3%	92.7%	5.3%

22 PJM and the MMU cannot publish more detailed information about the Economic Program Zonal Settlements as a result of confidentiality requirements in the PJM Market Rules.
23 Parent companies may own one CSP or multiple CSPs. All HHI calculations in this section are at the parent company level.

Table 6-9 shows average MWh reductions and credits by hour for 2014 and 2015. In 2014, 90.1 percent of reductions and 86.0 percent of credits occurred in hours ending 0700 to 2100, and in 2015, 94.9 percent of reductions and 92.5 percent of credits occurred in hours ending 0700 to 2100.

Table 6-9 Hourly frequency distribution of economic program MWh reductions and credits: 2014 and 2015

	MWh Reductions			Program Credits		
Hour Ending (EPT)	2014	2015	Percent Change	2014	2015	Percent Change
1	775	344	(56%)	$127,551	$38,507	(70%)
2	723	332	(54%)	$112,251	$33,943	(70%)
3	878	360	(59%)	$149,137	$40,799	(73%)
4	1,550	431	(72%)	$292,816	$46,072	(84%)
5	1,614	424	(74%)	$204,016	$46,877	(77%)
6	2,366	864	(64%)	$319,197	$105,431	(67%)
7	6,353	4,604	(28%)	$945,568	$525,202	(44%)
8	8,295	6,555	(21%)	$1,178,582	$663,641	(44%)
9	9,301	7,419	(20%)	$948,681	$468,425	(51%)
10	8,842	5,614	(37%)	$1,055,720	$396,137	(62%)
11	6,494	4,846	(25%)	$912,614	$332,583	(64%)
12	5,490	5,147	(6%)	$818,427	$331,492	(59%)
13	5,958	5,421	(9%)	$699,418	$310,139	(56%)
14	8,633	7,572	(12%)	$885,323	$422,659	(52%)
15	11,650	8,979	(23%)	$981,805	$489,452	(50%)
16	12,306	11,732	(5%)	$1,045,709	$633,723	(39%)
17	12,680	12,559	(1%)	$1,106,482	$742,171	(33%)
18	13,813	12,648	(8%)	$1,371,388	$807,154	(41%)
19	10,214	10,020	(2%)	$1,178,391	$696,329	(41%)
20	8,437	6,880	(18%)	$1,212,590	$502,101	(59%)
21	6,241	5,133	(18%)	$992,114	$397,128	(60%)
22	3,423	1,899	(45%)	$612,657	$169,504	(72%)
23	1,938	816	(58%)	$380,048	$77,939	(79%)
24	1,588	739	(53%)	$289,122	$70,348	(76%)
Total	149,560	121,338	(19%)	$17,819,607	$8,347,755	(53%)

Table 6-10 shows the distribution of economic program MWh reductions and credits by ranges of real-time zonal, load-weighted, average LMP in 2014 and 2015. Reductions occurred at all price levels. In 2015, 0.6 percent of MWh reductions and 3.3 percent of program credits occurred during hours when the applicable zonal LMP was higher than $400 per MWh.

Table 6-10 Frequency distribution of economic program zonal, load-weighted, average LMP (By hours): 2014 and 2015

	MWh Reductions			Program Credits		
LMP	2014	2015	Percent Change	2014	2015	Percent Change
$0 to $25	722	8,143	1,028%	$12,882	$234,052	1,717%
$25 to $50	60,151	67,157	12%	$2,572,764	$2,775,977	8%
$50 to $75	28,330	18,771	(34%)	$1,878,847	$1,220,214	(35%)
$75 to $100	13,257	9,207	(31%)	$1,295,045	$828,155	(36%)
$100 to $125	7,481	5,255	(30%)	$921,624	$594,150	(36%)
$125 to $150	5,360	2,891	(46%)	$804,728	$409,199	(49%)
$150 to $175	4,351	1,886	(57%)	$776,070	$296,726	(62%)
$175 to $200	3,638	1,872	(49%)	$768,439	$357,606	(53%)
$200 to $225	3,079	1,744	(43%)	$672,056	$333,531	(50%)
$225 to $250	3,132	1,002	(68%)	$713,340	$222,931	(69%)
$250 to $275	2,546	625	(75%)	$637,912	$154,373	(76%)
$275 to $300	1,997	634	(68%)	$558,849	$174,985	(69%)
$300 to $325	1,579	382	(76%)	$459,897	$112,120	(76%)
$325 to $350	1,229	233	(81%)	$359,764	$70,018	(81%)
$350 to $375	1,404	609	(57%)	$435,346	$213,604	(51%)
$375 to $400	1,095	194	(82%)	$333,491	$71,818	(78%)
> $400	10,197	722	(93%)	$4,618,554	$278,431	(94%)
Total	149,549	121,328	(19%)	$17,819,607	$8,347,890	(53%)

Following FERC Order No. 745, all ISO/RTOs are required to calculate an NBT threshold price each month above which the net benefits of DR are deemed to exceed the cost to load. PJM calculates the NBT price threshold by first taking the generation offers from the same month of the previous year. For example, the NBT price calculation for February 2015 was calculated using generation offers from February 2014. PJM then adjusts these offers to account for changes in fuel prices and uses these adjusted offers to create an average monthly supply curve. PJM estimates a function that best fits this supply curve and then finds the point on this curve where the elasticity is equal to 1.[24] The price at this point is the NBT threshold price

The NBT test is a crude tool that is not based in markets logic. The NBT threshold price is a monthly estimate calculated from a monthly supply curve that does not incorporate the real-time or day-ahead prices. In addition, it is a single price used to trigger payments to economic demand response resources throughout the entire RTO, regardless of their location.

The necessity for the NBT test is an illustration of the illogical approach to demand side compensation embodied in paying full LMP to demand resources. The benefit of demand side resources is not that they

24 PJM. "Manual 11: Energy & Ancillary Services Market Operations," Revision 79 (December 17, 2015), p 125.

suppress market prices, but that customers can choose not to consume at the current price of power, that individual customers benefit from their choices and that the choices of all customers are reflected in market prices. If customers face the market price, customers should have the ability to not purchase power and the market impact of that choice does not require a test for appropriateness.

When the LMP is above the NBT threshold price, economic demand response resources that reduce their power consumption are paid the full LMP. When the LMP is below the NBT threshold price, economic demand response resources are not paid for any load reductions. About 0.63 percent of DR dispatch occurred during hours with LMP lower than the NBT threshold price.

Table 6-11 shows the NBT threshold price from April 2012, when FERC Order No. 745 was implemented in PJM, through December of 2015. Significantly lower fuel prices in 2015 led to lower NBT threshold prices.

Table 6-11 Net benefits test threshold prices: April 2012 through December 2015

	Net Benefits Test Threshold Price ($/MWh)			
Month	2012	2013	2014	2015
Jan		$25.72	$29.51	$29.63
Feb		$26.27	$30.44	$26.52
Mar		$25.60	$34.93	$24.99
Apr	$25.89	$26.96	$32.59	$24.92
May	$23.46	$27.73	$32.08	$23.79
Jun	$23.86	$28.44	$31.62	$23.80
Jul	$22.99	$29.42	$31.62	$23.03
Aug	$24.47	$28.58	$29.85	$23.17
Sep	$24.93	$28.80	$29.83	$21.69
Oct	$25.96	$29.13	$30.20	$21.48
Nov	$25.63	$31.63	$29.17	$22.28
Dec	$25.97	$28.82	$29.01	$22.31
Average	$24.80	$28.09	$30.91	$23.97

Table 6-12 shows the number of hours that at least one zone in PJM had day-ahead LMP or real-time LMP higher than the NBT threshold price. In 2015, the highest zonal LMP in PJM was higher than the NBT threshold price 8,192 hours out of the entire 8,760 hours, or 93.5 percent of all hours. Reductions occurred in 7,561 hours, or 92.3 percent, of the 8,192 hours in of 2015. The last three columns illustrate how often economic demand response activity occurred when LMPs exceeded NBT threshold prices in 2014 and 2015.

Table 6-12 Hours with price higher than NBT and DR occurrences in those hours: 2014 through 2015

	Number of Hours	Number of Hours with LMP Higher than NBT			Percentage of NBT Hours with DR		
Month	2014/ 2015	2014	2015	Percent Change	2014	2015	Percent Change
Jan	744	742	669	(9.8%)	93.8%	83.0%	(10.8%)
Feb	672	672	670	(0.3%)	92.9%	93.1%	0.3%
Mar	743	732	719	(1.8%)	81.8%	90.8%	9.0%
Apr	720	661	713	7.9%	86.5%	96.6%	10.1%
May	744	694	692	(0.3%)	85.3%	100.0%	14.7%
Jun	720	557	659	18.3%	87.8%	93.3%	5.5%
Jul	744	540	708	31.1%	97.8%	100.0%	2.2%
Aug	744	586	665	13.5%	88.6%	100.0%	11.4%
Sep	720	605	659	8.9%	90.9%	100.0%	9.1%
Oct	744	710	708	(0.3%)	93.4%	88.1%	(5.2%)
Nov	721	719	676	(6.0%)	96.5%	74.1%	(22.4%)
Dec	744	703	654	(7.0%)	87.6%	87.9%	0.3%
Total	8,760	7,921	8,192	3.4%	90.2%	92.3%	2.1%

Economic DR revenues are paid by real-time loads and real-time scheduled exports as an uplift charge. Table 6-13 shows the sum of real-time DR charges and day-ahead DR charges for each zone and for exports. Real-time loads in AEP, Dominion, and ComEd paid the highest DR charges in 2015.

Table 6-13 Zonal DR charge: 2015

Zone	January	February	March	April	May	June	July	August	September	October	November	December	Total
AECO	$8,144	$32,233	$7,885	$1,675	$6,752	$9,830	$13,208	$5,325	$6,801	$3,002	$1,437	$859	$97,151
AEP	$110,175	$460,039	$108,168	$35,842	$73,540	$120,888	$145,840	$56,877	$67,862	$48,580	$36,216	$23,834	$1,287,861
AP	$46,313	$186,348	$43,950	$14,169	$28,661	$45,064	$55,760	$21,279	$25,583	$18,221	$13,654	$9,491	$508,493
ATSI	$53,788	$218,608	$55,824	$19,925	$39,112	$63,114	$78,631	$30,821	$37,763	$25,846	$18,820	$12,708	$654,958
BGE	$31,720	$124,739	$28,379	$8,934	$20,043	$35,112	$41,528	$16,457	$19,268	$11,789	$8,768	$6,214	$352,949
ComEd	$58,545	$275,905	$69,202	$18,046	$42,842	$82,223	$117,173	$45,452	$58,942	$32,680	$25,804	$15,969	$842,782
DAY	$14,864	$56,946	$14,135	$4,813	$9,977	$16,888	$20,690	$8,084	$9,623	$6,666	$4,894	$3,425	$171,006
DEOK	$20,275	$89,027	$21,328	$6,816	$16,210	$28,087	$33,858	$12,734	$15,622	$10,200	$7,524	$4,841	$266,523
Dominion	$93,812	$388,679	$84,586	$26,191	$60,039	$107,084	$125,545	$48,151	$55,234	$35,569	$26,815	$17,663	$1,069,368
DPL	$18,319	$75,492	$16,560	$3,070	$10,660	$16,842	$20,435	$8,365	$10,947	$5,569	$4,211	$2,611	$193,082
DLCO	$9,970	$35,023	$11,012	$3,864	$9,227	$14,519	$18,241	$6,782	$8,561	$5,284	$3,836	$2,488	$128,806
EKPC	$11,403	$54,120	$11,522	$2,788	$6,507	$11,799	$14,052	$5,224	$6,192	$4,247	$3,537	$2,359	$133,749
JCPL	$18,592	$72,039	$17,775	$4,136	$13,725	$23,025	$30,367	$12,173	$15,694	$7,170	$3,529	$1,845	$220,070
Met-Ed	$13,736	$53,971	$13,034	$2,642	$8,660	$11,134	$14,472	$6,179	$8,403	$4,856	$2,292	$1,271	$140,650
PECO	$34,695	$137,349	$32,562	$6,487	$23,321	$31,876	$42,687	$17,720	$23,928	$11,964	$5,817	$3,416	$371,822
PENELEC	$15,541	$60,547	$15,391	$4,838	$9,599	$14,545	$17,959	$7,212	$8,946	$6,792	$4,520	$3,018	$168,909
Pepco	$29,008	$114,217	$26,061	$8,609	$20,091	$34,254	$40,812	$15,694	$18,509	$11,291	$8,486	$5,687	$332,719
PPL	$38,227	$153,234	$36,723	$6,891	$22,204	$25,649	$38,119	$15,540	$21,233	$12,859	$6,180	$4,052	$380,911
PSEG	$36,731	$133,282	$33,547	$8,416	$24,829	$40,193	$52,829	$21,200	$27,995	$14,223	$6,908	$4,301	$404,454
RECO	$1,231	$4,301	$1,110	$291	$1,076	$1,552	$2,157	$837	$1,099	$508	$298	$184	$14,645
Exports	$33,144	$83,014	$19,015	$5,828	$9,552	$16,723	$21,808	$9,501	$13,128	$9,543	$6,864	$4,889	$233,010
Total	$698,233	$2,809,114	$667,768	$194,270	$456,625	$750,400	$946,170	$371,609	$461,331	$286,860	$200,411	$131,126	$7,973,919

Table 6-14 shows the total zonal DR charge per MWh of real-time load and exports during 2015. On a dollar per MWh basis, real-time load and exports in EKPC, JCPL, and PECO paid the highest charges for economic demand response in 2015. The highest average monthly per MWh charges for economic demand response occurred in February 2015, when real-time load and exports paid an average of $0.05/MWh.

Table 6-14 Zonal DR charge per MWh of load and exports: 2015

Zone	January	February	March	April	May	June	July	August	September	October	November	December	Zonal Average
AECO	$0.016	$0.046	$0.013	$0.005	$0.010	$0.024	$0.020	$0.008	$0.011	$0.009	$0.007	$0.005	$0.014
AEP	$0.021	$0.046	$0.013	$0.005	$0.010	$0.016	$0.017	$0.007	$0.008	$0.007	$0.007	$0.004	$0.013
AP	$0.017	$0.045	$0.012	$0.005	$0.010	$0.016	$0.017	$0.007	$0.008	$0.007	$0.007	$0.004	$0.013
ATSI	$0.018	$0.043	$0.012	$0.005	$0.010	$0.017	$0.017	$0.007	$0.008	$0.007	$0.007	$0.004	$0.013
BGE	$0.016	$0.046	$0.012	$0.005	$0.010	$0.015	$0.014	$0.006	$0.008	$0.007	$0.006	$0.004	$0.013
ComEd	$0.024	$0.049	$0.014	$0.006	$0.011	$0.018	$0.018	$0.008	$0.009	$0.007	$0.007	$0.004	$0.014
DAY	$0.020	$0.044	$0.013	$0.005	$0.009	$0.016	$0.016	$0.007	$0.008	$0.007	$0.007	$0.004	$0.013
DEOK	$0.022	$0.049	$0.015	$0.006	$0.010	$0.017	$0.017	$0.007	$0.009	$0.007	$0.007	$0.004	$0.014
Dominion	$0.019	$0.048	$0.013	$0.005	$0.010	$0.016	$0.015	$0.007	$0.008	$0.007	$0.007	$0.004	$0.013
DPL	$0.017	$0.048	$0.013	$0.005	$0.009	$0.023	$0.020	$0.008	$0.010	$0.008	$0.006	$0.004	$0.014
DLCO	$0.019	$0.048	$0.012	$0.005	$0.010	$0.018	$0.018	$0.007	$0.009	$0.007	$0.007	$0.004	$0.014
EKPC	$0.024	$0.053	$0.016	$0.006	$0.010	$0.017	$0.017	$0.007	$0.009	$0.007	$0.007	$0.004	$0.015
JCPL	$0.017	$0.047	$0.013	$0.005	$0.011	$0.025	$0.021	$0.008	$0.011	$0.009	$0.007	$0.004	$0.015
Met-Ed	$0.017	$0.047	$0.013	$0.005	$0.010	$0.022	$0.020	$0.008	$0.011	$0.009	$0.007	$0.004	$0.014
PECO	$0.017	$0.047	$0.013	$0.005	$0.010	$0.022	$0.020	$0.008	$0.011	$0.009	$0.008	$0.005	$0.015
PENELEC	$0.016	$0.042	$0.012	$0.006	$0.009	$0.018	$0.018	$0.007	$0.009	$0.007	$0.008	$0.005	$0.013
Pepco	$0.017	$0.047	$0.012	$0.005	$0.010	$0.016	$0.015	$0.007	$0.008	$0.007	$0.006	$0.004	$0.013
PPL	$0.017	$0.047	$0.013	$0.005	$0.010	$0.021	$0.021	$0.008	$0.011	$0.008	$0.007	$0.005	$0.014
PSEG	$0.015	$0.041	$0.012	$0.005	$0.010	$0.023	$0.021	$0.008	$0.010	$0.008	$0.007	$0.005	$0.014
RECO	$0.016	$0.040	$0.012	$0.005	$0.011	$0.023	$0.022	$0.008	$0.011	$0.008	$0.008	$0.005	$0.014
Exports	$0.012	$0.031	$0.009	$0.004	$0.005	$0.009	$0.011	$0.004	$0.004	$0.005	$0.004	$0.003	$0.008
Monthly Average	$0.018	$0.045	$0.013	$0.005	$0.010	$0.019	$0.018	$0.007	$0.009	$0.007	$0.007	$0.004	$0.014

Table 6-15 shows the monthly day-ahead and real-time DR charges and the per MWh DR charges in 2014 and 2015. The day-ahead DR charges decreased by $5.10 million, or 70.6 percent, from $7.22 million in 2014 to $2.12 million in 2015. The real-time DR charges decreased $4.84 million, or 45.7 percent, from $10.6 million in 2014 to $5.76 million in 2015. The per MWh charge paid by all real-time load and exports for economic DR decreased $0.02/MWh, or 54.5 percent, from $0.04/MWh in 2014 to $0.2/MWh in 2015.

Table 6-15 Monthly day-ahead and real-time DR charge: 2014 and 2015

	Day-ahead DR Charge			Real-time DR Charge			Per MWh Charge ($/MWh)		
Month	2014	2015	Percent Change	2014	2015	Percent Change	2014	2015	Percent Change
Jan	$3,580,411	$202,040	(94%)	$4,108,903	$496,193	(88%)	$0.131	$0.025	(81%)
Feb	$1,148,053	$647,566	(44%)	$760,591	$2,161,548	184%	$0.038	$0.059	56%
Mar	$762,224	$140,310	(82%)	$2,366,688	$527,458	(78%)	$0.075	$0.020	(73%)
Apr	$67,996	$58,036	(15%)	$282,918	$136,234	(52%)	$0.012	$0.008	(35%)
May	$151,962	$262,336	73%	$498,703	$194,289	(61%)	$0.024	$0.015	(38%)
Jun	$309,885	$300,585	(3%)	$259,651	$449,816	73%	$0.018	$0.021	18%
Jul	$506,523	$269,317	(47%)	$471,085	$676,853	44%	$0.031	$0.020	(36%)
Aug	$158,297	$94,046	(41%)	$386,444	$277,563	(28%)	$0.019	$0.008	(56%)
Sep	$143,293	$71,642	(50%)	$546,589	$389,690	(29%)	$0.029	$0.011	(63%)
Oct	$97,563	$56,564	(42%)	$277,857	$230,296	(17%)	$0.014	$0.008	(41%)
Nov	$167,769	$15,710	(91%)	$294,371	$173,022	(41%)	$0.013	$0.008	(33%)
Dec	$121,823	$0	(100%)	$349,946	$48,372	(86%)	$0.017	$0.004	(73%)
Total	$7,215,799	$2,118,153	(71%)	$10,603,747	$5,761,334	(46%)	$0.043	$0.020	(54%)

Emergency and Pre-Emergency Programs

The emergency and pre-emergency load response programs consist of the limited, extended summer and annual demand response product in the capacity market during the 2014/2015 and 2015/2016 Delivery Years. To participate as a limited demand resource, the provider must clear MW in an RPM auction. Emergency resources receive capacity revenue from the capacity market and also receive revenue at a predefined strike price from the energy market for reductions during a PJM initiated emergency event. The rules applied to demand resources in the current market design do not treat demand resources in a manner comparable to generation capacity resources, even though demand resources are sold in the same capacity market, are treated as a substitute for other capacity resources and displace other capacity resources in RPM auctions.

The MMU recommends that if demand resources remain on the supply side of the capacity market, a daily must offer requirement in the Day-Ahead Energy Market apply to demand resources, comparable to the rule applicable to generation capacity resources. This will help to ensure comparability and consistency for demand resources.

The MMU recommends that the option to specify a minimum dispatch price under the Emergency and Pre-Emergency Program Full option be eliminated and that participating resources receive the hourly real-time LMP less any generation component of their retail rate.[25]

Demand Resources were moderately concentrated in 2015. The HHI for Demand Resources was 1760 for the 2014/2015 Delivery Year and 1497 for the 2015/2016 Delivery Year. In 2015, the four largest companies contributed 65.3 percent of all registered Demand Resources.

Table 6-16 shows the HHI value for LDAs by delivery year. The HHI values are calculated by the cleared UCAP MW in each delivery year for Demand Resources. The ownership of DR in two LDAs was moderately concentrated in the 2014/2015 Delivery Year and the ownership of DR in five LDAs was moderately concentrated in the 2015/2016 Delivery Year. The ownership of DR in six LDAs was highly concentrated in the 2014/2015 Delivery Year and the ownership of DR in four LDAs was highly concentrated in the 2015/2016 Delivery Year.

Table 6-16 HHI value for LDAs by delivery year: 2014/2015 and 2015/2016 Delivery Year

Delivery Year	LDA	UCAP MW	HHI Value
2014/2015	DPL-SOUTH	220.9	2131
	EMAAC	1,756.5	1879
	MAAC	2,207.1	2355
	PEPCO	920.0	2643
	PS-NORTH	468.4	1558
	PSEG	531.1	1548
	RTO	7,490.6	2373
	SWMAAC	1,348.4	3564
2015/2016	ATSI	2,167.9	2257
	DPL-SOUTH	86.3	2923
	EMAAC	1,750.4	1355
	MAAC	2,029.0	1607
	PEPCO	867.7	2462
	PS-NORTH	263.5	1622
	PSEG	523.8	1381
	RTO	6,610.4	1734
	SWMAAC	1,154.7	3541

25 See "Complaint and Motion to Consolidate of the Independent Market Monitor for PJM," Docket No. EL14-20-000 (January 28, 2014); "Comments of the Independent Market Monitor for PJM," Docket No. ER15-852-000 (February 13, 2015).

Table 6-17 shows zonal monthly capacity market revenue to demand resources for 2015. Capacity market revenue increased in 2015 by $178.9 million, or 28.3 percent, compared to 2014, from $632.8 million to $811.7 million, as a result of higher RPM prices and more cleared DR in RPM for the 2014/2015 and 2015/2016 delivery years.

Table 6-17 Zonal monthly capacity revenue: January through December 2015

Zone	January	February	March	April	May	June	July	August	September	October	November	December	Total
AECO	$832,282	$751,739	$832,282	$805,435	$832,282	$985,380	$1,018,226	$1,018,226	$985,380	$1,018,226	$985,380	$1,018,226	$11,083,065
AEP, EKPC	$6,410,228	$5,789,884	$6,410,228	$6,203,447	$6,410,228	$6,659,173	$6,881,145	$6,881,145	$6,659,173	$6,881,145	$6,659,173	$6,881,145	$78,726,116
AP	$3,492,803	$3,154,790	$3,492,803	$3,380,132	$3,492,803	$3,174,034	$3,279,835	$3,279,835	$3,174,034	$3,279,835	$3,174,034	$3,279,835	$39,654,773
ATSI	$3,841,060	$3,469,344	$3,841,060	$3,717,154	$3,841,060	$18,481,726	$19,097,783	$19,097,783	$18,481,726	$19,097,783	$18,481,726	$19,097,783	$150,545,989
BGE	$5,311,878	$4,797,825	$5,311,878	$5,140,527	$5,311,878	$5,367,246	$5,546,155	$5,546,155	$5,367,246	$5,546,155	$5,367,247	$5,546,155	$64,160,345
ComEd	$6,041,237	$5,456,601	$6,041,237	$5,846,358	$6,041,237	$6,463,717	$6,679,174	$6,679,174	$6,463,717	$6,679,174	$6,463,717	$6,679,174	$75,534,515
DAY	$902,087	$814,788	$902,087	$872,987	$902,087	$736,289	$760,832	$760,832	$736,289	$760,832	$736,289	$760,832	$9,646,234
DEOK	$341,676	$308,610	$341,676	$330,654	$341,676	$1,277,237	$1,319,812	$1,319,812	$1,277,237	$1,319,812	$1,277,237	$1,319,812	$10,775,252
DLCO	$5,338,145	$4,821,550	$5,338,145	$5,165,946	$5,338,145	$5,066,824	$5,235,719	$5,235,719	$5,066,825	$5,235,719	$5,066,825	$5,235,719	$62,145,278
Dominion	$1,593,999	$1,439,741	$1,593,999	$1,542,580	$1,593,999	$2,130,080	$2,201,083	$2,201,083	$2,130,080	$2,201,083	$2,130,080	$2,201,083	$22,958,890
DPL	$868,800	$784,722	$868,800	$840,774	$868,800	$849,964	$878,296	$878,296	$849,964	$878,296	$849,964	$878,296	$10,294,974
JCPL	$1,766,944	$1,595,949	$1,766,944	$1,709,946	$1,766,944	$1,665,010	$1,720,510	$1,720,510	$1,665,010	$1,720,510	$1,665,010	$1,720,510	$20,483,797
Met-Ed	$1,610,323	$1,454,485	$1,610,323	$1,558,377	$1,610,323	$1,613,449	$1,667,231	$1,667,231	$1,613,449	$1,667,231	$1,613,449	$1,667,231	$19,353,102
PECO	$3,358,207	$3,033,220	$3,358,207	$3,249,878	$3,358,207	$3,700,859	$3,824,221	$3,824,221	$3,700,859	$3,824,221	$3,700,859	$3,824,221	$42,757,179
PENELEC	$1,730,838	$1,563,337	$1,730,838	$1,675,004	$1,730,838	$2,540,797	$2,625,490	$2,625,490	$2,540,797	$2,625,490	$2,540,797	$2,625,490	$26,555,209
Pepco	$3,583,429	$3,236,645	$3,583,429	$3,467,834	$3,583,429	$4,096,205	$4,232,745	$4,232,745	$4,096,205	$4,232,745	$4,096,205	$4,232,745	$46,674,363
PPL	$5,389,586	$4,868,013	$5,389,586	$5,215,729	$5,389,586	$5,411,083	$5,591,452	$5,591,452	$5,411,083	$5,591,452	$5,411,083	$5,591,452	$64,851,556
PSEG	$5,642,193	$5,096,174	$5,642,193	$5,460,187	$5,642,193	$3,738,271	$3,862,880	$3,862,880	$3,738,271	$3,862,880	$3,738,271	$3,862,880	$54,149,275
RECO	$122,927	$111,031	$122,927	$118,962	$122,927	$99,707	$103,031	$103,031	$99,707	$103,031	$99,707	$103,031	$1,310,019
Total	$58,178,643	$52,548,452	$58,178,643	$56,301,913	$58,178,643	$74,057,052	$76,525,620	$76,525,620	$74,057,052	$76,525,621	$74,057,052	$76,525,621	$811,659,932

Table 6-18 shows the amount of energy efficiency (EE) resources in PJM for the 2012/2013 through 2015/2016 delivery years. Energy efficiency resources are offered in the PJM Capacity Market. The total MW of energy efficiency resources cleared in the capacity auction increased by 19.5 percent from 1,231.8 MW in the 2014/2015 delivery year to 1,471.4 MW in 2015/2016 Delivery Year.

Table 6-18 Energy efficiency resources by MW: 2012/2013 through 2015/2016

	EE ICAP (MW)				EE UCAP (MW)			
	2012/2013	2013/2014	2014/2015	2015/2016	2012/2013	2013/2014	2014/2015	2015/2016
Total	609.7	991.0	1,231.8	1,471.4	631.2	1,029.2	1,282.4	1,525.5

Table 6-19 shows the number of customer locations and the nominated MW by product type and lead time for the 2014/2015 Delivery Year. The annual and extended summer products are new for the 2014/2015 Delivery Year. The quick lead time demand response, which is obligated to respond within 30 minutes compared to short lead at 60 minutes and long lead at 120 minutes, is also new for the 2014/2015 Delivery Year. The quick lead time product has 7.5 percent of all nominated MW with 704.0 MW and only 22 locations.

FERC accepted PJM's proposed 30 minute lead time as a phased in approach on May 9, 2014, effective on June 1, 2015.[26] The quick lead time demand response was defined after Demand Resources cleared in the RPM base residual auctions for the 2014/2015, 2015/2016, 2016/2017 and 2017/2018 delivery years. PJM submitted a filing on October 20, 2014, to allow DR that is unable to respond within 30 minutes to exit the market without penalty before the mandatory 30 minute lead time with the 2015/2016 Delivery Year.[27]

26 See "Order Rejecting, in part, and Accepting, in part, Proposed Tariff Changes, Subject to Conditions," Docket No. ER14-822-001 (May 9, 2014).
27 See "PJM Interconnection, L.L.C.," Docket No. ER14-135-000 (October 20, 2014).

Table 6-19 Lead time by product type: 2014/2015 Delivery Year

Lead Type	Product Type	Locations	Nominated MW
Long Lead (120 Minutes)	Annual and Extended Summer	2,079	1,130.9
	Limited	13,781	7,039.8
Short Lead (60 Minutes)	Annual, Extended Summer and Limited	55	485.7
Quick Lead (30 Minutes)	Annual and Limited	22	704.0
Total		15,937	9,360.3

Table 6-20 shows the number of customer locations and nominated MW by product type and lead time during the 2015/2016 Delivery Year. The quick lead time is the default lead time for the 2015/2016 Delivery Year, unless a CSP submits an exception request for 60 or 120 minute notification time due to a physical constraint.[28] There were 3,174 locations which have 4,334.6 MW of nominated MW capacity approved by PJM to respond in 60 or 120 minutes.

Table 6-20 Lead time by product type: 2015/2016 Delivery Year

Lead Type	Product Type	Locations	Nominated MW
Long Lead (120 Minutes)	Annual and Extended Summer	791	697.0
	Limited	1,957	3,057.8
Short Lead (60 Minutes)	Extended Summer and Limited	426	579.8
Quick Lead (30 Minutes)	Annual	191	173.6
	Extended Summer	3,723	2,043.4
	Limited	10,635	5,091.6
Total		17,723	11,643.2

Table 6-21 shows the MW registered by measurement and verification method and by load drop method for the 2014/2015 Delivery Year.

There are three different ways to measure load reductions of Demand Resources. The Firm Service Level (FSL) method measures the difference between a customer's peak load contribution (PLC) and real time load multiplied by the loss factor. The Guaranteed Load Drop (GLD) method calculates the minimum of: the CBL minus real time load multiplied by the loss factor; or the PLC minus the real time load multiplied by the loss factor. The GLD method uses the minimum of the two to avoid the possibility of double counting reductions which could occur if the CBL were used and the CBL were greater than the PLC.[29] The Direct Load Control (DLC) method measures when the CSP turns on and turns off the direct load control switch to remotely control load reductions. DLC customers do not measure metered real time load for reductions. For the 2014/2015 Delivery Year, 2.4 percent use the GLD measurement and verification method, 91.2 percent use the FSL method and 6.3 percent use DLC.

Table 6-21 Reduction MW by each demand response method: 2014/2015 Delivery Year

Program Type	On-site Generation MW	HVAC MW	Refrigeration MW	Lighting MW	Manufacturing MW	Water Heating or Other MW	Total	Percent by Type
Firm Service Level	2,119.6	1,970.8	207.4	740.6	3,428.5	69.9	8,536.8	91.2%
Guaranteed Load Drop	25.2	152.9	1.8	12.2	33.9	0.5	226.6	2.4%
DLC (Non hourly metered sites)	0.0	551.1	0.0	0.0	0.0	41.0	592.1	6.3%
Total	2,144.7	2,674.8	209.2	752.8	3,462.4	111.4	9,355.4	100.0%
Percent by Method	22.9%	28.6%	2.2%	8.0%	37.0%	1.2%	100.0%	

Table 6-22 shows the MW registered by measurement and verification method and by load drop method for the 2015/2016 Delivery Year. For the 2015/2016 Delivery Year, 1.6 percent use the guaranteed load drop (GLD) measurement and verification method, 94.3 percent use the firm service level (FSL) method and 4.1 percent use direct load control (DLC). FSL registrations increased by 2,437.9 MW while GLD registrations decreased by 38.8 MW and DLC registrations decreased by 111.9 MW from the 2014/2015 delivery year to the 2015/2016 delivery year.

28 See "Manual 18: Capacity Market," Revision 2 (August 3, 2015), p. 57.
29 135 FERC ¶ 61,212.

Table 6-22 Reduction MW by each demand response method: 2015/2016 Delivery Year

Program Type	On-site Generation MW	HVAC MW	Refrigeration and Lighting MW	Manufacturing or Water Heating MW	Other, Batteries or Plug Load MW	Total MW	Percent by Type
Firm Service Level	2,636.7	2,541.3	1,162.8	4,575.0	58.8	10,974.6	94.3%
Guaranteed Load Drop	20.6	106.1	13.5	47.6	0.0	187.8	1.6%
DLC (Non hourly metered sites)	0.0	444.9	0.0	35.3	0.0	480.1	4.1%
Total	2,657.3	3,092.3	1,176.3	4,657.8	58.8	11,642.6	100.0%
Percent by Method	22.8%	26.6%	10.1%	40.0%	0.5%	100.0%	

Table 6-23 shows the fuel type used in the on-site generators identified in Table 6-21 and Table 6-22 for the 2014/2015 and 2015/2016 Delivery Year. Of the 22.9 percent of emergency demand response identified as using on-site generation for the 2014/2015 Delivery Year, 85.5 percent of MW are diesel, 11.7 percent are natural gas and 2.8 percent is coal, gasoline, kerosene, oil, propane or waste products. Of the 22.8 percent of emergency demand response identified as using on-site generation for the 2015/2016 Delivery Year, 84.7 percent of MW are diesel, 12.0 percent are natural gas and 3.3 percent is coal, gasoline, kerosene, oil, propane or waste products.

Table 6-23 On-site generation fuel type by MW: 2014/2015 and 2015/2016 Delivery Year

Fuel Type	MW	Percent
Coal, Gasoline, Kerosene, Oil, Propane, Waste Products	87.9	3.3%
Diesel	2,250.9	84.7%
Natural Gas	318.5	12.0%
Total	2,657.3	100.0%

Emergency and Pre-Emergency Event Reported Compliance

PJM declared two events in the 2014/2015 Delivery Year, one on April 21, 2015 and one on April 22, 2015. PJM dispatched pre emergency and emergency resources for both events. There were 13 events during the 2013/2014 Delivery Year, two events during the 2012/2013 Delivery Year and one event in the 2011/2012 Delivery Year. Since all of the events in the 2014/2015 Delivery Year were called in PENELEC and there were no annual demand resources there, none were considered for a compliance assessment.[30]

Table 6-24 shows the demand response cleared UCAP MW for PJM by Delivery Year. Total demand response cleared in PJM increased by 3.4 percent from 14,943 MW in the 2014/2015 Delivery Year to 15,453.7 MW in the 2015/2016 Delivery Year. The DR Cleared MW UCAP increased by 510.7 MW, from 14,943.0 MW in the 2014/2015 Delivery Year to 15,453.7 MW in the 2015/2016 Delivery Year. The DR percent of capacity decreased by 3.4 percent, from 9.3 percent in the 2014/2015 Delivery Year to 8.9 percent in the 2015/2016 Delivery Year.

Table 6-24 Demand response cleared MW UCAP for PJM: 2011/2012 through 2015/2016 Delivery Year

	2011/2012 Delivery Year		2012/2013 Delivery Year		2013/2014 Delivery Year		2014/2015 Delivery Year		2015/2016 Delivery Year	
	DR Cleared MW UCAP	DR Percent of Capacity MW UCAP	DR Cleared MW UCAP	DR Percent of Capacity MW UCAP	DR Cleared MW UCAP	DR Percent of Capacity MW UCAP	DR Cleared MW UCAP	DR Percent of Capacity MW UCAP	DR Cleared MW UCAP	DR Percent of Capacity MW UCAP
Total	1,826.6	1.4%	8,740.9	6.2%	10,779.6	6.7%	14,943.0	9.3%	15,453.7	8.9%

Table 6-25 lists PJM emergency and pre-emergency load management events declared in PJM in 2015 and the affected zones. Subzonal dispatch of emergency demand resources was mandatory for the 2014/2015 Delivery Year but only if the subzone was defined by PJM no later than the day before the dispatch. There are ten dispatchable subzones in PJM as of August 11, 2015: AEP_CANTON, ATSI_CLE, DPL_SOUTH, PS_NORTH, ATSI_NEWCASOE, PPL_WESCO, ATSI_BLKRIVER, PENELEC_ERIC, APS_EAST, DOM_CHES.[31] Demand resources can be dispatched for voluntary compliance during any hour of any day, but dispatched resources are not measured for compliance outside

30 Extended summer and limited demand response products are not required to respond in April.
31 See "Load Management Subzones," <http://www.pjm.com/~/media/markets-ops/demand-response/subzone-definition-workbook.ashx> (Accessed February 26, 2016).

of the mandatory compliance window for each demand product. A demand response event during a product's mandatory compliance window also may not result in a compliance score. When demand response events occur for partial hours under 30 minutes or for a subzone dispatch that was not defined one business day before dispatch, the events are not measured for compliance. The category of Minutes not Measured for Compliance is the amount of time during which compliance was not measured when demand resources were dispatched.

The Erie Subzone was not defined the day before the PJM event and therefore the subzone could not be dispatched for mandatory curtailment. If Demand Resources were dispatchable by node, PJM could dispatch Demand Resources that would help a constrained area rather than having to dispatch the entire zone. When the Erie Subzone was constrained during these two demand response events, PJM dispatched DR in the entire PENELEC Zone resulting in reductions across that zone to help a localized problem in the Eric Subzone. Demand Resources that reduced received their associated strike price for reducing, even when the reductions occurred in an area that did not help relieve the constraint. The Erie Subzone was defined on April 21, 2015, which made it eligible for the April 22, 2015, call. The PENELEC Zone was the only zone called for both events.

All demand response events called in 2015 were voluntary. The 2015 voluntary events resulted in under compliance and no penalty for under compliant resources.

Table 6-25 PJM declared load management events: 2015

Event Date	Event Times	Compliance Hours	Minutes not Measured for Compliance	Lead Time	Area
21-Apr-15	20:20-21:30	None	70	Long Lead	PENELEC
	19:20-21:30	None	130	Short Lead	PENELEC
	18:50-21:30	None	160	Quick Lead	PENELEC
22-Apr-15	7:30-12:30	None	300	Long Lead	PENELEC
	6:30-12:30	None	360	Short Lead	PENELEC
	6:00-12:30	None	390	Quick Lead	PENELEC

Demand Resources are paid based on the average performance by registration for the duration of a demand response event. Demand response should measure compliance no less than hourly to accurately report reductions during demand response events. The current rules use the average reduction for the duration of an event. The average duration across multiple hours does not provide an accurate metric for each hour of the event and is inconsistent with the measurement of generation resources. Measuring compliance hourly would provide accurate information to the PJM system. The MMU recommends demand response event compliance be calculated for each hour and the penalty structure reflect hourly compliance.[32]

PJM allows compliance to be measured across zones within a compliance aggregation area (CAA).[33] This changes the way CSPs dispatch resources when multiple electrically contiguous areas with the same RPM clearing prices are dispatched. The compliance rules determine how CSPs are paid and thus create incentives that CSPs will incorporate in their decisions about how to respond to PJM dispatch.[34] The multiple zone approach is even less locational than the zonal and subzonal approaches and creates larger mismatches between the locational need for the resources and the actual response. If multiple zones within a CAA are called by PJM, a CSP will dispatch the least cost resources across the zones to cover the CSP's obligation. This can result in more MW dispatched in one zone that are locationally distant from the relief needed and no MW dispatched in another zone, yet the CSP could be considered 100 percent compliant and pay no penalties. More locational deployment of load management resources would improve efficiency. The MMU recommends that demand resources be required to provide their nodal location. Nodal dispatch of demand resources would be consistent with the nodal dispatch of generation.

32 PJM "Manual 18: Capacity Market," Revision 29 (October 16, 2015), p 148.

33 CAA is "a geographic area of Zones or sub-Zones that are electrically-contiguous and experience for the relevant Delivery Year, based on Resource Clear Prices of, *for Delivery Years through May 31, 2018*, Annual Resources *and for the 2018/2019 Delivery Year and subsequent Delivery Years, Capacity Performance Resources*, the same locational price separation in the Base Residual Auction, the same locational price separation in the First Incremental Auction, the same locational price separation in the Second Incremental Auction, or the same locational price separation in the Third Incremental Auction." OATT Attachment DD.2 Definitions 2.6A.

34 See "Answer and Motion for Leave to Answer of the Independent Market Monitor for PJM," Docket No. ER14-822-002 (July 25, 2014). See "Manual 18: Capacity Market," Revision 28 (August, 3, 2015) p. 152.

Load increases are not netted against load decreases for dispatched demand resources across hours or across registrations within hours for compliance purposes, but are treated as zero. This skews the compliance results towards higher compliance since poorly performing demand resources are not used in the compliance calculation. When load is above the peak load contribution during a demand response event, the load reduction is negative; it is a load increase rather than a decrease. PJM ignores such negative reduction values and instead replaces the negative values with a zero MW reduction value. The PJM Tariff and PJM Manuals do not limit the compliance calculation value to a zero MW reduction value.[35] The compliance values PJM reports for demand response events are different than the actual compliance values accounting for both increases and decreases in load from demand resources that are called on and paid under the program.

The MMU recommends that compliance rules be revised to include submittal of all necessary hourly load data, and that negative values be included when calculating event compliance across hours and registrations.

Demand Resources that are also registered as Economic Resources have a calculated CBL for the emergency event days. Demand Resources that are not registered as Economic Resources use the hour before a dispatched event as the CBL for measuring energy reductions. A 2011 KEMA report stated that the hour before method performs poorly during early winter hours. "The hour before the reduction event is typically prior to the morning peak, therefore this CBL severely underestimates the morning peak and the subsequent hours."[36] The calculated CBL more accurately measures reductions for Demand Resources.

Table 6-26 shows the performance for the April 21, 2015 and April 22, 2015 events. Before Demand Resources were dispatched, there was a post contingency local relief warning for FE-PN at 5:50 on April 21, 2015. Demand Resources were then dispatched on April 21, 2015 at 18:25 through 18:28, followed by a maximum generation emergency action at 18:45. Demand Resources were dispatched at 5:28 and 5:30 on April 22, 2015 without any warnings on the April 22, 2015. The nominated value column shows the reduction capability indicated for each registration. The nominated MW are used to fulfill the committed MW capacity obligation and may exceed the committed MW. The nominated MW are less than the committed MW capacity obligation because these events occurred during the voluntary compliance period. The committed MW are the MW cleared in the RPM auction. The reported load reduction is reported by PJM and does not include load increases. The observed load reduction in MWh includes all reported reduction values, including load increases, is calculated by the MMU. The observed load reduction is a conservative estimate of what occurred during the demand response events as load increases are not required to be reported. Reported and observed compliance is calculated by comparing the reported and observed load reduction during an event to the committed MW value. The average row is the average results across both events for the PENELEC Zone.

The PENELEC Zone did not have any annual Demand Resources. The response from the limited and extended summer products was voluntary.

35 PJM. OATT Attachment K § PJM Emergency Load Response Program at Reporting and Compliance.

36 See "PJM Empirical Analysis of Demand Response Baseline Methods," KEMA, April 2011, <https://www.pjm.com/~/media/markets-ops/dsr/pjm-analysis-of-dr-baseline-methods-full-report.ashx> (Accessed February 26, 2016).

Table 6-26 Demand response event performance: April 21, 2015 and April 22, 2015

Event Date	Zone	Product Type	Nominated ICAP (MW)	Committed MW	Load Reduction Reported (MW)	Load Reduction Observed (MW)	Difference	Percent Compliance Reported	Percent Compliance Observed
21-Apr-15	PENELEC	Limited and Extended Summer	39.5	281.5	27.4	25.5	1.93	9.7%	9.1%
22-Apr-15	PENELEC	Limited and Extended Summer	40.8	281.5	38.3	36.7	1.67	13.6%	13.0%
Average	PENELEC	Limited and Extended Summer	40.1	281.5	32.9	31.1	1.80	11.7%	11.0%

Performance for specific customers varied significantly. Table 6-27 shows the distribution of participant event days by performance levels for the April 21, 2015, and April 22, 2015, events.[37] Table 6-27 includes the participation for all resources dispatched for the emergency events. There was no reduction, load increased or participants did not report data on 45.9 percent of participant event days including 40.9 percent of the nominated MW. There was a reduction of less than 50 percent on 15.5 percent of participant event days including 17.9 percent of the nominated MW.

Table 6-27 Distribution of participant event days and nominated MW across ranges of performance levels across the events: 2015

Ranges of performance as a percent of nominated ICAP MW	Number of participant event days	Proportion of participant event days	Nominated MW	Proportion of nominated MW
0%, load increase, or no reporting	101	45.9%	37.4	40.9%
0% - 50%	34	15.5%	16.4	17.9%
50% - 300%	85	38.6%	37.8	41.3%
Total	220	100.0%	91.6	100.0%

Definition of Compliance

Currently, the calculation methods of event and test compliance do not provide reliable results. PJM's interpretation of load management event rules allows over compliance to be reported when there is no actual over compliance. Settlement locations with a negative load reduction value (load increase) are not netted by PJM within registrations or within demand response portfolios. A resource that has load above their baseline during a demand response event has a negative performance value. PJM limits compliance shortfall values to zero MW. This is not explicitly stated in the Tariff or supporting Manuals and the compliance formulas for FSL and GLD customers do allow negative values.[38]

Limiting compliance to positive values only incorrectly calculates compliance. For example, if a registration had two locations, one with a 50 MWh load increase when called, and another with a 75 MWh load reduction when called, PJM calculates compliance for that registration as a 75 MWh load reduction for that event hour. Negative settlement MWh are not netted across hours or across registrations for compliance purposes. A location with a load increase is set to a zero MW reduction. For example, in a two hour event, if a registration showed a 15 MWh load increase in hour one, but a 30 MWh reduction in hour two, the registration would have a calculated 0 MWh reduction in hour one and a 30 MWh reduction in hour two. This has compliance calculated at an average hourly 15 MWh load reduction for that two hour event, compared to a 7.5 MWh observed reduction. Reported compliance is greater than observed compliance, as locations with load increases, i.e. negative reductions, are treated as zero for compliance purposes.

Changing a demand resource compliance calculation from a negative value to 0 MW inaccurately values event performance and capacity performance. Inflated compliance numbers for an event overstates the true value and capacity of demand resources. A demand response capacity resource that performs negatively is also displacing another capacity resource that could supply capacity during a delivery year. By setting the negative compliance value to 0 MW, PJM is inaccurately calculating the value of demand resources.

An extreme example makes clear the fundamental problems with the use of measurement and verification methods to define the level of power that would have been used but for the DR actions, and the payments to DR customers that result from these methods. The current rules for measurement and verification for demand resources make a bankrupt company, a customer that no longer exists due to closing of a

37 A participant is a customer.
38 OATT Attachment K Section 8.9.

facility or a permanently shut down company, or a company with a permanent reduction in peak load due to a partial closing of a facility, an acceptable demand response customer under some interpretations of the tariff, although it is the view of the MMU that such customers should not be permitted to be included as registered demand resources. Companies that remain in business, but with a substantially reduced load, can maintain their pre-bankruptcy FSL (firm service level to which the customer agrees to reduce in an event) commitment which can be greater than or equal to the post-bankruptcy peak load. The customer agrees to reduce to a level which is greater than or equal to its new peak load after bankruptcy. When demand response events occur the customer would receive credit for 100 percent reduction, even though the customer took no action and could take no action to reduce load. This problem exists regardless of whether the customer is still paying for capacity. To qualify and participate as a Demand Resource, the customer must have the ability to reduce load. "A participant that has the ability to reduce a measurable and verifiable portion of its load, as metered on an EDC account basis."[39] Such a customer no longer has the ability to reduce load in response to price or a PJM demand response event. CSPs in PJM have and continue to register bankrupt customers as DR customers. PJM finds acceptable the practice of CSPs maintaining the registration of customers with a bankruptcy related reduction in demand that are unable, as a result, to respond to emergency events.

Emergency Energy Payments

For any PJM declared load management event in 2015, participants registered under the full option, which contains 99.6 percent of registrations, that were dispatched and demonstrated a load reduction were eligible to receive emergency energy payments. The full program option includes an energy payment for load reductions during a pre-emergency or emergency event for demand response events and capacity payments.[40] The Demand Resource energy payments are equal to the higher of hourly zonal LMP or a strike price energy offer made by the participant, including a dollar per MWh minimum dispatch price and an associated shutdown cost. The new scarcity pricing rules increased the maximum DR energy price offer for the 2013/2014 Delivery Year to $1,800 per MWh. The maximum offer decreased to $1,599 per MWh for the 2014/2015 Delivery Year and increased to $1,849 per MWh for the 2015/2016 Delivery Year. The maximum generator offer will remain at $1,000 per MWh.[41,42]

Shutdown costs for demand response resources are not adequately defined in Manual 15. PJM's Cost Development Subcommittee (CDS) approved changes to Manual 15 to eliminate shutdown costs for demand response resources participating in the Synchronized Reserve Market, but not Demand Resources or Economic Resources.[43]

Table 6-28 shows the distribution of registrations and associated MW in the full option across ranges of minimum dispatch prices for the 2014/2015 Delivery Year. The majority of participants, 94.7 percent, have a minimum dispatch price between $1,000 and $1,100 per MWh, and 0.1 percent of participants have a dispatch price between $1,276 and $1,549 per MWh, which is the maximum price allowed for the 2014/2015 Delivery Year. Energy offers are further increased by submitted shutdown costs, which, in the 2014/2015 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 energy offer. The shutdown cost of resources with $1,101 to $1,275 per MWh strike prices had the highest average at $160.05 per location.

Table 6-28 Distribution of registrations and associated MW in the full option across ranges of minimum dispatch prices: 2014/2015 Delivery Year[44]

Ranges of Strike Prices ($/MWh)	Locations	Percent of Total	Nominated MW (ICAP)	Percent of Total	Shutdown Cost per Location
$0-$1	570	3.6%	630.0	6.7%	$0.00
$1-$999	218	1.4%	160.9	1.7%	$28.54
$1,000-$1,100	15,101	94.7%	7,497.1	80.1%	$72.88
$1,101-$1,275	29	0.2%	368.7	3.9%	$160.05
$1,276-$1,549	21	0.1%	703.6	7.5%	$66.67
Total	15,939	100.0%	9,360.3	100.0%	$69.81

39 OATT Attachment K Appendix Section 8.2.
40 OATT Attachment K Appendix Section 8.2.
41 139 FERC ¶ 61,057 (2012).
42 FERC accepted proposed changes to have the maximum strike price for 30 minute demand response to be $1,000/MWh + 1*Shortage penalty - $1.00, for 60 minute demand response to be $1,000/MWh + (Shortage Penalty/2) and for 120 minute demand response to be $1,100/MWh from ER14-822-000.
43 PJM. "Manual 15: Cost Development Guidelines," Revision 26 (November 5, 2014), p. 54.
44 In this analysis nominated MW does not include capacity only resources, which do not receive energy market credits.

Table 6-29 shows the distribution of registrations and associated MW in the emergency full option across ranges of minimum dispatch prices for the 2015/2016 Delivery Year. The majority of participants, 77.0 percent, have a minimum dispatch price between $1,550 and $1,850 per MWh, which is the maximum price allowed for the 2015/2016 Delivery Year, and 3.4 percent of participants have a dispatch price between $0 and $1 per MWh. Energy offers are further increased by submitted shutdown costs, which, in the 2014/2015 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 energy offer. The shutdown cost of resources with $1,000 to $1,100 per MWh strike prices had the highest average at $183.69 per location and $141.56 per MW.

Table 6-29 Distribution of registrations and associated MW in the emergency full option across ranges of minimum dispatch prices: 2015/2016 Delivery Year[45]

Ranges of Strike Prices ($/MWh)	Locations	Percent of Total	Nominated MW (ICAP)	Percent of Total	Shutdown Cost per Location	Shutdown Cost Per Nominated MW (ICAP)
$0-$1	609	3.4%	562.9	4.8%	$0.00	$0.00
$1-$999	192	1.1%	217.0	1.9%	$136.08	$120.42
$1,000-$1,100	2,850	16.1%	3,698.1	31.8%	$183.69	$141.56
$1,101-$1,275	0	0.0%	0.0	0.0%	$0.00	$0.00
$1,276-$1,549	422	2.4%	514.0	4.4%	$59.11	$48.53
$1,550-$1,850	13,650	77.0%	6,651.3	57.1%	$26.97	$55.35
Total	17,723	100.0%	11,643.2	100.0%	$53.19	$80.97

45 In this analysis nominated MW does not include capacity only resources, which do not receive energy market credits.