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 in its entirety Order No. 745, which provided for payment of demand-side resources at full LMP.[1] The decision calls into question the jurisdictional foundation for all demand response programs currently subject to FERC oversight, and, in particular, for those programs that involve FERC regulated payments to demand resources. *EPSA v. FERC* is now subject to a stay pending the Supreme Court's review of the decision in its October 2015 term. The Supreme Court granted certiorari on May 4, 2015, and heard oral arguments on October 14, 2015.

  FirstEnergy filed an amended complaint on September 22, 2014, that seeks to extend *EPSA v. FERC* to the PJM capacity markets, and would, if granted, eliminate tariff provisions that provide for the compensation of Demand Resources as a form of supply effective May 23, 2014, and require a rerun of the 2017/2018 Base Residual Auction.[2]

  On March 31, 2015, the FERC rejected as premature certain tariff revisions filed by PJM on January 14, 2015, which had been intended to adapt the PJM demand response rules depending on the outcomes and timing of the outcomes on potential review of EPSA v. FERC and PJM's pending capacity performance proposal.[3]

- **Demand Response Activity.** Demand response includes the economic program and the emergency program. Emergency program revenue includes both capacity and energy revenue. The capacity market is still the primary source of revenue to participants in PJM demand response programs, including both capacity market revenue and the associated emergency energy revenue. In the first nine months of 2015, capacity market revenue increased by $82.0 million, or 16.3 percent, from $503.1 million in the first nine months of 2014 to $585.1 million in the first nine months of 2015.[4] Emergency energy revenue decreased by $42.5 million, from $43.0 million in the first nine months of 2014 to $0.5 million in the first nine months of 2015. Economic program revenue is energy revenue only. Economic program credits decreased by $9.7 million, from $16.5 million in the first nine months of 2014 to $6.8 million in the first nine months of 2015, a 58.5 percent decrease.[5] Total revenue in the first nine months of 2015 increased by 13.7 percent from $524.0 million in the first nine months of 2014 to $595.8 million in the first nine months of 2015. Not all DR activities in the first nine months of 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. 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 price determined under the net benefits test for that month.[6]

- **Demand Response Market Concentration.** Economic demand response was highly concentrated in the first nine months of 2014 and 2015. The HHI for economic demand response reductions increased from 7780 in the first nine months of 2014 to 7929 in the first nine months of 2015. Emergency demand response was moderately concentrated in the first nine months of 2015. The HHI for emergency demand response registrations was 1760 for the 2014/2015 Delivery Year and 1497 for the

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 See FirstEnergy Service Company complaint, FERC Docket No. EL14-55-000, amending the complaint filed May 23, 2014.

3 150 FERC ¶ 61,251.

4 The total credits and MWh numbers for demand resources were calculated as of July 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.

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 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.

Recommendations

The MMU recognizes the substantial uncertainty related to the treatment of demand response in wholesale power markets which depends on Supreme Court review and on FERC treatment of PJM's Capacity Performance filing. 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 September 30, 2015.

- 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.)
- The MMU recommends that, if demand response remains in the PJM market, 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 2013. Status: Partially Adopted.[7])
- The MMU recommends that, if demand response remains in the PJM market, 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: Partially adopted.[8])
- The MMU recommends that, if demand response remains in the PJM market, a daily energy market must offer requirement apply to demand resources, comparable to the rule applicable to generation capacity resources.[9] (Priority: High. First reported 2013. Status: Not adopted.)
- The MMU recommends that, if demand response remains in the PJM market, demand response programs adopt an offer cap equal to the offer cap applicable to energy offers from generation capacity resources, currently $1,000 per MWh.[10] (Priority: High. First reported 2013. Status: Not adopted.)
- The MMU recommends that, if demand response remains in the PJM market, 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: Adopted in full, Q1, 2014.)
- The MMU recommends that, if demand response remains in the PJM market, demand resources be required to provide their nodal location on the electricity grid. (Priority: High. First reported 2011. Status: Not adopted.)
- The MMU recommends that, if demand response remains in the PJM market, PJM require nodal dispatch of demand resources with no advance notice required or, if nodal location not required, subzonal dispatch of demand resources with no advance notice required. (Priority: High. New recommendation. Status: Not adopted.)
- The MMU recommends that, if demand response remains in the PJM market, 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

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 The pre emergency demand response product does not need an emergency to be called before dispatch and does not create a PJM emergency when called.

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

10 *Id* at 1.

mismatches between the locational need for the resources and the actual response. (Priority: High. New recommendation. Status: Not adopted.)

- The MMU recommends that, if demand response remains in the PJM market, measurement and verification methods for demand resources be further modified to more accurately reflect compliance. (Priority: Medium. First reported 2009. Status: Not adopted.)
- The MMU recommends that, if demand response remains in the PJM market, 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. (Priority: Medium. First reported 2012. Status: Not adopted.)
- The MMU recommends that, if demand response remains in the PJM market, 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.[11] (Priority: Medium. First reported 2013. Status: Not adopted.)
- The MMU recommends that, if demand response remains in the PJM market, demand response event compliance be calculated for each hour and the penalty structure reflect hourly compliance. (Priority: Medium. First reported 2013. Status: Not adopted. Pending before FERC.)
- The MMU recommends that, if demand response remains in the PJM market, demand resources whose load drop method is designated as "Other" explicitly record the method of load drop. (Priority: Low. First reported 2013. Status: Adopted in full, Q2, 2014.)
- The MMU recommends that, if demand response remains in the PJM market, 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, 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. Pending before FERC.)

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.

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. That 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 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

11 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.

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. With the new CP rules, demand response will be structured for hourly performance.[12]

In order to be a substitute for generation, any demand resource and its CSP, if any, 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 would 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.

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.

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

This approach would work under the current RPM design and this approach would work under the CP design. This approach is entirely consistent with any Supreme Court decision on *EPSA* as it does not require FERC to have jurisdiction over the demand side. This approach will allow the Commission to more fully realize its overriding policy objective to create competitive and efficient wholesale energy markets.

PJM Demand Response Programs

All demand response programs in PJM can be grouped into economic and emergency programs.[13] Table 6-1 provides an overview of the key features of PJM demand response programs. Demand response program is used here to refer to both emergency and economic programs. Demand resource is used here to refer to both resources participating in the capacity market and resources participating in the energy market. In both the economic and emergency 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 compensates 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 of entry.

In a panel decision issued May 23, 2014, the U.S. Court of Appeals for the District of Columbia Circuit vacated in its entirety Order No. 745, which provided for payment of demand-side resources at full LMP.[14] The court found Order No. 745 arbitrary and capricious on its merits.[15] More importantly, 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."[16] The decision calls into question the jurisdictional foundation for all demand response programs currently subject to FERC oversight, and, in particular, for those programs that involve FERC regulated payments to demand resources. *EPSA v. FERC* is now subject to a stay pending the Supreme Court's review of the decision in the October 2015 term. The Supreme Court granted certiorari on May 4, 2015, and heard oral arguments on October 14, 2015.

FirstEnergy filed an amended complaint on September 22, 2014, that seeks to extend the finding in *EPSA v. FERC* to the PJM Capacity Market, and would, if granted, eliminate tariff provisions that provide for the compensation of Demand Resources as a form of capacity supply effective May 23, 2014.[17] The complaint also seeks to void the results of the 2017/2018 Base Residual Auction conducted in May 2014 and to rerun the auction excluding demand

14 Electric Power Supply Association v. FERC, No. 11-1486.
15 *Id.*, slip. op. at 14.
16 *Id.*
17 See FirstEnergy Service Company complaint, FERC Docket No. EL14-55-000, amending the complaint filed May 23, 2014.

Table 6-1 Overview of demand response programs

	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 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.

13 Throughout this document, emergency demand response refers to both emergency and pre emergency demand response.

resources. The Market Monitor issued a report on July 10, 2014, analyzing the worst case effects in the event that such relief were granted.[18] The report concludes that "should a legal or policy decision be made to eliminate demand resources from its current participation as supply in the PJM Capacity Market, PJM markets could adapt."[19] The proceeding is pending before the Commission.

On March 31, 2015, the FERC rejected as premature certain tariff revisions filed by PJM on January 14, 2015, which had been intended to adapt the PJM demand response rules depending on the outcomes and timing of the outcomes on potential review of *EPSA v. FERC* and PJM's pending capacity performance proposal.[20,21]

EPSA presents an opportunity to reform the rules for demand response to make them consistent with the functioning of an efficient and competitive market. The current rules for demand response have evolved to create a negative impact on market efficiency and pose obstacles to the growth of an effective demand component to the market. This negative impact is not the result of demand side resources which are an invaluable part of the markets but is a result of current PJM rules. These flaws have been well documented, and some are the subject of pending litigation at the Commission.[22] Now is an appropriate time for decisive steps away from the flawed approach of treating demand as a form of supply and toward treating demand response as changes in demand.

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 the first nine months of 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.[23]

In the first nine months of 2015, emergency revenue, which includes capacity and emergency energy revenue, accounted for 98.2 percent of all revenue received by demand response providers, credits from the economic program were 1.1 percent and revenue from synchronized reserve was 0.7 percent.

Total emergency revenue increased by $82.0 million, or 16.3 percent, from $503.1 million in the first nine months of 2014 to $585.1 in 2015. Of the total emergency revenue, capacity market revenue increased by $124.5 million, or 27.0 percent, from $460.1 million in the first nine months of 2014 to $584.6 million in the first nine months of 2015, due to higher clearing prices and volumes in the Capacity Market for the 2013/2014 and 2014/2015 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.[24] Emergency energy revenue decreased by $42.5 million, from $43.0 million in the first nine months of 2014 to $0.5 million in

18 See Monitoring Analytics, LLC, The 2017/2018 RPM Base Residual Auction: Sensitivity Analyses, which can be accessed at: <http://www.monitoringanalytics.com/reports/Reports/2014/IMM_20172018_RPM_BRA_Sensitivity_Analyses_20140710.pdf>.

19 *Id.* at 10.

20 150 FERC ¶ 61,251.

21 See Comments of the Independent Market Monitor for PJM, ER15-852-000 (February 13, 2015).

22 The Market Monitor has documented in numerous reports the price suppressing effects and market design flaws attributable to the current treatment of Demand Resources in the PJM Capacity Market, including:

The failure to require performance from Demand Resources that is comparable to the performance provided by Generation Capacity Resources and that would therefore make Demand Resources substitutes for Generation Resources while providing substantially the same compensation to both. *See, e.g.,* Monitoring Analytics, LLC, 2013 State of the Market Report for PJM (March 13, 2013) ("2013 SOM") at 197, 203; *see also*, Monitoring Analytics, LLC, Analysis of the 2016/2017 RPM Base Residual Auction (April 18, 2014) at 3, 35–27 ("2016/2017 BRA Report"), which can be accessed at: <http://www.monitoringanalytics.com/reports/Reports/2014/IMM_Analysis_of_the_20162017_RPM_Base_Residual_Auction_20140418.pdf>.

The failure to remove inferior demand resource products from the capacity markets which cannot, by definition of the products, be substitutes for generation resources and the failure to require demand resource products to respond year round during any hour.

The failure to eliminate the 2.5 shift in the demand curve used in RPM Base Residual Actions. *See, e.g.,* 2013 SOM at 157, 160; 2016/2017 BRA Report at 4–5.

The failure to require demand resources to make physical offers. *See, e.g.,* 2013 SOM at 160, 171–172; Monitoring Analytics, LLC, Analysis of Replacement Capacity for RPM Commitments: June 1, 2007 to June 1, 2013 (September 13, 2013), which can be accessed at: <http://www.monitoringanalytics.com/reports/Reports/2013/IMM_Report_on_Capacity_Replacement_Activity_2_20130913.pdf>; Comments of the Independent Market Monitor for PJM, Docket No. ER14-1461 (April 1, 2014).

The failure to require demand resources to make daily offers into the Day-Ahead Energy Market as required of generation capacity resources. *See, e.g.,* 2013 SOM at 197, 203; Complaint and Motion to Consolidate of the Independent Market Monitor for PJM, Docket No. EL14-20 (January 27, 2014).

The failure to apply a uniform system offer cap to demand resources and generation capacity resources. *Id.*

The failure to develop measurement and verification rules sufficient to ensure that demand resources do not consume capacity when it is needed by those who pay for it. *See, e.g.,* 2013 SOM at 197–198, 210; Comments of the Independent Market Monitor for PJM, Docket No. ER14-822 (January 1, 2014).

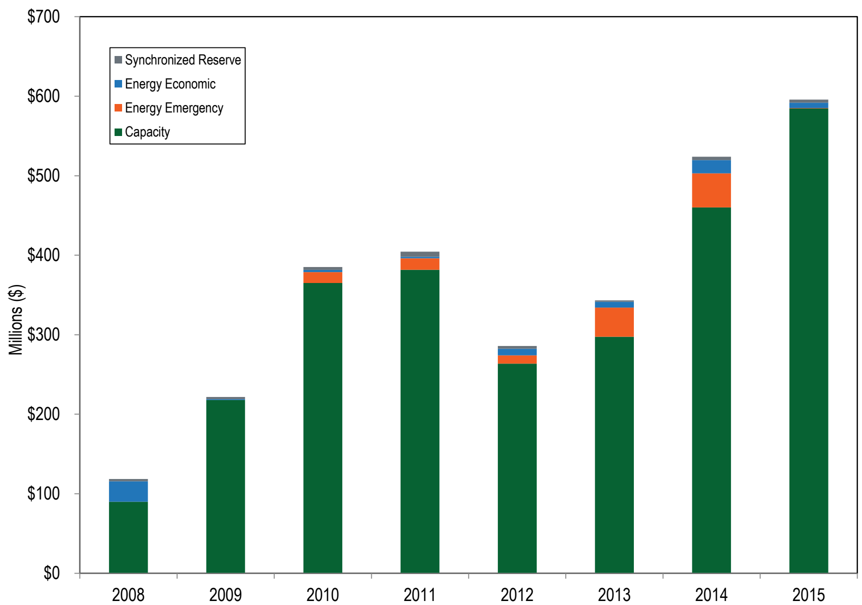
23 This includes both capacity market revenue and emergency energy revenue for capacity resources.

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

the first nine months of 2015. Total revenue in the first nine months of 2015 increased by 13.7 percent from $503.1 million in the first nine months of 2014 to $585.1 million in the first nine months of 2015.

Total credits under the economic program decreased by $9.7 million from $16.5 million in the first nine months of 2014 to $6.8 million in the first nine months of 2015, a 58.5 percent decrease.

Figure 6-1 Demand response revenue by market: January through September 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 September 2015. Registration is a prerequisite for CSPs to participate in the economic program. The average number of registrations for economic demand response decreased and the average registered MW increased in the first nine months of 2015 compared to the same time period in 2014. The average number of monthly registrations decreased by 93 from 1,067 in the first nine months of 2014 to 974 in the first nine months of 2015. The average monthly registered MW for the first nine months of 2015 increased by 56 MW, or 2.0 percent, from 2,732 MW in the nine months of 2014 to 2,788 MW in the first nine months of 2015.

Several demand response resources are registered for both the economic and emergency demand response programs. There were 277 registrations and 1,370 nominated MW in the emergency program that were also registered in the economic program during the first nine months of 2015.

Table 6-2 Economic program registrations on the last day of the month: January 2010 through September 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		
Nov	1,605	2,444	1,988	2,255	824	2,267	1,192	2,307	1,063	2,995		
Dec	1,598	2,439	1,992	2,259	846	2,283	1,192	2,311	1,071	2,923		
Avg. (Jan-Sep)	1,609	2,432	1,606	2,382	1,150	2,175	1,113	2,364	1,067	2,732	974	2,788

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 September 2015. The monthly maximum is the sum of each registration's monthly noncoincident peak dispatched MW and the nine month annual maximum is the sum of each registration's noncoincident peak dispatched MW during the first nine months of the respective year. This aggregated maximum dispatched MW for all economic demand response registered resources in the first nine months of 2015 increased by 316 MW, from 1,532 MW in the first nine months of 2014 to 1,848 MW in the first nine months of 2015.[25]

Table 6-3 Sum of peak MW reductions for all registrations per month: January through September, 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	357	272
Sep	276	84	451	548	795	623
Annual (Jan - Sep)	1,202	840	1,942	1,467	1,532	1,848

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.[26] The zonal allocation is shown in Table 6-13.

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

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

Table 6-4 shows the total MW reductions made by participants in the economic program and the total credits paid for these reductions in the first nine months of 2010 through 2015. The average credits per MWh paid in the first nine months of 2015 decreased by $68.61 per MWh, or 50.4 percent, from $136.15 per MWh in 2014 to $67.54 per MWh dispatched in 2015. The average real-time load weighted PJM LMP decreased by $19.66 per MWh, from $58.60 per MWh during the first nine months of 2014 to $38.94 per MWh during the first nine months of 2015. Curtailed energy for the economic program was 101,348 MWh in the first nine months of 2015 and the total payments were $6,845,179. Total credits paid for economic DR in the first nine months of 2015 decreased by $9.7 million or 58.5 percent, compared to the first nine months of 2014.

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

Year (Jan-Sep)	Total MWh	Total Credits	$/MWh
2010	58,280	$2,677,937	$45.95
2011	15,376	$1,943,507	$126.40
2012	122,080	$8,179,884	$67.00
2013	105,299	$7,387,658	$70.16
2014	121,266	$16,510,277	$136.15
2015	101,348	$6,845,179	$67.54

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 of the economic strike price of $100 per MWh. 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 September 2015. Higher energy prices and FERC Order No. 745 increased incentives to participate starting in April 2012. The high prices in the first three months of 2014 resulted in higher credits. Lower prices in the first three months of 2015 resulted in lower prices and lower credits.

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

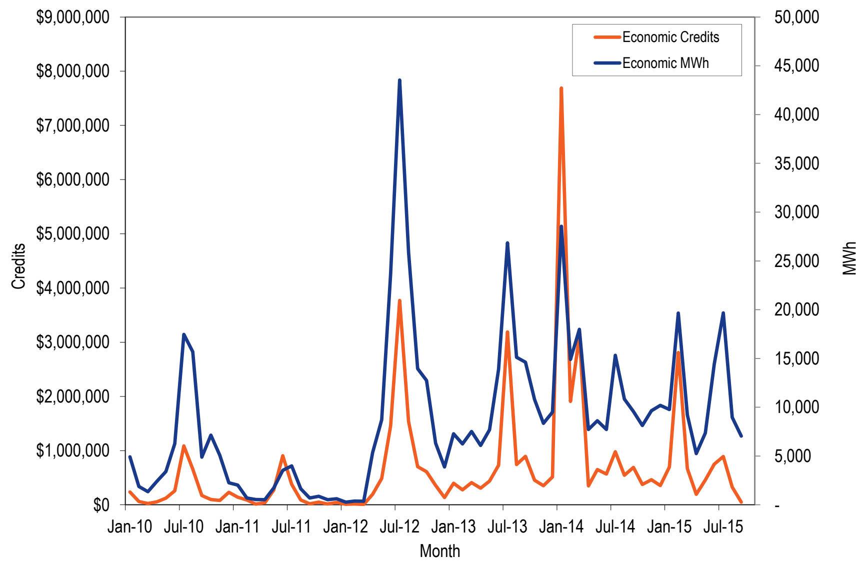


Table 6-5 shows performance for the first nine months of 2014 and 2015 in the economic program by control zone and participation type. Total economic program reductions decreased 16.4 percent from 121,266 MW in the first nine months of 2014 to 101,348 MW in the first nine months of 2015. The economic credits decreased by 58.5 percent from $16,510,277 in the first nine months of 2014, to $6,845,179 in the first nine months of 2015.

Table 6-5 PJM economic program participation by zone: January through September of 2014 and 2015[27]

	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	$2,417,455	$478,687	(80.2%)	9,336	4,417	(52.7%)	$258.93	$108.38	(58.1%)
AEP, AP	$315,236	$125,561	(60.2%)	3,403	1,767	(48.1%)	$92.64	$71.05	(23.3%)
ATSI, ComEd, DAY, DEOK, DLCO, EKPC	$934,835	$648,638	(30.6%)	7,933	15,491	95.3%	$117.84	$41.87	(64.5%)
BGE, DPL, Met-Ed, PENELEC	$1,128,016	$700,797	(37.9%)	10,310	17,277	67.6%	$109.41	$40.56	(62.9%)
Dominion	$9,211,386	$4,121,876	(55.3%)	74,154	50,717	(31.6%)	$124.22	$81.27	(34.6%)
PPL, PSEG	$2,503,350	$769,620	(69.3%)	16,130	11,679	(27.6%)	$155.20	$65.90	(57.5%)
Total	$16,510,277	$6,845,179	(58.5%)	121,266	101,348	(16.4%)	$136.15	$67.54	(50.4%)

Table 6-6 shows total settlements submitted for the first nine months of 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: January through September of 2009 through 2015

Year (Jan - Sep)	2009	2010	2011	2012	2013	2014	2015
Number of Settlements	1,642	3,368	703	4,195	1,960	1,899	1,334

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

Table 6-7 Participants and CSPs submitting settlements in the economic program by year: January through September of 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
Total Distinct Active	15	206	16	257	15	203	22	428	20	273	18	162	18	114

Economic demand response was highly concentrated in the first nine months of both 2014 and 2015.[28] Table 6-8 shows the monthly HHI and the HHI for the first nine months of 2015. The table also lists the share of reductions provided by, and the share of credits claimed by the four largest DR companies in each year. In the first nine months of 2015, 78.9 percent of all economic DR reductions and 90.2 percent of economic DR revenue were attributable to the four largest DR companies. The HHI for demand response reductions increased 149 points, from 7780 in the first six months of 2014 to 7929 in the first nine months of 2015.

27 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.
28 Parent companies may own one CSP or multiple CSPs. All HHI calculations in this section are at the parent company level.

Table 6-8 HHI and market concentration in the economic program: January through September of 2014 and 2015

	HHI			Top Four Companies Share of Reduction			Top Four Companies Share of Credit		
Month	2014	2015	Percent Change	2014	2015	Change Percent	2014	2015	Change Percent
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	7751	7539	(2.7%)	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	8157	0.2%	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%	82.0%	(3.6%)
Aug	8351	8397	0.5%	97.8%	94.9%	(2.9%)	96.7%	95.4%	(1.2%)
Sep	8632	8893	3.0%	89.7%	98.6%	9.0%	87.4%	100.0%	12.6%
Total	7780	7929	1.9%	81.3%	78.9%	(2.4%)	85.9%	90.2%	4.3%

Table 6-9 shows average MWh reductions and credits by hour for the first nine months of 2014 and 2015. In the first nine months of 2014, 88.3 percent of reductions and 85.1 percent of credits occurred from hours ending 0700 to 2100, and in the first nine months of 2015, 94.9 percent of reductions and 91.2 percent of credits occurred from 0700 to 2100.

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

	MWh Reductions			Program Credits		
Hour Ending (EPT)	2014	2015	Percent Change	2014	2015	Percent Change
1	771	282	(63%)	$127,414	$38,047	(70%)
2	719	268	(63%)	$112,127	$33,461	(70%)
3	875	293	(66%)	$149,110	$40,490	(73%)
4	1,473	361	(75%)	$290,489	$45,630	(84%)
5	1,533	351	(77%)	$201,531	$46,191	(77%)
6	2,205	678	(69%)	$316,148	$99,134	(69%)
7	5,143	3,645	(29%)	$872,658	$440,564	(50%)
8	6,263	5,320	(15%)	$1,079,702	$563,819	(48%)
9	6,758	5,962	(12%)	$840,177	$391,703	(53%)
10	6,680	4,791	(28%)	$966,816	$357,207	(63%)
11	4,990	3,959	(21%)	$845,383	$283,514	(66%)
12	4,098	4,238	3%	$758,971	$281,734	(63%)
13	4,592	4,569	(1%)	$644,767	$264,668	(59%)
14	7,247	6,710	(7%)	$829,930	$350,145	(58%)
15	10,269	8,040	(22%)	$928,947	$398,127	(57%)
16	10,886	10,677	(2%)	$994,598	$517,865	(48%)
17	11,017	11,257	2%	$1,030,773	$593,808	(42%)
18	11,117	10,872	(2%)	$1,228,832	$594,555	(52%)
19	7,250	7,847	8%	$1,028,397	$520,824	(49%)
20	5,924	4,665	(21%)	$1,068,685	$368,648	(66%)
21	4,848	3,613	(25%)	$929,067	$318,041	(66%)
22	3,117	1,571	(50%)	$597,435	$152,501	(74%)
23	1,909	722	(62%)	$379,388	$75,722	(80%)
24	1,583	655	(59%)	$288,934	$68,780	(76%)
Total	121,266	101,348	(16%)	$16,510,277	$6,845,179	(59%)

Table 6-10 shows the distribution of economic program MWh reductions and credits by ranges of real-time zonal, load-weighted, average LMP in the first nine months of 2014 and 2015. Reductions occurred at all price levels. In the first nine months of 2015, 0.7 percent of MWh reductions and 4.1 percent of program credits occurred during the 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): January through September 2014 and 2015

	MWh Reductions			Program Credits		
LMP	2014	2015	Percent Change	2014	2015	Percent Change
$0 to $25	428	3,383	691%	$5,152	$63,410	1,131%
$25 to $50	38,737	54,829	42%	$1,763,674	$1,973,769	12%
$50 to $75	24,487	17,277	(29%)	$1,647,666	$975,387	(41%)
$75 to $100	11,714	8,648	(26%)	$1,168,842	$720,972	(38%)
$100 to $125	6,738	4,880	(28%)	$845,457	$528,100	(38%)
$125 to $150	5,171	2,602	(50%)	$780,771	$344,500	(56%)
$150 to $175	4,259	1,806	(58%)	$763,545	$273,977	(64%)
$175 to $200	3,516	1,788	(49%)	$748,172	$330,124	(56%)
$200 to $225	3,064	1,740	(43%)	$672,056	$335,290	(50%)
$225 to $250	3,133	1,002	(68%)	$713,586	$222,931	(69%)
$250 to $275	2,537	616	(76%)	$636,510	$151,050	(76%)
$275 to $300	1,988	634	(68%)	$558,020	$174,618	(69%)
$300 to $325	1,578	382	(76%)	$459,670	$112,247	(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	1,080	194	(82%)	$333,491	$71,818	(78%)
> $400	10,197	722	(93%)	$4,618,554	$283,364	(94%)
Total	121,259	101,346	(16%)	$16,510,277	$6,845,179	(59%)

Following FERC Order No. 745, each month the NBT threshold price is calculated above which the net benefits of DR are deemed to exceed the cost to load. Demand resource (DR) reductions have two effects on the per MWh energy payment by loads and exports. DR reduces LMP by reducing demand in the energy market. At the same time, DR payments cause an additional uplift charge. The NBT threshold price is a monthly estimate calculated from the supply curve of PJM, and it does not incorporate the real-time or day-ahead prices. When the LMP is above the NBT threshold price, the demand response resource receives credit for the full LMP. Demand resources are not paid for any load reductions during hours where the LMP is below the NBT threshold price. About 0.35 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 September of 2015.

Table 6-11 Result from net benefits tests: April 2012 through September 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	
Nov	$25.63	$31.63	$29.17	
Dec	$25.97	$28.82	$29.01	
Average	$24.80	$28.09	$30.91	$25.61

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 the first nine months of 2015, the highest zonal LMP in PJM was higher than the NBT threshold price 6,154 hours out of the entire 6,551 hours, or 93.9 percent of all hours. Reductions occurred in 5,789 hours, or 94.0 percent, of the 6,154 hours in the first nine months of 2015. The last three columns illustrate how often economic demand response activity occurred when LMPs exceeded NBT threshold prices in the first nine months 2014 and 2015.

Table 6-12 Hours with price higher than NBT and DR occurrences in those hours: January through September 2014 and 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	Change Percent
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%	80.3%	(10.6%)
Total	6,551	5,789	6,154	6.3%	89.3%	93.1%	3.8%

Following the implementation of FERC Order No. 745, DR in PJM is paid by real-time loads and real-time scheduled exports. 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 the first nine months of 2015.

Table 6-14 shows the total zonal DR charge per MWh of real-time load and exports during the first nine months of 2015. On a dollar per MWh basis, real-time load and exports in EKPC paid the highest charges for economic demand response in the first nine months of 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 $0.07/MWh.

Table 6-13 Zonal DR charge: January through September 2015

Zone	January	February	March	April	May	June	July	August	September	Total
AECO	$8,144	$32,233	$7,885	$1,675	$6,752	$9,830	$12,360	$4,658	$730	$84,266
AEP	$110,175	$460,039	$108,168	$35,842	$73,540	$120,888	$137,583	$50,436	$7,200	$1,103,872
AP	$46,313	$186,348	$43,950	$14,169	$28,661	$45,064	$52,642	$18,821	$2,747	$438,715
ATSI	$53,788	$218,608	$55,824	$19,925	$39,112	$63,114	$74,103	$27,218	$4,036	$555,726
BGE	$31,720	$124,739	$28,379	$8,934	$20,043	$35,112	$39,442	$14,611	$2,088	$305,067
ComEd	$58,545	$275,905	$69,202	$18,046	$42,842	$82,223	$110,022	$40,410	$6,022	$703,216
DAY	$14,864	$56,946	$14,135	$4,813	$9,977	$16,888	$19,546	$7,176	$1,018	$145,363
DEOK	$20,275	$89,027	$21,328	$6,816	$16,210	$28,087	$32,039	$11,258	$1,680	$226,721
Dominion	$93,812	$388,679	$84,586	$26,191	$60,039	$107,084	$118,823	$43,003	$5,907	$928,124
DPL	$18,319	$75,492	$16,560	$3,070	$10,660	$16,842	$19,126	$7,310	$1,174	$168,555
DLCO	$9,970	$35,023	$11,012	$3,864	$9,227	$14,519	$17,157	$5,976	$934	$107,681
EKPC	$11,403	$54,120	$11,522	$2,788	$6,507	$11,799	$13,264	$4,622	$651	$116,676
JCPL	$18,592	$72,039	$17,775	$4,136	$13,725	$23,025	$28,533	$10,568	$1,633	$190,028
Met-Ed	$13,736	$53,971	$13,034	$2,642	$8,660	$11,134	$13,520	$5,371	$848	$122,915
PECO	$34,695	$137,349	$32,562	$6,487	$23,321	$31,876	$40,037	$15,372	$2,568	$324,267
PENELEC	$15,541	$60,547	$15,391	$4,838	$9,599	$14,545	$16,913	$6,374	$954	$144,703
Pepco	$29,008	$114,217	$26,061	$8,609	$20,091	$34,254	$38,709	$13,967	$1,974	$286,890
PPL	$38,227	$153,234	$36,723	$6,891	$22,204	$25,649	$35,659	$13,529	$2,104	$334,220
PSEG	$36,731	$133,282	$33,547	$8,416	$24,829	$40,193	$49,621	$18,444	$2,933	$347,996
RECO	$1,231	$4,301	$1,110	$291	$1,076	$1,552	$2,034	$728	$115	$12,439
Exports	$33,144	$83,014	$19,015	$5,828	$9,552	$16,723	$20,661	$8,328	$1,475	$197,740
Total	$698,233	$2,809,114	$667,768	$194,270	$456,626	$750,400	$891,797	$328,182	$48,789	$6,845,179

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

Zone	January	February	March	April	May	June	July	August	September	Zonal Average
AECO	$0.012	$0.065	$0.011	$0.005	$0.011	$0.024	$0.019	$0.007	$0.002	$0.017
AEP	$0.013	$0.087	$0.013	$0.010	$0.009	$0.016	$0.016	$0.006	$0.002	$0.019
AP	$0.014	$0.070	$0.014	$0.010	$0.008	$0.016	$0.016	$0.006	$0.002	$0.017
ATSI	$0.012	$0.075	$0.013	$0.009	$0.008	$0.017	$0.016	$0.006	$0.002	$0.018
BGE	$0.011	$0.063	$0.011	$0.008	$0.009	$0.015	$0.014	$0.006	$0.002	$0.015
ComEd	$0.009	$0.115	$0.012	$0.006	$0.009	$0.018	$0.017	$0.007	$0.002	$0.021
DAY	$0.012	$0.077	$0.012	$0.009	$0.009	$0.016	$0.015	$0.006	$0.002	$0.018
DEOK	$0.010	$0.098	$0.012	$0.008	$0.011	$0.017	$0.016	$0.006	$0.002	$0.020
Dominion	$0.012	$0.077	$0.012	$0.009	$0.009	$0.016	$0.015	$0.006	$0.002	$0.017
DPL	$0.018	$0.069	$0.015	$0.006	$0.008	$0.023	$0.018	$0.007	$0.002	$0.018
DLCO	$0.010	$0.068	$0.012	$0.008	$0.010	$0.018	$0.017	$0.007	$0.002	$0.017
EKPC	$0.014	$0.112	$0.016	$0.008	$0.009	$0.017	$0.016	$0.006	$0.002	$0.022
JCPL	$0.013	$0.066	$0.012	$0.006	$0.010	$0.025	$0.020	$0.007	$0.002	$0.018
Met-Ed	$0.019	$0.067	$0.017	$0.007	$0.009	$0.022	$0.019	$0.007	$0.002	$0.019
PECO	$0.017	$0.067	$0.014	$0.005	$0.009	$0.022	$0.019	$0.007	$0.002	$0.018
PENELEC	$0.015	$0.063	$0.015	$0.010	$0.007	$0.018	$0.017	$0.006	$0.002	$0.017
Pepco	$0.011	$0.067	$0.011	$0.008	$0.010	$0.016	$0.014	$0.006	$0.002	$0.016
PPL	$0.021	$0.069	$0.019	$0.007	$0.008	$0.021	$0.020	$0.007	$0.002	$0.019
PSEG	$0.014	$0.055	$0.012	$0.006	$0.009	$0.023	$0.019	$0.007	$0.002	$0.016
RECO	$0.012	$0.056	$0.011	$0.006	$0.012	$0.023	$0.020	$0.007	$0.002	$0.017
Exports	$0.017	$0.030	$0.008	$0.005	$0.005	$0.009	$0.010	$0.003	$0.001	$0.010
Monthly Average	$0.014	$0.072	$0.013	$0.007	$0.009	$0.019	$0.017	$0.006	$0.002	$0.018

Table 6-15 Monthly day-ahead and real-time DR charge: January through September 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	$212,849	(58%)	$471,085	$678,948	44%	$0.031	$0.018	(40%)
Aug	$158,297	$68,312	(57%)	$386,444	$259,870	(33%)	$0.019	$0.007	(61%)
Sep	$143,293	$2,584	(98%)	$546,589	$46,205	(92%)	$0.029	$0.002	(92%)
Total	$6,828,643	$1,894,618	(72%)	$9,681,572	$4,950,561	(49%)	$0.051	$0.022	(57%)

Table 6-15 shows the monthly day-ahead and real-time DR charges and the per MWh DR charges in the first nine months of 2014 and 2015. The day-ahead DR charges decreased by $4.93 million, or 72.3 percent, from $6.83 million in the first nine months of 2014 to $1.89 million in the first nine months of 2015. The real-time DR charges decreased $4.73 million, or 48.9 percent, from $9.68 million in the first nine months of 2014 to $4.95 million in the first nine months of 2015. The per MWh charge paid by all real-time load and exports for economic DR decreased $0.03/MWh, or 57.1 percent, from $0.05/MWh in the first nine months of 2014 to $0.2/MWh in the first nine months of 2015.

Emergency Program

The emergency load response program consists of the limited, extended summer and annual demand response product in the capacity market during the 2014/2015 Delivery Year. 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 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 also recommends that demand resources have an offer cap equal to the offer cap applicable to energy offers from generation capacity resources, currently $1,000 per MWh.[29]

Emergency demand response was moderately concentrated in the first nine months of 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.

Table 6-16 Zonal monthly capacity revenue: January through September 2015

Zone	January	February	March	April	May	June	July	August	September	Total
AECO	$411,097	$371,313	$411,097	$805,435	$832,282	$985,380	$1,018,226	$1,018,226	$985,380	$6,838,436
AEP, EKPC	$425,101	$383,962	$425,101	$6,203,447	$6,410,228	$6,659,173	$6,881,145	$6,881,145	$6,659,173	$40,928,474
AP	$185,478	$167,528	$185,478	$3,380,132	$3,492,803	$3,174,034	$3,279,835	$3,279,835	$3,174,034	$20,319,157
ATSI	$19,859	$17,937	$19,859	$3,717,154	$3,841,060	$18,481,726	$19,097,783	$19,097,783	$18,481,726	$82,774,887
BGE	$5,430,108	$4,904,613	$5,430,108	$5,140,527	$5,311,878	$5,367,246	$5,546,155	$5,546,155	$5,367,246	$48,044,036
ComEd	$405,926	$366,643	$405,926	$5,846,358	$6,041,237	$6,463,717	$6,679,174	$6,679,174	$6,463,717	$39,351,870
DAY	$63,670	$57,508	$63,670	$872,987	$902,087	$736,289	$760,832	$760,832	$736,289	$4,954,166
DEOK	$8,185	$7,393	$8,185	$330,654	$341,676	$1,277,237	$1,319,812	$1,319,812	$1,277,237	$5,890,190
DLCO	$49,718	$44,907	$49,718	$840,774	$868,800	$849,964	$5,235,719	$5,235,719	$5,066,825	$18,242,143
Dominion	$306,929	$277,226	$306,929	$5,165,946	$5,338,145	$5,066,825	$2,201,083	$2,201,083	$2,130,080	$22,994,245
DPL	$1,547,049	$1,397,335	$1,547,049	$1,542,580	$1,593,999	$2,130,080	$878,296	$878,296	$849,964	$12,364,650
JCPL	$1,495,628	$1,350,890	$1,495,628	$1,709,946	$1,766,944	$1,665,010	$1,720,510	$1,720,510	$1,665,010	$14,590,075
Met-Ed	$1,044,281	$943,222	$1,044,281	$1,558,377	$1,610,323	$1,613,449	$1,667,231	$1,667,231	$1,613,449	$12,761,844
PECO	$2,660,069	$2,402,643	$2,660,069	$3,249,878	$3,358,207	$3,700,859	$3,824,221	$3,824,221	$3,700,859	$29,381,025
PENELEC	$1,144,857	$1,034,064	$1,144,857	$1,675,004	$1,730,838	$2,540,797	$2,625,490	$2,625,490	$2,540,797	$17,062,195
Pepco	$1,906,591	$1,722,082	$1,906,591	$3,467,834	$3,583,429	$4,096,205	$4,232,745	$4,232,745	$4,096,205	$29,244,427
PPL	$3,247,272	$2,933,020	$3,247,272	$5,215,729	$5,389,586	$5,411,083	$5,591,452	$5,591,452	$5,411,083	$42,037,948
PSEG	$2,354,400	$2,126,555	$2,354,400	$5,460,187	$5,642,193	$3,738,271	$3,862,880	$3,862,880	$3,738,271	$33,140,039
RECO	$14,896	$13,454	$14,896	$118,962	$122,927	$99,707	$103,031	$103,031	$99,707	$690,610
Total	$22,721,111	$20,522,294	$22,721,111	$56,301,913	$58,178,643	$74,057,052	$76,525,620	$76,525,620	$74,057,052	$481,610,417

Table 6-17 Energy efficiency resources by MW: 2012/2013 through 2015/2016 Delivery Year

	EE ICAP (MW)				EE UCAP (MW)			
	2012/2013	2013/2014	2014/2015	2015/2016	2012/2013	2013/2014	2014/201	2015/2016
Total	609.7	991.0	1,231.8	1,471.4	631.2	1,029.2	1,282.4	1,525.5

29 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 6-16 shows zonal monthly capacity market revenue to demand resources for the first nine months of 2015. Capacity market revenue increased in the first nine months of 2015 by $124.5 million, or 27.0 percent, compared to the first nine months of 2014, from $460.1 million to $584.6 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 shows the amount of energy efficiency (EE) resources in PJM for 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 shows the number of customers 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 product, 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.

The quick lead time product was defined after the auctions cleared. FERC accepted PJM's proposed 30 minute lead time as a phased in approach on May 9, 2014.[30] PJM submitted a filing on October 20, 2014, to allow DR that is unable to respond within 30 minutes to exit the

30 See "Order Rejecting, in part, and Accepting, in part, Proposed Tariff Changes, Subject to Conditions," Docket No. ER14-822-001 (May 9, 2014).

market without penalty before the mandatory 30 minute lead time with the 2015/2016 Delivery Year.[31]

Table 6-18 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 6-19 shows the number of customers and nominated MW by product type and lead time during the 2015/2016 Delivery Year. The quick lead time product 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.[32] 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 6-19 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
	Limited	1,957	3,058
Short Lead (60 Minutes)	Extended Summer and Limited	426	580
Quick Lead (30 Minutes)	Annual	191	174
	Extended Summer	3,723	2,043
	Limited	10,635	5,092
Total		17,723	11,643

Table 6-20 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%
Non hourly metered sites (DLC)	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 6-20 shows the MW registered by measurement and verification method and by load drop method for the 2014/2015 Delivery Year. Of the DR MW committed, 2.4 percent use the guaranteed load drop (GLD) measurement and verification method, 91.2 percent use the firm service level (FSL) method and 6.3 percent use direct load control (DLC).

Table 6-21 shows the MW registered by measurement and verification method and by load drop method for the 2015/2016 Delivery Year. Of the DR MW committed, 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.

31 See "PJM Interconnection, L.L.C.," Docket No. ER14-135-000 (October 20, 2014).
32 See "Manual 18: Capacity Market," Revision 2 (August 3, 2015), p. 57.

Table 6-21 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%
Non hourly metered sites (DLC)	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 6-22 shows the fuel type used in the on-site generators identified in Table 6-20 and Table 6-21 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 6-22 On-site generation fuel type by MW: 2014/2015 and 2015/2016 Delivery Year

	2014		2015	
Fuel Type	MW	Percent	MW	Percent
Coal, Gasoline, Kerosene, Oil, Propane, Waste Products	59.6	2.8%	87.9	3.3%
Diesel	1,834.1	85.5%	2,250.9	84.7%
Natural Gas	251.0	11.7%	318.5	12.0%
Total	2,144.7	100.0%	2,657.3	100.0%

Emergency Event Reported Compliance

PJM declared two events in 2015, one on April 21, 2015 and one on April 22, 2015. PJM dispatched emergency and pre emergency resources for both events. There were two events during the 2014/2015 Delivery Year, 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 2015 were called in PENELEC and there were no annual Demand Resources there, none were considered in PJM's compliance assessment.[33] Table 6-23 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 total percent of capacity resources in the 2015/2016 Delivery Year decreased by 0.4 percent from 9.3 percent in the 2014/2015 Delivery Year to 8.9 percent in the 2015/2016 Delivery Year.

33 Extended summer and limited demand response products do not need to respond in April.

Table 6-23 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 6-24 lists PJM pre-emergency and emergency load management events declared in PJM in 2015 and the affected zones. Subzonal dispatch was mandatory for the 2014/2015 Delivery Year but only if the subzone is defined no later than the day before. When events occur for partial hours, during times outside of the mandatory compliance window or for a subzone that was not defined one business day before dispatch, the events are not measured for compliance. Demand resources can be dispatched during any hour of any day, but compliance for an event outside of the mandatory compliance window is not measured. The category of Minutes not Measured for Compliance is the amount of time during which compliance is not measured for a dispatched event. The Erie Subzone was not defined the day before the PJM event and therefore it could not be dispatched. 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 the first nine months of 2015 were voluntary, so no penalties are assessed for under compliance.

Table 6-24 PJM declared load management events: 2015

Event Date	Event Times	Compliance Hours	Minutes not Measured for Compliance	Lead Time	Geographical 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

Participants in the pre-emergency and emergency demand response program are paid based on the average performance by registration for the duration of a demand response event. Demand response should measure compliance 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. With the new CP rules, demand response will be structured for hourly performance.[34]

PJM allows compliance to be measured across zones within a compliance aggregation area (CAA). 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.[35] 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. 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 need 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.

34 PJM "Manual 18: Capacity Market," Revision 29 (10/16/2015), p 148.
35 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.[36] 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.

Emergency demand response customers that registered for economic demand response had an adjusted baseline for the emergency event days. The change of baseline resulted in a greater calculated load reduction for the PJM system emergency event days. The changes in reported load reductions reflect emergency resources registering as economic resources to have modified baselines for measurement during the emergency voluntary event days.

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 calculated negative performance value. PJM limits compliance shortfall values at the nominated MW value for underperformance. This is not explicitly stated in the Tariff or supporting Manuals. According to the Tariff, the compliance formulas for FSL and GLD customers allow for negative compliance values.[37] 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, compliance for that registration is calculated as a 75 MWh load reduction for that event hour. 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 show a 0 MWh reduction in hour one and a 30 MWh reduction in hour two and an average hourly 15 MWh load reduction for that two hour event. Reported compliance is less than actual compliance, as locations with load increases, negative reductions, are treated as zero for compliance purposes.

Settlements that are not submitted to PJM are treated as zero compliance for the event. Registrations with negative compliance are treated as zero for the purposes of imposing penalties and reporting.

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 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

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

37 PJM. OATT. PJM Emergency Load Response Program.

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 total 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. 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 of the emergency load response program, which contains 99.6 percent of registrations, that were dispatched and demonstrated a load reduction were eligible to receive emergency energy payments. The emergency 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.[38,39]

Participants may elect to be paid their emergency offer, regardless of the zonal LMP.

38 139 FERC ¶ 61,057 (2012).
39 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 from ER14-822-000.

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 the emergency or economic demand response program.[40]

Table 6-25 shows the distribution of registrations and associated MW in the emergency 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 6-25 Distribution of registrations and associated MW in the emergency full option across ranges of minimum dispatch prices: 2014/2015 Delivery Year[41]

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

Table 6-26 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

40 PJM. "Manual 15: Cost Development Guidelines," Revision 26 (November 5, 2014), p. 54.
41 In this analysis nominated MW does not include capacity only resources, which do not receive energy market credits.

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 6-26 Distribution of registrations and associated MW in the emergency full option across ranges of minimum dispatch prices: 2015/2016 Delivery Year[42]

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

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