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.

  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 is split into two main categories; economic and emergency. 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. In the first three months of 2015, capacity market revenue increased by $31.1 million, or 22.6 percent, from $137.8 million in the first three months of 2014 to $168.9 million in the first three months of 2015.[4] Emergency energy revenue decreased by $43.0 million, from $43.0 million in the first three months of 2014 to zero in the first three months of 2015. Economic program revenue is energy revenue only. Economic program credits decreased by $11.2 million, from $12.7 million in the first three months of 2014 to $1.6 million in the first three months of 2015, an 88 percent decrease.[5] Not all DR activities in the first three 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 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.[6]

- **Demand Response Market Concentration.** Economic demand response was highly concentrated in the first three months of 2014 and 2015. The HHI for economic demand response reductions increased from 7120 in the first three months of 2014 to 7899 in the first three months of 2015. Emergency demand response was moderately concentrated in the first three months of 2015. The HHI for emergency demand response registrations was 1760. 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, if the subzone is defined at least one day before dispatched. More locational dispatch of demand 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 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 May 1st, 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.

in a nodal market improves market efficiency. The goal should be nodal dispatch of demand resources.

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 the time of this report.

- 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: Not Adopted.[7] Pending before FERC.)
- 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. (Priority: High. First reported 2012. Status: Not adopted.)
- 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.[8] (Priority: High. First reported 2013. Status: Not adopted. Pending before FERC.)
- 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.[9] (Priority: High. First reported 2013. Status: Not adopted. Pending before FERC.)
- 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 2013. 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 2012. 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.[10] (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.)

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.

9 *Id* at 1.

10 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.

- 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 2013. 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. 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.

With exception of large wholesale customers in some areas, most customers in PJM are not on retail rates that directly expose them to the wholesale price of energy or capacity. As a result, most customers in PJM do not have the direct ability to see, respond to or benefit from a response to price signals in PJM's markets. PJM's demand side programs are generally designed to allow customers (or their intermediaries in the form of load serving entities (LSEs) or curtailment service providers (CSPs)) to either directly, or through intermediaries, be paid as if they were directly paying the wholesale price of energy and capacity and avoiding those prices when reducing load. PJM's demand side programs are designed to provide direct incentives for load resources to respond, via load reductions, to wholesale market price signals and/or system emergency events.

If retail markets reflected hourly wholesale locational prices and customers or their intermediaries received direct savings associated with reducing consumption in response to real time prices, there would not be a need for a PJM economic load response program, or for extensive measurement and verification protocols. In the transition to that point, however, as long as there are demand side programs, there is a need for robust measurement and verification techniques to ensure that transitional programs incent the desired behavior. The baseline methods used in PJM programs today are not adequate to determine and quantify deliberate actions taken to reduce consumption.

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 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 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.

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.

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 side 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 side 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 suggested 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 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.[11] 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.

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

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.

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.[12] The court found Order No. 745 arbitrary and capricious on its merits.[13] 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."[14] 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.

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.[15] 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 Resources. The Market Monitor issued a report on July 10, 2014, analyzing the worst case effects in the event that such relief were granted.[16] 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."[17] 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.[18,19]

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.[20] Now is an

12 Electric Power Supply Association v. FERC, No. 11-1486.
13 *Id.*, slip. op. at 14.
14 *Id.*
15 See FirstEnergy Service Company complaint, FERC Docket No. EL14-55-000, amending the complaint filed May 23, 2014.
16 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>.
17 *Id.* at 10.
18 150 FERC ¶ 61,251.
19 See Comments of the Independent Market Monitor for PJM, ER15-852-000 (February 13, 2015).
20 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>.

appropriate time for decisive steps away from the flawed approach of treating demand as a form of supply and 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 charge for wholesale power already included in customers' tariff rates.

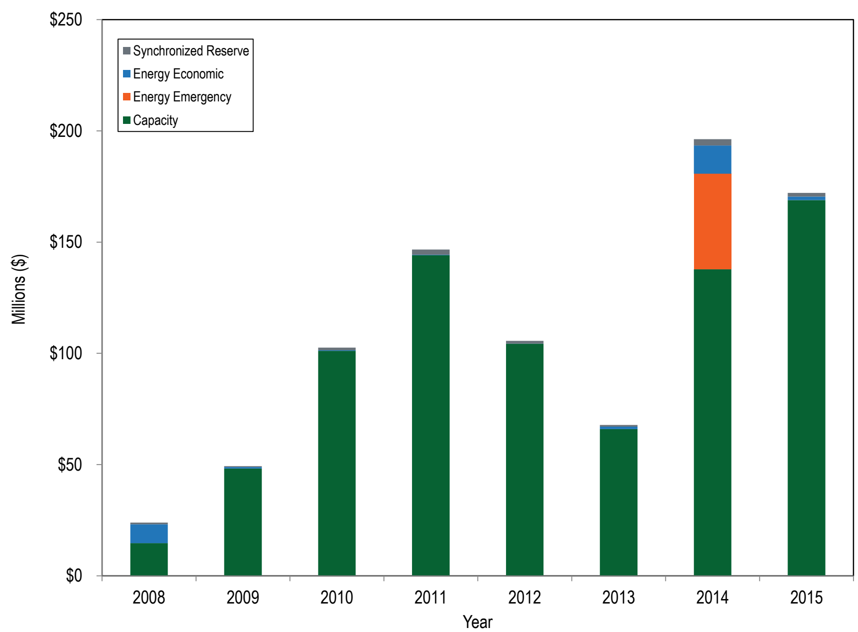
Figure 6-1 shows all revenue from PJM demand response programs by market for the first three months of each year for the period 2008 through 2015. Since the implementation of the RPM capacity market on June 1, 2007, demand response that participated through the capacity market, which includes emergency energy revenue, has been the primary source of revenue to demand response participants.[21]

In the first three months of 2015, emergency revenue, which includes capacity and emergency energy revenue, accounted for 98.1 percent of all revenue received by demand response providers, credits from the economic program were 0.9 percent and revenue from synchronized reserve was 1.0 percent.

Total emergency revenue decreased by $12.6 million, or 7.0 percent, from $180.7 million in the first three months of 2014 to $168.0 in 2015. Of the total emergency revenue, capacity market revenue increased by $30.3 million, or 22.0 percent, from $137.8 million in the first three months of 2014 to $168.1 million in the first three 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 23.1 percent from $99.39 per MW-day to $122.32 per MW-day.[22] Of the total emergency revenue, emergency energy revenue to demand response that sold capacity increased by $6.2 million from $36.7 million in 2013, to $43.0 million in 2014.

Total credits under the economic program decreased by $11.2 million from $12.7 million in the first three months of 2014 to $1.6 million in the first three months of 2015, an 88 percent decrease.

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



- 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).

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

22 *2014 State of the Market Report for PJM,* Section 5: Capacity, Table 5-13.

Economic Program

Table 6-2 shows registered sites and MW for the last day of each month for the period January 2010 through March 2015. Registration is a prerequisite for CSPs to participate in the economic program. The average number of registrations decreased and the average registered MW increased in the first three months of 2015 compared to the same time period in 2014. The average number of registrations decreased by 103 from 1,180 in the first three months of 2014 to 1,076 in the first three months of 2015. The average monthly registered MW for the first three months of 2015 increased by 489 MW, or 20.0 percent, from 2,449 MW in the first three months of 2014 to 2,938 MW in the first three months of 2015.

Economic demand response was highly concentrated in the first three months of 2014 and 2015. The HHI for demand response reductions increased 779 points, from 7120 in the first three months of 2014 to 7899 in the first three months of 2015.[23]

There is some overlap between economic registrations and emergency capacity registrations. There were 305 registrations and 1,820 nominated MW in the emergency program that were also in the economic program during the first three months of 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 amount of MW registered in the program.

Table 6-3 shows the sum of maximum economic MW dispatched by registration each month for January 2010 through March 2015. The monthly maximum is the sum of each registration's monthly noncoincident peak dispatched MW. The annual maximum is the sum of each registration's annual noncoincident peak dispatched MW. This aggregated maximum dispatched MW for all economic demand response registered resources in the first quarter of 2015 decreased by 148 MW, from 517 MW in the first quarter of 2014 to 369 MW in the first quarter of 2015.[24]

Table 6-2 Economic program registrations on the last day of the month: January 2010 through March 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	1,077	2,956
Feb	1,842	2,624	1,612	2,435	1,995	2,384	843	2,327	1,174	2,330	1,075	2,952
Mar	1,845	2,623	1,612	2,519	1,996	2,356	788	2,284	1,185	2,692	1,074	2,945
Apr	1,849	2,587	1,611	2,534	189	1,318	970	2,346	1,194	2,827		
May	1,875	2,819	1,687	3,166	371	1,669	1,375	2,414	745	2,511		
Jun	813	1,608	1,143	1,912	803	2,347	1,302	2,144	928	2,943		
Jul	1,192	2,159	1,228	2,062	942	2,323	1,315	2,443	1,036	3,006		
Aug	1,616	2,398	1,987	2,194	1,013	2,373	1,299	2,527	1,080	3,033		
Sep	1,609	2,447	1,962	2,183	1,052	2,421	1,280	2,475	1,077	2,919		
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-Mar)	1,843	2,623	1,611	2,462	1,995	2,375	824	2,308	1,180	2,449	1,075	2,951

23 For more information, see Table 6-8.

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

Table 6-3 Maximum economic MW dispatched by registration per month: 2010 through March 2015

	Maximum Dispatched MW by Registration					
Month	2010	2011	2012	2013	2014	2015
Jan	233	243	104	193	446	169
Feb	121	190	101	119	307	335
Mar	115	153	72	127	369	166
Apr	111	80	108	133	146	
May	172	98	143	192	151	
Jun	209	561	944	433	483	
Jul	999	561	1,641	1,088	665	
Aug	794	161	980	497	357	
Sep	276	84	451	530	795	
Oct	118	81	242	168	214	
Nov	111	86	165	155	165	
Dec	41	88	99	168	155	
Annual	1,209	841	1,956	1,486	1,739	369

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.[25]

Table 6-4 shows total credits paid to participants in the economic program. The average credits per MWh paid in the first three months of 2015 decreased by $175.57 per MWh, or 76 percent, from $217.92 per MWh in 2014 to $42.36 per MWh dispatched in 2015. The average real-time load weighted PJM LMP decreased by $42.07 per MWh, from $92.98 per MWh during the first three months of 2014 to $50.91 per MWh during the first three months of 2015. Curtailed energy for the economic program was 37,100 MWh in the first quarter of 2015 and the total payments were $1,571,409. Total credits paid for economic DR in the first quarter of 2015 decreased by $11.2 million or 88 percent, compared to the first quarter of 2014.

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

Year (Jan-Mar)	Total MWh	Total Credits	$/MWh
2010	8,139	$321,648	$39.52
2011	3,272	$240,304	$73.45
2012	1,030	$30,406	$29.52
2013	21,048	$1,083,755	$51.49
2014	58,401	$12,726,837	$217.92
2015	37,100	$1,571,409	$42.36

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 was 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 March 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.

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

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

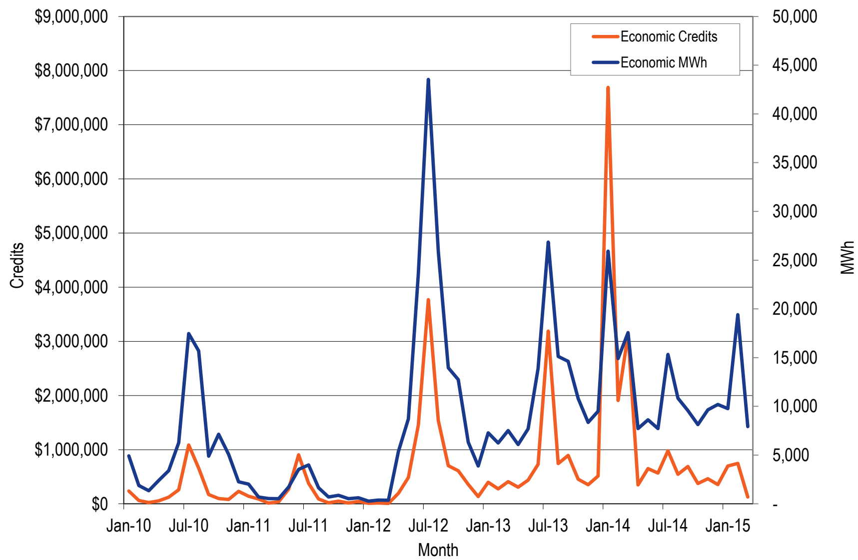


Table 6-5 PJM economic program participation by zone: January through March of 2014 and 2015[26]

	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	$2,207,996	$330,767	(85.0%)	7,014	1,559	(77.8%)	$314.78	$212.17	(32.6%)
AEP, APS	$269,270	$71,348	(73.5%)	2,348	438	(81.3%)	$114.69	$162.94	42.1%
ATSI, ComEd, DAY, DEOK, DLCO, EKPC	$822,631	$160,661	(80.5%)	5,628	3,260	(42.1%)	$146.17	$49.29	(66.3%)
BGE, DPL, Met-Ed, PENELEC	$519,825	$122,954	(76.3%)	2,568	1,996	(22.3%)	$202.40	$61.61	(69.6%)
Dominion	$6,785,542	$482,344	(92.9%)	32,369	24,701	(23.7%)	$209.63	$19.53	(90.7%)
PPL, PSEG	$2,121,573	$403,335	(81.0%)	8,474	5,147	(39.3%)	$250.36	$78.36	(68.7%)
Total	$12,726,837	$1,571,409	(87.7%)	58,401	37,100	(57.4%)	$217.92	$42.36	(80.6%)

Table 6-5 shows the first three months of 2014 and 2015 performance in the economic program by control zone and participation type. Total economic program reductions decreased 36.5 percent from 58,401 MW in the first three months of 2014 to 37,100 MW in the first three months of 2015. The economic credits decreased by 87.6 percent from $12,726,837 in the first three months of 2014, to $1,571,409 in the first three months of 2015.

Table 6-6 shows total settlements submitted for the first three 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 March of 2009 through 2015

Year (Jan - Mar)	2009	2010	2011	2012	2013	2014	2015
Number of Settlements	701	693	91	21	293	1,100	424

Table 6-7 shows the number of curtailment service providers (CSPs), and the number of participants in their portfolios, submitting settlements by year for 2009 through the first three months of 2015. There were 68 fewer active participants in the first three months of 2015 than in the first three months of 2014. All participants must be included in a CSP.

26 PJM and the MMU cannot publish more detailed information about the Economic Program Zonal Settlements as a result of confidentiality requirements.

Table 6-7 Participants and CSPs submitting settlements in the economic program by year: January through March 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	11	146	5	90	5	25	4	9	9	49	12	115	11	47

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

Economic demand response was highly concentrated in the first three months of both 2014 and 2015. Table 6-8 shows the monthly HHI and the quarterly HHI in 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 three months of 2015, 90.7 percent of all Economic DR reductions and 73.3 percent of Economic DR revenue were attributable to the four largest DR companies. The HHI for demand response reductions increased 779 points, from 7120 in the first three months of 2014 to 7899 in the first three months of 2015.

Table 6-8 HHI and market concentration in the economic program: January through March 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	7098	8025	13.1%	86.7%	96.8%	10.0%	84.2%	98.6%	14.4%
Feb	6547	7357	12.4%	84.1%	91.3%	7.3%	77.5%	59.1%	(18.5%)
Mar	7744	8480	9.5%	87.4%	96.5%	9.0%	88.5%	100.0%	11.5%
Total	7120	7899	10.9%	86.1%	90.7%	4.6%	85.2%	73.3%	(11.8%)

Table 6-9 shows average MWh reductions and credits by hour for the first three months of 2014 and 2015. In the first three months of 2014, 78.7 percent of reductions and 81.0 percent of credits occurred from 0700 to 2100, and in the first three months of 2015, 89.1 percent of reductions and 88.3 percent of credits occurred from 0700 to 2100.

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

	MWh Reductions			Program Credits		
Hour Ending (EPT)	2014	2015	Percent Change	2014	2015	Percent Change
1	739	263	(64%)	$126,301	$10,093	(92%)
2	707	253	(64%)	$112,124	$10,041	(91%)
3	863	276	(68%)	$149,107	$11,983	(92%)
4	1,453	344	(76%)	$290,486	$13,941	(95%)
5	1,284	333	(74%)	$201,530	$13,293	(93%)
6	1,780	657	(63%)	$316,145	$25,795	(92%)
7	3,667	3,091	(16%)	$831,186	$72,419	(91%)
8	4,450	4,265	(4%)	$1,022,561	$157,719	(85%)
9	4,409	4,406	(0%)	$765,072	$118,549	(85%)
10	4,529	3,124	(31%)	$881,480	$101,533	(88%)
11	3,329	2,047	(39%)	$774,098	$81,714	(89%)
12	2,535	1,697	(33%)	$674,838	$81,761	(88%)
13	2,498	1,538	(38%)	$506,640	$62,954	(88%)
14	2,397	1,213	(49%)	$479,179	$58,783	(88%)
15	2,130	1,213	(43%)	$415,047	$50,070	(88%)
16	2,133	1,266	(41%)	$347,881	$53,676	(85%)
17	2,074	1,402	(32%)	$367,943	$69,586	(81%)
18	2,740	1,778	(35%)	$665,788	$120,437	(82%)
19	2,936	2,129	(27%)	$806,998	$139,164	(83%)
20	3,147	2,030	(35%)	$944,204	$117,102	(88%)
21	3,016	1,869	(38%)	$826,248	$101,960	(88%)
22	2,401	957	(60%)	$564,800	$45,046	(92%)
23	1,729	495	(71%)	$372,234	$25,915	(93%)
24	1,456	456	(69%)	$284,947	$27,878	(90%)
Total	58,401	37,100	(36%)	$12,726,837	$1,571,409	(88%)

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 three months of 2014 and 2015. Reductions occurred at all price levels. In the first three months of 2015, 1.8 percent of MWh reductions and 5.2 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): 2014 and 2015

	MWh Reductions			Program Credits		
LMP	2014	2015	Percent Change	2014	2015	Percent Change
$0 to $25	122	229	87%	$155	$1,215	686%
$25 to $50	6,571	11,801	80%	$372,078	$240,353	(35%)
$50 to $75	8,954	5,812	(35%)	$626,857	$218,580	(65%)
$75 to $100	6,197	5,043	(19%)	$673,931	$225,163	(67%)
$100 to $125	3,618	3,319	(8%)	$506,213	$150,058	(70%)
$125 to $150	3,451	2,102	(39%)	$560,392	$121,811	(78%)
$150 to $175	3,333	1,533	(54%)	$640,508	$58,945	(91%)
$175 to $200	3,211	1,683	(48%)	$710,019	$90,043	(87%)
$200 to $225	2,774	1,399	(50%)	$635,042	$68,220	(89%)
$225 to $250	2,773	905	(67%)	$697,696	$72,162	(90%)
$250 to $275	2,233	608	(73%)	$616,202	$39,026	(94%)
$275 to $300	1,843	607	(67%)	$545,863	$22,808	(96%)
$300 to $325	1,529	360	(76%)	$447,031	$45,022	(90%)
$325 to $350	1,059	232	(78%)	$359,764	$43,213	(88%)
$350 to $375	1,259	601	(52%)	$435,209	$61,174	(86%)
$375 to $400	897	194	(78%)	$330,783	$31,662	(90%)
> $400	8,576	674	(92%)	$4,569,093	$81,954	(98%)
Total	58,401	37,100	(36%)	$12,726,837	$1,571,409	(88%)

Following 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 0.5 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 March of 2015.

Table 6-11 Result from net benefits tests: April 2012 through March 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	
May	$23.46	$27.73	$32.08	
Jun	$23.86	$28.44	$31.62	
Jul	$22.99	$29.42	$31.62	
Aug	$24.47	$28.58	$29.85	
Sep	$24.93	$28.80	$29.83	
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	$27.05

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 three months of 2015, the highest zonal LMP in PJM was higher than the NBT threshold price 2,058 hours out of the entire 2,159 hours, or 95.3 percent of all hours. Reductions occurred in 1,546 hours, or 75.1 percent, of the 2,058 hours in the first three months of 2015. The last three columns illustrate how often economic demand response activity occurred when LMPs exceeded NBT threshold prices in the first three months 2014 and 2015.

Table 6-12 Hours with price higher than NBT and DR occurrences in those hours: January through March 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%	90.0%	(2.9%)
Mar	743	732	719	(1.8%)	81.8%	54.0%	(27.9%)
Total	2,159	2,146	2,058	(4.1%)	89.4%	75.1%	(14.3%)

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 three months of 2015.

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

Zone	January	February	March	Total
AECO	$8,144	$8,489	$1,503	$18,136
AEP	$110,234	$123,969	$20,337	$254,539
APS	$46,307	$49,216	$8,141	$103,663
ATSI	$53,788	$58,046	$10,262	$122,096
BGE	$31,715	$32,414	$5,375	$69,504
ComEd	$58,588	$76,847	$14,055	$149,490
DAY	$14,866	$15,487	$2,636	$32,990
DEOK	$20,288	$24,244	$4,074	$48,607
DLCO	$9,971	$10,089	$1,991	$22,051
Dominion	$93,795	$100,751	$15,948	$210,493
DPL	$18,317	$19,528	$3,153	$40,998
EKPC	$11,409	$14,602	$2,347	$28,358
JCPL	$18,591	$19,029	$3,316	$40,936
Met-Ed	$13,735	$14,181	$2,367	$30,283
PECO	$34,693	$36,080	$6,105	$76,877
PENELEC	$15,539	$16,114	$2,831	$34,484
Pepco	$29,004	$29,979	$4,943	$63,926
PPL	$38,223	$40,084	$6,747	$85,054
PSEG	$36,722	$35,617	$6,352	$78,692
RECO	$1,231	$1,165	$212	$2,608
Export	$33,140	$20,925	$3,560	$57,625
Total	$698,297	$746,855	$126,256	$1,571,409

Table 6-14 shows the monthly day-ahead and real-time DR charges and the per MWh DR charges in the first three months of 2014 and 2015. The day-ahead DR charges decreased by $4.69 million, or 85 percent, from $5.49 million in the first quarter of 2014 to $0.80 million in the first quarter of 2015. The real-time DR charges decreased $6.47 million, or 89 percent, from $7.24 million in the first three months of 2014 to $0.77 million in the first three months of 2015. The per MWh charge paid by all real-time load and exports for economic DR decreased $0.07/MWh, or 89 percent, from $0.08/MWh in the first three months of 2014 to $0.01/MWh in the first three months of 2015.

Table 6-14 Monthly day-ahead and real-time DR charge: January through March 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	$197,939	(94%)	$4,108,903	$500,358	(88%)	$0.131	$0.025	(81%)
Feb	$1,148,053	$518,689	(55%)	$760,591	$228,166	(70%)	$0.011	$0.017	54%
Mar	$762,224	$84,105	(89%)	$2,366,688	$42,151	(98%)	$0.015	$0.012	(76%)
Total	$5,490,688	$800,733	(85%)	$7,236,183	$770,676	(89%)	$0.084	$0.009	(89%)

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 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.[27]

Emergency demand response was moderately concentrated in 2015. The HHI for emergency demand response registrations is 1760 in 2014. In 2015, the four largest companies contributed 65.3 percent of all registered emergency demand response resources.

27 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 6-15 shows zonal monthly capacity market revenue to demand resources for the first three months of 2015. Capacity market revenue increased in the first three months of 2015 by $31.1 million, or 22.6 percent, compared to the first three months of 2014, from $137.8 million to $168.9 million, as a result of higher RPM prices and more cleared DR in RPM for the 2013/2014 and 2014/2015 delivery years.

Table 6-15 Zonal monthly capacity revenue: January through March 2015

Zone	January	February	March	Total
AECO	$411,097	$371,313	$411,097	$1,193,507
AEP, EKPC	$425,101	$383,962	$425,101	$1,234,163
AP	$185,478	$167,528	$185,478	$538,484
ATSI	$19,859	$17,937	$19,859	$57,654
BGE	$5,430,108	$4,904,613	$5,430,108	$15,764,828
ComEd	$405,926	$366,643	$405,926	$1,178,494
DAY	$63,670	$57,508	$63,670	$184,848
DEOK	$8,185	$7,393	$8,185	$23,762
DLCO	$49,718	$44,907	$49,718	$144,343
Dominion	$306,929	$277,226	$306,929	$891,084
DPL	$1,547,049	$1,397,335	$1,547,049	$4,491,434
JCPL	$1,495,628	$1,350,890	$1,495,628	$4,342,145
Met-Ed	$1,044,281	$943,222	$1,044,281	$3,031,784
PECO	$2,660,069	$2,402,643	$2,660,069	$7,722,780
PENELEC	$1,144,857	$1,034,064	$1,144,857	$3,323,777
Pepco	$1,906,591	$1,722,082	$1,906,591	$5,535,263
PPL	$3,247,272	$2,933,020	$3,247,272	$9,427,564
PSEG	$2,354,400	$2,126,555	$2,354,400	$6,835,356
RECO	$14,896	$13,454	$14,896	$43,245
Total	$22,721,111	$20,522,294	$22,721,111	$65,964,516

Table 6-16 shows the amount of energy efficiency (EE) resources in PJM for 2012/2013 through 2014/2015 delivery years. Energy efficiency resources are offered in the PJM Capacity Market. The total MW of energy efficiency resources increased by 24 percent from 1,029.2 MW in the 2013/2014 delivery year to 1,282.4 MW in 2014/2015 Delivery Year.

Table 6-16 Energy efficiency resources by MW: 2012/2013 through 2014/2015 Delivery Year

	EE ICAP (MW)			EE UCAP (MW)		
	2012/2013	2013/2014	2014/2015	2012/2013	2013/2014	2014/2015
Total	609.8	990.9	1,231.8	631.2	1,029.2	1,282.4

Table 6-17 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, 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.[28] 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.[29]

Table 6-17 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 6-18 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). FSL registrations increased by 751.8 MW while GLD registrations decreased by 86.7 MW and DLC registrations

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

decreased by 260.5 MW from the 2013/2014 delivery year to the 2014/2015 delivery year.

Table 6-18 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 6-19 shows the fuel type used in the on-site generators identified in Table 6-18 for the 2014/2015 Delivery Year. Of the 22.9 percent of emergency demand response identified as using on-site generation, 85.5 percent of MW are diesel, 11.7 percent are natural gas and 2.8 percent is coal, gasoline, kerosene, oil, propane, waste products.

Table 6-19 On-site generation fuel type by MW: 2014/2015 Delivery Year

Fuel Type	MW	Percent
Coal, Gasoline, Kerosene, Oil, Propane, Waste Products	59.6	2.8%
Diesel	1,834.1	85.5%
Natural Gas	251.0	11.7%
Total	2,144.7	100.0%

Emergency Event Reported Compliance

Table 6-20 Demand response cleared MW UCAP for PJM: 2011/2012 through 2014/2015 Delivery Year

	2011/2012 Delivery Year		2012/2013 Delivery Year		2013/2014 Delivery Year		2014/2015 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
Total	1,826.6	1.4%	8,740.9	6.2%	10,779.6	6.7%	14,943.0	9.3%

Table 6-20 shows the demand response cleared UCAP MW for PJM by Delivery Year. Total demand response cleared in PJM increased from 1.4 percent in the 2011/2012 Delivery Year to 9.3 percent of capacity resources in the 2014/2015 Delivery Year.

Subzonal dispatch by zip code is mandatory beginning on June 1, 2014, with the 2014/2015 Delivery Year. However, the subzone must be defined at least one day before dispatch for the event to be mandatory. PJM proposed to allow compliance to be measured across zones within a compliance aggregation area (CAA). This would change 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.[30] 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.

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.[31] The compliance values PJM reports for demand response events are different than the actual compliance values

30 See "Answer and Motion for Leave to Answer of the Independent Market Monitor for PJM," Docket No. ER14-822-002 (July 25, 2014), at 2.

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

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.[32] 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 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 commitment which can be greater than or equal to the post-bankruptcy total load. 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 is 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.

32 PJM. OATT. PJM Emergency Load Response Program.

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 will increase to $1,849 per MWh for the 2015/2016 Delivery Year. The maximum generator offer will remain at $1,000 per MWh.[33,34]

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

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.[35]

Table 6-21 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.

33 139 FERC ¶ 61,057 (2012).
34 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.
35 PJM. "Manual 15: Cost Development Guidelines," Revision 26 (November 5, 2014), p. 54.

Table 6-21 Distribution of registrations and associated MW in the emergency full option across ranges of minimum dispatch prices: 2014/2015 Delivery Year[36]

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

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