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. A motion for stay was granted until at least December 16, 2014, by the United States Court of Appeals. The FERC is now deciding whether to petition the Supreme Court for review. If a petition is filed, the stay will remain in effect until the Supreme Court's final disposition. FirstEnergy filed an amended complaint on September 22, 2014, that seeks to the 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]

- **Demand Response Activity.** Demand response is split into two main categories; economic and emergency. The emergency program revenue consists of 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 nine months of 2014, capacity market revenue increased by $162.7 million, or 54.7 percent, from $297.4 million in the first nine months of 2013 to $460.1 million in the first nine months of 2014.[3] Emergency energy revenue increased by $6.2 million, from $36.7 million in the first nine months of 2013 to $43.0 million compared to the first nine months of 2013. The economic program only consists of energy revenue. Economic program credits increased by $7.9 million, from $7.4 million in the first nine months of 2013 to $16.3 million in the first nine months of 2014, a 121 percent increase.[4] Due to the cold winter, economic DR credits increased 1,075 percent in the first three months of 2014. In contrast, economic DR credits in the third quarter of 2014 decreased by 57.5 percent, from $4.8 million in the third quarter of 2013 to $2.0 million in the third quarter of 2014. Not all DR activities in the third quarter of 2014 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.[5]

- **Demand Response Market Concentration.** Economic demand response had high market concentration in the first nine months of 2013 and 2014. The HHI for economic demand response reductions decreased 472 points, from 8260 in the first nine months of 2013 to 7788 in the first nine months of 2014. Emergency demand response had moderate market concentration in the first nine months of 2014. The HHI for emergency demand response registrations increased 231 points, from 1529 in the first nine months of 2013 to 1760 in the first nine months of 2014. In the first nine months of 2014, the four largest companies contributed 65.3 percent of all registered emergency demand response resources.

- **Locational Dispatch of Demand Resources.** PJM dispatches demand resources on a zonal or subzonal basis, but subzonal dispatches are only on a voluntary basis during the 2013/2014 Delivery Year. Beginning

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 The total credits and MWh numbers for demand resources were calculated as of October 15, 2014 and may change as a result of continued PJM billing updates.

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

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

with the 2014/2015 Delivery Year, demand resources are dispatchable for mandatory reduction on a subzonal basis, defined by zip codes. More locational dispatch of demand resources in a nodal market improves market efficiency. The goal should be nodal dispatch of demand resources.

- **Emergency Event Day Analysis.** PJM's calculations overstate participants' compliance during emergency load management events. In PJM's calculations, 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 showing apparent higher compliance since poorly performing demand resources are not used in the compliance calculation. Considering all reported positive and negative values, the observed average load reduction of the eight events in the first nine months of 2014 should have been 2,198.6 MW, rather than the 2,840.9 MW calculated using PJM's method. The observed compliance is 29.2 percent rather than PJM's calculated 37.7 percent. This does not include locations that did not report their load during the emergency event days. All locations should be required to report their load.

Recommendations

- The MMU recommends that there be only one demand response product, with an obligation to respond when called for all hours of the year, and that the demand response be on the demand side of the capacity market. (Priority: High. First reported 2013.)
- The MMU recommends that the emergency load response program be classified as an economic program, responding to economic price signals and not an emergency program responding only after an emergency is called. (Priority: High. First reported 2012.)
- The MMU recommends that a daily must offer requirement apply to demand resources, comparable to the rule applicable to generation capacity resources.[6] (Priority: High. First reported 2013.)
- The MMU recommends that 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.7 (Priority: High. First reported 2013.)
- The MMU recommends that the lead times for demand resources be shortened to 30 minutes with an hour minimum dispatch for all resources. This recommendation has been adopted. (Priority: Medium. First reported 2013.)
- The MMU recommends that demand resources be required to provide their nodal location on the electricity grid. (Priority: High. First reported 2013.)
- The MMU recommends that measurement and verification methods for demand resources be further modified to more accurately reflect compliance. (Priority: Medium. First reported 2012.)
- 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. (Priority: Medium. First reported 2012.)
- The MMU recommends that PJM adopt the ISO-NE five-minute metering requirements in order to ensure that dispatchers have the necessary information for reliability and that market payments to demand resources be calculated based on interval meter data at the site of the demand reductions.8 (Priority: Medium. First reported 2013.)
- The MMU recommends that demand response event compliance be calculated for each hour and the penalty structure reflect hourly compliance. (Priority: Medium. First reported 2013.)
- The MMU recommends that demand resources whose load drop method is designated as "Other" explicitly record the method of load drop. (Priority: Low. First reported 2013.)

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

7 *Id* at 1.

8 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 November 11, 2013) 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 load management testing be initiated by PJM with limited warning to CSPs in order to more accurately resemble the conditions of an emergency event. (Priority: Low. First reported 2013.)

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. Customers would avoid paying for capacity by interrupting designated load when PJM indicates that it is a critical hour. Customers would pay for actual load on the system during PJM-defined critical hours, e.g. maximum generation alerts, rather than relying on flawed measurement and verification methods. Capacity costs would be assigned to LSEs and by LSEs to customers, based on actual load on the system during these critical hours.

PJM Demand Response Programs

All demand response programs in PJM can be grouped into economic and emergency programs. 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 a panel decision issued May 23, 2014, the U.S. Court of Appeals for the District of Columbia Circuit vacated in its entirely Order No. 745, which provided for payment of demand-side resources at full LMP.[9] The court found Order No. 745 arbitrary and capricious on its merits.[10] 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."[11] 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. An appeal to the court for en banc review is pending. A motion for stay was granted until at least December 16, 2014, by the United States Court of Appeals. The FERC is now deciding whether to petition the Supreme Court for review. If a petition is filed, the stay will remain in effect until the Supreme Court's final disposition.

FirstEnergy filed an amended complaint on September 22, 2014, that seeks to the 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.[12] 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.[13] 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."[14] The proceeding is pending before the Commission.

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) is met rather than payment of LMP offset by the payment for wholesale power already included in customers' tariff rates. In the first nine months of 2014, credits in the economic program were higher than in the same period for each of the last five years. There were fewer settlements submitted and more active participants in the first nine months of 2014 compared to the first nine months of 2013, and credits increased.

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.

9 Electric Power Supply Association v. FERC, No. 11-1486.
10 *Id.*, slip. op. at 14.
11 *Id.*

12 See FirstEnergy Service Company complaint, FERC Docket No. EL14-55-000, amending the complaint filed May 23, 2014.
13 See IMM, 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>.
14 *Id.* at 10.

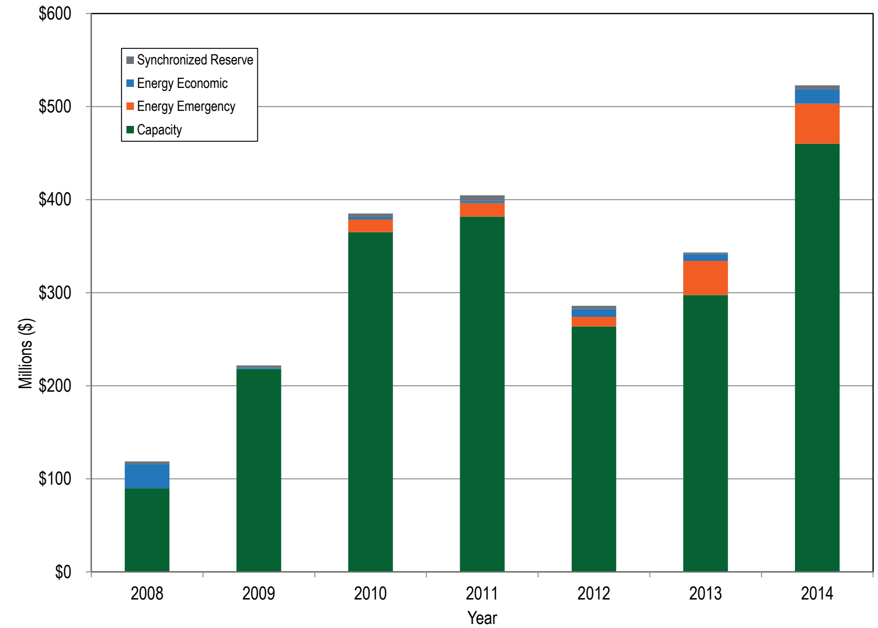
Figure 6-1 shows all revenue from PJM demand response programs by market for the period 2002 through the first nine months of 2014. Since the implementation of the RPM capacity market on June 1, 2007, demand response that participated through the capacity market, which includes emergency energy revenue, has been the primary source of revenue to demand response participants.[15]

Total emergency revenue increased by $169.0 million, or 50.6 percent, from $334.1 million in the first nine months of 2013 to $503.1 in the first nine months of 2014. Of the total emergency revenue, capacity market revenue increased by $162.7 million, or 54.7 percent, from $297.4 million in the first nine months of 2013 to $460.1 million in the first nine months of 2014, primarily due to higher clearing prices in the capacity market for the 2013/2014 and 2014/2015 delivery years. Of the total emergency revenue, emergency energy revenue to demand response that sold capacity increased by $6.2 million from $36.7 million in the first nine months of 2013, to $43.0 million in the first nine months of 2014.

Total credits under the economic program increased by $8,960,269 from $7,387,658 in the first nine months of 2013 to $16,347,928 in the first nine months of 2014, a 121 percent increase.

In the first nine months of 2014, emergency revenue, which includes capacity and emergency energy revenue, accounted for 96.2 percent of all revenue received by demand response providers, credits from the economic program were 2.9 percent and revenue from synchronized reserve was 0.8 percent.

Figure 6-1 Demand response revenue by market: January through September, 2008 through 2014



Economic Program

Table 6-2 shows registered sites and MW for the last day of each month for the period January 2010 through September 2014. 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 nine months of 2014. The average number of registrations decreased by 46 from 1,113 in the first nine months of 2013 to 1,067 in the first nine months of 2014. The average monthly registered MW for the first nine months of 2014 increased by 318 MW, or 13.5 percent, from 2,364 MW in the first nine months of 2013 to 2,750 MW in the first nine months of 2014.

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

The economic program registered MW did not increase after FERC Order No. 745. The average registered MW in the first nine months of 2011, before FERC Order No. 745, was 2,382 MW, and the average registered MW in the first nine months of 2013, right after the implementation of FERC Order No. 745, was 2,364 MW, a decrease of 18 MW, or 0.76 percent.

Economic demand response had high market concentration in the first nine months of 2013 and 2014. The HHI for demand response reductions decreased 472 points, from 8260 in the first nine months of 2013 to 7788 in the first nine months of 2014.[16]

There is some overlap between economic registrations and emergency capacity registrations. There were 307 registrations and 1,885 MW of nominated MW in the emergency program that were also in the economic program at the end of the first nine months of 2014.

The registered MW in the economic load response program are not a good measure of the amount of 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 2011 through September 2014. 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 annual aggregated maximum dispatched MW for all economic demand response registered resources in the first nine months of 2014 increased by 12 MW, from 1,458 MW in the first nine months of 2013 to 1,470 MW in the first nine months of 2014.[17] The dispatch reflected the demand conditions in 2014 compared to prior years. For example, January through March of 2014 had significantly more dispatched MW than January through March in each of the last four years.

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.[18]

Table 6-2 Economic program registrations on the last day of the month: January, 2010 through September, 2014

	2011		2012		2013		2014	
Month	Registrations	Registered MW	Registrations	Registered MW	Registrations	Registered MW	Registrations	Registered MW
Jan	1,609	2,432	1,993	2,385	841	2,314	1,180	2,343
Feb	1,612	2,435	1,995	2,384	843	2,327	1,174	2,349
Mar	1,612	2,5 19	1,996	2,356	788	2,284	1,185	2,710
Apr	1,611	2,534	189	1,318	970	2,346	1,194	2,845
May	1,687	3,166	371	1,669	1,375	2,414	745	2,529
Jun	1,143	1,912	803	2,347	1,302	2,144	928	2,961
Jul	1,228	2,062	942	2,323	1,315	2,443	1,036	3,024
Aug	1,987	2,194	1,013	2,373	1,299	2,527	1,080	3,052
Sep	1,962	2,183	1,052	2,421	1,280	2,475	1,077	2,937
Oct	1,954	2,179	828	2,269	1,210	2,335		
Nov	1,988	2,255	824	2,267	1,192	2,307		
Dec	1,992	2,259	846	2,283	1,192	2,311		
Avg.	1,699	2,344	1,071	2,200	1,134	2,352	1,067	2,750

16 For more information, see Table 6-8.

17 As a result of the 60 day data lag from event date to settlement, not all settlements for June 2014 are incorporated in this report.

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

Table 6-3 Maximum economic MW dispatched by registration per month: January, 2010 through September, 2014

	Maximum Dispatched MW by Registration				
Month	2010	2011	2012	2013	2014
Jan	233	243	104	193	446
Feb	121	190	101	119	307
Mar	115	153	72	127	369
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	284
Sep	276	84	451	530	611
Oct	118	81	242	168	
Nov	111	86	165	155	
Dec	41	88	99	168	
Total	1,209	841	1,956	1,486	1,470

Table 6-4 shows total credits paid to participants in the economic program. The average credits per MWh increased by $71.47 per MWh, or 101.9 percent, from $70.16 per MWh in the first nine months of 2013 to $141.63 per MWh dispatched in the first nine months of 2014. The average real time PJM LMP increased by $20.42 per MWh, from $37.30 per MWh during the first nine months of 2013 to $57.72 per MWh during the first nine months of 2014. Curtailed energy for the economic program was 115,427 MWh in the first nine months of 2014 and the total payments were $16,347,928. Credits, for the first nine months of 2014, increased by $8,960,269, or 121 percent, compared to the first nine months of 2013.

Table 6-4 Credits paid to the PJM economic program participants: January through September, 2010 through 2014

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	115,427	$16,347,928	$141.63

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, for 2010 through the first nine months of 2014. Higher energy prices and FERC Order No. 745 increased incentives to participate starting in April 2012. The high LMPs in the first nine months of 2014, driven by an extremely cold winter in PJM, resulted in more participation in the economic program. The January economic credits were more than twice the previous monthly maximum from July 2012 and the highest in the last five years.

Figure 6-2 Economic program credits and MWh by month: January, 2010 through September, 2014

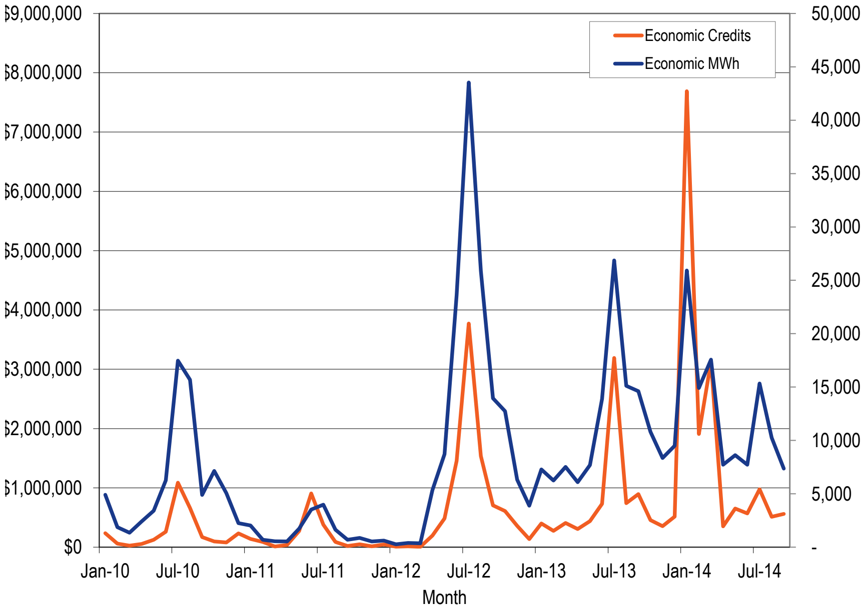


Table 6-5 PJM economic program participation by zone: January through September, 2013 and 2014[19]

	Credits			MWh Reductions		
Zones	2013	2014	Percentage Change	2013	2014	Percentage Change
AECO, JCPL, PECO, Pepco, RECO	$510,155	$3,192,586	526%	3,785	15,760	316%
AEP, APS	$192,243	$315,236	64%	2,833	3,187	13%
ATSI, ComEd, DAY, DEOK, DLCO, EKPC	$714,647	$932,929	31%	13,875	7,803	(44%)
BGE, DPL, Met-Ed, PENELEC	$948,990	$10,064,421	961%	8,437	80,349	852%
Dominion	$4,322,168	$195,717	(95%)	68,407	617	(99%)
PPL	$280,695	$44,343	(84%)	3,310	435	(87%)
PSEG	$418,760	$1,602,696	283%	4,653	7,276	56%
Total	$7,387,658	$16,347,928	121%	105,299	115,427	10%

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

Table 6-5 shows 2013 and 2014 performance in the economic program by control zone and participation type. Total economic program reductions increased ten percent from 105,299 MW in the first nine months of 2013 to 115,427 MW in the first nine months of 2014. The economic credits increased by 121 percent from $7,387,658 in the first nine months of 2013, to $16,347,928 in the first nine months of 2014.

Table 6-6 shows total settlements submitted by year for the first nine months of 2009 through the first nine months of 2014. A settlement is counted for every day on which a registration is dispatched in the economic program. Settlements increased after FERC Order No. 745 in 2012, but decreased in 2013. There were 1,821 economic settlements in the first nine months of 2014 compared to 1,952 settlements in the first nine months of 2013.

Table 6-6 Settlements submitted by year in the economic program: January through September, 2009 through 2014

Jan – Sep	2009	2010	2011	2012	2013	2014
Number of Settlements	1,642	3,367	703	4,195	1,952	1,821

Table 6-7 shows the number of curtailment service providers (CSPs) and participants actively submitting settlements by year for the first nine months of 2009 through the first nine months of 2014. The number of active participants during the first nine months of 2014 was lower by 119 participants than in the first nine months of 2013.

Economic demand response had high market concentration in the first nine months of 2013 and 2014, as shown in Table 6-8. Table 6-8 shows the monthly HHI index, the overall HHI index in the first nine months of 2014. The table also lists the percentage of reductions provided by, and the percentage of credits claimed by, the four DR companies that provided the highest amount of economic DR reduction. The HHI for demand response reductions decreased 472 points, from 8260 in the first nine months of 2013 to 7788 in the first nine months of 2014. In the first nine months of 2014, the four most dispatched CSPs contributed 81.3 percent of all Economic DR reduction, and they claimed 78.2 percent of Economic DR revenue.

Table 6-7 Participants and CSPs submitting settlements in the economic program by year: January through September, 2009 through 2014

	2009		2010		2011		2012		2013		2014	
	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	16	154

Table 6-8 HHI and market concentration in the economic program: January through September, 2013 and 2014

	HHI			Top Four Companies Share of Reduction			Top Four Companies Share of Credit		
Month	2013	2014	Percentage Change	2013	2014	Change Percent	2013	2014	Change Percent
Jan	7981	3347	(58.1%)	98.0%	86.7%	(11.2%)	94.1%	84.2%	(9.9%)
Feb	8478	2559	(69.8%)	100.0%	84.1%	(15.9%)	99.0%	77.5%	(21.5%)
Mar	8237	4435	(46.2%)	99.9%	87.4%	(12.4%)	99.9%	88.5%	(11.3%)
Apr	8573	5951	(30.6%)	100.0%	100.0%	0.0%	100.0%	100.0%	0.0%
May	5468	6092	11.4%	99.5%	98.8%	(0.7%)	99.8%	99.1%	(0.7%)
Jun	3682	2404	(34.7%)	88.2%	90.8%	2.6%	86.0%	87.1%	1.1%
Jul	1943	3358	72.8%	75.4%	87.9%	12.5%	71.0%	85.2%	14.2%
Aug	2862	5506	92.4%	98.2%	100.0%	1.8%	98.5%	100.0%	1.5%
Sep	3702	3880	4.8%	92.8%	99.0%	6.2%	87.4%	98.4%	11.0%
Total	3793	3617	(4.6%)	88.2%	81.3%	(6.9%)	76.1%	78.2%	2.1%

Table 6-9 shows average MWh reductions and credits by hour for the first nine months of 2013 and the first nine months of 2014. The majority of reductions occurred between the hour ending 0700 and hour ending 2100 in the first nine months of 2013 and 2014. In the first nine months of 2013, 98 percent of reductions and 99 percent of credits occurred from 0700 to 2100, and in the first nine months of 2014, 88 percent of reductions and 85 percent of credits occurred from 0700 to 2100. The credits earned increased for all hours except hours ending 1500, 1600 and 1700 in the first nine months of 2014 compared to the first nine months of 2013.

Table 6-9 Hourly frequency distribution of economic program MWh reductions and credits: January through September, 2013 and 2014

	MWh Reductions			Program Credits		
Hour Ending (EPT)	2013	2014	Percentage Change	2013	2014	Percentage Change
1	152	771	406%	$5,101	$127,448	2,398%
2	140	719	415%	$3,303	$112,127	3,295%
3	140	875	524%	$2,520	$149,110	5,817%
4	139	1,473	960%	$1,683	$290,489	17,157%
5	145	1,304	802%	$1,687	$201,531	11,844%
6	152	1,801	1,085%	$3,592	$316,148	8,701%
7	3,616	4,646	28%	$192,380	$872,658	354%
8	4,356	5,847	34%	$266,581	$1,079,702	305%
9	4,457	6,242	40%	$213,867	$837,467	292%
10	4,418	6,440	46%	$195,747	$962,270	392%
11	3,809	4,754	25%	$182,047	$841,202	362%
12	3,610	3,948	9%	$166,844	$753,218	351%
13	5,514	4,441	(19%)	$308,768	$638,323	107%
14	8,912	7,069	(21%)	$798,680	$822,022	3%
15	12,353	9,860	(20%)	$956,763	$908,335	(5%)
16	12,806	10,349	(19%)	$1,101,327	$963,144	(13%)
17	12,668	10,458	(17%)	$1,113,826	$998,988	(10%)
18	12,085	10,536	(13%)	$930,150	$1,202,584	29%
19	8,881	6,880	(23%)	$554,598	$1,022,290	84%
20	4,036	5,755	43%	$225,716	$1,061,535	370%
21	1,551	4,680	202%	$97,641	$922,105	844%
22	742	3,087	316%	$40,233	$596,910	1,384%
23	363	1,909	426%	$14,788	$379,388	2,466%
24	256	1,583	520%	$9,814	$288,934	2,844%
Total	105,299	115,427	10%	$7,387,658	$16,347,928	121%

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 2013 and 2014. Reductions occurred at all price levels. In the hours when the applicable zonal LMP was higher than $400 per MWh, 7.5 percent of MWh reductions and 28.3 percent of program credits occurred in the first nine months of 2014. When LMP was above $1,000 per MWh, 0.45 percent of MWh reductions and 3.13 percent of program credits occurred. MWh reductions in the first nine months of 2014 increased 10 percent compared to the first nine months of 2013.

Table 6-10 Frequency distribution of economic program zonal, load-weighted, average LMP (By hours): January through September, 2013 and 2014

	MWh Reductions			Program Credits		
LMP	2013	2014	Percentage Change	2013	2014	Percentage Change
$0 to $25	433	259	(40%)	$5,702	$2,751	(52%)
$25 to $50	59,212	37,091	(37%)	$2,472,053	$1,697,382	(31%)
$50 to $75	22,378	23,848	7%	$1,479,817	$1,608,096	9%
$75 to $100	6,612	11,568	75%	$641,211	$1,157,598	81%
$100 to $125	6,221	6,700	8%	$855,156	$844,644	(1%)
$125 to $150	4,089	5,062	24%	$639,673	$779,456	22%
$150 to $175	1,318	4,109	212%	$203,376	$758,596	273%
$175 to $200	990	3,447	248%	$172,700	$748,172	333%
$200 to $225	830	2,951	256%	$143,437	$672,056	369%
$225 to $250	1,068	2,816	164%	$182,700	$702,572	285%
$250 to $275	143	2,303	1,515%	$34,753	$636,510	1,732%
$275 to $300	640	1,844	188%	$169,186	$545,908	223%
$300 to $325	374	1,529	309%	$99,169	$447,031	351%
$325 to $350	205	1,059	417%	$19,008	$359,764	1,793%
$350 to $375	216	1,259	483%	$50,647	$435,346	760%
$375 to $400	47	916	1,851%	$12,574	$333,491	2,552%
> $400	523	8,660	1,554%	$206,495	$4,618,554	2,137%
Total	105,299	115,420	10%	$7,387,658	$16,347,928	121%

Following the implementation of FERC Order No. 745 on April 1, 2012, demand resources were paid full LMP for any load reductions during the hours they were dispatched, provided that LMP was greater than the net benefits test threshold. The Economic DR program revenue was $16,347,928 in the first nine months of 2014. Without FERC Order 745, the estimated total revenue would have been $9,526,185, or 41.7 percent lower.[20]

Following Order 745, the NBT is calculated for each month to define a price point above which the net benefits of DR are deemed to exceed the cost to load. Demand response reduction has 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 payment causes an additional uplift charge. NBT is designed as a threshold above which the payment reduction effect overweighs the payment inflation effect. NBT 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, 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 net benefits test price. About two percent of DR dispatch occurred during hours with LMP lower than NBT.

Table 6-11 shows the net benefit test threshold from April 2012, when FERC Order 745 was implemented in PJM, through the first nine months of 2014.

Table 6-11 Result from net benefit tests: April, 2012 through September, 2014

	Net Benefit Test Threshold ($/MWh)		
Month	2012	2013	2014
Jan		$25.72	$29.51
Feb		$26.27	$30.44
Mar		$25.60	$34.93
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	
Nov	$25.63	$31.63	
Dec	$25.97	$28.82	
Average	$24.80	$28.09	$31.39

Table 6-12 shows the number of hours that at least one zone in PJM has day-ahead LMP or real-time LMP higher than NBT. In the first nine months of 2014, the highest zonal LMP in PJM was higher than NBT in 5,789 hours out of the entire 6,551 hours, or 88.4 percent of all hours. Reductions occurred in 5,125 hours, or 88.5 percent, out of the 5,789 hours in the first nine months of 2014.

Table 6-12 Hours with price higher than NBT and DR occurrences in those hours: January through September, 2013 and 2014

	Number of Hours	Number of Hours with LMP Higher than NBT			Percentage of NBT Hours with DR		
Month	2013/2014	2013	2014	Percentage Change	2013	2014	Change Percent
Jan	744	716	742	3.6%	78.9%	93.8%	14.9%
Feb	672	672	672	0.0%	89.3%	92.9%	3.6%
Mar	743	743	732	(1.5%)	80.8%	81.8%	1.1%
Apr	720	717	661	(7.8%)	86.6%	86.5%	(0.1%)
May	744	669	694	3.7%	88.3%	85.3%	(3.0%)
Jun	720	597	557	(6.7%)	94.0%	87.8%	(6.2%)
Jul	744	609	540	(11.3%)	94.7%	97.8%	3.0%
Aug	744	550	586	6.5%	89.8%	88.6%	(1.3%)
Sep	720	582	605	4.0%	88.8%	83.6%	(5.2%)
Total	6,551	5,855	5,789	(1.1%)	87.5%	88.5%	1.0%

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. The demand response charges in January 2014 were 47.0 percent of the total economic DR charges in the first nine months of 2014. Real-time loads in AEP, Dominion, and ComEd paid the highest DR charges in the first nine months of 2014.

20 We use the average day-ahead LMP as an approximation of the generation potion of retail rate. Per unit DR payment for a zone is estimated as (day-ahead hourly LMP – average LMP).

Table 6-14 shows the monthly day-ahead and real-time DR charges and the per MWh DR charges in the first nine months of 2013 and 2014. The day-ahead DR charges increased $2,959,092, or 78.0 percent, from $3,792,296 in the first nine months of 2013 to $6,751,388 in the first nine months of 2014. The real-time DR charge increased $6,001,082, or 167 percent, from $3,595,362 in the first nine months of 2013 to $9,596,444 in the first nine months of 2014. The per MW load charge from DR increased $0.0243/MWh, or 89.8 percent, from $0.027/MWh in the first nine months of 2013 to $0.0514/MWh in the first nine months of 2014.

Table 6-13 Zonal DR charge: January through September 2014

Zone	January	February	March	April	May	June	July	August	September	Total
AECO	$88,787	$21,811	$36,352	$4,216	$6,575	$7,867	$16,679	$6,786	$8,203	$197,277
AEP	$1,287,055	$312,328	$490,612	$55,153	$105,762	$86,463	$130,093	$79,304	$82,060	$2,628,831
APS	$499,040	$121,446	$194,455	$20,964	$38,630	$32,054	$54,049	$29,254	$31,587	$1,021,479
ATSI	$610,023	$155,457	$248,281	$30,829	$57,728	$48,066	$71,721	$42,787	$46,213	$1,311,105
BGE	$336,929	$79,554	$130,350	$14,007	$28,830	$24,750	$48,599	$23,288	$26,010	$712,318
ComEd	$751,170	$204,212	$329,208	$35,592	$77,758	$70,601	$83,644	$66,001	$60,560	$1,678,746
DAY	$163,297	$40,896	$62,819	$7,580	$14,810	$12,270	$17,406	$11,432	$12,192	$342,705
DEOK	$248,017	$62,898	$93,801	$10,662	$23,030	$19,939	$27,326	$17,958	$18,590	$522,222
DLCO	$125,595	$24,946	$49,291	$5,212	$12,433	$10,406	$15,241	$8,968	$9,219	$261,312
Dominion	$1,021,400	$236,410	$393,303	$40,645	$91,199	$72,760	$133,387	$64,534	$76,837	$2,130,474
DPL	$199,098	$46,459	$75,679	$7,990	$12,526	$13,135	$27,171	$11,720	$12,952	$406,729
EKPC	$156,880	$34,851	$52,705	$4,838	$9,578	$8,339	$12,025	$7,747	$7,720	$294,683
JCPL	$200,870	$50,017	$81,694	$8,870	$15,532	$17,879	$38,668	$15,056	$17,810	$446,395
Met-Ed	$147,504	$36,986	$60,434	$6,656	$9,572	$9,503	$19,167	$7,837	$9,296	$306,954
PECO	$375,055	$92,690	$150,894	$17,175	$26,901	$27,270	$56,417	$22,286	$27,223	$795,912
PENELEC	$164,067	$42,050	$68,023	$8,248	$14,718	$10,794	$18,958	$10,089	$10,518	$347,464
Pepco	$313,611	$73,684	$119,799	$13,360	$28,608	$23,994	$45,233	$22,606	$25,615	$666,510
PPL	$420,890	$104,335	$167,056	$18,205	$26,241	$24,189	$48,016	$20,558	$24,073	$853,563
PSEG	$368,239	$92,173	$150,738	$18,849	$30,794	$31,715	$66,823	$26,544	$31,852	$817,727
RECO	$12,180	$3,050	$5,037	$658	$1,098	$1,239	$2,527	$1,064	$1,243	$28,096
Export	$199,606	$72,391	$168,380	$21,206	$18,342	$16,302	$44,458	$16,505	$20,140	$577,330
Total	$7,689,314	$1,908,644	$3,128,912	$350,913	$650,665	$569,536	$977,608	$512,326	$559,914	$16,347,832

Table 6-14 Monthly day-ahead and real-time DR charge: January through September, 2013 and 2014

	Day-ahead DR Charge			Real-time DR Charge			Per MW Charge ($/MWh)		
Month	2013	2014	Percentage Change	2013	2014	Percentage Change	2013	2014	Percentage Change
Jan	$251,494	$3,580,411	1,324%	$147,937	$4,108,903	2,677%	$0.016	$0.131	725%
Feb	$241,179	$1,148,053	376%	$34,565	$760,591	2,100%	$0.011	$0.038	246%
Mar	$344,210	$762,224	121%	$64,371	$2,366,688	3,577%	$0.015	$0.075	(76%)
Apr	$267,301	$67,996	(75%)	$39,944	$282,918	608%	$0.013	$0.012	(4%)
May	$276,352	$151,962	(45%)	$161,883	$498,703	208%	$0.018	$0.024	38%
Jun	$323,881	$309,885	(4%)	$406,716	$259,651	(36%)	$0.022	$0.018	(20%)
Jul	$1,467,622	$506,523	(65%)	$1,722,650	$471,085	(73%)	$0.068	$0.031	(55%)
Aug	$182,941	$141,828	(22%)	$560,348	$370,497	(34%)	$0.020	$0.018	(11%)
Sep	$437,316	$82,507	(81%)	$456,949	$477,407	4%	$0.031	$0.028	(8%)
Total	$3,792,296	$6,751,388	78%	$3,595,362	$9,596,444	167%	$0.027	$0.051	90%

Emergency Program

The emergency load response program consists of the limited demand response product in the capacity market during the 2013/2014 Delivery Year and 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.[21]

Emergency demand response had moderate market concentration in the first nine months of 2014. The HHI for emergency demand response registrations increased 231 points, from 1529 in the first nine months of 2013 to 1760 in the first nine months of 2014. In the first nine months of 2014, the four largest companies contributed 65.3 percent of all registered emergency demand response resources.

Table 6-15 shows zonal monthly capacity market revenue to demand resources for the first nine months of 2014. Capacity market revenue increased in the first nine months of 2014 by $162.7 million, or 54.7 percent, compared to the first nine months of 2013, from $297.4 million to $460.1 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 September, 2014

Zone	January	February	March	April	May	June	July	August	September	Total
AECO	$1,035,717	$935,486	$1,035,717	$1,002,307	$1,035,717	$805,435	$832,282	$832,282	$805,435	$8,320,379
AEP, EKPC	$776,197	$701,081	$776,197	$751,158	$776,197	$6,203,447	$6,410,228	$6,410,228	$6,203,447	$29,008,179
AP	$493,260	$445,525	$493,260	$477,348	$493,260	$3,380,132	$3,492,803	$3,492,803	$3,380,132	$16,148,523
ATSI	$377,750	$341,193	$377,750	$365,564	$377,750	$3,717,155	$3,841,060	$3,841,060	$3,717,155	$16,956,434
BGE	$7,736,807	$6,988,083	$7,736,807	$7,487,232	$7,736,807	$5,140,527	$5,311,878	$5,311,878	$5,140,527	$58,590,547
ComEd	$808,185	$729,973	$808,185	$782,114	$808,185	$5,846,358	$6,041,237	$6,041,237	$5,846,358	$27,711,833
DAY	$44,278	$39,993	$44,278	$42,849	$44,278	$872,987	$902,087	$902,087	$872,987	$3,765,824
DEOK	$16,653	$15,041	$16,653	$16,115	$16,653	$330,654	$341,676	$341,676	$330,654	$1,425,774
DLCO	$148,045	$133,718	$148,045	$143,269	$148,045	$840,774	$5,338,145	$5,338,145	$5,165,946	$17,404,131
Dominion	$605,391	$546,805	$605,391	$585,862	$605,391	$5,165,946	$1,593,999	$1,593,999	$1,542,580	$12,845,366
DPL	$1,979,013	$1,787,496	$1,979,013	$1,915,174	$1,979,013	$1,542,580	$868,800	$868,800	$840,774	$13,760,662
JCPL	$2,288,883	$2,067,378	$2,288,883	$2,215,048	$2,288,883	$1,709,946	$1,766,944	$1,766,944	$1,709,946	$18,102,852
Met-Ed	$2,246,581	$2,029,170	$2,246,581	$2,174,111	$2,246,581	$1,558,377	$1,610,323	$1,610,323	$1,558,377	$17,280,426
PECO	$5,314,219	$4,799,939	$5,314,219	$5,142,792	$5,314,219	$3,249,878	$3,358,207	$3,358,207	$3,249,878	$39,101,559
PENELEC	$2,980,723	$2,692,266	$2,980,723	$2,884,571	$2,980,723	$1,675,004	$1,730,838	$1,730,838	$1,675,004	$21,330,692
Pepco	$4,229,396	$3,820,100	$4,229,396	$4,092,964	$4,229,396	$3,467,834	$3,583,429	$3,583,429	$3,467,834	$34,703,778
PPL	$7,253,736	$6,551,762	$7,253,736	$7,019,745	$7,253,736	$5,215,729	$5,389,586	$5,389,586	$5,215,729	$56,543,345
PSEG	$8,859,978	$8,002,561	$8,859,978	$8,574,172	$8,859,978	$5,460,187	$5,642,193	$5,642,193	$5,460,187	$65,361,427
RECO	$257,721	$232,781	$257,721	$249,408	$257,721	$118,962	$122,927	$122,927	$118,962	$1,739,131
Total	$47,452,531	$42,860,351	$47,452,531	$45,921,805	$47,452,531	$56,301,913	$58,178,643	$58,178,643	$56,301,913	$460,100,861

21 See "Complaint and Motion to Consolidate of the Independent Market Monitor," Docket No. EL14-20-000 (January 28, 2014).

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, which is obligated to respond within 30 minutes, is also new for the 2014/2015 Delivery Year. The quick lead time has 7.5 percent of all nominated MW with 704.0 MW and only 22 locations responding.

The quick, 30 minute, lead time was defined after the auctions cleared. FERC accepted PJM's proposed 30 minute lead time as a phased in approach on May 9, 2014.[22] 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.[23]

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 2013/2014 Delivery Year. Of the DR MW committed, 4.9 percent use the guaranteed load drop (GLD) measurement and verification method, 86.8 percent use the firm service level (FSL) method and 8.4 percent use direct load control (DLC).

The program type is submitted as "Other" for 1.5 percent of committed MW, which does not explain the basis for the reduction. The choice of other is no longer a valid option for new registrations as of the 2014/2015 Delivery Year.

Table 6-18 Reduction MW by each demand response method: 2013/2014 Delivery Year

Program Type	On-site Generation MW	HVAC MW	Refrigeration MW	Lighting MW	Manufacturing MW	Water Heating MW	Other MW	Total	Percentage by type
Firm Service Level	1,810.8	1,414.7	241.7	737.0	3,382.1	77.8	121.0	7,785.0	87.0%
Guaranteed Load Drop	69.9	169.2	4.1	23.6	33.7	0.8	12.0	313.2	3.5%
Non hourly metered sites (DLC)	0.0	812.6	0.0	0.0	0.0	40.0	0.0	852.6	9.5%
Total	1,880.7	2,396.6	245.7	760.6	3,415.7	118.6	133.0	8,950.8	100.0%
Percentage by method	21.0%	26.8%	2.7%	8.5%	38.2%	1.3%	1.5%	100.0%	

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

Table 6-19 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	Percentage 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%
Percentage by method	22.9%	28.6%	2.2%	8.0%	37.0%	1.2%	100.0%	

Table 6-19 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 decreased by 260.6 MW from the 2013/2014 delivery year to the 2014/2015 delivery year.

Table 6-20 shows the fuel type used by the on-site generators identified in Table 6-18 for the 2013/2014 Delivery Year. Of the 17.5 percent of emergency demand response identified as using on-site generation, 76.2 percent of MW are diesel, 5.3 percent are natural gas and 0.9 percent is coal, oil, other and 17.6 percent are no fuel source, meaning that the participant responded inaccurately.[24]

Table 6-20 On-site generation fuel type by MW: 2013/2014 Delivery Year

Fuel Type	MW	Percentage
Coal, Oil, Other	16.3	0.9%
Diesel	1,432.8	76.2%
Natural Gas	100.2	5.3%
None	331.3	17.6%
Total	1,880.7	100.00%

Table 6-21 shows the fuel type used in the on-site generators identified in Table 6-19 for the 2014/2015 Delivery Year. Of the 17.5 percent of emergency demand response identified as using on-site generation, 81.6 percent of MW are diesel, 11.7 percent are natural gas and 2.8 percent is coal, gasoline, kerosene, oil, propane, waste products and 4.0 percent are no fuel source, meaning the participant responded inaccurately.

Table 6-21 On-site generation fuel type by MW: 2014/2015 Delivery Year

Fuel Type	MW	Percentage
Coal, Gasoline, Kerosene, Oil, Propane, Waste Products	59.6	2.8%
Diesel	1,749.1	81.6%
Natural Gas	251.0	11.7%
None	85.0	4.0%
Total	2,144.7	100.00%

Emergency Event Reported Compliance

PJM declared eight emergency events in the first nine months of 2014, two on January 7, one on January 8, one on January 22, two on January 23, one on January 24 and one on March 4. There were 13 events during the 2013/2014 Delivery Year, two events during the 2012/2013 Delivery Year and one event in the 2011/2012 Delivery Year. Since all of the 2014 events occurred outside of the summer compliance period, none were considered in PJM's compliance assessment.[25] Table 6-22 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.

24 Since 1.5 percent of committed MW are registered under the other option, the 17.5 percent of emergency load response resources registered with on-site generation could be conservatively low.

25 Annual and extended summer demand response products were not active in PJM's demand response program until June 1, 2014.

Table 6-22 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 Percentage of Capacity MW UCAP	DR Cleared MW UCAP	DR Percentage of Capacity MW UCAP	DR Cleared MW UCAP	DR Percentage of Capacity MW UCAP	DR Cleared MW UCAP	DR Percentage 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 6-23 lists PJM emergency load management events declared by PJM in the first nine months of 2014 and the affected zones. The SWMAAC LDA was the only LDA called for all eight events. All demand response events called in the first nine months of 2014 were voluntary, so no penalties are assessed for under compliance.

Participants in the 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 based on each hour to accurately report reductions during demand response events. This would be consistent with the rules that apply to generation resources. The MMU recommends demand response event compliance be calculated for each hour and the penalty structure reflect hourly compliance.

PJM deployed both long lead time resources, which require more than one hour but less than two hours notification, and short lead time resources, which require less than an hour notification during the 2013/2014 Delivery Year. Any resource is eligible to be either a short lead time or long lead time resource, and there are no differences in payment for these resources. Approximately 99.5 percent of registrations, accounting for 91.6 percent of registered MW, are designated as long lead time resources. The MMU recommends that the lead times for demand resources be shortened to 30 minute lead time with an hour minimum dispatch for all resources. This will enable quicker response and greater flexibility.

Table 6-23 PJM declared load management events: January through September, 2014

Event Date	Event Times	Compliance Hours	Minutes not Measured for Compliance	Lead Time	Geographical Area
7-Jan-14	5:30-11:00	None	330	Short Lead	RTO
	6:30-11:00	None	270	Long Lead	RTO
	16:00-18:15	None	135	Short Lead	RTO
	17:00-18:15	None	75	Long Lead	RTO
8-Jan-14	6:00-7:00	None	60	Short Lead	RTO
	7:00-7:00	None	0	Long Lead	RTO
22-Jan-14	15:00-21:00	None	360	Short Lead	SWMAAC
	16:00-21:00	None	300	Long Lead	SWMAAC
23-Jan-14	5:30-8:30	None	180	Short Lead	MAAC, APS, Dominion
	6:30-8:30	None	120	Long Lead	MAAC, APS, Dominion
	15:00-19:00	None	240	Short Lead	MAAC, APS, Dominion
	16:00-19:00	None	180	Long Lead	MAAC, APS, Dominion
24-Jan-14	5:30-8:45	None	195	Short Lead	MAAC, APS, Dominion
	6:30-8:45	None	135	Long Lead	MAAC, APS, Dominion
4-Mar-14	5:30-8:30	None	180	Short Lead	RTO
	6:30-8:30	None	120	Long Lead	RTO

There were eight events in 2014, on January 7, 2014, January 8, 2014, January 22, 2014, January 23, 2014, January 24, 2014, and March 4, 2014, for which PJM requested voluntary dispatch of emergency demand side resources. All of these events occurred outside of the limited demand response product's window of mandatory response from June through September and from 12:00 to 20:00.[26] Compliance penalties are not applicable to the events in the first nine months of 2014 for that reason, but resources that did curtail received emergency energy payments, which are paid by PJM market participants in proportion to their net purchases in the real-time market.

26 Annual and extended summer demand response products were not active in PJM's demand response program until June 1, 2014.

Subzonal dispatch by zip code was voluntary for the 2013/2014 Delivery Year, but is mandatory beginning on June 1, 2014 with the 2014/2015 Delivery Year. 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.[27] 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.[28] 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.

Table 6-24 shows the performance for the first January 7, 2014, event. The first column shows the nominated value, which is the reduction capability indicated for each registration. The nominated MW are used to fulfill the committed MW capacity obligation and may exceed the committed MW. The second column shows load management committed MW, which are used to assess RPM compliance. The third column shows the reported load reduction in MW during the hours of an event. The reported load reduction is reported by PJM and does not include load increases. The fourth column shows the observed load reduction in MWh, which includes all reported reduction values, including load increases. The observed load reduction is calculated by the MMU. The observed load reduction is a conservative estimate of what occurred during the demand response events as load increases are not required to be reported. Compliance is calculated by comparing the load reduction during an event to the committed MW value.

The APS, ComEd, Day, DEOK and EKPC zones did not submit any data for this event. Since the event was voluntary, none of these customers responded or received payments for this event. The reported compliance for the DPL Control Zone was 104.7 percent. Overall, the reported compliance for the first event on January 7, 2014, was 39.9 percent, or 3,007.2 MW out of 7,535.7 MW committed. The observed compliance was 30.7 percent, or 2,314.6 MW, a difference of 692.6 MW compared to the reported load reduction.

27 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.
28 OATT Attachment K § PJM Emergency Load Response Program at Reporting and Compliance.

Table 6-24 Demand response event performance: January 7, 2014 (Event 1)

Zone	Nominated ICAP (MW)	Committed MW	Load Reduction Reported (MW)	Load Reduction Observed (MW)	Difference	Percent Compliance Reported	Percent Compliance Observed
AECO	124.9	102.5	25.0	20.6	4.4	24.4%	20.1%
AEP	1,635.7	1,253.6	792.3	683.5	108.8	63.2%	54.5%
APS	674.0	499.4	0.0	0.0	0.0	0.0%	0.0%
ATSI	796.1	683.1	452.9	349.3	103.6	66.3%	51.1%
BGE	826.6	627.2	217.9	191.7	26.2	34.7%	30.6%
ComEd	1,129.8	820.3	0.0	0.0	0.0	0.0%	0.0%
DAY	96.7	68.6	0.0	0.0	0.0	0.0%	0.0%
DEOK	436.2	155.4	0.0	0.0	0.0	0.0%	0.0%
DLCO	113.1	69.2	33.3	4.2	29.1	48.1%	6.1%
Dominion	872.4	757.0	516.4	445.9	70.4	68.2%	58.9%
DPL	301.7	65.9	69.1	51.5	17.5	104.7%	78.1%
EKPC	110.3	79.9	0.0	0.0	0.0	0.0%	0.0%
JCPL	209.1	156.7	81.4	61.6	19.8	51.9%	39.3%
Met-Ed	233.9	173.9	80.8	56.9	24.0	46.5%	32.7%
PECO	587.5	410.3	200.0	147.5	52.5	48.7%	35.9%
PENELEC	330.1	265.1	67.4	0.1	67.3	25.4%	0.0%
Pepco	795.8	372.0	108.1	81.3	26.8	29.1%	21.8%
PPL	800.0	621.1	249.7	144.4	105.2	40.2%	23.3%
PSEG, RECO	488.7	354.6	113.0	76.2	36.9	31.9%	21.5%
Total	10,562.6	7,535.7	3,007.2	2,314.6	692.6	39.9%	30.7%

The second event on January 7, 2014, called both long and short lead resources for the RTO at 1600 and ended the event at 1815 EPT. Long lead resources were only dispatched for one hour during this event, even though minimum dispatch is two hours for demand resources. Since PJM canceled the demand response event before the minimum run time requirement was met, demand resources still received energy settlements for two hours after the event started. As a result, the effective dispatch period for long lead resources was actually from 1700 to 1900 EPT. Short lead resources were dispatched for more than two hours.

Table 6-25 shows the performance for the second January 7, 2014, event. The APS, ComEd, Day, DEOK and EKPC zones did not submit any data for this event. The reported compliance for the DPL Control Zone was 105.9 percent, or 69.8 MW out of 65.9 MW committed. The observed compliance for the DPL Control Zone was 85.6 percent, or 56.4 MW out of 65.9 MW committed. Overall, the reported compliance for the second event on January 7, 2014, was 42.5 percent, or 3,203.0 MW out of 7,535.7 MW committed. The observed compliance was 34.6 percent, or 2,604.4 MW, a difference of 598.6 MW compared to the reported load reduction.

Table 6-25 Demand response event performance: January 7, 2014 (Event 2)

Zone	Nominated ICAP (MW)	Committed MW	Load Reduction Reported (MW)	Load Reduction Observed (MW)	Difference	Percent Compliance Reported	Percent Compliance Observed
AECO	124.9	102.5	23.4	20.9	2.6	22.9%	20.4%
AEP	1,635.7	1,253.6	872.4	740.6	131.8	69.6%	59.1%
APS	674.0	499.4	0.0	0.0	0.0	0.0%	0.0%
ATSI	796.1	683.1	534.9	452.3	82.6	78.3%	66.2%
BGE	826.6	627.2	230.9	210.2	20.7	36.8%	33.5%
ComEd	1,129.8	820.3	0.0	0.0	0.0	0.0%	0.0%
DAY	96.7	68.6	0.0	0.0	0.0	0.0%	0.0%
DEOK	436.2	155.4	0.0	0.0	0.0	0.0%	0.0%
DLCO	113.1	69.2	32.6	(16.3)	48.9	47.1%	(23.6%)
Dominion	872.4	757.0	513.5	465.2	48.3	67.8%	61.5%
DPL	301.7	65.9	69.8	56.4	13.4	105.9%	85.6%
EKPC	110.3	79.9	0.0	0.0	0.0	0.0%	0.0%
JCPL	209.1	156.7	78.6	58.0	20.6	50.2%	37.0%
Met-Ed	233.9	173.9	85.4	71.7	13.6	49.1%	41.2%
PECO	587.5	410.3	190.8	150.3	40.5	46.5%	36.6%
PENELEC	330.1	265.1	97.7	60.3	37.4	36.8%	22.8%
Pepco	795.8	372.0	111.3	92.1	19.2	29.9%	24.8%
PPL	800.0	621.1	252.4	174.3	78.1	40.6%	28.1%
PSEG, RECO	488.7	354.6	109.3	68.4	41.0	30.8%	19.3%
Total	10,562.6	7,535.7	3,203.0	2,604.4	598.6	42.5%	34.6%

There was one event on January 8, 2014. The event was called for both long and short lead resources for the RTO at 500 and ended the event at 700 EPT. Since PJM canceled the demand response event before the minimum run time requirement was met, demand resources still received energy settlements for two hours after the event started. Short lead resources were active for one hour and long lead resources were not active during this call.

Table 6-26 shows the performance for the January 8, 2014, event. The APS, ComEd, Day, DEOK and EKPC zones did not submit any data for this event. The reported compliance for the DPL Control Zone was 64.4 percent, or 42.4 MW out of 65.9 MW committed. The observed compliance for the DPL Control Zone was 56.9 percent, or 37.5 MW out of 65.9 MW committed. Overall, the reported compliance for the event on January 8, 2014, was 30.4 percent, or 2,289.7 MW out of 7,537.7 MW committed. The observed compliance was 22.3 percent, or 1,683.0 MW, a difference of 606.8 MW compared to the reported load reduction.

Table 6-26 Demand response event performance: January 8, 2014

Zone	Nominated ICAP (MW)	Committed MW	Load Reduction Reported (MW)	Load Reduction Observed (MW)	Difference	Percent Compliance Reported	Percent Compliance Observed
AECO	124.9	102.5	18.1	16.1	1.9	17.6%	15.8%
AEP	1,635.7	1,253.6	752.9	628.1	124.8	60.1%	50.1%
APS	674.0	499.4	0.0	0.0	0.0	0.0%	0.0%
ATSI	796.1	683.1	364.6	274.0	90.7	53.4%	40.1%
BGE	826.6	627.2	132.2	110.1	22.1	21.1%	17.6%
ComEd	1,129.8	820.3	0.0	0.0	0.0	0.0%	0.0%
DAY	96.7	68.6	0.0	0.0	0.0	0.0%	0.0%
DEOK	436.2	155.4	0.0	0.0	0.0	0.0%	0.0%
DLCO	113.1	69.2	17.1	9.2	7.9	24.7%	13.3%
Dominion	872.4	757.0	359.4	279.2	80.2	47.5%	36.9%
DPL	301.7	65.9	42.4	37.5	4.9	64.4%	56.9%
EKPC	110.3	79.9	0.0	0.0	0.0	0.0%	0.0%
JCPL	209.1	156.7	59.0	42.4	16.5	37.6%	27.1%
Met-Ed	233.9	173.9	54.3	14.3	40.0	31.2%	8.2%
PECO	587.5	410.3	129.7	91.0	38.7	31.6%	22.2%
PENELEC	330.1	265.1	46.5	(6.0)	52.5	17.5%	(2.3%)
Pepco	795.8	372.0	61.1	42.0	19.1	16.4%	11.3%
PPL	800.0	621.1	166.1	87.9	78.2	26.7%	14.2%
PSEG, RECO	488.7	354.6	86.2	57.1	29.2	24.3%	16.1%
Total	10,562.6	7,535.7	2,289.7	1,683.0	606.8	30.4%	22.3%

Table 6-27 Demand response event performance: January 22, 2014

Zone	Nominated ICAP (MW)	Committed MW	Load Reduction Reported (MW)	Load Reduction Observed (MW)	Difference	Percent Compliance Reported	Percent Compliance Observed
BGE	826.6	627.2	239.6	218.5	21.1	38.2%	34.8%
Pepco	795.8	372.0	166.1	148.8	17.3	44.7%	40.0%
Total	1,622.5	999.2	405.7	367.3	38.4	40.6%	36.8%

There was one event on January 22, 2014. The event was called for both long and short lead resources for the SWMAAC LDA at 1400 and ended the event at 2100 EPT.

Table 6-27 shows the performance for the January 22, 2014, event. The reported compliance for the BGE Control Zone was 38.2 percent, or 239.6 MW out of 627.2 MW committed. The observed compliance for the BGE Control Zone was 34.8 percent, or 218.5 MW out of 627.2 MW committed. Overall, the reported compliance for the event on January 22, 2014, was 40.6 percent, or 405.7 MW out of 999.2 MW committed. The observed compliance was 36.8 percent, or 367.3 MW, a difference of 38.4 MW compared to the reported load reduction.

There were two events on January 23, 2014. The first event was called for both long and short lead resources for the MAAC LDA, APS and Dominion zones at 430 and ended the event at 830 EPT.

Table 6-28 shows the performance for the first January 23, 2014, event. The APS Control Zone did not submit any data for this event. The reported compliance for the RECO Control Zone was 154.2 percent, or 6.2 MW out of 4.0 MW committed. The observed compliance for the RECO Control Zone was 149.2 percent, or 6.0 MW out of 4.0 MW committed. Overall, the reported compliance for the first event on January 23, 2014, was 40.8 percent, or 1,799.5 MW out of 4,405.6 MW committed. The observed compliance was 30.6 percent, or 1,349.0 MW, a difference of 450.5 MW compared to the reported load reduction.

The second event on January 23, 2014, was called for both long and short lead resources for the MAAC LDA, APS and Dominion zones at 1400 and ended the event at 1900 EPT.

Table 6-29 shows the performance for the second January 23, 2014, event. The APS Control Zone did not submit any data for this event. The reported compliance for the RECO Control Zone was 69.6 percent, or 2.8 MW out of

Table 6-28 Demand response event performance: January 23, 2014 (Event 1)

Zone	Nominated ICAP (MW)	Committed MW	Load Reduction Reported (MW)	Load Reduction Observed (MW)	Difference	Percent Compliance Reported	Percent Compliance Observed
AECO	124.9	102.5	20.3	18.5	1.8	19.8%	18.0%
APS	674.0	499.4	0.0	0.0	0.0	0.0%	0.0%
BGE	826.6	627.2	226.8	192.9	33.9	36.2%	30.8%
Dominion	872.4	757.0	516.3	457.8	58.5	68.2%	60.5%
DPL	301.7	65.9	53.4	39.8	13.6	80.9%	60.3%
JCPL	209.1	156.7	82.3	55.7	26.6	52.5%	35.5%
Met-Ed	233.9	173.9	90.3	66.3	23.9	51.9%	38.2%
PECO	587.5	410.3	199.7	145.5	54.2	48.7%	35.5%
PENELEC	330.1	265.1	50.7	(5.7)	56.4	19.1%	(2.1%)
Pepco	795.8	372.0	165.5	138.5	27.0	44.5%	37.2%
PPL	800.0	621.1	264.4	143.7	120.6	42.6%	23.1%
PSEG	482.3	350.6	123.7	90.0	33.7	35.3%	25.7%
RECO	6.4	4.0	6.2	6.0	0.2	154.2%	149.2%
Total	6,244.7	4,405.6	1,799.5	1,349.0	450.5	40.8%	30.6%

Table 6-29 Demand response event performance: January 23, 2014 (Event 2)

Zone	Nominated ICAP (MW)	Committed MW	Load Reduction Reported (MW)	Load Reduction Observed (MW)	Difference	Percent Compliance Reported	Percent Compliance Observed
AECO	124.9	102.5	19.4	17.9	1.5	18.9%	17.4%
APS	674.0	499.4	0.0	0.0	0.0	0.0%	0.0%
BGE	826.6	627.2	225.4	199.2	26.2	35.9%	31.8%
Dominion	872.4	757.0	547.1	508.3	38.8	72.3%	67.1%
DPL	301.7	65.9	0.0	0.0	0.0	0.0%	0.0%
JCPL	209.1	156.7	81.5	54.7	26.8	52.0%	34.9%
Met-Ed	233.9	173.9	98.4	85.1	13.3	56.6%	49.0%
PECO	587.5	410.3	195.6	148.2	47.4	47.7%	36.1%
PENELEC	330.1	265.1	61.0	25.4	35.6	23.0%	9.6%
Pepco	795.8	372.0	167.8	150.2	17.6	45.1%	40.4%
PPL	800.0	621.1	263.4	181.0	82.4	42.4%	29.2%
PSEG	482.3	350.6	110.8	80.1	30.7	31.6%	22.8%
RECO	6.4	4.0	2.8	2.7	0.1	69.6%	67.6%
Total	6,244.7	4,405.6	1,773.2	1,452.8	320.4	40.2%	33.0%

4.0 MW committed. The observed compliance for the RECO Control Zone was 67.6 percent, or 2.7 MW out of 4.0 MW committed. Overall, the reported compliance for the second event on January 23, 2014, was 40.2 percent, or 1,773.2 MW out of 4,405.6 MW committed. The observed compliance was 33.0 percent, or 1,452.8 MW, a difference of 320.4 MW compared to the reported load reduction.

There was one event on January 24, 2014. The event was called for both long and short lead resources for the MAAC LDA, APS and Dominion zones at 430 and ended the event at 845 EPT.

Table 6-30 shows the performance for the January 24, 2014, event. The APS Control Zone did not submit any data for this event. The reported compliance for the DPL Control Zone was 60.1 percent, or 39.6 MW out of 65.9 MW committed. The observed compliance for the DPL Control Zone was 50.0 percent, or 33.0 MW out of 65.9 MW committed. Overall, the reported compliance for the event on January 24, 2014, was 33.1 percent, or 1,459.1 MW out of 4,405.6 MW committed. The observed compliance was 24.9 percent, or 1,095.2 MW, a difference of 363.9 MW compared to the reported load reduction.

There was one event on March 4, 2014. The event was called for both long and short lead resources for the RTO at 430 and ended the event at 830 EPT.

Table 6-31 shows the performance for the March 4, 2014, event. The APS, ComEd, DAY, DEOK and EKPC Control Zones did not submit any data for this event. The reported compliance for the DPL Control Zone was 75.9 percent, or 50.0 MW out of 65.9 MW committed. The observed compliance for the DPL Control Zone was 69.7 percent, or 45.9 MW out of 65.9 MW committed. Overall, the reported compliance for the event on March 4, 2014, was 36.2 percent, or 2,730.3 MW out of 7,535.7 MW committed. The observed compliance was 27.0 percent, or 2,031.9 MW, a difference of 698.4 MW compared to the reported load reduction.

Table 6-30 Demand response event performance: January 24, 2014

Zone	Nominated ICAP (MW)	Committed MW	Load Reduction Reported (MW)	Load Reduction Observed (MW)	Difference	Percent Compliance Reported	Percent Compliance Observed
AECO	124.9	102.5	18.3	16.6	1.7	17.9%	16.2%
APS	674.0	499.4	0.0	0.0	0.0	0.0%	0.0%
BGE	826.6	627.2	156.3	133.2	23.2	24.9%	21.2%
Dominion	872.4	757.0	446.2	385.7	60.4	58.9%	51.0%
DPL	301.7	65.9	39.6	33.0	6.6	60.1%	50.0%
JCPL	209.1	156.7	64.3	39.4	24.9	41.1%	25.2%
Met-Ed	233.9	173.9	83.0	60.8	22.3	47.8%	35.0%
PECO	587.5	410.3	161.7	116.1	45.7	39.4%	28.3%
PENELEC	330.1	265.1	50.7	9.4	41.3	19.1%	3.6%
Pepco	795.8	372.0	123.0	98.9	24.1	33.1%	26.6%
PPL	800.0	621.1	209.8	127.5	82.4	33.8%	20.5%
PSEG, RECO	488.7	354.6	106.0	74.6	31.4	29.9%	21.0%
Total	6,244.7	4,405.6	1,459.1	1,095.2	363.9	33.1%	24.9%

Table 6-31 Demand response event performance: March 4, 2014

Zone	Nominated ICAP (MW)	Committed MW	Load Reduction Reported (MW)	Load Reduction Observed (MW)	Difference	Percent Compliance Reported	Percent Compliance Observed
AECO	124.9	102.5	17.1	14.3	2.8	16.7%	13.9%
AEP	1,635.7	1,253.6	764.2	530.9	233.3	61.0%	42.3%
APS	674.0	499.4	0.0	0.0	0.0	0.0%	0.0%
ATSI	796.1	683.1	484.5	401.3	83.2	70.9%	58.7%
BGE	826.6	627.2	183.1	160.9	22.2	29.2%	25.7%
ComEd	1,129.8	820.3	0.0	0.0	0.0	0.0%	0.0%
DAY	96.7	68.6	0.0	0.0	0.0	0.0%	0.0%
DEOK	436.2	155.4	0.0	0.0	0.0	0.0%	0.0%
DLCO	113.1	69.2	20.3	10.2	10.1	29.3%	14.7%
Dominion	872.4	757.0	430.4	370.7	59.7	56.9%	49.0%
DPL	301.7	65.9	50.0	45.9	4.1	75.9%	69.7%
EKPC	110.3	79.9	0.0	0.0	0.0	0.0%	0.0%
JCPL	209.1	156.7	62.5	41.1	21.4	39.9%	26.3%
Met-Ed	233.9	173.9	65.1	34.0	31.1	37.5%	19.6%
PECO	587.5	410.3	176.8	138.7	38.1	43.1%	33.8%
PENELEC	330.1	265.1	52.4	(1.6)	53.9	19.7%	(0.6%)
Pepco	795.8	372.0	107.3	87.4	20.0	28.9%	23.5%
PPL	800.0	621.1	217.1	119.7	97.3	34.9%	19.3%
PSEG, RECO	488.7	354.6	99.5	78.4	21.1	28.1%	22.1%
Total	10,562.6	7,535.7	2,730.3	2,031.9	698.4	36.2%	27.0%

Table 6-32 shows aggregated load management event performance for the eight demand response emergency events for 2014. The reported compliance for all PJM control zones was 37.7 percent in the first nine months of 2014 for resources called during emergency events, while observed compliance was 29.2 percent. The reported compliance for the DPL Control Zone was 64.8 percent, or 42.7 MW out of 65.9 MW committed. The observed compliance for the DPL Control Zone was 51.1 percent, or 33.7 MW out of 65.9 MW committed. The reported and observed compliance for the DPL Control Zone were the highest in PJM. The reported and observed compliance for the APS, ComEd, Day, DEOK and EKPC control zones reported were 0.0 percent, the lowest in PJM.

The average observed compliance for the BGE Control Zone, which responded to all eight emergency events in 2014, was 36.7 percent, or 229.9 MW out of 627.2 MW committed. The average observed compliance for the Pepco Control Zone, which also responded to all eight emergency events in 2014, was 37.5 percent, or 139.4 MW out of 621.1 MW committed.

Table 6-32 Aggregated load management event performance: January through September, 2014

Zone	Nominated ICAP (MW)	Committed MW	Load Reduction Reported (MW)	Load Reduction Observed (MW)	Difference	Percent Compliance Reported	Percent Compliance Observed
AECO	124.9	102.5	20.2	17.8	2.4	19.7%	17.4%
AEP	1,635.7	1,253.6	698.4	557.2	141.1	55.7%	44.4%
APS	674.0	499.4	0.0	0.0	0.0	0.0%	0.0%
ATSI	796.1	683.1	401.1	328.2	72.9	58.7%	48.1%
BGE	826.6	627.2	229.9	198.2	31.7	36.7%	31.6%
ComEd	1,129.8	820.3	0.0	0.0	0.0	0.0%	0.0%
DAY	96.7	68.6	0.0	0.0	0.0	0.0%	0.0%
DEOK	436.2	155.4	0.0	0.0	0.0	0.0%	0.0%
DLCO	113.1	69.2	36.3	10.1	26.2	52.4%	14.6%
Dominion	872.4	757.0	430.3	381.6	48.7	56.9%	50.4%
DPL	301.7	65.9	42.7	33.7	9.0	64.8%	51.1%
EKPC	110.3	79.9	0.0	0.0	0.0	0.0%	0.0%
JCPL	209.1	156.7	72.1	46.4	25.7	46.0%	29.6%
Met-Ed	233.9	173.9	90.4	66.6	23.8	52.0%	38.3%
PECO	587.5	410.3	167.3	120.0	47.3	40.8%	29.3%
PENELEC	330.1	265.1	63.0	18.6	44.4	23.8%	7.0%
Pepco	795.8	372.0	139.4	110.6	28.8	37.5%	29.7%
PPL	800.0	621.1	217.3	132.3	85.0	35.0%	21.3%
PSEG, RECO	488.7	354.6	99.1	70.9	28.2	27.9%	20.0%
Weighted Total	10,562.6	7,535.7	2,840.9	2,198.6	428.9	37.7%	29.2%

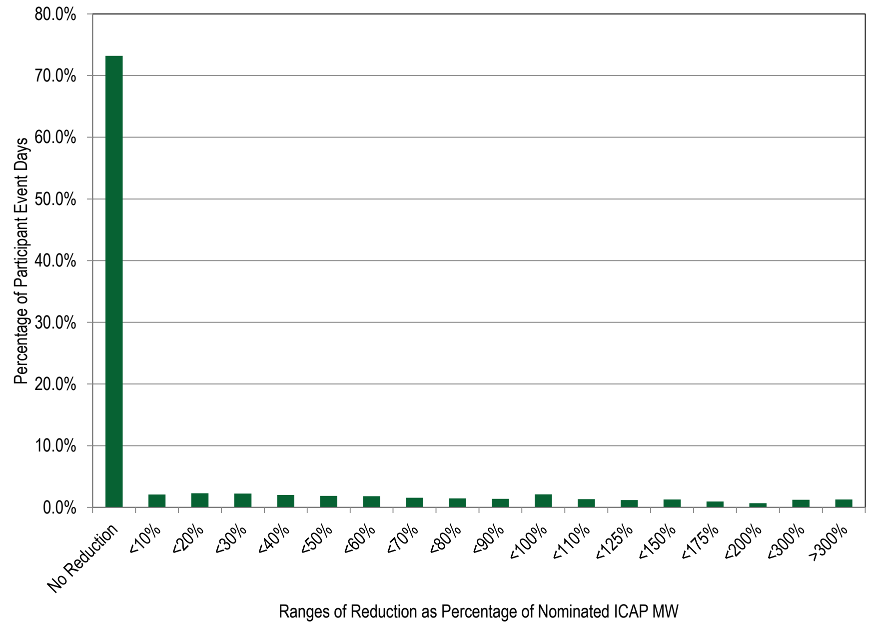
Performance for specific customers varied significantly. Table 6-33 shows the distribution of participant event days by performance levels for the eight events in the 2013/2014 compliance period. Table 6-33 includes the participation for all resources dispatched for the emergency events. For these events, 73.2 percent of participant event days showed no reduction, load increased or participants did not report data. For these events 83.7 percent of participant event days provided less than half of their nominated MW, while 81.0 percent of the nominated MW provided less than half of their nominated MW. The majority of participants, 92.0 percent, provided less than 100 percent reduction compared to their nominated MW, while 91.2 percent of the nominated MW provided less than 100 percent reduction.

Table 6-33 Distribution of participant event days and nominated MW across ranges of performance levels across the events: January through September, 2014

Ranges of performance as a percentage of nominated ICAP MW	Number of participant event days	Proportion of participant event days	Nominated MW	Proportion of Nominated MW
0%, load increase, or no reporting	67,953	73.2%	42,977	68.6%
0% - 10%	1,951	2.1%	1,746	2.8%
10% - 20%	2,121	2.3%	1,684	2.7%
20% - 30%	2,088	2.2%	1,736	2.8%
30% - 40%	1,874	2.0%	1,367	2.2%
40% - 50%	1,730	1.9%	1,186	1.9%
50% - 60%	1,672	1.8%	1,257	2.0%
60% - 70%	1,439	1.6%	1,118	1.8%
70% - 80%	1,363	1.5%	1,099	1.8%
80% - 90%	1,293	1.4%	915	1.5%
90% - 100%	1,953	2.1%	2,002	3.2%
100% - 110%	1,239	1.3%	2,289	3.7%
110% - 125%	1,099	1.2%	818	1.3%
125% - 150%	1,193	1.3%	752	1.2%
150% - 175%	884	1.0%	420	0.7%
175% - 200%	625	0.7%	336	0.5%
200% - 300%	1,151	1.2%	524	0.8%
> 300%	1,198	1.3%	381	0.6%
Total	92,826	100.0%	62,607	100.0%

Figure 6-3 shows the data in Table 6-33.[29]

Figure 6-3 Distribution of participant event days across ranges of performance levels across the events: January through September, 2014



29 Participant event days, shown in Figure 6-3, and Table 6-22, are defined as distinct event performances by registration. If a registration was deployed for multiple events, each event constitutes a single participant event day. The load reduction values associated do not reflect actual MWh curtailments, but average curtailments in each event, summed for all events in the period.

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.[30] 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. Overall, 73 percent of event hours demonstrated negative reductions or no reduction in load, as shown in Table 6-33.[31]

Settlements that are not submitted to PJM are treated as zero compliance for the event. Overall, 63.0 percent of locations were not submitted to PJM for compliance purposes. While the performance of these resources is not known, it is reasonable to assume, given the incentives to report reductions, that these locations had negative compliance (load increases relative to baseline), further skewing reported compliance values and performance penalties. 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.

Table 6-34 shows the number of locations that did not report during the first three months of 2014 event days. In total, 63.0 percent of locations did not report during event days in 2013 and were assigned zero load response. This accounted for 60.1 percent of all nominated MW for those events. It is likely that these locations were not responding to the emergency event and had loads greater than their committed MW for those locations, and the corresponding registrations.

Table 6-34 Non-reporting locations and nominated ICAP: January through September, 2014 event days

	Locations Not Reporting	Percent Non Reporting	Nominated ICAP Not Reporting	Percent N on Reporting
Total	58,443	63.0%	37,627	60.1%

Emergency Energy Payments

For any PJM declared load management event in the first nine months of 2014, 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

30 OATT PJM Emergency Load Response Program.
31 The demand response events that occurred in the first nine months of 2014 were all voluntary since they were outside the mandatory curtailment window of June 1, through September 30 from 1200 to 2000.

increase to $1,849 per MWh for the 2015/2016 Delivery Year. The maximum generator offer will remain at $1,000 per MWh.[32] [33]

Participants may elect to be paid their emergency offer, regardless of the zonal LMP. Table 6-35 shows the distribution of registrations and associated MW in the emergency full option across ranges of minimum dispatch prices for the 2013/2014 Delivery Year. The majority of participants, 69.7 percent, have a minimum dispatch price of $1,000 per MWh, and 18.4 percent of participants have a dispatch price of $1,800 per MWh, which is the maximum price allowed for the 2013/2014 Delivery Year. Energy offers are further increased by submitted shutdown costs, which, in the 2013/2014 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 $500 to $800 strike prices had the highest average at $3,262.88 per location.

Shutdown costs for demand response resources are not adequately defined in Manual 15. PJM's Cost Development Subcommittee (CDS) recently 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.[34]

Table 6-35 Distribution of registrations and associated MW in the emergency full option across ranges of minimum dispatch prices: 2013/2014 Delivery Year[35]

Ranges of Strike Prices ($/MWh)	Locations	Percent of Total	Nominated MW (ICAP)	Percent of Total	Shutdown Cost per Location
$0-$1	538	3.6%	861.0	9.6%	$0.00
$1-$200	905	6.0%	379.9	4.2%	$8.73
$200-$500	216	1.4%	186.9	2.1%	$141.90
$500-$800	66	0.4%	82.8	0.9%	$3,262.88
$800-$999	67	0.4%	50.8	0.6%	$520.37
$1,000	10,499	69.7%	5,926.0	66.1%	$26.05
$1,800	2,776	18.4%	1,479.5	16.5%	$0.00
Total	15,067	100.0%	8,966.9	100.0%	$37.32

32 139 FERC ¶ 61,057 (2012).
33 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.
34 PJM. "Manual 15: Cost Development Guidelines," Revision 23 (August 1, 2013), p. 51.
35 In this analysis nominated MW does not include capacity only resources, which do not receive energy market credits.

Table 6-36 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 6-36 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.

Table 6-37 includes the energy reduction MWh and average real time LMP during the eight demand response event days. The first column shows the hour beginning for each event day. The second column has the emergency demand response MWh reductions, which are calculated by comparing each resource's CBL to their actual load during the demand response event.[37] If a resource is registered for both the economic and emergency program, the economic CBL is used for the emergency CBL. If a resource is only registered under the emergency option, the CBL is the hour before the reductions occur.[38] On January 7, 2014, all demand response resources in the RTO were called at 430 to reduce at 530 and 630 EPT for short and long lead resources. If a resource could reduce before their designated lead time, that resource was eligible for energy settlements. The average LMP columns consist of the average LMP for each hour of an event day based on what zones were called. The January 22, 2014, event day included only SWMAAC, so the average LMP is the average of the BGE and Pepco zones. The LMP was only greater than $1,000 per MWh for the dispatched areas for three events, both of the January 7 events and the January 22 event.

Table 6-38 shows emergency revenue for each event day in 2014. Energy payments in the emergency program differ significantly from energy payments in the economic program and from capacity payments through the emergency load response program in that they are not based on or tied to any market price signal. Once an emergency demand response event is called for a zone or sub zone, payments are guaranteed if a resource is determined to have responded. Emergency demand response energy costs are paid by PJM market participants in proportion to their net purchases in the Real-Time Energy Market.[39] Emergency demand response energy costs are not covered by LMP. All demand response energy payments and shutdown costs are out of market payments. These payments are a form of uplift.

The events on January 7, 2014, were the first voluntary events of 2014, and all resources in the RTO were called for both events. January 7 had the most MWh reductions and highest average LMP which resulted in the total emergency revenue of $22,691,122. The total emergency revenue for the voluntary emergency event days in the first nine months of 2014 were $42,971,731.

37 This table assumes that PJM's CBL calculation is correct.
38 PJM has stated in the demand response subcommittee meeting, that when two events occurred in a single calendar day, that the hour before the first event is the CBL used for both events. If a resource does not submit for an energy settlement for the first event, the CBL would be the hour before the second event.

39 PJM. "Manual 28: Operating Agreement Accounting," Revision 64 (April 11, 2014), p 69.

Table 6-37 Energy reduction MWh and average real-time LMP during demand response event days: January through September, 2014

	January 7, 2014		January 8, 2014		January 22, 2014		January 23, 2014		January 24, 2014		March 4, 2014	
Hour Beginning	MWh Reduction	Average LMP ($/MWh)	MWh Reduction	Average LMP ($/MWh)	MWh Reduction	Average LMP ($/MWh)	MWh Reduction	Average LMP ($/MWh)	MWh Reduction	Average LMP ($/MWh)	MWh Reduction	Average LMP ($/MWh)
0		321.5		159.3		60.7		285.2		382.0		147.3
1		416.4		179.8		160.4		245.6		445.6		164.1
2		422.7		170.3		185.7		283.3		520.1		190.5
3		277.8		110.3		153.2		272.4		468.0		225.6
4	464.3	473.1		119.7		102.0	127.8	283.3	144.8	487.4	307.7	231.3
5	834.0	487.0	447.1	198.5		404.7	233.9	203.9	217.6	618.6	575.3	847.6
6	1,359.8	1,030.5	902.7	328.6		312.1	448.4	278.5	484.2	678.1	1,319.1	191.2
7	1,740.2	1,726.3	1,095.6	290.8		557.7	620.2	348.3	578.0	833.6	1,763.9	199.4
8	1,981.7	1,832.7	911.1	184.3		515.6	544.3	225.8	575.2	540.2	1,634.0	180.1
9	1,955.2	1,784.2		213.5		460.0		123.7		426.1		239.9
10	1,799.9	1,772.1		200.0		503.0		272.0		361.1		250.2
11		1,434.3		216.0		513.8		502.1		278.2		309.0
12		406.3		101.1		462.9		395.9		294.7		228.6
13		495.8		121.0		274.8		488.7		313.4		242.0
14		327.6		42.2	10.9	274.3	423.7	587.8		250.9		234.3
15	1,247.9	244.1		96.4	37.6	1,206.8	588.0	565.7		144.5		186.4
16	1,802.5	291.6		131.4	93.7	466.8	905.6	353.6		207.0		145.7
17	2,346.9	1,018.2		182.0	108.0	1,818.6	930.7	476.7		398.0		210.4
18	2,227.9	437.8		117.4	133.0	1,816.6	957.1	553.3		283.3		261.8
19		438.0		127.8	154.0	1,825.1		623.1		276.0		192.8
20		354.8		156.1	159.3	1,749.3		707.9		396.0		227.8
21		258.8		100.7		592.7		647.4		371.2		273.7
22		215.3		65.4		469.6		627.8		144.9		126.3
23		211.2		39.8		358.7		492.8		230.4		128.8
Total	17,760.0	694.9	3,356.4	152.2	696.6	635.2	5,779.7	410.2	1,999.7	389.6	5,600.0	234.8

Table 6-38 Emergency revenue by event: January through September, 2014

Event Date	Total
January 7, 2014	$22,691,122
January 8, 2014	$3,536,061
January 22, 2014	$1,210,678
January 23, 2014	$7,076,824
January 24, 2014	$2,637,138
March 4, 2014	$5,819,908
Total	$42,971,731

Limited Demand Resource Penalty Charge

Limited demand response resources are required to be available for only 10 times during the months of June through September in a delivery year on weekdays other than PJM holidays from 1200 (EPT) to 2000 (EPT) and be capable of maintaining an interruption for a minimum of two hours to a maximum of six hours. Limited demand response resources have one or two hours to reduce load once PJM initiates an event. When a provider under complies based on their committed MW, a penalty is charged. The penalty is based on the amount of under compliance, the number of events called during the DY and the cost per MW day for that provider. DR penalties are only assessed for PJM initiated events, after a compliance review is complete.

No penalties were assessed based on events that occurred during the first nine months of 2014, because all emergency events in 2014 were voluntary curtailment. The penalties are assessed daily and have increased by $15,817,614.31 from $2,037,700.10 in the 2012/2013 Delivery Year compared to $17,855,314.41 of the 2013/2014 Delivery Year. Table 6-39 shows penalty charges by zone for the 2012/2013 and 2013/2014 Delivery Year. The PECO Control Zone had the highest penalty amount, due to the clearing prices in EMAAC and a reported performance at 93.2 percent of the committed MW.[40] The penalty charges represent 3.3 percent of the capacity revenue for the 2013/2014 Delivery Year and 0.8 percent of the capacity revenue for the 2012/2013 Delivery Year.

There were no penalties for the 2014/2015 Delivery Year since there were no emergency events called and testing compliance was not completed at the date of report publication.

Table 6-39 Penalty charges per zone: 2012/2013 and 2013/2014 Delivery Years

	2012/2013 Penalty Charge	2013/2014 Penalty Charge
AECO	$91.25	$125,889.92
AEP	$143,499.75	$590,009.95
AP	$0.00	$0.00
ATSI	$0.00	$1,104,441.56
BGE, Met-Ed, Pepco	$634,753.25	$2,468,448.72
ComEd	$0.00	$0.00
DAY	$0.00	$0.00
DEOK	$0.00	$0.00
Dominion	$59,020.50	$310,907.51
DPL	$740,756.55	$766,832.39
DLCO	$0.00	$74,600.56
EKPC	$0.00	$0.00
JCPL	$5,332.65	$604,141.64
PECO	$399,404.90	$5,768,980.77
PENELEC	$44,066.45	$434,076.46
PPL	$594.95	$3,601,276.68
PSEG, RECO	$10,179.85	$2,005,708.25
Total	$2,037,700.10	$17,855,314.41

40 Refer to Section 5: Capacity, Table 5-11 for complete listing of capacity prices.