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 Activity.** Economic program credits increased by $10.5 million, from $1.0 million in the first three months of 2013 to $11.6 million in the first three months of 2014, a 970 percent increase. Emergency energy credits increased by $37.1 million to $37.1 million compared to the first three months of 2013. The capacity market is the primary source of revenue to participants in PJM demand response programs. In the first three months of 2014, capacity market revenues increased by $71.8 million, or 108.8 percent, from $66.0 million in the first three months of 2013 to $137.8 million in the first three months of 2014.[1]

  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. Emergency demand response energy costs are not covered by LMP. Economic demand response energy costs are assigned to PJM market participants based on 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.2

- **Locational Dispatch of Demand Resources.** PJM dispatches demand resources on a zonal or subzonal basis when appropriate, but subzonal dispatches are only on a voluntary basis. Beginning with the 2014/2015 Delivery Year, demand resources will be 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.

- **Emergency Event Day Analysis.** Emergency energy revenue increased by $37.1 million, from $0.0 million in the first three months of 2013 to $37.1 in the first three months of 2014. Emergency load management event rules over-calculate a participants' compliance levels. Increases in load for dispatched demand resources, negative reduction MWh values, are not netted across hours or across registrations within hours for compliance purposes, but are treated as zero. Considering all positive and negative reported values, the observed average load reduction of the seven events in the first three months of 2014 should have been 1,594.6 MW, rather than the 2,079.5 MW calculated using PJM's method. The correct calculation of compliance is 26.9 percent rather than PJM's calculated 35.1 percent. This does not include locations that did not report their load during the emergency event days.

Recommendations

- The MMU recommends that there be only one demand resources product, with an obligation to respond when called for all hours of the year.
- The MMU recommends that the emergency load response program be classified as an economic program and not an emergency program.
- The MMU recommends that a daily must offer requirement apply to demand resources, comparable to the rule applicable to generation capacity resources.[3]
- 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.[4]
- 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.

1 The total credits and MWh numbers for demand resources were calculated as of March 7, 2014 and may change as a result of continued PJM billing updates.
2 PJM: "Manual 28: Operating Agreement Accounting," Revision 64 (April 11, 2014), p 70.
3 See "Complaint and Motion to Consolidate of the Independent Market Monitor for PJM," Docket No. EL14-20-000 (January 27, 2014) at 1.
4 *Id* at 1.

- The MMU recommends that demand resources be required to provide their nodal location on the electricity grid.
- The MMU recommends that demand resources measurement and verification be further modified to more accurately reflect compliance.
- The MMU recommends that compliance rules be revised to include submittal of all necessary hourly load data, and negative values when calculating event compliance across hours and registrations.
- The MMU recommends that PJM adopt the ISO-NE 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.[5]
- The MMU recommends that demand response event compliance be calculated for each hour and the penalty structure reflect hourly compliance.
- The MMU recommends that demand resources whose load drop method is designated as "Other" explicitly record the method of load drop.
- 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.

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.

If retail markets reflected hourly wholesale prices and customers received direct savings associated with reducing consumption in response to real-time prices, there would not be a need for a PJM economic load response program, or for extensive measurement and verification protocols. In the transition to that point, however, there is a need for robust measurement and verification techniques to ensure that transitional programs incent the desired behavior. The baseline methods used in PJM programs today 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 should include both increases and decreases in load. The current method applied by PJM simply ignores increases in load.

5 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.

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.

Table 6-1 Overview of demand response programs

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

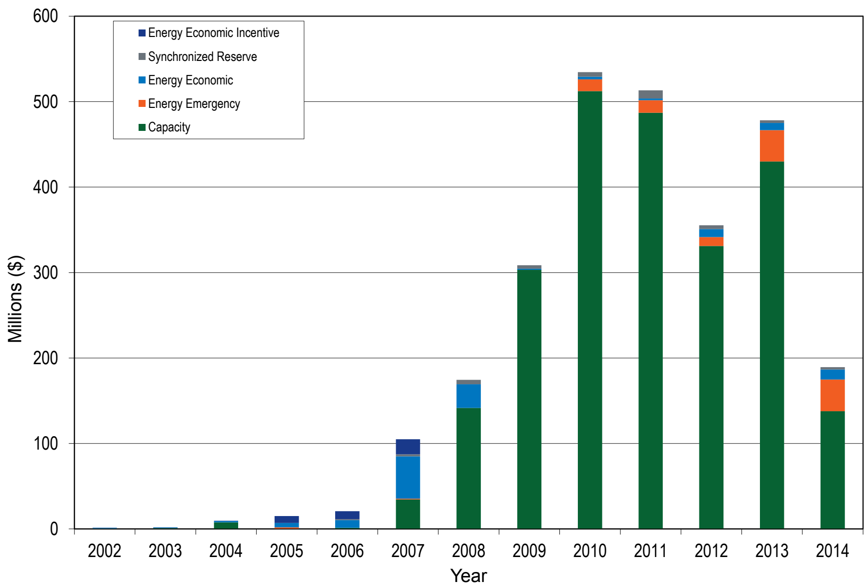
Participation in Demand Response Programs

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. In the first three months of 2014, credits and MWh in the economic program were higher than in the same period for each of the last five years. There were more settlements submitted and more active participants in the first three months of 2014 compared to the first three months of 2013, and credits increased.

Figure 6-1 shows all revenue from PJM demand response programs by market for the period 2002 through the first three months of 2014. Since the implementation of the RPM capacity market on June 1, 2007, the capacity market has been the primary source of revenue to demand response participants, accounting for 92.4 percent of all revenue received through demand response programs in the first three months of 2014. In the first three months of 2014, total credits under the economic program increased by $10,509,971, from $1,083,755 in the first three months of 2013 to $11,593,726 in the first three months of 2014. This represents a 970 percent increase in credits. In the first three months of 2014, capacity revenue accounted for 72.8 percent of all revenue received by demand response providers, emergency energy revenue was 19.6 percent, revenue from the economic program was 6.1 percent and revenue from synchronized reserve was 1.5 percent.

Capacity revenue increased by $71.8 million, or 108.8 percent, from $66.0 million in the first three months of 2013 to $137.8 million in the first three months of 2014, primarily due to higher clearing prices in the capacity market for the 2013/2014 Delivery Year. The emergency energy revenue increased by $37.1 million to $37.1 million in the first three months of 2014.

Figure 6-1 Demand response revenue by market: 2002 through March, 2014



Economic Program

Table 6-2 shows registered sites and MW for the last day of each month for the period 2010 through the first three months of 2014. The average number of registrations and registered MW increased in the first three months of 2014. The average monthly registered MW for the first three months of 2014 increased by 135 MW from 2,331 MW in the first three months of 2013 to 2,466 MW in the first three months of 2014. Registration is a prerequisite for CSPs to participate in the economic program. The average number of registrations increased by 356 from 824 in the first three months of 2013 to 1,180 in the first three months of 2014. The economic program's registered MW have not increased significantly with FERC Order No. 745. The average registered MW in the first three months of 2011, before FERC Order No. 745, was 2,461 MW, and the average registered MW in the first three months of 2014 was 2,466 MW, an increase of 5 MW.

There is a large overlap between economic registrations and emergency capacity registrations. There were 499 registrations and 2,406 MW of nominated MW in the emergency program, that were in both the economic and emergency programs. The registered MW in the economic load response program are not a good measure of the amount of MW available for dispatch. Economic resources can dispatch more, less or the amount of MW registered in the program.

Table 6-2 Economic program registrations on the last day of the month: 2011 through March, 2014

	2011		2012		2013		2014	
Month	Registrations	Registered MW	Registrations	Registered MW	Registrations	Registered MW	Registrations	Registered MW
Jan	1,607	2,429	1,993	2,385	841	2,336	1,180	2,357
Feb	1,612	2,435	1,995	2,384	843	2,350	1,174	2,363
Mar	1,610	2,518	1,996	2,356	788	2,307	1,185	2,679
Apr	1,611	2,534	189	1,321	970	2,369		
May	1,600	2,483	371	1,709	1,375	2,437		
Jun	1,136	1,849	803	2,435	1,302	2,166		
Jul	1,228	2,062	942	2,416	1,315	2,501		
Aug	1,982	2,194	1,013	2,469	1,299	2,597		
Sep	1,960	2,181	1,052	2,516	1,280	2,545		
Oct	1,954	2,179	828	2,364	1,210	2,405		
Nov	1,986	2,220	824	2,362	1,192	2,377		
Dec	1,992	2,259	846	2,379	1,192	2,382		
Avg.	1,690	2,279	1,071	2,258	1,134	2,398	1,180	2,466

Since response by participants in the economic demand response program is optional, not all registrations or registered MW performed each year. Table 6-3 shows the sum of maximum economic MW dispatched by registration each month for 2010 through the first three months of 2014. The maximum dispatched MW for each registration for each month were added together to get the maximum economic MW dispatch value. Economic dispatch can occur above, at or below the registered MW amount for each registration. The total maximum MW by registration dispatched in the first three months of 2014 increased by 259 MW, from 233 MW in the first three months of 2013 to 493 MW in the first three months of 2014. The increase of dispatched MW by registration was a result of high LMP in the first three months of 2014. January and February of 2014 had more dispatched MW than January and February in each of the last four years. July of 2012 had the highest recorded MW dispatched for the last four years at 1,641 maximum MW dispatched by registration.

Table 6-3 Maximum economic MW dispatched by registration per month: 2011 through March, 2014

	Maximum Dispatched MW by Registration			
Month	2011	2012	2013	2014
Jan	243	104	193	426
Feb	190	101	119	306
Mar	153	72	127	271
Apr	80	108	133	
May	98	143	192	
Jun	561	944	431	
Jul	561	1,641	1,088	
Aug	161	980	497	
Sep	84	451	517	
Oct	81	242	157	
Nov	86	165	154	
Dec	88	99	161	
Total	841	1,956	1,472	493

Economic demand response energy costs are assigned to PJM market participants as uplift based on real-time exports from the PJM Region and real-time loads in each zone for which the load-weighted average real-time LMP for the hour during which the reduction occurred is greater than the price determined under the net benefits test for that month.[6] All demand response energy payments are out of market.

Table 6-4 shows total credits paid to participants in the economic program. The average credits per MWh increased by $169.45 per MWh, from $51.49 per MWh in the first three months of 2013 to $220.94 per MWh dispatched in the first three months of 2014. The average LMP for the RTO increased by $49.77 per MWh, from $37.49 per MWh during the first three months of 2013 to $87.26 per MWh during the first three months of 2014. The increase in Table 6-4 is a result of high LMPs in the first quarter of 2014. Curtailed energy for the economic program was 52,475 MWh in the first three months of 2014 and the total payments were $11,593,726. Credits, for the first three months of 2014, increased by $10,509,971, or 970 percent, compared to the first three months of 2013. Economic demand response resources that are dispatched in both the economic and emergency programs 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.

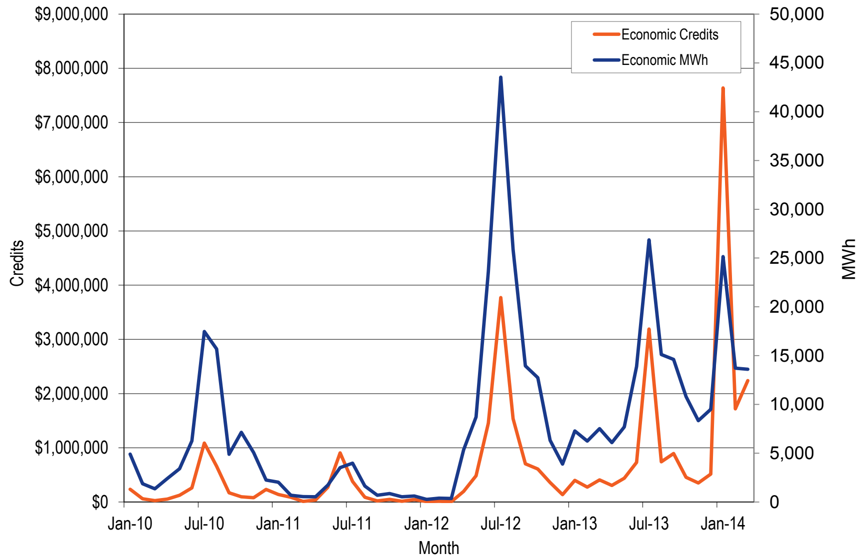
Table 6-4 Credits paid to the PJM economic program participants excluding incentive credits: January through March, 2010 through 2014

Year (Jan-Mar)	Total MWh	Total Credits	$/MWh
2010	8,139	$321,648	$39.52
2011	3,272	$240,304	$73.45
2012	1,030	$30,406	$29.52
2013	21,048	$1,083,755	$51.49
2014	52,475	$11,593,726	$220.94

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

Figure 6-2 shows monthly economic demand response credits and MWh, for 2010 through the first three 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 quarter 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 in July 2012 and the highest in the last five years.

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



Total economic program reductions increased 149 percent from 21,048 MW in the first three months of 2013 to 52,475 MW in the first three months of 2014. The economic credits increased by 970 percent from $1,083,755 in the first three months of 2013, to $11,593,726 in the first three months of 2014. (Table 6-5)

Table 6-5 PJM Economic program participation by zone: January through March, 2013 and 2014[7]

	Credits			MWh Reductions		
Zones	2013	2014	Percentage Change	2013	2014	Percentage Change
Total	$1,083,755	$11,593,726	970%	21,048	52,475	149%

Table 6-6 shows total settlements submitted by year for 2008 through the first three months of 2014. A settlement is counted for every day on which a registration is dispatched in the economic program. Settlements submitted by year in the economic program have decreased from 2008 to 2013. Settlements increased after FERC Order No. 745 in 2012, but decreased in 2013. There were 1,724 economic settlements in the first three months of 2014, which increased by 1,314 from the 410 settlements in the first three months of 2013.

Table 6-6 Settlements submitted by year in the economic program: 2008 through March, 2014

	2008	2009	2010	2011	2012	2013	2014 (Jan-Mar)
Total	32,990	21,605	12,697	4,591	7,894	3,904	1,724

Table 6-7 shows the number of distinct curtailment service providers (CSPs) and distinct participants actively submitting settlements by year for the period 2009 through the first three months of 2014. The number of active participants during the first three months of 2014 increased by 74 to 127, compared to the first three months of 2013, when 53 participants from 10 CSPs were active.

7 PJM and the MMU cannot publish more detailed information about the Economic Program Zonal Settlements as a result of confidentiality requirements. See "Manual 33: Administrative Services for the PJM Interconnection Agreement," Revision 09 (July 22, 2010).

Table 6-7 Distinct participants and CSPs submitting settlements in the Economic Program by year: 2009 through March, 2014

	2009		2010		2011		2012		2013		2014-Q1	
Month	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	25	747	24	438	20	610	24	520	22	291	13	127

Table 6-8 shows average MWh reductions and credits by hour for the first three months of 2013 and the first three months of 2014. The majority of reductions occurred between hours ending 0800 and hour ending 1900 in the first three months of 2014. The credits earned increased for each hour in the first three months of 2014 compared to the first three months of 2013. Reductions occurred over all hours when LMP was above the net benefit test threshold in the first three months of 2014. The MWh reductions increased by 149 percent compared to 2013, and credits increased by 970 percent.

Table 6-8 Hourly frequency distribution of economic program MWh reductions and credits: January through March, 2013 and 2014

	MWh Reductions			Program Credits		
Hour Ending (EPT)	2013	2014	Percentage Change	2013	2014	Percentage Change
1 through 7	3,104	9,487	206%	$168,168	$1,827,157	987%
8	3,373	3,987	18%	$221,471	$934,116	322%
9	3,204	4,018	25%	$164,528	$699,368	325%
10	2,911	4,190	44%	$132,995	$815,804	513%
11	2,315	3,072	33%	$108,284	$714,435	560%
12	1,923	2,323	21%	$83,366	$628,938	654%
13	1,363	2,261	66%	$58,242	$465,190	699%
14	502	2,119	322%	$20,453	$432,496	2,015%
15	264	1,855	604%	$9,375	$363,680	3,779%
16	265	1,788	575%	$9,544	$314,293	3,193%
17	314	1,833	485%	$11,968	$337,111	2,717%
18	325	2,394	637%	$16,190	$621,482	3,739%
19	474	2,592	447%	$28,311	$731,596	2,484%
20 through 24	711	10,556	1,384%	$50,861	$2,708,061	5,224%
Total	21,048	52,475	149%	$1,083,755	$11,593,726	970%

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 NBT is used to define a price point above which the net benefits of DR are deemed to exceed the cost to load. When the LMP is above the NBT threshold, the demand response resource receives credit for the full LMP. The net benefits test defined an average price of $31.63 per MWh for the first three months of 2014, a $5.76 per MWh increase from $25.87 per MWh in the first three months of 2013. Demand resources are not paid for any load reductions during hours where the LMP is below the net benefits test price.

Table 6-9 shows the distribution of economic program MWh reductions and credits by ranges of real-time zonal, load-weighted, average LMP in the first three months of 2013 and 2014. Reductions occurred at all price levels. Approximately 30 percent of MWh reductions and 58 percent of program credits are associated with hours when the applicable zonal LMP was higher than $250 per MWh. MWh reductions in the first three months of 2014 increased 149 percent compared to the first three months of 2013.

Table 6-9 Frequency distribution of economic program zonal, load-weighted, average LMP (By hours): January through March, 2013 and 2014

	MWh Reductions			Program Credits		
LMP	2013	2014	Percentage Change	2013	2014	Percentage Change
$0 to $50	14,479	5,721	(60%)	$596,493	$359,302	(40%)
$50 to $75	3,236	8,580	165%	$194,052	$600,429	209%
$75 to $100	947	5,829	515%	$67,853	$627,737	825%
$100 to $125	993	3,324	235%	$72,677	$456,842	529%
$125 to $150	296	3,234	994%	$28,636	$519,174	1,713%
$150 to $200	460	5,751	1,151%	$60,489	$1,213,833	1,907%
$200 to $250	450	4,569	915%	$46,424	$1,095,991	2,261%
> $250	187	15,466	8,166%	$17,131	$6,720,418	39,131%
Total	21,048	52,475	149%	$1,083,755	$11,593,726	970%

Emergency Program

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 a daily must offer requirement apply to demand resources, comparable to the rule applicable to generation capacity resources. This will 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 at $1,000 per MWh.[8]

Table 6-10 shows zonal monthly capacity credits to demand resources for the first three months of 2014. Capacity revenue increased in the first three months of 2014 by $71.8 million, or 108.8 percent, compared to the first three months of 2013, from $66.0 million to $137.8 million as a result of higher RPM prices and more cleared DR in RPM for the 2013/2014 Delivery Year.[9]

Table 6-10 Zonal monthly capacity credits: January through March, 2014

Zone	January	February	March	Total
AECO	$1,035,717	$935,486	$1,035,717	$3,006,921
AEP, EKPC	$776,197	$701,081	$776,197	$2,253,474
AP	$493,260	$445,525	$493,260	$1,432,044
ATSI	$377,750	$341,193	$377,750	$1,096,692
BGE	$7,736,807	$6,988,083	$7,736,807	$22,461,697
ComEd	$808,185	$729,973	$808,185	$2,346,343
DAY	$44,278	$39,993	$44,278	$128,548
DEOK	$16,653	$15,041	$16,653	$48,346
DLCO	$605,391	$546,805	$605,391	$1,757,587
Dominion	$1,979,013	$1,787,496	$1,979,013	$5,745,522
DPL	$148,045	$133,718	$148,045	$429,808
JCPL	$2,288,883	$2,067,378	$2,288,883	$6,645,143
Met-Ed	$2,246,581	$2,029,170	$2,246,581	$6,522,333
PECO	$5,314,219	$4,799,939	$5,314,219	$15,428,377
PENELEC	$2,980,723	$2,692,266	$2,980,723	$8,653,713
Pepco	$4,229,396	$3,820,100	$4,229,396	$12,278,892
PPL	$7,253,736	$6,551,762	$7,253,736	$21,059,234
PSEG	$8,859,978	$8,002,561	$8,859,978	$25,722,517
RECO	$257,721	$232,781	$257,721	$748,223
Total	$47,452,531	$42,860,351	$47,452,531	$137,765,414

Table 6-11 shows the amount of energy efficiency (EE) resources in PJM for the 2012/2013 and 2013/2014 Delivery Year. Energy efficiency resources are offered in the PJM Capacity Market. The total MW of energy efficiency resources increased by 63 percent from 631.2 MW in 2012/2013 to 1,029.2 MW in 2013/2014 Delivery Year.

Table 6-11 LDA Energy efficiency resources by MW: 2012/2013 and 2013/2014 Delivery Year

	EE ICAP (MW)			EE UCAP (MW)		
LDA Name	2012/2013	2013/2014	Percentage Change	2012/2013	2013/2014	Percentage Change
Total	609.8	990.9	62%	631.2	1,029.2	63%

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

9 For more detail on RPM prices see the *2013 State of the Market Report for PJM*, Volume II, Section 5, "Capacity Market," <http://www.monitoringanalytics.com/reports/PJM_State_of_the_Market/2013.shtml>.

Table 6-12 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	1,767.1	2,092.7	279.6	842.4	3,267.2	78.6	235.8	8,563.6	88.1%
Guaranteed Load Drop	60.6	216.1	0.9	84.4	27.5	0.8	12.5	402.8	4.1%
Non hourly metered sites (DLC)	0.0	712.4	0.0	0.0	0.0	40.0	0.0	752.4	7.7%
Total	1,827.8	3,021.2	280.5	926.8	3,294.7	119.4	248.3	9,718.7	100.0%
Percentage by method	18.8%	31.1%	2.9%	9.5%	33.9%	1.2%	2.6%	100.0%	

Table 6-12 shows the MW registered by measurement and verification method and by load drop method. Of the DR MW committed, 4.1 percent use the guaranteed load drop (GLD) measurement and verification method, 88.1 percent use firm service level (FSL) method and 7.7 percent use direct load control (DLC).

The program type is submitted as "Other" for 2.6 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 6-13 shows the fuel type used in the on-site generators identified in Table 6-12. Of the 18.8 percent of emergency demand response identified as using on-site generation, 79.1 percent of MW are diesel, 5.2 percent are natural gas and 15.7 percent is coal, oil, other or no fuel source.[10]

Table 6-13 On-site generation fuel type by MW: 2013/2014 Delivery Year

Fuel Type	MW	Percentage
Coal, Oil, Other	16.3	0.9%
Diesel	1,446.0	79.1%
Natural Gas	94.2	5.2%
None	271.2	14.8%
Total	1,827.8	100.00%

Emergency Event Reported Compliance

PJM declared eight emergency events in the first three 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 through March 2014, 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. Table 6-14 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 6.7 percent of capacity resources in the 2013/2014 Delivery Year.

Table 6-14 Demand response cleared MW UCAP for PJM: 2011/2012 through 2013/2014 Delivery Year

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

10 Since 2.6 percent of committed MW are registered under the other option, the 18.7 percent of emergency load response resources registered with on-site generation could be conservatively low.

Table 6-15 lists PJM emergency load management events declared by PJM in the first three months of 2014 and the affected zones. The SWMAAC region was called for all eight events. All demand response events called in the first three months of 2014 were voluntary, so no penalties are assessed for under compliance.

The emergency demand response program currently settles 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 6-15 PJM declared load management events: January through March, 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. Compliance penalties are not applicable to the events in the first three months of 2014 for that reason, but resources that did curtail can submit for emergency energy settlements, which are paid by PJM market participants in proportion to their net purchases in the real-time market.

Subzonal dispatch by zip code is currently voluntary, but will be mandatory beginning with the 2014/2015 delivery year.[11] 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.

11 If PJM Interconnection L.L.C., Docket No. ER14-822-000 (December 24, 2013) is approved by the FERC, the mandatory requirement for subzonal dispatch will be delayed until the 2015/2016 Delivery Year.

PJM ignores load increases from demand resources when calculating response and compliance. PJM calculates compliance for demand response events by reducing increases in load, negative compliance values, during an event to a zero MW reduction. 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 the negative reduction value and instead replaces the value 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.[12] 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.

Table 6-16 shows the performance for the first January 7, 2014, event. The first column shows the nominated value, which is the reduction capability indicated by the participant at registration. The second column shows load management committed MW, which are used to assess RPM compliance. Differences between these two columns reflect, in part, differences between MW offered and cleared for any partially cleared DR. In addition, RPM commitments consider any RPM transactions, such as capacity replacement sales or purchases for demand resources, while the nominated ICAP does not. The third column shows the reported load reduction in MWh, or the reported load drop during the hours of an event. The reported reduction does not include negative reductions, load increases. The reported reduction is as reported by PJM. The fourth column shows the observed load reduction in MWh, which includes all reported reduction values. The observed load reduction is as calculated by the MMU.

The APS, ComEd, Day, DEOK and EKPC zones did not submit any data for this event. The RECO Control Zone was the only zone to achieve over 100 percent compliance at 119.7 percent reported compliance, or 114.0 percent observed compliance. Overall, the reported compliance for the first event on January 7, 2014, was 37.4 percent, or 2,815.3 MW out of 7,535.7 MW committed. The observed compliance level was 28.4 percent compliance or 2,143.2 MW, a difference of 672.1 MW compared to the reported load reduction.

Table 6-16 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	41.5	102.5	23.8	19.4	4.4	23.3%	18.9%
AEP	1,211.4	1,253.6	756.2	650.0	106.1	60.3%	51.9%
APS	0.0	499.4	0.0	0.0	0.0	0.0%	0.0%
ATSI	674.6	683.1	452.9	349.3	103.6	66.3%	51.1%
BGE	243.4	627.2	205.7	181.8	23.9	32.8%	29.0%
ComEd	0.0	820.3	0.0	0.0	0.0	0.0%	0.0%
DAY	0.0	68.6	0.0	0.0	0.0	0.0%	0.0%
DEOK	0.0	155.4	0.0	0.0	0.0	0.0%	0.0%
DLCO	38.5	69.2	22.7	(2.0)	24.8	32.9%	(3.0%)
Dominion	656.1	757.0	440.6	370.2	70.4	58.2%	48.9%
DPL	103.4	65.9	58.2	41.8	16.4	88.2%	63.4%
EKPC	0.0	79.9	0.0	0.0	0.0	0.0%	0.0%
JCPL	97.5	156.7	77.4	59.9	17.6	49.4%	38.2%
Met-Ed	169.9	173.9	80.6	57.0	23.5	46.3%	32.8%
PECO	309.6	410.3	182.3	131.8	50.6	44.4%	32.1%
PENELEC	203.1	265.1	66.1	0.3	65.9	24.9%	0.1%
Pepco	102.0	372.0	97.6	72.7	24.9	26.2%	19.5%
PPL	505.1	621.1	241.0	137.7	103.3	38.8%	22.2%
PSEG	194.5	350.6	105.2	68.7	36.5	30.0%	19.6%
RECO	3.8	4.0	4.8	4.6	0.2	119.7%	114.0%
Total	4,554.4	7,535.7	2,815.3	2,143.2	672.1	37.4%	28.4%

The second event 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.

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

Table 6-17 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 DPL Control Zone performed at an 86.8 percent reported compliance, or 57.3 MW out of 65.9 MW committed. The DPL Control Zone performed at a 67.6 percent observed compliance, or 44.5 MW out of 65.9 MW committed. Overall, the reported compliance for the second event on January 7, 2014, was 39.6 percent, or 2,984.4 MW out of 7,535.7 MW committed. The observed compliance level was 31.9 percent compliance or 2,405.2 MW, a difference of 579.1 MW.

Table 6-17 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	41.5	102.5	22.7	20.1	2.6	22.1%	19.6%
AEP	1,211.4	1,253.6	806.9	681.1	125.8	64.4%	54.3%
APS	0.0	499.4	0.0	0.0	0.0	0.0%	0.0%
ATSI	674.6	683.1	534.9	452.3	82.6	78.3%	66.2%
BGE	243.4	627.2	219.3	200.7	18.7	35.0%	32.0%
ComEd	0.0	820.3	0.0	0.0	0.0	0.0%	0.0%
DAY	0.0	68.6	0.0	0.0	0.0	0.0%	0.0%
DEOK	0.0	155.4	0.0	0.0	0.0	0.0%	0.0%
DLCO	38.5	69.2	22.2	(23.5)	45.7	32.1%	(34.0%)
Dominion	656.1	757.0	439.2	390.8	48.3	58.0%	51.6%
DPL	103.4	65.9	57.3	44.5	12.7	86.8%	67.6%
EKPC	0.0	79.9	0.0	0.0	0.0	0.0%	0.0%
JCPL	97.5	156.7	74.3	55.9	18.4	47.4%	35.7%
Met-Ed	169.9	173.9	84.8	71.3	13.6	48.8%	41.0%
PECO	309.6	410.3	172.9	133.3	39.6	42.1%	32.5%
PENELEC	203.1	265.1	96.9	62.0	34.9	36.6%	23.4%
Pepco	102.0	372.0	102.2	84.0	18.2	27.5%	22.6%
PPL	505.1	621.1	244.2	167.1	77.2	39.3%	26.9%
PSEG	194.5	350.6	104.4	63.5	40.9	29.8%	18.1%
RECO	3.8	4.0	2.2	2.2	0.1	55.7%	54.0%
Total	4,554.4	7,535.7	2,984.4	2,405.2	579.1	39.6%	31.9%

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 6-18 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 DPL Control Zone performed at 60.9 percent reported compliance, or 40.2 MW out of 65.9 MW committed. The DPL Control Zone performed at a 54.5 percent observed compliance, or 36.0 MW out of 65.9 MW committed. Overall, the reported compliance for the event on January 8, 2014, was 28.2 percent, or 2,123.6 MW out of 7,537.7 MW committed. The observed compliance level was 20.4 percent compliance or 1,535.7 MW, a difference of 587.9 MW.

Table 6-18 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	27.2	102.5	17.1	15.2	1.9	16.7%	14.8%
AEP	1,116.2	1,253.6	699.7	582.1	117.6	55.8%	46.4%
APS	0.0	499.4	0.0	0.0	0.0	0.0%	0.0%
ATSI	588.1	683.1	364.6	274.0	90.7	53.4%	40.1%
BGE	162.2	627.2	120.8	100.6	20.2	19.3%	16.0%
ComEd	0.0	820.3	0.0	0.0	0.0	0.0%	0.0%
DAY	0.0	68.6	0.0	0.0	0.0	0.0%	0.0%
DEOK	0.0	155.4	0.0	0.0	0.0	0.0%	0.0%
DLCO	22.4	69.2	16.4	8.5	7.9	23.7%	12.3%
Dominion	537.0	757.0	288.9	208.6	80.2	38.2%	27.6%
DPL	70.3	65.9	40.2	36.0	4.2	60.9%	54.5%
EKPC	0.0	79.9	0.0	0.0	0.0	0.0%	0.0%
JCPL	65.0	156.7	55.3	40.8	14.5	35.3%	26.0%
Met-Ed	147.2	173.9	54.1	14.1	40.0	31.1%	8.1%
PECO	212.2	410.3	115.6	78.3	37.3	28.2%	19.1%
PENELEC	137.1	265.1	46.5	(4.9)	51.4	17.5%	(1.8%)
Pepco	60.7	372.0	57.3	38.3	19.0	15.4%	10.3%
PPL	411.9	621.1	162.7	88.8	73.9	26.2%	14.3%
PSEG	145.9	350.6	83.6	54.4	29.2	23.8%	15.5%
RECO	1.0	4.0	0.8	0.8	0.0	21.0%	21.0%
Total	3,704.2	7,535.7	2,123.6	1,535.7	587.9	28.2%	20.4%

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 6-19 shows the performance for the January 22, 2014, event.

The BGE Control Zone performed at 35.6 percent reported compliance, or 223.0 MW out of 627.2 MW committed. The BGE Control Zone performed at a 32.2 percent observed compliance, or 202.1 MW out of 627.2 MW committed. Overall, the reported compliance for the event on January 22, 2014, was 35.5 percent, or 355.0 MW out of 999.2 MW committed. The observed compliance level was 31.8 percent compliance or 317.3 MW, a difference of 37.7 MW.

Table 6-19 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	248.0	627.2	223.0	202.1	20.9	35.6%	32.2%
Pepco	98.5	372.0	132.0	115.2	16.8	35.5%	31.0%
Total	346.5	999.2	355.0	317.3	37.7	35.5%	31.8%

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 6-20 shows the performance for the first January 23, 2014, event. The APS Control Zone did not submit any data for this event. The RECO Control Zone performed at 154.2 percent reported compliance, or 6.2 MW out of 4.0 MW committed. The RECO Control Zone performed at a 149.2 percent observed compliance, or 6.0 MW out of 4.0 MW committed. Overall, the reported compliance for the first event on January 23, 2014, was 37.1 percent, or 1,634.9 MW out of 4,412.2 MW committed. The observed compliance level was 27.2 percent compliance or 1,199.7 MW, a difference of 435.2 MW.

The second event 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 6-21 shows the performance for the second January 23, 2014, event. The APS Control Zone did not submit any data for this event. The RECO Control Zone performed at 69.6 percent reported compliance, or 2.8 MW out of 4.0 MW committed. The RECO Control Zone performed at a 67.6 percent observed compliance, or 2.7 MW out of 4.0 MW committed. Overall, the reported compliance for the second event on January 23, 2014, was 36.0 percent, or 1,586.5 MW out of 4,412.2 MW committed. The observed compliance level was 29.2 percent compliance or 1,289.4 MW, a difference of 297.0 MW.

Table 6-20 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	32.0	102.5	19.4	17.6	1.8	18.9%	17.2%
APS	0.0	499.4	0.0	0.0	0.0	0.0%	0.0%
BGE	250.3	627.2	214.0	180.5	33.5	34.1%	28.8%
Dominion	605.4	757.0	442.6	384.1	58.5	58.5%	50.7%
DPL	81.0	65.9	41.7	30.4	11.3	63.2%	46.0%
JCPL	101.3	156.7	78.6	53.8	24.8	50.2%	34.4%
Met-Ed	170.6	173.9	90.1	66.2	23.9	51.8%	38.0%
PECO	304.2	410.3	184.9	133.2	51.7	45.1%	32.5%
PENELEC	174.5	265.1	49.2	(7.2)	56.4	18.5%	(2.7%)
Pepco	103.4	372.0	126.0	102.7	23.3	33.9%	27.6%
PPL	528.4	621.1	260.3	144.2	116.1	41.9%	23.2%
PSEG	208.2	350.6	121.9	88.1	33.7	34.8%	25.1%
RECO	5.0	4.0	6.2	6.0	0.2	154.2%	149.2%
Total	2,564.1	4,405.6	1,634.9	1,199.7	435.2	37.1%	27.2%

Table 6-21 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	32.0	102.5	18.8	17.2	1.5	18.3%	16.8%
APS	0.0	499.4	0.0	0.0	0.0	0.0%	0.0%
BGE	250.3	627.2	212.3	186.9	25.4	33.8%	29.8%
Dominion	605.4	757.0	472.6	433.8	38.8	62.4%	57.3%
DPL	0.0	65.9	0.0	0.0	0.0	0.0%	0.0%
JCPL	81.0	156.7	41.1	31.4	9.7	26.2%	20.1%
Met-Ed	170.6	173.9	98.0	84.7	13.3	56.4%	48.7%
PECO	304.2	410.3	184.8	141.1	43.7	45.0%	34.4%
PENELEC	174.5	265.1	60.7	25.2	35.5	22.9%	9.5%
Pepco	103.4	372.0	125.4	109.5	15.9	33.7%	29.4%
PPL	528.4	621.1	259.9	177.5	82.3	41.8%	28.6%
PSEG	208.2	350.6	110.0	79.2	30.7	31.4%	22.6%
RECO	5.0	4.0	2.8	2.7	0.1	69.6%	67.6%
Total	2,462.9	4,405.6	1,586.5	1,289.4	297.0	36.0%	29.3%

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 6-22 shows the performance for the January 24, 2014, event. The APS Control Zone did not submit any data for this event. The DPL Control Zone performed at 54.4 percent reported compliance, or 35.9 MW out of 65.9 MW committed. The DPL Control Zone performed at a 45.0 percent observed compliance, or 29.7 MW out of 65.9 MW committed. Overall, the reported compliance for the event on January 24, 2014, was 29.8 percent, or 1,313.8 MW out of 4,405.6 MW committed. The observed compliance level was 21.8 percent compliance or 958.9 MW, a difference of 354.9 MW.

Table 6-22 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	27.6	102.5	17.4	15.7	1.7	17.0%	15.4%
APS	0.0	499.4	0.0	0.0	0.0	0.0%	0.0%
BGE	181.1	627.2	142.4	119.8	22.6	22.7%	19.1%
Dominion	523.1	757.0	370.6	310.2	60.4	49.0%	41.0%
DPL	71.6	65.9	35.9	29.7	6.2	54.4%	45.0%
JCPL	72.4	156.7	60.7	37.7	22.9	38.7%	24.1%
Met-Ed	154.1	173.9	82.9	60.7	22.3	47.7%	34.9%
PECO	236.2	410.3	149.2	106.0	43.3	36.4%	25.8%
PENELEC	162.2	265.1	49.2	7.9	41.3	18.6%	3.0%
Pepco	84.3	372.0	96.6	76.2	20.4	26.0%	20.5%
PPL	450.3	621.1	204.8	122.5	82.3	33.0%	19.7%
PSEG	177.5	350.6	103.0	71.8	31.2	29.4%	20.5%
RECO	2.0	4.0	1.0	0.8	0.2	25.7%	21.0%
Total	2,142.3	4,405.6	1,313.8	958.9	354.9	29.8%	21.8%

Table 6-23 shows load management event performance for the first seven demand response emergency events for 2014.[13] RTO wide percent reported compliance was 35.1 percent in the first three months of 2014 for resources called during emergency events, while observed compliance was 26.9 percent. The reported performance values treated locations showing increases in load, negative performance, as zero performance. The RECO Control Zone reported 74.3 percent compliance and observed 71.1 percent compliance were the highest in PJM, while the APS, ComEd, Day, DEOK and EKPC observed 0.0 percent compliance were the lowest.

The BGE and Pepco zones had all seven emergency calls and performed at an average of 26.7 and 23.0 percent observed compliance. Every zone underperformed compared to their nominated ICAP MW. CSPs have more MW registered than are committed in each zone to ensure deliverability at the committed MW level.

Table 6-23 Load management event performance: January through March, 2014 Aggregated

Zone	Nominated ICAP (MW)	Committed MW	Load Reduction Reported (MW)	Load Reduction Observed (MW)	Difference	Percent Compliance Reported	Percent Compliance Observed
AECO	33.7	102.5	19.9	17.5	2.3	19.4%	17.1%
AEP	1,179.6	1,253.6	754.3	637.7	116.5	60.2%	50.9%
APS	0.0	499.4	0.0	0.0	0.0	0.0%	0.0%
ATSI	645.8	683.1	450.8	358.5	92.3	66.0%	52.5%
BGE	225.5	627.2	191.1	167.5	23.6	30.5%	26.7%
ComEd	0.0	820.3	0.0	0.0	0.0	0.0%	0.0%
DAY	0.0	68.6	0.0	0.0	0.0	0.0%	0.0%
DEOK	0.0	155.4	0.0	0.0	0.0	0.0%	0.0%
DLCO	33.1	69.2	20.4	(5.7)	26.1	29.5%	(8.2%)
Dominion	597.2	757.0	409.1	349.6	59.5	54.0%	46.2%
DPL	71.6	65.9	38.9	30.4	8.5	58.9%	46.1%
EKPC	0.0	79.9	0.0	0.0	0.0	0.0%	0.0%
JCPL	85.8	156.7	64.6	46.6	18.0	41.2%	29.7%
Met-Ed	163.7	173.9	81.8	59.0	22.8	47.0%	33.9%
PECO	279.3	410.3	165.0	120.6	44.4	40.2%	29.4%
PENELEC	175.8	265.1	61.5	13.9	47.6	23.2%	5.2%
Pepco	93.5	372.0	105.3	85.5	19.8	28.3%	23.0%
PPL	488.2	621.1	228.8	139.6	89.2	36.8%	22.5%
PSEG	188.1	350.6	104.7	71.0	33.7	29.9%	20.2%
RECO	3.4	4.0	3.0	2.9	0.1	74.3%	71.1%
Weighted Total	4,264.2	5,923.0	2,079.5	1,594.6	413.9	35.1%	26.9%

13 The data for the March 4, 2014 will not be finalized until after publication.

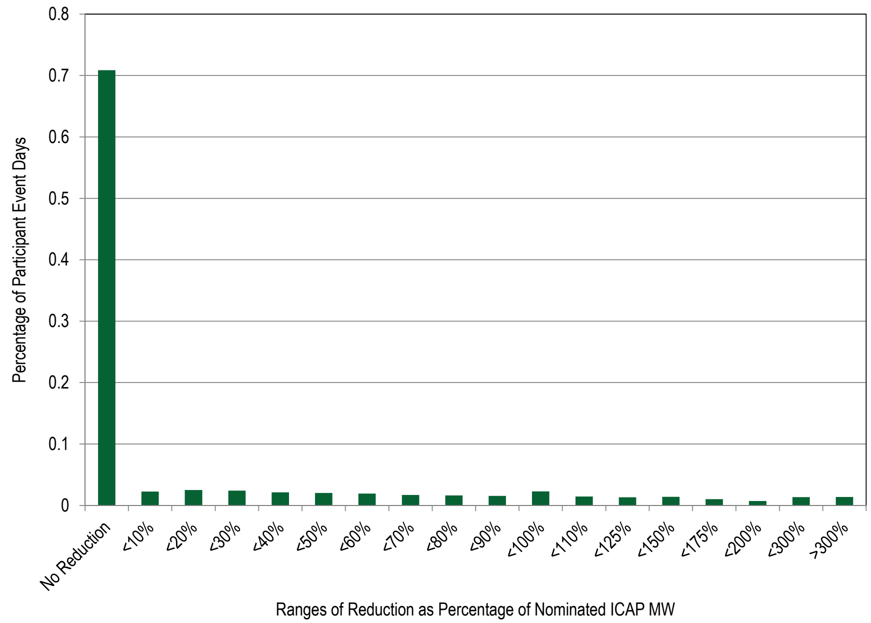
Performance for specific customers varied significantly. Table 6-24 shows the distribution of participant event days across various levels of performance for January 7, January 8, January 22, January 23 and January 24, 2014, events in the 2013/2014 compliance period. Table 6-24 includes the participation for all resources dispatched for the emergency events. For these events, 71 percent of participant event days showed no reduction, load increased or participants did not report data. Approximately 82 percent of participant event days provided less than half of their nominated MW, while 80 percent of the nominated MW provided less than half of their nominated MW. The majority of participants, approximately 91 percent, provided less than 100 percent reduction compared to their nominated MW, while 91 percent of the nominated MW provided less than 100 percent reduction.

Table 6-24 Distribution of participant event days and nominated MW across ranges of performance levels across the events: January through March; 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	50,127	70.9%	32,400	67.0%
0% - 10%	1,604	2.3%	1,379	2.9%
10% - 20%	1,770	2.5%	1,421	2.9%
20% - 30%	1,702	2.4%	1,433	3.0%
30% - 40%	1,511	2.1%	1,158	2.4%
40% - 50%	1,434	2.0%	1,007	2.1%
50% - 60%	1,371	1.9%	1,065	2.2%
60% - 70%	1,210	1.7%	910	1.9%
70% - 80%	1,149	1.6%	982	2.0%
80% - 90%	1,095	1.5%	766	1.6%
90% - 100%	1,612	2.3%	1,676	3.5%
100% - 110%	1,035	1.5%	1,569	3.2%
110% - 125%	947	1.3%	685	1.4%
125% - 150%	993	1.4%	592	1.2%
150% - 175%	733	1.0%	357	0.7%
175% - 200%	511	0.7%	258	0.5%
200% - 300%	956	1.4%	436	0.9%
> 300%	982	1.4%	295	0.6%
Total	70,742	100.0%	48,389	100.0%

Figure 6-3 shows the data in Table 6-24.[14] The distribution illustrates high frequencies of underperforming registrations, and very few resources performing at or above 100 percent.

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



14 Participant event days, shown in Figure 6-3, and Table 6-24, 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. Load management event rules allow 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 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. 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 dalled, 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, 71 percent of event hours demonstrated negative reductions or no reduction in load, as shown in Table 6-24.

Settlements that are not submitted to PJM are treated as zero compliance for the event. Overall, 59.8 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 6-25 shows the number of locations that did not report during the first three months of 2014 event days. In total, 59.8 percent of locations did not report during event days in 2013 and were assigned zero load response. This accounted for 58.1 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 6-25 Non-reporting locations and nominated ICAP on 2014 event days

	Locations Not Reporting	Percent Not Reporting	Nominated ICAP Not Reporting	Percent Not Reporting
Total	42,277	59.8%	28,092	58.1%

Emergency Energy Payments

For any PJM declared load management event in the first three 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 increases to $2,100 per MWh for the 2014/2015 Delivery Year and $2,700 per MWh for the 2015/2016 Delivery Year. The maximum generator offer will remain at $1,000 per MWh.[15]

15 139 FERC ¶ 61,057 (2012).

Participants may elect to be paid their emergency offer, regardless of the zonal LMP. Table 6-26 shows the distribution of registrations and associated MW in the emergency full option across ranges of minimum dispatch prices. The majority of participants, 70.5 percent, have a minimum dispatch price of $1,000 per MWh, and 18.8 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 in 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.[16]

Table 6-26 Distribution of registrations and associated MW in the emergency full option across ranges of minimum dispatch prices effective for the 2013/2014 Delivery Year[17]

Ranges of Strike Prices ($/MWh)	Locations	Percent of Total	Nominated MW (ICAP)	Percent of Total	Shutdown Cost per Location
$0-$1	455	3.3%	852.5	8.7%	$0.00
$1-$200	712	5.2%	349.6	3.6%	$2.67
$200-$500	179	1.3%	107.2	1.1%	$171.23
$500-$800	66	0.5%	84.0	0.9%	$3,262.88
$800-$999	56	0.4%	52.9	0.5%	$622.59
$1,000	9,705	70.5%	6,560.3	67.1%	$28.18
$1,800	2,595	18.8%	1,776.3	18.2%	$0.00
Total	13,768	100.0%	9,782.7	100.0%	$40.40

16 PJM. "Manual 15: Cost Development Guidelines," Revision 23 (August 1, 2013), p. 51.
17 In this analysis nominated MW does not include capacity only resources, which do not receive energy market revenue.

Table 6-27 has the energy reduction MWh and average real-time LMPs during the January demand response event days. The first column shows the hour beginning for each event day. The second column has the MWh reductions, which are calculated by comparing each resource's CBL to their actual load during the demand response event.[18] 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.[19] On January 7, 2014, the whole RTO was called at 430 to reduce at 530 and 630 EPT for short and long lead resources respectively. 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.

18 This table assumes that PJM's CBL calculation is correct.
19 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.

Table 6-27 Energy reduction MWh and average real-time LMP during demand response event days: 2014

	7-Jan		8-Jan		22-Jan		23-Jan		24-Jan	
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)
0		$322		$159		$61		$285		$382
1		$416		$180		$160		$246		$446
2		$423		$170		$186		$283		$520
3		$278		$110		$153		$272		$468
4	464.3	$473		$120		$102	127.8	$283	144.8	$487
5	834.0	$487	447.1	$198		$405	233.9	$204	217.6	$619
6	1,359.8	$1,030	902.7	$329		$312	448.4	$279	484.2	$678
7	1,740.2	$1,726	1,095.6	$291		$558	620.2	$348	578.0	$834
8	1,981.7	$1,833	911.1	$184		$516	544.3	$226	575.2	$540
9	1,955.2	$1,784		$214		$460		$124		$426
10	1,799.9	$1,772		$200		$503		$272		$361
11		$1,434		$216		$514		$502		$278
12		$406		$101		$463		$396		$295
13		$496		$121		$275		$489		$313
14		$328		$42	10.9	$274	423.7	$588		$251
15	1,247.9	$244		$96	37.6	$1,207	588.0	$566		$145
16	1,802.5	$292		$131	93.7	$467	905.6	$354		$207
17	2,346.9	$1,018		$182	108.0	$1,819	930.7	$477		$398
18	2,227.9	$438		$117	133.0	$1,817	957.1	$553		$283
19		$438		$128	154.0	$1,825		$623		$276
20		$355		$156	159.3	$1,749		$708		$396
21		$259		$101		$593		$647		$371
22		$215		$65		$470		$628		$145
23		$211		$40		$359		$493		$230
Total	17,760.0	$695	3,356.4	$152	696.6	$635	5,779.7	$410	1,999.7	$390

Table 6-28 shows emergency credits for each event in 2014. Emergency demand response energy costs are paid by PJM market participants in proportion to their net purchases in the Real-Time Energy Market.[20] 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 the entire RTO was called for both events. January 7 had the most MWh reductions and highest average LMP which resulted in the total emergency credits of $22,691,122. The total emergency credits for the voluntary emergency event days in the first three months of 2014 were $37,146,554.

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 event is called in a zone, these payments are guaranteed if a resource is determined to have responded.[21]

Table 6-28 Emergency credits by event: 2014

Event Date	Total
7-Jan-14	$22,691,122
8-Jan-14	$3,536,061
22-Jan-14	$1,210,678
23-Jan-14	$7,076,824
24-Jan-14	$2,631,869
Total	$37,146,554

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.

Subzonal dispatch and events outside of the June through September window were voluntary, so there were no penalties assessed based on events that occurred during the first three months of 2014. The penalties are assessed daily and have increased by $12,001,510.43 from $1,697,152.96 in June through March of the 2012/2013 Delivery Year compared to $13,698,663.39 of the same period in the 2013/2014 Delivery Year. Table 6-29 shows penalty charges by zone for June through March of 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.[22] The penalty charges represent 3.0 percent of the capacity credits for the 2013/2014 Delivery Year and 0.8 percent of the capacity credits for the 2012/2013 Delivery Year.

20 PJM. "Manual 28: Operating Agreement Accounting," Revision 64 (April 11, 2014), p 69.
21 The emergency energy payments for the first quarter events are not available at date of publication.

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

Table 6-29 Penalty charges per zone: June through March 2012/2013 and 2013/2014 Delivery Years

	2012/2013 Penalty Charge	2013/2014 Penalty Charge
AECO	$76.00	$94,390.74
AEP	$119,517.60	$439,541.25
APS	$0.00	$0.00
ATSI	$0.00	$860,795.97
BGE, Met-Ed, Pepco	$528,671.20	$1,838,542.59
ComEd	$0.00	$0.00
DAY	$0.00	$0.00
DEOK	$0.00	$0.00
Dominion	$49,156.80	$231,037.77
DPL	$616,958.88	$572,013.03
DLCO	$0.00	$55,950.42
EKPC	$0.00	$0.00
JCPL	$4,441.44	$449,234.58
PECO	$332,655.04	$4,548,577.56
PENELEC	$36,701.92	$323,111.97
PPL	$495.52	$2,781,356.16
PSEG, RECO	$8,478.56	$1,504,111.35
Total	$1,697,152.96	$13,698,663.39