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. An appeal to the court for en banc review is pending.

- **Demand Response Activity.** Economic program credits increased by $11.2 million, from $2.6 million in the first six months of 2013 to $13.8 million in the first six months of 2014, a 439 percent increase.[2] Emergency energy revenue increased by $43.0 million, from $0.0 million in the first six months of 2013 to $43.0 million compared to the first six months of 2013. The capacity market is the primary source of revenue to participants in PJM demand response programs. In the first six months of 2014, capacity market revenue increased by $130.8 million, or 83.6 percent, from $156.6 million in the first six months of 2013 to $287.4 million in the first six months of 2014.[3]

  All demand response energy payments are uplift. LMP does not cover demand response energy 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.[4] Emergency demand response energy costs are paid by PJM market participants in proportion to their net purchases in the real-time market.

- **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. 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 higher compliance since poorly performing demand resources are not used in the compliance calculation. Considering all positive and negative reported values, the observed average load reduction of the eight events in the first six months of 2014 should have been 1,658.9 MW, rather than the 2,163.7 MW calculated using PJM's method. The observed compliance is 28.0 percent rather than PJM's calculated 36.5 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.
- 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.

1 Electric Power Supply Association v. FERC, No. 11-1486; *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 Economic credits are synonymous with revenue received for reductions under the economic load response program.
3 The total credits and MWh numbers for demand resources were calculated as of August 5, 2014 and may change as a result of continued PJM billing updates.
4 PJM: "Manual 28: Operating Agreement Accounting," Revision 64 (April 11, 2014), p 70.

- The MMU recommends that a daily must offer requirement apply to demand resources, comparable to the rule applicable to generation capacity resources.[5]
- 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.[6]
- 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.
- The MMU recommends that demand resources be required to provide their nodal location on the electricity grid.
- The MMU recommends that measurement and verification methods for demand resources 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 that negative values be included when calculating event compliance across hours and registrations.
- 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.[7]
- 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.

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 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

5 See "Complaint and Motion to Consolidate of the Independent Market Monitor for PJM," Docket No. EL14-20-000 (January 27, 2014) at 1.
6 *Id* at 1.
7 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.

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.

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.[8] The court found Order No. 745 arbitrary and capricious on its merits.[9] 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."[10] 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.

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.

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

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 six 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 six months of 2014 compared to the first six months of 2013, and credits increased.

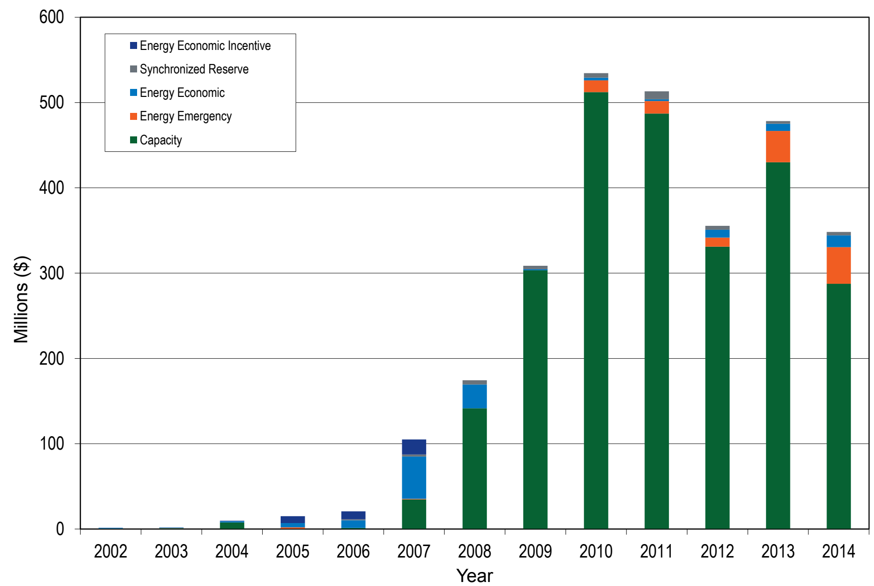
Figure 6-1 shows all revenue from PJM demand response programs by market for the period 2002 through the first six months of 2014. Since the implementation of the RPM capacity market on June 1, 2007, demand response that participated through the capacity market has been the primary source of revenue to demand response participants, accounting for 94.9 percent of all revenue received through demand response programs in the first six months of 2014.[11] Total credits under the economic program increased by $11,231,689, from $2,559,832 in the first six months of 2013 to $13,791,520 in the first six months of 2014, a 439 percent increase.

Capacity revenue increased by $130.8 million, or 83.6 percent, from $156.6 million in the first six months of 2013 to $287.4 million in the first six months of 2014, primarily due to higher clearing prices in the capacity market for the 2013/2014 Delivery Year. Emergency energy revenue to demand response that sold capacity increased by $43.0 million from $0.0 million in the first six months of 2013, to $43.0 million in the first six months of 2014.

In the first six months of 2014, capacity revenue accounted for 82.5 percent of all revenue received by demand response providers, emergency energy revenue was 12.3 percent, credits from the economic program were 4.0 percent and revenue from synchronized reserve was 1.2 percent.

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

Figure 6-1 Demand response revenue by market: 2002 through June, 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 six months of 2014. The average number of registrations and registered MW increased in the first six months of 2014. The average monthly registered MW for the first six months of 2014 increased by 262 MW from 2,305 MW in the first six months of 2013 to 2,567 MW in the first six months of 2014. Registration is a prerequisite for CSPs to participate in the economic program. The average number of registrations increased by 48 from 1,020 in the first six months of 2013 to 1,068 in the first six 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 six months of 2011, before FERC Order No. 745, was 2,500 MW, and the average registered MW in the first six months of 2014 was 2,567 MW, an increase of 67 MW.

There is some overlap between economic registrations and emergency capacity registrations. There were 325 registrations and 1,902 MW of nominated MW in the emergency program that were also in the economic program at the end of the first six 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 6-2 Economic program registrations on the last day of the month: 2011 through June, 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	2,287
Feb	1,612	2,435	1,995	2,384	843	2,327	1,174	2,292
Mar	1,612	2,519	1,996	2,356	788	2,284	1,185	2,654
Apr	1,611	2,534	189	1,318	970	2,346	1,194	2,789
May	1,687	3,166	371	1,669	1,375	2,414	745	2,472
Jun	1,143	1,912	803	2,347	1,302	2,144	928	2,905
Jul	1,228	2,062	942	2,323	1,315	2,443		
Aug	1,987	2,194	1,013	2,373	1,299	2,527		
Sep	1,962	2,183	1,052	2,421	1,280	2,475		
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	1,068	2,567

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

	Maximum Dispatched MW by Registration			
Month	2011	2012	2013	2014
Jan	243	104	193	446
Feb	190	101	119	307
Mar	153	72	127	369
Apr	80	108	133	146
May	98	143	192	151
Jun	561	944	433	93
Jul	561	1,641	1,088	
Aug	161	980	497	
Sep	84	451	530	
Oct	81	242	168	
Nov	86	165	155	
Dec	88	99	168	
Maximum	841	1,956	1,486	572

Table 6-3 shows the sum of maximum economic MW dispatched by registration each month for 2011 through the first six months of 2014. The monthly maximum is the noncoincident peak dispatched MW by month for all registrations. The maximum for each year is the noncoincident peak dispatched MW for the year for all registrations. This annual maximum dispatched MW for all economic demand response registered resources in the first six months of 2014 increased by 10 MW, from 562 MW in the first six months of 2013 to 572 MW in the first six months of 2014.[12] January through April of 2014 had more dispatched MW than January through April in each of the last four years.

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

12 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.

that month.[13] All demand response energy payments are uplift rather than market payments.

Table 6-4 shows total credits paid to participants in the economic program. The average credits per MWh increased by $127.97 per MWh, from $52.55 per MWh in the first six months of 2013 to $180.52 per MWh dispatched in the first six months of 2014. The average real time PJM LMP increased by $25.58 per MWh, from $36.56 per MWh during the first six months of 2013 to $62.14 per MWh during the first six months of 2014. The increase in Table 6-4 is a result of high LMPs in the first six months of 2014. Curtailed energy for the economic program was 76,400 MWh in the first six months of 2014 and the total payments were $13,791,520. Credits, for the first six months of 2014, increased by $11,231,689, or 439 percent, compared to the first six 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: January through June, 2010 through 2014

Year (Jan-Jun)	Total MWh	Total Credits	$/MWh
2010	20,225	$761,854	$37.67
2011	9,055	$1,456,324	$160.84
2012	38,714	$2,165,599	$55.94
2013	48,711	$2,559,832	$52.55
2014	76,400	$13,791,520	$180.52

13 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 six 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 six 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 June, 2014

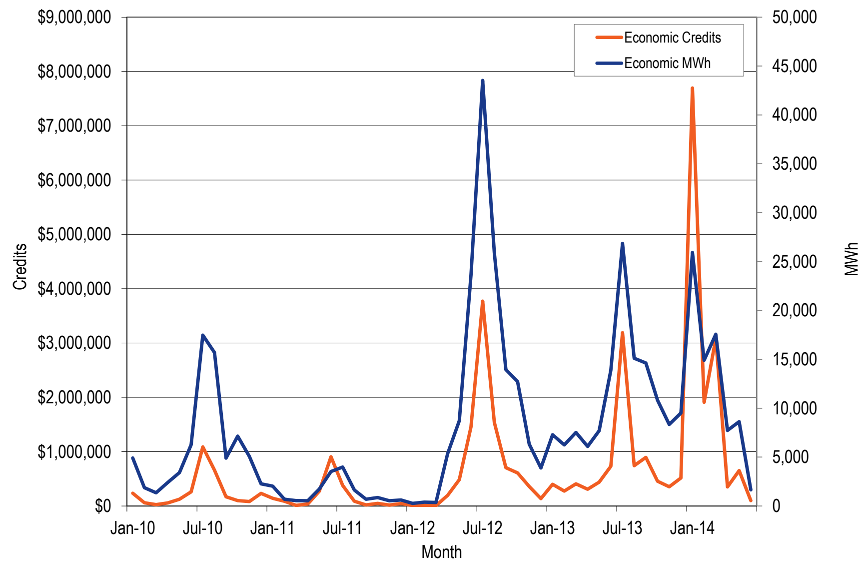


Table 6-5 shows 2013 and 2014 performance in the economic program by control zone and participation type. Total economic program reductions increased 57 percent from 48,711 MW in the first six months of 2013 to 76,400 MW in the first six months of 2014. The economic credits increased by 439 percent from $ 2,559,832 in the first six months of 2013, to $13,791,520 in the first six months of 2014.

Table 6-5 PJM Economic program participation by zone: January through June, 2013 and 2014[14]

	Credits			MWh Reductions		
Zones	2013	2014	Percentage Change	2013	2014	Percentage Change
AECO, JCPL, PECO, PSEG, RECO	$107,302	$2,981,727	2,679%	1,707	13,256	677%
APS, Dominion	$2,101,413	$7,838,960	273%	40,327	47,134	17%
AEP, ATSI, ComEd, DAY, DEOK, DLCO, EKPC	$168,194	$887,320	428%	3,674	6,542	78%
BGE, DPL, Met-Ed, PENELEC, Pepco	$131,587	$592,419	350%	2,053	3,899	90%
PPL	$51,336	$1,491,095	2,805%	950	5,570	486%
Total	$2,559,832	$13,791,520	439%	48,711	76,400	57%

Table 6-6 shows total settlements submitted by year for 2009 through the first six 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 1,403 economic settlements in the first six months of 2014 compared to 659 settlements in the first six months of 2013.

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

Year	2009	2010	2011	2012	2013	2014 (Jan-Jun)
Number of Settlements	2,227	3,781	732	4,554	2,353	1,403

Table 6-7 shows the number of curtailment service providers (CSPs) and participants actively submitting settlements by year for the period 2009 through the first six months of 2014. The number of active participants during the first six months of 2014 was 42 higher than in the first six months of 2013.

Table 6-8 shows average MWh reductions and credits by hour for the first six months of 2013 and the first six months of 2014. The majority of reductions occurred between the hours ending 0700 and hour ending 1900 in the first six months of 2013 and 2014. In the first six months of 2013, 93 percent of reductions and 93 percent of credits occurred from 0700 to 1900, and in the first six months of 2014, 72 percent of reductions and 69 percent of credits occurred from 0700 to 1900. The credits earned increased for each hour in the first six months of 2014 compared to the first six months of 2013. Reductions occurred over all hours when LMP was above the net benefit test threshold in the first six months of 2014.

Table 6-7 Participants and CSPs submitting settlements in the Economic Program by year: 2009 through January through June, 2014

	2009		2010		2011		2012		2013		2014 (Jan-Jun)	
	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	20	276	13	127

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

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

	MWh Reductions			Program Credits		
Hour Ending (EPT)	2013	2014	Percentage Change	2013	2014	Percentage Change
1 through 5	230	5,045	2,091%	$3,160	$879,581	27,732%
6	57	1,780	3,002%	$1,280	$316,145	24,591%
7	3,516	4,613	31%	$188,709	$859,606	356%
8	4,101	5,642	38%	$256,766	$1,069,549	317%
9	3,935	5,787	47%	$195,367	$822,105	321%
10	3,700	5,900	59%	$165,794	$939,376	467%
11	2,863	4,110	44%	$133,679	$810,347	506%
12	2,490	3,115	25%	$109,168	$706,214	547%
13	2,526	3,391	34%	$115,040	$570,782	396%
14	2,541	3,523	39%	$128,861	$570,512	343%
15	3,767	3,510	(7%)	$208,355	$516,691	148%
16	4,056	3,574	(12%)	$231,344	$491,405	112%
17	4,180	3,589	(14%)	$249,032	$487,409	96%
18	4,152	4,170	0%	$234,016	$761,596	225%
19	3,515	4,245	21%	$174,745	$870,855	398%
20	2,094	4,369	109%	$108,823	$994,211	814%
21	613	3,969	548%	$38,115	$880,456	2,210%
22	241	2,839	1,080%	$11,980	$585,786	4,790%
23 through 24	135	3,228	2,291%	$5,596	$658,893	11,675%
Total	48,711	76,400	57%	$2,559,832	$13,791,520	439%

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 $31.86 per MWh for the first six months of 2014, a $5.08 per MWh increase from $26.79 per MWh in the first six 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 six months of 2013 and 2014. Reductions occurred at all price levels. In the hours when the applicable zonal LMP was higher than $250 per MWh, 23.0 percent of MWh reductions and 53.4 percent of program credits occurred in the first six months of 2014. When LMP was above $1,000 per MWh, 0.7 percent of MWh reductions and 3.7 percent of program credits occurred. MWh reductions in the first six months of 2014 increased 56.8 percent compared to the first six months of 2013.

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

	MWh Reductions			Program Credits		
LMP	2013	2014	Percentage Change	2013	2014	Percentage Change
$0 to $25	389	154	(60%)	$5,363	$1,329	(75%)
$25 to $50	31,793	17,541	(45%)	$1,378,744	$838,903	(39%)
$50 to $75	10,224	12,638	24%	$650,648	$852,765	31%
$75 to $100	2,384	7,933	233%	$179,900	$814,583	353%
$100 to $125	1,545	4,251	175%	$120,515	$566,282	370%
$125 to $150	668	3,715	456%	$56,393	$594,246	954%
$150 to $175	348	3,495	904%	$27,419	$660,632	2,309%
$175 to $200	309	3,374	992%	$50,261	$730,211	1,353%
$200 to $225	305	2,949	867%	$28,668	$664,792	2,219%
$225 to $250	441	2,773	529%	$40,030	$697,859	1,643%
> $250	304	17,570	5,683%	$21,892	$7,369,919	33,565%
Total	48,711	76,394	57%	$2,559,832	$13,791,520	439%

Emergency Program

The emergency load response program consists of the limited demand response product in the capacity market during the 2013/2014 Delivery Year. To participate as a limited demand resource, a CSP 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 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 at $1,000 per MWh.[15]

Table 6-10 shows zonal monthly capacity market revenue to demand resources for the first six months of 2014. Capacity market revenue increased in the first six months of 2014 by $91.2 million, or 46.5 percent, compared to the first six months of 2013, from $196.2 million to $287.4 million, as a result of higher RPM prices and more cleared DR in RPM for the 2013/2014 Delivery Year.

Table 6-10 Zonal monthly capacity revenue: January through June, 2014

Zone	January	February	March	April	May	June	Total
AECO	$1,035,717	$935,486	$1,035,717	$1,002,307	$1,035,717	$805,435	$5,850,379
AEP, EKPC	$776,197	$701,081	$776,197	$751,158	$776,197	$6,203,447	$9,984,275
AP	$493,260	$445,525	$493,260	$477,348	$493,260	$3,380,132	$5,782,784
ATSI	$377,750	$341,193	$377,750	$365,564	$377,750	$3,717,155	$5,557,160
BGE	$7,736,807	$6,988,083	$7,736,807	$7,487,232	$7,736,807	$5,140,527	$42,826,263
ComEd	$808,185	$729,973	$808,185	$782,114	$808,185	$5,846,358	$9,783,001
DAY	$44,278	$39,993	$44,278	$42,849	$44,278	$872,987	$1,088,662
DEOK	$16,653	$15,041	$16,653	$16,115	$16,653	$330,654	$411,768
DLCO	$148,045	$133,718	$148,045	$143,269	$148,045	$840,774	$1,561,896
Dominion	$605,391	$546,805	$605,391	$585,862	$605,391	$5,165,946	$8,114,788
DPL	$1,979,013	$1,787,496	$1,979,013	$1,915,174	$1,979,013	$1,542,580	$11,182,289
JCPL	$2,288,883	$2,067,378	$2,288,883	$2,215,048	$2,288,883	$1,709,946	$12,859,019
Met-Ed	$2,246,581	$2,029,170	$2,246,581	$2,174,111	$2,246,581	$1,558,377	$12,501,403
PECO	$5,314,219	$4,799,939	$5,314,219	$5,142,792	$5,314,219	$3,249,878	$29,135,266
PENELEC	$2,980,723	$2,692,266	$2,980,723	$2,884,571	$2,980,723	$1,675,004	$16,194,012
Pepco	$4,229,396	$3,820,100	$4,229,396	$4,092,964	$4,229,396	$3,467,834	$24,069,086
PPL	$7,253,736	$6,551,762	$7,253,736	$7,019,745	$7,253,736	$5,215,729	$40,548,444
PSEG	$8,859,978	$8,002,561	$8,859,978	$8,574,172	$8,859,978	$5,460,187	$48,616,854
RECO	$257,721	$232,781	$257,721	$249,408	$257,721	$118,962	$1,374,314
Total	$47,452,531	$42,860,351	$47,452,531	$45,921,805	$47,452,531	$56,301,913	$287,441,662

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 Energy efficiency resources by MW: 2012/2013 and 2013/2014 Delivery Year

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

Table 6-12 shows the MW registered by measurement and verification method and by load drop method. 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.

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

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	1,911.8	2,276.7	300.1	945.2	3,487.6	81.4	145.3	9,148.1	86.8%
Guaranteed Load Drop	71.2	268.7	4.3	111.5	40.8	0.9	14.1	511.5	4.9%
Non hourly metered sites (DLC)	0.0	844.1	0.0	0.0	0.0	40.0	0.0	884.1	8.4%
Total	1,983.0	3,389.5	304.4	1,056.7	3,528.4	122.3	159.4	10,543.7	100.0%
Percentage by method	18.8%	32.1%	2.9%	10.0%	33.5%	1.2%	1.5%	100.0%	

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, 76.8 percent of MW are diesel, 5.2 percent are natural gas and 0.8 percent is coal, oil, other and 17.2 percent are no fuel source, meaning that the participant responded inaccurately.[16]

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

Fuel Type	MW	Percentage
Coal, Oil, Other	16.3	0.8%
Diesel	1,522.8	76.8%
Natural Gas	103.0	5.2%
None	340.9	17.2%
Total	1,983.0	100.00%

Emergency Event Reported Compliance

PJM declared eight emergency events in the first six 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. 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.

16 Since 1.5 percent of committed MW are registered under the other option, the 18.8 percent of emergency load response resources registered with on-site generation could be conservatively low.

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%

Table 6-15 lists PJM emergency load management events declared by PJM in the first six months of 2014 and the affected zones. The SWMAAC region was called for all eight events. All demand response events called in the first six 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. This recommendation is being implemented.[17]

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 six months of 2014 for that reason, but resources that did curtail can request emergency energy payments, which are paid by PJM market participants in proportion to their net purchases in the real-time market.

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. 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 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.[18] 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.

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 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. Compliance is calculated by comparing the load reduction during an event to the committed MW value.

17 See "PJM Interconnection L.L.C.," Docket No. ER14-822-002 (June 2, 2014).

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

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 104.7 percent. The observed compliance for the RECO Control Zone was 78.1 percent, or 51.5 MW out of 69.1 MW committed. Overall, the reported compliance for the first event on January 7, 2014, was 38.9 percent, or 2,931.7 MW out of 7,535.7 MW committed. The observed compliance was 29.7 percent, or 2,239.1 MW, a difference of 692.6 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	124.9	102.5	25.0	20.6	4.4	24.4%	20.1%
AEP	1,635.7	1,253.6	791.2	682.4	108.8	63.1%	54.4%
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	442.3	371.9	70.4	58.4%	49.1%
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	249.3	144.1	105.2	40.1%	23.2%
PSEG, RECO	488.7	354.6	113.0	76.2	36.6	31.9%	21.5%
Total	10,562.6	7,535.7	2,931.7	2,239.1	692.6	38.9%	29.7%

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 6-17 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 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 41.5 percent, or 3,128.6 MW out of 7,535.7 MW committed. The observed compliance was 33.6 percent, or 2,530.0 MW, a difference of 598.6 MW compared to the reported load reduction.

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	124.9	102.5	23.4	20.9	2.6	22.9%	20.4%
AEP	1,635.7	1,253.6	871.3	739.5	131.8	69.5%	59.0%
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	440.6	392.2	48.3	58.2%	51.8%
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	252.0	174.0	78.1	40.6%	28.0%
PSEG, RECO	488.7	354.6	109.3	68.4	41.0	30.8%	19.3%
Total	10,562.6	7,535.7	3,128.6	2,530.0	598.6	41.5%	33.6%

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 6-18 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 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 29.4 percent, or 2,218.6 MW out of 7,537.7 MW committed. The observed compliance was 21.4 percent, or 1,611.9 MW, a difference of 606.8 MW compared to the reported load reduction.

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	124.9	102.5	18.1	16.1	1.9	17.6%	15.8%
AEP	1,635.7	1,253.6	751.7	626.9	124.8	60.0%	50.0%
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	289.9	209.6	80.2	38.3%	27.7%
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	165.8	87.6	78.2	26.7%	14.1%
PSEG, RECO	488.7	354.6	86.2	57.1	29.2	24.3%	16.1%
Total	10,562.6	7,535.7	2,218.6	1,611.9	606.8	29.4%	21.4%

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 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.

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	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 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 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 39.2 percent, or 1,726.6 MW out of 4,405.6 MW committed. The observed compliance was 29.0 percent, or 1,276.1 MW, a difference of 450.5 MW compared to the reported load reduction.

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	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	443.7	385.3	58.5	58.6%	50.9%
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	264.0	143.4	120.6	42.5%	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	1,726.6	1,276.1	450.5	39.2%	29.0%

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 6-21 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 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 38.6 percent, or 1,699.3 MW out of 4,405.6 MW committed. The observed compliance was 31.3 percent, or 1,378.9 MW, a difference of 320.4 MW compared to the reported load reduction.

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	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	473.5	434.7	38.8	62.6%	57.4%
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	263.1	180.7	82.4	42.4%	29.1%
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	1,699.3	1,378.9	320.4	38.6%	31.3%

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 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 31.4 percent, or 1,384.3 MW out of 4,405.6 MW committed. The observed compliance was 23.2 percent, or 1,020.4 MW, a difference of 363.9 MW compared to the reported load reduction.

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	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	371.7	311.3	60.4	49.1%	41.1%
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	209.5	127.1	82.4	33.7%	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	1,384.3	1,020.4	363.9	31.4%	23.2%

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 6-23 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 35.2 percent, or 2,654.4 MW out of 7,535.7 MW committed. The observed compliance was 26.0 percent, or 1,956.0 MW, a difference of 698.4 MW compared to the reported load reduction.

Table 6-24 shows load management event performance for the eight demand response emergency events for 2014. The reported compliance for all PJM control zones was 36.5 percent in the first six months of 2014 for resources called during emergency events, while observed compliance was 28.0 percent. The reported compliance for the DPL Control Zone was 70.3 percent, or 46.3 MW out of 65.9 MW committed. The observed compliance for the DPL Control Zone was 57.2 percent, or 37.7 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 28.2 percent, or 177.1 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 28.2 percent, or 104.9 MW out of 621.1 MW committed.

Table 6-23 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	762.7	529.4	233.3	60.8%	42.2%
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	356.0	296.3	59.7	47.0%	39.1%
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	2,654.4	1,956.0	698.4	35.2%	26.0%

Table 6-24 Load management event performance: January through June, 2014 Aggregated

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	794.2	644.5	149.7	63.4%	51.4%
APS	674.0	499.4	0.0	0.0	0.0	0.0%	0.0%
ATSI	796.1	683.1	459.2	369.2	90.0	67.2%	54.1%
BGE	826.6	627.2	201.5	177.1	24.4	32.1%	28.2%
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	25.8	1.8	24.0	37.3%	2.6%
Dominion	872.4	757.0	402.5	343.1	59.5	53.2%	45.3%
DPL	301.7	65.9	46.3	37.7	8.6	70.3%	57.2%
EKPC	110.3	79.9	0.0	0.0	0.0	0.0%	0.0%
JCPL	209.1	156.7	72.8	50.4	22.4	46.5%	32.2%
Met-Ed	233.9	173.9	79.6	55.6	24.0	45.8%	32.0%
PECO	587.5	410.3	179.2	133.9	45.3	43.7%	32.6%
PENELEC	330.1	265.1	60.9	11.7	49.2	23.0%	4.4%
Pepco	795.8	372.0	126.3	104.9	21.4	33.9%	28.2%
PPL	800.0	621.1	231.5	139.5	92.0	37.3%	22.5%
PSEG	482.3	350.6	105.5	73.6	31.9	30.1%	21.0%
RECO	6.4	4.0	2.8	2.6	0.1	68.6%	65.1%
Weighted Total	10,562.6	5,923.0	2,163.7	1,658.9	450.3	36.5%	28.0%

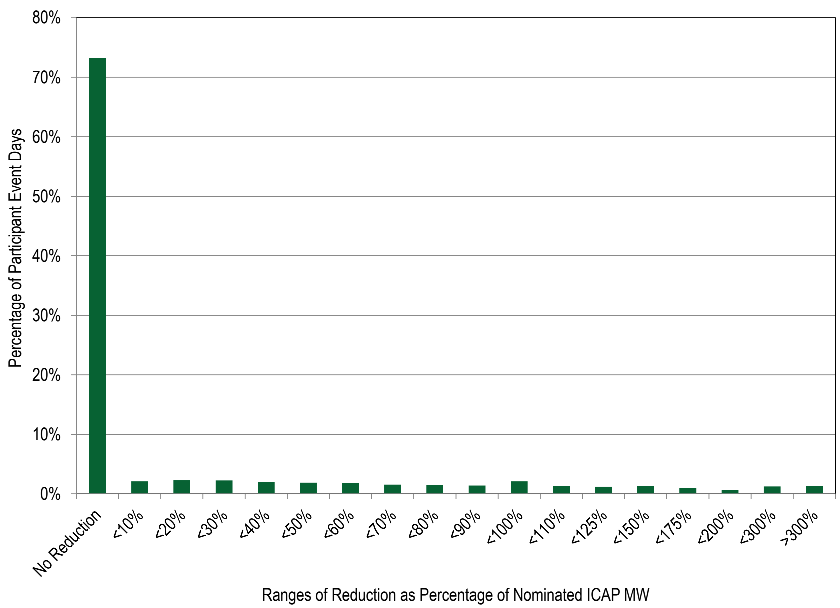
Table 6-25 Distribution of participant event days and nominated MW across ranges of performance levels across the events: January through June, 2014

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%

Performance for specific customers varied significantly. Table 6-25 shows the distribution of participant event days by performance levels for the eight events in the 2013/2014 compliance period. Table 6-25 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, approximately 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.

Figure 6-3 shows the data in Table 6-25.[19]

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



19 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.[20] 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 6-25.[21]

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.

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

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 6-26 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 6-26 Non-reporting locations and nominated ICAP on 2014 event days

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

Emergency Energy Payments

For any PJM declared load management event in the first six 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.[22] [23]

Participants may elect to be paid their emergency offer, regardless of the zonal LMP. Table 6-27 shows the distribution of registrations and associated MW in the emergency full option across ranges of minimum dispatch prices. 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.[24]

Table 6-27 Distribution of registrations and associated MW in the emergency full option across ranges of minimum dispatch prices effective for the 2013/2014 Delivery Year[25]

Ranges of Strike Prices ($/MWh)	Locations	Percent of Total	Nominated MW (ICAP)	Percent of Total	Shutdown Cost per Location
$0-$1	538	3.6%	971.2	9.2%	$0.00
$1-$200	905	6.0%	536.1	5.1%	$8.73
$200-$500	216	1.4%	190.8	1.8%	$141.90
$500-$800	66	0.4%	84.0	0.8%	$3,262.88
$800-$999	67	0.4%	54.8	0.5%	$520.37
$1,000	10,499	69.7%	6,891.9	65.2%	$26.05
$1,800	2,776	18.4%	1,833.7	17.4%	$0.00
Total	15,067	100.0%	10,562.6	100.0%	$37.32

Table 6-28 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

22 139 FERC ¶ 61,057 (2012).
23 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, but the tariff changes have not been approved by FERC as of the date of publication.
24 PJM. "Manual 15: Cost Development Guidelines," Revision 23 (August 1, 2013), p. 51.
25 In this analysis nominated MW does not include capacity only resources, which do not receive energy market credits.

CBL to their actual load during the demand response event.[26] 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.[27] 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 6-28 Energy reduction MWh and average real-time LMP during demand response event days: 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	466.1	473.1		119.7		102.0	135.5	283.3	149.2	487.4	312.6	231.3
5	840.1	487.0	467.2	198.5		404.7	247.3	203.9	221.5	618.6	597.9	847.6
6	1,374.6	1,030.5	947.8	328.6		312.1	466.8	278.5	489.9	678.1	1,371.6	191.2
7	1,759.3	1,726.3	1,173.0	290.8		557.7	647.2	348.3	586.2	833.6	1,837.0	199.4
8	2,003.6	1,832.7	1,003.7	184.3		515.6	577.9	225.8	586.0	540.2	1,717.9	180.1
9	1,974.9	1,784.2		213.5		460.0		123.7		426.1		239.9
10	1,822.0	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	10.8	274.3	452.2	587.8		250.9		234.3
15	1,266.9	244.1		96.4	38.0	1,206.8	607.1	565.7		144.5		186.4
16	1,817.3	291.6		131.4	93.7	466.8	918.0	353.6		207.0		145.7
17	2,361.6	1,018.2		182.0	108.5	1,818.6	938.4	476.7		398.0		210.4
18	2,239.2	437.8		117.4	133.4	1,816.6	963.1	553.3		283.3		261.8
19		438.0		127.8	154.4	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	17,925.5	694.9	3,591.6	152.2	698.2	635.2	5,953.4	410.2	2,032.7	389.6	5,837.0	234.8

26 This table assumes that PJM's CBL calculation is correct.
27 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 6-29 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.[28] 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 six months of 2014 were $42,971,731.

Table 6-29 Emergency revenue by event: 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.

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 six months of 2014. 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 6-30 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.[29] 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.

Table 6-30 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

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

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