Demand-Side Response (DSR)

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.

Overview

- **Demand-Side Response Activity.** In 2012, the total MWh of load reduction under the Economic Load Response Program increased by 124,170 MWh compared to the same period in 2011, from 17,398 MWh in 2011 to 141,568 MWh in 2012, a 714 percent increase. Total payments under the Economic Program increased by $7,106,385, from $2,052,996 in 2011 to $9,159,381 in 2012, a 346 percent increase.

  Settled MWh and credits were greater in 2012 compared to 2011, and there were more settlements submitted compared to the same period in 2010. Participation levels increased following the implementation of Order 745, on April 1, 2012, allowing payment of full LMP for demand resources. On the peak load day for 2012 (July 17, 2012), there were 2,302.4 MW registered in the Economic Load Response Program, compared to 2,041.5 MW for 2011 (July 21,2011).

  Since the implementation of the RPM design on June 1, 2007, the capacity market has been the primary source of revenue to participants in PJM demand side programs. In 2012, Load Management (LM) Program revenue decreased $156.0 million, or 32.0 percent, from $487 million to $331 million. Through 2012 Synchronized Reserve credits for demand side resources decreased by $4.9 million compared to the same period in 2011, from $9.4 million to $4.5 million in 2012.

- **Locational Dispatch of Demand-Side Resources.** PJM dispatches demand-side resources on a subzonal basis when appropriate, but only on a voluntary basis. Beginning with the 14/15 Delivery Year, demand resources will be dispatchable on a subzonal basis. More locational deployment of demand-side resources improves efficiency in a nodal market.

- **Load Management Product.** The load management product is currently defined as an emergency product. The Load Management product is an economic product and should be treated as an economic product in the PJM market design and in PJM dispatch. Demand resources should be called when the resources are required and prior to the declaration of an emergency. The MMU recommends that the DR program be classified as an economic program and not an emergency program.

- **Emergency Event Day Analysis.** Load management event rules allow overcompliance to be reported when there is no actual overcompliance. Settlement MWh are not netted across hours or across registrations within hours for compliance purposes, but are treated as zero even if load actually increases. Considering all and only reported values, the observed load reduction of the two events in 2012 should have been 3,713.4, rather than the 3,922.5 reported. Overall, compliance decreases from the reported 103.0 percent to 97.6 percent. This does not include locations that did not report their load during the emergency event days.

Conclusions

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.

Most end use customers pay a fixed retail rate with no direct relationship to the hourly wholesale market locational marginal price (LMP). End use customers pay load serving entities (LSEs) an annual amount designed to recover, among other things, the total cost of wholesale power for the year.[1] End use customers

1 In PJM, load pays the average zonal LMP, which is the weighted average of the actual nodal locational marginal price. While individual customers have the option to pay nodal LMP, very few customers do so.

paying fixed retail rates do not face even the hourly zonal average LMP. Thus, it would be a substantial step forward for customers to face the hourly zonal average price. But the actual market price of energy and the appropriate price signal for end use customers is the nodal locational marginal price. Within a zone, the actual costs of serving load, as reflected in the nodal hourly LMP, can vary substantially as a result of transmission constraints. A customer on the high price side of a constraint would have a strong incentive to add demand side resources if they faced the nodal price while that customer currently has an incentive to use more energy than is efficient, under either a flat retail rate or a rate linked to average zonal LMP. The nodal price provides a price signal with the actual locational marginal value of energy. In order to achieve the full benefits of nodal pricing on the supply and the demand side, load should ultimately pay nodal prices. However, a transition to nodal pricing could have substantial impacts and therefore must be managed carefully.

Today, most end use customers do not face the market price of energy, that is the locational marginal price of energy, or the market price of capacity, the locational price of capacity. Most end use customers pay a fixed retail rate with no direct relationship to the hourly wholesale market LMP, either on an average zonal or on a nodal basis. This results in a market failure because when customers do not know the market price and do not pay the market price, the behavior of those customers is inconsistent with the market value of electricity. This market failure does not imply that PJM markets have failed. This market failure means that customers do not pay the actual hourly locational cost of energy as a result of the disconnect between wholesale markets and retail pricing. When customers pay a price less than the market price, customers will tend to consume more than if they faced the market price and when customers pay a price greater than the market price, customers will tend to consume less than they would if they faced the market price. This market failure is relevant to the wholesale power market because the actual hourly locational price of power used by customers is determined by the wholesale power market, regardless of the average price actually paid by customers. The transition to a more functional demand side in the wholesale power market requires that the default energy price for all customers be the day-ahead or real-time hourly locational marginal price (LMP) and the locational clearing price of capacity. While the initial default energy price could be the zonal average LMP, the transition to nodal LMP pricing should begin.

PJM's Economic Load Response Program (ELRP) is designed to address this market failure by attempting to replicate the price signal to customers that would exist if customers were exposed to the real-time wholesale zonal price of energy and by providing settlement services to facilitate the participation of third party Curtailment Service Providers (CSPs) in the market.[2] In PJM's Economic Load Response Program, participants have the option to receive credits for load reductions based on a more locationally defined pricing point than the zonal LMP. PJM's PRD program does incorporate some aspects of nodal pricing, although the link between the nodal wholesale price and the retail price is extremely attenuated.

FERC Order 745 was implemented effective April 1, 2012. Order 745 requires RTOs and ISOs to pay full LMP to demand resources rather than LMP less the cost of generation and transmission paid by retail customers, if the demand resources are cost effective as determined by a "Net Benefits Test" (NBT).[3] This approach is based on the view that dispatching demand resources may result in a net increase in cost to non-demand response loads, and requires the NBT as mitigation. The payment of full LMP to demand resources, effective April 1, 2012, increased participation in the Economic Load Response Program. This change explicitly permitted subsidies to be paid to retail customers on fixed rates that incorporate a fixed price of wholesale power, and to customers paying LMP for wholesale power. While the subsidy has a rationale as an incentive for fixed rate retail customers, there is no reason to provide this subsidy to LMP customers who are already receiving the price signal from the wholesale power market.

PJM's Load Management (LM) Program in the RPM market attempts to replicate the price signal to customers that would exist if customers were exposed to the locational market price of capacity. The PJM market design also creates the opportunity for demand resources

2 While the primary purpose of the ELRP is to replicate the hourly zonal price signal to customers on fixed retail rate contracts, customers with zonal or nodal hourly LMP contracts are currently eligible to participate in the DA scheduling and the PJM dispatch options of the Program.

3 The NBT uses a single monthly price for PJM and does not reflect hourly, locational price differences in the Real-Time and Day-Ahead markets.

to participate in ancillary services markets.[4] Within the LM Program, there are new shortage pricing rules that increase maximum bid offers for the 2012/2013 DY to $1,500/MWh.

PJM's demand side programs, by design, provide a work around for end use customers that are not directly exposed to the incremental, locational costs of energy and capacity. The demand side programs should be understood as one relatively small part of a transition to a fully functional demand side for PJM markets. The complete transition to a fully functional demand side will require explicit agreement and coordination among the Commission, state public utility commissions and RTOs/ISOs.

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. The MMU recommends that actual meter load data should be provided in order to measure and verify actual demand resource behavior.

The MMU recommends that demand side measurement and verification should be further modified to more accurately reflect compliance. Increases in load during event hours should not be considered zero response, but should be included for reporting and determining compliance. Load management testing does not adequately reflect actual resource performance during event days. Testing should be initiated by PJM with limited warning to CSPs in order to more accurately reflect the conditions of an emergency event.

PJM Demand Side Programs

All load response programs in PJM can be grouped into the Economic and the Emergency Programs. Table 5-1 provides an overview of the key features of PJM load response programs.[6] Interruptible Load for Reliability (ILR) ended with the 2011/2012 planning year.

Participation in Demand Side Programs

On April 1, 2012, FERC Order 745 was implemented in the PJM Economic Program, mandating payment of full LMP for dispatched demand resources. In 2012, in the Economic Program, participation increased compared to 2011. There were more settlements submitted and active registrations in 2012 compared to 2011, and credits increased.

Table 5-1 Overview of Demand Side Programs[5]

Emergency Load Response Program			Economic Load Response Program
Load Management (LM)			
Capacity Only	Capacity and Energy	Energy Only	Energy Only
Registered ILR only	DR cleared in RPM; Registered ILR	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. ILR program ended with 2012/2013 DY.	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.

4 See *2012 State of the Market Report for PJM*, Volume 2, "Section 9: Ancillary Service Markets."

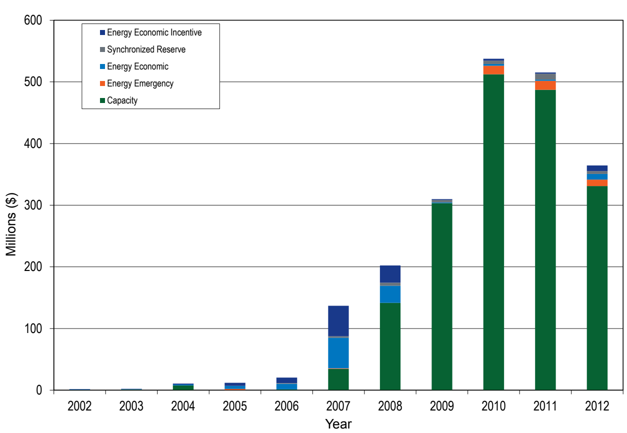
5 Prior to April 1, 2012, payment for the Economic Load Response Program was based on LMP minus the generation and transmission components of the retail rate.

6 For more detail on the historical development of PJM Load Response Programs see the *2011 State of the Market Report for PJM*, Volume II, Section 2, "Energy Market," <http://www.monitoringanalytics.com/reports/PJM_State_of_the_Market/2011.shtml>.

Figure 5-1 shows all revenue from PJM Demand Side Response Programs by market for the period 2002 through 2012. Since the implementation of the RPM design on June 1, 2007, the capacity market has been the primary source of revenue to demand side participants, representing 91.6 percent of all revenue received through demand response programs in 2012. In 2012, total payments under the Economic Program increased by $7,106,385, from $2,052,996 in 2011 to $9,159,381 in 2012, a 346 percent increase, but still only 2.6 percent of all revenue received through PJM demand response programs. In 2012, capacity revenue represents 93.2 percent of all revenue received by demand response providers, emergency energy revenue represented 2.9 percent, revenue from the economic program represented 2.6 percent and revenue from Synchronized Reserve represented 1.3 percent.

Capacity revenue decreased by $156.0 million, or 32.0 percent, from $487 million to $331 million in 2012, primarily due to lower clearing prices in the RPM market. Synchronized Reserve credits for demand side resources decreased by $4.9 million, from $9.4 million to $4.5 million in 2012, due to lower clearing prices in the Synchronized Reserve market. In 2012, there were two Load Management Event Days, occurring on July 17, and July 18, 2012.

Figure 5-1 Demand Response revenue by market: 2002 through 2012



Economic Program

Table 5-2 shows the number of registered sites and MW per peak load day for 2002 through 2012.[7] On July 17, 2012, there were 2,302.4 MW registered in the Economic Program compared to the 2,041.8 MW on July 21, 2011, a 12.8 percent increase in peak load day capability. This was still below peak load capability in 2009, when peak load capability was 2,486.6 MW. Program totals are subject to monthly and seasonal variation, as registrations begin, expire and renew. The implementation of LMP payments for Economic demand resources increased the amount of MWh reductions by 714 percent for 2012.

Table 5-3 shows registered sites and MW for the last day of each month for the period 2008 through 2012.[8] The average registered MW decreased by 151 MW from 2,344 in 2011 to 2,193 registered MW in 2012. The overall credits paid by the Economic Program increased to $9,159,381 in 2012 from $2,052,996 in 2011. Historically, registered MW have declined in June but increased in August, which is likely the result of expirations and renewals. Registration in the Economic Program means that customers have been signed up and can participate if they choose. Thus, registrations represent the maximum level of potential participation. During 2012, the implementation of Order 745 caused all participants to have to register again during April 2012, causing a drop in registration levels during that month.

Table 5-2 Economic Program registration on peak load days: 2002 to 2012

	Registrations	Peak-Day, Registered MW
14-Aug-02	96	335.4
22-Aug-03	240	650.6
3-Aug-04	782	875.6
26-Jul-05	2,548	2,210.2
2-Aug-06	253	1,100.7
8-Aug-07	2,897	2,498.0
9-Jun-08	956	2,294.7
10-Aug-09	1,321	2,486.6
6-Jul-10	899	1,725.7
21-Jul-11	1,237	2,041.8
17-Jul-12	885	2,302.4

7 Table 5-2 and Table 5-3 reflect distinct registration counts. They do not reflect the number of distinct sites registered for the Economic Program, as multiple sites may be aggregated within a single registration.

8 The site count and registered MW associated with May 2007 are for May 9, 2007. Several new sites registered in May of 2007 overstated their MW capability, and it remains overstated in PJM data.

Table 5-3 Economic Program registrations on the last day of the month: 2009 through 2012

	2009		2010		2011		2012	
Month	Registrations	Registered MW	Registrations	Registered MW	Registrations	Registered MW	Registrations	Registered MW
Jan	4,862	3,303	1,841	2,623	1,609	2,432	1,993	2,385
Feb	4,869	3,219	1,842	2,624	1,612	2,435	1,995	2,384
Mar	4,867	3,227	1,845	2,623	1,612	2,519	1,996	2,356
Apr	2,582	3,242	1,849	2,587	1,611	2,534	189	1,313
May	1,250	2,860	1,875	2,819	1,687	3,166	371	1,660
Jun	1,265	2,461	813	1,608	1,143	1,912	803	2,337
Jul	1,265	2,445	1,192	2,159	1,228	2,062	942	2,313
Aug	1,653	2,650	1,616	2,398	1,987	2,194	1,013	2,364
Sep	1,879	2,727	1,609	2,447	1,962	2,183	1,052	2,411
Oct	1,875	2,730	1,606	2,444	1,954	2,179	828	2,259
Nov	1,874	2,730	1,605	2,444	1,988	2,255	824	2,257
Dec	1,853	2,627	1,598	2,439	1,992	2,259	846	2,273
Avg.	2,508	2,852	1,608	2,435	1,699	2,344	1,071	2,193

Table 5-4 shows the zonal distribution of capability in the Economic Program on July 17, 2012. The PPL Control Zone included 227 sites and 355.3 MW, 25 percent of sites and 15 percent of registered MW in the Economic Program. The BGE Control Zone included 59 registrations and 626.6 MW, 7.6 percent of sites and 27 percent of registered MW in the Economic Program.

Table 5-4 Distinct registrations and sites in the Economic Program: July 17, 2012[9]

	Registrations	Sites	MW
AECO	8	8	34.9
AEP	15	15	100.7
AP	68	84	122.3
ATSI	23	23	78.3
BGE	59	83	626.6
ComEd	35	38	69.7
DAY	0	0	0.0
DEOK	1	1	35.0
DLCO	32	37	61.0
Dominion	36	50	236.2
DPL	16	16	85.2
JCPL	11	14	47.7
Met-Ed	80	91	71.2
PECO	164	218	128.2
PENELEC	77	81	55.1
Pepco	11	29	128.3
PPL	227	273	355.3
PSEG	22	38	66.6
RECO	0	0	0.0
Total	885	1,099	2,302.4

Total payments in Table 5-5 exclude incentive payments in the Economic Program for the years 2006 and 2007. The economic incentive program expired in December of 2007.[10] Total MWh per peak-day, registered MW increased from 8.5 MWh in 2011 to 61.5 MWh in 2012, a 622 percent increase.

Table 5-5 Performance of PJM Economic Program participants excluding incentive payments: 2002 through 2012

	Total MWh	Total Payments	$/MWh	Total MWh per Peak-Day, Registered MW
2002	6,727	$801,119	$119	20.1
2003	19,518	$833,530	$43	30.0
2004	58,352	$1,917,202	$33	66.6
2005	157,421	$13,036,482	$83	71.2
2006	258,468	$10,213,828	$40	234.8
2007	714,148	$31,600,046	$44	285.9
2008	452,222	$27,087,495	$60	197.1
2009	57,157	$1,389,136	$24	23.0
2010	74,070	$3,088,049	$42	42.9
2011	17,398	$2,052,996	$118	8.5
2012	141,568	$9,159,381	$65	61.5

Figure 5-2 shows monthly economic program payments, excluding incentive payments, for 2007 through 2012. Economic Program credits declined from June 2008 through 2009. In 2009, payments were down significantly in every month compared to the same time period in 2007 and 2008. Lower energy prices and growth in the capacity market program were the biggest factors. Energy prices declined significantly in 2008 and again in 2009, and have remained low through

9 The second column of Table 5-4 reflects the number of registered end-user sites, including sites that are aggregated to a single registration.

10 In 2006 and 2007, when LMP was greater than, or equal to, $75 per MWh, customers were paid the full LMP and the amount not paid by the LSE, equal to the generation and transmission components of the applicable retail rate (recoverable charges), was charged to all LSEs in the zone of the load reduction. As of December 31, 2007, the incentive payments totaled $17,391,099, an increase of 108 percent from 2006. No incentive credits were paid in November and December 2007 because the total exceeded the specified cap.

2012.[11] In 2012, credits were up substantially compared to 2011, following the implementation of Order 745 on April 1, 2012. Total payments were lower than 2007 and 2008, when prices in PJM were higher. Participation has increased since the implementation of Order 745 despite lower prices in 2012 than 2011, both in MWh and number of registrations.

Figure 5-2 Economic Program payments by month: 2007[12] through 2012

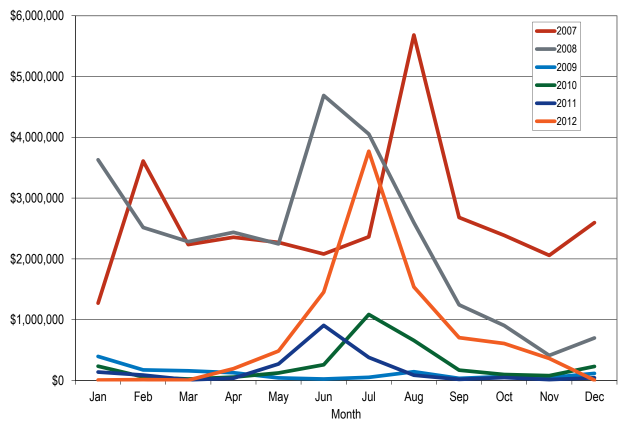


Table 5-6 shows 2012 performance in the Economic Program by control zone and participation type. The total number of curtailed MWh for the Economic Program was 141,567.7 and the total payment amount was $9,159,381.[13] The Dominion Control Zone accounted for $4,092,014 or 45 percent of all Economic Program credits, associated with 62,200.5 or 44 percent of total program MWh reductions. Table 5-6 shows the average participation in the Economic Program by zone and amount of customers in each zone. The Dominion zone does not include the most customers, but has the highest average MW reductions per customer and average credits per customer. Since the implementation of Order 745 on April 1, 2012, credits to demand resources through the Economic Program were $7,106,385 more than in 2011, an increase of 346 percent.

Table 5-7 shows the average participation in the PJM economic program by zone during 2012. Dominion and PSEG showed the largest MWh reduction per customer as well as credits per customer. PPL has the largest number of customers participating in the economic program during 2012, with 149.

Table 5-6 PJM Economic Program participation by zone: 2011 and 2012

	Credits			MWh Reductions		
	2011	2012	Percentage Change	2011	2012	Percentage Change
AECO	$0	$20,555	NA	0	98	NA
AEP	$24,279	$13,272	(45%)	310	155	(50%)
AP	$18,164	$1,065,216	5,764%	372	16,737	4,397%
ATSI	$1,829	$9,034	394%	19	110	467%
BGE	$730,278	$180,995	(75%)	2,295	1,004	(56%)
ComEd	$2,420	$460,123	18,915%	197	8,136	4,021%
DAY	$13,435	$0	(100%)	19	0	(100%)
DEOK	$0	$0	NA	0	0	NA
DLCO	$534	$3,032	468%	13	38	198%
Dominion	$1,107,895	$4,092,014	269%	11,938	62,201	421%
DPL	$59	$37,865	63,936%	0	287	81,760%
JCPL	$1,075	$244,640	22,650%	3	2,062	63,342%
Met-Ed	$17,429	$204,860	1,075%	184	3,618	1,868%
PECO	$78,559	$620,132	689%	1,707	8,686	409%
PENELEC	$3,376	$489,265	14,393%	81	9,461	11,611%
Pepco	$2,637	$118,789	4,404%	38	1,051	2,668%
PPL	$46,041	$442,950	862%	188	5,075	2,598%
PSEG	$4,986	$1,156,640	23,098%	34	22,850	67,365%
RECO	$0	$0	NA	0	0	NA
Total	$2,052,996	$9,159,381	346%	17,398	141,568	714%

11 The reduction was also the result in part of the revisions to the Customer Baseline Load (CBL) calculation effective June 12, 2008, and the newly implemented activity review process effective November 3, 2008.

12 In 2006 and 2007, when LMP was greater than, or equal to, $75 per MWh, customers were paid the full LMP and the amount not paid by the LSE, equal to the generation and transmission components of the retail rate, was charged to all LSEs. Economic Program payments for 2007 shown in Figure 5-2 do not include these incentive payments.

13 If two different retail customers curtail the same hour in the same zone, it is counted as two curtailed hours.

Table 5-7 PJM Economic Program average participation by zone: 2012

Zone	Customers	Credits per Customer	MWh Reduction per Customer	MW Registered per Customer
AECO/JCPL	5	$53,039	432.0	16.5
AEP	4	$3,318	38.7	25.2
AP	33	$32,279	507.2	3.7
ATSI	5	$1,807	22.0	15.7
BGE	40	$4,525	25.1	15.7
ComEd	15	$30,675	542.4	4.6
DAY	0	$0	0.0	0.0
DEOK	0	$0	0.0	0.0
DLCO	21	$144	1.8	2.9
Dominion	19	$215,369	3,273.7	12.4
DPL	4	$9,466	71.6	21.3
Met-Ed	21	$9,755	172.3	3.4
PECO	118	$5,255	73.6	1.1
PENELEC	19	$25,751	497.9	2.9
Pepco	5	$23,758	210.1	25.7
PPL	149	$2,973	34.1	2.4
PSEG	7	$165,234	3,264.4	9.5
RECO	0	$0	0.0	0.0
Average	24	$19,698	304.4	5.0

Table 5-8 shows total settlements submitted by month for 2007 through 2012. For January through July of 2008, total monthly settlements were higher than the monthly totals for 2007, despite the expiration of the incentive program. In October of 2008, settlement submissions dropped significantly from the prior month and from the same month in 2007, a trend that continued through early 2009. This drop in participation corresponds with the implementation of the PJM daily review process, as well as the lower overall price levels in PJM. April of 2009 showed the lowest level of settlements submitted in the three year period, after which, settlements began to show steady growth. Settlements dropped off significantly after the summer period in 2009, and January through May of 2010 were generally lower than historical levels while summer of 2010 showed a moderate increase, consistent with 2009. February of 2012 showed the lowest level of settlements in the five year period, and 2011 and the first three months of 2012 overall showed a substantial decrease in the number of settlements submitted compared to previous years. Since the implementation of Order 745 in April 2012, settlements have increased, and settlements in July 2012 were consistent with summer settlements prior to 2011, though settlements decreased after the summer period ended.

Table 5-8 Settlement days submitted by month in the Economic Program: 2007 through 2012

Month	2007	2008	2009	2010	2011	2012
Jan	937	2,916	1,264	1,415	562	62
Feb	1,170	2,811	654	546	148	30
Mar	1,255	2,818	574	411	82	46
Apr	1,540	3,406	337	338	102	93
May	1,649	3,336	918	673	298	144
Jun	1,856	3,184	2,727	1,221	743	1,477
Jul	2,534	3,339	2,879	3,010	1,412	2,899
Aug	3,962	3,848	3,760	2,158	793	1,681
Sep	3,388	3,264	2,570	660	294	555
Oct	3,508	1,977	2,361	699	66	481
Nov	2,842	1,105	2,321	672	51	280
Dec	2,675	986	1,240	894	40	124
Total	27,316	32,990	21,605	12,697	4,591	7,872

Table 5-9 shows the number of distinct Curtailment Service Providers (CSPs) and distinct customers actively submitting settlements by month for the period 2008 through 2012.[14] The number of active customers per month decreased in early 2009. Since then, monthly

Table 5-9 Distinct customers and CSPs submitting settlements in the Economic Program by month: 2008 through 2012

	2008		2009		2010		2011		2012	
Month	Active CSPs	Active Customers	Active CSPs	Active Customers	Active CSPs	Active Customers	Active CSPs	Active Customers	Active CSPs	Active Customers
Jan	13	261	17	257	11	153	5	40	5	15
Feb	13	243	12	129	9	92	6	29	3	9
Mar	11	216	11	149	7	124	3	15	3	12
Apr	12	208	9	76	5	77	3	15	3	8
May	12	233	9	201	6	140	6	144	5	20
Jun	17	317	20	231	11	152	10	304	16	338
Jul	16	295	21	183	18	267	15	214	21	383
Aug	17	306	15	400	14	317	14	186	17	361
Sep	17	312	11	181	11	96	7	47	11	127
Oct	13	226	11	93	8	37	3	9	9	50
Nov	14	208	9	143	7	38	3	13	5	63
Dec	13	193	10	160	7	44	5	12	3	10
Total Distinct Active	24	522	25	747	24	438	20	610	24	520

14 November and December credits are likely understated due to the lag associated with the submittal and processing of settlements. Settlements may be submitted up to 60 days following an event day. EDC/LSEs have up to 10 business days to approve which could account for a maximum lag of approximately 74 calendar days.

customer counts vary substantially. There was less activity in the first three months of 2012 than in any year since 2009. However, following the April 1 implementation of FERC Order 745 rules on demand resource compensation, activity returned to historical summer levels during the 2012 summer months.

Table 5-10 shows a frequency distribution of MWh reductions and credits at each hour for 2012. The period from hour ending 1500 EPT to 1800 EPT accounts for 51 percent of MWh reductions and 60 percent of credits.

Table 5-11 shows the frequency distribution of Economic Program MWh reductions and credits by real-time zonal, load-weighted, average LMP in various price ranges. MWh reductions in the $0 to $25 bracket increased 8,872 percent from 18 MWh in 2011 to 1,615 MWh in 2012. MWh reductions in the $25 to $50 LMP bracket increased 3,725 percent from 2,028 MWh to 77,574 MWh in 2012.

Total Economic Program reductions increased by 124,786 MWh, from 16,782 MWh in 2011 to 141,568 MWh in 2012. Reductions occurred at all price levels. Approximately 76.9 percent of MWh reductions and 52.3 percent of program credits are associated with hours when the applicable zonal LMP was between $25 and $75.

Table 5-10 Hourly frequency distribution of Economic Program MWh reductions and credits: 2012

	MWh Reductions				Program Credits			
Hour Ending (EPT)	MWh Reductions	Percent	Cumulative MWh	Cumulative Percent	Credits	Percent	Cumulative Credits	Cumulative Percent
1	177	0.13%	177	0.13%	$4,124	0.05%	$4,124	0.05%
2	176	0.12%	353	0.25%	$3,514	0.04%	$7,637	0.08%
3	179	0.13%	532	0.38%	$1,733	0.02%	$9,370	0.10%
4	220	0.16%	753	0.53%	$1,632	0.02%	$11,003	0.12%
5	227	0.16%	980	0.69%	$2,276	0.02%	$13,279	0.14%
6	291	0.21%	1,271	0.90%	$4,961	0.05%	$18,240	0.20%
7	2,371	1.67%	3,642	2.57%	$126,089	1.38%	$144,329	1.58%
8	3,793	2.68%	7,435	5.25%	$173,655	1.90%	$317,984	3.47%
9	4,501	3.18%	11,936	8.43%	$170,314	1.86%	$488,298	5.33%
10	4,373	3.09%	16,308	11.52%	$171,336	1.87%	$659,634	7.20%
11	4,291	3.03%	20,599	14.55%	$195,128	2.13%	$854,762	9.33%
12	5,112	3.61%	25,711	18.16%	$265,291	2.90%	$1,120,053	12.23%
13	8,254	5.83%	33,965	23.99%	$570,616	6.23%	$1,690,669	18.46%
14	12,652	8.94%	46,617	32.93%	$817,418	8.92%	$2,508,086	27.38%
15	17,002	12.01%	63,619	44.94%	$1,210,368	13.21%	$3,718,454	40.60%
16	18,234	12.88%	81,854	57.82%	$1,460,737	15.95%	$5,179,191	56.54%
17	18,782	13.27%	100,636	71.09%	$1,493,164	16.30%	$6,672,355	72.85%
18	18,306	12.93%	118,942	84.02%	$1,320,621	14.42%	$7,992,976	87.27%
19	8,984	6.35%	127,925	90.36%	$541,467	5.91%	$8,534,443	93.18%
20	6,333	4.47%	134,258	94.84%	$325,732	3.56%	$8,860,175	96.73%
21	3,607	2.55%	137,865	97.38%	$173,580	1.90%	$9,033,756	98.63%
22	2,044	1.44%	139,908	98.83%	$80,237	0.88%	$9,113,992	99.50%
23	942	0.67%	140,851	99.49%	$27,129	0.30%	$9,141,121	99.80%
24	718	0.51%	141,568	100.00%	$18,308	0.20%	$9,159,429	100.00%

Table 5-11 Frequency distribution of Economic Program zonal, load-weighted, average LMP (By hours): 2012

	MWh Reductions				Program Credits			
LMP	MWh Reductions	Percent	Cumulative MWh	Cumulative Percent	Credits	Percent	Cumulative Credits	Cumulative Percent
$0 to $25	1,615	1.14%	1,615	1.14%	$8,663	0.09%	$8,663	0.09%
$25 to $50	77,574	54.80%	79,189	55.94%	$2,944,492	32.15%	$2,953,156	32.24%
$50 to $75	31,253	22.08%	110,442	78.01%	$1,898,881	20.73%	$4,852,036	52.97%
$75 to $100	11,442	8.08%	121,885	86.10%	$1,010,065	11.03%	$5,862,101	64.00%
$100 to $125	6,707	4.74%	128,592	90.83%	$788,321	8.61%	$6,650,422	72.61%
$125 to $150	4,179	2.95%	132,770	93.79%	$568,642	6.21%	$7,219,065	78.82%
$150 to $200	3,002	2.12%	135,773	95.91%	$505,094	5.51%	$7,724,159	84.33%
$200 to $250	3,028	2.14%	138,801	98.05%	$628,775	6.86%	$8,352,933	91.19%
$250 to $300	1,829	1.29%	140,630	99.34%	$471,562	5.15%	$8,824,495	96.34%
> $300	939	0.66%	141,568	100.00%	$334,934	3.66%	$9,159,429	100.00%

Following the implementation of Order 745 on April 1, 2012, demand resources were paid full LMP for any load reductions during hours they were dispatched. If the demand resources are cost effective as determined by a Net Benefits Test (NBT), they are eligible to receive the full LMP. The NBT is used to define a threshold point where net benefits of DR are considered to exceed the cost to load. The Net Benefits Test defined an average threshold of $24.80 from April through December 2012. Demand resources are not paid for any load reductions during hours where the LMP is below the Net Benefits Test threshold.

Load Management Program

Table 5-12 shows zonal monthly capacity credits paid during 2012 to ILR and DR resources.[15] Capacity revenue decreased by $156.0 million, or 32.0 percent, compared to the same period in 2011, from 487.1 million to 331.1 million in 2012. Credits from January to May are associated with participation in the 2011/2012 RPM delivery year, and credits from June are associated with participation in the 2012/2013 RPM delivery year. The decrease in capacity credits in 2012 is the result of a decrease in RPM clearing prices in the rest of RTO region. While prices increased for MAAC zones to $133.37, the rest of the PJM RTO cleared at $16.46 in the 2012/2013 delivery year, an 85 percent decrease from the RTO wide $110.04 clearing price in the 2011/2012 delivery year The decrease is also partially due to the end of the ILR program, as well as a decrease in available capacity due to the FERC order ending the ability to count reductions above peak load contribution.[16]

The load management product is currently defined as an emergency product. The Load Management product is an economic product and should be treated as an economic product in the PJM market design and in PJM dispatch. Demand resources should be called when the resources are required and prior to the declaration of an emergency. The MMU recommends that the DR program be classified as an economic program and not an emergency program.

Table 5-12 Zonal monthly capacity credits: 2012

Zone	January	February	March	April	May	June	July	August	September	October	November	December	Total
AECO	$343,831	$321,649	$343,831	$332,740	$343,831	$397,836	$411,097	$411,097	$397,836	$411,097	$397,836	$411,097	$4,523,777
AEP	$5,390,887	$5,043,088	$5,390,887	$5,216,988	$5,390,887	$411,388	$425,101	$425,101	$411,388	$425,101	$411,388	$425,101	$29,367,303
AP	$3,410,799	$3,190,748	$3,410,799	$3,300,774	$3,410,799	$179,495	$185,478	$185,478	$179,495	$185,478	$179,495	$185,478	$18,004,316
ATSI	$4,821	$4,510	$4,821	$4,665	$4,821	$19,218	$19,859	$19,859	$19,218	$19,859	$19,218	$19,859	$160,724
BGE	$3,630,571	$3,396,340	$3,630,571	$3,513,455	$3,630,571	$5,254,943	$5,430,108	$5,430,108	$5,254,943	$5,430,108	$5,254,943	$5,430,108	$55,286,766
ComEd	$6,180,266	$5,781,539	$6,180,266	$5,980,903	$6,180,266	$392,831	$405,926	$405,926	$392,831	$405,926	$392,831	$405,926	$33,105,439
DAY	$824,485	$771,293	$824,485	$797,889	$824,485	$61,616	$63,670	$63,670	$61,616	$63,670	$61,616	$63,670	$4,482,166
DEOK	$0	$0	$0	$0	$0	$7,921	$8,185	$8,185	$7,921	$8,185	$7,921	$8,185	$56,500
DLCO	$2,418	$2,262	$2,418	$2,340	$2,418	$48,114	$49,718	$49,718	$48,114	$49,718	$48,114	$49,718	$355,071
Dominion	$3,977,804	$3,721,172	$3,977,804	$3,849,488	$3,977,804	$297,028	$306,929	$306,929	$297,028	$306,929	$297,028	$306,929	$21,622,872
DPL	$817,336	$764,605	$817,336	$790,970	$817,336	$1,497,145	$1,547,049	$1,547,049	$1,497,145	$1,547,049	$1,497,145	$1,547,049	$14,687,215
JCPL	$883,220	$826,238	$883,220	$854,729	$883,220	$1,447,382	$1,495,628	$1,495,628	$1,447,382	$1,495,628	$1,447,382	$1,495,628	$14,655,283
Met-Ed	$909,516	$850,837	$909,516	$880,176	$909,516	$1,010,595	$1,044,281	$1,044,281	$1,010,595	$1,044,281	$1,010,595	$1,044,281	$11,668,469
PECO	$2,375,286	$2,222,042	$2,375,286	$2,298,664	$2,375,286	$2,574,260	$2,660,069	$2,660,069	$2,574,260	$2,660,069	$2,574,260	$2,660,069	$30,009,621
PENELEC	$1,380,240	$1,291,192	$1,380,240	$1,335,716	$1,380,240	$1,107,926	$1,144,857	$1,144,857	$1,107,926	$1,144,857	$1,107,926	$1,144,857	$14,670,832
Pepco	$1,174,938	$1,099,136	$1,174,938	$1,137,037	$1,174,938	$1,845,088	$1,906,591	$1,906,591	$1,845,088	$1,906,591	$1,845,088	$1,906,591	$18,922,612
PPL	$2,739,610	$2,562,861	$2,739,610	$2,651,235	$2,739,610	$3,142,521	$3,247,272	$3,247,272	$3,142,521	$3,247,272	$3,142,521	$3,247,272	$35,849,577
PSEG	$1,468,327	$1,373,596	$1,468,327	$1,420,962	$1,468,327	$2,278,452	$2,354,400	$2,354,400	$2,278,452	$2,354,400	$2,278,452	$2,354,400	$23,452,497
RECO	$22,526	$21,072	$22,526	$21,799	$22,526	$14,415	$14,896	$14,896	$14,415	$14,896	$14,415	$14,896	$213,275
Total	$35,536,881	$33,244,179	$35,536,881	$34,390,530	$35,536,881	$21,988,172	$22,721,111	$22,721,111	$21,988,172	$22,721,111	$21,988,172	$22,721,111	$331,094,314

15 ILR ended after the 2011/2012 DY.

16 137 FERC ¶ 61,108

Table 5-13 shows registered MW in the Load Management Program by program type for delivery years 2007/2008 through 2012/2013. Due to the end of the ILR program and the FERC order on measurement and verification, available demand response capacity decreased during the 2012/2013 delivery year.

The MMU has reported that a significant percentage of demand resources that clear in base residual auctions buy out of those positions in incremental auctions.[17] This has raised the issue of whether demand resources and generation resources commit to providing a physical resource when they offer capacity in a base residual auction. The tariff makes it clear that the specific resources must be identified when offering in capacity auctions.

Table 5-13 Registered MW in the Load Management Program by program type: Delivery years 2007/2008 through 2012/2013

Delivery Year	Total DR MW	Total ILR MW	Total LM MW
2007/2008	560.7	1,584.6	2,145.3
2008/2009	1,017.7	3,480.5	4,498.2
2009/2010	1,020.5	6,273.8	7,294.3
2010/2011	1,070.0	7,982.4	9,052.4
2011/2012	2,792.1	8,730.5	11,522.7
2012/2013	7,449.3	0.0	7,449.3

Load Management Event Reported Compliance

In calendar year 2012, PJM declared two Load Management events, on July 17 and 18, 2012. These events affected resources committed for the 2012/2013 Delivery Year. Since each of these events occurred within the summer compliance period, each was considered in compliance assessment. Table 5-14 lists Load Management Events declared by PJM in 2012 and the affected zones.

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. 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. It is not clear that short lead or long lead time resources are dispatched differently, though it is the case that not all resources will be dispatched for every event in some zones. As a result, the nominal ICAP stated in event compliance tables in this section will not equal total nominal ICAP for the zone, as not all resources were called in each zone during the events. Approximately 97.6 percent of registrations, accounting for 87.1 percent of registered MW, are designated as long lead time resources.

There were no events in 2012 for which PJM requested voluntary subzonal dispatch of emergency demand side resources. While PJM may voluntarily declare Load Management Events for part of a zone, the only locational requirement for the aggregation of multiple end use customers to a single registration is that they reside in the same control zone. Similarly, compliance for testing and for zonal Emergency Events, is aggregated for each CSP to a zonal level.

Subzonal dispatch events will again be required by PJM beginning with the 2014/2015 delivery year, but are currently voluntary only. 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.

Table 5-14 PJM declared Load Management Events: 2012

Event Date	Event Times	Delivery Year	Lead Time	Geographical area
17-Jul-12	HE 1700 - 1900	2012/2013	Long Lead	AEP, Dominion
18-Jul-12	HE 1600 - 1800	2012/2013	Long Lead	BGE, DPL, JCPL, PECO, PENELEC, Pepco
18-Jul-12	HE 1600 - 1800	2012/2013	Short Lead	AECO, BGE, DPL, JCPL, Met-Ed, PECO, PENELEC, Pepco, PPL, PSEG

17 For more detail on the replacement capacity issue see: the *2012 State of the Market Report for PJM*, Volume II, Section 4, "Capacity Market," "*Analysis of Replacement Capacity for RPM Commitments: June 1, 2007 to June 1, 2012*," <http://www.monitoringanalytics.com/reports/Reports/2012/IMM_Report_Replacement_Capacity_Activity_20121211.pdf> (December 11, 2012), and "Definition of DR Commitment in Auctions," IMM presentation to the DR Plan Enhancements Meeting (February 14, 2013) <http://www.monitoringanalytics.com/reports/Presentations/2013/IMM_DRPE_Definition_of_DR_Commitment_in_Auctions_20130214.pdf >.

Table 5-15 Load Management event performance: July 17, 2012

Zone	Nominal ICAP (MW)	Committed MW	Load Reduction Observed (MWh)	Over/Under Compliance	Percent Compliance	Percent of Nominal ICAP
AEP	1,201.5	1,045.6	1,101.2	55.7	105.3%	91.6%
Dominion	663.8	624.4	635.4	11.0	101.8%	95.7%
Total	1,865.3	1,669.9	1,736.6	66.6	104.0%	93.1%

Table 5-15 shows performance for the July 17, 2012 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 MW commitments, 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 resource. In addition, RPM commitments consider any RPM transactions, such as capacity replacement sales or purchases for Demand Resources, while the nominal ICAP does not, although resources fully buying out of their commitments are not included in this analysis. The third column shows the observed load reduction in MWh, or the reported load drop during the hours of an event.

Overall, the reported performance was 104.0 percent, or 1,736.6 MW out of 1,669.9 MW committed. AEP showed the highest MW reduction with 1,101.2 MW in observed load reduction or 63.4 percent of the total load reduction during the event, as well as the highest aggregate performance percentage of 105.3 percent. This reported performance value treated locations showing negative performance as zero performance.

Table 5-16 shows performance for the July 18, 2012 event. Overall, the performance was 103.3 percent, or 4,352.5 MW out of 4,214.6 MW committed. BGE showed the highest MW reduction with 817.6 MW of total load reduction observed. Met-Ed showed the highest aggregated performance of 141.1 percent. The PSEG Zone had poor performance with 10.6 percent compliance, though most PSEG customers are long lead time resources and most MW were not called in the PSEG Zone. This reported performance value treated locations showing negative performance as zero performance.

Table 5-16 Load Management event performance: July 18, 2012

Zone	Nominal ICAP (MW)	Committed MW	Load Reduction Observed (MWh)	Over/Under Compliance	Percent Compliance	Percent of Nominal ICAP
AECO	37.4	32.3	36.1	3.8	111.9%	96.6%
BGE	861.1	794.2	817.6	23.4	103.0%	95.0%
BGE Short Lead	92.2	89.7	90.6	1.0	101.1%	98.3%
BGE Long Lead	768.9	704.5	727.0	22.5	103.2%	94.6%
DPL	197.2	173.5	161.2	(12.3)	92.9%	81.8%
DPL Short Lead	52.6	46.7	48.4	1.7	103.7%	92.0%
DPL Long Lead	144.6	126.8	112.8	(14.0)	89.0%	78.0%
JCPL	190.9	165.4	192.9	27.5	116.6%	101.1%
JCPL Short Lead	24.7	24.4	31.4	7.0	128.6%	127.1%
JCPL Long Lead	166.2	141.0	161.5	20.5	114.5%	97.2%
Met-Ed	11.6	11.0	15.5	4.5	141.1%	133.5%
PECO	442.5	401.4	408.8	7.4	101.9%	92.4%
PECO Short Lead	0.7	0.7	0.4	(0.2)	63.9%	59.5%
PECO Long Lead	441.8	400.7	408.4	7.7	101.9%	92.4%
PENELEC	297.7	236.4	238.0	1.6	100.7%	79.9%
PENELEC Short Lead	0.3	0.2	0.1	(0.1)	26.5%	16.0%
PENELEC Long Lead	297.4	236.2	237.9	1.8	100.7%	80.0%
Pepco	381.0	308.8	330.9	22.1	107.1%	86.8%
Pepco Short Lead	136.8	107.2	136.6	29.3	127.4%	99.9%
Pepco Long Lead	244.3	201.6	194.3	(7.3)	96.4%	79.5%
PPL	1.9	1.8	1.0	(0.8)	56.2%	55.5%
PSEG	20.0	10.1	1.1	(9.0)	10.6%	5.4%
Total	4,811.7	4,214.6	4,352.5	138.0	103.3%	90.5%

Table 5-17 shows load management event performance for the two event days. RTO wide percent compliance was 103.1 percent in 2012 for resources called during emergency events. This reported performance value treated locations showing negative performance as zero performance.

Table 5-17 Load Management event performance: 2012 Aggregate

Zone	Nominal ICAP (MW)	Committed MW	Load Reduction Observed (MWh)	Over/Under Compliance	Percent Compliance	Percent of Nominal ICAP
AECO	37.4	32.3	36.1	3.8	111.9%	96.6%
AEP	1,201.5	1,045.6	1,101.2	55.7	105.3%	91.6%
BGE	861.1	794.2	817.6	23.4	103.0%	95.0%
Dominion	663.8	624.4	635.4	11.0	101.8%	95.7%
DPL	197.2	173.5	144.0	(29.5)	83.0%	73.0%
JCPL	190.9	165.4	192.9	27.5	116.6%	101.1%
Met-Ed	11.6	11.0	15.5	4.5	141.1%	133.5%
PECO	442.5	401.4	408.8	7.4	101.9%	92.4%
PENELEC	297.7	236.4	238.0	1.6	100.7%	79.9%
Pepco	381.0	308.8	330.9	22.1	107.1%	86.8%
PPL	1.9	1.8	1.0	(0.8)	56.2%	55.5%
PSEG	20.0	10.1	1.1	(9.0)	10.6%	5.4%
Total	4,306.7	3,804.8	3,922.5	117.7	103.1%	91.1%

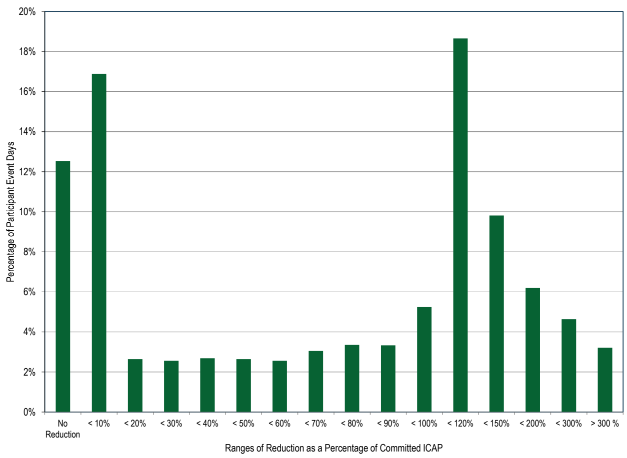
Performance for specific customers varied significantly. Table 5-18 shows the distribution of participant event days across various levels of performance for July 17 and July 18, 2012, events in the 2012/2013 compliance period. For these events, approximately 29 percent of participants showed little or no reduction. Approximately 40 percent of participants did not meet half of their committed MW. The majority of participants, approximately 57 percent, showed less than 100 percent reduction compared to their commitment. Figure 5-3 shows the data in Table 5-18.[18] The distribution includes high frequencies of both under performing and over performing registrations. This large disparity in performance indicates over compliance of some resources is making up for the non-response of resources to emergency events. This indicates that negative load reductions (load increase) are not treated appropriately for event compliance, and current rules should be modified to more accurately reflect event compliance.

Table 5-18 Distribution of participant event days across ranges of performance levels across the event in the 2012/2013 Delivery Year compliance period

Ranges of performance as a percentage of committed MW	Number of participant event days	Proportion of participant event days	Cumulative Proportion
0% or load increase	617	13%	13%
0% -10%	831	17%	29%
10% - 20%	130	3%	32%
20% - 30%	126	3%	35%
30% - 40%	132	3%	37%
40% - 50%	130	3%	40%
50% - 60%	126	3%	43%
60% - 70%	150	3%	46%
70% - 80%	165	3%	49%
80% - 90%	164	3%	52%
90% - 100%	258	5%	57%
100% - 120%	918	19%	76%
120% - 150%	483	10%	86%
150% - 200%	305	6%	92%
200% - 300%	228	5%	97%
> 300%	158	3%	100%
Total	4,921	100%	

18 Participant event days, shown in Figure 5-3, and Table 5-18, are defined as distinct event performances by registration. If a registration was deployed for multiple events, each event constitutes a single participant even day. In addition, the load reduction values associated do not reflect actual MWh curtailments, but average curtailments in each event, summed for all events in the period.

Figure 5-3 Distribution of participant event days across ranges of performance levels across the event in the 2012/2013 Delivery Year compliance period



GLD customers, in years prior to the 2012/2013 delivery year, reported reductions which were greater than their PLCs. This was not consistent with economic logic or the design of the program. This practice was ended by a FERC order on the measurement and verification of demand response, effective with the 2012/2013 delivery year.[19] The results for the events occurring during the summer, which fell in the 2012/2013 delivery year, show that the FERC order was effective in ending this practice. Table 5-19 shows the distribution of GLD participant event days and observed load reductions across ranges of load reduction as a percentage of PLC for all events in the 2012/2013 Delivery Year. The results in Table 5-19 show the distribution of GLD participant event hours and observed load reductions as a percentage of the location's PLC. Load reductions greater than PLC no longer count for event compliance, and are counted as a reduction up to the PLC value. The issue of GLD customers reporting reductions greater than their PLCs has been eliminated with the imposition of the PLC cap on load response MW.

Load Management Analysis

Currently, load management event rules allow overcompliance to be reported when there is no actual overcompliance. Settlement locations with a negative load reduction value (load increase) are netted within registrations, within hours. For example, if a registration had two locations, one with a 50 MWh load increase, and another with a 75 MWh load reduction, compliance for that registration would show a 25 MWh load reduction for that event hour. Settlement MWh are not netted across hours or across registrations for compliance purposes, but are set to zero if they are negative. 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 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 a negative reduction are treated as zero for compliance purposes. Overall, 23 percent of event hours reported showed negative reductions, or an increase in the load at the site.

Settlements that are not submitted to PJM are treated as zero compliance for the event. Overall, 6.5 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 as treated as zero for the purposes of imposing penalties and reporting.

Table 5-20 shows load management event performance, explicitly netting out negative load reduction values that were reported. These reported negative values were

Table 5-19 Distribution of GLD participant event hours and observed load reductions across ranges of load reduction as a percentage of Peak Load Contribution (PLC) for the events in the 2012/2013 Delivery Year

Ranges of load reduction as a percentage of PLC	Number of GLD participant event hours	Proportion of total GLD participant event hours	Cumulative Proportion	Observed reductions (MWh)	Proportion of total GLD observed reductions	Cumulative Proportion
0% - 25%	170	9%	9%	0.0	0%	0%
25% - 50%	977	54%	64%	64.6	9%	9%
50% - 75%	269	15%	79%	209.1	30%	40%
75% - 100%	174	10%	88%	44.2	6%	46%
100%	210	12%	100%	367.6	54%	100%
Total	1,800	100%		685.5	100%	

19 137 FERC ¶ 61,108

set to zero in PJM's reported compliance values, consistent with the rules. This analysis conservatively assumes that non-reporting locations were zero. Compliance decreases from 103.1 percent to 97.6 percent. Considering all and only reported values, the observed load reduction of the two events in 2012 was 3,713.4 MW, rather than the 3,922.5 MW reported. It is likely that these results still overstate compliance, as 444 locations did not report for 2012 event compliance. The PSEG Zone shows a negative performance of 32.7 percent as some resources in this zone increased their load during emergency event hours.

Table 5-21 shows the difference between actual performance and reported performance, including the negative values that were measured during emergency events. This adjustment shows less than 100 percent compliance for multiple zones. Actual compliance for the Dominion zone was 96.7 percent rather than 101.8 percent. Actual compliance for the JCPL zone was 69.6 percent rather than 116.6 percent. Actual compliance for the PECO Zone was 97.5 percent rather than 101.9 percent. Actual compliance for the PENELEC Zone was 95.8 percent rather than 100.7 percent.

Table 5-22 shows the number of locations attached to registrations that did not report during 2012 event days. In total, 6.5 percent of locations did not report during event days in 2012 and were assigned zero load response MW in the actual PJM accounting 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 5-20 Load Management Event Performance with negatives: 2012

Zone	Nominal ICAP (MW)	Committed MW	Load Reduction Observed (MWh)	Over/Under Compliance	Percent Compliance	Percent of Nominal ICAP
AECO	37.4	32.3	36.1	3.8	111.9%	96.6%
AEP	1,201.5	1,045.6	1,065.3	19.7	101.9%	88.7%
BGE	861.1	794.2	801.2	7.0	100.9%	93.0%
Dominion	663.8	624.4	603.9	(20.4)	96.7%	91.0%
DPL	197.2	173.5	144.0	(29.5)	83.0%	73.0%
JCPL	190.9	165.4	115.1	(50.3)	69.6%	60.3%
Met-Ed	11.6	11.0	15.5	4.5	141.1%	133.5%
PECO	442.5	401.4	391.3	(10.1)	97.5%	88.4%
PENELEC	297.7	236.4	226.5	(9.9)	95.8%	76.1%
Pepco	381.0	308.8	316.8	8.0	102.6%	83.2%
PPL	1.9	1.8	1.0	(0.8)	56.2%	55.5%
PSEG	20.0	10.1	(3.3)	(13.4)	(32.7%)	(16.5%)
Total	4,306.7	3,804.8	3,713.4	(91.4)	97.6%	86.2%

Table 5-21 Load Management Event Performance Comparison: Reported Reduction vs. Actual Reduction: 2012

Zone	Committed MW	Load Reduction Reported (MWh)	Actual Load Reduction (MWh)	Difference	Percent Compliance Reported	Percent Compliance Actual
AECO	32.3	36.1	36.1	0.0	111.9%	111.9%
AEP	1,045.6	1,101.2	1,065.3	36.0	105.3%	101.9%
BGE	794.2	817.6	801.2	16.5	103.0%	100.9%
Dominion	624.4	635.4	603.9	31.4	101.8%	96.7%
DPL	173.5	144.0	144.0	0.0	83.0%	83.0%
JCPL	165.4	192.9	115.1	77.8	116.6%	69.6%
Met-Ed	11.0	15.5	15.5	0.0	141.1%	141.1%
PECO	401.4	408.8	391.3	17.5	101.9%	97.5%
PENELEC	236.4	238.0	226.5	11.5	100.7%	95.8%
Pepco	308.8	330.9	316.8	14.0	107.1%	102.6%
PPL	1.8	1.0	1.0	0.0	56.2%	56.2%
PSEG	10.1	1.1	(3.3)	4.4	10.6%	(32.7%)
Total	3,804.8	3,922.5	3,713.4	209.1	103.1%	97.6%

Table 5-22 Non Reporting Locations on 2012 Event Days

Zone	Locations Not Reporting	Total Locations	Percent Non Reporting
AECO	2	15	13.3%
AEP	95	1,092	8.7%
BGE	60	810	7.4%
Dominion	46	760	6.1%
DPL	23	447	5.1%
JCPL	42	416	10.1%
Met-Ed	6	7	85.7%
PECO	104	1,308	8.0%
PENELEC	34	1,308	2.6%
Pepco	29	586	4.9%
PPL	0	23	0.0%
PSEG	3	28	10.7%
Total	444	6,800	6.5%

Table 5-23 shows the nominated capacity of nonreporting locations. Approximately 2.7 percent of nominated capacity, by MW, during event days did not report. It is likely that these locations had load above or equal to their commitment and took no action to reduce load during the PJM declared emergency.

Along with the removal of load increases from compliance, non-reporting can cause an overstatement of load reductions of the reported load at a node. 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. Negative event performance of a portfolio should be netted against the positive performance of other resources. Reported compliance should include those locations that increased load in addition to those that reduced load during an emergency event.

Table 5-23 Non Reporting Locations by MW on 2012 Event Days

Zone	Nominated ICAP Not Reporting	Nominated ICAP	Percent Non Reporting
AECO	1.1	37.4	3.1%
AEP	27.4	1,201.5	2.3%
BGE	16.3	861.1	1.9%
Dominion	10.3	663.8	1.6%
DPL	6.3	197.2	3.2%
JCPL	10.2	190.9	5.3%
Met-Ed	1.0	11.6	8.3%
PECO	25.0	442.5	5.7%
PENELEC	6.0	297.7	2.0%
Pepco	12.0	381.0	3.1%
PPL	0.0	1.9	0.0%
PSEG	0.6	20.0	2.8%
Total	116.2	4,306.7	2.7%

Emergency Energy Payments

For any PJM declared Load Management event in 2012, participants registered under the Full option of the Emergency Load Response Program that were deployed and that demonstrated a load reduction were eligible to receive emergency energy payments, which are equal to the higher of hourly zonal LMP or an energy offer made by the participant, including a dollar per MWh minimum dispatch price and an associated shutdown cost. The new shortage pricing rules increases the maximum offer for the 2012/2013 DY to $1,500/MWh. The maximum offer increases to $1,800/MWh for the 2013/2014 DY, $2,100/MWh for the 2014/2015 and $2,700/MWh for the 2015/2016 DY. The maximum generator offer will stay constant at $1,000/MWh.

Participants may elect to be paid their emergency offer, regardless of the zonal LMP. Table 5-24 shows the distribution of registrations and associated MW in the Emergency Full Option across ranges of minimum dispatch prices. The majority of participants, 78.9 percent, have a minimum dispatch price of $999/MWh or higher. Energy offers are further increased by submitted shutdown costs, which, in the 2012/2013 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 $200 - $500 strike prices had the highest average at $765.77 per registration.

Shutdown cost currently is not adequately defined in Manual 15. The MMU recommends that shutdown cost should be defined as the cost to curtail load for a given period that does not vary with the measured reduction, or for behind the meter generators, should be equivalent to the start cost defined in Manual 15.

Table 5-24 Distribution of registrations and associated MW in the Emergency Full Option across ranges of Minimum Dispatch Prices effective for the 2012/2013 Delivery Year[20]

Ranges of Strike Prices ($/MWh)	Registrations	Percent of Total	Nominated MW (ICAP)	Percent of Total	Shutdown Cost per Registration
$0 - $1	1,047	12.1%	1,051.9	14.9%	$0.00
$1.01 - $200	227	2.6%	205.2	2.9%	$0.00
$200 - $500	520	6.0%	311.6	4.4%	$765.77
$500 - $998	37	0.4%	51.8	0.7%	$235.65
$999+	6,827	78.9%	5,417.8	77.0%	$41.84
Total	8,658	100.0%	7,038.2	100.0%	$79.99

Table 5-25 shows emergency credits and make whole payments for each event in 2012. The emergency credit is the market value of the load reductions observed during the event, based on applicable zonal LMPs. Make whole payments are the difference between the market value of the load reduction and the submitted energy offer, which includes the strike price and shutdown cost of each resource.

Table 5-25 Emergency credits and make whole payments by event: 2012

Event	Emergency Credits	Emergency Make Whole Payments	Total
17-Jul-12	$1,010,372.27	$3,751,680.48	$4,762,052.75
18-Jul-12	$592,597.01	$5,126,683.66	$5,719,280.67
Total	$1,602,969.28	$8,878,364.14	$10,481,333.42

Energy payments in the Emergency Program differ significantly from energy payments in the Economic Program and from capacity payments through the Load Management Program in that they are not based on or tied to any market price signal. These payments are simply guaranteed offers which are not required to provide any documentation or justification.

Load Management Testing

In the 2007/2008 and the 2008/2009 delivery years, Load Management (LM) compliance was assessed only for actual PJM declared events. If no event was declared, no capacity testing was required. PJM filed amendments to the tariff providing for LM testing if no emergency event is called by August 15 of the delivery year, which became effective in the 2009/2010 delivery year. All of a provider's committed DR and certified ILR resources in the same zone are required to test at the same time for a one hour period between 12:00 PM EPT to 8:00 PM EPT on a non-holiday weekday between June 1 and September 30. The resource provider must notify PJM of the intent to test 48 hours in advance.[21]

Depending on initial test results, multiple tests may be conducted. If a Curtailment Service Provider (CSP) shows greater than or equal to 75 percent test compliance across a portfolio of resources, all noncompliant resources are eligible for retesting. However, if the initial test shows less than 75 percent compliance, no associated resources are eligible for a retest.

There were 3,639.4 MW of Committed ICAP not deployed in an event during the compliance period for the 2012/2013 Delivery year and thus required to perform testing. Load Management testing results are shown in Table 5-26. Overall, test results showed 568.8 MW available over RPM commitments, or 116 percent test compliance. The RECO Control Zone showed the highest percentage of compliance, with load reductions at 170 percent of RPM Commitments, while the ATSI Control Zone showed the highest level of MW reduction in testing, with load reductions at 971.7 MW, or 149.6 MW over RPM commitments.

Load Management test results are submitted by CSPs directly to PJM. The test results consist of metered load data provided by the CSP which are compared to a baseline consumption level or firm service level determined by LM participation type. There is no physical or technical oversight or verification by PJM or by the relevant LSE of actual testing. PJM screens the data for unreasonable test results, but relies on the CSP to submit accurate metered load data for the testing period with no verification.

20 In this analysis Nominated MW does not include capacity only resources, which do not receive energy market revenue.

21 For more information, see PJM, "Manual 18, PJM Capacity Market," Revision 17 (December 20, 2012), Section 8.6.

Table 5-26 Load Management test results and compliance by zone for the 2012/2013 delivery year

Zone	Nominal ICAP	Committed MW	Load Reduction Test Results	Over/Under Compliance	Percent Test Compliance	Percent of Nominal ICAP
AECO	60.4	48.5	66.7	18.2	137%	110%
AEP	136.6	134.2	158.1	23.8	118%	116%
AP	543.2	481.7	539.6	57.9	112%	99%
ATSI	977.7	822.1	971.7	149.6	118%	99%
ComEd	809.9	755.8	805.5	49.7	107%	99%
DAY	102.5	84.5	95.6	11.1	113%	93%
DEOK	295.4	231.7	316.3	84.6	137%	107%
DLCO	110.4	80.4	97.6	17.2	121%	88%
Dominion	1.1	1.1	0.8	(0.3)	73%	73%
Met-Ed	185.5	158.6	196.7	38.1	124%	106%
PPL	623.6	542.8	609.6	66.9	112%	98%
PSEG	355.0	294.8	344.7	49.8	117%	97%
RECO	5.3	3.2	5.4	2.2	170%	102%
Total	4,206.6	3,639.4	4,208.2	568.8	116%	100%

This form of testing is not an adequate measurement and verification protocol to ensure that demand side capacity resources can reliably reduce during a system emergency. Given prior warning of a test event, customers have time to prepare to drop load, unlike in a real emergency event in which a customer will only have one to two hours' notice before an event begins. Customers can test on any day in the summer period, and choose any other day in that period to serve as the baseline consumption for estimating load reductions. There are no criteria to establish comparability between the baseline day and test day.

The MMU recommends that the testing program be modified to require verification of test methods and results. Tests should be initiated by PJM without prior scheduling by CSPs, in order to more accurately model demand response during an emergency event.

Resources are currently able to retest under certain conditions, and negative values are zeroed out for purposes of compliance. Table 5-27 shows test results without retests and including negative values, or measurement of load above the customer's baseline. This shows overall test compliance of approximately 112 percent, or 4 percent below the apparent reported compliance. With these changes, load management testing will more accurately reflect event day performance.

Table 5-27 Load Management Test Results with negatives, excluding retests

Zone	Nominal ICAP	Committed MW	Load Reduction Test Results	Over/Under Compliance	Percent Test Compliance	Percent of Nominal ICAP
AECO	60.4	48.5	57.8	9.3	119%	96%
AEP	136.6	134.2	158.1	23.8	118%	116%
AP	543.2	481.7	527.5	45.8	110%	97%
ATSI	977.7	822.1	948.3	126.2	115%	97%
ComEd	809.9	755.8	768.2	12.4	102%	95%
DAY	102.5	84.5	86.0	1.5	102%	84%
DEOK	295.4	231.7	314.5	82.8	136%	106%
DLCO	110.4	80.4	95.0	14.6	118%	86%
Dominion	1.1	1.1	0.8	(0.3)	73%	73%
Met-Ed	185.5	158.6	193.0	34.5	122%	104%
PPL	623.6	542.8	585.1	42.4	108%	94%
PSEG	355.0	294.8	328.7	33.9	111%	93%
RECO	5.3	3.2	5.1	1.9	159%	95%
Total	4,206.6	3,639.4	4,068.2	428.8	112%	97%

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 12:00pm to 8:00pm EPT and be capable of maintaining an interruption for 6 hours within a two hour window of PJM starting the event. When a provider under complies based on their registered MW, a penalty occurs 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.

Table 5-28 shows penalty charges by zone for the 2012/2013 DY. Met-Ed was the only zone that was called for an event that had no penalty charges.

Table 5-28 Penalty Charges per Zone: Delivery Year 2012/2013

	Penalty Charge
AECO	$53.50
AEP	$84,134.10
AP	$0.00
ATSI	$0.00
BGE	$78,475.94
ComEd	$0.00
DAY	$0.00
DEOK	$0.00
Dominion	$34,603.80
DPL	$434,306.58
DLCO	$0.00
JCPL	$3,126.54
Met-Ed	$0.00
PECO	$234,171.64
PENELEC	$25,836.22
Pepco	$293,680.76
PPL	$348.82
PSEG	$5,968.46
RECO	$0.00
Total	$1,194,706.36

Measurement and Verification

Since the beginning of the program, there have been significant issues with the approach to measuring demand-side response MW. An inaccurate or unrepresentative measurement protocol can lead to payments when the customer has taken no action to respond to market prices. Substantial improvement in measurement and verification methods must be implemented in order to ensure the credibility of PJM demand-side programs. These could take the form of improvements in the customer base line calculation and/or improvements in the verification and customer documentation of load reducing activities. The goal should be to treat the measurement of demand-side resources like the measurement of any other resource in the wholesale power market, including generation and load, that is paid by other participants or makes payments to other participants. PJM has made changes to improve the settlement review process, but more needs to be done.[22]

In the future, retail markets will reflect hourly wholesale prices and customers will receive direct savings associated with reducing consumption in response to real-time prices. There will not be a need for a PJM Economic Load Response Program, or for an extensive measurement and verification protocol. In the transition to that point, there is a need for robust measurement and verification techniques to ensure that transitional programs are incenting the desired behavior. These techniques are designed to estimate what consumption would have been, absent any load reducing activities.

Customer Base Line Issues

The customer base line (CBL) is a generic formula applied to nearly every customer's usage and is not adequate to serve as the sole or primary basis for determining if an intentional load reduction took place. There are no mandatory CBL enhancements for customers with highly volatile load patterns. If a customer normally has lower load on one particular weekday, that day will appear as a reduction eligible for payment under the current CBL methodology although no deliberate load reducing actions were taken in response to real time price signals. There are no mandatory adjustments to the standard CBL for load levels that are a function of weather. In a mild week, following a week of extreme temperatures and high load levels, a customer can submit settlements without taking any load reducing action and it will appear as a reduction eligible for payment because metered load is below CBL. In the registration process, an alternative CBL may be proposed by the CSP or the relevant LSE/EDC, though following Order 745 changes, CBLs must undergo a Relative Root Mean Squared Error (RRMSE) test to determine the most accurate method.[23] PJM has developed thirteen alternative CBL calculations, three of which include a weather sensitivity adjustment.

22 123 FERC ¶ 61,257 (2008).
23 If, however, agreement cannot be reached, then PJM will determine the alternative CBL.

Determining the accuracy of a CBL is difficult. More data are required than the metered load associated with settlement and the CBL used to determine the reduction amount. However, those are the only data currently available to PJM at the time of settlement review. Complete historical metered load data is required in order to determine whether the CBL is representative of normal load patterns.

Load Management Program

There have been three approaches to measurement and verification of resources in the load management program. The most common is specifying a firm MW level to which usage will be reduced, termed Firm Service Level (FSL). The less common approach for capacity resources is to establish a base line usage level by analyzing prior usage levels for a set of days that are intended to be representative of or similar to the day of the reduction. In the Load Management Program, this measurement and verification option is called Guaranteed Load Drop (GLD) and there are several baseline methods to choose from. The least common method is called Direct Load Control (DLC), which relies on direct LSE or CSP action to cause a customer to drop load.

FSL customers establish a firm consumption level which they must reach during an emergency event and the difference between that firm service level and the Peak Load Contribution (PLC) is the amount nominated in the LM Program. FSL customers are contractually obligated to reduce load to a nominal value. The measurement and verification of load reductions under FSL option for purposes of event compliance is relatively straightforward.

GLD customers establish a baseline of unrestricted consumption absent the emergency event, similar to the measurement and verification procedure in the Economic Program. The load reduction for GLD customers is the reduction of committed MW when an event is called. There are several techniques for estimation available to participants. The comparable day option determines reductions based on consumption on similar day experience. Another option determines reduction as differences from hourly load immediately prior to or following an event. A third option is the standard CBL calculation used in the Economic Program. Other options include regression analysis and load profile modeling. Following the implementation of the FERC order on measurement and verification, GLD customers no longer can count load reductions greater than their PLC value.

For DLC customers, load reductions are estimated through PJM reported or site surveyed impact studies. No telemetry or load data are required for verification of actual event performance. Rather, the CSP submits to PJM the time at which the equipment is deployed. There is no way for PJM or the MMU to determine if any load reduction took place in an emergency event.

The MMU recommends that the compliance rules in the Load Management Program be improved. CSPs should be required to submit metered load for all locations called during an emergency event. Non-responding resources with load increases during events should be included and netted against positively performing resources within a CSP's portfolio. The testing protocols are also inadequate, in that they do not simulate an event day. Tests should be initiated by PJM on a zonal basis by CSP, and not planned in advance by CSPs. Barring those changes; there should be no allowance to re-test resources. The MMU recommends refinement of the baseline methods used to calculate compliance in Load Management for GLD customers. The baseline pilot study conducted by KEMA indicated that the CBL used by the PJM Economic Program is an improvement, and consequently should be used by the GLD option in the Load Management Program.

Economic Program

In the Economic Program, the baseline method is the default approach, and the standard baseline is referred to as Customer Baseline Load (CBL).

In PJM's Economic Load Response Program, the primary tool used to establish what unrestricted load would have been is the default CBL with Symmetrical Additive Adjustment. The modifications to the CBL calculations currently occurring represent significant improvements to the Economic Program, but the review process is not yet adequate to ensure that other customers are receiving the benefit of actual demand reductions when payments are made under the program. The default CBL is now the CBL with Symmetrical Additive Adjustment (SAA), which incorporates a same day adjustment to minimize the inherent variability in the measurement of load reductions. In addition, to further limit variability inherent in the measurement process, all registrations for locations participating in energy programs must submit a Relative Root Mean Squared Error (RRMSE) analysis of sample load data for each location. The RRMSE must be less than 20 percent. A protocol submitted as part of the registration process must have a RRMSE of less than 20 percent and be more accurate than the CBL with SAA.

The definition of the standard or default CBL should continue to be refined to ensure that it reflects the actual normal use of individual customers including normal daily and hourly fluctuations in usage and usage that is a function of measurable weather conditions.