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 without depending on special programs.

Overview

- **Demand-Side Response Activity.** In the first six months of 2013, total load reduction under the Economic Load Response Program decreased by 3,773 MWh compared to the same period in 2012, from 38,692 MWh in the first six months of 2012 to 34,919 MWh in the first six months of 2013, a 10 percent decrease. Total credits under the Economic Program decreased by $321,417, from $2,172,454 in the first six months of 2012 to $1,851,037 in the same period of 2013, a 15 percent decrease. However, total credits increased by 516 percent from the first four months of 2012 to the first four months of 2013. May and June, 2013 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.

  The capacity market is the primary source of revenue to participants in PJM demand side programs. In the first six months of 2013, Load Management (LM) Program revenue decreased $39.6 million, or 20.2 percent, from $196.2 million to $156.6 million. Through the first six months of 2013, Synchronized Reserve credits for demand side resources decreased by $1.4 million compared to the same period in 2012, from $2.5 million to $1.4 million in 2013.

Conclusion

A fully functional demand side of the electricity market means that end use customers or their designated intermediaries will have the ability to see real-time energy price signals in real time, will have the ability to react to real-time prices in real time, and will have the ability to receive the direct benefits or costs of changes in real-time energy use. In addition, customers or their designated intermediaries will have the ability to see current capacity prices, will have the ability to react to capacity prices and will have the ability to receive the direct benefits or costs of changes in the demand for capacity. A functional demand side of these markets means that customers will have the ability to make decisions about levels of power consumption based both on the value of the uses of the power and on the actual cost of that power.

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 be further modified to more accurately reflect compliance. Increases in load by load management resources during event hours should not be considered zero response or ignored, 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.[1] The MMU recommends that load management resources whose load drop method is designated as "Other" explicitly record the method of load drop.

The load management product is currently defined as an emergency product. In fact, the load management product is an economic product and it is treated as an economic product in the PJM capacity market design where it competes directly with generation capacity, affects market clearing prices and

1 For additional conclusions see the *2012 State of the Market Report for PJM*, Volume 2: Section 5, "Demand Response."

receives the market clearing price. The load management product should also be treated as an economic product in PJM dispatch meaning that demand resources should be called when the resources are required and prior to the declaration of an emergency. For these reasons, the MMU recommends that the DR program be classified as an economic program and not an emergency program.[2]

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.[3]

Table 5-1 Overview of Demand Side Programs[4]

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

2 This issue is currently being discussed in the Capacity Senior Task Force (CSTF) with an expected resolution by summer 2014.
3 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>.
4 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.

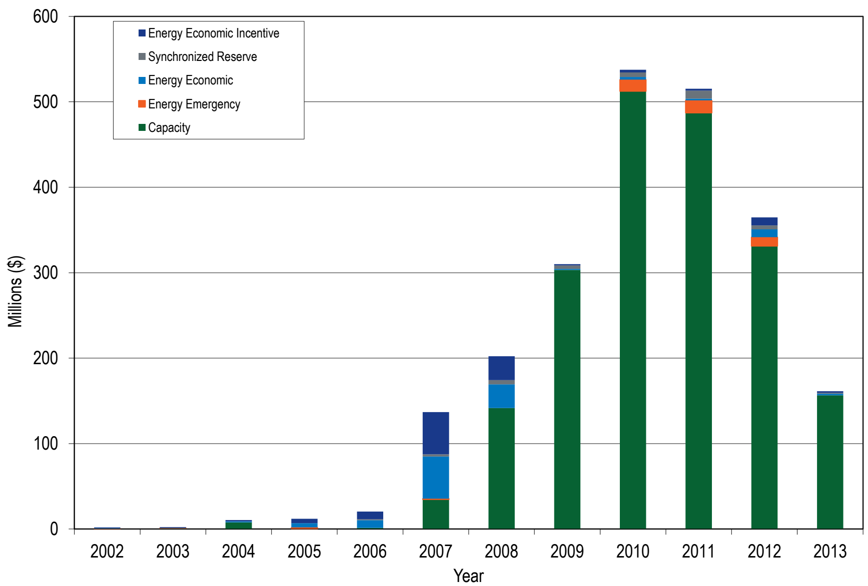
Participation in Demand Side Programs

On April 1, 2012, FERC Order No. 745 was implemented in the PJM Economic Program, mandating payment of full LMP for dispatched demand resources. In the first six months of 2013, in the Economic Program, participation decreased compared to the same period in 2012. There were fewer settlements submitted and active registrations in 2013 compared to the same period in 2012, and credits decreased. However, May and June 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.

Figure 5-1 shows all revenue from PJM Demand Side Response Programs by market for the period 2002 through the first six months of 2013. 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 98.2 percent of all revenue received through demand response programs in the first six months of 2013. In the first six months of 2013, total credits under the Economic Program decreased by $321,417, from $2,172,454 in the first six months of 2012 to $1,851,037 in the same period of 2013. This represents a 15 percent decrease in credits, but only 1.2 percent of all revenue received through PJM demand response programs. The total MWh reductions increased by 325 percent for the first four months of 2013 compared to the first four months of 2012. In the first six months of 2013, capacity revenue represents 98.2 percent of all revenue received by demand response providers, emergency energy revenue represented 0.0 percent, revenue from the economic program represented 1.2 percent and revenue from Synchronized Reserve represented 0.7 percent.

Capacity revenue decreased by $39.6 million, or 20.2 percent, from $196.2 million to $156.6 million in the first six months of 2013, primarily due to lower clearing prices in the RPM market. Synchronized Reserve credits for demand side resources decreased by $1.4 million, from $2.5 million to $1.0 million in the first six months 2013, due to lower clearing prices in the Synchronized Reserve market.

Figure 5-1 Demand Response revenue by market: 2002 through June 2013



Economic Program

Table 5-2 shows registered sites and MW for the last day of each month for the period 2010 through the first six months of 2013. The average registered MW for the first six months increased by 241 MW from 2,077 in 2012 to 2,318 registered MW in 2013. 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. Registrations in January through June 2013 were 1,228 less than 2012. Although registrations decreased, total registered MW were higher by 1,446 MW in the first six months of 2013 compared to the same period of 2012. The registered MW per registration increased in the first six months of 2013 compared to the first six months of 2012. The average number of active registrations was 1,225 in the first six months of 2012 and 1,020 in the same period in 2013.

Table 5-2 Economic Program registrations on the last day of the month: 2010 through June 2013

	2010		2011		2012		2013	
Month	Registrations	Registered MW	Registrations	Registered MW	Registrations	Registered MW	Registrations	Registered MW
Jan	1,841	2,623	1,609	2,432	1,993	2,385	841	2,332
Feb	1,842	2,624	1,612	2,435	1,995	2,384	843	2,345
Mar	1,845	2,623	1,612	2,519	1,996	2,356	788	2,302
Apr	1,849	2,587	1,611	2,534	189	1,318	970	2,352
May	1,875	2,819	1,687	3,166	371	1,669	1,375	2,424
Jun	813	1,608	1,143	1,912	803	2,347	1,302	2,150
Jul	1,192	2,159	1,228	2,062	942	2,323		
Aug	1,616	2,398	1,987	2,194	1,013	2,373		
Sep	1,609	2,447	1,962	2,183	1,052	2,421		
Oct	1,606	2,444	1,954	2,179	828	2,269		
Nov	1,605	2,444	1,988	2,255	824	2,267		
Dec	1,598	2,439	1,992	2,259	846	2,283		
Avg.	1,608	2,435	1,699	2,344	1,071	2,200	1,020	2,318

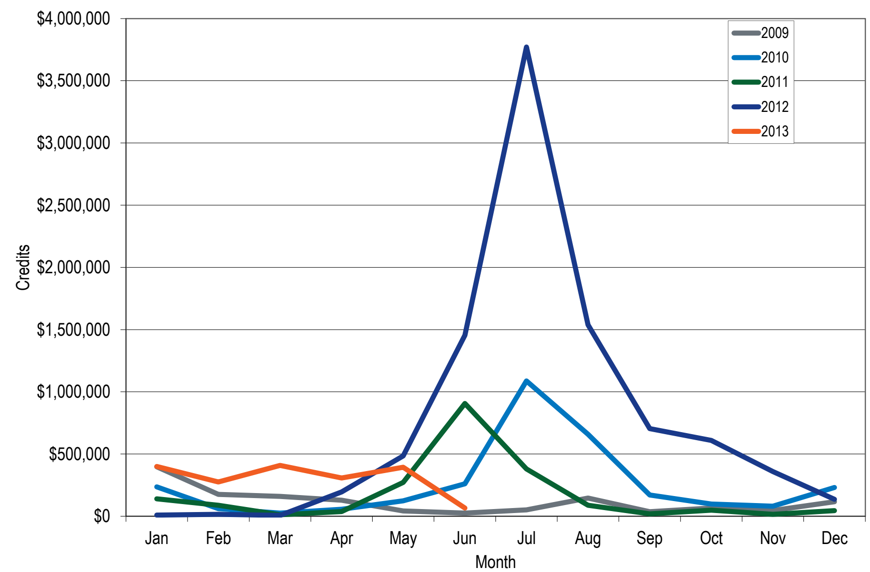
Total credits in Table 5-3 exclude incentive credits in the Economic Program for the years 2006 and 2007. The economic incentive program expired in December of 2007.[5]

Table 5-3 Performance of PJM Economic Program participants excluding incentive credits: 2003 through June 2013

	Total MWh	Total Credits	$/MWh
2003	19,518	$833,530	$42.71
2004	58,352	$1,917,202	$32.86
2005	157,421	$13,036,482	$82.81
2006	258,468	$10,213,828	$39.52
2007	714,148	$31,600,046	$44.25
2008	452,222	$27,087,495	$59.90
2009	57,157	$1,389,136	$24.30
2010	74,070	$3,088,049	$41.69
2011	17,398	$2,052,996	$118.00
2012	145,019	$9,284,118	$64.02
2013	34,919	$1,851,037	$53.01

Figure 5-2 shows monthly economic program credits, excluding incentive credits, for 2009 through June 2013. Higher energy prices and FERC Order 745 increased incentives to participate during the first six months of 2013. January through April, 2013, had greater economic credits than the same period since 2009. May and June of 2013 do not yet reflect complete economic program activity results as participants have up to 60 days to submit data for settlement.

Figure 5-2 Economic Program credits by month: 2009 through June 2013



5 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.

Table 5-4 shows the first six months of 2012 and 2013 performance in the Economic Program by control zone and participation type. Curtailed energy for the Economic Program was 34,919 MWh and the total payment amount was $1,851,037. The Dominion Control Zone accounted for $1,545,699 or 84 percent of all Economic Program credits, associated with 29,442 MWh or 84 percent of total program reductions. Table 5-4 shows the average participation in the Economic Program by zone and amount of customers in each zone. The Dominion Control Zone has the highest average MW reductions per customer and average credits per customer. Credits for the first six months of 2013 decreased by $321,417, or 15 percent, compared to the same time period of 2012. However, this does not fully account for data lag in May and June settlements by demand response providers that have up to 60 days to submit data after a demand response event. The total credits increased by 516 percent for the first four months of 2012 compared to the first four months of 2013.

Table 5-4 PJM Economic Program participation by zone: January through June 2012 and 2013

	Credits			MWh Reductions		
	2012	2013	Percentage Change	2012	2013	Percentage Change
AECO	$0	$0	NA	0	0	NA
AEP	$1,469	$1,073	(27%)	21	22	6%
AP	$195,858	$33,319	(83%)	3,399	822	(76%)
ATSI	$2,514	$107	(96%)	68	3	(95%)
BGE	$4,225	$24,717	485%	20	134	578%
ComEd	$64,473	$63,921	(1%)	1,854	1,464	(21%)
DAY	$0	$0	NA	0	0	NA
DEOK	$0	$0	NA	0	0	NA
DLCO	$2,793	$0	(100%)	40	0	(100%)
Dominion	$1,230,715	$1,545,699	26%	20,916	29,442	41%
DPL	$10,037	$0	(100%)	99	0	(100%)
EKPC	$0	$0	NA	0	0	NA
JCPL	$39,398	$57,732	47%	324	678	109%
Met-Ed	$36,138	$1,177	(97%)	378	22	(94%)
PECO	$91,898	$19,963	(78%)	1,467	392	(73%)
PENELEC	$166,506	$78,760	(53%)	3,507	1,420	(60%)
Pepco	$27,127	$0	(100%)	359	0	(100%)
PPL	$71,374	$19,377	(73%)	839	360	(57%)
PSEG	$227,930	$5,194	(98%)	5,400	160	(97%)
RECO	$0	$0	NA	0	0	NA
Total	$2,172,454	$1,851,037	(15%)	38,692	34,919	(10%)

Table 5-5 shows total settlements submitted by month for 2008 through June 2013.

Table 5-5 Settlement days submitted by month in the Economic Program: 2008 through June 2013

Month	2008	2009	2010	2011	2012	2013
Jan	2,916	1,264	1,415	562	62	192
Feb	2,811	654	546	148	30	92
Mar	2,818	574	411	82	46	126
Apr	3,406	337	338	102	93	160
May	3,336	918	673	298	144	188
Jun	3,184	2,727	1,221	743	1,480	402
Jul	3,339	2,879	3,010	1,412	2,906	
Aug	3,848	3,760	2,158	793	1,693	
Sep	3,264	2,570	660	294	555	
Oct	1,977	2,361	699	66	481	
Nov	1,105	2,321	672	51	280	
Dec	986	1,240	894	40	124	
Total	32,990	21,605	12,697	4,591	7,894	1,160

Table 5-6 shows the number of distinct Curtailment Service Providers (CSPs) and distinct customers actively submitting settlements by month for the period 2009 through June 2013.[6] The number of active customers during the first six months of 2013 decreased by 281 compared to the same period in 2012. The smaller number of active customers in 2013 responded more frequently compared to customers in the same period of 2012.

Table 5-7 shows a frequency distribution of MWh reductions and credits in each hour for the first six months of 2012 and 2013. In the first six months of 2013, 56.6 percent of the reductions occurred between hour ending 7 and hour ending 12, while in the first six months of 2012, 53.8 percent of hourly reductions occurred from hour ending 15 to hour ending 18.

Table 5-6 Distinct customers and CSPs submitting settlements in the Economic Program by month: 2009 through June 2013

	2009		2010		2011		2012		2013	
Month	Active CSPs	Active Customers	Active CSPs	Active Customers	Active CSPs	Active Customers	Active CSPs	Active Customers	Active CSPs	Active Customers
Jan	17	257	11	153	5	40	5	15	8	47
Feb	12	129	9	92	6	29	3	9	5	14
Mar	11	149	7	124	3	15	3	12	5	19
Apr	9	76	5	77	3	15	3	8	5	16
May	9	201	6	140	6	144	5	20	6	33
Jun	20	231	11	152	10	304	16	338	9	53
Jul	21	183	18	267	15	214	21	383		
Aug	15	400	14	317	14	186	17	361		
Sep	11	181	11	96	7	47	11	127		
Oct	11	93	8	37	3	9	9	50		
Nov	9	143	7	38	3	13	5	63		
Dec	10	160	7	44	5	12	3	10		
Total Distinct Active	25	747	24	438	20	610	24	520	12	89

6 May and June 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.

Table 5-7 Hourly frequency distribution of Economic Program MWh reductions and credits: January through June 2012 and 2013

	MWh Reductions			Program Credits		
Hour Ending (EPT)	2012	2013	Percentage Change	2012	2013	Percentage Change
1	31	3	(89%)	$678	($191)	(128%)
2	25	10	(59%)	$623	$1	(100%)
3	25	19	(21%)	$113	$324	188%
4	14	21	52%	($48)	$423	NA
5	14	20	47%	($49)	$353	NA
6	45	29	(36%)	$499	$927	86%
7	732	3,480	376%	$25,721	$187,640	630%
8	1,261	3,990	216%	$35,834	$253,007	606%
9	1,212	3,829	216%	$41,182	$191,511	365%
10	1,032	3,527	242%	$39,495	$159,021	303%
11	1,142	2,677	134%	$45,868	$125,228	173%
12	1,227	2,276	86%	$53,705	$99,058	84%
13	2,031	1,819	(10%)	$99,687	$79,964	(20%)
14	3,124	1,349	(57%)	$166,059	$69,813	(58%)
15	4,674	1,878	(60%)	$262,884	$104,038	(60%)
16	5,376	1,887	(65%)	$347,751	$110,413	(68%)
17	5,474	2,016	(63%)	$409,258	$125,482	(69%)
18	5,304	2,065	(61%)	$363,264	$119,948	(67%)
19	2,262	1,898	(16%)	$139,264	$101,821	(27%)
20	1,737	1,512	(13%)	$71,728	$83,766	17%
21	1,105	415	(62%)	$48,233	$28,659	(41%)
22	502	156	(69%)	$16,155	$7,756	(52%)
23	218	28	(87%)	$3,491	$977	(72%)
24	127	14	(89%)	$1,060	$1,098	4%
Total	38,692	34,919	(10%)	2,172,454	1,851,037	(15%)

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, provided that LMP was greater than the Net Benefits Test (NBT) 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 $26.79 from January through June 2013. Demand resources are not paid for any load reductions during hours where the LMP is below the Net Benefits Test price.

Table 5-8 shows the frequency distribution of Economic Program MWh reductions and credits by ranges of real-time zonal, load-weighted, average LMP. MWh reductions in the $0 to $25 bracket decreased from 754 MWh in 2012 to 111 MWh in the first six months of 2013. Since these reductions occurred when LMP was below the Net Benefits Test, they did not receive any credits for their reduction from the economic program. MWh reductions in the $50 to $75 LMP bracket increased 37.4 percent from 7,542 MWh to 10,365 MWh in the first six months of 2013.

Total Economic Program reductions decreased by 3,773 MWh, from 38,692 MWh in the first six months of 2012 to 34,919 MWh in the same time period of 2013. Reductions occurred at all price levels. Approximately 89.0 percent of MWh reductions and 78.5 percent of program credits are associated with hours when the applicable zonal LMP was between $25 and $75. MWh reductions in the first six months of 2013 decreased 9.8 percent compared to the same period in 2012. However, the 2013 data is not fully representative of activity in May and June due to the lag in settlements by demand response providers that have up to 60 days to submit data after a demand response event. The total MWh reductions increased by 325 percent for the first four months of 2013 compared to the first four months of 2012.

Table 5-8 Frequency distribution of Economic Program zonal, load-weighted, average LMP (By hours): January through June 2012 and 2013

	MWh Reductions			Program Credits		
LMP	2012	2013	Percentage Change	2012	2013	Percentage Change
$0 to $25	754	111	(85.34%)	$7,583	$0	(100.00%)
$25 to $50	23,552	20,694	(12.13%)	$853,597	$828,110	(2.99%)
$50 to $75	7,542	10,365	37.44%	$440,713	$625,376	41.90%
$75 to $100	2,699	2,174	(19.47%)	$222,779	$187,546	(15.82%)
$100 to $125	1,336	885	(33.80%)	$149,017	$97,988	(34.24%)
$125 to $150	1,103	385	(65.10%)	$141,919	$51,033	(64.04%)
$150 to $200	427	263	(38.46%)	$59,234	$49,761	(15.99%)
$200 to $250	806	29	(96.43%)	$153,014	$6,191	(95.95%)
$250 to $300	281	2	(99.13%)	$61,185	$628	(98.97%)
> $300	191	12	(93.85%)	$83,413	$4,403	(94.72%)
Total	38,692	34,919	(9.75%)	$2,172,454	$1,851,037	(14.80%)

Load Management Program

Table 5-9 shows zonal monthly capacity credits to DR resources for the period January through June of 2013. Capacity revenue decreased in the first six months of 2013 by $39.6 million, or 20.2 percent, compared to the first six months of 2012; from $196.2 million to $156.6 million in the same time period of 2013. The decrease in capacity credits in 2013 is the result of a decrease in RPM clearing prices for the 2012/2013 Delivery Year. RPM prices increased for the 2013/2014 Delivery Year resulting in higher capacity credits in June 2013 by $23.2 million compared to May 2013.[7]

Table 5-9 Zonal monthly capacity credits: January through June 2013

Zone	January	February	March	April	May	June	Total
AECO	$411,097	$371,313	$411,097	$397,836	$411,097	$1,002,307	$3,004,747
AEP	$425,101	$383,962	$425,101	$411,388	$425,101	$749,663	$2,820,314
AP	$185,478	$167,528	$185,478	$179,495	$185,478	$477,348	$1,380,805
ATSI	$19,859	$17,937	$19,859	$19,218	$19,859	$365,564	$462,295
BGE	$5,430,108	$4,904,613	$5,430,108	$5,254,943	$5,430,108	$7,487,232	$33,937,111
ComEd	$405,926	$366,643	$405,926	$392,831	$405,926	$782,114	$2,759,366
DAY	$63,670	$57,508	$63,670	$61,616	$63,670	$42,849	$352,984
DEOK	$8,185	$7,393	$8,185	$7,921	$8,185	$16,115	$55,982
DLCO	$49,718	$44,907	$49,718	$48,114	$49,718	$143,269	$385,445
Dominion	$306,929	$277,226	$306,929	$297,028	$306,929	$585,863	$2,080,903
DPL	$1,547,049	$1,397,335	$1,547,049	$1,497,145	$1,547,049	$1,915,174	$9,450,802
EKPC	$0	$0	$0	$0	$0	$1,495	$1,495
JCPL	$1,495,628	$1,350,890	$1,495,628	$1,447,382	$1,495,628	$2,215,048	$9,500,203
Met-Ed	$1,044,281	$943,222	$1,044,281	$1,010,595	$1,044,281	$2,174,111	$7,260,771
PECO	$2,660,069	$2,402,643	$2,660,069	$2,574,260	$2,660,069	$5,142,792	$18,099,901
PENELEC	$1,144,857	$1,034,064	$1,144,857	$1,107,926	$1,144,857	$2,884,571	$8,461,131
Pepco	$1,906,591	$1,722,082	$1,906,591	$1,845,088	$1,906,591	$4,092,964	$13,379,905
PPL	$3,247,272	$2,933,020	$3,247,272	$3,142,521	$3,247,272	$7,019,745	$22,837,102
PSEG	$2,354,400	$2,126,555	$2,354,400	$2,278,452	$2,354,400	$8,574,172	$20,042,381
RECO	$14,896	$13,454	$14,896	$14,415	$14,896	$249,408	$321,963
Total	$22,721,111	$20,522,294	$22,721,111	$21,988,172	$22,721,111	$45,921,805	$156,595,604

7 For more detail on the historical RPM prices of PJM Load Response Programs see the *2012 State of the Market Report for PJM*, Volume II, Section 4, "Capacity Market," <http://www.monitoringanalytics.com/reports/PJM_State_of_the_Market/2012.shtml>.

Table 5-10 shows the amount of Energy Efficiency resources in each LDA for the 2012/2013 and 2013/2014 Delivery Year. 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 5-10 LDA Energy Efficiency resources by MW: 2012/2013 and 2013/2014 Delivery Year

	EE ICAP (MW)			EE UCAP (MW)		
LDA Name	2012/2013	2013/2014	Percentage Change	2012/2013	2013/2014	Percentage Change
DPL-SOUTH	0.0	12.4	NA	0.0	12.9	NA
EMAAC	18.7	17.3	(7%)	19.0	17.1	(10%)
MAAC	44.3	81.1	83%	45.7	83.9	84%
PEPCO	0.0	74.6	NA	0.0	77.5	NA
PS-NORTH	6.6	10.4	58%	6.8	10.8	59%
PSEG	6.1	13.1	115%	6.1	13.3	118%
RTO	395.5	593.5	50%	410.0	617.5	51%
SWMAAC	138.6	188.5	36%	143.6	196.2	37%
Total	609.8	990.9	62%	631.2	1,029.2	63%

Table 5-11 shows the MW registered by load drop method and by measurement and verification method. Of the DR MW committed, 3.5 percent use the Guaranteed Load Drop method, 87.0 percent use the Firm Service Level method and 9.5 percent use the Direct Load Control method as the measurement and verification method.

There is a lack of transparency in the load drop method for demand response resources. The load drop method of 20.3 percent of committed MW is labeled as "Other." The MMU recommends that any MW designated as "Other" explicitly record the method of load drop. DR has 30.2 percent of registered MW as reduced by applications at manufacturing facilities, 22.0 percent of registered MW by applications using HVAC units, 20.3 percent of registered MW as reduced by non-specified other applications, 18.0 percent of registered MW as reduced by on-site generation, 6.2 percent of registered MW as reduced by lighting applications, 1.9 percent of registered MW as reduced by refrigeration applications and 1.3 percent of registered MW as reduced by water heater applications.

Table 5-11 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	1,550.0	1,042.2	171.4	535.9	2,678.6	77.4	1,743.9	7,799.3	87.0%
Guaranteed Load Drop	61.3	157.6	1.9	19.8	31.0	0.4	41.4	313.4	3.5%
Non hourly metered sites (DLC)	0.0	775.6	0.0	0.0	0.0	40.0	37.0	852.7	9.5%
Total	1,611.3	1,975.4	173.2	555.7	2,709.6	117.9	1,822.3	8,965.3	100.0%
Percentage by method	18.0%	22.0%	1.9%	6.2%	30.2%	1.3%	20.3%	100.0%	

Table 5-12 shows the fuel type used in the on-site generators identified in Table 5-11. Of the load management resources identified as using on-site generation, 92.5 percent of MW are diesel, 6.2 percent are natural gas and 1.3 percent is coal, oil, other or no fuel source. The Other category in Table 5-11 could also include on-site generation, but there is no detailed information about the Other category at present.

Table 5-12 On-site generation fuel type by MW: 2013/2014 Delivery Year

Fuel Type	MW	Percentage
Coal	1.0	0.1%
Diesel	1,489.7	92.5%
Gas	100.7	6.2%
None	4.3	0.3%
Oil	8.7	0.5%
Other	6.8	0.4%
Total	1,611.3	100.00%

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. 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 registered MW, 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. The penalties are assessed daily and have increased by $842,993.74 since December 31, 2012. Table 5-13 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 5-13 Penalty Charges per Zone: Delivery Year 2012/2013[8]

	Penalty Charge
AECO	$91.25
AEP	$143,499.75
AP	$0.00
ATSI	$0.00
BGE	$133,849.15
ComEd	$0.00
DAY	$0.00
DEOK	$0.00
Dominion	$59,020.50
DPL	$740,756.55
DLCO	$0.00
JCPL	$5,332.65
Met-Ed	$0.00
PECO	$399,404.90
PENELEC	$44,066.45
Pepco	$500,904.10
PPL	$594.95
PSEG	$10,179.85
RECO	$0.00
Total	$2,037,700.10

8 EKPC was not integrated until June 1, 2013, during the 2013/2014 Delivery Year.