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 the first three months of 2013, total load reduction under the Economic Load Response Program increased by 12,936 MWh compared to the same period in 2012, from 1,030 MWh in the first three months of 2012 to 13,966 MWh in the first three months of 2013, a 1,256 percent increase. Total payments under the Economic Program increased by $659,823, from $30,406 in the first three months of 2012 to $690,229 in the same period of 2013, a 2,170 percent increase.

  Settled reductions and credits were greater in the first three months of 2013 compared to 2012. Participation levels increased following the implementation of Order No. 745, on April 1, 2012, allowing payment of full LMP for demand resources.

  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 the first three months of 2013, Load Management (LM) Program revenues revenue decreased $38.4 million, or 36.8 percent, from $104 million to $66 million. Through the first three months of 2013, Synchronized Reserve credits for demand side resources decreased by $0.6 million compared to the same period in 2012, from $1.3 million to $0.7 million in 2013.

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.

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.[1]

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.[2]

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

Table 5-1 Overview of Demand Side Programs[3]

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

Participation in Demand Side Programs

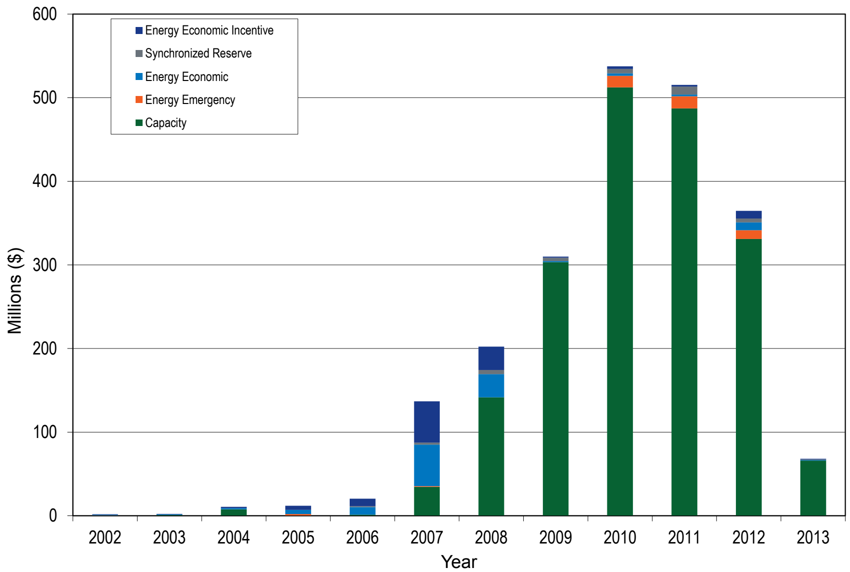
On April 1, 2012, FERC Order No. 745 was implemented in the PJM Economic Program, mandating payment of full LMP for dispatched demand resources. In the first three months of 2013, in the Economic Program, participation increased compared to the same period in 2012. There were more settlements submitted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

Figure 5-1 shows all revenue from PJM Demand Side Response Programs by market for the period 2002 through the first three 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 97.91 percent of all revenue received through demand response programs in the first three months of 2013. In the first three months of 2013, total payments under the Economic Program increased by $659,823, from $30,406 in the first three months of 2012 to $690,229 in the same period of 2013. This represents a 2,170 percent increase in payments, but still only 1.0 percent of all revenue received through PJM demand response programs. In the first quarter of 2013, capacity revenue represents 97.9 percent of all revenue received by demand response providers, emergency energy revenue represented 0.0 percent, revenue from the economic program represented 1.0 percent and revenue from Synchronized Reserve represented 1.1 percent.

Capacity revenue decreased by $38.4 million, or 36.8 percent, from $104.3 million to $66.0 million in the first three months of 2013, primarily due to lower clearing prices in the RPM market. Synchronized Reserve credits for demand side resources decreased by $0.6 million, from $1.3 million to $0.7 million in the first three months 2013, due to lower clearing prices in the Synchronized Reserve market.

3 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.

Figure 5-1 Demand Response revenue by market: 2002 through March 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 three months of 2013.[4] The average registered MW for the first three months decreased by 131 MW from 2,375 in 2012 to 2,244 registered MW in 2013. The overall credits paid by the Economic program increased to $690,229 in the first three months of 2013 from $30,406 in the same period of 2012. 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 March 2013 were 1,171 less than 2012. The average amount of active registrations was 1,995 in the first three months of 2012 and 824 in the same period in 2013.

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

Figure 5-2 shows monthly economic program payments, excluding incentive payments, for 2009 through March 2013. Lower energy prices and growth in the capacity market program resulted in reduced incentives to participate. Energy prices declined significantly in 2009, and have remained low through the first three months of 2013.[6] In the first three months of 2013, credits were up substantially compared to 2012, following the implementation of Order No. 745 on April 1, 2012. February of 2013 showed the highest credits paid in a month since 2009. The credits paid to economic demand response participants were $175,145 in February of 2009 and increased by $97,857 to $273,002 in 2013. Participation has increased since the implementation of Order 745 in the first three months of 2013 compared to the same period of 2012, both in MWh and number of registrations. The data for March 2013 do not reflect total activity because participants have up to 60 days to submit data for settlement.

4 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.

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.

6 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.

Table 5-2 Economic Program registrations on the last day of the month: 2010 through March 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	2,250
Feb	1,842	2,624	1,612	2,435	1,995	2,384	843	2,262
Mar	1,845	2,623	1,612	2,519	1,996	2,356	788	2,219
Apr	1,849	2,587	1,611	2,534	189	1,318		
May	1,875	2,819	1,687	3,166	371	1,669		
Jun	813	1,608	1,143	1,912	803	2,347		
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	824	2,244

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

	Total MWh	Total Payments	$/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	13,966	$690,229	$49.42

Figure 5-2 Economic Program payments by month: 2009 through March 2013

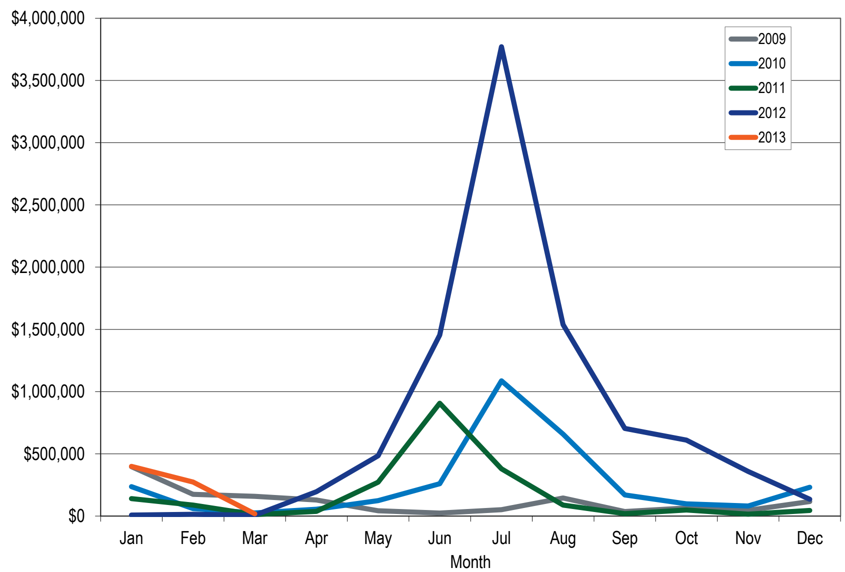


Table 5-4 shows the first three months of 2013 performance in the Economic Program by control zone and participation type. Curtailed energy for the Economic Program was 13,966 MWh and the total payment amount was $690,229.[7] The Dominion Control Zone accounted for $590,714 or 86 percent of all Economic Program credits, associated with 12,155 or 87 percent of total program MWh reductions. Table 5-4 shows the average participation in the Economic Program by zone and amount of customers in each zone. The Dominion has the highest average MW reductions per customer and average credits per customer. Since the implementation of Order No. 745 on April 1, 2012, credits have increased. Credits for the first three months of 2013 increased by $659,823 or 2,170 percent compared to the same time period of 2012.

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

	Credits			MWh Reductions		
	2012	2013	Percentage Change	2012	2013	Percentage Change
AECO	$0	$0	NA	0	0	NA
AEP	$0	$818	NA	0	17	NA
AP	$0	$9,001	NA	0	290	NA
ATSI	$0	$107	NA	0	3	NA
BGE	$0	$24,717	NA	0	134	NA
ComEd	$0	$25,435	NA	0	722	NA
DAY	$0	$0	NA	0	0	NA
DEOK	$0	$0	NA	0	0	NA
DLCO	$0	$0	NA	0	0	NA
Dominion	$29,862	$590,714	1,878%	1,010	12,155	1,104%
DPL	$0	$0	NA	0	0	NA
JCPL	$0	$0	NA	0	0	NA
Met-Ed	$133	$727	448%	4	9	128%
PECO	$412	$6,619	1,508%	17	82	395%
PENELEC	$0	$16,177	NA	0	198	NA
Pepco	$0	$0	NA	0	0	NA
PPL	$0	$11,605	NA	0	222	NA
PSEG	$0	$4,309	NA	0	134	NA
RECO	$0	$0	NA	0	0	NA
Total	$30,406	$690,229	2,170%	1,030	13,966	1,256%

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

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

Table 5-5 Settlement days submitted by month in the Economic Program: 2008 through March 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	
May	3,336	918	673	298	144	
Jun	3,184	2,727	1,221	743	1,477	
Jul	3,339	2,879	3,010	1,412	2,899	
Aug	3,848	3,760	2,158	793	1,681	
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	7,872	410

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 March 2013.[8] The number of active customers during the first three months of 2013 increased by 30 compared to the same period in 2012.

8 February and March 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 5-6 Distinct customers and CSPs submitting settlements in the Economic Program by month: 2009 through March 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		
May	9	201	6	140	6	144	5	20		
Jun	20	231	11	152	10	304	16	338		
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	10	53

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

	MWh Reductions				Program Credits			
Hour Ending (EPT)	MWh Reductions	Percent	Cumulative MWh	Cumulative Percent	Credits	Percent	Cumulative Credits	Cumulative Percent
1	8	0.06%	8	0.06%	$91	0.01%	$91	0.01%
2	6	0.04%	14	0.10%	($117)	(0.02%)	($26)	(0.00%)
3	6	0.04%	20	0.14%	($40)	(0.01%)	($66)	(0.01%)
4	6	0.04%	26	0.18%	$174	0.03%	$108	0.02%
5	10	0.07%	36	0.26%	$239	0.03%	$347	0.05%
6	13	0.09%	49	0.35%	$404	0.06%	$751	0.11%
7	2,096	15.01%	2,145	15.36%	$109,162	15.82%	$109,913	15.92%
8	2,351	16.83%	4,496	32.20%	$148,627	21.53%	$258,540	37.46%
9	2,187	15.66%	6,683	47.85%	$108,468	15.71%	$367,009	53.17%
10	1,931	13.83%	8,614	61.68%	$81,826	11.85%	$448,834	65.03%
11	1,350	9.67%	9,964	71.35%	$57,456	8.32%	$506,290	73.35%
12	1,064	7.62%	11,028	78.97%	$41,690	6.04%	$547,980	79.39%
13	605	4.33%	11,634	83.30%	$23,643	3.43%	$571,623	82.82%
14	373	2.67%	12,007	85.97%	$14,900	2.16%	$586,523	84.98%
15	209	1.50%	12,216	87.47%	$7,263	1.05%	$593,786	86.03%
16	262	1.87%	12,478	89.35%	$9,398	1.36%	$603,184	87.39%
17	258	1.85%	12,736	91.19%	$9,472	1.37%	$612,657	88.76%
18	263	1.88%	12,999	93.08%	$11,280	1.63%	$623,937	90.40%
19	409	2.93%	13,408	96.00%	$24,179	3.50%	$648,115	93.90%
20	339	2.43%	13,747	98.43%	$24,554	3.56%	$672,670	97.46%
21	156	1.12%	13,902	99.55%	$14,471	2.10%	$687,141	99.55%
22	26	0.19%	13,928	99.73%	$1,116	0.16%	$688,257	99.71%
23	23	0.17%	13,952	99.90%	$813	0.12%	$689,070	99.83%
24	14	0.10%	13,966	100.00%	$1,159	0.17%	$690,229	100.00%

Table 5-7 shows a frequency distribution of MWh reductions and credits at each hour for the first three months of 2013. The period from hour ending 0700 EPT to 1200 EPT accounts for 79 percent of MWh reductions and 79 percent of credits.

Table 5-8 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 from 0 MWh in 2012 to 88 MWh in the first three months of 2013. Since these reductions were below the Net Benefits Test, they did not receive any credits for their reduction from the economic program. MWh reductions in the $25 to $50 LMP bracket increased 1,625 percent from 612 MWh to 10,559 MWh in the first three months of 2013.

Total Economic Program reductions increased by 12,785 MWh, from 1,181 MWh in the first three months of 2012 to 13,966 MWh in the same time period of 2013. Reductions occurred at all price levels. Approximately 89.0 percent of MWh reductions and 74.3 percent of program credits are associated with hours when the applicable zonal LMP was between $25 and $75.

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 $25.86 from January through March 2013. Demand resources are not paid for any load reductions during hours where the LMP is below the Net Benefits Test threshold.

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

	MWh Reductions				Program Credits			
LMP	MWh Reductions	Percent	Cumulative MWh	Cumulative Percent	Credits	Percent	Cumulative Credits	Cumulative Percent
$0 to $25	88	0.63%	88	0.63%	$0	0.00%	$0	0.00%
$25 to $50	10,559	75.61%	10,647	76.24%	$403,058	58.39%	$403,058	58.39%
$50 to $75	1,876	13.43%	12,523	89.67%	$109,979	15.93%	$513,037	74.33%
$75 to $100	637	4.56%	13,160	94.23%	$54,013	7.83%	$567,050	82.15%
$100 to $125	211	1.51%	13,371	95.74%	$22,658	3.28%	$589,708	85.44%
$125 to $150	299	2.14%	13,670	97.88%	$41,617	6.03%	$631,325	91.47%
$150 to $200	262	1.88%	13,932	99.76%	$49,664	7.20%	$680,989	98.66%
$200 to $250	20	0.14%	13,952	99.90%	$4,304	0.62%	$685,293	99.28%
$250 to $300	2	0.02%	13,954	99.92%	$590	0.09%	$685,884	99.37%
> $300	12	0.08%	13,966	100.00%	$4,346	0.63%	$690,229	100.00%

Load Management Program

Table 5-9 shows zonal monthly capacity credits paid during January through March of 2013 to DR resources. Capacity revenue decreased in the first three months of 2013 by $38.4 million, or 36.8 percent, compared to the first three months of 2012; from 104.3 million to 66.0 million in the same time period of 2013. Credits from January to March are associated with participation in the 2012/2013 RPM delivery year. The decrease in capacity credits in 2013 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 related 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.[9]

The load management product is currently defined as an emergency product. The Load Management product is an economic product and it is treated as an economic product in the PJM capacity market design. 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.

9 137 FERC ¶ 61,108

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

Zone	January	February	March	Total
AECO	$411,097	$371,313	$411,097	$1,193,507
AEP	$425,101	$383,962	$425,101	$1,234,163
AP	$185,478	$167,528	$185,478	$538,484
ATSI	$19,859	$17,937	$19,859	$57,654
BGE	$5,430,108	$4,904,613	$5,430,108	$15,764,828
ComEd	$405,926	$366,643	$405,926	$1,178,494
DAY	$63,670	$57,508	$63,670	$184,848
DEOK	$8,185	$7,393	$8,185	$23,762
DLCO	$49,718	$44,907	$49,718	$144,343
Dominion	$306,929	$277,226	$306,929	$891,084
DPL	$1,547,049	$1,397,335	$1,547,049	$4,491,434
JCPL	$1,495,628	$1,350,890	$1,495,628	$4,342,145
Met-Ed	$1,044,281	$943,222	$1,044,281	$3,031,784
PECO	$2,660,069	$2,402,643	$2,660,069	$7,722,780
PENELEC	$1,144,857	$1,034,064	$1,144,857	$3,323,777
Pepco	$1,906,591	$1,722,082	$1,906,591	$5,535,263
PPL	$3,247,272	$2,933,020	$3,247,272	$9,427,564
PSEG	$2,354,400	$2,126,555	$2,354,400	$6,835,356
RECO	$14,896	$13,454	$14,896	$43,245
Total	$22,721,111	$20,522,294	$22,721,111	$65,964,516

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. The penalties are assessed daily and have increased by $502,446 since December 31, 2012. Table 5-10 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 5-10 Penalty Charges per Zone: Delivery Year 2012/2013

	Penalty Charge
AECO	$76.00
AEP	$119,517.60
AP	$0.00
ATSI	$0.00
BGE	$111,479.84
ComEd	$0.00
DAY	$0.00
DEOK	$0.00
Dominion	$49,156.80
DPL	$616,958.88
DLCO	$0.00
JCPL	$4,441.44
Met-Ed	$0.00
PECO	$332,655.04
PENELEC	$36,701.92
Pepco	$417,191.36
PPL	$495.52
PSEG	$8,478.56
RECO	$0.00
Total	$1,697,152.96