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.

Highlights

- In January through June 2012, the total MWh of load reduction under the Economic Load Response Program increased by 6,262 MWh compared to the same period in 2011, from 9,054 MWh in 2011 to 15,316 MWh in 2012, a 69 percent increase. Total payments under the Economic Program decreased by $884,924, from $1,456,324 in 2011 to $571,399 in 2012, a 61 percent decrease.
- In January through June 2012, total capacity payments to demand response resources under the PJM Load Management (LM) Program, which integrated Emergency Load Response Resources into the Reliability Pricing Model, decreased by $80.0 million, or 29.0 percent, compared to the same period in 2011, from $276 million in 2011 to $196 million in 2012.

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 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 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 (LMP), or the market price of capacity, the locational capacity market clearing price. 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

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.

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 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 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. However, less than one percent of participants have taken this option while almost all participants received credits based on the zonal average LMP. PJM's proposed 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 2, 2012. Order 745 requires RTOs and ISOs to pay full LMP to demand resources.

PJM's Load Management (LM) Program in the RPM market also 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 to participate in ancillary services markets.[3]

PJM's demand side programs, by design, provide a work around for end use customers that are not otherwise exposed to the incremental, locational costs of energy and capacity. They should be understood as one relatively small part of a transition to a fully functional demand side for its 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, particularly in the Emergency Program which consists entirely of capacity resources, are not adequate to determine and quantify deliberate actions taken to reduce consumption.

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.[4]

Table 5-1 Overview of Demand Side Programs[5] (See the 2011 SOM, Table 5-1)

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	Voluntary 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 voluntary curtailment.

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 See the *2011 State of the Market Report for PJM*, Volume II, Section 9, "Ancillary Service Markets."

4 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>.

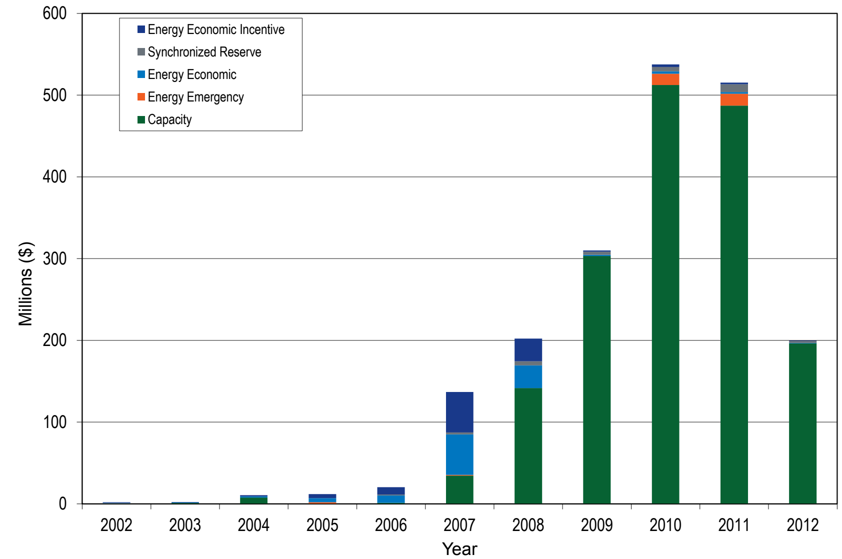
5 Prior to April 2, 2012, payment for the Economic Load Response Program was based on LMP minus the generation and transmission components of the retail rate.

Participation in Demand Side Programs

In the first six months of 2012, in the Economic Program, participation became more concentrated by site compared to 2011. There were fewer settlements submitted and active registrations in 2012 compared to 2011, and credits decreased. The number of sites registered decreased more significantly than the level of registered MW.

Figure 5-1 shows all revenue from PJM Demand Side Response Programs by market for the period 2002 through the first six months of 2012. Since the implementation of the RPM design on June 1, 2007, the capacity market has become the primary source of revenue to demand side participants. In the first six months of 2012, total payments under the Economic Program decreased by $884,924, from $1,456,324 in the first six months of 2011 to $571,399 in 2012, a 61 percent decrease. Capacity revenue decreased $80.0 million, or 29.0 percent, from $276 million to $196 million. From January through June 2012, Synchronized Reserve credits for demand side resources decreased by $1.9 million compared to the same period in 2011, from $4.4 million in 2011 to $2.5 million in 2012. In the first six months of 2012, there were no Load Management Event Days.

Figure 5-1 Demand Response revenue by market: Calendar years 2002 through 2011 and the first six months of 2012 (See the 2011 SOM, Figure 5-1)



Economic Program

Table 5-2 shows the number of registered sites and MW per peak load day for calendar years 2002 through the first six months of 2012.[6] On June 20, 2012, there were 2,231.7 MW registered in the Economic Program compared to the 2,041.8 MW on July 21, 2011, a 9.8 percent increase in peak load day capability. Program totals are subject to monthly and seasonal variation, as registrations begin, expire and renew. Table 5-3 shows registered sites and MW for the last day of each month for the period calendar years 2008 through the first six months of 2012.[7] 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

6 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.

7 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.

been signed up and can participate if they choose. Thus, registrations represent the maximum level of potential participation. During 2012, administrative changes caused by 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: Calendar years 2002 to 2011 and January through June 2012 (See the 2011 SOM, Table 5-2)

	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
20-Jun-12	693	2,231.7

Table 5-3 Economic Program registrations on the last day of the month: 2008 through June 2012 (See the 2011 SOM, Table 5-3)

	2008		2009		2010		2011		2012	
Month	Registrations	Registered MW	Registrations	Registered MW	Registrations	Registered MW	Registrations	Registered MW	Registrations	Registered MW
Jan	4,906	2,959	4,862	3,303	1,841	2,623	1,609	2,432	1,993	2,385
Feb	4,902	2,961	4,869	3,219	1,842	2,624	1,612	2,435	1,995	2,384
Mar	4,972	3,012	4,867	3,227	1,845	2,623	1,612	2,519	1,996	2,356
Apr	5,016	3,197	2,582	3,242	1,849	2,587	1,611	2,534	189	1,313
May	5,069	3,588	1,250	2,860	1,875	2,819	1,687	3,166	371	1,661
Jun	3,112	3,014	1,265	2,461	813	1,608	1,143	1,912	803	2,337
Jul	4,542	3,165	1,265	2,445	1,192	2,159	1,228	2,062		
Aug	4,815	3,232	1,653	2,650	1,616	2,398	1,987	2,194		
Sep	4,836	3,263	1,879	2,727	1,609	2,447	1,962	2,183		
Oct	4,846	3,266	1,875	2,730	1,606	2,444	1,954	2,179		
Nov	4,851	3,271	1,874	2,730	1,605	2,444	1,954	2,179		
Dec	4,851	3,290	1,853	2,627	1,598	2,439	1,992	2,259		
Avg.	4,727	3,185	2,508	2,852	1,608	2,435	1,696	2,338	1,225	2,073

Table 5-4 shows the zonal distribution of capability in the Economic Program on June 20, 2012. The ComEd Control Zone includes 238 sites and 351.2 MW, 28 percent of sites and 16 percent of registered MW in the Economic Program. The BGE Control Zone includes 61 sites and 612.2 MW, 7.2 percent of sites and 27 percent of registered MW in the Economic Program.

Table 5-4 Distinct registrations and sites in the Economic Program: June 20, 2012[8] (See the 2011 SOM, Table 5-4)

	Registrations	Sites	MW
AECO	7	7	34.6
AEP	9	9	98.5
AP	49	64	111.7
ATSI	18	18	76.9
BGE	55	61	612.2
ComEd	20	23	54.3
DAY	0	0	0.0
DEOK	1	1	35.0
DLCO	25	29	58.7
Dominion	33	37	234.1
DPL	15	15	84.7
JCPL	3	6	46.1
Met-Ed	44	44	58.2
PECO	144	190	123.1
PENELEC	48	52	46.8
Pepco	9	25	127.1
PPL	192	238	351.2
PSEG	21	26	78.4
RECO	0	0	0.0
Total	693	845	2,231.7

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.[9]

Table 5-5 Performance of PJM Economic Program participants without incentive payments: Calendar years 2002 through 2011 and January through June 2012 (See the 2011 SOM, Table 5-5)

	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	15,316	$571,399	$37	6.9

Figure 5-2 shows monthly economic program payments, excluding incentive payments, for 2007 through June 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.[10] 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 2012.[11] In the first six months of 2012, credits were down compared to 2011, although there was some additional response following the implementation of Order 745 in April.

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

9 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 calendar year 2006. No incentive credits were paid in November and December 2007 because the total exceeded the specified cap.

10 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.

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.

Figure 5-2 Economic Program payments by month: Calendar years 2007[12] through 2011 and January through June 2012 (See the 2011 SOM, Figure 5-2)

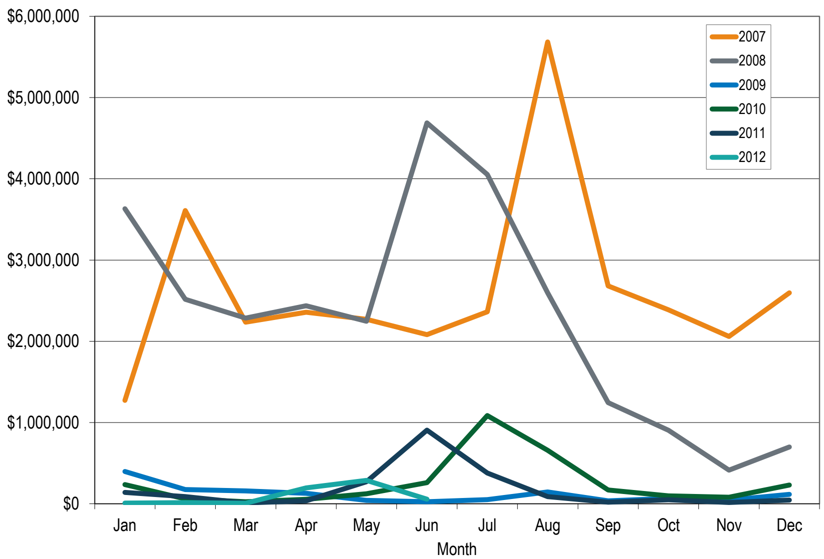


Table 5-6 shows the first six months of 2012 performance in the Economic Program by control zone and participation type. The total number of curtailed MWh for the Economic Program was 15,315.8 and the total payment amount was $571,399.[13] The Dominion Control Zone accounted for $305,935 or 53 percent of all Economic Program credits, associated with 7,714.9 or 50 percent of total program MWh reductions. Despite the implementation of Order 745 on April 2, 2012, credits to demand resources through the Economic Program were $884,925 less than in the first six months of 2011, a decline of 61 percent.

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 5-6 PJM Economic Program participation by zone: January through June 2011 and 2012 (See the 2011 SOM, Table 5-6)

	Credits			MWh Reductions		
	2011	2012	Percent Change	2011	2012	Percent Change
AECO	$0	$0	0%	0.0	0.0	0%
AEP	$0	$0	0%	0.0	0.3	0%
AP	$10,753	$1,643	(85%)	211.2	43.5	(79%)
ATSI	$0	$0	0%	0.0	0.0	0%
BGE	$681,184	$0	0%	1,854.8	0.0	0%
ComEd	$326	$15,407	0%	10.6	533.9	0%
DAY	$13,435	$0	0%	18.8	0.0	0%
DEOK	$0	$0	0%	0.0	0.0	0%
DLCO	$44	$0	(100%)	1.9	0.0	(100%)
Dominion	$679,731	$305,935	(55%)	5,500.1	7,714.9	40%
DPL	$0	$0	0%	0.0	0.0	0%
JCPL	$0	$0	0%	0.0	0.0	0%
Met-Ed	$0	$133	NA	0.0	158.0	NA
PECO	$67,305	$4,296	(94%)	1,420.2	149.2	(89%)
PENELEC	$206	$105,566	0%	6.6	2,631.7	0%
Pepco	$209	$0	0%	3.0	0.0	0%
PPL	$3,131	$1,159	0%	27.4	11.9	(57%)
PSEG	$0	$137,262	0%	0.0	4,072.4	0%
RECO	$0	$0	0%	0.0	0.0	0%
Total	$1,456,324	$571,399	(61%)	9,054.5	15,315.8	69%

Table 5-7 shows total settlements submitted by month for calendar years 2007 through the first six months of 2012. For January through July of 2008, total monthly settlements were higher than the monthly totals for 2007, despite the recent 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, although settlements increased following the implementation of Order 745 on April 2, 2012.

Table 5-7 Settlement days submitted by month in the Economic Program: Calendar years 2007 through 2011 and January through June 2012 (See the 2011 SOM, Table 5-7)

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	81
May	1,649	3,336	918	673	298	142
Jun	1,856	3,184	2,727	1,221	743	1,439
Jul	2,534	3,339	2,879	3,007	1,411	
Aug	3,962	3,848	3,760	2,158	790	
Sep	3,388	3,264	2,570	660	294	
Oct	3,508	1,977	2,361	699	66	
Nov	2,842	1,105	2,321	672	51	
Dec	2,675	986	1,240	894	40	
Total	26,423	32,990	21,605	12,694	4,587	1,800

Table 5-8 shows the number of distinct Curtailment Service Providers (CSPs) and distinct customers actively submitting settlements by month for the period 2008 through the first six months of 2012. The number of active customers per month decreased in early 2009, reaching a three year low in April. Since then, monthly customer counts vary significantly. There was less activity in the first six months of 2012 than in any year since 2009, however, this is changing following the April 2 implementation of FERC 745 rules on demand resource compensation, with increased activity in May and June 2012.

Table 5-9 shows a frequency distribution of MWh reductions and credits at each hour for January through June 2012. The period from hour ending 0800 EPT to 2300 EPT accounts for 95 percent of MWh reductions and 95 percent of credits.

Table 5-10 shows the frequency distribution of Economic Program MWh reductions and credits by real-time zonal, load-weighted, average LMP in various price ranges. Reductions occurred at all price levels. Approximately 99.2 percent of MWh reductions and 99.8 percent of program credits are associated with hours when the applicable zonal LMP was greater than or equal to $25.

Table 5-8 Distinct customers and CSPs submitting settlements in the Economic Program by month: Calendar years 2008 through 2011 and January through June 2012 (See the 2011 SOM, Table 5-8)

	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	162	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	243	15	214		
Aug	17	306	15	400	14	302	14	186		
Sep	17	312	11	181	11	97	7	47		
Oct	13	226	11	93	8	37	3	9		
Nov	14	208	9	143	7	40	3	13		
Dec	13	193	10	160	7	46	5	12		
Total Distinct Active	24	522	25	747	24	438	20	610	19	370

Table 5-9 Hourly frequency distribution of Economic Program MWh reductions and credits: January through June 2012 (See the 2011 SOM, Table 5-9)

	MWh Reductions				Program Credits			
Hour Ending (EPT)	MWh Reductions	Percent	Cumulative MWh	Cumulative Percent	Credits	Percent	Cumulative Credits	Cumulative Percent
1	0	0.00%	0	0.00%	$0	0.00%	$0	0.00%
2	0	0.00%	0	0.00%	$0	0.00%	$0	0.00%
3	0	0.00%	0	0.00%	$0	0.00%	$0	0.00%
4	0	0.00%	0	0.00%	$0	0.00%	$0	0.00%
5	7	0.04%	7	0.04%	$0	0.00%	$0	0.00%
6	18	0.12%	25	0.16%	$305	0.05%	$305	0.05%
7	695	4.54%	720	4.70%	$24,778	4.34%	$25,082	4.39%
8	1,182	7.72%	1,903	12.42%	$33,214	5.81%	$58,296	10.20%
9	1,049	6.85%	2,952	19.27%	$35,772	6.26%	$94,068	16.46%
10	827	5.40%	3,779	24.67%	$30,832	5.40%	$124,901	21.86%
11	723	4.72%	4,502	29.40%	$25,204	4.41%	$150,104	26.27%
12	615	4.01%	5,117	33.41%	$22,030	3.86%	$172,134	30.13%
13	757	4.95%	5,874	38.35%	$30,325	5.31%	$202,459	35.43%
14	1,018	6.64%	6,892	45.00%	$42,153	7.38%	$244,612	42.81%
15	1,508	9.85%	8,400	54.85%	$64,189	11.23%	$308,800	54.04%
16	1,557	10.17%	9,957	65.01%	$63,770	11.16%	$372,570	65.20%
17	1,582	10.33%	11,539	75.34%	$67,432	11.80%	$440,003	77.00%
18	1,503	9.82%	13,042	85.15%	$61,079	10.69%	$501,081	87.69%
19	789	5.15%	13,831	90.31%	$26,616	4.66%	$527,698	92.35%
20	721	4.71%	14,552	95.02%	$19,840	3.47%	$547,538	95.82%
21	472	3.08%	15,025	98.10%	$16,389	2.87%	$563,927	98.69%
22	253	1.65%	15,278	99.75%	$6,684	1.17%	$570,611	99.86%
23	37	0.24%	15,315	99.99%	$788	0.14%	$571,399	100.00%
24	1	0.01%	15,316	100.00%	$0	0.00%	$571,399	100.00%

Table 5-10 Frequency distribution of Economic Program zonal, load-weighted, average LMP (By hours): January through June 2012 (See the 2011 SOM, Table 5-10)

	MWh Reductions				Program Credits			
LMP	MWh Reductions	Percent	Cumulative MWh	Cumulative Percent	Credits	Percent	Cumulative Credits	Cumulative Percent
$0 to $25	117	0.76%	117	0.76%	$1,147	0.20%	$1,147	0.20%
$25 to $50	13,466	87.92%	13,583	88.68%	$453,570	79.38%	$454,717	79.58%
$50 to $75	1,163	7.59%	14,746	96.28%	$58,705	10.27%	$513,422	89.85%
$75 to $100	437	2.85%	15,183	99.13%	$30,922	5.41%	$544,344	95.27%
$100 to $125	68	0.45%	15,251	99.58%	$4,147	0.73%	$548,491	95.99%
$125 to $150	4	0.03%	15,255	99.61%	$527	0.09%	$549,018	96.08%
$150 to $200	2	0.01%	15,258	99.62%	$293	0.05%	$549,311	96.13%
$200 to $250	2	0.01%	15,259	99.63%	$290	0.05%	$549,601	96.19%
$250 to $300	22	0.14%	15,282	99.78%	$6,310	1.10%	$555,911	97.29%
> $300	34	0.22%	15,316	100.00%	$15,489	2.71%	$571,399	100.00%

Load Management Program

Table 5-11 shows zonal monthly capacity credits that were paid during January through June 2012 to ILR and DR resources. Capacity revenue decreased by $80.0 million, or 29.0 percent, compared to the same period in 2011, from $276 million in 2011 to $196 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.

Table 5-11 Zonal monthly capacity credits: January through June 2012 (See the 2011 SOM, Table 5-13)

Zone	January	February	March	April	May	June	Total
AECO	$343,831	$321,649	$343,831	$332,740	$343,831	$397,836	$2,083,718
AEP	$5,390,887	$5,043,088	$5,390,887	$5,216,988	$5,390,887	$411,388	$26,844,125
APS	$3,410,799	$3,190,748	$3,410,799	$3,300,774	$3,410,799	$179,495	$16,903,415
ATSI	$4,821	$4,510	$4,821	$4,665	$4,821	$19,218	$42,854
BGE	$3,630,571	$3,396,340	$3,630,571	$3,513,455	$3,630,571	$5,254,943	$23,056,450
ComEd	$6,180,266	$5,781,539	$6,180,266	$5,980,903	$6,180,266	$392,831	$30,696,073
DAY	$824,485	$771,293	$824,485	$797,889	$824,485	$61,616	$4,104,254
DEOK	$0	$0	$0	$0	$0	$7,921	$7,921
DLCO	$2,418	$2,262	$2,418	$2,340	$2,418	$48,114	$59,970
Dominion	$3,977,804	$3,721,172	$3,977,804	$3,849,488	$3,977,804	$297,028	$19,801,101
DPL	$817,336	$764,605	$817,336	$790,970	$817,336	$1,475,222	$5,482,805
JCPL	$883,220	$826,238	$883,220	$854,729	$883,220	$1,447,382	$5,778,008
Met-Ed	$909,516	$850,837	$909,516	$880,176	$909,516	$1,010,595	$5,470,155
PECO	$2,375,286	$2,222,042	$2,375,286	$2,298,664	$2,375,286	$2,574,260	$14,220,825
PENELEC	$1,380,240	$1,291,192	$1,380,240	$1,335,716	$1,380,240	$1,107,926	$7,875,554
Pepco	$1,174,938	$1,099,136	$1,174,938	$1,137,037	$1,174,938	$1,845,088	$7,606,075
PPL	$2,739,610	$2,562,861	$2,739,610	$2,651,235	$2,739,610	$3,142,521	$16,575,447
PSEG	$1,468,327	$1,373,596	$1,468,327	$1,420,962	$1,468,327	$2,245,202	$9,444,741
RECO	$22,526	$21,072	$22,526	$21,799	$22,526	$14,415	$124,863
Total	$35,536,881	$33,244,179	$35,536,881	$34,390,530	$35,536,881	$21,932,999	$196,178,353

Table 5-12 shows data on compensation to a hypothetical demand response resource and a generation resource during calendar year 2011, using the BGE zone as an example. Both the DR and generation resource are assumed to be 100 MW. The table shows the revenues that would have been received by a demand resource, under four scenarios, and revenues that would have been received by three types of generation resources.

The four scenarios are:

- The actual six hour event on July 22, 2011, assuming that the demand and generation resources were price takers and received the actual hourly LMP.
- The actual six hour event on July 22, 2011, assuming that the demand resources specified a strike price of $999 per MWh and received that amount while the generation resources were price takers.
- The demand resource was dispatched for the maximum 10 events, each of six hours duration, during the ten highest LMP days from June through August 2011, assuming that the demand and generation resources were price takers and received the actual hourly LMP.
- The demand resource was dispatched for the maximum 10 events, each of six hours duration, assuming that the demand resources specified a strike price of $999 per MWh and received that amount while the generation resources were price takers.

In summary, the results show, for each scenario, the hours of operation, the E&AS (energy and ancillary services) market revenues, capacity market revenues, total revenues and the average net revenue margin per MWh provided.

The results show that a 100 MW demand resource, limited to operating for only ten events with a maximum duration of six hours, or a total of 60 hours, if it takes the strike price option, could earn about as much in total net revenue as a 100 MW combustion turbine unit or a 100 MW coal unit, operating over thousands of hours. The majority of demand resources use the strike price option. In addition, the results show that the average margin per MWh is substantially higher for the demand resources than for the generation resources.

Table 5-12 Comparison of Demand Response and Generation Resources, Calendar year 2011[14,15] (New Table)

	DSR (July 22, 2011 Event)	DSR (July 22, 2011 Event)	DSR (10x6 Events)	DSR ($999 strike price)	DSR (No Events)	CC	CT	Coal
Hours of Operation	6	6	60	60	0	7,524	2,489	4,751
E&AS	$230,244	$599,400	$1,751,744	$5,994,000	$0	$13,080,600	$4,864,200	$5,694,000
Capacity	$4,985,779	$4,985,779	$4,985,779	$4,985,779	$4,985,779	$4,985,779	$4,985,779	$4,985,779
Total	$5,216,023	$5,585,179	$6,737,523	$10,979,779	$4,985,779	$18,066,379	$9,849,979	$10,679,779
Average margin per MWh	$384	$999	$292	$999		$17	$20	$12

14 CC, CT, and Coal plant revenue for BGE zone from the *2011 State of the Market Report for PJM*.
15 Capacity revenues do not net out the cost of capacity for either generation or demand resources.