Demand Response

Markets require both a supply side and a demand side to function effectively. The demand side of wholesale electricity markets is underdeveloped. Wholesale power markets will be more efficient when the demand side of the electricity market becomes fully functional without depending on special programs as a proxy for full participation.

Overview

- **Demand Response Activity.** Demand response includes the economic program and the emergency program. The economic program includes the response to energy prices in the energy market. The emergency and pre-emergency programs are part of the capacity market program which includes both capacity payments and associated energy revenues when the capacity is called on to respond.[1] In the first nine months of 2017, the emergency program accounted for 98.6 percent of all revenue received by demand response providers, the economic program for 0.5 percent, synchronized reserve for 0.6 percent and the regulation market for 0.3 percent. Total emergency revenue decreased by $166.0 million, 31.2 percent, from $ 531.3 million in the first nine months of 2016 to $365.4 million in the first nine months of 2017. Capacity market revenue, which comprised 100.0 percent of the emergency demand response program in the first nine months of 2017, decreased by $166.0 million, 31.2 percent, from $531.3 million in the first nine months of 2016 to $365.4 million in the first nine months of 2017.[2]

  Economic program revenue decreased by $1.3 million, 43.2 percent, from $3.0 million in the first nine months of 2016 to $1.7 million in the first nine months of 2017.[3] Synchronized reserve revenue decreased by $0.5 million, 17.2 percent, from $2.7 million in the first nine months of 2016 to $2.3 million in the first nine months of 2017. Regulation revenue increased by $0.5 million, 69.7 percent, from $0.8 million in the first nine months of 2016 to $1.3 million in the first nine months of 2017.

  Total demand response revenue decreased by $167.2 million, 31.1 percent, from $537.8 million in the first nine months of 2016 to $370.6 million in the first nine months of 2017. Not all DR activities in the first nine months of 2017 had been reported to PJM at the time of this report.

  Emergency and Economic demand response energy payments are uplift. LMP does not cover demand response energy payments although emergency demand response can and does set LMP. Emergency demand response energy costs are paid by PJM market participants in proportion to their net purchases in the real-time market. Economic demand response energy costs are paid by real-time exports from the PJM Region and real-time loads in each zone for which the load-weighted average real-time LMP for the hour during which the reduction occurred is greater than the single system price determined under the net benefits test for that month.[4]

- **Demand Response Market Concentration.** The ownership of economic demand response was highly concentrated in the first nine months of 2016 and 2017. The HHI for economic demand response reductions increased from 7658 in the first nine months of 2016 to 7883 in the first nine months of 2017. The ownership of emergency demand response was moderately concentrated in 2017. The HHI for emergency demand response registrations was 1433 for the 2017/2018 Delivery Year. In the 2017/2018 Delivery Year, the four largest companies contributed 69.6 percent of all registered emergency demand response resources.

- **Locational Dispatch of Demand Resources.** Beginning with the 2014/2015 Delivery Year, demand resources are dispatchable for mandatory reduction on a subzonal basis, defined by zip codes, but only if the subzone is defined at least one day before it is dispatched and only until PJM removes the definition of the subzone. More locational dispatch of demand resources in a nodal market improves market efficiency. The goal should be nodal dispatch of demand resources with no advance notice required, as is the case for generation resources.

1 Throughout this document, emergency demand response refers to both emergency and pre-emergency demand response.
2 The total credits and MWh numbers for demand resources were calculated as of October 16, 2017 and may change as a result of continued PJM billing updates.
3 Economic credits are synonymous with revenue received for reductions under the economic load response program.
4 "PJM Manual 28: Operating Agreement Accounting," Rev. 76 (June 1, 2017) at 78.

Recommendations

The MMU recognizes that PJM incorporated some of the recommendations related to Demand Response in the Capacity Performance filing. The status of each recommendation reflects the status at September 30, 2017.

- The MMU recommends, as a preferred alternative to having PJM demand side programs, that demand response be on the demand side of the markets and that customers be able to avoid capacity and energy charges by not using capacity and energy at their discretion and that customer payments be determined only by metered load. (Priority: High. First reported 2014. Status: Not adopted.)
- The MMU recommends that the option to specify a minimum dispatch price under the Emergency and Pre-Emergency Program Full option be eliminated and that participating resources receive the hourly real-time LMP less any generation component of their retail rate. (Priority: Medium. First reported 2010. Status: Not adopted.)
- The MMU recommends that the emergency load response program be treated as an economic resource, responding to economic price signals like other capacity resources and not an emergency program responding only after an emergency is called, and not triggering the definition of a PJM emergency and not triggering a Performance Assessment Hour under the new PJM Capacity Market rules. (Priority: High. First reported 2012. Status: Not adopted.)
- The MMU recommends that the Emergency Program Energy Only option be eliminated because the opportunity to receive the appropriate energy market incentive is already provided in the Economic Program. (Priority: Low. First reported 2010. Status: Not adopted.)
- The MMU recommends that a daily energy market must offer requirement apply to demand resources, comparable to the rule applicable to generation capacity resources.[5] (Priority: High. First reported 2013. Status: Not adopted.)
- The MMU recommends that demand resources be required to provide their nodal location, comparable to generation resources. (Priority: High. First reported 2011. Status: Not adopted.)
- The MMU recommends that PJM require nodal dispatch of demand resources with no advance notice required or, if nodal location is not required, subzonal dispatch of demand resources with no advance notice required. (Priority: High. First reported 2015. Status: Not adopted.)
- The MMU recommends that PJM eliminate the measurement of compliance across zones within a compliance aggregation area (CAA). The multiple zone approach is less locational than the zonal and subzonal approach and creates larger mismatches between the locational need for the resources and the actual response. (Priority: High. First reported 2015. Status: Not adopted.)
- The MMU recommends that measurement and verification methods for demand resources be modified to reflect compliance more accurately. (Priority: Medium. First reported 2009. Status: Not adopted.)
- The MMU recommends that compliance rules be revised to include submittal of all necessary hourly load data, and that negative values be included when calculating event compliance across hours and registrations. (Priority: Medium. First reported 2012. Status: Not adopted.)
- The MMU recommends that PJM adopt the ISO-NE five-minute metering requirements in order to ensure that dispatchers have the necessary information for reliability and that market payments to demand resources be calculated based on interval meter data at the site of the demand reductions.[6] (Priority: Medium. First reported 2013. Status: Not adopted.)
- The MMU recommends that demand response event compliance be calculated for each hour and the penalty structure reflect hourly compliance for the base and capacity performance products. (Priority: Medium. First reported 2013. Status: Partially adopted.)

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

6 See ISO-NE Tariff, Section III, Market Rule 1, Appendix E1 and Appendix E2, "Demand Response," <http://www.iso-ne.com/regulatory/tariff/sect_3/mr1_append-e.pdf>. (Accessed October 17, 2017) ISO-NE requires that DR have an interval meter with five minute data reported to the ISO and each behind the meter generator is required to have a separate interval meter. After June 1, 2017, demand response resources in ISO-NE must also be registered at a single node.

- The MMU recommends that load management testing be initiated by PJM with limited warning to CSPs in order to more accurately represent the conditions of an emergency event. (Priority: Low. First reported 2012. Status: Not adopted.)
- The MMU recommends that shutdown cost 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, be the start cost defined in Manual 15 for generators. (Priority: Low. First reported 2012. Status: Not adopted.)
- The MMU recommends that the Net Benefits Test be eliminated and that demand response resources be paid LMP less any generation component of the applicable retail rate. (Priority: Low. First reported 2015. Status: Not adopted.)
- The MMU recommends that the tariff rules for demand response clarify that a resource and its CSP, if any, must notify PJM of material changes affecting the capability of the resource to perform as registered and to terminate registrations that are no longer capable of responding to PJM dispatch directives because load has been reduced or eliminated, such as in the case of bankrupt and/or out of service facilities. (Priority: Medium. First reported 2015. Status: Not adopted.)
- The MMU recommends that PJM not remove any defined subzone and maintain a public record of all created and removed subzones. (Priority: Low. First reported 2016. Status: Not adopted.)
- The MMU recommends that there be only one demand response product, with an obligation to respond when called for all hours of the year. (Priority: High. First reported 2011. Status: Partially adopted.[7])
- The MMU recommends that the lead times for demand resources be shortened to 30 minutes with an hour minimum dispatch for all resources. (Priority: Medium. First reported 2013. Status: Partially adopted.)
- The MMU recommends capping the baseline for measuring capacity compliance under winter compliance at the customers' PLC, similar to GLD, to avoid double counting. (Priority: High. First reported 2010. Status: Partially adopted.)
- The MMU recommends capping the baseline for measuring compliance under GLD, for the limited summer product, at the customers' PLC. (Priority: High. First reported 2010. Status: Adopted 2015.)
- The MMU recommends that demand resources whose technology type (load drop method) is designated as "Other" explicitly record the technology type. (Priority: Low. First reported 2013. Status: Adopted, 2014.)

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 in the same year in which demand for capacity changes. 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.

In the energy market, if there is to be a demand side program, demand resources should be paid the value of energy, which is LMP less any generation component of the applicable retail rate. There is no reason to have the net benefits test. The necessity for the net benefits test is an illustration of the illogical approach to demand side compensation embodied in paying full LMP to demand resources. The benefit of demand side resources is not that they suppress market prices, but that customers can choose not to consume at the current price of power, that individual customers benefit from their choices and that the choices of all customers are reflected in market prices. If customers face the market price, customers should have the ability to not

7 PJM's Capacity Performance proposal includes this change. See "Reforms to the Reliability Pricing Market ("RPM") and Related Rules in the PJM Open Access Transmission Tariff ("Tariff") and Reliability Assurance Agreement Among Load Serving Entities ("RAA")," Docket No. ER15-632-000 and "PJM Interconnection, L.L.C." Docket No. EL15-29-000.

purchase power and the market impact of that choice does not require a test for appropriateness.

If demand resources are to continue competing directly with generation capacity resources in the PJM Capacity Market, the product must be defined such that it can actually serve as a substitute for generation. This is a prerequisite to a functional market design.

In order to be a substitute for generation, demand resources should be defined in PJM rules as an economic resource, as generation is defined. Demand resources should be required to offer in the Day-Ahead Energy Market and should be called when the resources are required and prior to the declaration of an emergency. Demand resources should be available for every hour of the year and not be limited to a small number of hours.

In order to be a substitute for generation, demand resources should be subject to robust measurement and verification techniques to ensure that transitional DR programs incent the desired behavior. The methods used in PJM programs today are not adequate to determine and quantify deliberate actions taken to reduce consumption.

In order to be a substitute for generation, demand resources should provide a nodal location and should be dispatched nodally to enhance the effectiveness of demand resources and to permit the efficient functioning of the energy market. Both subzonal and multi-zone compliance should be eliminated because they are inconsistent with an efficient nodal market.

In order to be a substitute for generation, compliance by demand resources to PJM dispatch instructions should include both increases and decreases in load. The current method applied by PJM simply ignores increases in load and thus artificially overstates compliance.

In order to be a substitute for generation, reductions should be calculated hourly for dispatched DR. The current rules use the average reduction for the duration of an event. The average reduction across multiple hours does not provide an accurate metric for each hour of the event and is inconsistent with the measurement of generation resources. Measuring compliance hourly would provide accurate information to the PJM system. Under the new CP rules, the performance of demand response during Performance Assessment Hours (PAH) will be measured on an hourly basis.

In order to be a substitute for generation, any demand resource and its Curtailment Service Provider (CSP), should be required to notify PJM of material changes affecting the capability of the resource to perform as registered and to terminate registrations that are no longer capable of responding to PJM dispatch directives, such as in the case of bankrupt and out of service facilities. Generation resources are required to inform PJM of any change in availability status, including outages and shutdown status.

As a preferred alternative, demand response should be on the demand side of the capacity market rather than on the supply side. Rather than complex demand response programs with their attendant complex and difficult to administer rules, customers would be able to avoid capacity and energy charges by not using capacity and energy at their discretion.

The long term appropriate end state for demand resources in the PJM markets should be comparable to the demand side of any market. Customers should use energy as they wish and that usage will determine the amount of capacity and energy for which each customer pays. There would be no counterfactual measurement and verification.

Under this approach, customers that wish to avoid capacity payments would reduce their load during expected high load hours. Capacity costs would be assigned to LSEs and by LSEs to customers, based on actual load on the system during these critical hours. Customers wishing to avoid high energy prices would reduce their load during high price hours. Customers would pay for what they actually use, as measured by meters, rather than relying on flawed measurement and verification methods. No M&V estimates are required. No promises of future reductions which can only be verified by M&V are required. To the extent that customers enter into contracts with CSPs or

LSEs to manage their payments, M&V can be negotiated as part of a bilateral commercial contract between a customer and its CSP or LSE.

This approach provides more flexibility to customers to limit usage at their discretion. There is no requirement to be available year round or every hour of every day. There is no 30 minute notice requirement. There is no requirement to offer energy into the day-ahead market. All decisions about interrupting are up to the customers only and they may enter into bilateral commercial arrangements with CSPs at their sole discretion. Customers would pay for capacity and energy depending solely on metered load.

A transition to this end state should be defined in order to ensure that appropriate levels of demand side response are incorporated in PJM's load forecasts and thus in the demand curve in the capacity market for the next three years. That transition should be defined by the PRD rules, modified as proposed by the MMU.

This approach would work under the current RPM design and this approach would work under the CP design. This approach is entirely consistent with the Supreme Court decision in *EPSA* as it does not depend on whether FERC has jurisdiction over the demand side. This approach will allow FERC to more fully realize its overriding policy objective to create competitive and efficient wholesale energy markets. The decision of the Supreme Court addressed jurisdictional issues and did not address the merits of FERC's approach. The Supreme Court's decision has removed the uncertainty surrounding the jurisdictional issues and created the opportunity for FERC to revisit its approach to demand side.

PJM Demand Response Programs

All PJM demand response programs in can be grouped into economic, emergency and pre-emergency programs or Price Responsive Demand (PRD). Pre-emergency demand response is defined to be dispatchable before an emergency event is declared.[8] Pre-emergency demand response functions as emergency demand response because a pre-emergency event triggers a PAH.

8 147 FERC ¶ 61,103 (2014).

Table 6-1 provides an overview of the key features of PJM demand response programs. Demand response program is used here to refer to pre-emergency, emergency and economic programs. Demand Resources is used here to refer to emergency and pre-emergency load response, which participate in the capacity market, and Economic Resources refer to economic load response, which participates solely in the energy market. All Demand Resources must register as pre-emergency unless the participant relies on behind the meter generation or the resource has environmental restrictions that limit the resource's ability to operate only in emergency conditions.[9] In all demand response programs, CSPs are companies that seek to sign up end-use customers, participants, that have the ability to reduce load. After a demand response event occurs, PJM compensates CSPs for their participants' load reductions and CSPs in turn compensate their participants. Only CSPs are eligible to participate in the PJM demand response program, but a participant can register as a PJM special member and become a CSP without any additional cost. PRD does not receive capacity or energy payments. PRD reduces the amount of capacity that must be purchased by the LSE and therefore reduces the LSE's payments for capacity. When PRD load is not on the system, that load also avoids paying for the associated energy. PRD meets it obligation by responding when LMP is at or above price thresholds outlined in the PRD plan.[10] PRD does not have to respond during performance assessment hours (PAH) and therefore is inferior to other capacity resources and is not a substitute for other capacity resources in the capacity performance construct.

9 OA Schedule 1 § 8.5.
10 The Demand Response Subcommittee (DRSC) is currently working to align PRD with the CP designed products.

Table 6-1 Overview of demand response programs

	Emergency and Pre-Emergency Load Response Program			Economic Load Response Program	Price Responsive Demand
	Load Management (LM)				
Market	Capacity Only	Capacity and Energy	Energy Only	Energy Only	Capacity Only
Capacity Market	DR cleared in RPM	DR cleared in RPM	Not included in RPM	Not included in RPM	PRD cleared in RPM
Dispatch Requirement	Mandatory Curtailment	Mandatory Curtailment	Voluntary Curtailment	Dispatched Curtailment	Price Threshold
Penalties	RPM event or test compliance penalties	RPM event or test compliance penalties	NA	NA	RPM event or test compliance penalties
Capacity Payments	Capacity payments based on RPM clearing price	Capacity payments based on RPM clearing price	NA	NA	Avoided capacity costs
Energy Payments	No energy payment	Energy payment based on submitted higher of "minimum dispatch price" and LMP. Energy payment during PJM declared Emergency Event mandatory curtailments.	Energy payment based on submitted higher of "minimum dispatch price" and LMP. Energy payment only for voluntary curtailments.	Energy payment based on full LMP. Energy payment for hours of dispatched curtailment.	NA

Non-PJM Demand Response Programs

Within the PJM footprint, states may have additional demand response programs as part of a Renewable Portfolio Standard (RPS) or a separate program. Indiana, Ohio, Pennsylvania and North Carolina include demand response in their RPS.[11] If demand response is dispatched by a state run program, the demand response resources are ineligible to receive payments from PJM during the state dispatch.

Participation in Demand Response Programs

On April 1, 2012, FERC Order No. 745 was implemented in the PJM economic program, requiring payment of full LMP for dispatched demand resources when a net benefits test (NBT) price threshold is exceeded. This approach replaced the payment of LMP minus the charges for wholesale power and transmission included in customers' tariff rates.

Figure 6-1 shows all revenue from PJM demand response programs by market for the first nine months of 2008 through 2017. Since the implementation of the RPM Capacity Market on June 1, 2007, demand response that participated through the capacity market, which includes emergency energy revenue, has been the primary source of revenue to demand response participants.[12]

11 See the *2017 State of the Market Report for PJM: January through September*, Section 8: Environmental and Renewables, Table 8-6.
12 This includes both capacity market revenue and emergency energy revenue for capacity resources.

In the first nine months of 2017, emergency and pre-emergency revenue, which includes capacity and emergency energy revenue, accounted for 98.6 percent of all revenue received by demand response providers, the economic program for 0.5 percent, synchronized reserve for 0.6 percent and the regulation market for 0.3 percent.

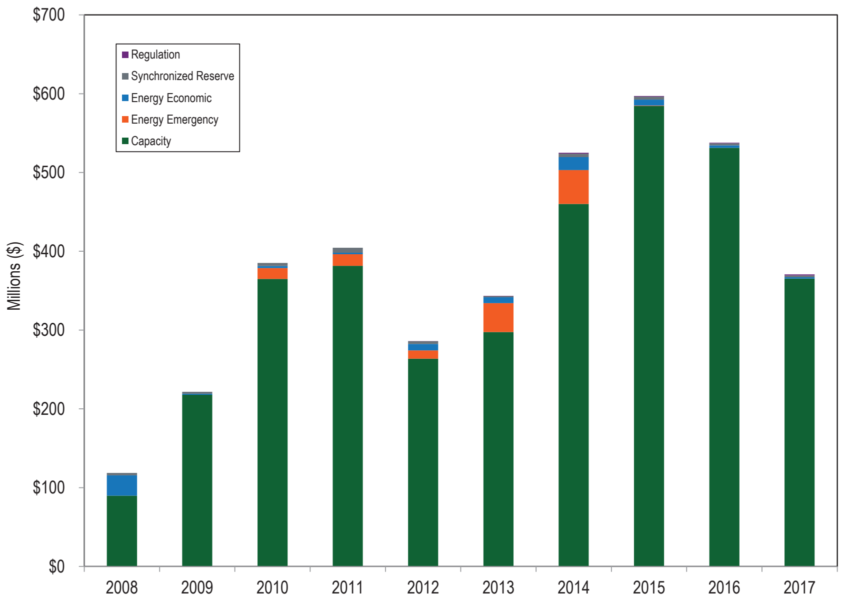
Total emergency revenue decreased by $166.0 million, 31.2 percent, from $531.3 million in the first nine months of 2016 to $365.4 million in the first nine months of 2017. Capacity market revenue, which comprised 100.0 percent of the emergency demand response program in the first nine months of 2017, decreased by $166.0 million, 31.2 percent, from $531.3 million in the first nine months of 2016 to $365.4 million in the first nine months of 2017. This was in part a result of lower capacity market prices in 2017. The capacity revenue in 2016 is from 2015/2016 and 2016/2017 RPM auction clearing prices and the capacity revenue in 2017 is from 2016/2017 and 2017/2018 RPM auction clearing prices. Weighted average capacity market prices decreased $38 per MW-day from $160 in the 2015/2016 Delivery Year to $122 in the 2016/2017 Delivery Year, a 23.9 percent decrease.[13] Total demand response revenue decreased by $167.2 million, 31.1 percent, from $537.8 million in the first nine months of 2016 to $370.6 million in the first nine months of 2017. Total

13 See the *2016 State of the Market Report for PJM*, Volume 2, Section 7: Net Revenues, Table 7-6.

demand response revenue includes economic, pre-emergency, emergency, synchronized reserve and regulation revenue.

Economic program revenue decreased by $1.3 million, 43.2 percent, from $3.0 million in the first nine months of 2016 to $1.7 million in the first nine months of 2017.

Figure 6-1 Demand response revenue by market: January 1 through September 30, 2008 through 2017



Economic Program

Table 6-2 shows registered sites and MW for the last day of each month for the period January 1, 2010 through September 30, 2017. Registration is a prerequisite for CSPs to participate in the economic program. The average number of registrations for economic demand response increased and the average registered MW decreased in the first nine months of 2017 compared to the first nine months of 2016. The average number of monthly registrations decreased by seven, 0.9 percent, from 760 in the first nine months of 2016 to 754 in the first nine months of 2017. The average monthly registered MW decreased by 428 MW, 16.8 percent, from 2,541 MW in the first nine months of 2016 to 2,113 MW in the first nine months of 2017.

Several demand response resources are registered for both the economic and emergency demand response programs. There were 1,671 registrations and 1,265 nominated MW in the emergency program that were also registered in the economic program during the first nine months of 2017.

Table 6-2 Economic program registrations on the last day of the month: January 1, 2010 through September 30, 2017

	2010		2011		2012		2013		2014		2015		2016		2017	
Month	Registrations	Registered MW	Registrations	Registered MW	Registrations	Registered MW	Registrations	Registered MW	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	2,314	1,180	2,325	1,078	2,960	838	2,557	871	2,603
Feb	1,842	2,624	1,612	2,435	1,995	2,384	843	2,327	1,174	2,330	1,076	2,956	835	2,557	842	2,578
Mar	1,845	2,623	1,612	2,519	1,996	2,356	788	2,284	1,185	2,692	1,075	2,949	834	2,556	850	2,576
Apr	1,849	2,587	1,611	2,534	189	1,318	970	2,346	1,194	2,827	1,076	2,938	832	2,556	897	2,574
May	1,875	2,819	1,687	3,166	371	1,669	1,375	2,414	745	2,511	980	2,846	829	2,545	977	2,626
Jun	813	1,608	1,143	1,912	803	2,347	1,302	2,144	928	2,943	871	2,614	518	2,500	577	1,305
Jul	1,192	2,159	1,228	2,062	942	2,323	1,315	2,443	1,036	3,006	870	2,609	519	2,421	589	1,548
Aug	1,616	2,398	1,987	2,194	1,013	2,373	1,299	2,527	1,080	3,033	869	2,609	805	2,569	590	1,541
Sep	1,609	2,447	1,962	2,183	1,052	2,421	1,280	2,475	1,077	2,919	867	2,608	831	2,608	589	1,664
Oct	1,606	2,444	1,954	2,179	828	2,269	1,210	2,335	1,060	2,943	858	2,568	822	2,564		
Nov	1,605	2,444	1,988	2,255	824	2,267	1,192	2,307	1,063	2,995	851	2,566	820	2,564		
Dec	1,598	2,439	1,992	2,259	846	2,283	1,192	2,311	1,071	2,923	850	2,566	807	2,561		
Avg	1,609	2,432	1,606	2,382	1,150	2,175	1,113	2,364	1,067	2,732	974	2,788	774	2,547	754	2,113

The registered MW in the economic load response program are not a good measure of the MW available for dispatch in the energy market. Economic resources can dispatch less or the same amount of MW as registered in the program. Table 6-3 shows the sum of peak economic MW dispatched by registration each month from January 1, 2010 through September 30, 2017. The monthly peak is the sum of each registration's monthly noncoincident peak dispatched MW and annual peak is the sum of each registration's annual noncoincident peak dispatched MW. The peak dispatched MW for all economic demand response registered resources decreased by 243 MW, 17.0 percent, from 1,429 MW in the first nine months of 2016 to 1,186 MW in the first nine months of 2017.[14]

Table 6-3 Sum of peak MW reductions for all registrations per month: January 1, 2010 through September 30, 2017

	Sum of Peak MW Reductions for all Registrations per Month							
Month	2010	2011	2012	2013	2014	2015	2016	2017
Jan	183	132	110	193	446	169	139	123
Feb	121	89	101	119	307	336	128	83
Mar	115	81	72	127	369	198	120	111
Apr	111	80	108	133	146	143	118	54
May	172	98	143	192	151	161	131	155
Jun	209	561	954	433	483	833	121	240
Jul	999	561	1,631	1,088	665	1,362	1,316	936
Aug	794	161	952	497	358	272	249	134
Sep	276	84	451	530	795	816	263	13
Oct	118	81	242	168	214	136	150	
Nov	111	86	165	155	166	127	116	
Dec	114	88	98	168	155	122	147	
Annual	1,202	840	1,942	1,486	1,739	1,858	1,451	1,186

Emergency and Economic demand response energy payments are uplift rather than market payments. Economic demand response energy costs are assigned to real-time exports from the PJM Region and real-time loads in each zone for which the load-weighted average real-time LMP for the hour during which the

14 As a result of the 60 day data lag from event date to settlement, not all settlements for August and September 2017 are incorporated in this report.

reduction occurred is greater than the price determined under the net benefits test for that month.[15] The zonal allocation is shown in Table 6-13.

Table 6-4 shows the total MW reductions made by participants in the economic program and the total credits paid for these reductions for the first nine months of 2010 through 2017. The average credits per MWh paid decreased by $4.94 per MWh, 11.0 percent, from $44.91 per MWh in the first nine months of 2016 to $39.97 per MWh in the first nine months of 2017. The load-weighted, average LMP was 3.5 percent higher in the first nine months of 2017 than in the first nine months of 2016, $30.36 per MWh versus $29.32 per MWh. Curtailed energy for the economic program decreased by 24,406, 36.1 percent, from 67,516 MWh in the first nine months of 2016 to 43,110 MWh in the first nine months of 2017. Total credits paid for economic DR in the first nine months of 2017 decreased by $1.3 million, 43.2 percent, from $3.0 million in the first nine months of 2016 to $1.7 million in the first nine months of 2017.

Table 6-4 Credits paid to the PJM economic program participants: January 1 through September 30, 2010 through 2017

Year (Jan-Sep)	Total MWh	Total Credits	$/MWh
2010	58,280	$2,677,937	$45.95
2011	15,376	$1,943,507	$126.40
2012	121,381	$8,172,654	$67.33
2013	105,299	$7,387,658	$70.16
2014	118,007	$16,510,733	$139.91
2015	103,721	$7,355,263	$70.91
2016	67,516	$3,032,039	$44.91
2017	45,545	$1,722,986	$37.83

Economic demand response resources that are dispatched in both the economic and emergency programs at the same time are settled under emergency rules. For example, assume a demand resource has an economic offer price of $100 per MWh and an emergency strike price of $1,800 per MWh. If this resource were scheduled to reduce in the Day-Ahead Energy Market, the demand resource would receive $100 per MWh, but if an emergency event were called during the economic dispatch, the demand resource would receive its emergency strike price of $1,800 per MWh instead. The rationale for this rule is not clear. All other resources that clear in the day-ahead market are financially firm at the clearing price.

15 "PJM Manual 28: Operating Agreement Accounting," Rev. 76 (June 1, 2017) at 78.

Figure 6-2 shows monthly economic demand response credits and MWh, from January 2010 through June 2017.

Figure 6-2 Economic program credits and MWh by month: January 1, 2010 through September 30, 2017

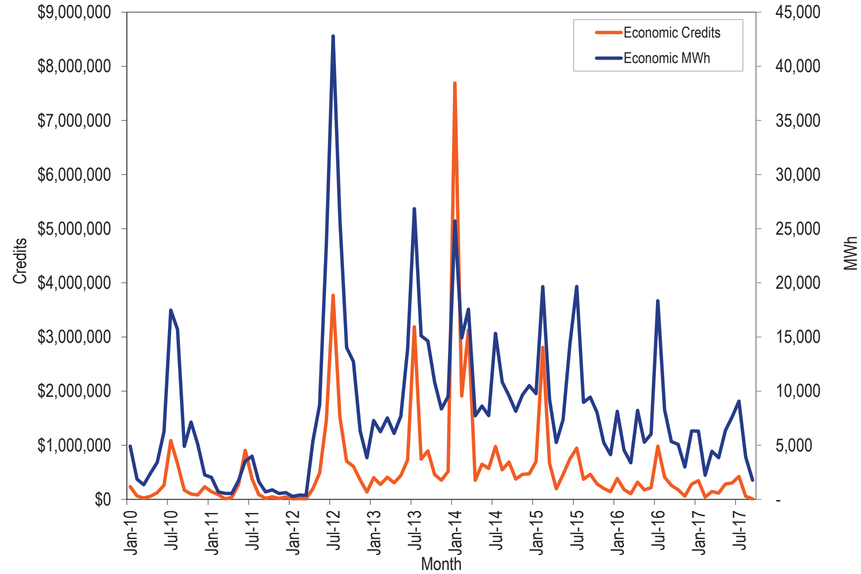


Table 6-5 shows performance for the first nine months of 2016 and 2017 in the economic program by control zone. Total reductions under the economic program decreased by 21,971 MW, 32.5 percent, from 67,516 MW in the first nine months of 2016 to 45,545 MW in the first nine months of 2017. Total revenue under the economic program decreased by $1.3 million, 43.2 percent, from $3.0 million in the first nine months of 2016 to $1.7 million in the first nine months of 2017.[16]

16 Economic demand response reductions that are submitted to PJM for payment but have not received payment are not included in Table 6-5. Payments for Economic demand response reductions are settled monthly.

Table 6-5 PJM economic program participation by zone: January 1 through September 30, 2016 and 2017

	Credits			MWh Reductions			Credits per MWh Reduction		
Zones	Jan-Sep 2016	Jan-Sep 2017	Percent Change	Jan-Sep 2016	Jan-Sep 2017	Percent Change	Jan-Sep 2016	Jan-Sep 2017	Percent Change
AECO	$5,900.85		NA	110		NA	$53.78		
AEP		$8.84	NA		0	NA		$42.19	
APS	$53,971.54	$9,414.81	(82.6%)	1,213	293	(75.8%)	$44.51	$32.12	(27.8%)
ATSI	$381,084.89	$91,257.07	(76.1%)	9,302	3,515	(62.2%)	$40.97	$25.96	(36.6%)
BGE	$488,046.57	$132,077.02	(72.9%)	8,608	2,500	(71.0%)	$56.70	$52.84	(6.8%)
ComED	$201,077.16	$117,143.03	(41.7%)	5,082	3,619	(28.8%)	$39.57	$32.37	(18.2%)
DEOK	$28,324.20	$12,682.20	(55.2%)	287	91	(68.3%)	$98.81	$139.45	41.1%
Dominion	$848,285.77	$510,804.40	(39.8%)	17,953	7,850	(56.3%)	$47.25	$65.07	37.7%
DPL	$23,435.88	$11,019.81	(53.0%)	410	516	25.8%	$57.12	$21.36	(62.6%)
JCPL	$176,199.52	$85,579.20	(51.4%)	3,051	1,242	(59.3%)	$57.75	$68.92	19.3%
Met-Ed	$3,677.98	$9,816.66	166.9%	79	223	182.9%	$46.66	$44.02	(5.7%)
PECO	$44,373.11	$4,815.59	(89.1%)	491	152	(69.1%)	$90.40	$31.73	(64.9%)
PENELEC	$330,930.20	$176,804.20	(46.6%)	8,953	7,813	(12.7%)	$36.96	$22.63	(38.8%)
PEPCO	$36,066.78	$53,642.85	48.7%	1,009	1,095	8.5%	$35.75	$49.00	37.1%
PPL	$51,603.48	$57,285.40	11.0%	894	1,508	68.6%	$57.70	$37.99	(34.2%)
PSEG	$359,061.40	$450,634.67	25.5%	10,074	15,129	50.2%	$35.64	$29.79	(16.4%)
Total	$3,032,039.33	$1,722,976.91	(43.2%)	67,516	45,545	(32.5%)	$44.91	$37.83	(15.8%)

Table 6-6 shows total settlements submitted for the first nine months of 2010 through 2017. A settlement is counted for every day on which a registration is dispatched in the economic program.

Table 6-6 Settlements submitted in the economic program: January 1 through September 30, 2010 through 2017

Year	Jan-Sep 2010	Jan-Sep 2011	Jan-Sep 2012	Jan-Sep 2013	Jan-Sep 2014	Jan-Sep 2015	Jan-Sep 2016	Jan-Sep 2017
Number of Settlements	3,367	703	5,334	2,358	2,425	1,851	1,524	1,417

Table 6-7 shows the number of CSPs, and the number of participants in their portfolios, submitting settlements by year for the first nine months of 2010 through 2017. The number of active participants increased by 13, 22.4 percent, from 58 in the first nine months of 2016 to 71 in the first nine months of 2017. All participants must be included in a CSP.

Table 6-7 Participants and CSPs submitting settlements in the economic program by year: January 1 through September 30, 2010 through 2017

	(Jan-Sep) 2010		(Jan-Sep) 2011		(Jan-Sep) 2012		(Jan-Sep) 2013		(Jan-Sep) 2014		(Jan-Sep) 2015		(Jan-Sep) 2016		(Jan-Sep) 2017	
	Active CSPs	Active Participants	Active CSPs	Active Participants	Active CSPs	Active Participants	Active CSPs	Active Participants	Active CSPs	Active Participants	Active CSPs	Active Participants	Active CSPs	Active Participants	Active CSPs	Active Participants
Total Distinct Active	16	257	15	203	22	428	20	273	16	154	18	114	12	58	12	71

The ownership of economic demand response resources was highly concentrated in the first nine months of 2016 and 2017.[17] Table 6-8 shows the average hourly HHI for each month and the average hourly HHI for 2016 and the first nine months of 2017. Table 6-8 also lists the share of reductions provided by, and the share of credits claimed by the four largest parent companies in each year. In the first nine months of 2017, 82.6 percent of all economic DR reductions and 85.1 percent of economic DR revenue were attributable to the four largest parent companies. The HHI for economic demand response increased 225 points, 2.9 percent, from 7658 in the first nine months of 2016 to 7883 in the first nine months of 2017.

Table 6-8 HHI and market concentration in the economic program: January 1, 2016 through September 30, 2017[18]

	HHI			Top Four Companies Share of Reduction			Top Four Companies Share of Credit		
Month	2016	2017	Percent Change	2016	2017	Change in Percent	2016	2017	Change in Percent
Jan	7434	8952	20.4%	97.5%	99.7%	2.2%	98.0%	99.6%	1.7%
Feb	7697	9263	20.3%	100.0%	100.0%	0.0%	100.0%	100.0%	0.0%
Mar	8587	8170	(4.9%)	98.9%	99.4%	0.5%	99.4%	98.1%	(0.0%)
Apr	6754	6099	(9.7%)	100.0%	100.0%	0.0%	100.0%	100.0%	0.0%
May	8150	7095	(12.9%)	97.9%	100.0%	2.1%	96.3%	100.0%	3.7%
Jun	7700	7702	0.0%	100.0%	91.6%	(8.4%)	100.0%	88.9%	(8.4%)
Jul	7282	7549	3.7%	96.0%	92.4%	(3.6%)	89.2%	93.0%	3.2%
Aug	7557	8006	5.9%	93.5%	99.6%	6.1%	89.3%	98.3%	10.3%
Sep	7631	9887	29.6%	93.8%			92.7%		
Oct	7710			100.0%			100.0%		
Nov	8856			100.0%			100.0%		
Dec	7541			93.4%			92.5%		
Total	7658	7883	2.9%	90.6%	82.6%	(8.0%)	90.3%	85.1%	(5.2%)

Table 6-9 shows average MWh reductions and credits by hour for the first nine months of 2016 and 2017. In the first nine months of 2016, 88.5 percent of reductions and 87.7 percent of credits occurred in hours ending 0900 to 2100, and in the first nine months of 2017, 92.9 percent of reductions and 90.7 percent of credits occurred in hours ending 0900 to 2100.

17 Parent companies may own one CSP or multiple CSPs. All HHI calculations in this section are at the parent company level.
18 September 2017 is omitted for the top four companies share of reductions and credits columns due to confidentiality requirements.

Table 6-9 Hourly frequency distribution of economic program MWh reductions and credits: January 1 through September 30, 2016 and 2017

	MWh Reductions			Program Credits		
Hour Ending (EPT)	Jan-Sep 2016	Jan-Sep 2017	Percent Change	Jan-Sep 2016	Jan-Sep 2017	Percent Change
1 through 6	622	529	(15%)	$15,553	$35,014	125%
7	2,226	335	(85%)	$142,574	$20,767	(85%)
8	3,629	1,212	(67%)	$175,577	$54,407	(69%)
9	4,109	1,839	(55%)	$147,014	$59,329	(60%)
10	3,475	2,153	(38%)	$117,229	$62,244	(47%)
11	2,906	2,398	(18%)	$94,898	$68,360	(28%)
12	2,979	2,595	(13%)	$101,787	$78,086	(23%)
13	3,189	2,797	(12%)	$115,445	$89,537	(22%)
14	4,804	3,664	(24%)	$235,107	$134,309	(43%)
15	5,637	4,199	(26%)	$293,362	$161,236	(45%)
16	6,765	4,467	(34%)	$334,271	$176,979	(47%)
17	7,229	4,545	(37%)	$357,406	$204,461	(43%)
18	6,929	4,650	(33%)	$351,651	$209,652	(40%)
19	5,280	3,803	(28%)	$230,802	$145,281	(37%)
20	3,570	3,098	(13%)	$128,322	$100,625	(22%)
21	2,879	2,104	(27%)	$102,168	$73,670	(28%)
22	723	723	0%	$22,310	$37,790	69%
23 through 24	564	435	(23%)	$10,639	$11,239	6%
Total	67,516	45,545	(33%)	$2,976,115	$1,722,986	(42%)

Table 6-10 shows the distribution of economic program MWh reductions and credits by ranges of real-time zonal, load-weighted, average LMP in the first nine months of 2016 and 2017. In the first nine months of 2017, 0.1 percent of MWh reductions and 0.3 percent of program credits occurred during hours when the applicable zonal LMP was higher than $175 per MWh.

Table 6-10 Frequency distribution of economic program zonal, load-weighted, average LMP (By hours): January 1 through September 30, 2016 and 2017

	MWh Reductions			Program Credits		
LMP	Jan-Sep 2016	Jan-Sep 2017	Percent Change	Jan-Sep 2016	Jan-Sep 2017	Percent Change
$0 to $25	10,009	2,762	(72%)	$221,540	$23,209	(90%)
$25 to $50	42,907	31,108	(27%)	$1,576,090	$891,476	(43%)
$50 to $75	7,992	7,486	(6%)	$482,040	$412,898	(14%)
$75 to $100	2,265	2,169	(4%)	$165,376	$169,469	2%
$100 to $125	2,217	960	(57%)	$227,592	$90,768	(60%)
$125 to $150	1,046	640	(39%)	$135,013	$77,382	(43%)
$150 to $175	470	349	(26%)	$58,826	$51,945	(12%)
> $175	594	63	(89%)	$109,361	$5,839	(95%)
Total	67,499	45,538	(33%)	$2,975,839	$1,722,986	(42%)

Following Order No. 745, all ISO/RTOs are required to calculate an NBT threshold price each month above which the net benefits of DR are deemed to exceed the cost to load. PJM calculates the NBT price threshold by first taking the generation offers from the same month of the previous year. For example, the NBT price calculation for February 2016 was calculated using generation offers from February 2015. PJM then adjusts these offers to account for changes in fuel prices and uses these adjusted offers to create an average monthly supply curve. PJM estimates a function that best fits this supply curve and then finds the point on this curve where the elasticity is equal to 1.[19] The price at this point is the NBT threshold price.

The NBT test is a crude tool that is not based in market logic. The NBT threshold price is a monthly estimate calculated from a monthly supply curve that does not incorporate real-time or day-ahead prices. In addition, it is a single price used to trigger payments to economic demand response resources throughout the entire RTO, regardless of their location.

The necessity for the NBT test is an illustration of the illogical approach to demand side compensation embodied in paying full LMP to demand resources. The benefit of demand side resources is not that they suppress market prices, but that customers can choose not to consume at the current price of power, that individual customers benefit from their choices and that the choices of all customers are reflected in market prices. If customers face the market price, customers should have the ability to not purchase power and the market impact of that choice does not require a test for appropriateness.

When the LMP is above the NBT threshold price, economic demand response resources that reduce their power consumption are paid the full LMP. When the LMP is below the NBT threshold price, economic demand response resources are not paid for any load reductions.

Table 6-11 shows the NBT threshold price from April 1, 2012, when Order No. 745 was implemented in PJM, through September 30, 2017.

Table 6-11 Net benefits test threshold prices: April 1, 2012 through September 30, 2017

	Net Benefits Test Threshold Price ($/MWh)					
Month	2012	2013	2014	2015	2016	2017
Jan		$25.72	$29.51	$29.63	$23.67	$32.60
Feb		$26.27	$30.44	$26.52	$26.71	$31.57
Mar		$25.60	$34.93	$24.99	$22.10	$30.56
Apr	$25.89	$26.96	$32.59	$24.92	$19.93	$30.45
May	$23.46	$27.73	$32.08	$23.79	$20.69	$29.77
Jun	$23.86	$28.44	$31.62	$23.80	$20.62	$27.14
Jul	$22.99	$29.42	$31.62	$23.03	$20.73	$24.42
Aug	$24.47	$28.58	$29.85	$23.17	$23.24	$22.75
Sep	$24.93	$28.80	$29.83	$21.69	$24.70	$21.51
Oct	$25.96	$29.13	$30.20	$21.48	$26.50	
Nov	$25.63	$31.63	$29.17	$22.28	$29.27	
Dec	$25.97	$28.82	$29.01	$22.31	$29.71	
Average	$24.80	$28.09	$30.91	$23.97	$23.99	$27.86

Table 6-12 shows the number of hours that at least one zone in PJM had day-ahead LMP or real-time LMP higher than the NBT threshold price. In the first nine months of 2017, the highest zonal LMP in PJM was higher than the NBT threshold price 4,319 hours out of 6,551 hours, or 65.9 percent of all hours. Reductions occurred in 2,423 hours, 56.1 percent, of those 4,319 hours in the first nine months of 2017. The last three columns illustrate how often economic demand response activity occurred when LMPs exceeded NBT threshold prices for January 1, 2016 through September 30, 2017. There were

19 "PJM Manual 11: Energy & Ancillary Services Market Operations," Rev.91 (October 3, 2017) at 146.

1.4 percent of hours with demand response below the NBT threshold price in the first nine months of 2016 and 7.0 percent of hours with demand response below the NBT threshold price in the first nine months of 2017.

Table 6-12 Hours with price higher than NBT and DR occurrences in those hours: January 1, 2016 through September 30, 2017

	Number of Hours		Number of Hours with LMP Higher than NBT			Percent of NBT Hours with DR		
Month	2016	2017	2016	2017	Percent Change	2016	2017	Percent Change
Jan	744	744	690	388	(43.8%)	47.5%	63.4%	15.9%
Feb	696	672	595	414	(30.4%)	32.3%	37.7%	5.4%
Mar	743	743	710	484	(31.8%)	29.0%	64.3%	35.2%
Apr	720	720	692	407	(41.2%)	60.1%	72.7%	12.6%
May	744	744	602	445	(26.1%)	70.1%	76.0%	5.9%
Jun	720	720	576	421	(26.9%)	67.7%	67.5%	(0.2%)
Jul	744	744	697	546	(21.7%)	65.6%	67.2%	1.6%
Aug	744	744	704	573	(18.6%)	64.2%	48.9%	(15.3%)
Sep	720	720	651	641	(1.5%)	49.0%	22.6%	(26.4%)
Oct	744		693			48.6%		
Nov	721		401			52.1%		
Dec	744		519			72.4%		
Total	8,784	6,551	8,192	4,319	(47.3%)	59.8%	56.1%	(3.7%)

Economic DR revenues are paid by real-time loads and real-time scheduled exports as an uplift charge. Table 6-13 shows the sum of real-time DR charges and day-ahead DR charges paid in each zone and paid by exports. Real-time loads in AEP, Dominion, and exports paid the highest DR charges in the first nine months of 2017.

Table 6-13 Zonal DR charge: January 1 through September 30, 2017

Zone	January	February	March	April	May	June	July	August	September	Total
AECO	$4,351	$186	$1,126	$727	$3,405	$4,007	$6,985	$830	$95	$21,712
AEP	$51,963	$3,130	$16,305	$13,425	$41,704	$41,958	$62,115	$8,189	$1,217	$240,007
APS	$22,797	$1,432	$6,373	$5,307	$16,047	$16,540	$23,634	$3,181	$447	$95,757
ATSI	$26,957	$2,190	$9,581	$8,097	$22,836	$24,670	$34,318	$4,611	$677	$133,938
BGE	$16,680	$1,915	$4,947	$4,167	$11,813	$13,543	$18,460	$2,224	$308	$74,057
ComEd	$17,767	$1,894	$9,538	$7,797	$22,974	$35,092	$53,462	$6,322	$1,124	$155,971
DAY	$6,596	$584	$2,295	$2,352	$6,343	$6,112	$8,674	$1,170	$175	$34,300
DEOK	$9,180	$540	$2,981	$2,666	$9,256	$9,104	$14,189	$1,878	$273	$50,067
Dominion	$50,509	$2,916	$13,496	$12,459	$36,978	$37,705	$57,187	$6,917	$924	$219,092
DPL	$9,422	$3,025	$2,399	$1,638	$5,916	$6,872	$11,110	$1,335	$164	$41,880
DLCO	$5,236	$348	$1,694	$1,511	$4,925	$5,059	$7,394	$1,001	$142	$27,310
EKPC	$5,657	$280	$1,511	$1,080	$3,839	$3,916	$6,658	$798	$112	$23,852
JCPL	$10,106	$1,241	$3,012	$2,162	$8,835	$10,439	$15,269	$1,856	$232	$53,153
Met-Ed	$6,970	$560	$2,270	$2,586	$5,408	$5,587	$7,931	$1,056	$148	$32,516
PECO	$17,178	$695	$4,851	$4,196	$14,229	$14,831	$22,742	$2,852	$390	$81,964
PENELEC	$7,453	$830	$2,271	$2,774	$5,488	$4,981	$7,016	$1,020	$159	$31,992
Pepco	$14,713	$1,276	$4,379	$3,980	$11,762	$12,650	$18,124	$2,199	$299	$69,381
PPL	$19,561	$1,853	$6,217	$3,928	$12,675	$13,837	$19,092	$2,609	$363	$80,135
PSEG	$18,859	$2,788	$5,675	$4,265	$16,364	$18,918	$26,420	$3,289	$442	$97,020
RECO	$601	$89	$175	$146	$640	$749	$1,021	$125	$17	$3,563
Exports	$24,075	$14,581	$11,475	$23,798	$21,391	$17,626	$14,673	$1,418	$265	$129,302
Total	$346,632	$42,353	$112,574	$109,060	$282,830	$304,195	$436,473	$54,880	$7,973	$1,696,969

Table 6-14 shows the total zonal DR charge per MWh of real-time load and exports in the first nine months of 2017. On a dollar per MWh basis, real-time load and exports in PSEG paid the highest charges for economic demand response in the first nine months of 2017. The highest average zonal monthly per MWh charges for economic demand response occurred in March, when EKPC paid an average of $0.022/MWh.

Table 6-14 Zonal DR charge per MWh of load and exports: January 1 through September 30, 2017

Zone	January	February	March	April	May	June	July	August	September	Zonal Average
AECO	$0.016	$0.010	$0.019	$0.002	$0.001	$0.004	$0.013	$0.005	$0.005	$0.008
AEP	$0.012	$0.009	$0.020	$0.002	$0.000	$0.004	$0.011	$0.004	$0.005	$0.008
APS	$0.013	$0.009	$0.019	$0.002	$0.001	$0.004	$0.011	$0.004	$0.006	$0.008
ATSI	$0.012	$0.009	$0.018	$0.002	$0.001	$0.004	$0.011	$0.004	$0.006	$0.007
BGE	$0.014	$0.008	$0.018	$0.002	$0.000	$0.004	$0.011	$0.005	$0.006	$0.008
ComEd	$0.009	$0.009	$0.013	$0.002	$0.001	$0.005	$0.010	$0.004	$0.006	$0.007
DAY	$0.012	$0.008	$0.018	$0.002	$0.001	$0.004	$0.011	$0.005	$0.006	$0.007
DEOK	$0.013	$0.009	$0.020	$0.002	$0.001	$0.004	$0.011	$0.004	$0.006	$0.008
Dominion	$0.012	$0.009	$0.019	$0.002	$0.001	$0.004	$0.011	$0.004	$0.006	$0.007
DPL	$0.015	$0.010	$0.019	$0.002	$0.001	$0.004	$0.013	$0.006	$0.006	$0.008
DLCO	$0.013	$0.009	$0.019	$0.002	$0.001	$0.004	$0.012	$0.004	$0.006	$0.008
EKPC	$0.012	$0.009	$0.022	$0.002	$0.001	$0.004	$0.011	$0.004	$0.005	$0.008
JCPL	$0.018	$0.011	$0.018	$0.002	$0.001	$0.004	$0.013	$0.008	$0.006	$0.009
Met-Ed	$0.014	$0.010	$0.018	$0.002	$0.001	$0.004	$0.013	$0.006	$0.008	$0.008
PECO	$0.015	$0.010	$0.019	$0.002	$0.001	$0.004	$0.014	$0.004	$0.006	$0.008
PENELEC	$0.013	$0.008	$0.018	$0.002	$0.001	$0.004	$0.011	$0.007	$0.008	$0.008
Pepco	$0.014	$0.009	$0.018	$0.002	$0.001	$0.004	$0.011	$0.005	$0.006	$0.008
PPL	$0.015	$0.010	$0.018	$0.002	$0.001	$0.004	$0.013	$0.007	$0.006	$0.008
PSEG	$0.016	$0.010	$0.018	$0.002	$0.001	$0.004	$0.013	$0.009	$0.006	$0.009
RECO	$0.017	$0.011	$0.017	$0.002	$0.001	$0.004	$0.013	$0.008	$0.006	$0.009
Exports	$0.006	$0.005	$0.008	$0.001	$0.000	$0.004	$0.006	$0.009	$0.009	$0.005
Monthly Average	$0.013	$0.009	$0.018	$0.002	$0.001	$0.004	$0.012	$0.006	$0.006	$0.008

Table 6-15 Monthly day-ahead and real-time DR charge: January 1, 2016 through September 30, 2017

	Day-ahead DR Charge			Real-time DR Charge			Per MWh Charge ($/MWh)		
Month	2016	2017	Percent Change	2016	2017	Percent Change	2016	2017	Percent Change
Jan	$163,639	$35,134	(78.5%)	$222,281	$311,498	40.1%	$0.010	$0.013	34.9%
Feb	$64,230	$25,562	(60.2%)	$117,388	$16,797	(85.7%)	$0.022	$0.009	(58.3%)
Mar	$14,620	$70,093	379.4%	$90,349	$75,293	(16.7%)	$0.002	$0.018	791.6%
Apr	$94,264	$87,514	(7.2%)	$223,013	$27,455	(87.7%)	$0.009	$0.002	(79.5%)
May	$64,456	$57,455	(10.9%)	$111,839	$225,376	101.5%	$0.010	$0.001	(94.7%)
Jun	$71,162	$132,225	85.8%	$144,731	$171,970	18.8%	$0.004	$0.004	1.6%
Jul	$310,567	$96,325	(69.0%)	$670,150	$327,436	(51.1%)	$0.063	$0.012	(81.7%)
Aug	$98,494	$12,821	(87.0%)	$312,815	$42,059	(86.6%)	$0.010	$0.006	(43.5%)
Sep	$58,644	$0	(100.0%)	$199,396	$7,973	(96.0%)	$0.014	$0.006	(56.6%)
Oct	$40,868			$136,214			$0.003		
Nov	$24,038			$35,821			$0.001		
Dec	$122,480			$159,075			$0.002		
Total	$1,127,462	$517,129		$2,423,073	$1,205,857		$0.013	$0.008	
Jan-Sep	$940,076	$517,129	(45.0%)	$2,091,963	$1,205,857	(42.4%)	$0.016	$0.008	(51.3%)

Table 6-15 shows the monthly day-ahead and real-time DR charges and the per MWh DR charges for January 1, 2016, through September 30, 2017. The day-ahead DR charges decreased by $0.4 million, 45.0 percent, from $0.9 million in the first nine months of 2016 to $0.5 million in the first nine months of 2017. The real-time DR charges decreased $0.8 million, 42.4 percent, from $2.1 million in the first nine months of 2016 to $1.2 million in the first nine months of 2017. The per MWh charge paid by all real-time load and exports for economic DR decreased $0.008/MWh, 51.3 percent, from $0.016/MWh in the first nine months of 2016 to $0.008/MWh in the first nine months of 2017.

Emergency and Pre-Emergency Programs

The emergency and pre-emergency load response programs consist of the limited, extended summer, annual and capacity performance demand response products. To participate as an emergency or pre-emergency demand resource, the CSP must clear MW in an RPM auction. Emergency and pre-emergency resources receive capacity revenue from the capacity market and also receive energy revenue at a predefined strike price from the energy market for reductions during a PJM initiated emergency or pre-emergency event. The rules applied to demand resources in the current market design do not treat demand resources in a manner comparable to generation capacity resources, even though demand resources are sold in the same capacity market, are treated as a substitute for other capacity resources and displace other capacity resources in RPM auctions.

The MMU recommends that if demand resources remain on the supply side of the capacity market, a daily must offer requirement in the Day-Ahead Energy Market apply to demand resources, comparable to the rule applicable to generation capacity resources. This will help to ensure comparability and consistency for demand resources.

The MMU recommends that the option to specify a minimum dispatch price under the Emergency and Pre-Emergency Program Full option be eliminated and that participating resources receive the hourly real-time LMP less any generation component of their retail rate.[20]

The ownership of Demand Resources was moderately concentrated in 2017. The HHI for Demand Resources was 1433 for the 2017/2018 Delivery Year. In the 2017/2018 Delivery Year, the four largest companies contributed 69.6 percent of all registered Demand Resources.

Table 6-16 shows the HHI value for LDAs by delivery year. The HHI values are calculated by the cleared UCAP MW in each delivery year for Demand Resources. The ownership of DR was unconcentrated in one LDA in the 2016/2017 Delivery Year. The ownership of DR in five LDAs was moderately concentrated in the 2016/2017 Delivery Year. The ownership of DR in four LDAs was highly concentrated in the 2016/2017 Delivery Year. The ownership of DR was unconcentrated in one LDA in the 2017/2018 Delivery Year. The ownership of DR in four LDAs was moderately concentrated in the 2017/2018 Delivery Year. The ownership of DR in seven LDAs was highly concentrated in the 2017/2018 Delivery Year.

20 See "Complaint and Motion to Consolidate of the Independent Market Monitor for PJM," Docket No. EL14-20-000 (January 28, 2014); "Comments of the Independent Market Monitor for PJM," Docket No. ER15-852-000 (February 13, 2015).

Table 6-16 HHI value for LDAs by delivery year: 2016/2017 and 2017/2018 Delivery Years

Delivery Year	LDA	UCAP MW	HHI Value
2016/2017	RTO	4,911.1	2522
	MAAC	1,743.3	1913
	EMAAC	1,270.0	2045
	SWMAAC	935.6	5178
	DPL-SOUTH	105.7	2338
	PSEG	395.5	1443
	PS-NORTH	223.4	1666
	PEPCO	663.9	3619
	ATSI	1,343.2	2817
	ATSI-CLEVELAND	468.7	3768
2017/2018	RTO	4,018.0	2593
	MAAC	655.7	1914
	EMAAC	1,057.3	2093
	DPL-SOUTH	86.3	3145
	PSEG	236.9	1409
	PS-NORTH	151.5	2043
	PEPCO	608.4	3726
	ATSI	720.8	3615
	ATSI-CLEVELAND	282.4	4927
	COMED	1,470.8	3353
	BGE	790.7	5309
	PPL	650.5	2167

Table 6-17 shows zonal monthly capacity market revenue to demand resources for the first nine months of 2017. Capacity market revenue decreased in the first nine months of 2017 by $165.9 million, 31.2 percent, from $531.3 million in the first nine months of 2016 to $365.4 million in the first nine months of 2017. This reduction is a result of lower RPM prices and fewer MW of DR cleared in RPM for the 2017/2018 delivery year.

Table 6-17 Zonal monthly capacity revenue: January 1 through September 30, 2017

Zone	January	February	March	April	May	June	July	August	September	Total
AECO	$638,888	$577,060	$638,888	$618,278	$638,888	$474,310	$490,121	$490,121	$474,310	$5,040,863
AEP, EKPC	$3,402,006	$3,072,780	$3,402,006	$3,292,264	$3,402,006	$6,075,467	$6,277,982	$6,277,982	$6,075,467	$41,277,960
APS	$1,666,929	$1,505,613	$1,666,929	$1,613,157	$1,666,929	$3,518,353	$3,635,631	$3,635,631	$3,518,353	$22,427,523
ATSI	$5,891,717	$5,321,551	$5,891,717	$5,701,661	$5,891,717	$3,937,233	$4,068,474	$4,068,474	$3,937,233	$44,709,775
BGE	$3,467,109	$3,131,582	$3,467,109	$3,355,267	$3,467,109	$2,882,337	$2,978,415	$2,978,415	$2,882,337	$28,609,679
ComEd	$3,079,815	$2,781,769	$3,079,815	$2,980,466	$3,079,815	$5,739,694	$5,931,017	$5,931,017	$5,739,694	$38,343,102
DAY	$463,438	$418,589	$463,438	$448,489	$463,438	$732,787	$757,213	$757,213	$732,787	$5,237,393
DEOK	$596,264	$538,561	$596,264	$577,029	$596,264	$658,601	$680,554	$680,554	$658,601	$5,582,692
DLCO	$2,475,103	$2,235,577	$2,475,103	$2,395,261	$2,475,103	$4,301,456	$4,444,838	$4,444,838	$4,301,456	$29,548,733
Dominion	$1,624,702	$1,467,472	$1,624,702	$1,572,292	$1,624,702	$1,445,005	$1,493,172	$1,493,172	$1,445,005	$13,790,222
DPL	$401,741	$362,863	$401,741	$388,781	$401,741	$643,123	$664,561	$664,561	$643,123	$4,572,234
JCPL	$824,053	$744,306	$824,053	$797,470	$824,053	$596,570	$616,455	$616,455	$596,570	$6,439,984
Met-Ed	$1,158,290	$1,046,198	$1,158,290	$1,120,926	$1,158,290	$1,085,982	$1,122,182	$1,122,182	$1,085,982	$10,058,322
PECO	$1,961,524	$1,771,699	$1,961,524	$1,898,249	$1,961,524	$1,800,302	$1,860,312	$1,860,312	$1,800,302	$16,875,752
PENELEC	$1,596,528	$1,442,025	$1,596,528	$1,545,027	$1,596,528	$1,287,278	$1,330,187	$1,330,187	$1,287,278	$13,011,565
Pepco	$2,458,692	$2,220,754	$2,458,692	$2,379,380	$2,458,692	$2,245,984	$2,320,851	$2,320,851	$2,245,985	$21,109,880
PPL	$3,690,484	$3,333,341	$3,690,484	$3,571,436	$3,690,484	$2,410,862	$2,491,224	$2,491,224	$2,410,862	$27,780,404
PSEG	$4,224,394	$3,815,581	$4,224,394	$4,088,123	$4,224,394	$2,493,066	$2,576,169	$2,576,169	$2,493,066	$30,715,354
RECO	$37,300	$33,690	$37,300	$36,097	$37,300	$12,072	$12,475	$12,475	$12,072	$230,780
Total	$39,658,975	$35,821,010	$39,658,975	$38,379,653	$39,658,975	$42,340,483	$43,751,832	$43,751,832	$42,340,483	$365,362,218

Table 6-18 shows the amount of energy efficiency (EE) resources in PJM for the 2012/2013 through 2017/2018 delivery years. Energy efficiency resources are offered in the PJM Capacity Market. The total MW of energy efficiency resources committed increased by 18.7 percent from 1,784.3 MW in the 2016/2017 delivery year to 2,117.9 MW in the 2017/2018 Delivery Year.[21]

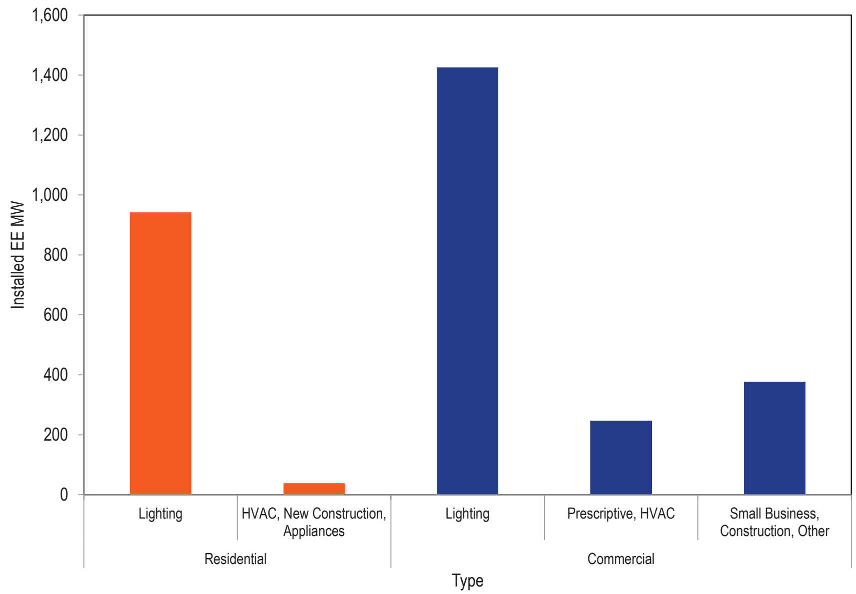
Table 6-18 Energy efficiency resources (MW): 2012/2013 through 2017/2018 Delivery Year

	UCAP (MW) RPM Commitments
1-Jun-12	631.2
1-Jun-13	1,024.8
1-Jun-14	1,282.4
1-Jun-15	1,525.5
1-Jun-16	1,784.3
1-Jun-17	2,117.9

Figure 6-3 shows the amount of installed EE MW in PJM by technology available for the 2017/2018 Delivery Year. An installed EE resource has four years to participate as a capacity resource. The installed EE resources for the 2017/2018 Delivery Year include any installed EE resource between June 1, 2013 and May 31, 2017.

21 See the *2017 Quarterly State of the Market Report for PJM: January through September*, Section 5: Capacity Market, Table 5-10.

Figure 6-3 Installed energy efficiency MW by type: 2017/2018 Delivery Year



FERC accepted PJM's proposed 30 minute lead time as a phased in approach on May 9, 2014, effective on June 1, 2015.[22] The quick lead time demand response was defined after Demand Resources cleared in the RPM base residual auctions for the 2014/2015, 2015/2016, 2016/2017 and 2017/2018 delivery years. PJM submitted a filing on October 20, 2014, to allow DR that is unable to respond within 30 minutes to exit the market without penalty before the mandatory 30 minute lead time with the 2015/2016 Delivery Year.[23] The quick lead time is the default lead time starting June 1, 2015, unless a CSP submits an exception request for 60 or 120 minute notification time due to a physical constraint.[24] The exception requests must clearly state why the resource is unable to respond within 30 minutes based on the defined reasons for exception listed in Manual 18. Once a location is granted a longer lead time, the resource does not need to resubmit for a longer lead time each delivery year. Resources that request longer lead times without a physical constraint are rejected.

Table 6-19 shows the amount of nominated MW and locations by product type and lead time for the 2016/2017 Delivery Year. PJM approved 2,675 locations, or 16.8 percent of all locations, which have 3,593.1 nominated MW, or 38.5 percent of all nominated MW, for exceptions to the 30 minute lead time rule for the 2016/2017 delivery year.

22 See 147 FERC ¶ 61,103 (2014).
23 See PJM Interconnection, L.L.C., Docket No. ER14-135-000 (October 20, 2014).
24 See "PJM Manual 18: Capacity Market," Rev. 38 (July 27, 2017) at 62.

Table 6-19 Nominated MW and locations by product type and lead time: 2016/2017 Delivery Year

	Pre-Emergency MW					Emergency MW					
Lead Type	Limited	Extended Summer	Annual	Capacity Performance	Pre-Emergency Total	Limited	Extended Summer	Annual	Capacity Performance	Emergency Total	Total
Quick Lead (30 Minutes)	4,716.8	453.5	69.0	302.8	5,542.1	185.0	0.0	0.3	22.7	208.1	5,750.2
Short Lead (60 Minutes)	387.2	0.5	0.0	19.1	406.8	16.0	0.0	0.0	0.0	16.0	422.8
Long Lead (120 Minutes)	2,342.9	414.7	101.3	240.2	3,099.2	60.7	0.0	0.0	10.3	71.1	3,170.3
Total	7,446.9	868.7	170.4	562.1	9,048.1	261.7	0.0	0.3	33.1	295.1	9,343.3
	Pre-Emergency Locations					Emergency Locations					
Lead Type	Limited	Extended Summer	Annual	Capacity Performance	Pre-Emergency Total	Limited	Extended Summer	Annual	Capacity Performance	Emergency Total	Total
Quick Lead (30 Minutes)	11,928	658	127	93	12,806	375	0	1	24	400	13,206
Short Lead (60 Minutes)	276	1	0	3	280	33	0	0	0	33	313
Long Lead (120 Minutes)	1,959	21	307	23	2,310	51	0	0	1	52	2,362
Total	14,163	680	434	119	15,396	459	0	1	25	485	15,881

Table 6-20 shows the amount of nominated MW and locations by product type and lead time for the 2017/2018 Delivery Year. PJM approved 2,682 locations, or 17.1 percent of all locations, which have 3,681.5 nominated MW, or 40.2 percent of all nominated MW, for exceptions to the 30 minute lead time rule for the 2017/2018 delivery year.

Table 6-20 Nominated MW and locations by product type and lead time: 2017/2018 Delivery Year

	Pre-Emergency MW					Emergency MW					
Lead Type	Limited	Extended Summer	Annual	Capacity Performance	Pre-Emergency Total	Limited	Extended Summer	Annual	Capacity Performance	Emergency Total	Total
Quick Lead (30 Minutes)	1,410.8	3,137.9	418.0	280.6	5,247.3	51.1	160.4	7.5	7.0	225.9	5,473.2
Short Lead (60 Minutes)	129.5	140.8	46.0	79.6	395.9	3.0	13.2	0.0	0.0	16.1	412.0
Long Lead (120 Minutes)	822.6	1,701.2	476.6	156.4	3,156.7	18.8	43.1	44.7	6.2	112.8	3,269.6
Total	2,362.9	4,979.8	940.6	516.6	8,799.9	72.8	216.7	52.2	13.2	354.8	9,154.7
	Pre-Emergency Locations					Emergency Locations					
Lead Type	Limited	Extended Summer	Annual	Capacity Performance	Pre-Emergency Total	Limited	Extended Summer	Annual	Capacity Performance	Emergency Total	Total
Quick Lead (30 Minutes)	3,712	7,587	1,205	126	12,630	84	269	8	23	384	13,014
Short Lead (60 Minutes)	97	155	47	6	305	17	6	0	0	23	328
Long Lead (120 Minutes)	380	617	1,288	15	2,300	12	35	6	1	54	2,354
Total	4,189	8,359	2,540	147	15,235	113	310	14	24	461	15,696

There are three different ways to measure load reductions of Demand Resources. The Firm Service Level (FSL) method measures the difference between a customer's peak load contribution (PLC) and real time load, multiplied by the loss factor (LF). The Guaranteed Load Drop (GLD) method measures the minimum of: the comparison load minus real time load multiplied by the loss factor; or the PLC minus the real time load multiplied by the loss factor. The comparison load estimates what the load would have been if PJM did not declare a Load Management Event, similar to a CBL, by using a comparable day, same day, customer baseline, regression analysis or backup generation method. Limiting the GLD method to the minimum of the two calculations ensures reductions occur below the

PLC, thus avoiding double counting of load reductions.[25] The Direct Load Control (DLC) method measures when the CSP turns on and turns off the direct load control switch to remotely trigger load reductions. DLC customers were not required to submit meter data to calculate load reductions. The direct load control method is no longer an eligible reduction method after May 31, 2016.[26] The FSL and GLD equations for calculating load reductions are:

$$\text{FSL Reduction} = \text{PLC} - (\text{Load} \cdot \text{LF})$$

$$\text{GLD Reduction} = \text{Minimum of } \{(\text{comparison load} - \text{Load}) \cdot \text{LF}; \text{PLC} - (\text{Load} \cdot \text{LF})\}$$

Table 6-21 shows the MW registered by measurement and verification method and by technology type for the 2016/2017 Delivery Year. If a CSP does not submit a technology type for a registration, the MW are allocated to the Other category. For the 2016/2017 Delivery Year, 99.1 percent use the firm service level (FSL) method and 0.9 percent use the guaranteed load drop (GLD) measurement and verification method. The direct load control method is no longer an eligible reduction method after May 31, 2016.[27]

Table 6-21 Reduction MW by each demand response method: 2016/2017 Delivery Year

	Technology Type								
Measurement and Verification Method	On-site Generation MW	HVAC MW	Refrigeration MW	Lighting MW	Manufacturing MW	Water Heating MW	Other, Batteries or Plug Load MW	Total	Percent by type
Firm Service Level	1,139.3	2,950.0	223.4	805.5	3,930.3	142.4	67.7	9,258.6	99.1%
Guaranteed Load Drop	17.1	25.9	1.6	8.7	31.1	0.1	0.0	84.6	0.9%
Total	1,156.4	2,976.0	225.1	814.2	3,961.4	142.6	67.7	9,343.3	100.0%
Percent by method	12.4%	31.9%	2.4%	8.7%	42.4%	1.5%	0.7%	100.0%	

Table 6-22 shows the MW registered by measurement and verification method and by technology type for the 2017/2018 Delivery Year. For the 2017/2018 Delivery Year, 99.4 percent use the FSL method and 0.6 percent use the GLD measurement and verification method.

Table 6-22 Reduction MW by each demand response method: 2017/2018 Delivery Year

	Technology Type								
Measurement and Verification Method	On-site Generation MW	HVAC MW	Refrigeration MW	Lighting MW	Manufacturing MW	Water Heating MW	Other, Batteries or Plug Load MW	Total	Percent by type
Firm Service Level	1,266.4	2,973.7	237.4	769.6	3,726.2	78.7	52.0	9,104.0	99.4%
Guaranteed Load Drop	8.9	19.4	1.6	3.6	17.1	0.1	-0.0	50.7	0.6%
Total	1,275.4	2,993.1	239.0	773.2	3,743.2	78.8	52.0	9,154.7	100.0%
Percent by method	13.9%	32.7%	2.6%	8.4%	40.9%	0.9%	0.6%	100.0%	

25 135 FERC ¶ 61,212.
26 PJM "Manual 18: PJM Capacity Market," Rev. 38 (July 27, 2017) at 63.
27 *Id.*

Table 6-23 shows the fuel type used in the onsite generators identified in Table 6-21 for the 2016/2017 Delivery Year. Of the 12.4 percent of nominated emergency and pre-emergency demand response MW identified as using onsite generation for the 2016/2017 Delivery Year, 75.5 percent of MW are diesel, 19.2 percent of MW are natural gas and 5.3 percent of MW are gasoline, kerosene, oil, propane or waste products.

Table 6-23 Onsite generation fuel type (MW): 2016/2017 Delivery Year

	2016/2017	
Fuel Type	MW	Percent
Diesel	855.6	74.0%
Natural Gas	273.4	23.6%
Gasoline, Kerosene, Oil, Propane, Waste Products	27.4	2.4%
Total	1,156.4	100.0%

Table 6-24 shows the fuel type used in the onsite generators for the 2017/2018 Delivery Year. Of the 13.9 percent of nominated emergency and pre-emergency demand response MW identified as using onsite generation for the 2017/2018 Delivery Year, 74.5 percent of MW are diesel, 24.4 percent of MW are natural gas and 1.1 percent of MW are gasoline, kerosene, oil, propane or waste products.

Table 6-24 Onsite generation fuel type (MW): 2017/2018 Delivery Year

	2017/2018	
Fuel Type	MW	Percent
Diesel	950.1	74.5%
Natural Gas	311.3	24.4%
Gasoline, Kerosene, Oil, Propane, Waste Products	13.9	1.1%
Total	1,275.4	100.0%

Emergency and Pre-Emergency Event Reported Compliance

Table 6-25 shows the demand response cleared UCAP MW for PJM by Delivery Year. Total demand response cleared in PJM decreased by 2,188.4 MW, or 11.5 percent, from 15,453.7 MW in the 2015/2016 Delivery Year to 13,265.3 MW in the 2016/2017 Delivery Year. The DR percent of capacity decreased by 3.9 percent, from 8.9 percent in the 2015/2016 Delivery Year to 5.1 percent in the 2016/2017 Delivery Year.

Table 6-25 Demand response cleared MW UCAP for PJM: 2011/2012 through 2016/2017 Delivery Year

Delivery Year	DR Cleared MW UCAP	DR Percent of Capacity MW UCAP
2011/2012	1,826.6	1.4%
2012/2013	8,740.9	6.2%
2013/2014	10,779.6	6.7%
2014/2015	14,943.0	9.3%
2015/2016	15,453.7	8.9%
2016/2017	13,265.3	5.1%

Subzonal dispatch of emergency demand resources was mandatory for the 2014/2015 Delivery Year, but only if the subzone was defined by PJM no later than the day before the dispatch. There are twelve dispatchable subzones in PJM effective April 26, 2017: AEP_CANTON, ATSI_CLE, DPL_SOUTH, PS_NORTH, ATSI_NEWCASOE, PPL_WESCO, ATSI_BLKRIVER, PENELEC_ERIC, APS_EAST, DOM_CHES, DOM_YORKTOWN, AECO_ENGLAND, JCPL_REDBANK.[28] PJM can remove a defined subzone at their discretion. Subzones should not be removed once defined, as the subzone may need to be dispatched again in the future. The METED_EAST, PENELEC_EAST, PPL_EAST and DOM_NORFOLK subzones were removed by PJM. More subzones may have been removed by PJM but PJM does not keep a record of created and removed subzones. The MMU recommends that PJM not remove any defined subzones and maintain a public record of all created and removed subzones.

The subzone design and closed loop interfaces are related. PJM implemented closed loop interfaces with the stated purpose of improving the incorporation of reactive constraints into energy prices and to allow emergency DR to set price.[29] PJM applies closed loop interfaces so that it can use units needed for reactive support to set the energy price when they would not otherwise set price under the LMP algorithm. PJM also applies closed loop interfaces so

28 See "Load Management Subzones," <http://www.pjm.com/~/media/markets-ops/demand-response/subzone-definition-workbook.ashx> (Accessed June 23, 2017).

29 See PJM/Alstom. "Approaches to Reduce Energy Uplift and PJM Experiences," presented at the FERC Technical Conference: Increasing Real-Time and Day-Ahead Market Efficiency Through Improved Software in Docket No. AD10-12-006 <http://www.ferc.gov/june-tech-conf/2015/presentations/m2-3.pdf> (June 23, 2015).

that it can use emergency DR resources to set the real-time LMP when DR resources would not otherwise set price under the fundamental LMP logic. Of the 17 closed loop interface definitions, 11 (65 percent) were created for the purpose of allowing emergency DR to set price.[30]

Demand resources can be dispatched for voluntary compliance during any hour of any day, but dispatched resources are not measured for compliance outside of the mandatory compliance window for each demand product. A demand response event during a product's mandatory compliance window also may not result in a compliance score. When demand response events occur for partial hours under 30 minutes or for a subzone dispatch that was not defined one business day before dispatch, the events are not measured for compliance.

Limited, Extended Summer and Annual Demand Resources are paid based on the average performance by registration for the duration of a demand response event. Demand response should measure compliance no less than hourly to accurately report reductions during demand response events. The current rules use the average reduction for the duration of an event. The average duration across multiple hours does not provide an accurate metric for each hour of the event and is inconsistent with the measurement of generation resources. Measuring compliance hourly would provide accurate information to the PJM system. The MMU recommends demand response event compliance be calculated for each hour and the penalty structure reflect hourly compliance.[31]

Under the new capacity performance design of the PJM Capacity Market, compliance for potential penalties will be measured for DR only during performance assessment hours (PAH).[32] When pre-emergency or emergency demand response is dispatched, a PAH is triggered for PJM. As a result, PJM now classifies all demand response as an emergency resource.

The MMU recommends that demand response resources be treated as economic resources like all other capacity resources and therefore that the dispatch of demand response resources not automatically trigger a Performance Assessment Hour (PAH) for CP compliance.

PJM allows compliance to be measured across zones within a compliance aggregation area (CAA).[33] This changes the way CSPs dispatch resources when multiple electrically contiguous areas with the same RPM clearing prices are dispatched. The compliance rules determine how CSPs are paid and thus create incentives that CSPs will incorporate in their decisions about how to respond to PJM dispatch.[34] The multiple zone approach is even less locational than the zonal and subzonal approaches and creates larger mismatches between the locational need for the resources and the actual response. If multiple zones within a CAA are called by PJM, a CSP will dispatch the least cost resources across the zones to cover the CSP's obligation. This can result in more MW dispatched in one zone that are locationally distant from the relief needed and no MW dispatched in another zone, yet the CSP could be considered 100 percent compliant and pay no penalties. More locational deployment of load management resources would improve efficiency. The MMU recommends that demand resources be required to provide their nodal location. Nodal dispatch of demand resources would be consistent with the nodal dispatch of generation.

Load increases are not netted against load decreases for dispatched demand resources across hours or across registrations within hours for compliance purposes, but are treated as zero. This skews the compliance results towards higher compliance since poorly performing demand resources are not used in the compliance calculation. When load is above the peak load contribution during a demand response event, the load reduction is negative; it is a load increase rather than a decrease. PJM ignores such negative reduction values and instead replaces the negative values with a zero MW reduction value. The PJM Tariff and PJM Manuals do not limit the compliance calculation value to a zero MW reduction value.[35] The compliance values PJM reports for demand

30 See the *2017 Quarterly State of the Market Report for PJM: January through September*, Section 4, Energy Uplift, for additional information regarding all closed loop interfaces and the impacts to the PJM markets.
31 PJM "Manual 18: Capacity Market," Rev. 338 (July 27, 2017) at 148.
32 OATT § 1 (Performance Assessment Hour).
33 CAA is "a geographic area of Zones or sub-Zones that are electrically-contiguous and experience for the relevant Delivery Year, based on Resource Clear Prices of, *for Delivery Years through May 31, 2018*, Annual Resources *and for the 2018/2019 Delivery Year and subsequent Delivery Years, Capacity Performance Resources*, the same locational price separation in the Base Residual Auction, the same locational price separation in the First Incremental Auction, the same locational price separation in the Second Incremental Auction, or the same locational price separation in the Third Incremental Auction." OATT § 1.
34 See PJM "Manual 18: Capacity Market," Rev. 38 (July 27, 2017) at 166.
35 OA Schedule 1 § 8.9.

response events are different than the actual compliance values accounting for both increases and decreases in load from demand resources that are called on and paid under the program.

The MMU recommends that compliance rules be revised to include submittal of all necessary hourly load data, and that negative values be included when calculating event compliance across hours and registrations.

Demand Resources that are also registered as Economic Resources have a calculated CBL for the emergency event days. Demand Resources that are not registered as Economic Resources use the hour before a dispatched event as the CBL for measuring energy reductions. A 2011 KEMA report stated that the hour before method performs poorly during early winter hours. “The hour before the reduction event is typically prior to the morning peak, therefore this CBL severely underestimates the morning peak and the subsequent hours.”[36] The calculated CBL more accurately measures reductions for Demand Resources.

Definition of Compliance

Currently, the calculation methods of event and test compliance do not provide reliable results. PJM’s interpretation of load management event rules allows over compliance to be reported when there is no actual over compliance. Settlement locations with a negative load reduction value (load increase) are not netted by PJM within registrations or within demand response portfolios. A resource that has load above their baseline during a demand response event has a negative performance value. PJM limits compliance shortfall values to zero MW. This is not explicitly stated in the Tariff or supporting Manuals and the compliance formulas for FSL and GLD customers do allow negative values.[37]

Limiting compliance to only positive values incorrectly calculates compliance. For example, if a registration had two locations, one with a 50 MWh load increase when called, and another with a 75 MWh load reduction when called, PJM calculates compliance for that registration as a 75 MWh load reduction for that event hour. Negative settlement MWh are not netted across hours or across registrations for compliance purposes. A location with a load increase is set to a zero MW reduction. For example, in a two hour event, if a registration showed a 15 MWh load increase in hour one, but a 30 MWh reduction in hour two, the registration would have a calculated 0 MWh reduction in hour one and a 30 MWh reduction in hour two. This has compliance calculated at an average hourly 15 MWh load reduction for that two hour event, compared to a 7.5 MWh observed reduction. Reported compliance is greater than observed compliance, as locations with load increases, i.e. negative reductions, are treated as zero for compliance purposes.

Changing a demand resource compliance calculation from a negative value to 0 MW inaccurately values event performance and capacity performance. Inflated compliance numbers for an event overstates the true value and capacity of demand resources. A demand response capacity resource that performs negatively is also displacing another capacity resource that could supply capacity during a delivery year. By setting the negative compliance value to 0 MW, PJM is inaccurately calculating the value of demand resources.

An extreme example makes clear the fundamental problems with the use of measurement and verification methods to define the level of power that would have been used but for the DR actions, and the payments to DR customers that result from these methods. The current rules for measurement and verification for demand resources make a bankrupt company, a customer that no longer exists due to closing of a facility or a permanently shut down company, or a company with a permanent reduction in peak load due to a partial closing of a facility, an acceptable demand response customer under some interpretations of the tariff, although it is the view of the MMU that such customers should not be permitted to be included as registered demand resources. Companies that remain in business, but with a substantially reduced load, can maintain their pre-bankruptcy FSL (firm service level to which the customer agrees to reduce in an event) commitment, which can be greater than or equal to the post-bankruptcy peak load. The customer agrees to reduce to a level which is greater than or equal to its new peak load after bankruptcy. When demand

36 See “PJM Empirical Analysis of Demand Response Baseline Methods,” KEMA, April 2011, <https://www.pjm.com/~/media/markets-ops/dsr/pjm-analysis-of-dr-baseline-methods-full-report.ashx>.
37 OA Schedule 1 § 8.9.

response events occur the customer would receive credit for 100 percent reduction, even though the customer took no action and could take no action to reduce load. This problem exists regardless of whether the customer is still paying for capacity. To qualify and participate as a Demand Resource, the customer must have the ability to reduce load. "A participant that has the ability to reduce a measurable and verifiable portion of its load, as metered on an EDC account basis."[38] Such a customer no longer has the ability to reduce load in response to price or a PJM demand response event. CSPs in PJM have and continue to register bankrupt customers as DR customers. PJM finds acceptable the practice of CSPs maintaining the registration of customers with a bankruptcy related reduction in demand that are unable, as a result, to respond to emergency events.

Emergency Energy Payments

Emergency and pre-emergency demand response dispatched during a load management event by PJM are eligible to receive emergency energy payments if registered under the full program option. The full program option includes an energy payment for load reductions during a pre-emergency or emergency event for demand response events and capacity payments.[39] There were 97.9 percent of nominated MW for the 2016/2017 Delivery Year and 98.2 percent of nominated MW for the 2017/2018 Delivery Year registered under the full program option. The dispatch price is set by the CSP before the delivery year starts and cannot be changed during the delivery year. The demand resource energy payments are equal to the higher of hourly zonal LMP or a strike price energy offer made by the participant, including a dollar per MWh minimum dispatch price and an associated shutdown cost. The scarcity pricing rules allow a maximum DR energy price of $1,849 per MWh for the 2016/2017 Delivery Year and the 2017/2018 Delivery Year.[40] [41]

Shutdown costs for demand response resources are not adequately defined in Manual 15. PJM's Cost Development Subcommittee (CDS) approved changes to Manual 15 to eliminate shutdown costs for demand response resources participating in the Synchronized Reserve Market, but not Demand Resources or Economic Resources.[42]

FERC Order No. 831 requires all energy offers above $1,000 per MWh to provide supporting documentation.[43] CSPs must provide documentation to verify the marginal costs of Demand Resources and Economic Resources for offers above $1,000 per MWh. To date, CSPs have indicated that they cannot calculate their marginal costs.

Table 6-26 shows the distribution of registrations and associated MW in the emergency full option across ranges of minimum dispatch prices for the 2016/2017 Delivery Year. The majority of participants, 78.6 percent of locations and 59.8 percent of nominated MW, have a minimum dispatch price between $1,550 and $1,849 per MWh, which is the maximum price allowed for the 2016/2017 Delivery Year, 4.6 percent of location and 3.6 percent of nominated MW have a dispatch price between $0 and $999 per MWh, and 95.4 percent of locations and 96.4 percent of nominated MW have a dispatch price above $1,000 per MWh. Energy offers are further increased by submitted shutdown costs, which, in the 2016/2017 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 $1,000 to $1,275 per MWh strike prices had the highest average at $184.65 per location and $143.22 per nominated MW.

38 OA Schedule 1 § 8.2.
39 *Id.*
40 139 FERC ¶ 61,057 (2012).
41 FERC accepted proposed changes to have the maximum strike price for 30 minute demand response to be $1,000/MWh + 1*Shortage penalty - $1.00, for 60 minute demand response to be $1,000/MWh + (Shortage Penalty/2) and for 120 minute demand response to be $1,100/MWh from ER14-822-000.
42 PJM "Manual 15: Cost Development Guidelines," Rev. 29 (May 15, 2017) at 59.
43 157 FERC ¶ 61,115 (2016).

Table 6-26 Distribution of registrations and associated MW in the full option across ranges of minimum dispatch prices: 2016/2017 Delivery Year[44]

Ranges of Strike Prices ($/MWh)	Locations	Percent of Total	Nominated MW (ICAP)	Percent of Total	Shutdown Cost per Location	Shutdown Cost Per Nominated MW (ICAP)
$0-$999	728	4.6%	331.1	3.6%	$51.81	$49.15
$1,000-$1,275	2,363	15.0%	3,047.1	33.3%	$184.65	$143.22
$1,276-$1,549	287	1.8%	300.3	3.3%	$56.00	$53.51
$1,550-$1,849	12,390	78.6%	5,470.8	59.8%	$41.76	$94.57
Total	15,768	100.0%	9,149.3	100.0%	$62.12	$107.06

Table 6-27 shows the distribution of registrations and associated MW in the emergency full option across ranges of minimum dispatch prices for the 2017/2018 Delivery Year. The majority of participants, 73.4 percent of locations and 65.7 percent of nominated MW, have a minimum dispatch price between $1,550 and $1,849 per MWh, which is the maximum price allowed for the 2017/2018 Delivery Year, 4.8 percent of location and 4.0 percent of nominated MW have a dispatch price between $0 and $999 per MWh, and 95.2 percent of locations and 96.0 percent of nominated MW have a dispatch price above $1,000 per MWh. The shutdown cost of resources with $999 to $1,100 per MWh strike prices had the highest average at $239.13 per location and $937.37 per nominated MW.

Table 6-27 Distribution of registrations and associated MW in the full option across ranges of minimum dispatch: 2017/2018 Delivery Year

Ranges of Strike Prices ($/MWh)	Locations	Percent of Total	Nominated MW (ICAP)	Percent of Total	Shutdown Cost per Location	Shutdown Cost Per Nominated MW (ICAP)
$0-$1	459	2.9%	53.9	0.6%	$0.00	$0.00
$1-$999	291	1.9%	305.4	3.4%	$77.61	$73.94
$999-$1,100	1,288	8.3%	328.6	3.7%	$239.13	$937.37
$1,100-$1,275	1,789	11.5%	2,925.9	32.5%	$94.68	$57.89
$1,275-$1,550	315	2.0%	283.5	3.2%	$57.43	$63.81
$1,550-$1,849	11,437	73.4%	5,093.4	56.7%	$44.54	$100.01
Total	15,579	100.0%	8,990.8	100.0%	$65.95	$114.28

44 In this analysis nominated MW does not include capacity only resources, which do not receive energy market credits.