Ancillary Service Markets

The United States Federal Energy Regulatory Commission (FERC) defined six ancillary services in Order No. 888: scheduling, system control and dispatch; reactive supply and voltage control from generation service; regulation and frequency response service; energy imbalance service; operating reserve – synchronized reserve service; and operating reserve – supplemental reserve service.[1] PJM provides scheduling, system control and dispatch and reactive on a cost basis. PJM provides regulation, energy imbalance, synchronized reserve, and supplemental reserve services through market mechanisms.[2] Although not defined by the FERC as an ancillary service, black start service plays a comparable role. Black start service is provided on the basis of formulaic rates or cost.

The Market Monitoring Unit (MMU) analyzed measures of market structure, conduct and performance for the PJM Synchronized Reserve Market, the PJM DASR Market, and the PJM Regulation Market for the first six months of 2016.

Table 10-1 The Tier 2 Synchronized Reserve Market results were competitive

Market Element	Evaluation	Market Design
Market Structure: Regional Markets	Not Competitive	
Participant Behavior	Competitive	
Market Performance	**Competitive**	**Mixed**

- The Tier 2 Synchronized Reserve Market structure was evaluated as not competitive because of high levels of supplier concentration.
- Participant behavior was evaluated as competitive because the market rules require competitive, cost based offers, although there is concern about failure to comply with the must offer requirement.
- Market performance was evaluated as competitive because the interaction of participant behavior with the market design results in competitive prices.
- Market design was evaluated as mixed. Market power mitigation rules result in competitive outcomes despite high levels of supplier concentration. However, tier 1 reserves are inappropriately compensated when the non-synchronized reserve market clears with a nonzero price.

Table 10-2 The Day-Ahead Scheduling Reserve Market results were competitive

Market Element	Evaluation	Market Design
Market Structure	Competitive	
Participant Behavior	Mixed	
Market Performance	**Competitive**	**Mixed**

- The Day-Ahead Scheduling Reserve Market structure was evaluated as competitive because market participants failed the three pivotal supplier test in only 2.2 percent of all cleared hours in the first six months of 2016.
- Participant behavior was evaluated as mixed because while most offers were equal to marginal costs, a significant proportion of offers reflected economic withholding.
- Market performance was evaluated as competitive because there were adequate offers in every hour to satisfy the requirement and the clearing prices reflected those offers, although there is concern about offers above the competitive level affecting prices. Offers above $0.00 set the clearing price in 560 hours (18.6 percent).
- Market design was evaluated as mixed because while the market is functioning effectively to provide DASR, the three pivotal supplier test and appropriate market power mitigation should be added to the market to ensure that market power cannot be exercised at times of system stress.

Table 10-3 The Regulation Market results were competitive

Market Element	Evaluation	Market Design
Market Structure	Not Competitive	
Participant Behavior	Competitive	
Market Performance	Competitive	Flawed

1 75 FERC ¶ 61,080 (1996).
2 Energy imbalance service refers to the Real-Time Energy Market.

- The regulation market structure was evaluated as not competitive for the first six months of 2016 because the PJM Regulation Market failed the three pivotal supplier (TPS) test in 91.6 percent of the hours in the first six months of 2016.
- Participant behavior in the PJM Regulation Market was evaluated as competitive for the first six months of 2016 because market power mitigation requires competitive offers when the three pivotal supplier test is failed and there was no evidence of generation owners engaging in anti-competitive behavior.
- Market performance was evaluated as competitive, despite significant issues with the market design.
- Market design was evaluated as flawed. While the design of the PJM Regulation Market was improved with changes introduced October 1, 2012, new issues were introduced. The market design has failed to correctly incorporate a consistent implementation of the marginal benefit factor in optimization, pricing and settlement. The market results continue to include the incorrect definition of opportunity cost. The result is significantly flawed market signals to existing and prospective suppliers of regulation.

Overview

Primary Reserve

PJM's primary reserves are made up of resources, both synchronized and non-synchronized, that can provide energy within 10 minutes. Primary reserve is PJM's implementation of the NERC 15-minute contingency reserve requirement.[3]

Market Structure

- **Supply.** Primary reserve is satisfied by both synchronized reserve (generation or demand response currently synchronized to the grid and available within 10 minutes), and non-synchronized reserve (generation currently off-line but available to start and provide energy within 10 minutes).
- **Demand.** The PJM primary reserve requirement is 150 percent of the largest contingency. The primary reserve requirement in the RTO Zone was raised on January 8, 2015, to 2,175 MW of which at least 1,700 MW must be available within the Mid-Atlantic Dominion (MAD) Subzone. Adjustments to the primary reserve requirement can occur when grid maintenance or outages change the largest contingency. The actual demand for primary reserve in the RTO Zone in the first six months of 2016 was 2,180.5 MW. The actual demand for primary reserve in the MAD Subzone was 1,700.3 MW.

Tier 1 Synchronized Reserve

Synchronized reserve is energy or demand reduction synchronized to the grid and capable of increasing output or decreasing load within 10 minutes. Synchronized reserve is of two distinct types, tier 1 and tier 2.

Tier 1 synchronized reserve is part of primary reserve and is the capability of online resources following economic dispatch to ramp up in 10 minutes from their current output in response to a synchronized reserve event. There is no formal market for tier 1 synchronized reserve.

- **Supply.** No offers are made for tier 1 synchronized reserve. The market solution estimates tier 1 synchronized reserve as available 10-minute ramp from the energy dispatch. In the first six months of 2016, there was an average hourly supply of 1,336.5 MW of tier 1 for the RTO Synchronized Reserve Zone, and an average hourly supply of 1,077.6 MW of tier 1 in the Mid-Atlantic Dominion Subzone.
- **Demand.** The default hourly required synchronized reserve requirement is 1,450 MW in the RTO Reserve Zone and 1,450 MW for the Mid-Atlantic Dominion Reserve Subzone. The requirement can be met with tier 1 or tier 2 synchronized reserves.
- **Tier 1 Synchronized Reserve Event Response.** Tier 1 synchronized reserve is paid when a synchronized reserve event occurs and it responds.

3 See PJM. "Manual 10: Pre-Scheduling Operations," Revision. 34 (July 1, 2016), p. 24.

When a synchronized reserve event is called, all tier 1 response is paid the average of five-minute LMPs during the event, rather than hourly integrated LMP, plus $50/MW. This is the Synchronized Energy Premium Price. The synchronized reserve event response credits for tier 1 response are independent of the tier 2 synchronized reserve market clearing price and independent of the non-synchronized reserve market clearing price.

Of the DGP adjusted tier 1 synchronized reserve resources estimated at market clearing, 81.0 percent actually responded during the three distinct synchronized reserve events with duration of 10 minutes or longer in the first six months of 2016. PJM made changes to the way it calculated tier 1 MW for settlements beginning in July 2014. These changes improved the reported response rate by reducing the initial tier 1 estimate.

- **Issues.** The competitive offer for tier 1 synchronized reserves is zero, as there is no incremental cost associated with the ability to ramp up from the current economic dispatch point and the appropriate payment for responding to an event is the five-minute LMP plus $50 per MWh. A tariff change included in the shortage pricing tariff changes (October 1, 2012) added the requirement to pay tier 1 synchronized reserve the tier 2 synchronized reserve market clearing price whenever the non-synchronized reserve market clearing price rises above zero.

  The rationale for this change was and is unclear, but it has had a significant impact on the cost of tier 1 synchronized reserves, resulting in a windfall payment of $10,406,363 to tier 1 resources in 2014, and $34,135,671 in 2015. During the first six months of 2016, payments to tier 1 synchronized reserve resources when the NSRMCP is above $0.00 were $3,335,329. This is a significant reduction from the first six months of 2015 when payments to tier 1 synchronized reserve when the NSRMCP was above $0.00 were $25,806,250.

Tier 2 Synchronized Reserve Market

Tier 2 synchronized reserve is part of primary reserve and is comprised of resources that are synchronized to the grid, that incur costs to be synchronized, that have an obligation to respond with corresponding penalties, and that must be dispatched in order to satisfy the synchronized reserve requirement.

When the synchronized reserve requirement cannot be met with tier 1 synchronized reserve, PJM conducts a market to satisfy the balance of the requirement with tier 2 synchronized reserve. The Tier 2 Synchronized Reserve Market includes the PJM RTO Reserve Zone and a subzone, the Mid-Atlantic Dominion Reserve Subzone (MAD).

Market Structure

- **Supply.** In the first six months of 2016, the supply of offered and eligible synchronized reserve was 20,301.6 MW in the RTO Zone of which 6,928.4 MW (including DSR) was available to the MAD Subzone.
- **Demand.** The default hourly required synchronized reserve requirement was 1,450 MW in the RTO Reserve Zone and 1,450 MW for the Mid-Atlantic Dominion Reserve Subzone. The requirement can be met with tier 1 or tier 2 synchronized reserves. After subtracting the tier 1 synchronized reserve estimate from the default requirement, the hourly average required tier 2 synchronized reserve was 393.9 MW in the MAD Subzone (including self-scheduled) and 618.7 MW in the RTO one (including self-scheduled).
- **Market Concentration.** In the first six months of 2016, the weighted average HHI for settled tier 2 synchronized reserve in the Mid-Atlantic Dominion Subzone was 5503 which is classified as highly concentrated. The MMU calculates that 73.0 percent of hours would have failed a three pivotal supplier test in the Mid-Atlantic Dominion Subzone.

  In the first six months of 2016, the weighted average HHI for cleared tier 2 synchronized reserve in the RTO Synchronized Reserve Zone was 4860 which is classified as highly concentrated. The MMU calculates that 42.7 percent of hours would have failed a three pivotal supplier test in the RTO Synchronized Reserve Zone.

  The MMU concludes from these results that both the Mid-Atlantic Dominion Subzone Tier 2 Synchronized Reserve Market and the RTO Synchronized Reserve Zone Market were characterized by structural market power in the first six months of 2016.

Market Conduct

- **Offers.** There is a must offer requirement for tier 2 synchronized reserve. All nonemergency generation capacity resources are required to submit a daily offer for tier 2 synchronized reserve. Tier 2 synchronized reserve offers from generating units are subject to an offer cap of marginal cost plus $7.50 per MW, plus opportunity cost, which is calculated by PJM.

Market Performance

- **Price.** The weighted average price for tier 2 synchronized reserve for all cleared hours in the Mid-Atlantic Dominion (MAD) Subzone was $4.45 per MW in the first six months of 2016, a decrease of $6.51, 59.4 percent, from the same time period in 2015.

  The weighted average price for tier 2 synchronized reserve for all cleared hours in the RTO Synchronized Reserve Zone was $4.40 per MW in the first six months of 2016, a decrease of $6.21, 59.5 percent, from the same time period in 2015.

Non-Synchronized Reserve Market

Non-synchronized reserve is part of primary reserve and includes the RTO Reserve Zone and the Mid-Atlantic Dominion Reserve Subzone (MAD). Non-synchronized reserve is comprised of nonemergency energy resources not currently synchronized to the grid that can provide energy within 10 minutes. Non-synchronized reserve is available to fill the primary reserve requirement above the synchronized reserve requirement. The market for non-synchronized reserve does not include any direct participation by market participants. PJM defines the demand curve for non-synchronized reserve and PJM defines the supply curve based on nonemergency generation resources that are available to provide energy and can start in 10 minutes or less and on the associated resource opportunity costs calculated by PJM. Generation owners do not submit supply offers.

Market Structure

- **Supply.** In the first six months of 2016, the supply of eligible non-synchronized reserve was 2,279.9 MW in the RTO Zone and 1,641.5 MW in MAD Subzone.
- **Demand.** Demand for non-synchronized reserve is the remaining primary reserve requirement after tier 1 synchronized reserve is estimated and tier 2 synchronized reserve is scheduled.[4] In the RTO Zone, the market cleared an hourly average of 333.2 MW of non-synchronized reserve in the first six months of 2016. The MAD Subzone cleared an average of 302.0 MW in the first six months of 2016.
- **Market Concentration.** In the first six months of 2016, the weighted average HHI for cleared non-synchronized reserve in the MAD Subzone was 3792 which is classified as highly concentrated. In the RTO Zone the weighted average HHI was 3753, which is also highly concentrated. The MMU calculates that 25.7 percent of hours would have failed a three pivotal supplier test in the MAD Subzone and 1.3 hours would have failed a three pivotal supplier test in the RTO Zone.

Market Conduct

- **Offers.** No offers are made for non-synchronized reserve by resource owners. Nonemergency generation resources that are available to provide energy and can start in 10 minutes or less are considered available for non-synchronized reserves by the market solution software. PJM calculates the associated offer prices based on PJM calculations of resource specific opportunity costs.

Market Performance

- **Price.** The non-synchronized reserve price is determined by the opportunity cost of the marginal non-synchronized reserve unit. The non-synchronized reserve weighted average price for all cleared hours (188 hours) in the RTO Reserve Zone was $0.19 per MW in the first six

4 See PJM. "Manual 11: Energy & Ancillary Services Market Operations," Revision 82 (July 1, 2016), p. 81. "Because Synchronized Reserve may be utilized to meet the Primary Reserve requirement, there is no explicit requirement for non-synchronized reserves."

months of 2016 and in 95.7 percent of hours the market clearing price was $0. The non-synchronized reserve weighted average price for the MAD Subzone was the RTO price because the MAD Subzone did not clear separately.

Secondary Reserve (Day-Ahead Scheduling Reserve)

PJM maintains a day-ahead, offer-based market for 30-minute secondary reserve, designed to provide price signals to encourage resources to provide 30-minute reserve.[5] The DASR Market has no performance obligations.

Market Structure

- **Supply.** The DASR Market is a must offer market. Any resources that do not make an offer have their offer set to $0.00 per MW. DASR is calculated by the day-ahead market solution as the lesser of the thirty minute energy ramp rate or the economic maximum MW minus the day-ahead dispatch point for all online units. In the first six months of 2016, the average available hourly DASR was 36,752.2 MW.
- **Demand.** The DASR requirement in 2016 is 5.70 percent of peak load forecast, down from 5.93 percent in 2015. The average DASR MW purchased was 5,501.0 MW per hour in the first six months of 2016.
- **Concentration.** In the first six months of 2016, the DASR Market would have failed a three pivotal supplier test in 2.2 percent of hours.

Market Conduct

- **Withholding.** Economic withholding remains an issue in the DASR Market. The direct marginal cost of providing DASR is zero. PJM calculates the opportunity cost for each resource. All offers by resource owners greater than zero constitute economic withholding. In the first six months of 2016 a daily average of 36.2 percent of units offered above $0.00. In the first six months of 2016 a daily average of 13.5 percent of units offered above $5.
- **DR.** Demand resources are eligible to participate in the DASR Market. Six demand resources have entered offers for DASR.

Market Performance

- **Price.** In the first six months of 2016, the weighted average DASR price for all hours when the DASRMCP was above $0.00 was $0.29, a decrease from $2.99 per MW in the first six months of 2015.

Regulation Market

The PJM Regulation Market is a real-time market. Regulation is provided by generation resources and demand response resources that qualify to follow a regulation signal (RegA or RegD). PJM jointly optimizes regulation with synchronized reserve and energy to provide all three services at least cost. The PJM regulation market design includes three clearing price components: capability; performance; and lost opportunity cost. The marginal benefit factor and performance score translate a resource's capability in actual MW into effective MW.

Market Structure

- **Supply.** In the first six months of 2016, the average hourly eligible supply of regulation for off peak hours was 1,219.5 actual MW (921.7 effective MW). This was an increase of 72.3 actual MW (an increase of 62.7 effective MW) from the same period of 2015, when the average hourly eligible supply of regulation was 1,147.2 actual MW (859.0 effective MW). In the first six months of 2016, the average hourly eligible supply of regulation for on peak hours was 1,161.5 actual MW (921.1 effective MW). This was an increase of 6.8 actual MW (an increase of 3.1 effective MW) from the same period of 2015, when the average hourly eligible supply of regulation was 1,154.7 actual MW (918.0 effective MW).
- **Demand.** The hourly regulation demand is set to 525.0 effective MW for off peak hours (00:00 to 04:59) and 700.0 effective MW for on peak hours (05:00 to 23:59). The average hourly cleared MW for off peak hours were 524.4 actual MW in the first six months of 2016. This is an increase of

5 See PJM. "Manual 35: Definitions and Acronyms," Revision 23 (April 11, 2014), p. 22.

26.2 actual MW from the same period of 2015, when the average hourly regulation cleared MW for off peak hours were 498.2 actual MW. The average hourly cleared MW for on peak hours were 642.0 actual MW in the first six months of 2016. This is a decrease of 42.1 actual MW from the same period of 2015, where the average hourly regulation cleared MW for on peak hours were 684.1 actual MW.

- **Supply and Demand.** The ratio of the average hourly eligible supply of regulation to average hourly regulation demand for on peak hours was 1.86. This is an increase of 7.5 percent from the same period of 2015, when the ratio was 1.73. The ratio of the average hourly eligible supply of regulation to average hourly regulation demand required for off peak hours was 2.28. This is an increase of 9.1 percent from the same period of 2015, when the ratio was 2.09.

- **Market Concentration.** In the first six months of 2016, the weighted average HHI of RegA resources was 2666, which is highly concentrated and the weighted average HHI of RegD resources was 1850, which is highly concentrated. The weighted average HHI of all resources was 1133 which is moderately concentrated. In the first six months of 2016, the three pivotal supplier test was failed in 91.6 percent of hours.

Market Conduct

- **Offers.** Daily regulation offer prices are submitted for each unit by the unit owner. Owners are required to submit a cost-based offer and may submit a price-based offer. Offers include both a capability offer and a performance offer. Owners must specify which signal type the unit will be following, RegA or RegD.[6] In the first six months of 2016, there were 201 resources following the RegA signal and 45 resources following the RegD signal.

Market Performance

- **Price and Cost.** The weighted average clearing price for regulation was $15.90 per effective MW of regulation in the first six months of 2016, a decrease of $25.04 per MW, or 61.2 percent, from the same period of 2015. The cost of regulation in the first six months of 2016 was $18.30 per effective MW of regulation, a decrease of $31.27 per MW, or 63.1 percent, from the same period of 2015. The decreases in regulation price and regulation cost in the first six months of 2016 resulted primarily from reductions in the LOC component of the regulation clearing prices due to lower energy prices in the first six months of 2016 compared to the first six months of 2015.

- **Prices.** RegD resources continue to be over compensated relative to RegA resources due to an inconsistent application of the marginal benefit factor in the optimization, assignment, pricing, and settlement processes. If the Regulation Market were functioning efficiently, RegD and RegA resources would be paid the same price per effective MW.

  The result has been that the PJM Regulation Market has over procured RegD relative to RegA in most hours and has provided a consistently inefficient market signal to participants regarding the value of RegD to the market in every hour. This over procurement began to degrade the ability of PJM to control ACE in some hours while at the same time increasing the cost of regulation. When the price paid for RegD is above the level defined by an accurate MBF function, there is an artificial incentive for inefficient entry of RegD resources.

- **Marginal Benefit Factor Function.** The marginal benefit factor (MBF) measures the substitutability of RegD resources for RegA resources. The marginal benefit factor function is incorrectly applied in the market clearing and incorrectly describes the operational relationship between RegA and RegD.

- **Interim changes to the MBF function.** On December 14, 2015, PJM changed the MBF curve. The modification to the marginal benefit curve did not correct the identified issues with the optimization engine.

Black Start Service

Black start service is required for the reliable restoration of the grid following a blackout. Black start service is the ability of a generating unit to start without

6 See the *2015 State of the Market Report for PJM*, Volume II, Appendix F "Ancillary Services Markets."

an outside electrical supply, or is the demonstrated ability of a generating unit to automatically remain operating at reduced levels when disconnected from the grid (automatic load rejection or ALR).[7]

In the first six months of 2016, total black start charges were $31.7 million with $28.2 million in revenue requirement charges and $140.5 thousand in operating reserve charges. Black start revenue requirements for black start units consist of fixed black start service costs, variable black start service costs, training costs, fuel storage costs, and an incentive factor. Black start operating reserve charges are paid to units scheduled in the Day-Ahead Energy Market or committed in real time to provide black start service under the ALR option or for black start testing. Black start zonal charges for the first six months of 2016 ranged from $0.05 per MW-day in the DLCO Zone (total charges were $25,618) to $4.22 per MW-day in the PENELEC Zone (total charges were $2,324,797).

Reactive

Reactive service, reactive supply and voltage control are provided by generation and other sources of reactive power (measured in MVAr). Reactive power helps maintain appropriate voltages on the transmission system and is essential to the flow of real power (measured in MW).

Reactive capability revenue requirements are based on FERC approved filings. Reactive service charges are paid for scheduling in the Day-Ahead Energy Market and committing in real time units that provide reactive service. In first six months of 2016, total reactive capability charges were $151.3 million, a 2.4 percent increase from $147.8 million in the first six months of 2015. Reactive capability revenue requirement charges increased from $139.6 million in the first six months of 2015 to $151.3 million and Reactive service charges fell from $9.2 million to $626.2 thousand in the first six months of 2016. Total charges in 2016 ranged from $0 in the RECO Zone to $18.51 million in the PSEG Zone.

7 OATT Schedule 1 § 1.3BB.

Ancillary Services Costs per MWh of Load: 1999 through 2016

Table 10-4 shows PJM ancillary services costs for January through June of 1999 through 2016, per MWh of load. The rates are calculated as the total charges for the specified ancillary service divided by the total PJM real-time load in MWh. The scheduling, system control, and dispatch category of costs is comprised of PJM scheduling, PJM system control and PJM dispatch; owner scheduling, owner system control and owner dispatch; other supporting facilities; black start services; direct assignment facilities; and Reliability*First* Corporation charges. The cost per MWh of load in Table 10-4 is a different metric than the cost of each ancillary service per MW of that service. The cost per MWh of load includes the effects both of price changes per MW of the ancillary service and changes in total load.

Table 10-4 History of ancillary services costs per MWh of Load: January through June, 1999 through 2016[8]

Year (Jan-Jun)	Regulation	Scheduling, Dispatch and System Control	Reactive	Synchronized Reserve	Total
1999	$0.08	$0.23	$0.27	$0.00	$0.58
2000	$0.26	$0.32	$0.33	$0.00	$0.91
2001	$0.50	$0.73	$0.22	$0.00	$1.45
2002	$0.31	$0.81	$0.19	$0.00	$1.31
2003	$0.57	$1.06	$0.24	$0.16	$2.03
2004	$0.53	$1.07	$0.26	$0.16	$2.02
2005	$0.58	$0.80	$0.27	$0.11	$1.76
2006	$0.48	$0.74	$0.29	$0.08	$1.59
2007	$0.61	$0.71	$0.27	$0.09	$1.68
2008	$0.73	$0.52	$0.34	$0.08	$1.67
2009	$0.38	$0.32	$0.36	$0.04	$1.10
2010	$0.34	$0.36	$0.37	$0.06	$1.13
2011	$0.33	$0.35	$0.40	$0.10	$1.18
2012	$0.20	$0.41	$0.47	$0.03	$1.11
2013	$0.26	$0.41	$0.65	$0.03	$1.35
2014	$0.46	$0.41	$0.42	$0.20	$1.49
2015	$0.29	$0.41	$0.38	$0.14	$1.22
2016	$0.11	$0.42	$0.40	$0.05	$0.98

8 Table 10-4 no longer includes the heading for "Supplemental Operating Reserve" costs. This heading included day-ahead and balancing operating reserve charges. These charges are accounted for in the Energy Uplift (Operating Reserves) section.

Recommendations

- The MMU recommends that the Regulation Market be modified to incorporate a consistent application of the marginal benefit factor throughout the optimization, assignment and settlement process. (Priority: High. First reported 2012. Status: Not adopted.)
- The MMU recommends a number of market design changes to improve the performance of the Regulation Market, including use of a single clearing price based on actual LMP, modifications to the LOC calculation methodology, a software change to save some data elements necessary for verifying market outcomes, and further documentation of the implementation of the market design through SPREGO. (Priority: Medium. First reported 2010. Status: Partially adopted in 2012.)
- The MMU recommends that the lost opportunity cost in the ancillary services markets be calculated using the schedule on which the unit was scheduled to run in the energy market. (Priority: High. First reported 2010. Status: Partially Adopted.)
- The MMU recommends that the single clearing price for synchronized reserves be determined based on the actual LMP and not the forecast LMP. (Priority: Low. First reported 2010. Status: Adopted.)
- The MMU recommends that the rule requiring the payment of tier 1 synchronized reserve resources when the non-synchronized reserve price is above zero be eliminated immediately. (Priority: High. First reported 2013. Status: Not adopted. Stakeholder process.)
- The MMU recommends that no payments be made to tier 1 resources if they are deselected in the PJM market solution. The MMU also recommends that documentation of the Tier 1 synchronized reserve deselection process be published. (Priority: High. First reported 2014. Status: Adopted July 2014.)
- The MMU recommends that the tier 2 synchronized reserve must offer requirement be enforced. The MMU recommends that PJM define a set of acceptable reasons why a unit can be made unavailable daily or hourly and require operators to select a reason in Markets Gateway whenever making a unit unavailable or setting the daily offer MW to 0 MW. (Priority: Medium. First reported 2013. Status: Not adopted.)
- The MMU recommends that PJM be explicit about why tier 1 biasing is used in the Tier 2 Synchronized Reserve Market. The MMU recommends that PJM define explicit rules for the use of tier 1 biasing during any phase of the market solution and identify the relevant rule for each instance of biasing. (Priority: Low. First reported 2012. Status: Not adopted.)
- The MMU recommends that PJM replace the DASR Market with a real-time secondary reserve product that is available and dispatchable in real time. (Priority: Low. First reported 2013. Status: Not adopted.)
- The MMU recommends that PJM revise the current confidentiality rules in order to specifically allow a more transparent disclosure of information regarding black start resources and their associated payments in PJM. (Priority: Low. First reported 2013. Status: Partially adopted, 2014.)
- The MMU recommends that the three pivotal supplier test and market power mitigation be incorporated in the DASR Market. (Priority: Low. First reported 2009. Status: Not adopted.)
- The MMU recommends that a reason code be attached to every hour in which PJM market operations adds additional DASR MW. (Priority: Medium. First reported 2015. Status: Not adopted.)
- The MMU recommends that separate payments for reactive capability be eliminated and the cost of reactive capability be recovered in the capacity market. (Priority: Medium. New recommendation. Status: Not adopted.)

Conclusion

While the design of the Regulation Market was significantly improved with changes introduced October 1, 2012, a number of issues remain. The market results continue to include the incorrect definition of opportunity cost. The market design has failed to correctly incorporate the marginal benefit factor, or marginal rate of technical substitution, in optimization, pricing and settlement. The market design uses the marginal benefit factor in the optimization (incorrectly) and pricing (correctly), but a mileage ratio in settlement. This failure to correctly incorporate marginal benefit factor into the regulation market design has resulted in both underpayment and overpayment of RegD resources and in the over procurement of RegD resources in some hours. These issues have led to the MMU's conclusion that the regulation market design is flawed.

The structure of each Tier 2 Synchronized Reserve Market has been evaluated and the MMU has concluded that these markets are not structurally competitive as they are characterized by high levels of supplier concentration and inelastic demand. As a result, these markets are operated with market-clearing prices and with offers based on the marginal cost of producing the service plus a margin. As a result of these requirements, the conduct of market participants within these market structures has been consistent with competition, and the market performance results have been competitive. However, compliance with calls to respond to actual synchronized reserve events, while showing improvement in the first six months of 2016 remains less than 100 percent. The must offer requirement for tier 2 synchronized reserve has not been enforced although compliance has improved.

The rule that requires payment of the tier 2 synchronized reserve price to tier 1 synchronized reserve resources when the non-synchronized reserve price is greater than zero, is inefficient and results in a substantial windfall payment to the holders of tier 1 synchronized reserve resources. Such tier 1 resources have no obligation to perform and pay no penalties if they do not perform. Tier 1 resources are paid for their response if they do respond. Tier 1 resources require no additional payment. If tier 1 resources wish to be paid as tier 2 resources, they can make competitive offers in the tier 2 market and take on the associated obligations. Application of this rule added $10.4 million to the cost of primary reserve in 2014, $34.1 million to the cost of primary reserve in 2015, and $3.335 million to the cost of primary reserve in the first six months of 2016.

The benefits of markets are realized under these approaches to ancillary service markets. Even in the presence of structurally noncompetitive markets, there can be transparent, market clearing prices based on competitive offers that account explicitly and accurately for opportunity cost. This is consistent with the market design goal of ensuring competitive outcomes that provide appropriate incentives without reliance on the exercise of market power and with explicit mechanisms to prevent the exercise of market power.

The MMU concludes that the regulation market results were competitive. The MMU concludes that the synchronized reserve market results were competitive. The MMU concludes that the DASR market results were competitive, although there is concern about offers above the competitive level affecting prices.

Primary Reserve

PJM has an obligation to maintain 10 minute reserves (primary reserve) to ensure reliability in the event of disturbances. PJM's primary reserves are made up of resources, both synchronized and non-synchronized, that can provide energy within 10 minutes. Primary reserve is PJM's implementation of the NERC 10-minute contingency reserve requirement.[9] The NERC requirement is to carry sufficient contingency reserves to meet load requirements reliably and economically and provide reasonable protection against instantaneous load variations due to load forecasting error or loss of system capability due to generation malfunction.[10]

Market Structure

Supply

In the first six months of 2016, PJM's primary reserve requirement was 2,175 MW for the RTO Zone, and 1,700 MW for the MAD Subzone[11]. It is satisfied by tier 1 synchronized reserves, tier 2 synchronized reserves and non-synchronized reserves, subject to the requirement that synchronized reserves equal 100 percent of the largest contingency. The synchronized reserve requirement is 1,450 MW in both the Mid-Atlantic Dominion Subzone, and the RTO Zone. After the synchronized reserve requirement is satisfied, the

9 PJM. OATT (effective 2/5/2014), p.1740; § 1.3.29 F Primary Reserve.
10 NERC, IVGTF Task 2.4 Report; Operating Practices, Procedures, and Tools, March 2011, p. 20
11 In this State of the Market Report, scheduled MW and average clearing prices are calculated differently for the RTO Zone than in prior reports. Formerly data were reported for three geographic structures for primary reserve and its component synchronized and non-synchronized reserve. Those three structures were, Full RTO Zone, Mid-Atlantic Dominion Subzone, and the RTO Zone excluding the Mid-Atlantic Subzone. In this report the term RTO Zone is the Full RTO Zone.

remainder of primary reserves can come from the least expensive combination of synchronized and non-synchronized reserves.

Estimated tier 1 is credited against PJM's primary reserve requirement. In the MAD Subzone an average of 1,077.6 MW of tier 1 was identified by the ASO market solution as available hour ahead (Table 10-6). This tier 1 reduced the amount of tier 2 and non-synchronized reserve needed to fill the synchronized reserve and primary reserve requirements. Tier 1 synchronized reserve fully satisfied the MAD Subzone synchronized reserve requirement in only 3.2 percent of hours in the first six months of 2016. In the RTO Zone, an average of 1,336.5 MW of tier 1 was available (Table 10-6). Tier 1 synchronized reserve fully satisfied the RTO Zone synchronized reserve requirement in 38.4 percent of all hours.

Regardless of online/offline state, all nonemergency generation capacity resources must submit a daily offer for tier 2 synchronized reserve in Markets Gateway prior to the offer submission deadline (1800 the day prior to the operating day). Offer MW and other non-cost offer details can be changed during the operating day. Owners are permitted to make resources unavailable for synchronized reserve daily or hourly but only if they are physically unavailable. Certain unit types including nuclear, wind, solar, landfill gas and batteries, are expected to have zero MW tier 2 synchronized reserve offer quantities.[12]

After tier 1 is estimated, the remainder of the synchronized reserve requirement is met by tier 2. In the MAD Subzone, there was an average of 12,767.0 MW of offered tier 2 synchronized reserve available (Figure 10-11) to meet the average tier 2 hourly demand of 397.9 MW (Table 10-5). In the RTO Zone, there was an average of 13,382.7 MW of offered Tier 2 supply, available to meet the average hourly demand of 618.7 MW (Table 10-6).

In the MAD Subzone, there was an average of 1,767.3 MW of eligible non-synchronized reserve supply available to meet the average hourly demand of 302.0 MW (Table 10-6). In the RTO Zone, an hourly average of 2,275.3 MW supply was available to meet the average hourly demand of 333.2 MW (Table 10-5).

Demand

PJM requires that 150 percent of the largest contingency on the system be maintained as primary reserve. Adjustments to this value can occur when grid maintenance or outages change the largest contingency or in cases of hot weather alerts or cold weather alerts.

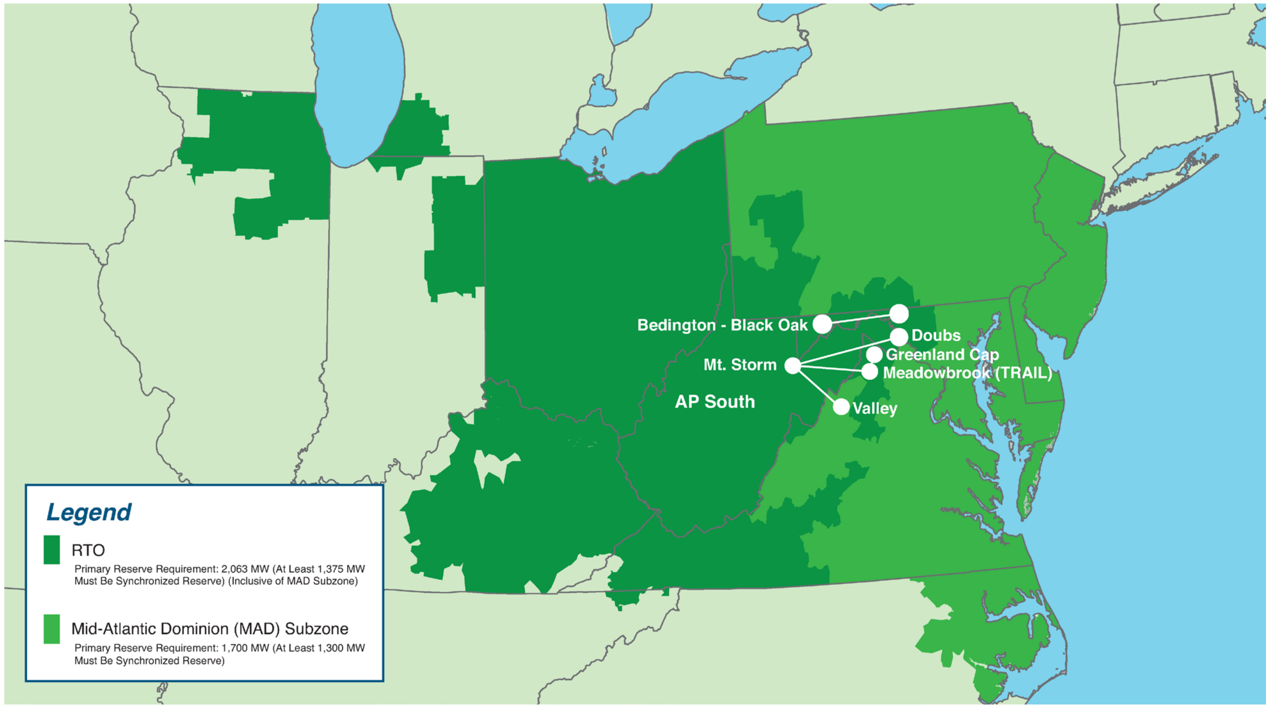
On February 22, 2016, the default primary reserve requirement in the RTO Reserve Zone was raised from 2,175 MW to 3,195 MW for 14 hours. On April 8, 2016, it was raised to 2,662 MW for 18 hours. These were the only adjustments to the RTO Zone primary reserve requirement in the first six months of 2016. The hourly average RTO primary reserve requirement was 2,180.6 MW in the first six months of 2016. In the MAD Subzone the primary reserve requirement was raised to 1,775 MW for 21 hours on April 8. It remained at 1,700 MW for all other hours in the first six months of 2016.

Transmission constraints limit the deliverability of reserves within the RTO, requiring the definition of the Mid-Atlantic Dominion (MAD) Subzone.[13] Of the 2,175 MW RTO primary reserve requirement, 1,700 MW (Table 10-15) must be deliverable to the MAD Subzone (Figure 10-1).

12 See PJM, "Manual 11: Energy & Ancillary Services Market Operations," Revision 82 (July 1, 2016), p. 69.

13 Additional subzones may be defined by PJM to meet system reliability needs. PJM will notify stakeholders in such an event. See PJM, "Manual 11: Energy & Ancillary Services Market Operations," Revision 82 (July 1, 2016), p. 69.

Figure 10-1 PJM RTO Zone and MAD Subzone geography: 2016



The Mid-Atlantic Dominion Reserve (MAD) Subzone is defined dynamically by the most limiting constraint separating MAD from the PJM RTO Reserve Zone. In 91.8 percent of hours in the first six months of 2016, that constraint was the Bedington – Black Oak Interface. The AP South transfer interface constraint was the limiting constraint in 8.2 percent of hours.

PJM requires that synchronized reserves equal at least 100 percent of the largest contingency. This means that 1,450 MW of the primary reserve requirement must be synchronized reserve for both RTO Reserve Zone and the Mid Atlantic Dominion Reserve Subzone.

Table 10-5 Average monthly tier 1 and tier 2 synchronized reserve, plus non-synchronized reserve used to satisfy the primary reserve requirement, MAD Subzone: January through June, 2016

Year	Month	Tier 1 Total MW	Tier 2 Synchronized Reserve MW	Non-Synchronized Reserve MW
2016	Jan	1,263.5	228.5	295.9
2016	Feb	1,230.1	241.5	302.2
2016	Mar	993.3	485.7	265.7
2016	Apr	912.4	565.0	289.2
2016	May	956.5	511.3	292.2
2016	Jun	1,116.9	348.4	368.7
2016	Average	1,071.1	406.4	289.0

Table 10-6 Average monthly tier 1 and tier 2 synchronized reserve, and non-synchronized reserve used to satisfy the primary reserve requirement, RTO Zone: January through June, 2016

Year	Month	Tier 1 Total MW	Tier 2 Synchronized Reserve MW	Non-Synchronized Reserve MW
2016	Jan	1,659.4	374.5	319.1
2016	Feb	1,564.1	411.4	329.4
2016	Mar	1,089.1	818.1	300.0
2016	Apr	1,011.7	878.3	318.0
2016	May	1,160.9	722.6	349.5
2016	Jun	1,546.0	497.1	384.2
2016	Average	1,297.0	641.0	323.2

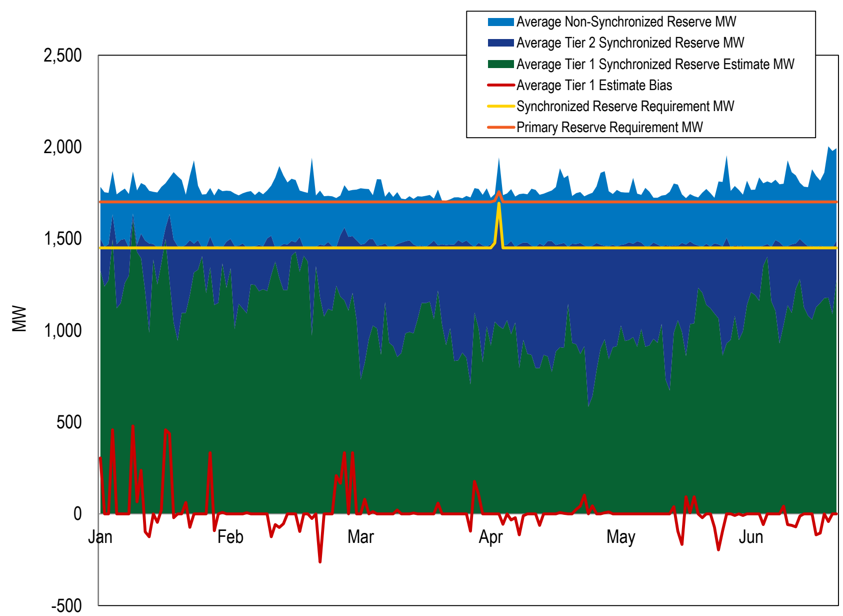
Supply and Demand

The market solution software relevant to reserves consists of: the Ancillary Services Optimizer (ASO) solving hourly; the intermediate term security constrained economic dispatch market solution (IT-SCED) solving every 15 minutes; and the real-time (short term) security constrained economic dispatch market solution (RT-SCED) solving every five minutes.

The ASO jointly optimizes energy, synchronized reserves, and non-synchronized reserves based on forecast system conditions to determine the most economic set of reserve resources to commit for the upcoming operating hour (before the hour commitments). IT-SCED runs at 15 minute intervals and jointly optimizes energy and reserves given the ASO's inflexible unit commitments. IT-SCED estimates available tier 1 synchronized reserve and can commit additional reserves (flexibly or inflexibly) if its forecasts indicate a need. RT-SCED runs at five minute intervals and produces load forecasts up to 20 minutes ahead. The RT-SCED estimates the available tier 1 provides a real-time ancillary services solution and can commit additional tier 2 resources (flexibly or inflexibly) if it forecasts a need.

Figure 10-2 illustrates how the ASO satisfies the primary reserve requirement (orange line) for the Mid-Atlantic Dominion Subzone. For the Mid-Atlantic Dominion Reserve Zone primary reserve solution the ASO must first satisfy the synchronized reserve requirement (yellow line) which is generally 1,450 MW in the MAD Subzone. Since the market solution considers tier 1 synchronized reserve to be zero cost, the ASO first estimates how much tier 1 synchronized reserve (green area) is available. If there is 1,450 MW of tier 1 available then ASO jointly optimizes synchronized reserve and non-synchronized reserve to assign the remaining primary reserve up to 1,700 MW. If there is not 1,450 MW of tier 1 then the remaining synchronized reserve requirement up to 1,450 MW is filled with tier 2 synchronized reserve (dark blue area). After 1,450 MW of synchronized reserve are assigned, the remaining 250 MW of the primary reserve requirement is filled by jointly optimizing synchronized reserve and non-synchronized reserve (light blue area). Since non-synchronized reserve is priced lower than or equal to synchronized reserve, almost all primary reserve between 1,450 MW and 1,700 MW is filled by non-synchronized reserve.

Figure 10-2 Mid-Atlantic Dominion Subzone primary reserve MW by source (Daily Averages): January through June, 2016



The solution methodology is similar for the RTO Reserve Zone (Figure 10-3) except that the required primary reserve MW is 2,175 MW.[14] Figure 10-3 shows how the hour ahead ASO satisfies the primary reserve requirement for the RTO Zone.

Figure 10-3 RTO Reserve Zone primary reserve MW by source (Daily Averages): January through June, 2016

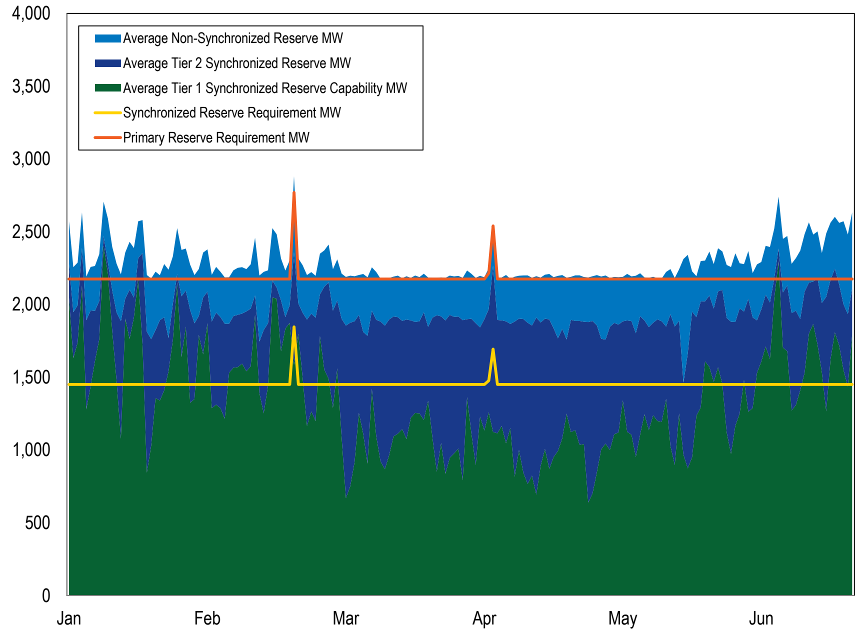


Figure 10-2 and Figure 10-3 show that tier 1 synchronized reserve remains the major contributor to satisfying the synchronized reserve requirements both in the RTO Zone and the Mid-Atlantic Dominion (MAD) Subzone.

Price and Cost

There is a separate price and cost for each component of primary reserve. In the market solution the cost of tier 1 synchronized reserves is zero except in defined circumstances, as there is no incremental cost associated with the ability to ramp up from the current economic dispatch point nor is there an obligation to ramp up during a synchronized reserve event. Tier 1 is credited when it responds to a synchronized reserve event. In addition, despite the absence of a performance obligation and an incremental cost to provide tier 1, PJM's current market rules require that tier 1 synchronized reserves be paid the tier 2 synchronized reserve market price in any hour that the non-synchronized reserve market clears with a price above $0.

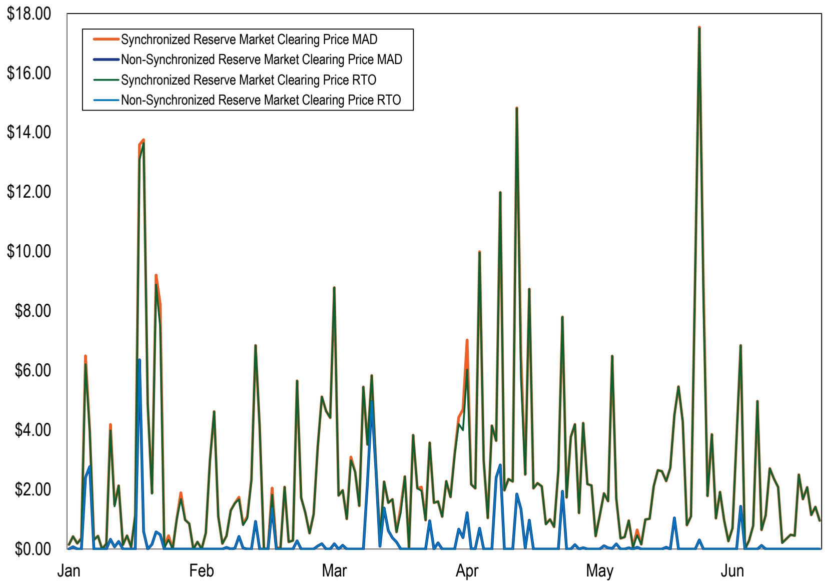
Under PJM's current market optimization approach, as available primary reserve approaches the primary reserve requirement the cost to serve the next MW of primary reserve is the non-synchronized reserve market clearing price (blue area in both Figure 10-2 and Figure 10-3).

In times of non-synchronized reserve shortage, the price of non-synchronized reserve will be capped at the currently effective penalty factor. The penalty factor is $850 per MW. PJM will review the penalty factor annually.

Figure 10-4 shows daily average synchronized and non-synchronized market clearing prices in the first six months of 2016.

14 Although tier 1 has a price of zero, changes made with shortage pricing on November 1, 2012, have given tier 1 a very high cost in some hours. This high cost raises questions about the economics of the solution methodology used by the ASO, IT-SCED, and RT-SCED market solutions which assume zero cost.

Figure 10-4 Daily weighted average market clearing prices ($/MW) for synchronized reserve and non-synchronized reserve: January through June, 2016



The cost of meeting PJM's primary reserve requirement (Figure 10-3) is shown in Table 10-7. Under most market conditions, most primary reserve identified by the hour ahead market solution is provided at no incremental cost by non-synchronized reserve and tier 1 synchronized reserve. The "Cost per MW" column is the total credits divided by the total MW of reserves. The "All-In Cost" column is the total credits paid divided by the load, or the total cost per MWh of energy to satisfy the primary reserve requirement.

Table 10-7 MW credited, price, cost, and all-in price for primary reserve and its component products, RTO Reserve Zone: January through June, 2016

Product	MW Share of Primary Reserve Requirement	MW Scheduled	Credits Paid	Price Per MW Reserve	Cost Per MW Reserve	All-In Cost
Tier 1 Synchronized Reserve Response	NA	2,065	$198,070	NA	$98.36	$0.00
Tier 1 Synchronized Reserve	4.4%	264,784	$3,335,329	$0.00	$12.60	$0.01
Tier 2 Synchronized Reserve	31.1%	1,853,735	$16,882,050	$4.47	$9.11	$0.05
Non-synchronized Reserve	64.4%	3,843,897	$4,087,360	$0.20	$1.06	$0.01
Primary Reserve (total of above)	100.0%	5,964,481	$24,502,809	$0.37	$4.11	$0.07

Tier 1 Synchronized Reserve

Tier 1 synchronized reserve is a component of primary reserve comprised of all online resources following economic dispatch and able to ramp up from their current output in response to a synchronized reserve event. The tier 1 synchronized reserve for a unit is measured as the lower of the available 10 minute ramp and the difference between the economic dispatch point and the economic maximum output. Tier 1 resources are identified by the market solution and the sum of their 10 minute availability equals available tier 1 synchronized reserve (green area of Figure 10-2 and Figure 10-3). Tier 1 synchronized reserve is the first element of primary reserve identified by the market software and is available at zero incremental cost unless called to respond to a synchronized reserve event or unless the non-synchronized reserve market clearing price is above $0.

While PJM relies on tier 1 resources to respond to a synchronized reserve event, tier 1 resources are not financially obligated to respond during an event.

Market Structure

Supply

All generating resources operating on the PJM system with the exception of those assigned to tier 2 synchronized reserve are available for tier 1 synchronized reserve. Demand resources are not available for tier 1 synchronized reserve.

In the first six months of 2016, in the RTO Reserve Zone the average hourly estimated tier 1 synchronized reserve was 1,336.5 MW (Table 10-6). In 38.4 percent of hours, the estimated tier 1 synchronized reserve was greater than the primary reserve requirement, meaning that the primary reserve requirement was met entirely by tier 1 synchronized reserve.

In the first six months of 2016, in the MAD Reserve Subzone the average hour ahead estimated tier 1 synchronized reserve was 1,077.6 MW (Table 10-5). In 2.2 percent of hours, the estimated tier 1 synchronized reserve was greater than the subzone requirement for synchronized reserve and no Tier 2 Synchronized Reserve Market was needed.

Table 10-8 Monthly average market solution Tier 1 Synchronized Reserve (MW) identified hourly: January through June, 2016

Mid-Atlantic Dominion Reserve Subzone						
Year	Month	Average Hourly Tier 1 Local to MAD	Synchronized Reserve Available from RTO	Average Hourly Tier 1 Used	Minimum Hourly Tier 1 Used	Maximum Hourly Tier 1 Used
2016	Jan	709.2	554.3	1,263.5	498.2	2,749.8
2016	Feb	649.0	581.1	1,230.1	437.7	2,257.2
2016	Mar	418.3	574.9	993.3	260.1	2,854.3
2016	Apr	355.2	557.1	912.4	243.7	1,625.6
2016	May	386.2	570.3	956.5	205.4	1,594.4
2016	Jun	619.4	497.5	1,116.9	231.9	2,335.0
2016	Average	522.9	555.9	1,078.8	312.8	2,236.1

RTO Reserve Zone						
Year	Month	Average Hourly Tier 1 Local to MAD	Synchronized Reserve Available from RTO	Average Hourly Tier 1 Used	Minimum Hourly Tier 1 Used	Maximum Hourly Tier 1 Used
2016	Jan	1,659.4	NA	1,659.4	0.0	3,954.1
2016	Feb	1,564.1	NA	1,564.1	295.9	3,417.4
2016	Mar	1,089.1	NA	1,089.1	197.4	3,681.3
2016	Apr	1,011.7	NA	1,011.7	0.0	2,426.4
2016	May	1,160.9	NA	1,160.9	0.0	2,888.9
2016	Jun	1,546.0	NA	1,546.0	0.0	3,282.1
2016	Average	1,338.5	NA	1,338.5	82.2	3,275.0

Demand

There is no fixed required amount of tier 1 synchronized reserve. The tier 1 synchronized reserve for each online resource is estimated from its synchronized reserve ramp rate as part of each market solution and not assigned. Given estimated tier 1, the market software (ASO) completes the primary reserve assignments under the assumption that the estimated tier 1 will be available if needed. The ancillary services market solution treats the cost of estimated tier 1 synchronized reserve as $0, even when the non-synchronized reserve market clearing price is above $0.

Beginning January 2015, DGP (Degree of Generator Performance) was introduced as a metric to improve the accuracy of the tier 1 MW estimate used by the market solution. DGP is calculated for all online resources for each market solution. DGP measures how closely the unit has been following economic dispatch for the past 30 minutes and the available tier 1 MW for that resource is adjusted by the DGP percentage. In May 2015, PJM began communicating to generation operators whose tier 1 MW are part of the market solution the latest estimate of units' tier 1 MW and units' current resource specific DGP.[15]

For the first six months of 2016, PJM estimated tier 1 MW for an average of 129 units as part of the solution each hour. The average DGP was 86.4 percent for those 129 units.

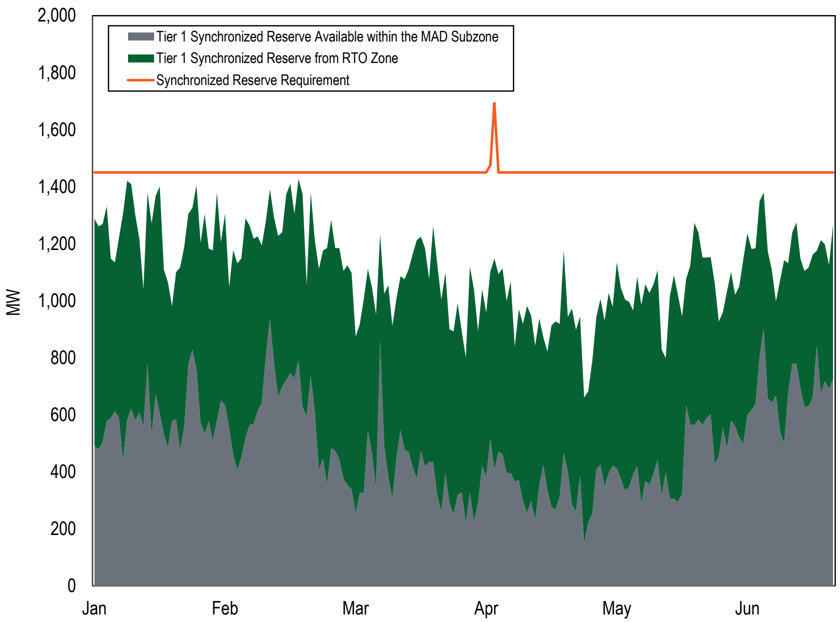
Supply and Demand

When solving for the synchronized reserve requirement the market solution first subtracts the amount of self-scheduled synchronized reserve from the requirement and then estimates the amount of tier 1. To improve its tier 1 estimates, PJM deselects certain resources from the tier 1 estimate. Tier 1 deselection is based on unit type, location and daily grid conditions.

In the MAD Subzone, the market solution takes all tier 1 MW estimated to be available within the MAD Subzone (gray area of Figure 10-5). It then adds the tier 1 MW estimated to be available within the MAD Subzone from the RTO Zone (green area of Figure 10-5) up to the synchronized reserve requirement. If the total tier 1 synchronized reserve is less than the synchronized reserve requirement, the remainder of the synchronized reserve requirement is filled with tier 2 synchronized reserve (white area below the synchronized reserve required line in Figure 10-5).

15 PJM. Ancillary Services, "Communication of Synchronized Reserve Quantities to Resource Owners," <http://www.pjm.com/~/media/markets-ops/ancillary/communication-of-synchronized-reserve-quantities-to-resource-owners.ashx> (May 6, 2015).

Figure 10-5 Daily average tier 1 synchronized reserve supply (MW) in the MAD Subzone: January through June, 2016



Demand for synchronized reserve in the RTO Zone January through June 2016, was 1,453.6 MW. There were temporary increases in the hourly synchronized reserve requirement to 2,130 MW on February 22, 2016, to 1,474.8 MW on April 7, 2016, and to 1,692.6 MW on April 8, 2016.

Tier 1 Synchronized Reserve Event Response

Tier 1 synchronized reserve is awarded credits when a synchronized reserve event occurs and it responds. These synchronized reserve event response credits for tier 1 response are independent of the tier 1 estimated, independent of the synchronized reserve market clearing price, and independent of the non-synchronized reserve market clearing price. Credits are awarded to tier 1 synchronized reserve resources equal to the increase in MW output (or decrease in MW consumption for demand resources) for each five minute interval times the five minute LMP plus $50 per MW. During a synchronized reserve event, tier 1 credits are awarded to all units that increase their output during the event regardless of their estimated tier 1 MW, or tier 1 deselection status at market clearing time. Only units that have cleared the tier 2 market are not awarded tier 1 credits for increasing their output.

In the first six months of 2016, tier 1 synchronized reserve synchronized reserve event response credits of $198,070 were paid for 2,065.2 MWh of tier 1 response at an average cost per MWh of $53.78, for six spinning events (Table 10-9).

Table 10-9 Tier 1 synchronized reserve event response costs: January 2015 through June 2016

Year	Month	Synchronized Reserve Event Response Hours	Total Tier 1 Synchronized Reserve Event Response MWh	Total Tier 1 Synchronized Reserve Event Response Credits	Tier 1 Synchronized Reserve Event Response Cost Per MW	Average Tier 1 MW Response
2015	Jan	1	397.3	$8,198	$20.64	397.3
2015	Feb	2	218.3	$9,634	$44.13	109.2
2015	Mar	4	2,445.8	$105,505	$43.14	611.4
2015	Apr	5	1,398.9	$69,399	$49.61	279.8
2015	May	0	NA	NA	NA	NA
2015	Jun	0	NA	NA	NA	NA
2015	Jul	1	502.2	$25,540	$50.86	502.2
2015	Aug	2	648.3	$7,730	$11.92	324.1
2015	Sep	3	678.5	$30,077	$44.33	226.2
2015	Oct	0	NA	NA	NA	NA
2015	Nov	2	252.9	$15,914	$62.92	126.5
2015	Dec	2	602.9	$79,215	$131.39	301.4
2015	Total	22	7,145.0	$351,212	$50.99	319.8
2016	Jan	2	730.8	$70,330	$96.24	730.8
2016	Feb	2	675.1	$40,622	$60.17	337.5
2016	Mar	0	NA	NA	NA	NA
2016	Apr	1	339.0	$66,199	$195.27	339.0
2016	May	2	113.4	$9,790	$86.35	56.7
2016	Jun	1	206.9	$11,129	$53.78	206.9
2016	Total	8	2,065.2	$198,070	$98.36	334.2

Paying Tier 1 the Tier 2 Price

The market solutions correctly treat tier 1 synchronized reserve as having zero marginal cost. The price for tier 1 synchronized reserves is zero as there is no incremental cost associated with providing the ability to ramp up from the current economic dispatch point. When called to respond to a spinning event tier 1 is compensated at the Synchronized Energy Premium Price (Table 10-12). However, the shortage pricing tariff changes (October 1, 2012) modified the pricing of tier 1 so that tier 1 synchronized reserve is paid the tier 2 synchronized reserve market clearing price whenever the non-synchronized reserve market clearing price rises above zero. The rationale for this change was and is unclear but it has had a significant impact on the cost of tier 1 synchronized reserves. The non-synchronized reserve market clearing price was above $0.00 in 188 hours in the first six months of 2016. For those 188 hours, tier 1 synchronized reserve resources were paid a weighted average synchronized reserve market clearing price of $12.60 per MW and earned $3,335,329 in credits. In all of 2015, PJM paid $34,135,671 in credits for tier 1 estimated during the 1,089 hours when the non-synchronized reserve market clearing price was above $0.

Table 10-10 Weighted price of tier 1 synchronized reserve attributable to a non-synchronized reserve price above zero: January 2015 to June 2016

Year	Month	Total Hours When NSRMCP>$0	Weighted Average SRMCP for Hours When NSRMCP>$0	Total Tier 1 MW Credited for Hours When NSRMCP>$0	Total Tier 1 Credits Paid When NSRMCP>$0	Average Tier 1 MW Paid
2015	Jan	148	$13.59	274,996	$3,727,945	1,858.1
2015	Feb	194	$24.83	369,111	$9,164,267	1,902.6
2015	Mar	181	$16.33	305,967	$4,985,446	1,690.4
2015	Apr	66	$25.56	102,117	$2,587,076	1,547.2
2015	May	72	$20.35	106,027	$2,158,080	1,472.6
2015	Jun	95	$17.64	185,148	$3,183,436	1,948.9
2015	Jul	46	$35.12	64,516	$2,265,614	1,402.5
2015	Aug	38	$22.40	48,479	$1,078,199	1,275.8
2015	Sep	36	$31.53	51,968	$1,522,913	1,060.5
2015	Oct	113	$17.10	126,879	$2,169,670	1,122.8
2015	Nov	29	$14.65	29,156	$427,056	1,005.4
2015	Dec	51	$16.07	53,898	$865,969	1,005.4
2015	Total	1,069	$21.26	1,718,263	$34,135,671	1,607.4
2016	Jan	37	$15.22	57,571	$876,367	1,556.0
2016	Feb	14	$9.42	24,752	$233,208	1,768.0
2016	Mar	73	$6.57	105,142	$690,294	1,440.3
2016	Apr	34	$28.83	38,662	$1,114,670	1,137.1
2016	May	22	$9.01	27,027	$243,515	1,228.5
2016	Jun	8	$15.24	11,630	$177,275	1,453.8
2016	Total	188	$12.60	264,785	$3,335,329	1,408.4

The additional payments to tier 1 synchronized reserves under the shortage pricing rule can be considered a windfall. The additional payment does not create an incentive to provide more tier 1 synchronized reserves. The additional payment is not a payment for performance as all estimated tier 1 receives the payment regardless of whether they provided any response during any spinning event. Tier 1 resources are not obligated to respond to synchronized reserve events. In the first six months of 2016, 81.0 percent of the DGP adjusted market solution's estimated tier 1 resources MW actually responded during synchronized reserve events of greater than 10 minutes. Total response however, including resources that were not part of the tier 1 estimate amounted to 190.1 percent of the original tier 1 estimate. Thus, 19.0 percent of DGP adjusted tier 1 estimated MW did not respond during spinning events. However, all resources that were included in the Tier 1 estimates were paid the Tier 2 price for their full estimated MW when the non-synchronized reserve price was greater than zero. Tier 2 synchronized reserve resources are paid the market clearing price for tier 2 because they stand ready to respond and incur costs to do so, have an obligation to perform and pay penalties for nonperformance.

When the next MW of non-synchronized reserve (NSR) required to satisfy the primary reserve requirement increases in price from $0.00 per MW to $0.01 per MW, the cost of all tier 1 MW increases significantly.

In the first six months of 2016, tier 1 synchronized reserve was paid $198,070 for responding to synchronized reserve events. Tier 1 synchronized reserve was paid $3.335 million simply because the NSRMCP was greater than $0.00 in 188 hours (Table 10-11).

Table 10-11 Dollar impact of paying tier 1 synchronized reserve the SRMCP when the NSRMCP goes above $0: January 2015 through June 2016

		Synchronized Reserve Events			Hours When NSRMCP > $0		
Year	Month	Total MWh	Total Credits	Average MWh Per Event	Total MW	Total Credits	Average MW Per Hour
2015	Jan	397	$8,198	397	274,996	$3,727,945	1,858
2015	Feb	218	$9,634	109	369,111	$9,164,267	1,903
2015	Mar	2,446	$105,505	611	305,967	$4,985,446	1,690
2015	Apr	1,399	$69,399	280	102,117	$2,587,076	1,547
2015	May	0	$0	0	106,027	$2,158,080	1,473
2015	Jun	0	$0	0	182,417	$3,183,436	1,961
2015	Jul	502	$25,540	502	64,516	$2,265,615	1,403
2015	Aug	648	$7,730	324	48,479	$1,078,199	1,276
2015	Sep	678	$30,077	226	51,968	$1,522,913	1,061
2015	Oct	0	$0	0	126,879	$2,169,670	1,123
2015	Nov	253	$15,914	126	29,156	$427,056	1,005
2015	Dec	603	$79,215	301	53,898	$865,969	1,054
2015	Total	7,145	$351,212	320	1,715,532	$34,135,671	1,446
2016	Jan	731	$70,330	731	57,571	$876,367	1,556
2016	Feb	675	$40,622	338	24,752	$233,208	1,768
2016	Mar	NA	NA	NA	105,142	$690,294	1,440
2016	Apr	339	$66,199	339	38,662	$1,114,670	1,137
2016	May	113	$9,790	57	27,027	$243,515	1,229
2016	Jun	207	$11,129	207	11,630	$177,275	1,454
2016	Total	2,065	$198,070	334	264,784	$3,335,329	1,408

The MMU recommends that the rule requiring the payment of tier 1 synchronized reserve resources when the non-synchronized reserve price is above zero be eliminated immediately.[16] Tier 1 should be compensated only for a response to synchronized reserve events, as it was before the shortage pricing changes. This compensation requires that when a synchronized reserve event is called, all tier 1 response is paid the average of five-minute LMPs during the event, rather than hourly integrated LMP, plus $50/MW, termed the Synchronized Energy Premium Price.

PJM's current tier 1 compensation rules are presented in Table 10-12.

Table 10-12 Tier 1 compensation as currently implemented by PJM

Tier 1 Compensation by Type of Hour as Currently Implemented by PJM		
Hourly Parameters	No Synchronized Reserve Event	Synchronized Reserve Event
NSRMCP=$0	T1 credits = $0	T1 credits = Synchronized Energy Premium Price * actual response MWh
NSRMCP>$0	T1 credits = T2 SRMCP * estimated tier 1 MW	T1 credits = T2 SRMCP * min(calculated tier 1 MW, actual response MWh)

The MMU's recommended compensation rules for tier 1 MW are in Table 10-13.

Table 10-13 Tier 1 compensation as recommended by MMU

Tier 1 Compensation by Type of Hour as Recommended by MMU		
Hourly Parameters	No Synchronized Reserve Event	Synchronized Reserve Event
NSRMCP=$0	T1 credits = $0	T1 credits = Synchronized Energy Premium Price * actual response MWh
NSRMCP>$0	T1 credits = $0	T1 credits = Synchronized Energy Premium Price * actual response MWh

16 This recommendation was presented as a proposal, "Tier 1 Compensation," to the Markets and Reliability Committee Meeting, October 22, 2015. The MMU proposal and a PJM counterproposal were both rejected.

Tier 1 Estimate Bias

PJM's market solution engines allow the dispatcher to bias the synchronized reserve solution by forcing the engine to assume a different tier 1 MW value than it estimates. PJM no longer allows dispatchers to use tier 1 biasing in the intermediate and real time SCED solutions but tier biasing can be used in the hour ahead solution, ASO. Biasing means manually modifying (increasing or decreasing) the tier 1 synchronized reserve estimate of the market solution. This forces the market clearing engine to clear more or less tier 2 synchronized reserve and non-synchronized reserve to satisfy the synchronized reserve and primary reserve requirements than the market solution.

PJM uses tier 1 estimate biasing in the MAD Subzone of the ASO market solution (Table 10-14). Tier 1 biasing is not used in any IT-SCED solutions.

Table 10-14 ASO tier 1 estimate biasing: January 2015 through June 2016

Year	Month	Number of Hours Biased Negatively	Average Negative Bias (MW)	Number of Hours Biased Positively	Average Positive Bias (MW)
2015	Jan	51	(1,731.4)	6	500.0
2015	Feb	62	(1,641.1)	0	0.0
2015	Mar	25	(794.0)	3	1,000.0
2015	Apr	31	(430.7)	0	0.0
2015	May	46	(582.6)	8	812.5
2015	Jun	25	(694.0)	1	1,000.0
2015	Jul	9	(588.9)	0	0.0
2015	Aug	1	(750.0)	1	750.0
2015	Sep	4	(475.0)	1	2,000.0
2015	Oct	24	(979.2)	0	0.0
2015	Nov	0	0.0	62	515.3
2015	Dec	1	(500.0)	59	549.2
2015	Total	279	(833.3)	141	890.9
2016	Jan	21	(628.6)	64	1,104.7
2016	Feb	27	(617.6)	12	762.5
2016	Mar	1	(300.0)	28	732.1
2016	Apr	31	(303.2)	22	502.0
2016	May	19	(447.4)	21	335.7
2016	Jun	46	(442.4)	3	500.0
2016	Total	145	(456.5)	150	656.2

Tier 1 biasing is not mentioned in the PJM manuals and does not appear to be defined in any public document. PJM dispatchers use tier 1 biasing to compensate for uncertainty in short-term load forecasting, generator performance, or uncertainty in the accuracy of the market solution's tier 1 estimate. Tier 1 estimate biasing directly affects the required amount of tier 2 and therefore the market results both for tier 2 synchronized reserve and for non-synchronized reserve.

The MMU recommends that PJM be more explicit about why tier 1 biasing is used in the optimized solution to the Tier 2 Synchronized Reserve Market. The MMU recommends that PJM define rules for estimating available tier 1 MW and for the use of biasing during any phase of the market solution and then identify the relevant rule for each instance of biasing.

Tier 2 Synchronized Reserve Market

Synchronized reserve is energy or demand reduction synchronized to the grid and capable of increasing output or decreasing load within 10 minutes. Synchronized reserve is of two distinct types, tier 1 and tier 2. Tier 2 synchronized reserve is primary reserve (10 minute availability) that must be dispatched in order to satisfy the synchronized reserve requirement. When the synchronized reserve requirement cannot be filled with tier 1 synchronized reserve, PJM clears a market to satisfy the requirement with tier 2 synchronized reserve.

PJM operates a Tier 2 Synchronized Reserve Market in both the RTO Synchronized Reserve Zone and the Mid-Atlantic Dominion Reserve Subzone. Market solutions provided by the ASO, IT-SCED and RT-SCED first estimate the amount of tier 1 synchronized reserve available from the current economic dispatch and subtract that amount from the synchronized reserve requirement to determine how much tier 2 synchronized reserve is needed. Tier 2 synchronized reserve is provided by online resources, either synchronized to the grid but not producing energy, or dispatched to provide synchronized reserve at an operating point below their economic dispatch point. Tier 2 synchronized reserve is also provided by demand resources that have offered to reduce load in the event of an synchronized reserve event. Tier 2 synchronized reserves are committed to be available in the event of a synchronized reserve event.

Tier 2 synchronized reserve resources may be inflexible for two reasons, the nature of the resource or if they are committed in the hour ahead for the full operating hour. Some resource types can only be committed by the ASO prior to the operational hour and require an hourly commitment due to physical limitations or market rules. Resources with hour ahead commitment requirements include synchronous condensers operating solely for the purpose of providing synchronized reserves and demand response that has qualified to act as synchronized reserves. Tier 2 resources are scheduled by the ASO sixty minutes before the operating hour, are committed to provide synchronized reserve for the entire hour, and are paid the higher of the SRMCP or their offer price plus lost opportunity cost (LOC). Demand response resources are paid SRMCP. Due to the hour long commitment that comes with the hour ahead ASO assignment, tier 2 synchronized reserve resources committed by the hour ahead market solution are flagged by the system software as inflexible resources, so they cannot be released for energy for the duration of the operational hour.

During the operating hour, the IT-SCED and the RT-SCED market solutions have the ability to dispatch additional resources flexibly depending on the current forecast need for synchronized reserve. A flexible commitment is one in which the IT-SCED or RT-SCED redispatches generating resources to meet the synchronized and primary reserve requirements within the operational hour.

Market Structure

Supply

All nonemergency generating resources are required to submit tier 2 synchronized reserve offers. All online, nonemergency generating resources are deemed available to provide both tier 1 and tier 2 synchronized reserve. If PJM issues a primary reserve warning, voltage reduction warning, or manual load dump warning, all off line emergency generation capacity resources available to provide energy must submit an offer for tier 2 synchronized reserve.[17]

In the first six months of 2016, the Mid Atlantic Dominion Reserve Subzone averaged 6,928.4 MW of synchronized reserve offers, and the RTO Reserve Zone averaged 20,301.6 MW of synchronized reserve offers (Figure 10-11) of which 1,500.2 MW was demand response.

The supply of offered tier 2 synchronized reserve in January through June 2016 was sufficient to cover the requirement in both the RTO Reserve Zone and the Mid-Atlantic Dominion Reserve Subzone.

The largest portion of cleared tier 2 synchronized reserve for all hours between January and June in 2016 is from CTs, 51.1 percent (Figure 10-6). Demand Resources (DR) remain a significant part of market scheduled tier 2 synchronized reserve. Although demand resources are limited to 33 percent of the total synchronized reserve requirement, the amount of tier 2 synchronized reserve required in any hour is often much less than the full synchronized reserve requirement because so much of it is met with tier 1 synchronized reserve. The DR MW share of the total cleared Tier 2 Synchronized Reserve Market was 25.5 percent in the first six months of 2016.[18] This is an increase from the 15.3 percent share of the tier 2 market in the first six months of 2015.

17 See PJM. "Manual 11: Energy & Ancillary Services Market Operations," Revision 82 (July 1, 2016), p. 66.

18 The cap on demand response participation is defined in MW terms. There is no cap on the proportion of cleared demand response consistent with the MW cap.

Figure 10-6 Cleared tier 2 synchronized reserve average hourly MW per hour by unit type, RTO Zone: January through June 2016

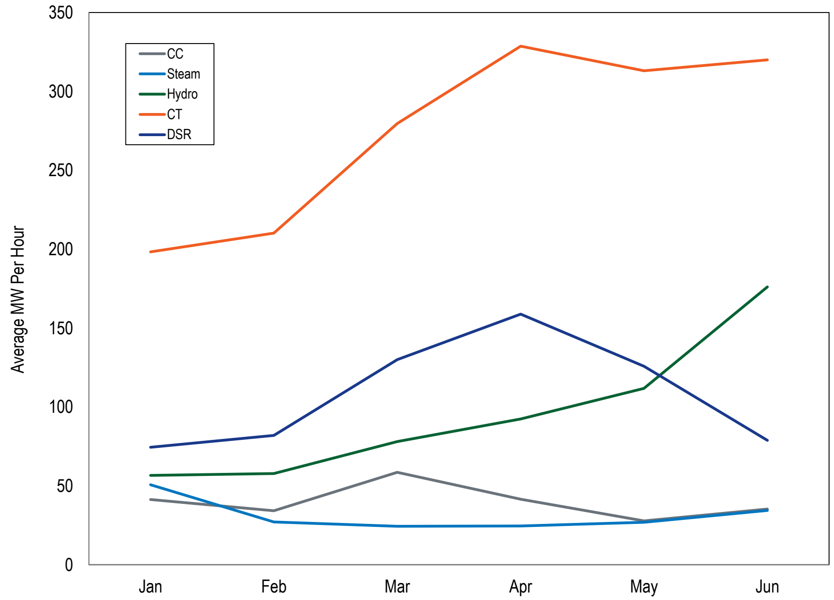
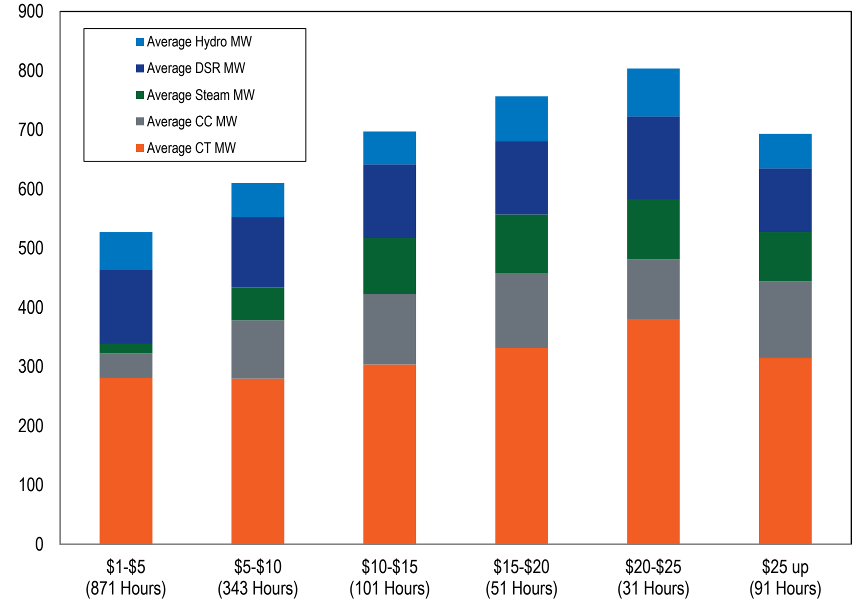


Figure 10-7 provides the average hourly cleared tier 2 MW by unit type by tier 2 clearing price range (SRMCP).

Figure 10-7 Average hourly tier 2 MW by unit type by SRMCP range: January through June, 2016



Demand

Effective January 8, 2015, the default synchronized reserve requirement was set at 1,450 MW in both the Mid-Atlantic Dominion Subzone and the RTO Zone (Table 10-15). There are two circumstances in which PJM may alter the synchronized reserve requirement from its default value. When PJM operators anticipate periods of heavy load, they may bring on additional units to account for increased operational uncertainty in meeting load. When a Hot Weather Alert, Cold Weather Alert or an escalating emergency procedure (as defined in Manual 11 § 4.2.2 Synchronized Reserve Requirement Determination) has been issued for the operating day, operators may increase the synchronized reserve requirement up to the full amount of the additional MW brought on line.[19] The synchronized reserve requirement was temporarily increased for

19 PJM. "Manual 11: Energy & Ancillary Services Market Operations," Revision 82 (July 1, 2016) pp. 70.

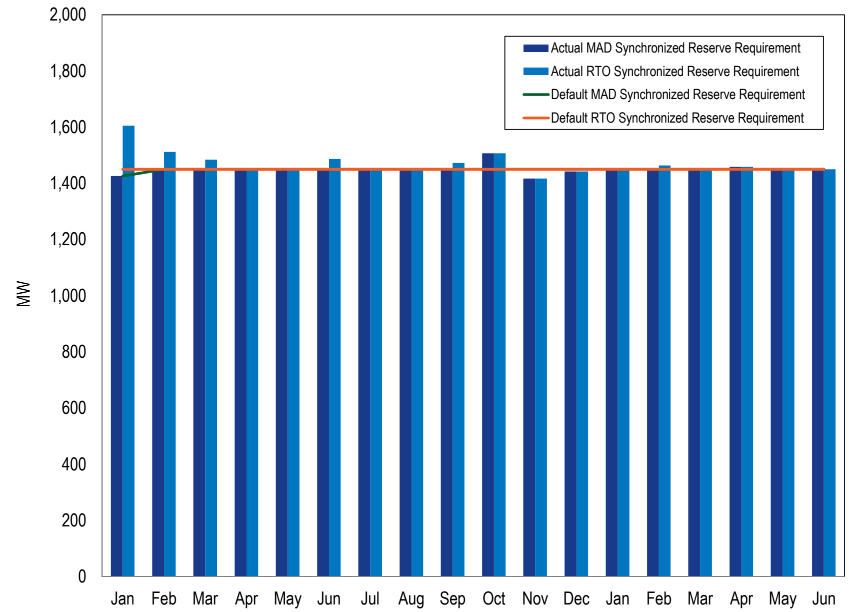
the RTO Zone on February 22, 2016 for a 14 hour period to 2,130 MW and on April 8, 2016 for 24 hours to 1,775 MW.

Table 10-15 Default Tier 2 Synchronized Reserve Markets required MW, RTO Zone and Mid-Atlantic Dominion Subzone

Mid-Atlantic Dominion Subzone			RTO Synchronized Reserve Zone		
From Date	To Date	Required MW	From Date	To Date	Required MW
May 10, 2008	May 8, 2010	1,150	May 10, 2008	Jan 1, 2009	1,305
May 8, 2010	Jul 13, 2010	1,200	Jan 1, 2009	Mar 15, 2010	1,320
July 13, 2010	Jan 1, 2015	1,300	Mar 15, 2010	Nov 12, 2012	1,350
Jan 1, 2015	Jan 8, 2015	1,342	Nov 12, 2012	Jan 8, 2015	1,375
Jan 8, 2015		1,450	Jan 8, 2015		1,450

PJM may also temporarily change the synchronized reserve requirement from its default value when grid maintenance or outages change the largest contingency. Figure 10-8 shows monthly average actual synchronized reserve requirements and the default synchronized reserve requirements. In the first six months of 2016, there were no increases in the synchronized reserve requirement as a result of a grid outage or maintenance contingency.

Figure 10-8 Monthly average actual vs default synchronized reserve requirements, RTO Zone and MAD Subzone: January 2015 through June 2016



The market demand for tier 2 synchronized reserve in the Mid-Atlantic Dominion Subzone is determined by subtracting the amount of forecast tier 1 synchronized reserve available in the subzone from the subzone requirement each five-minute period. Market demand is also reduced by subtracting the amount of self-scheduled tier 2 resources.

The RTO Reserve Zone cleared an average of 423.5 MW of tier 2 synchronized reserves each hour in the first six months of 2016. Of this, an average of 179.2 MW cleared in the MAD Subzone.

Figure 10-9 and Figure 10-10 show the average monthly synchronized reserve required and the average monthly tier 2 synchronized reserve MW scheduled

(PJM scheduled plus self-scheduled) in January 2015 through June 2016, for the RTO Reserve Zone and MAD Reserve Subzone.

Figure 10-9 Mid-Atlantic Dominion reserve subzone monthly average synchronized reserve required vs. tier 2 synchronized reserve scheduled MW: January 2015 through June 2016

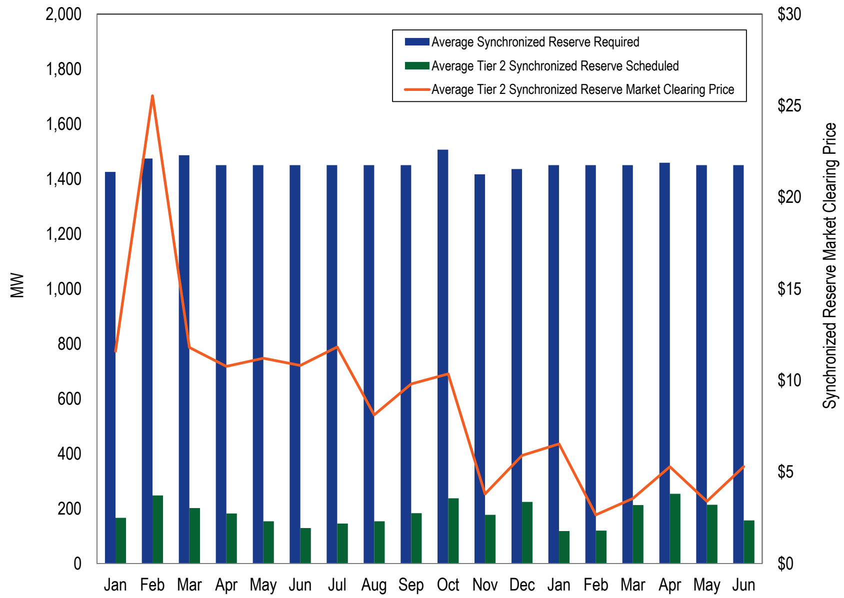
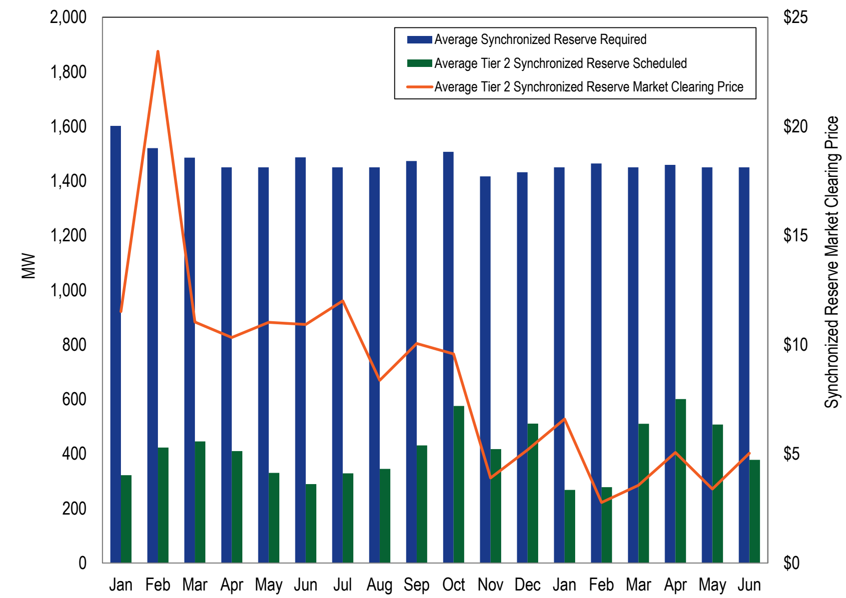


Figure 10-10 RTO reserve zone monthly average synchronized reserve required vs. tier 2 synchronized reserve scheduled MW: January 2015 through June 2016



Market Concentration

The HHI for settled tier 2 synchronized reserve during cleared hours of the Mid-Atlantic Dominion Subzone Tier 2 Synchronized Reserve Market for the first six months of 2016 is was 5503, which is defined as highly concentrated. This is a decrease from the 5705 HHI during the same time period of 2015. The largest hourly market share was 100 percent and 87.3 percent of all cleared hours had a maximum market share greater than or equal to 40 percent.

The HHI for settled tier 2 synchronized reserve during cleared hours of the RTO Zone Tier 2 Synchronized Reserve Market for the first six months of 2016 was 4860, which is defined as highly concentrated. This is a decrease from the 4886 HHI during the same time period of 2015. The largest hourly market share was 100 percent and 73.4 percent of cleared hours had a maximum market share greater than or equal to 40 percent.

In the MAD Subzone, flexible synchronized reserve was 1.5 percent of all tier 2 synchronized reserve in the first six months of 2016. In the RTO Zone, flexible synchronized reserve assigned was 1.0 percent of all tier 2 synchronized reserve during the same period.

The MMU calculates that 73.0 percent of hours would have failed the three pivotal supplier test in the MAD Subzone in the first six months of 2016 for the inflexible Synchronized Reserve Market (excluding self-scheduled synchronized reserve) in the hour ahead market (Table 10-16) and 42.7 percent of hours would have failed a three pivotal supplier test in the RTO Zone during the same time period.

Table 10-16 Three pivotal supplier test results for the RTO Zone and MAD Subzone: January 2015 through June 2016

Year	Month	Mid Atlantic Dominion Reserve Subzone Pivotal Supplier Hours	RTO Reserve Zone Pivotal Supplier Hours
2015	Jan	46.0%	34.2%
2015	Feb	87.0%	29.9%
2015	Mar	42.0%	45.2%
2015	Apr	31.1%	48.4%
2015	May	61.2%	45.3%
2015	Jun	39.2%	26.5%
2015	Jul	32.0%	25.0%
2015	Aug	32.3%	24.9%
2015	Sep	56.1%	23.5%
2015	Oct	81.5%	57.9%
2015	Nov	73.2%	49.3%
2015	Dec	87.7%	73.2%
2015	Average	55.8%	40.3%
2016	Jan	52.8%	43.1%
2016	Feb	71.9%	39.6%
2016	Mar	84.9%	59.1%
2016	Apr	93.2%	55.6%
2016	May	81.6%	31.3%
2016	Jun	53.8%	27.4%
2016	Average	73.0%	42.7%

The market structure results indicate that the RTO Zone and Mid-Atlantic Dominion Subzone Tier 2 Synchronized Reserve Markets are not structurally competitive.

Market Behavior

Offers

Daily cost based offer prices are submitted for each unit by the unit owner. For generators the offer price must include tier 1 synchronized reserve ramp rate, a tier 1 synchronized reserve maximum, self-scheduled status, synchronized reserve availability, synchronized reserve offer quantity (MW), tier 2 synchronized reserve offer price, energy use for tier 2 condensing resources (MW), condense to gen cost, shutdown costs, condense startup cost, condense hourly cost, condense notification time, and spin as a condenser status (a field to identify if a running CT or hydro resource can be dispatched for synchronized reserve). The synchronized reserve offer price made by the unit owner is subject to an offer cap of marginal cost plus $7.50 per MW. All suppliers are paid the higher of the market clearing price or their offer plus their unit specific opportunity cost. The offer quantity is limited to the economic maximum or less if a spin maximum value is less than economic maximum is supplied (subject to prior authorization by PJM). PJM monitors this offer by checking to ensure that all offers are greater than or equal to 90 percent of the resource's ramp rate times 10 minutes. A resource that is unable to participate in the synchronized reserve market during a given hour may set its hourly offer to 0 MW. A resource that cannot reliably provide synchronized reserve may offer 0 MW, e.g. nuclear, wind, solar, landfill gas and batteries.

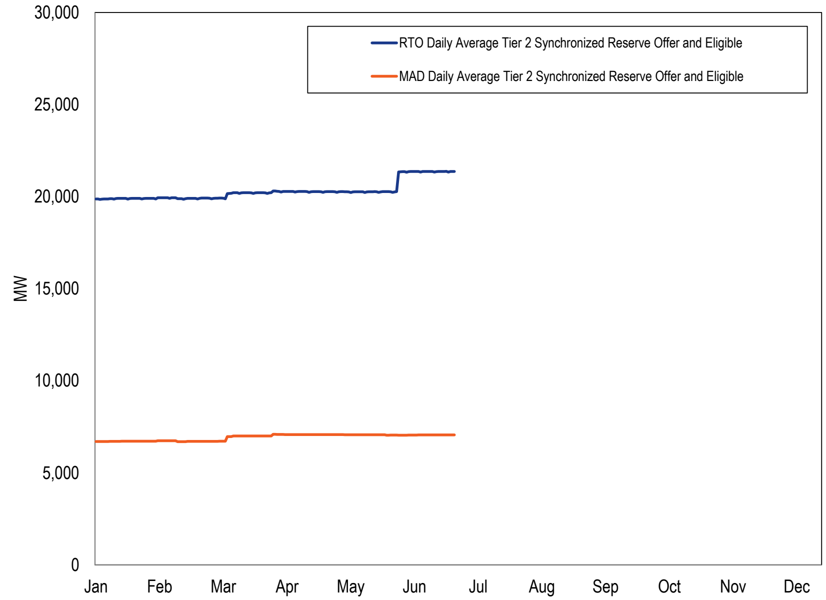
Figure 10-11 shows the daily average of hourly offered tier 2 synchronized reserve MW for both the RTO Synchronized Reserve Zone and the Mid-Atlantic Dominion Synchronized Reserve Subzone. In the first six months of 2016, the ratio of online and eligible tier 2 synchronized reserve to synchronized reserve required in the Mid-Atlantic Dominion Subzone was 4.16 averaged over all hours. For the RTO Synchronized Reserve Zone the ratio was 5.73.

On October 1, 2012, PJM adopted a must offer requirement for tier 2 synchronized reserve for all generation that is online, nonemergency, and physically able to operate with an output less than dictated by economic dispatch. Tier 2 synchronized reserve offers are made on a daily basis with hourly updates permitted. Daily offers can be changed as a result of maintenance status or physical limitations only and are required regardless of online/offline state.[20] Daily offer levels are stable and consistent over time. Per PJM M-11 "certain unit types including, but not limited to Nuclear, Wind, Solar, and Batteries are expected to have a zero MW tier 2 synchronized reserve offer quantity." [21] The exclusion of these unit types from the must offer requirement improved compliance with this rule from 88.5 percent to 98.3 percent. The Tier 2 Synchronized Reserve Market is not solved from daily offers but based on hourly updates to the daily offers. As a result of hourly updates the actual amount of eligible tier 2 MW can change significantly every hour (Figure 10-11). Changes to hourly eligibility levels are the result of online status, minimum/maximum runtimes, minimum notification times, maintenance status and grid conditions including constraints. But changes to the hourly offer status are only permitted when resources are physically unable to provide tier 2. Resource operators can make their units unavailable for an hour or block of hours via the Markets Gateway unavailable option without having to provide a reason. This means that while compliance with the must offer requirement can be done daily it is not possible to verify compliance with the tier 2 must offer requirement on an hourly basis.

20 See PJM. "Manual 11: Energy & Ancillary Services Market Operations," Revision 82 (July 1, 2016) p. 73, "Regardless of online/offline state, all non-emergency generation capacity resources must submit a daily offer for Tier 2 Synchronized Reserve in eMKT…"

21 See PJM "Manual 11: Energy & Ancillary Services Market Operations," Revision 82 (July 1, 2016) p. 74.

Figure 10-11 Tier 2 synchronized reserve hourly offer and eligible volume (MW), averaged daily: January through June, 2016



Of all nonemergency resources capable of reliably producing synchronized reserve (e.g. excluding batteries, wind, landfill gas, solar and CTs that have no ramp available), an average of 1.7 percent of units capable of providing tier 2 synchronized reserve did not enter a daily tier 2 synchronized reserve offer for January through June 2016.

Tier 2 synchronized reserve is subject to a must offer requirement. To help ensure compliance with this rule, the MMU recommends that PJM modify its Markets Gateway to enforce daily tier 2 synchronized reserve compliance by requiring an offer greater than 0 MW.

Figure 10-12 shows average offer MW volume by market and unit type for the MAD Subzone and Figure 10-13 shows average offer MW volume by market and unit type for the RTO Zone.

Figure 10-12 Mid-Atlantic Dominion subzone average daily tier 2 synchronized reserve offer by unit type (MW): January through June, 2014 through 2016

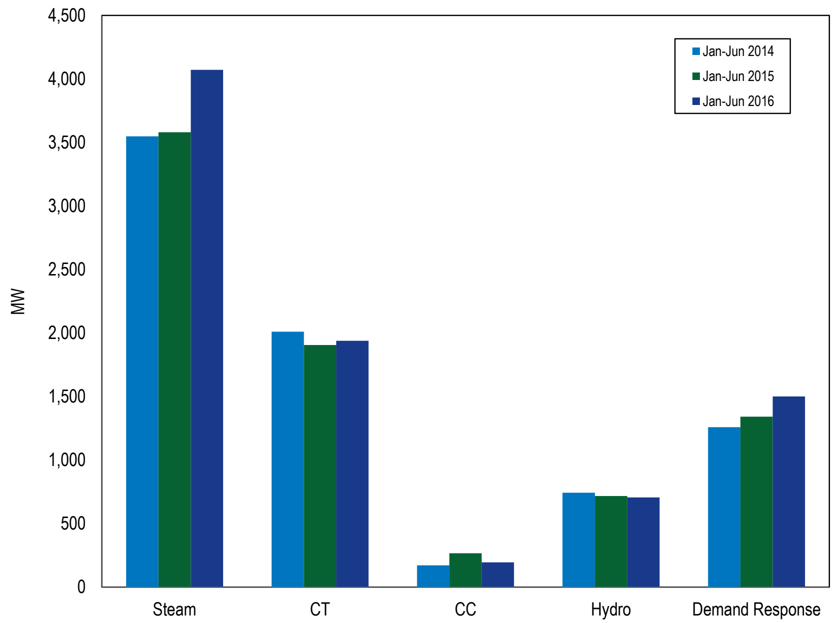
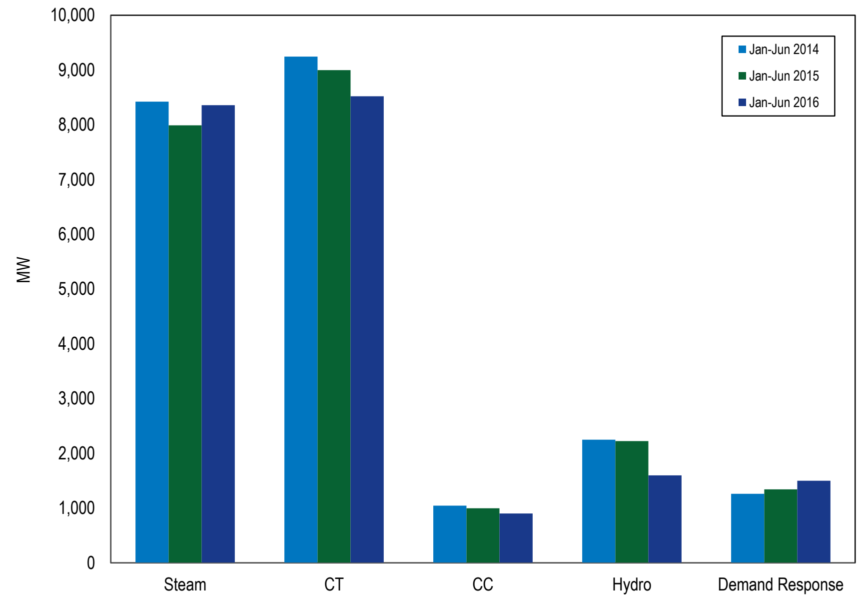


Figure 10-13 RTO Zone average daily tier 2 synchronized reserve offer by unit type (MW): January through June, 2014 through 2016



Market Performance

Price

The price of tier 2 synchronized reserve is calculated in real time every five minutes and averaged each hour for the RTO Reserve Zone and the MAD Subzone. In hours where total tier 1 MW synchronized reserve MW is less than the synchronized reserve requirement, PJM must clear a tier 2 market for synchronized reserves.

In the MAD Subzone, total tier 1 MW was less than the synchronized reserve requirement in 99.3 percent of hours in the first six months of 2016. In these hours in 2016, PJM scheduled an average 179.2 MW of tier 2 synchronized reserve in the MAD Subzone at a weighted average price of $4.45. In the first six months of 2015, the weighted average synchronized reserve market clearing price in the MAD Subzone was $13.62. The MAD weighted average prices reported here provides the weighted average price in the MAD Subzone for all hours where there was a price for Tier 2, regardless of whether or not the MAD Subzone separated from the RTO zone.

In the RTO Zone, total tier 1 MW was less than the synchronized reserve requirement in 80.3 percent of hours in the first six months of 2016. In these hours in 2016, PJM scheduled an average 423.5 MW of tier 2 synchronized reserve at a weighted average price of $4.40. In the first six months of 2015, the weighted average synchronized reserve market clearing price in the RTO Zone was $13.05. The RTO Zone weighted average price reported here provides the system-wide weighted average price for all hours where there was a price for Tier 2, regardless of whether or not the MAD Subzone separated from the RTO Zone.

Supply, performance, and demand are reflected in the price of synchronized reserve (Figure 10-9 and Figure 10-10). Mild weather and increased tier 2 synchronized reserve must offer compliance in January through June 2016, resulted in significantly lower prices for tier 2 synchronized reserve compared with the same time period in 2015.

Table 10-17 Mid-Atlantic Dominion subzone, weighted average SRMCP and average scheduled, tier 1 estimated and demand response MW January 2015 through June 2016

Year	Month	Weighted Average Synchronized Reserve Market Clearing Price	Average Tier 2 Generation Synchronized Reserve Purchased (MW)	Average Hourly Tier 1 Synchronized Reserve Estimated Hour Ahead (MW)	Average Hourly Demand Response Cleared (MW)
2015	Jan	$11.59	166.1	607.0	62.4
2015	Feb	$25.54	247.8	635.3	55.7
2015	Mar	$11.80	201.7	494.6	59.2
2015	Apr	$10.77	182.4	386.7	83.4
2015	May	$11.21	153.6	596.2	74.5
2015	Jun	$10.81	129.1	758.6	39.0
2015	Jul	$11.82	145.8	654.4	38.4
2015	Aug	$8.12	153.7	650.2	44.8
2015	Sep	$9.81	183.4	506.9	53.1
2015	Oct	$10.35	237.2	347.9	101.4
2015	Nov	$3.80	177.1	460.1	91.8
2015	Dec	$5.90	224.1	328.2	94.9
2015	Average	$10.96	183.5	535.5	66.5
2016	Jan	$6.53	118.1	556.4	62.2
2016	Feb	$2.66	119.8	575.7	63.1
2016	Mar	$3.56	212.7	361.4	97.8
2016	Apr	$5.28	254.0	319.3	125.7
2016	May	$3.40	213.8	370.5	96.6
2016	Jun	$5.29	157.0	600.2	67.1
2016	Average	$4.45	179.2	463.9	85.4

Table 10-18 RTO zone weighted average SRMCP and average scheduled, tier 1 estimated and demand response MW January 2015 through June 2016

Year	Month	Weighted Average Synchronized Reserve Market Clearing Price	Average Tier 2 Generation Synchronized Reserve Purchased (MW)	Average Hourly Tier 1 Synchronized Reserve Estimated Hour Ahead (MW)	Average Hourly Demand Response Cleared (MW)
2015	Jan	$11.52	321.7	1,737.0	62.4
2015	Feb	$23.44	423.1	1,593.9	55.8
2015	Mar	$11.04	445.3	1,276.0	59.3
2015	Apr	$10.33	410.1	1,175.7	83.6
2015	May	$11.03	330.4	1,348.0	74.7
2015	Jun	$10.93	289.1	1,704.2	39.1
2015	Jul	$12.01	328.3	1,545.2	38.4
2015	Aug	$8.36	344.5	1,609.0	48.8
2015	Sep	$10.06	430.6	1,362.9	60.0
2015	Oct	$9.57	575.4	1,056.0	116.3
2015	Nov	$3.89	417.0	1,220.4	111.0
2015	Dec	$5.18	510.9	1,044.8	105.6
2015	Average	$10.61	402.2	1,389.4	71.3
2016	Jan	$6.59	267.9	1,548.0	74.3
2016	Feb	$2.77	277.5	1,510.2	81.5
2016	Mar	$3.56	509.9	1,093.1	130.0
2016	Apr	$5.06	600.5	1,012.0	159.3
2016	May	$3.39	507.4	1,151.3	125.8
2016	Jun	$5.03	377.8	1,592.1	78.4
2016	Average	$4.40	423.5	1,317.8	108.2

Cost

As a result of changing grid conditions, load forecasts, and unexpected generator performance, prices do not always cover the full cost and final LOC for each resource. Because price formation occurs within the hour (on five minute basis integrated over the hour) but the synchronized reserve commitment occurs prior to the hour, the realized within hour price can be zero even when some tier 2 synchronized reserve is cleared. All resources cleared in the market are guaranteed to be made whole and are paid if the SRMCP does not compensate them for their offer plus LOC.

The full cost of tier 2 synchronized reserve including payments for the clearing price and out of market costs is calculated and compared to the price. The closer the price to cost ratio is to one hundred percent, the more the market price reflects the full cost of tier 2 synchronized reserve. A price to cost ratio close to one hundred percent is an indicator of an efficient synchronized reserve market design.

In the first six months of 2016, the price to cost (including self-scheduled) ratio of the RTO Zone Tier 2 Synchronized Reserve Market averaged 48.4 percent (Table 10-19); and the price to cost ratio of the MAD Subzone averaged 30.4 percent.

Table 10-19 RTO Zone, Mid-Atlantic Subzone tier 2 synchronized reserve MW, credits, weighted price, and cost (including self-scheduled): January through June, 2016

Zone	Year	Month	Total MW	Total Credits	Weighted Average Synchronized Reserve Market Clearing Price	Cost	Price/Cost Ratio
RTO Zone	2016	Jan	199,337	$2,114,022	$6.59	$10.61	62.2%
RTO Zone	2016	Feb	193,155	$1,352,974	$2.77	$7.00	39.5%
RTO Zone	2016	Mar	379,358	$3,209,337	$3.56	$8.46	42.1%
RTO Zone	2016	Apr	432,327	$4,444,878	$5.06	$10.28	49.2%
RTO Zone	2016	May	377,514	$2,935,572	$3.39	$7.78	43.6%
RTO Zone	2016	Jun	272,043	$2,825,266	$5.03	$10.39	48.4%
RTO Zone	2016	Total	1,853,735	$16,882,050	$4.40	$9.09	48.4%
MAD Subzone	2016	Jan	111,480	$833,768	$6.53	$14.57	44.8%
MAD Subzone	2016	Feb	109,785	$538,679	$2.66	$9.77	27.2%
MAD Subzone	2016	Mar	221,090	$1,000,199	$3.56	$13.96	25.5%
MAD Subzone	2016	Apr	249,474	$1,069,676	$5.28	$18.46	28.6%
MAD Subzone	2016	May	218,448	$666,969	$3.40	$14.26	23.8%
MAD Subzone	2016	Jun	159,032	$917,458	$5.29	$16.88	31.4%
MAD Subzone	2016	Total	1,069,309	$5,026,749	$4.45	$14.65	30.4%

Compliance

The MMU has identified and quantified the failure of scheduled tier 2 synchronized reserve resources to deliver during synchronized reserve events since 2011.[22] When synchronized reserve resources self schedule or clear the Tier 2 Synchronized Reserve Market they are obligated to provide their full scheduled Tier 2 MW during a synchronized reserve event. Actual synchronized

22 See the *2011 State of the Market Report for PJM*, Volume II, Section 9, "Ancillary Services" at pg. 250.

reserve event response is determined by final output minus initial output where final output is the largest output between 9 and 11 minutes after start of the event, and initial output is the lowest output between one minute before the event and one minute after the event.[23] Tier 2 resources are obligated to sustain their final output for the shorter of the length of the event or 30 minutes.[24]

The MMU has reported the wide range of synchronized reserve event response levels and recommended that PJM take action to increase compliance rates. Penalties can be assessed for any synchronized reserve event 10 minutes or longer during which flexible or inflexible synchronized reserve was scheduled either by the resource owner or by PJM. In 2015, there were 21 spinning events of which seven were 10 minutes or longer. In the first six months of 2016, there were six spinning events of which three were 10 minutes or longer.

Table 10-20 Synchronized reserve events 10 minutes or longer, tier 2 response compliance, RTO Reserve Zone: January through June, 2016

2016 Qualifying Synchronized Reserve Event (DD-Mon-YYYY HR)	Event Duration (Minutes)	Total Scheduled Tier 2 MW	Tier 2 Response MW	Percent T2 Compliance
18-Jan-2016 17	12	616.7	508.8	82.5%
08-Feb-2016 15	10	228.4	200.1	87.6%
14-Apr-2016 20	10	346.1	340.4	98.4%

Tier 1 resource owners are credited for the amount of synchronized reserve they provide in response to a synchronized reserve event.[25] Tier 2 resources owner are not credited for synchronized reserve event response. Tier 2 resources owners are penalized in the amount of their shortfall at SRMCP for the lesser of the average number of days between events, or the number of days since the previous event in which the resource did respond. For synchronized reserve events of 10 minutes or longer that occurred in the first six months of 2016, 11.9 percent of all scheduled tier 2 (including DSR) synchronized reserve MW were not delivered and were penalized (Table 10-20). In addition, a tier 2 resource will be penalized for the amount of MW it falls short of its offer for the entire hour, not just for the portion of the hour covered by the synchronized reserve event.[26] Resource owners are permitted to aggregate the response of multiple units to offset an under response from one unit with an overresponse from a different unit for the purpose of reducing an under response penalty. The average number of days between events calculated by PJM Performance Compliance for 2016 is 13 days.[27]

History of Synchronized Reserve Events

Synchronized reserve is designed to provide relief for disturbances.[28] [29] A disturbance is defined as loss of generation and/or transmission resources. PJM also calls synchronized reserve events for non-disturbance events, which it characterizes as "low ACE." In the absence of a disturbance, PJM dispatchers have used synchronized reserve as a source of energy to provide relief from low ACE. Such an event occurred on January 6, 2014. Five synchronized reserve events were declared during 2014 for low ACE. Five spinning events were declared for low ACE in 2015. There was one low ACE event in the first six months of 2016 on February 28, 2016. The risk of using synchronized reserves for energy or any other non-disturbance reason is that it reduces the amount of synchronized reserve available for a disturbance. Synchronized reserve has a requirement to sustain its output for up to thirty minutes. When the need is for reserve extending past thirty minutes secondary reserve is the appropriate source of the response. The use of synchronized reserve is an expensive solution during an hour when the hour ahead market solution and reserve dispatch indicated no shortage of primary reserve. PJM's primary reserve levels have been sufficient to recover from disturbances and should remain available in the absence of disturbance.

From January 2010 through December 2015, PJM experienced 173 synchronized reserve events (Table 10-21), approximately three events per month. During this period, synchronized reserve events had an average duration of 12.7 minutes. The average duration of spinning events has been lower in 2016 (8.5 minutes) than in any prior year (Figure 10-14). This corresponds with the higher rate of compliance by tier 2 synchronized reserve resources, and the higher rate of response by tier 1 resources to spinning event all calls.

23 See PJM "Manual 11: Energy & Ancillary Services Market Operations," Revision 82 (July 1, 2016) § 4.2.10 Settlements, p. 85.
24 See PJM "Manual 11: Energy & Ancillary Services Market Operations," Revision 82 (July 1, 2016) § 4.2.11 Verification, p. 85.
25 See PJM "Manual 11: Energy & Ancillary Services Market Operations," Revision 82 (July 1, 2016) § 4.2.12 Non Performance, p. 83.
26 See PJM. "Manual 28: Operating Agreement Accounting," Revision 73 (March 31, 2016) p. 45. *See also* "See PJM "Manual 11: Energy & Ancillary Services Market Operations," Revision 82 (July 1, 2016) § 4.2.12 Non-Performance, p. 85.
27 Report to PJM Operating Committee, "Synchronized Reserve Event Performance and Penalty Days," December 3, 2014.
28 *2013 State of the Market Report for PJM*, Appendix F – PJM's DCS Performance, pp 451-452.
29 See PJM. "Manual 12: Balancing Operations," Revision 34 (April 28, 2016) § 4.1.2 Loading Reserves pp. 36.

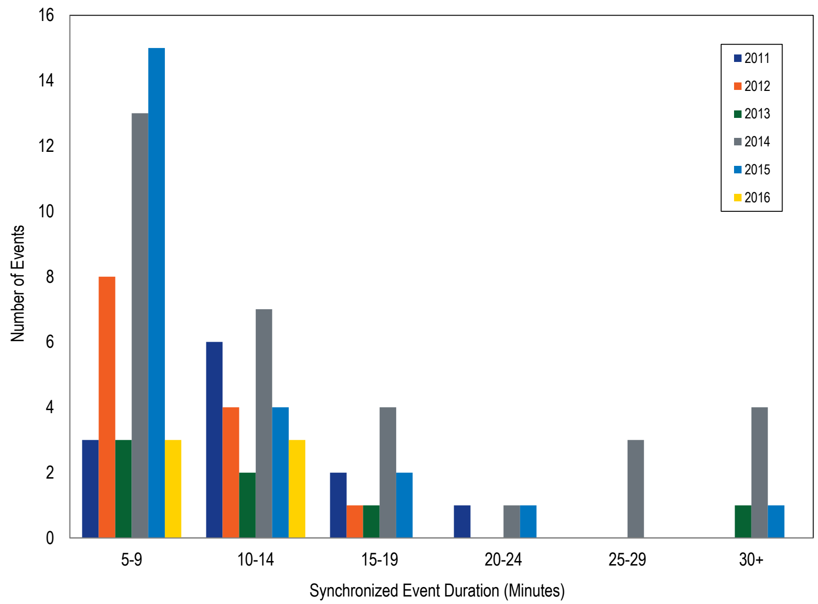
Table 10-21 Synchronized reserve events, January 2010 through June 2016

Effective Time	Region	Duration (Minutes)	Effective Time	Region	Duration (Minutes)	Effective Time	Region	Duration (Minutes)	Effective Time	Region	Duration (Minutes)
FEB-18-2010 13:27	Mid-Atlantic	19	JAN-11-2011 15:10	Mid-Atlantic	6	JAN-03-2012 16:51	RFC	9	JAN-22-2013 08:34	RTO	8
MAR-18-2010 11:02	RFC	27	FEB-02-2011 01:21	RFC	5	JAN-06-2012 23:25	RFC	8	JAN-25-2013 15:01	RTO	19
MAR-23-2010 20:14	RFC	13	FEB-08-2011 22:41	Mid-Atlantic	11	JAN-23-2012 15:02	Mid-Atlantic	8	FEB-09-2013 22:55	RTO	10
APR-11-2010 13:12	RFC	9	FEB-09-2011 11:40	Mid-Atlantic	16	MAR-02-2012 19:54	RFC	9	FEB-17-2013 23:10	RTO	13
APR-28-2010 15:09	Mid-Atlantic	8	FEB-13-2011 15:35	Mid-Atlantic	14	MAR-08-2012 17:04	RFC	6	APR-17-2013 01:11	RTO	11
MAY-11-2010 19:57	Mid-Atlantic	9	FEB-24-2011 11:35	Mid-Atlantic	14	MAR-19-2012 10:14	RFC	10	APR-17-2013 20:01	RTO	9
MAY-15-2010 03:03	RFC	6	FEB-25-2011 14:12	RFC	10	APR-16-2012 00:20	Mid-Atlantic	9	MAY-07-2013 17:33	RTO	8
MAY-28-2010 04:06	Mid-Atlantic	5	MAR-30-2011 19:13	RFC	12	APR-16-2012 11:18	RFC	8	JUN-05-2013 18:54	RTO	20
JUN-15-2010 00:46	RFC	34	APR-02-2011 13:13	Mid-Atlantic	11	APR-19-2012 11:54	RFC	16	JUN-08-2013 15:19	RTO	9
JUN-19-2010 23:49	Mid-Atlantic	9	APR-11-2011 00:28	RFC	6	APR-20-2012 11:08	Mid-Atlantic	7	JUN-12-2013 17:35	RTO	10
JUN-24-2010 00:56	RFC	15	APR-16-2011 22:51	RFC	9	JUN-20-2012 13:35	RFC	7	JUN-30-2013 01:22	RTO	10
JUN-27-2010 19:33	Mid-Atlantic	15	APR-21-2011 20:02	Mid-Atlantic	6	JUN-26-2012 17:51	RFC	7	JUL-03-2013 20:40	RTO	13
JUL-07-2010 15:20	RFC	8	APR-27-2011 01:22	RFC	8	JUL-23-2012 21:45	RFC	18	JUL-15-2013 18:43	RTO	29
JUL-16-2010 20:45	Mid-Atlantic	19	MAY-02-2011 00:05	Mid-Atlantic	21	AUG-03-2012 12:44	RFC	10	JUL-28-2013 14:20	RTO	10
AUG-11-2010 19:09	RFC	17	MAY-12-2011 19:39	RFC	9	SEP-08-2012 04:34	RFC	12	SEP-10-2013 19:48	RTO	68
AUG-13-2010 23:19	RFC	6	MAY-26-2011 17:17	Mid-Atlantic	20	SEP-27-2012 17:19	Mid-Atlantic	7	OCT-28-2013 10:44	RTO	33
AUG-16-2010 07:08	RFC	17	MAY-27-2011 12:51	RFC	6	OCT-17-2012 10:48	RTO	10	DEC-01-2013 11:17	RTO	9
AUG-16-2010 19:39	Mid-Atlantic	11	MAY-29-2011 09:04	RFC	7	OCT-23-2012 22:29	RTO	19	DEC-07-2013 19:44	RTO	7
SEP-15-2010 11:20	RFC	13	MAY-31-2011 16:36	RFC	27	OCT-30-2012 05:12	RTO	14			
SEP-22-2010 15:28	Mid-Atlantic	24	JUN-03-2011 14:23	RFC	7	NOV-25-2012 16:32	RTO	12			
OCT-05-2010 17:20	RFC	10	JUN-06-2011 22:02	Mid-Atlantic	9	DEC-16-2012 07:01	RTO	9			
OCT-16-2010 03:22	Mid-Atlantic	10	JUN-23-2011 23:26	RFC	8	DEC-21-2012 05:51	RTO	7			
OCT-16-2010 03:25	RFCNonMA	7	JUN-26-2011 22:03	Mid-Atlantic	10	DEC-21-2012 10:29	RTO	5			
OCT-27-2010 10:35	RFC	7	JUL-10-2011 11:20	RFC	10						
OCT-27-2010 12:50	Mid-Atlantic	10	JUL-28-2011 18:49	RFC	12						
NOV-26-2010 14:24	RFC	13	AUG-02-2011 01:08	RFC	6						
NOV-27-2010 11:34	RFC	8	AUG-18-2011 06:45	Mid-Atlantic	6						
DEC-08-2010 01:19	RFC	11	AUG-19-2011 14:49	RFC	5						
DEC-09-2010 20:07	RFC	5	AUG-23-2011 17:52	RFC	7						
DEC-14-2010 12:02	Mid-Atlantic	24	SEP-24-2011 15:48	RFC	8						
DEC-16-2010 18:40	Mid-Atlantic	20	SEP-27-2011 14:20	RFC	7						
DEC-17-2010 22:09	Mid-Atlantic	6	SEP-27-2011 16:47	RFC	9						
DEC-29-2010 19:01	Mid-Atlantic	15	OCT-30-2011 22:39	Mid-Atlantic	10						
			DEC-15-2011 14:35	Mid-Atlantic	8						
			DEC-21-2011 14:26	RFC	18						

Table 10-21 Synchronized reserve events, January 2010 through June 2016 (continued)

Effective Time	Region	Duration (Minutes)	Effective Time	Region	Duration (Minutes)	Effective Time	Region	Duration (Minutes)
JAN-06-2014 22:01	RTO	68	JAN-07-2015 22:36	RTO	8	JAN-18-2016 17:58	RTO	12
JAN-07-2014 02:20	RTO	25	FEB-24-2015 02:51	RTO	5	FEB-08-2016 15:05	RTO	10
JAN-07-2014 04:18	RTO	34	FEB-26-2015 15:20	RTO	6	FEB-28-2016 18:29	RTO	8
JAN-07-2014 11:27	RTO	11	MAR-03-2015 17:02	RTO	11	APR-14-2016 20:09	RTO	10
JAN-07-2014 13:20	RTO	41	MAR-16-2015 10:25	RTO	24	MAY-11-2016 15:55	RTO	6
JAN-10-2014 16:46	RTO	12	MAR-17-2015 23:34	RTO	17	JUN-01-2016 09:01	RTO	5
JAN-21-2014 18:52	RTO	6	MAR-23-2015 23:44	RTO	15			
JAN-22-2014 02:26	RTO	7	APR-06-2015 14:23	RTO	8			
JAN-22-2014 22:54	RTO	8	APR-07-2015 17:11	RTO	31			
JAN-25-2014 05:22	RTO	10	APR-15-2015 08:14	RTO	8			
JAN-26-2014 17:11	RTO	6	APR-25-2015 03:21	RTO	9			
JAN-31-2014 15:05	RTO	13	JUL-30-2015 14:04	RTO	10			
FEB-02-2014 14:03	Dominion	8	AUG-05-2015 19:47	RTO	7			
FEB-08-2014 06:05	Dominion	18	AUG-19-2015 16:47	RTO	9			
FEB-22-2014 23:05	RTO	7	SEP-05-2015 01:16	RTO	7			
MAR-01-2014 05:18	RTO	26	SEP-10-2015 10:12	RTO	8			
MAR-05-2014 21:25	RTO	8	SEP-29-2015 00:58	Mid-Atlantic	11			
MAR-13-2014 20:39	RTO	8	NOV-12-2015 16:42	RTO	8			
MAR-27-2014 10:37	RTO	56	NOV-21-2015 17:17	RTO	8			
APR-14-2014 01:16	RTO	10	DEC-04-2015 22:41	RTO	7			
APR-25-2014 17:33	RTO	6	DEC-24-2015 17:42	RTO	8			
MAY-01-2014 14:18	RTO	13						
MAY-03-2014 17:11	RTO	13						
MAY-14-2014 01:36	RTO	5						
JUL-08-2014 03:07	RTO	9						
JUL-25-2014 19:19	RTO	7						
SEP-06-2014 13:32	RTO	18						
SEP-20-2014 23:42	RTO	14						
SEP-29-2014 10:08	RTO	15						
OCT-20-2014 06:35	RTO	15						
OCT-23-2014 11:03	RTO	27						
NOV-01-2014 06:50	RTO	9						
NOV-08-2014 02:08	RTO	8						
NOV-22-2014 05:27	RTO	21						
NOV-22-2014 08:19	RTO	10						
DEC-10-2014 18:58	RTO	8						
DEC-31-2014 21:42	RTO	12						

Figure 10-14 Synchronized reserve events duration distribution curve: 2011 through 2016



Non-Synchronized Reserve Market

Non-synchronized reserve is reserve MW available within 10 minutes but not synchronized to the grid. There is no defined requirement for non-synchronized reserves. It is available to meet the primary reserve requirement. Generation resources that have designated their entire output as emergency are not eligible to provide non-synchronized reserves. Generation resources that are not available to provide energy are not eligible to provide non-synchronized reserves.

The market for non-synchronized reserve does not include any direct participation by market participants. PJM defines the demand curve for non-synchronized reserve and PJM defines the supply curve based on nonemergency generation resources that are available to provide energy and can start in 10 minutes or less and on the associated resource opportunity costs calculated by PJM. Generation owners do not submit supply offers.

Startup time for non-synchronized reserve resources is not subject to testing. There is no non-synchronized reserve offer MW or offer price. The market solution software evaluates all eligible resources and schedules them economically. Prices are determined solely by the lost opportunity cost created by any deviation from economic merit order required to maintain the non-synchronized reserve commitment. Since non-synchronized reserve is a lower quality product, its clearing price is always less than or equal to the synchronized reserve market clearing price. In most hours, the non-synchronized reserve clearing price is zero.

Market Structure

Demand

PJM specifies that 1,700 MW of ten minute primary reserve must be available in the Mid-Atlantic Dominion Reserve Subzone of which 1,450 MW must be synchronized reserve (Figure 10-2), and that 2,175 MW of 10 minute primary reserve must be available in the RTO Reserve Zone of which 1,450 MW must be synchronized reserve (Figure 10-3). The balance of primary reserve can be made up by the most economic combination of synchronized and non-synchronized reserve.

Supply

Figure 10-2 shows that most of the primary reserve requirement (orange line) in excess of the synchronized reserve requirement (yellow line) is satisfied by non-synchronized reserve (light blue area).

There are no offers for non-synchronized reserve. Neither MW nor price is offered for non-synchronized reserve. The market solution (ASO) optimizes synchronized reserve, non-synchronized reserve, and energy to satisfy the primary reserve requirement at the lowest cost. Non-synchronized reserve resources are scheduled economically based on LOC until the Primary Reserve requirement is filled. The non-synchronized reserve market clearing price is determined at the end of the hour as the marginal unit's LOC. When a unit clears the non-synchronized reserve market and is scheduled, it is committed to remain offline for the hour and available to provide 10 minute reserves.

Equipment that generally qualifies as non-synchronized reserve include run of river hydro, pumped hydro, combustion turbines, combined cycles and diesels.[30] In the first six months of 2016, an average of 302.0 MW of non-synchronized reserve was scheduled hourly out of 1,641.5 eligible MW as part of the primary reserve requirement in the Mid-Atlantic Dominion Subzone. In the first six months of 2016 an average of 333.2 MW of non-synchronized reserve was scheduled hourly out of 2,279.9 MW eligible MW in the RTO Zone.

During the first six months of 2016 CTs provided 52.9 percent of scheduled non-synchronized reserve and hydro provided 46.0 percent. The remaining 1.1 percent of cleared non-synchronized reserve was provided by diesel resources.

Market Concentration

The supply of non-synchronized reserves in the Mid-Atlantic Dominion Subzone and the RTO Zone was highly concentrated in the first six months of 2016. PJM market operations increased the required amount of primary reserve from 2,175 MW to 3,195 MW for a 14 hour period on February 22, 2016 in the RTO Zone. The required primary reserve was increased in the MAD Subzone from 1,700 to 1,775 MW and in the RTO zone from 2,175 MW to 2,662 MW for 20 hours on April 7 and 8, 2016.

30 See PJM. "Manual 11: Energy & Ancillary Services Market Operations," Revision 82 (July 1, 2016), p. 88.

Table 10-22 Non-synchronized reserve market HHIs: January through June, 2016

Year	Month	MAD HHI	RTO HHI
2016	Jan	4347	4297
2016	Feb	4002	3981
2016	Mar	3262	3227
2016	Apr	3884	3808
2016	May	3539	3507
2016	Jun	3720	3701
2016	Average	3792	3753

Table 10-23 Non-synchronized reserve market pivotal supply test: January through June, 2016

Year	Month	MAD Three Pivotal Supplier Hours	RTO Three Pivotal Supplier Hours
2016	Jan	35.6%	0.0%
2016	Feb	17.0%	0.0%
2016	Mar	12.6%	0.0%
2016	Apr	20.1%	0.0%
2016	May	43.0%	6.6%
2016	Jun	47.1%	0.8%
2016	Average	25.7%	1.3%

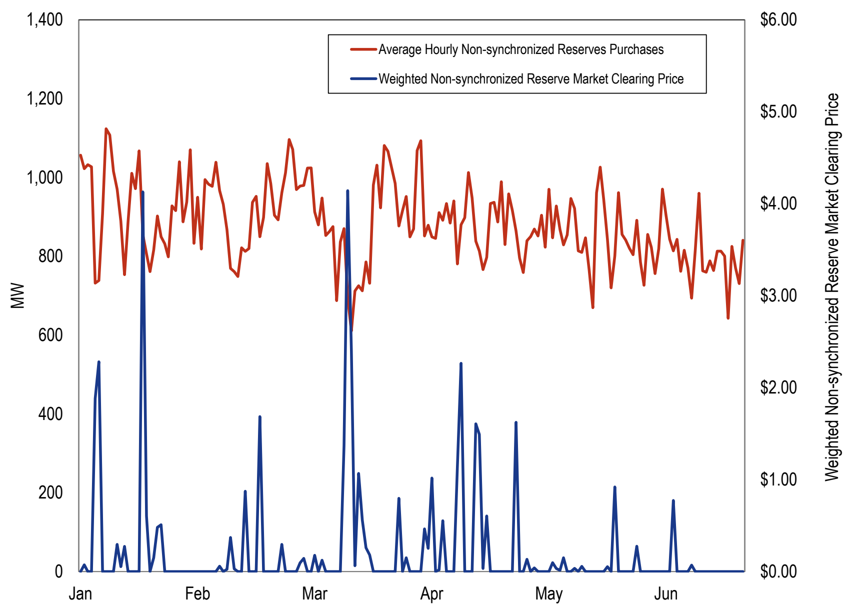
Price

The price of non-synchronized reserve is calculated in real time every five minutes and averaged each hour for the RTO Reserve Zone and the Mid-Atlantic Dominion Reserve Subzone. Resources eligible for non-synchronized reserve make no price offer or MW offer.

Figure 10-15 shows the daily average hour ahead non-synchronized reserve market clearing price and average scheduled MW for the RTO Zone. In the first six months of 2016 the MAD Subzone cleared at a price greater than $0 in 188 hours. The maximum hourly clearing price was $83.06 per MW on January 18, 2016. Figure 10-15 shows the daily average hour ahead non-synchronized reserve market clearing price and average scheduled MW for the RTO Zone including the MAD Subzone. The RTO Zone Non-Synchronized Reserve Market had a clearing price greater than zero in 188 hours (4.3 percent). The weighted non-synchronized reserve market clearing price for all hours in the

RTO Zone with a clearing price above $0 was $5.88. The clearing price for all hours including cleared hours when the price was zero, was $0.20 in 2016.

Figure 10-15 Daily average RTO zone non-synchronized reserve market clearing price and MW purchased: January through June, 2016



Price and Cost

As a result of changing grid conditions, load forecasts, and unexpected generator performance, prices sometimes do not cover the full LOC of each resource. All resources cleared in the market are guaranteed to be made whole and are paid uplift credits if the NSRMCP does not fully compensate them.

The full cost of non-synchronized reserve including payments for the clearing price and uplift costs is calculated and compared to the price (Table 10-24). The closer the price to cost ratio comes to one, the more the market price reflects the full cost of non-synchronized reserve.

In the first six months of 2016, the price to cost ratio of the RTO Zone Non-Synchronized Reserve Market averaged 18.8 percent; and the price to cost ratio of the MAD Subzone averaged 18.4 percent.

Table 10-24 RTO zone, MAD subzone non-synchronized reserve MW, credits, price, and cost: January through June, 2016

Market	Year	Month	Total Non-synchronized Reserve MW	Total Non-synchronized Reserve Charges	Weighted Non-synchronized Reserve Market Clearing Price	Non-synchronized Reserve Cost	Price/Cost Ratio
RTO Zone	2016	Jan	688,251	$1,334,499	$0.30	$1.94	15.6%
RTO Zone	2016	Feb	637,914	$672,179	$0.11	$1.05	10.0%
RTO Zone	2016	Mar	656,382	$405,979	$0.31	$0.62	49.6%
RTO Zone	2016	Apr	644,608	$786,807	$0.35	$1.22	28.5%
RTO Zone	2016	May	636,921	$274,391	$0.05	$0.43	10.9%
RTO Zone	2016	Jun	579,821	$613,506	$0.04	$1.06	3.6%
RTO Zone	2016	Total	3,843,897	$4,087,360	$0.20	$1.06	18.8%
MAD SubZone	2016	Jan	268,156	$540,358	$0.31	$2.02	15.6%
MAD SubZone	2016	Feb	250,478	$266,976	$0.11	$1.07	10.5%
MAD SubZone	2016	Mar	252,188	$159,892	$0.32	$0.63	49.8%
MAD SubZone	2016	Apr	246,393	$306,090	$0.35	$1.24	28.4%
MAD SubZone	2016	May	246,851	$109,339	$0.05	$0.44	11.0%
MAD SubZone	2016	Jun	226,637	$237,696	$0.04	$1.05	3.7%
MAD SubZone	2016	Total	1,490,702	$1,620,351	$0.20	$1.09	18.4%

Secondary Reserve (DASR)

PJM maintains a day-ahead, offer based market for 30-minute day-ahead secondary reserve.[31] The Day-Ahead Scheduling Reserves Market (DASR) has no performance obligations.

Market Structure

Supply

DASR is provided by both generation and demand resources. DASR offers consist of price only. DASR MW are calculated by the market clearing engine. Available DASR MW are the lesser of the energy ramp rate for all online units times thirty minutes, or the economic maximum minus the day-ahead dispatch

31 See PJM. "Manual 35: Definitions and Acronyms," Revision 23 (April 11, 2014), p. 89.

point. For offline resources capable of being online in thirty minutes, the DASR quantity is the economic maximum. In the first six months of 2016, the average available hourly DASR was 36,752 MW. This is a 1.5 percent increase from 36,192 MW from the same period in 2015. The DASR MW purchased averaged 5,501.0 MW per hour, an increase from 4,454.4 MW per hour in in the same period of 2015. Although there was no shortage of DASR in the market solution, the market has no requirements for or link to the availability of scheduled reserve during real-time hours. Spinning events longer than 30 minutes, while rare, do occur. The spinning events of September 10, 2013, March 27, 2014, and April 7, 2015, are examples of when secondary reserve was needed but not enough was available in real time.

The MMU has recommended since 2013 that PJM implement a real-time secondary reserve market.

PJM has proposed to exclude resources that cannot reliably provide reserves in real time from participating in the DASR Market. Such resources include nuclear, run-of-river hydro, self-scheduled pumped hydro, wind, solar, some dynamic transfer resources, and non-energy resources. The intent of this proposal is to limit cleared DASR resources to those resources actually capable of providing reserves in the real-time market. PJM has implemented changes to ensure that resources that clear DASR, but declare an outage in real time, will not be credited for DASR for that day. PJM is investigating how many resources have been credited for DASR over the past two years but were unavailable in real time. PJM will be requiring refunds from such resources.

All generation resources are required to offer a price for DASR.[32] Of the 5,501.1 MW hourly average DASR cleared in the first six months of 2016, 58.5 percent was from CTs, 13.8 percent was from steam, 18.5 percent was from hydro, and 7.6 percent was CCs. Load response resources which are registered in PJM's Economic Load Response and are dispatchable by PJM are eligible to provide DASR. In the first six months of 2016, six demand resources offered into the DASR Market.

32 See PJM "See PJM "Manual 11: Energy & Ancillary Services Market Operations," Revision 82 (July 1, 2016), p. 144 §11.2.3 Day-Ahead Scheduling Reserve Market Rules.

Demand

DASR 30-minute reserve requirements are determined by PJM for each reliability region. In the Reliability*First* (RFC) region, secondary reserve requirements are calculated based on historical under-forecasted load rates and generator forced outage rates.[33] The RFC and Dominion secondary reserve requirements are added together to form a single RTO DASR requirement defined as a percent of the daily peak load forecast. For 2016 the DASR requirement is set to 5.70 percent of daily peak load forecast. This is down from 5.93 percent of peak load forecast for 2015. The DASR requirement is applicable for all hours of the operating day. If the DASR Market does not procure adequate scheduling reserves, PJM is required to schedule additional operating reserves.[34]

Effective March 1, 2015, the DASR requirement can be increased by PJM dispatch under conditions of "hot weather or cold weather alert or max emergency generation alert or other escalating emergency."[35] The amount of additional DASR MW that may be required is the Adjusted Fixed Demand (AFD) determined by a Seasonal Conditional Demand (SCD) factor.[36] The SCD factor is calculated separately for the winter (November through March) and summer (April through October) seasons. The SCD factor is calculated every year based on the top 10 peak load days from the prior year. For November 2014 through October 2015, the values for additional percent of peak load was 3.87 percent for winter, 5.36 percent for summer. For November 2015 through October 2016, the SCD values are 3.45 percent for winter and 2.88 percent for summer. PJM Dispatch may also schedule additional Day-Ahead Scheduling Reserves as deemed necessary for conservative operations.[37] PJM has defined conservative operations to include, potential fuel delivery issues, forest/brush fires, extreme weather events, environmental alerts, solar disturbances,

33 See PJM. "Manual 13: Emergency Operations," Revision 59 (January 1, 2016), p. 11.
34 PJM uses the terms "supplemental operating reserves" and "scheduling operating reserves" interchangeably.
35 PJM. "Energy and Reserve Pricing & Interchange Volatility Final Proposal Report," <http://www.pjm.com/~/media/committees-groups/committees/mrc/20141030/20141030-item-04-erpiv-final-proposal-report.ashx>.
36 See PJM. "See PJM "Manual 11: Energy & Ancillary Services Market Operations," Revision 82 (July 1, 2016) p. 144 at 11.2.1 Day-Ahead Scheduling Reserve Market Requirement.
37 See PJM "See PJM "Manual 11: Energy & Ancillary Services Market Operations," Revision 82 (July 1, 2016) p. 152 at 11.2.1 Day-Ahead Scheduling Reserve Market Requirement.

unknown grid operating state.[38] The net result is substantial discretion for PJM to increase the demand for DASR under a variety of circumstances.

PJM invoked adjusted fixed demand during 14 days in 2015. In the first six months of 2016, PJM invoked adjusted fixed demand on one day, February 14, 2016. A record of PJM's use of adjusted fixed demand is in Table 10-25. The use of adjusted fixed demand (and other conservative operations adjustments) impacts the DASR Market in several significant ways.

Table 10-25 Adjusted Fixed Demand Days: 2016

Start Date	End Date	Number of Hours	Average Additional MW
14-Feb	14-Feb	24	3,008

An alternative to adjusted fixed demand would be to schedule secondary reserve in the real time market. The MMU recommends that PJM replace the DASR Market with a real-time secondary reserve product that is available and dispatchable in real time.

Market Concentration

Between January 2012 and April 2015, no hours would have failed a three pivotal supplier test in the DASR Market. Beginning in May 2015, when PJM began to invoke adjusted fixed demand for conservative operations, the DASR Market began to fail the three pivotal supplier test (Table 10-26).

Table 10-26 DASR market three pivotal supplier test results and number of hours with DASRMCP above $0: January 2015 through June 2016

Year	Month	Number of Hours When DASRMCP > $0	Percent of Hours Pivotal
2015	Jan	151	0.0%
2015	Feb	328	0.0%
2015	Mar	300	0.0%
2015	Apr	301	0.0%
2015	May	323	3.9%
2015	Jun	349	11.2%
2015	Jul	496	28.1%
2015	Aug	482	21.5%
2015	Sep	532	11.4%
2015	Oct	634	0.3%
2015	Nov	568	0.0%
2015	Dec	473	0.4%
2015	Average	411	6.4%
2016	Jan	326	0.3%
2016	Feb	235	0.4%
2016	Mar	369	1.9%
2016	Apr	392	0.0%
2016	May	259	4.2%
2016	Jun	193	6.2%
2016	Average	296	2.2%

Market Conduct

PJM rules allow any unit with reserve capability that can be converted into energy within 30 minutes to offer into the DASR Market.[39] Units that do not offer have their offers set to $0.00 per MW.

Economic withholding remains an issue in the DASR Market. The marginal cost of providing DASR is zero. All offers greater than zero constitute economic withholding. In the first six months of 2016, 36.2 percent of generation units offered DASR at a daily price above $0.00. This compares to 37.9 percent for the same period in 2015. In the first six months of 2016, 13.5 percent of daily offers were above $5.00 per MW.

38 See PJM, "Manual 13: Emergency Operations" Revision 60, (June 1, 2016), p. 47 at 3.2 Conservative Operations.

39 See PJM. "See PJM "Manual 11: Energy & Ancillary Services Market Operations," Revision 82 (July 1, 2016), p. 153.

Market Performance

Between May and September 2015, the use of Adjusted Fixed Demand (AFD) by PJM Market Operations significantly increased the demand in 366 hours. For 43.6 percent of hours in 2015, DASR cleared at a price of $0.00 per MWh (Figure 10-16). In the first six months of 2016 there was one AFD day, February 14. A total of 40.4 percent of hours cleared at a price above $0.00. In 2015, the weighted average DASR price for all hours when the DASRMCP was above $0.00 was $2.99. In the first six months of 2016, the weighted average DASR price for all hours when the DASRMCP was above $0.00 was $0.29. The average cleared MW in all hours when the DASRMCP was above $0.00 was 4,484.0 MW. The highest DASR price was $27.89 on June 20, 2016.

The introduction of Adjusted Fixed Demand (AFD) on March 1, 2015, created a bifurcated market (Table 10-27). There were 367 hours in 2015 when PJM Market Operations added an Adjusted Fixed Demand to the normal 5.93 percent of forecast load. On February 14, 2016, PJM Market Operations added AFD to the normal 5.70 percent of forecast load. The difference in market clearing price, MW cleared, obligation incurred, and charges to PJM load are substantial. On February 14, 2016, while AFD was in effect, the weighted average DASR price was $3.10 compared to $0.23 for hours when DASRMCP was greater than $0.00 and PJM dispatch did not augment the requirement.

While the new rules allow PJM dispatch substantial discretion to add to DASR demand for a variety of reasons, the rationale for each specific increase is not always clear. The MMU recommends that PJM Market Operations attach a reason code to every hour in which PJM dispatch adds additional DASR MW above the default DASR hourly requirement. The addition of such a code would make the reason explicit, increase transparency and facilitate analysis of the use of PJM's ability to add DASR MW.

Table 10-27 DASR Market, regular hours vs. adjusted fixed demand hours: January 2015 through June 2016

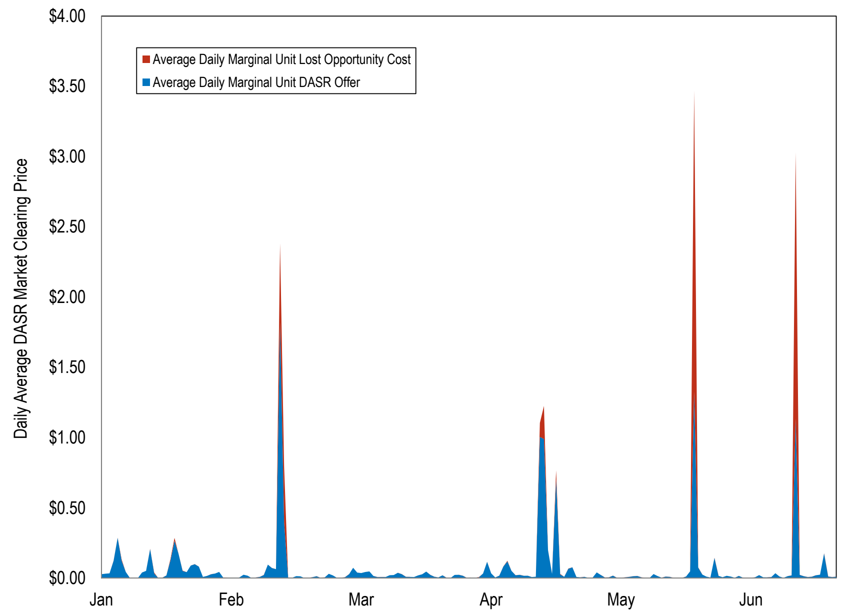
		Number of Hours DASRMCP>$0		Weighted DASRMCP		Average PJM Load MW		Hourly Average Cleared DASR MW		Average Hourly DASR Credits	
Year	Month	Normal Hour	AFD Hour	Normal Hour	AFD Hour	Normal Hour	AFD Hour	Normal Hour	AFD Hour	Normal Hour	AFD Hour
2015	Jan	151		$0.19		112,373		4,902		$937	
2015	Feb	328		$4.03		113,797		4,868		$19,610	
2015	Mar	300		$0.59		96,315		4,116		$2,429	
2015	Apr	301		$0.04		80,798		4,085		$155	
2015	May	279	44	$3.66	$12.34	92,863	96,726	4,574	9,042	$16,750	$111,598
2015	Jun	255	94	$0.92	$13.82	104,388	105,190	5,152	8,895	$4,724	$122,908
2015	Jul	410	86	$1.36	$18.56	106,605	114,868	5,553	9,599	$7,565	$178,164
2015	Aug	459	23	$0.95	$14.79	105,509	110,753	5,766	9,701	$5,483	$143,459
2015	Sep	412	120	$0.31	$14.63	91,491	109,028	5,003	11,337	$1,550	$165,870
2015	Oct	634		$0.35		77,657		4,231		$1,500	
2015	Nov	568		$0.29		80,844		4,477		$1,279	
2015	Dec	473		$0.13		87,166		4,807		$617	
2015	Average	381	73	$1.07	$14.83	95,817	107,313	4,794	9,715	$5,217	$144,400
2016	Jan	326		$0.15		103,263		4,723		$720	
2016	Feb	212	24	$0.05	$3.10	102,040	107,852	4,640	6,830	$249	$21,167
2016	Mar	369		$0.04		83,994		4,175		$175	
2016	Apr	393		$0.26		80,925		4,083		$1,060	
2016	May	259		$0.43		89,181		4,228		$1,839	
2016	Jun	191		$0.53		111,102		5,377		$2,892	
2016	Average	292	24	$0.24	$3.10	95,084	107,852	4,538	6,830	$1,156	$21,167

The implementation of the conservative operations adjustment to the DASR requirement in 367 hours during 2015 significantly increased the cost of DASR as a result of increases in DASR MW cleared and corresponding increases in the DASR clearing prices (Table 10-28). The impact of conservative operations changes was more limited in the first six months of 2016 because conservative operations were invoked on only one day.

Table 10-28 DASR Market all hours of DASR market clearing price greater than $0, January 2015 through June 2016

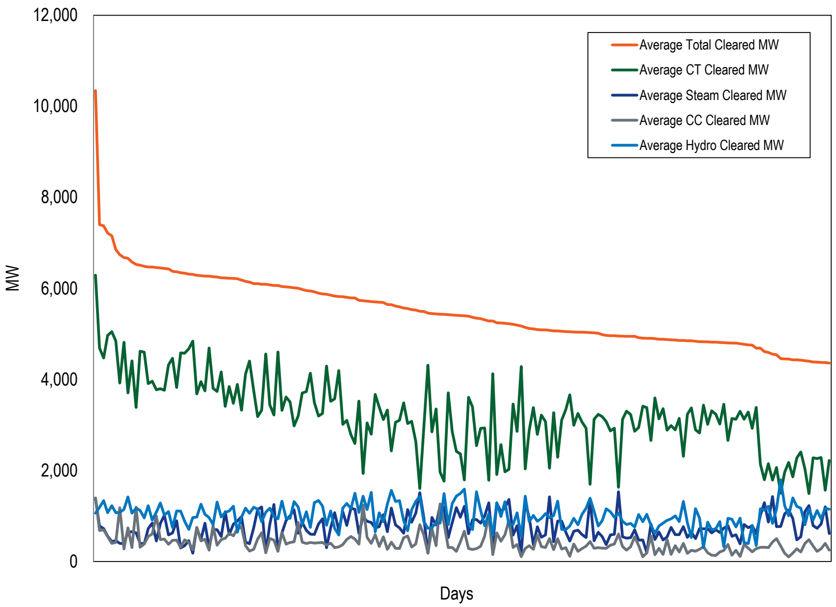
Year	Month	Number of Hours DASRMCP > $0	Weighted DASR Market Clearing Price	Average Hourly RT Load MW	Total PJM Cleared DASR MW	Total PJM Cleared Additional DASR MW	Total Charges
2015	Jan	151	$0.19	112,373	740,268	0	$141,561
2015	Feb	328	$4.03	113,797	1,596,639	0	$6,431,987
2015	Mar	300	$0.59	96,315	1,234,905	0	$728,829
2015	Apr	301	$0.04	80,798	1,229,513	0	$46,584
2015	May	323	$5.73	93,389	1,673,983	159,559	$9,583,568
2015	Jun	349	$5.93	104,604	2,150,052	294,881	$12,757,966
2015	Jul	496	$5.94	108,038	3,102,087	260,120	$18,423,687
2015	Aug	482	$2.03	105,759	2,869,630	59,414	$5,816,401
2015	Sep	532	$6.00	95,447	3,421,690	525,883	$20,542,872
2015	Oct	634	$0.35	77,657	2,682,429	0	$951,264
2015	Nov	568	$0.29	80,844	2,542,795	0	$726,549
2015	Dec	473	$0.13	87,166	2,273,497	0	$291,725
2015	Average	411	$2.60	96,349	2,126,457	108,321	$6,370,250
2015	Total	4,937			25,517,488	1,299,858	$76,442,995
2016	Jan	326	$0.15	103,263	1,539,783	0	$234,679
2016	Feb	212	$0.49	102,631	1,147,608	72,197	$560,692
2016	Mar	369	$0.04	83,994	1,540,415	0	$64,728
2016	Apr	393	$0.26	80,925	1,604,693	0	$416,418
2016	May	259	$0.43	89,181	1,094,991	0	$476,305
2016	Jun	191	$0.54	111,102	1,027,053	0	$552,455
2016	Average	292	$0.32	95,183	1,325,757	12,033	$384,213
2016	Total	1,750			7,954,544	72,197	$2,305,276

Figure 10-16 Daily average components of DASR clearing price ($/MW), marginal unit offer and LOC: January through June 2016



When the DASR requirement is increased by PJM dispatch, the reserve requirement frequently cannot be met without redispatching online resources which significantly affects the price. Figure 10-16 shows the impact of LOC on price when online resources must be redispatched to satisfy the DASR requirement. DASR prices increase at peak loads as a result of high LOCs. For the first six months of 2016, with the exception of three days (February 14, May 26, and June 20, 2016) DASR prices were low to moderate and did not include any LOC. The red at the top of the price for the three AFD days in Figure 10-16 shows the degree to which prices were determined by the LOC of the marginal unit(s). Figure 10-17 shows that when total DASR MW required is at its peak, a higher share of MW come from on line steam and CT units. While CTs have a low DASR related cost, steam units typically incur an LOC when redispatched to provide DASR. The redispatch of steam units to provide DASR has a significant impact on DASR prices.

Figure 10-17 Daily average DASR MW by unit type sorted from highest to lowest daily requirement: January through June 2016



Regulation Market

Regulation matches generation with very short term changes in load by moving the output of selected resources up and down via an automatic control signal. Regulation is provided by generators with a short-term response capability (less than five minutes) or by demand response (DR). The PJM Regulation Market is operated as a single real-time market. Significant technical and structural changes were made to the PJM Regulation Market in 2012.[40]

40 See the *2012 State of the Market Report for PJM*, Volume II, Section 9, "Ancillary Services," p. 271.

Market Design

The objective of PJM's regulation market design is to minimize the cost to provide regulation using two resource types, RegA and RegD, in a single market. To meet this objective, the marginal benefit factor (MBF) function describing the engineering substitutability between RegA and RegD must be correctly defined and consistently applied throughout the market design, from optimization to settlement. This is the only way to ensure that the engineering relationship is reflected in the relative value of RegA and RegD resources in the market price signals. That is not the case in PJM's current regulation market design. The MBF function is not correctly defined and it is not consistently applied throughout the market design, from optimization to settlement.

The result has been that the PJM Regulation Market has over procured RegD relative to RegA in most hours and has provided a consistently inefficient market signal to participants regarding the value of RegD to the market in every hour. This over procurement began to degrade the ability of PJM to control ACE in some hours while at the same time increasing the cost of regulation. When the price paid for RegD is above the level defined by an accurate MBF function, there is an artificial incentive for inefficient entry of RegD resources.

The MBF related issues with the Regulation Market have been raised in the PJM stakeholder process. In 2015, PJM stakeholders approved an interim, partial fix to the RegD over procurement problem which was implemented on December 14, 2015. The interim fix was designed to reduce the relative value of RegD MW in the optimization in all hours and to cap purchases of RegD MW during critical performance hours. But the interim fix does not address the fundamental issues in the optimization or the lack of consistency in the application of the MBF. The MMU and PJM are pursuing a comprehensive solution through the Regulation Market Issues Senior Task Force.

The Regulation Market includes resources following two signals: RegA and RegD. Resources responding to either signal help control ACE (area control error). RegA is PJM's slow-oscillation regulation signal and is designed for resources with the ability to sustain energy output for long periods of time, with slower ramp rates. RegD is PJM's fast-oscillation regulation signal and is designed for resources with limited ability to sustain energy output and with faster ramp rates. Resources must qualify to follow one or both of the RegA and RegD signals, but will be assigned by the market clearing engine to follow only one signal in a given market hour. The PJM regulation market design includes three clearing price components: capability ($/MW, based on the MW being offered); performance ($/mile, based on the total MW movement requested by the control signal, known as mileage); and lost opportunity cost ($/MW of lost revenue from the energy market as a result of providing regulation). The marginal benefit factor and performance score translate a resource's capability (actual) MW into effective MW.

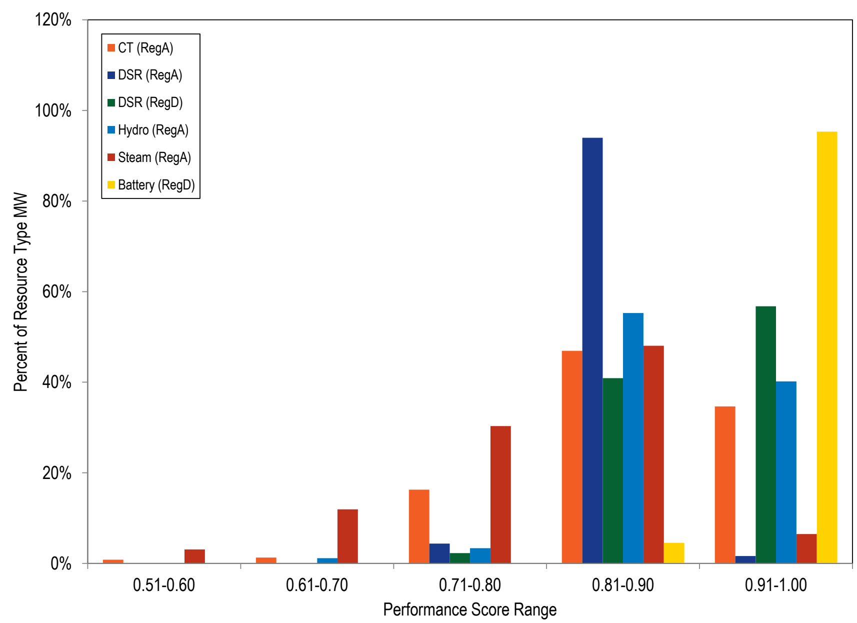
Regulation in PJM is frequently provided by fleets of resources rather than by individual units. A fleet is a set of resources owned or operated by a common entity. The regulation signals (RegA or RegD) are sent every two seconds to the fleet local control centers or, at the option of fleet owners, to their individual resources. Fleet local control centers report to PJM every two seconds the fleet response to the RegA and RegD signals.

Prior to the operating hour, fleet owners are allowed to replace an assigned regulation resource in their fleet with another resource in their fleet as long as that resource is qualified to provide regulation for the originally assigned signal, has an historic performance score close to the originally assigned resource and has notified PJM of the change.

Regulation performance scores (0.0 to 1.0) measure the response of a regulating resource to its assigned regulation signal (RegA or RegD) every 10 seconds by measuring: delay, the time delay of the regulation response to a change in the regulation signal; correlation, the correlation between the regulating resource output and the regulation signal; and precision, the difference between the regulation response and the regulation requested.[41]

Figure 10-18 and Figure 10-19 show the average performance score by resource type and the signal followed for the first six months of 2016. In these figures, the MW used are unadjusted regulation capability MW (actual MW not adjusted by performance score or benefit factor) and the performance score is the hourly performance score of the regulation resource.[42] Each category (color bar) is based on the percentage of the full performance score distribution for each resource (or signal) type. As Figure 10-19 shows, 94.4 percent of RegD resources had average performance scores within the 0.91-1.00 range, and 18.3 percent of RegA resources had average performance scores within that range.

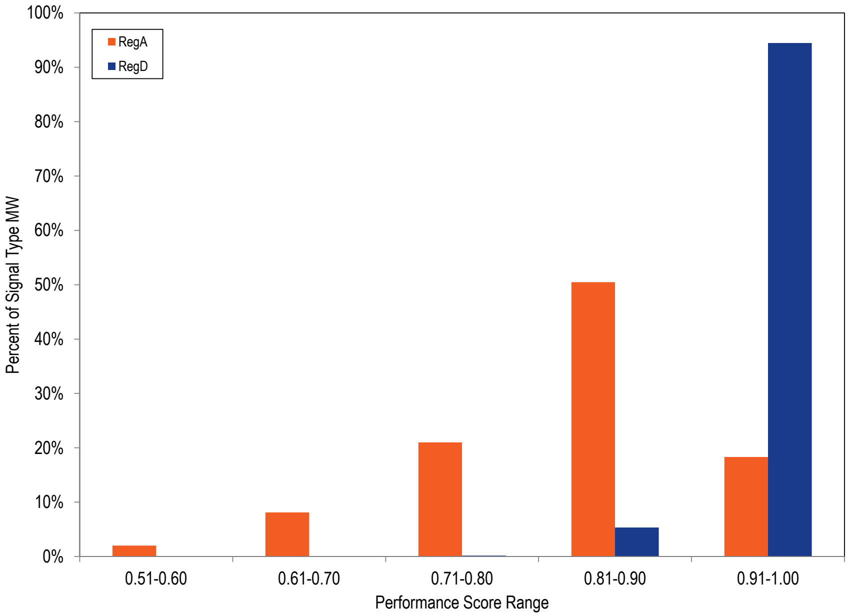
Figure 10-18 Hourly average performance score by unit type: January through June, 2016



41 PJM "Manual 12: Balancing Operations" Rev. 34 (April 28, 2016); 4.5.6, p 52.

42 Except where explicitly referred to as effective MW or effective regulation MW, MW means regulation capability MW unadjusted for either marginal benefit factor or performance factor.

Figure 10-19 Hourly average performance score by regulation signal type: January through June, 2016



PJM creates an individual resource's regulation signal proportionately by dividing the assigned regulation of the individual resource by the assigned regulation of the fleet. Then, PJM compares the individual resource's regulation signal to the individual resource's MW output (or, for DR, load) to calculate the performance score based on delay, correlation, and precision. Performance scores are calculated using data every 10 seconds, but are reported on an hourly basis for each individual regulating resource.

While resources following RegA and RegD can both provide regulation service in PJM's Regulation Market, PJM's joint optimization is intended to determine and assign the optimal mix of RegA and RegD MW to meet the hourly regulation requirement. The optimal mix is a function of the relative effectiveness and cost of available RegA and RegD resources. The optimization of RegA and RegD assignments is dependent on the conversion of RegA and RegD MW into a common unit of measure (effective MW). The marginal benefit factor (MBF) is the marginal measure of substitutability of RegD resources for RegA resources in satisfying the regulation requirement at any combination of RegA and RegD MW that can be used to meet the regulation requirement.

The MBF, as the marginal rate of substitution between RegA and RegD resource MW for a given regulation requirement, defines specific combinations of RegA and RegD MW needed to meet specific regulation performance levels. The use of the MBF in the optimization should result in the selection of the least cost combination/ratio of RegA and RegD MW when the prices of RegA and RegD are known. PJM's optimization engine has not properly implemented the MBF so that the market clearing combination of RegA and RegD MW is consistent with the combinations defined by the MBF curve.

For purposes of comparing effective MW to the regulation requirement, expressed in terms of effective MW of RegA, cleared regulation MW are converted to effective MW by multiplying each resource's offered capability MW by the product of the resource specific marginal benefit factor and performance score. This resource specific block assignment approach undercounts total effective MW, which are correctly calculated as the area under the MBF curve.

Total regulation offers (made up of a \$/MW capability offer and a \$/mile based performance offer) are converted to dollars per effective MW by dividing the offer by the effective MW.

For example, a 1.0 MW RegD resource with a total offer price of \$2/MW with a resource specific marginal benefit factor of 0.5 and a performance score of 100 percent, would be calculated as offering 0.5 effective MW (0.5 marginal benefit factor times 1.00 performance score times 1 MW). The total offer price would be \$4 per effective MW (\$2/MW offer divided by the 0.5 effective MW).

Market Design Issues

Marginal Benefit Factor Not Reflected Consistently or Correctly in Market

The marginal benefit factor function is incorrectly defined and improperly implemented in the current PJM regulation market. The market results do not represent the least cost solution that is consistent with a specific level of regulation service.

Properly defined, the marginal benefit factor is the rate of substitution between RegA and RegD MW at specific combinations of RegA and RegD that can be used to provide a defined level of regulation service. The specific combinations of RegA and RegD that can be used to provide a defined level of regulation service are feasible combinations of RegA and RegD. The objective of the market design is to find, given the relative costs of RegA and RegD MW, the least cost feasible combination of RegA and RegD MW. If the marginal benefit factor function is incorrectly defined, or improperly implemented in the market clearing and settlement, the resulting combinations of RegA and RegD will not represent the least cost solution.

The marginal benefit factor is not included in PJM's settlement process. This is a design flaw that results in incorrect payments for regulation. The issue results from two FERC orders. From October 1, 2012, through October 31, 2013, PJM adhered to a FERC order that required the marginal benefit factor be fixed at 1.0 for settlement calculations only. On October 2, 2013, the FERC directed PJM to eliminate the use of the marginal benefit factor entirely from settlement calculations of the capability and performance credits and replace it with the RegD to RegA mileage ratio in the performance credit paid to RegD resources, effective retroactively to October 1, 2012.[43]

The result of the FERC directive is that the marginal benefit factor is used in the optimization (currently using the incorrect PJM MBF) to determine the relative value of additional MW of RegD, but the marginal benefit factor is not used in the settlement for RegD.

Resources are paid Regulation Market Clearing Price (RMCP) credits and lost opportunity cost credits. If a resource's lost opportunity costs for an hour are greater than its RMCP credits, that resource receives lost opportunity cost credits equal to the difference.

Figure 10-20 compares the daily average marginal benefit factor and the mileage ratio for excursion and nonexcursion hours. Excursion hours (hours ending 7:00, 8:00, 18:00-21:00) are hours in which PJM has decided that more RegA is needed and has therefore limited the minimum marginal benefit factor that can be assigned to RegD MW to 1.0.[44] Once this limit is reached, the remaining regulation requirement satisfied with RegA MW.

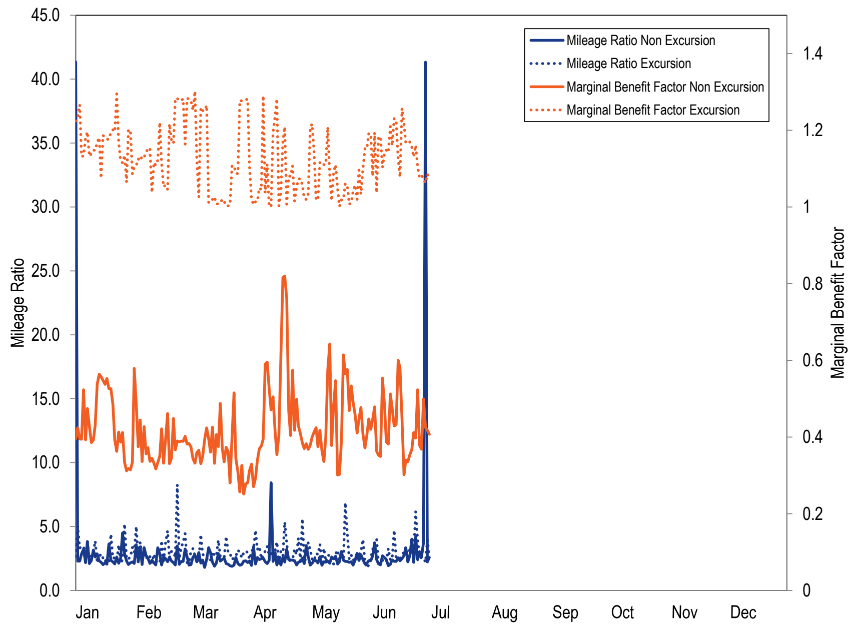
The very high mileage ratios on January 1, 2016, and June 28, 2016, were a result of the mechanics of the mileage ratio calculation. The extreme mileage ratios result when the RegA signal is fixed to control ACE and the RegD signal is not. The result of a fixed RegA signal is that RegA mileage is very small and therefore the mileage ratio of RegD/RegA is very large.

This result demonstrates why it is not appropriate to use the mileage ratio, rather than the marginal benefit factor, to measure the relative value of RegA and RegD resources. In these events RegA resources are providing ACE control (regulation service) despite not changing MW output (no mileage), while the change in MW output from RegD resources (positive mileage) is alternating between helping and hurting ACE control.

43 145 FERC ¶ 61,011 (2013).

44 See PJM. "Manual 11: Energy & Ancillary Services Market Operations," Revision 83, July 28, 2016); para 3.2.7, pp 63.

Figure 10-20 Daily average marginal benefit factor and mileage ratio during excursion and nonexcursion hours: January through June, 2016



The current settlement process does not result in RegA and RegD resources being paid the same price per effective MW. RegA resources are paid on the basis of dollars per effective MW of RegA. RegD resources are not paid in terms of dollars per effective MW of RegA because the marginal benefit factor is not used in settlements. When the marginal benefit factor is above one, RegD resources are generally (depending on the mileage ratio) underpaid on a per effective MW basis. When the marginal benefit factor is less than one, RegD resources are generally overpaid on a per effective MW basis. Currently, the marginal benefit factor is generally less than one, resulting in persistent overpayment of RegD resources.

PJM posts clearing prices for the Regulation Market (RMCCP, RMPCP and RMCP) in dollars per effective regulation capability MW. The regulation market clearing price (RMCP) for the hour is the simple average of the twelve five-minute RMCPs within the hour. The RMCP is set in each five-minute interval based on the marginal offer in each interval. The performance clearing price ($/effective MW) is based on the marginal performance offer (RMPCP) for the hour. The capability clearing price ($/effective MW) is equal to the difference between the RMCP for the hour and the RMPCP for the hour.

While prices are set on the basis of dollars per effective MW, only RegA receive payments (credits) that are consistent with their effective MW provided.[45] The current market design does not send the correct price signal to the RegD resources as a result of the inconsistent application of the marginal benefit factor.

Figure 10-21 shows, for the first six months of 2016, the maximum, minimum and average marginal benefit factor, based on PJM's incorrect marginal benefit factor curve, by month, for excursion and nonexcursion hours. The average MBF during excursion hours for the first six months of 2016 was 1.13, and the average MBF during nonexcursion hours for the first six months of 2016 was 0.41. The average MBF for all hours in the first six months of 2015 was 2.00. The marginal benefit factor (MBF) levels were a result of changes in the marginal benefit factor curve made effective on December 14, 2015, which reduced the relative value of RegD MW in the optimization in all hours. The change in the curve was that the slope of the benefit factor curve was altered to intercept the x-axis, defined in terms of RegD MW as a percent of the regulation requirement, at 40 percent instead of 62 percent. PJM also capped the procurement of RegD MW during excursion hours at the point where the MBF on the curve is equal to 1.0.

45 This is due to the fact that RegA resources performance adjusted MW are their effective MW.

Figure 10-21 Maximum, minimum, and average PJM calculated marginal benefit factor by month for excursion and nonexcursion hours: January through June, 2016

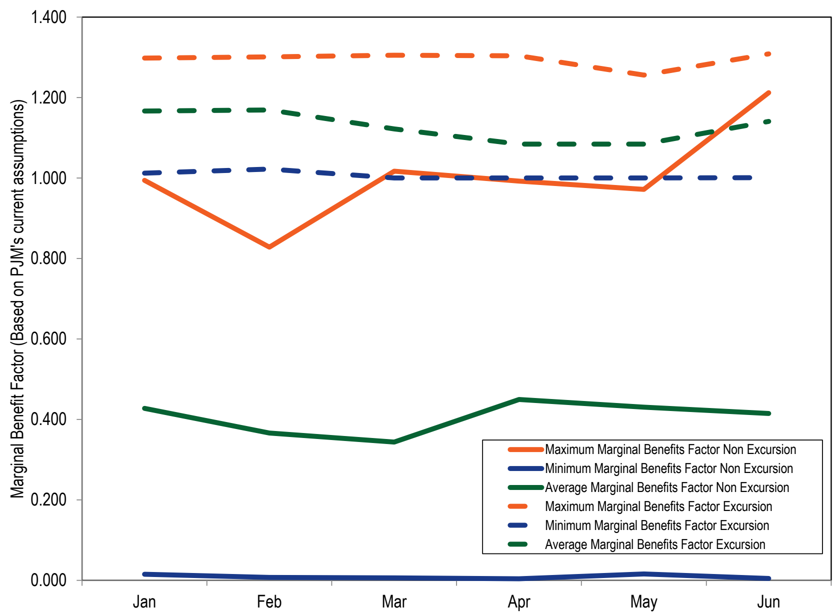
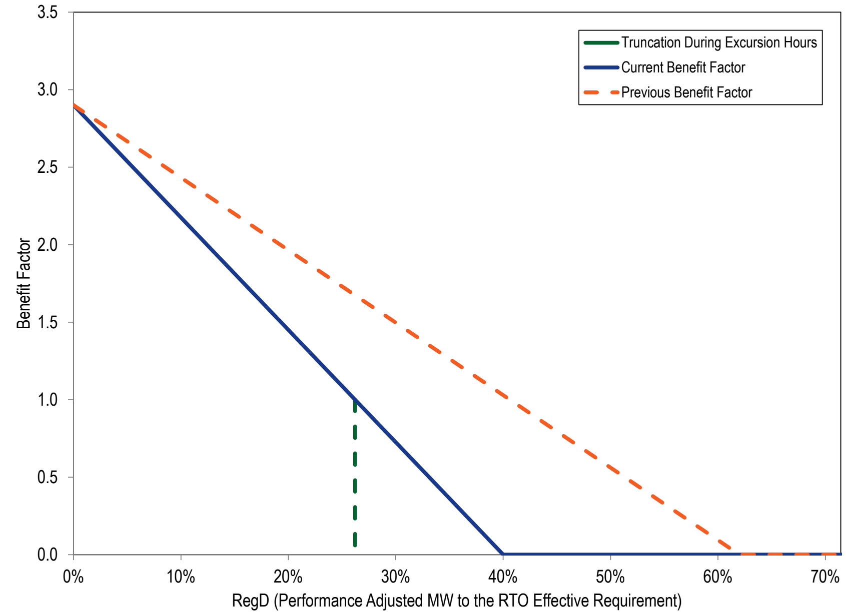


Figure 10-22 shows the marginal benefit factor curve (as incorrectly defined by PJM) before and after the December 14, 2015, modification. The modification to the marginal benefit factor curve reduced the amount of RegD procured, but did not correct for identified issues with the optimization engine.

Correcting the issues with the optimization engine would require correctly defining and using the marginal benefit factor curve, rather than continuing to incorrectly define the MBF as RegD MW cleared as a percentage of the effective MW target.

Figure 10-22 Marginal benefit factor curve before and after December 14, 2015, revisions by PJM



The MMU recommends that the Regulation Market be modified to incorporate a consistent and correct application of the marginal benefit factor throughout the optimization, assignment and settlement process.[46]

Incorrect MBF and Inconsistent Application of MBF in Optimization Causing Incorrect Proportion of RegD MW to Be Purchased

The current PJM MBF incorrectly defines the contribution of RegD MW as a percent of the regulation requirement rather than using the correct MBF, defined as the marginal rate of substitution between RegA and RegD.

46 See "Regulation Market Review," presented at the May 5, 2015 Operating Committee meeting. <http://www.pjm.com/~/media/committees-groups/committees/oc/20150505/20150505-item-17-regulation-market-review.ashx>

As a result, the market clearing engine is not correctly maintaining the shares of RegA and RegD that are the basis of the MBF function. The MBF, as the marginal rate of substitution between RegA and RegD resource MW for a given regulation requirement, defines specific combinations/ratios of RegA and RegD MW that are needed to meet specified regulation performance goals. Properly implemented, the use of the MBF should result in the selection of the least cost combination of RegA and RegD MW.

Instead, the current market clearing engine uses the incorrect MBF function to adjust RegD offers (both MW and price) for purposes of rank ordering RegA and RegD resources in the supply stack and then clears RegA and RegD resources in price order until the calculated effective MW target is reached. This market clearing is done without confirming that the resulting combinations of RegA and RegD are feasible and can meet the defined demand for regulation.

The result, combined with an increasing proportion of RegD offering at an effective price of zero, is that the market clears too much RegD relative to RegA MW.

This is illustrated in Table 10-29, for both the MBF curve used prior to December 14, 2015, and the current MBF curve. In Table 10-29 the contribution to the total regulation requirement of 700 MW for an on peak hour is given on both a performance adjusted actual RegD MW and effective RegD MW basis. For example, if the market cleared 280 MW of performance adjusted RegD (40 percent of the 700 performance adjusted MW needed) at a price of zero, the market clearing engine would determine it would need 149.9 MW of RegA to meet the 700 MW requirement using the previous MBF curve, and would need 294.0 MW using the current MBF curve. The resulting proportion of RegD to total regulation cleared would be 65 percent and 49 percent for the previous and current MBF curves, rather than the 40 percent that was assumed by the MBF function. Although there is a smaller difference between the proportion of RegD cleared under the current MBF curve and the correct amount, as compared to that of the previous MBF curve, the error still persists and is not eliminated by simply adjusting the curve. A full correction requires that the proportions assumed in the curve are maintained through the market clearing process.

Table 10-29 MBF assumed RegD proportions versus market solution realized RegD proportions[47]

RegD Percent of 700 MW	RegD MW (Performance Adjusted)	MBF (Previous)	MBF (Current)	Effective MW from RegD MW (Previous)	Effective MW from RegD MW (Current)	Residual A (700 MW Target, Previous)	Residual A (700 MW Target, Current)	RegD/ (RegA+RegD, Previous)	RegD/ (RegA+RegD, Current)
5%	35	2.67	2.54	97.41	95.16	602.59	604.84	5%	5%
10%	70	2.43	2.18	186.63	177.63	513.37	522.38	12%	12%
15%	105	2.20	1.81	267.67	247.41	432.33	452.59	20%	19%
20%	140	1.96	1.45	340.52	304.50	359.48	395.50	28%	26%
25%	175	1.73	1.09	405.18	348.91	294.82	351.09	37%	33%
30%	210	1.50	0.73	461.66	380.63	238.34	319.38	47%	40%
35%	245	1.26	0.36	509.96	399.66	190.04	300.34	56%	45%
40%	280	1.03	0.00	550.06	406.00	149.94	294.00	65%	49%
45%	315	0.80	-	581.99	-	118.01	-	73%	-
50%	350	0.56	-	605.73	-	94.27	-	79%	-
55%	385	0.33	-	621.28	-	78.72	-	83%	-
60%	420	0.09	-	628.65	-	71.35	-	85%	-

47 This example assumes that the calculation of effective MW from RegD was calculated correctly as the area under the MBF curve.

The effect of these market flaws on the amount of RegD MW clearing the market has been magnified by the increasing proportion of RegD MW with an effective price of $0.00 per MW. This guarantees that an increasing proportion of RegD MW in the market incorrectly appears as a cheap feasible source of incremental effective regulation MW when it the level of RegD is not feasible is therefore not consistent with maintaining the target level of regulation.

Excess RegD continues to be purchased both for this reason and because RegD is overcompensated given the low actual MBFs that result from the excess procurement.

The Effective MW of Regulation Purchased Are Understated

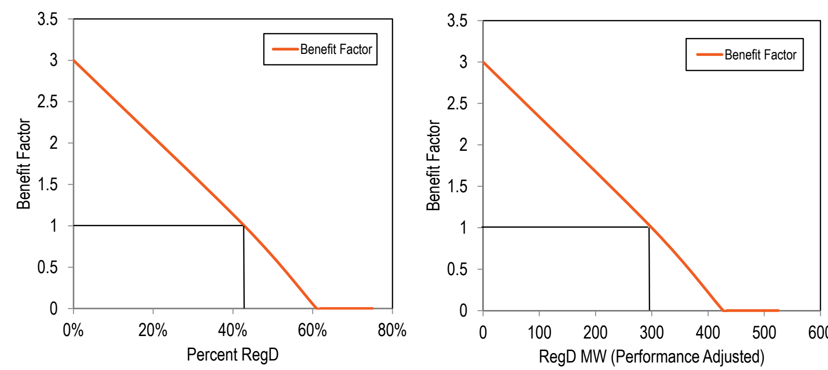
In 2015, the MMU determined that the regulation market optimization/market solution was understating the amount of effective MW provided by RegD. Rather than correctly calculating the total effective MW contribution of RegD MW based on the area under the marginal benefit factor curve, the regulation market optimization assigns the MBF associated with the last MW of a cleared unit to every MW of that unit (unit block). PJM calculates the effective MW as the simple product of the MW and the MBF, rather than the area under the MBF. The result is that 100 MW of RegD (performance adjusted) provided by a single resource (one 100 MW unit) will appear to provide fewer effective MW than 100 MW (performance adjusted) provided by two separate 50 MW units although they provide exactly the same effective MW.

In addition, the MMU determined that the regulation market optimization/market solution treats all RegD resources with the same effective price as a single resource (price block) for purposes of assigning a benefit factor and calculating effective MW. This means that all of the MW associated with multiple units with the same effective price (for example a price of zero) were assigned the MBF of the last MW of the last unit of that block of resources with the same effective price. PJM then calculates the effective MW as the simple product of the MW and the MBF, rather than the area under the MBF curve. This resulted in understating effective MW from RegD resources cleared at an effective price of zero or self-scheduled.

The identified effective MW measurement issue was not fully addressed by the modification that was put into effect on December 14, 2015. The modification rank orders self-scheduled units and assigns the MBF of the last MW of each of these units to all MW of that unit. The result is to break up the RegD MW in the zero price or self-scheduled block into unit specific blocks of MW that are each assigned a unit specific benefit factor. The resulting unit block effective MW calculation for all units better approximates the area under the marginal benefit factor curve for those price block MW. A full correction of the effective MW calculation requires the use of the area under the curve.

An example illustrates the issue. Figure 10-23 shows the same marginal benefit factor curve, in terms of RegD percent (left diagram) and RegD MW (right diagram) in a scenario where 700 MW of effective MW are needed and the market clears 300 MW of RegD (actual MW), all priced at $0.00, and 400 MW of RegA. Figure 10-23 shows that the 300 MW of cleared RegD are 42.9 percent of total cleared actual MW and that the marginal benefit factor is 1.0.

Figure 10-23 Example marginal benefit line in percent RegD and RegD MW terms



Using PJM's price block/unit block method for the calculation of effective MW from RegD resources, all RegD resources are assigned the lowest marginal benefit factor associated with the last RegD MW purchased. In this example, all 300 MW have an MBF of 1.0. PJM calculates total effective MW from RegD resources to be 300 (300MW x 1.0 = 300 effective MW).

In Figure 10-24, PJM's price block/unit block calculation of total effective MW from RegD is represented by the area of the blue rectangle which is 400 effective MW.

PJM's unit block method is flawed. By assigning a single benefit value to every MW, the unit block method undervalues the amount of effective MW provided by RegD MW. This is because the marginal benefit curve represents a marginal rate of substitution between RegD and RegA MW, and the area under the curve, at any RegD amount, represents the total effective MW supplied by RegD at that point. In fact, RegD is providing effective MW equal to area defined by the green triangle and the blue rectangle in Figure 10-24. This corresponds to 600 effective MW being supplied by RegD resources, not 300 effective MW. This means that the actual total effective MW cleared in the market solution is 300 more effective MW than needed to meet the regulation requirement.

Figure 10-24 Illustration of correct method for calculating effective MW

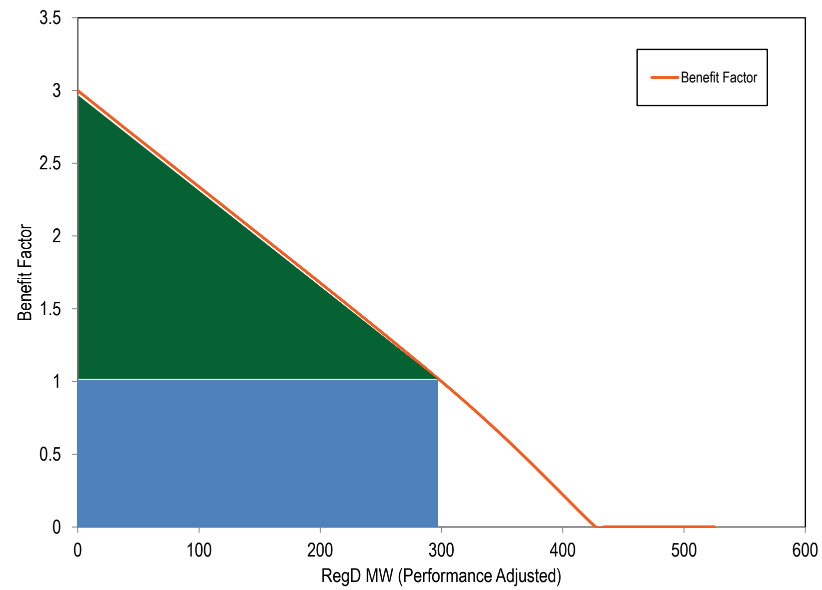


Figure 10-25 illustrates PJM's December 14, 2015, correction of the price block issue for RegD resources that clear with an effective price of zero. In this example, the PJM market clears two self-scheduled resources, one with 100 MW and one with 83 MW, for a total of 183 MW and a market MBF of 1.0. Prior to the correction, all 183 MW of RegD would have been assigned the MBF of 1.0.

After December 14, 2015, zero price offer and self scheduled resources are rank ordered by performance score and assigned unit specific MBF based on the MBF associated with the last MW of each unit that cleared. Using this approach, assuming the 83 MW resource was ranked higher than the 100 MW resource, the 83 MW resource would be assigned a unit specific benefit factor of 2.0 (Figure 10-25) and the 100 MW resource would be assigned a unit specific marginal benefit factor of 1.0.

This correction did not address the unit block issue. PJM still calculates effective MW as the simple product of the MW and the MBF, rather than the area under the MBF curve for cleared MW, which results in an effective MW total of 269.9 MW, due to 169.9 effective MW being attributed to the 83 MW resource (83 MW times 2.0 BF) and 100 effective MW being attributed to the 100 MW resource (100 MW times 1.0 BF). Using the area under the curve approach would correctly result in an effective MW total of 356.9 MW being attributed to the 183 MW cleared in the market, not the 266 effective MW of the corrected method.

Figure 10-25 Example of Pre and Post December 14, 2015, Effective MW Calculations for RegD MW offered at $0.00 or as Self Supply

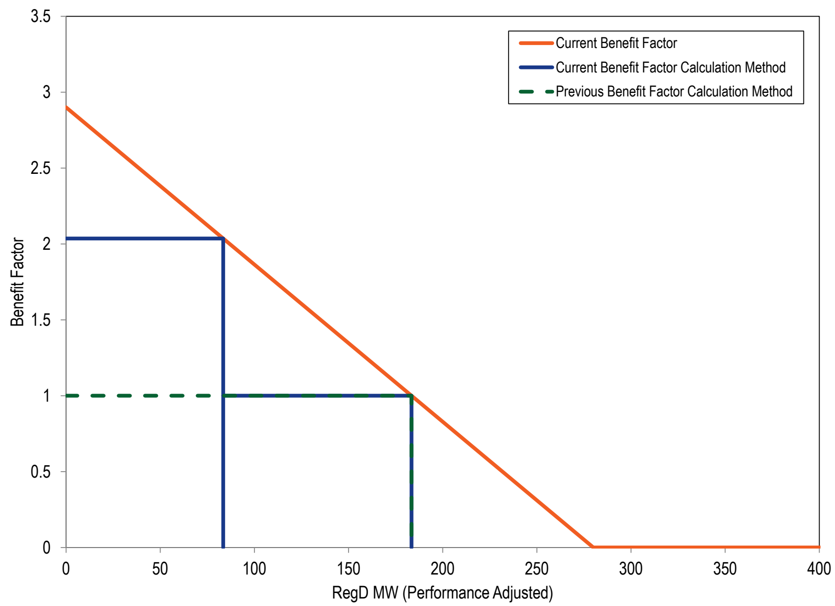
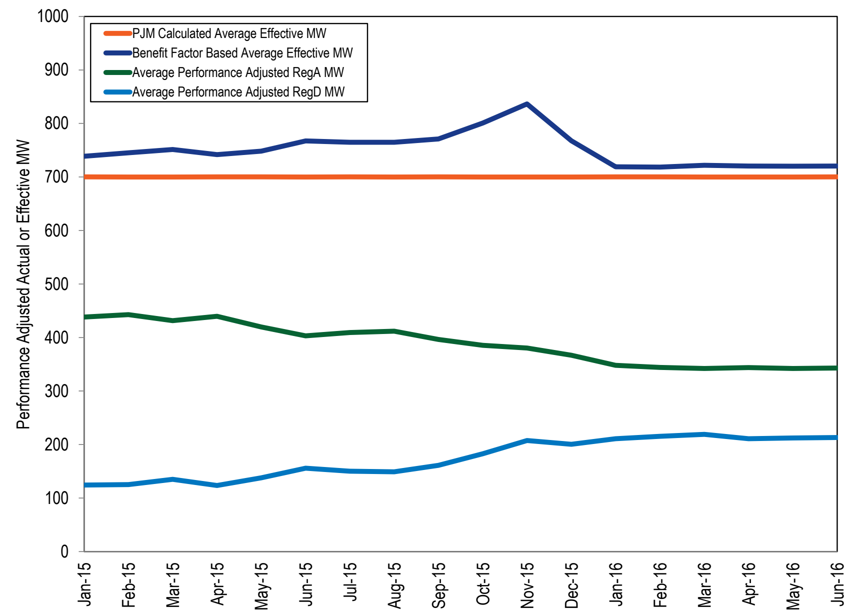


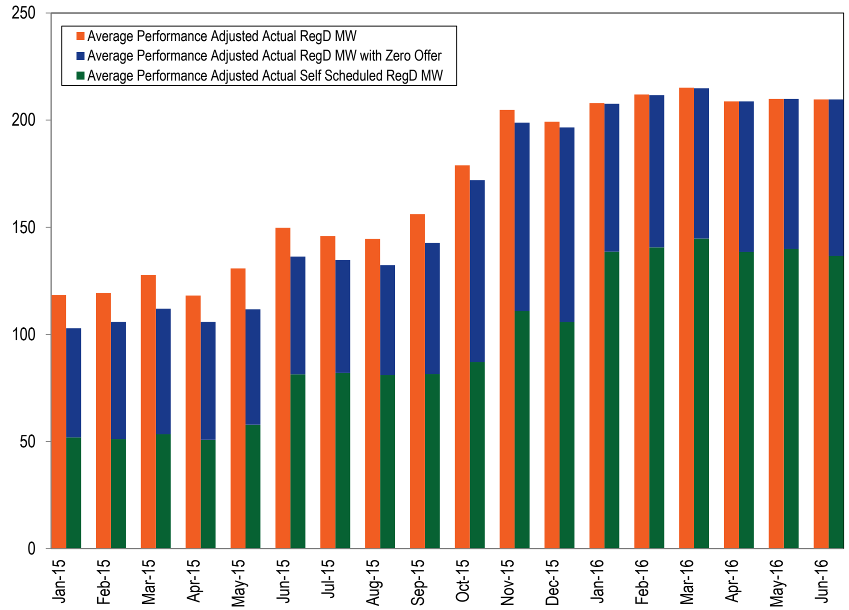
Figure 10-26 shows the average monthly peak total effective MW as calculated by PJM's incorrect effective MW accounting method(s) and as calculated by a correctly applied marginal benefit factor for the January 2015 through June 2016 period. The figure also shows the monthly average performance adjusted RegA MW and RegD MW cleared in the Regulation Market for the period. Figure 10-26shows that PJM had been clearing an increasing surplus of effective MW prior to December of 2015.

Figure 10-26 Average monthly peak effective MW: PJM market calculated versus benefit factor based: January 2015 through June 2016



The excess procurement of RegD combined with the overpayment of RegD has resulted in an increase in the level of $0.00 offers from RegD resources. RegD MW providers are ensured that $0.00 offers will be cleared and will be paid a price determined by the offers of RegA resources. Figure 10-27 shows, by month, both an increasing amount and increasing proportion of cleared RegD MW with an effective price of $0.00. The figure also shows a corresponding increase in the total RegD MW clearing the market in the period between January 1, 2015 and June 30, 2016. Figure 10-27 also shows that self-scheduling, the equivalent of offering RegD MW at $0.00, has increased.[48]

Figure 10-27 Average cleared RegD MW and average cleared RegD with an effective price of $0.00 by month: January 2015 through June 2016

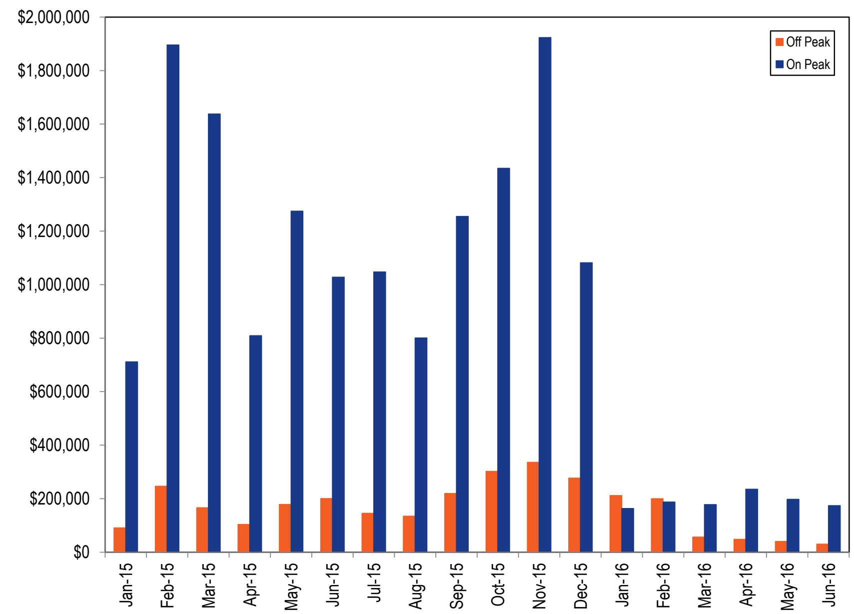


The Cost of Purchasing Too Many Regulation MW Due to Incorrect Effective MW Calculation Approach

Figure 10-28 shows the estimated cost of the excess effective MW cleared by month, peak and off peak, from January 1, 2015, through June 30, 2016, caused by PJM's incorrect approach(s) to calculating effective MW from RegD resources. To determine this excess cost, the total effective MW of RegD are calculated using the full area under the incorrect PJM marginal benefit factor curve, and the difference between that value and the one used by PJM is multiplied by the price in each hour. This excess cost calculation is a significant underestimate because it does not incorporate the correct MBF.

In the first six months of 2016, the estimated total cost of excess effective RegD MW during on peak and off peak hours was $1.14 million and $0.59 million. In the first six months of 2015, the estimated total cost of excess RegD MW during on peak and off peak hours was $7.36 million and $0.99 million. The implementation of the partial fix to the effective MW calculation and the changes in the marginal benefit factor curve in December of 2015 reduced, but did not eliminate, the excess effective MW clearing in the Regulation Market.

Figure 10-28 Cost of excess effective MW cleared by month, peak and off peak: January 2015 through June 2016



48 See the MMU's Regulation Market Review presentation from the May 5, 2015 Operating Committee. available at <http://www.pjm.com/~/media/committees-groups/committees/oc/20150505/20150505-item-17-regulation-market-review.ashx>.

Market Structure

Supply

Table 10-30 shows capability MW (actual), average daily offer MW (actual), average hourly eligible MW (actual and effective), and average hourly cleared MW (actual and effective) for all hours in the first six months of 2016. Actual MW are unadjusted regulation capability MW and effective MW are adjusted by the historic 100-hour moving average performance score and resource-specific benefit factor.[49] A resource must be either generation or demand. A resource can choose to follow both signals. For that reason, the sum of each signal type's capability can exceed the full regulation capability. Offered MW are calculated based on the daily offers from units that are categorized as available for the day. Eligible MW are calculated from the hourly offers from both units with daily offers and units that are categorized as unavailable for the day, but still offer MW into some hours. Additionally, units with daily offers are permitted to offer above or below their daily offer from hour to hour. Because of these hourly MW adjustments to MW offers beyond what was offered on a daily basis, the average hourly Eligible MW can be higher than the Offered MW.

Table 10-30 PJM regulation capability, daily offer and hourly eligible: January through June 2016[50 51]

			By Resource Type		By Signal Type	
		All Regulation	Generating Resources	Demand Resources	RegA Following Resources	RegD Following Resources
Capability MW	Daily	8,181.4	8,151.9	29.5	7,849.4	640.9
Offered MW	Daily	3,799.6	3,786.1	13.5	3,471.1	328.5
Actual eligible MW	On Peak	1,161.5	1,150.4	11.1	771.2	390.2
	Off Peak	1,219.5	1,209.0	10.5	834.1	385.4
Effective eligible MW	On Peak	921.1	914.6	6.5	563.4	357.7
	Off Peak	921.7	916.2	5.5	596.2	325.5
Actual cleared MW	On Peak	642.0	636.0	6.1	409.5	232.5
	Off Peak	524.4	520.5	4.0	302.1	222.3
Effective cleared MW	On Peak	700.0	694.1	5.9	343.8	356.2
	Off Peak	525.1	521.4	3.7	249.4	275.7

Table 10-31 provides the scheduled regulation in MW by source, the total scheduled regulation in MW provided by all resources (including DR), and the percent of scheduled regulation provided by each fuel type. In Table 10-31 the MW have been adjusted by the actual within hour performance score since this adjustment forms the basis of payment for units providing regulation. Total regulation performance adjusted capability MW increased from 2,425,060.0 MW in the first six months of 2015 to 2,488,638.9 MW in the first six months of 2016. The average proportion of regulation provided by battery units had the largest increase, providing 21.7 percent of regulation in the first six months of 2015 and 42.1 percent of regulation in the first six months of 2016. Natural gas units had the largest decrease in average proportion of regulation provided, decreasing from 45.5 percent in the first six months of 2015, to 28.6 percent in the first six months of 2016. The total regulation credits in the first six months of 2016 were $42,949,813 down 62.4 percent from $114,169,297 in the first six months of 2015.

49 Unless otherwise noted, analysis provided in this section uses PJM market data based on PJM's internal calculations of effective MW values, based on PJM's currently incorrect MBF curve. The MMU is working with PJM to correct the MBF curve and future analysis will show the effect of this correction.

50 Average Daily Offer MW excludes units that have offers but are unavailable for the day.

51 Total offer capability is defined as the sum of the maximum daily offer volume for each offering unit during the period, without regard to the actual availability of the resource or to the day on which the maximum was offered.

Table 10-31 PJM regulation by source in January through June 2015 and 2016[52]

	2015 (Jan-Jun)				2016 (Jan-Jun)			
Source	Number of Units	Adjusted Settled Regulation (MW)	Percent of Scheduled Regulation	Total Regulation Credits	Number of Units	Adjusted Settled Regulation (MW)	Percent of Scheduled Regulation	Total Regulation Credits
Battery	62	525,171.2	21.7%	$19,341,900	114	1,047,399.3	42.1%	$16,349,718
Coal	412	328,070.0	13.5%	$22,706,583	210	197,646.5	7.9%	$4,531,166
Hydro	174	452,590.1	18.7%	$24,296,364	152	505,681.3	20.3%	$9,905,633
Natural Gas	500	1,103,739.7	45.5%	$47,219,033	430	711,542.9	28.6%	$11,748,887
DR	158	15,489.0	0.6%	$605,418	138	26,368.9	1.1%	$414,408
Total	1,306	2,425,060.0	100.0%	$114,169,297	1,044	2,488,638.9	100.0%	$42,949,813

Significant flaws in the regulation market design have led to a significant over procurement of RegD MW primarily in the form of storage capacity. The incorrect market signals have led to more storage projects entering PJM's interconnection queue, despite clear evidence that the market design is flawed and despite operational evidence that the RegD market is saturated (Table 10-32).

Table 10-32 Active battery storage projects in the PJM queue system by submitted year from 2012 to 2016

Year	Number of Storage Projects	Total Capacity (MW)
2012	2	8.5
2013	4	22.0
2014	11	167.0
2015	48	439.6
2016	7	63.4
Total	72	700.5

The supply of regulation can also be affected by the retirement of regulating units. There are currently no regulating units that have announced plans to retire through the end of 2016.

Although the marginal benefit factor for RegA resources is 1.0, the effective MW of RegA resources was lower than the offered MW in the first six months of 2016, because the average performance score was less than 1.00. For the first six months of 2016, the MW weighted average RegA performance score was 0.84.

For RegD resources, the total effective MW vary from actual MW because the marginal benefit factor for RegD resources can range from 2.9 to 0.0. In the first six months of 2016, the marginal benefit factor, based on PJM's current assumed marginal benefit factor curve, for cleared RegD resources ranged from 0.004704 to 1.308497 with an average over all nonexcursion hours of 0.405366 and an average over all excursion hours of 1.127480. In the first six months of 2016, the MW weighted average RegD resource performance score was 0.95 and there were 45 resources following the RegD signal.

Demand

The demand for regulation does not change with price. The regulation requirement is set by PJM to meet NERC control standards, based on reliability objectives, which means that a significant amount of judgment is exercised by PJM in determining the actual demand. Prior to October 1, 2012, the regulation requirement was 1.0 percent of the forecast peak load for on peak hours and 1.0 percent of the forecast valley load for off peak hours. Between October 1, 2012, and December 31, 2012, PJM changed the regulation requirement several times. It had been scheduled to be reduced from 1.0 percent of peak load forecast to 0.9 percent on October 1, 2012, but instead it was changed from 1.0 percent of peak load forecast to 0.78 percent of peak load forecast. It was further reduced to 0.74 percent of peak load forecast on November 22, 2012 and reduced again to 0.70 percent of peak load forecast on December 18, 2012. On December 14, 2013, it was reduced to 700 effective MW during peak hours and 525 effective MW during off peak hours. The regulation requirement remained 700 effective MW during peak hours and 525 effective MW during off peak hours in 2016.

52 Biomass data have been added to the natural gas category for confidentiality purposes.

Table 10-33 PJM Regulation Market required MW and ratio of eligible supply to requirement for on and off peak hours: January through June 2015 and 2016

Peak	Month	Average Required Regulation (MW), 2015	Average Required Regulation (MW), 2016	Average Required Regulation (Effective MW), 2015	Average Required Regulation (Effective MW), 2016	Ratio of Supply MW to MW Requirement, 2015	Ratio of Supply MW to MW Requirement, 2016	Ratio of Supply Effective MW to Effective MW Requirement, 2015	Ratio of Supply Effective MW to Effective MW Requirement, 2016
On	Jan	675.8	657.5	700.1	700.1	1.82	1.83	1.33	1.34
	Feb	695.3	663.6	699.9	700.1	1.69	1.84	1.34	1.38
	Mar	689.5	640.6	700.0	700.0	1.67	1.90	1.33	1.39
	Apr	686.0	633.8	700.2	699.9	1.76	1.78	1.32	1.32
	May	690.2	625.4	700.1	699.9	1.66	1.82	1.31	1.29
	Jun	668.3	632.2	700.0	700.1	1.75	1.98	1.29	1.38
Off	Jan	495.8	553.8	525.5	525.0	2.07	2.15	1.46	1.56
	Feb	508.0	550.0	525.1	525.6	2.03	2.17	1.50	1.56
	Mar	497.7	517.0	525.3	525.0	2.06	2.25	1.43	1.57
	Apr	494.2	513.1	525.2	525.0	2.19	2.23	1.44	1.54
	May	499.0	504.5	525.0	525.0	2.07	2.24	1.37	1.52
	Jun	495.4	509.0	525.8	525.2	2.10	2.62	1.35	1.78

Table 10-33 shows the average hourly required regulation by month and the ratio of supply to demand for both actual and effective MW, for on and off peak hours. The average hourly required regulation by month is an average of the on and off peak hours in the month.

Market Concentration

In the first six months of 2016, the effective MW weighted average HHI of RegA resources was 2666 which is highly concentrated and the weighted average HHI of RegD resources was 1850 which is highly concentrated.[53] The weighted average HHI of all resources was 1133 which is moderately concentrated. The HHI of RegA resources and the HHI of RegD resources are higher than the HHI for all resources because different owners have large market shares in the RegA and RegD markets.

Table 10-34 includes a monthly summary of three pivotal supplier results. In the first six months of 2016, 91.6 percent of hours had three or fewer pivotal suppliers. The MMU concludes from these results, that the PJM Regulation Market in the first six months of 2016 was characterized by structural market power in 91.6 percent of hours.

Table 10-34 Regulation market monthly three pivotal supplier results: 2014 through June 2016

	Percent of Hours Pivotal		
Month	2014	2015	2016
Jan	96.9%	97.8%	93.9%
Feb	98.7%	96.3%	90.9%
Mar	94.9%	97.3%	87.8%
Apr	89.0%	98.1%	93.5%
May	95.7%	99.3%	94.0%
Jun	99.4%	98.6%	89.3%
Jul	100.0%	98.8%	
Aug	99.7%	97.7%	
Sep	99.4%	97.1%	
Oct	99.1%	96.1%	
Nov	98.9%	99.2%	
Dec	98.1%	97.2%	
Average	97.5%	97.8%	91.6%

53 HHI results are based on market shares of effective MW, defined as regulation capability MW adjusted by performance score and resource-specific benefit factor, consistent with the way the regulation market is cleared.

Market Conduct

Offers

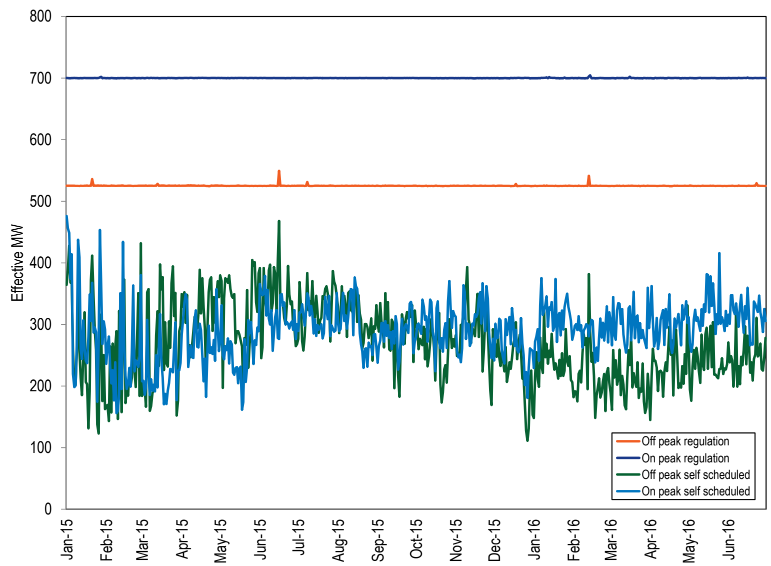
Resources seeking to regulate must qualify to follow a regulation signal by passing a test for that signal with at least a 75 percent performance score. The regulating resource must be able to supply at least 0.1 MW of regulation and must not allow the sum of its regulating ramp rate and energy ramp rate to exceed its economic ramp rate. When offering into the regulation market, regulating resources must submit a cost offer and, optionally, a price offer (capped at $100/MW) by 6:00 pm the day before the operating day.

Offers in the PJM Regulation Market consist of a capability component for the MW of regulation capability provided and a performance component for the miles (ΔMW of regulation movement) provided. The capability component for cost offers is not to exceed the increased costs (specifically, increased fuel costs and lower efficiency) resulting from operating the regulating unit at a lower output level than its economically optimal output level plus a $12.00/MW adder. The performance component for cost offers is not to exceed the increased costs (specifically, increased VOM and lower efficiency) resulting from operating the regulating unit in a nonsteady state. Batteries and flywheels have zero cost for lower efficiency from providing regulation instead of energy, as they are not net energy producers. Instead batteries and flywheels are, due to losses, net consumers of energy when providing regulation service. On April 1, 2015, PJM added an Energy Storage Loss component for batteries and flywheels as a cost component of regulation performance offers to the eMkt Regulation Offers screen, to reflect the net energy consumed to provide regulation service.[54]

Up until one hour before the operating hour, the regulating resource must input or may change: status (available, unavailable, or self-scheduled); capability (movement up and down in MW); regulation maximum and regulation minimum (the highest and lowest levels of energy output while regulating in MW); and the regulation signal type (RegA or RegD). Resources may offer regulation for both the RegA and RegD signals, but will be assigned to follow only one signal for a given operating hour. Resources have the option to submit a minimum level of regulation they require to regulate.[55]

All LSEs are required to provide regulation in proportion to their load share. LSEs can purchase regulation in the regulation market, purchase regulation from other providers bilaterally, or self schedule regulation to satisfy their obligation (Table 10-36).[56] Figure 10-29 compares average hourly regulation and self scheduled regulation during on peak and off peak hours on an effective MW basis. The average hourly regulation is the amount of regulation that actually cleared and is not the same as the regulation requirement because PJM clears the market within a two percent band around the requirement.[57] Self scheduled regulation comprised an average of 43.7 percent during on peak and 44.0 percent during off peak hours in the first six months of 2016.

Figure 10-29 Off peak and on peak regulation levels: January 2015 through June 2016



54 See PJM. "Manual 15: Cost Development Guidelines," Revision 27, (April 20, 2016); para 11.8, p. 60

55 See PJM. "Manual 11: Energy & Ancillary Services Market Operations," Revision 83, (July 28, 2016); para 3.2.2, pp 48.

56 See PJM. "Manual 28: Operating Agreement Accounting," Revision 74, (July 1, 2016); para 4.1, p 15.

57 See PJM. "Manual 11: Energy & Ancillary Services Market Operations," Revision 83, (July 28, 2016); para 3.2.9, p 59.

Table 10-35 shows the role of RegD resources in the regulation market. RegD resources are both a growing proportion of the market (10.9 percent of the total effective MW at the start of the performance based regulation market design in October 2012 and 51.3 percent in June 2016) and a growing proportion of resources that self schedule (10.1 percent in October 2012 and 26.9 percent in June 2016).

Table 10-35 RegD self-scheduled regulation by month, October 2012 through June 2016

Year	Month	RegD Self Scheduled Effective MW	RegD Effective MW	Total Self Scheduled Effective MW	Total Effective MW	Percent of Total Self Scheduled	RegD Percent of Total Self Scheduled	RegD Percent of Total Effective MW
2012	Oct	66.3	71.8	264.7	658.1	40.2%	10.1%	10.9%
2012	Nov	74.4	88.3	196.5	716.5	27.4%	10.4%	12.3%
2012	Dec	82.5	88.8	188.8	701.1	26.9%	11.8%	12.7%
2013	Jan	35.7	82.5	133.6	720.0	18.6%	5.0%	11.5%
2013	Feb	84.8	90.2	212.2	724.3	29.3%	11.7%	12.5%
2013	Mar	80.1	119.3	279.8	680.7	41.1%	11.8%	17.5%
2013	Apr	82.3	106.9	266.0	594.1	44.8%	13.8%	18.0%
2013	May	74.0	109.0	268.2	616.2	43.5%	12.0%	17.7%
2013	Jun	79.6	122.7	334.9	730.6	45.8%	10.9%	16.8%
2013	Jul	77.6	120.4	303.6	822.9	36.9%	9.4%	14.6%
2013	Aug	83.6	127.6	366.0	756.8	48.4%	11.0%	16.9%
2013	Sep	112.2	152.1	381.6	669.9	57.0%	16.7%	22.7%
2013	Oct	120.2	163.7	349.6	613.3	57.0%	19.6%	26.7%
2013	Nov	133.9	175.7	396.5	663.3	59.8%	20.2%	26.5%
2013	Dec	136.5	180.7	313.6	663.5	47.3%	20.6%	27.2%
2014	Jan	132.9	193.5	261.1	663.6	39.3%	20.0%	29.2%
2014	Feb	134.3	193.4	289.0	663.6	43.5%	20.2%	29.1%
2014	Mar	131.8	193.8	287.2	663.8	43.3%	19.9%	29.2%
2014	Apr	126.8	212.4	270.8	663.7	40.8%	19.1%	32.0%
2014	May	121.7	248.5	265.6	663.6	40.0%	18.3%	37.4%
2014	Jun	123.3	231.0	365.5	663.9	55.0%	18.6%	34.8%
2014	Jul	126.4	235.5	352.7	663.5	53.2%	19.0%	35.5%
2014	Aug	117.6	229.8	368.2	663.6	55.5%	17.7%	34.6%
2014	Sep	121.0	242.6	393.8	663.6	59.3%	18.2%	36.6%
2014	Oct	116.1	255.4	352.7	663.6	53.2%	17.5%	38.5%
2014	Nov	113.5	235.1	347.5	664.2	52.3%	17.1%	35.4%
2014	Dec	116.7	254.3	353.0	663.6	53.2%	17.6%	38.3%
2015	Jan	116.4	250.1	304.8	663.7	45.9%	17.5%	37.7%
2015	Feb	111.3	245.8	242.6	663.5	36.6%	16.8%	37.0%
2015	Mar	113.8	255.2	229.9	663.8	34.6%	17.1%	38.5%
2015	Apr	110.1	248.2	283.7	663.7	42.7%	16.6%	37.4%
2015	May	121.8	265.1	266.7	663.6	40.2%	18.4%	39.9%
2015	Jun	158.9	283.1	321.2	663.7	48.4%	23.9%	42.6%
2015	Jul	161.4	278.3	314.0	663.8	47.3%	24.3%	41.9%
2015	Aug	159.5	276.0	300.7	663.6	45.3%	24.0%	41.6%
2015	Sep	155.4	289.2	286.0	663.5	43.1%	23.4%	43.6%
2015	Oct	147.1	299.0	292.8	663.4	44.1%	22.2%	45.1%

Table 10-35 RegD self-scheduled regulation by month, October 2012 through June 2016 (continued)

Year	Month	RegD Self Scheduled Effective MW	RegD Effective MW	Total Self Scheduled Effective MW	Total Effective MW	Percent of Total Self Scheduled	RegD Percent of Total Self Scheduled	RegD Percent of Total Effective MW
2015	Nov	164.9	302.1	298.1	664.2	44.9%	24.8%	45.5%
2015	Dec	144.6	317.2	260.7	663.9	39.3%	21.8%	47.8%
2016	Jan	187.7	335.9	295.3	663.8	44.5%	28.3%	50.6%
2016	Feb	179.9	339.0	274.6	663.6	41.4%	27.1%	51.1%
2016	Mar	182.6	340.8	280.1	663.7	42.2%	27.5%	51.3%
2016	Apr	182.2	339.5	287.0	663.5	43.3%	27.5%	51.2%
2016	May	183.9	341.1	301.5	663.5	45.4%	27.7%	51.4%
2016	Jun	178.8	340.5	302.4	663.6	45.6%	26.9%	51.3%
Average		123.7	138.7	295.7	672.0	44.2%	18.5%	32.9%

Increased self-scheduled regulation lowers the requirement for cleared regulation, resulting in fewer MW cleared in the market and lower clearing prices. Of the LSEs' obligation to provide regulation in the first six months of 2016, 48.5 percent was purchased in the PJM market, 46.2 percent was self-scheduled, and 5.2 percent was purchased bilaterally (Table 10-36). Table 10-37 shows the total regulation by source including spot market regulation, self scheduled regulation, and bilateral regulation for the first six months of each year from 2011 to 2016. Table 10-36 and Table 10-37 are based on settled (purchased) unadjusted MW.

Table 10-36 Regulation sources: spot market, self-scheduled, bilateral purchases: January 2015 through June 2016

Year	Month	Spot Market Regulation (Unadjusted MW)	Spot Market Percent of Total	Self Scheduled Regulation (Unadjusted MW)	Self Scheduled Percent of Total	Bilateral Regulation (Unadjusted MW)	Bilateral Percent of Total	Total Regulation (Unadjusted MW)
2015	Jan	198,096.5	50.2%	173,319.4	43.9%	22,975.0	5.8%	394,390.9
2015	Feb	219,720.0	61.6%	116,607.5	32.7%	20,137.6	5.6%	356,465.0
2015	Mar	252,465.0	64.0%	122,001.9	30.9%	20,255.0	5.1%	394,721.8
2015	Apr	198,053.0	52.3%	159,511.3	42.1%	21,236.5	5.6%	378,800.8
2015	May	227,699.5	57.5%	148,998.3	37.6%	19,191.5	4.8%	395,889.3
2015	Jun	186,266.1	48.6%	174,157.4	45.5%	22,613.0	5.9%	383,036.5
2015	Jul	199,369.5	50.5%	172,743.7	43.7%	22,845.0	5.8%	394,958.2
2015	Aug	207,884.5	53.0%	162,197.5	41.3%	22,412.5	5.7%	392,494.5
2015	Sep	207,530.9	54.6%	150,467.7	39.6%	21,863.0	5.8%	379,861.6
2015	Oct	214,012.5	53.4%	169,283.3	42.2%	17,724.5	4.4%	401,020.3
2015	Nov	213,952.0	52.9%	172,561.3	42.7%	17,790.0	4.4%	404,303.3
2015	Dec	220,651.8	54.1%	166,189.2	40.7%	21,342.5	5.2%	408,183.5
Total		2,545,701.2	54.3%	1,888,038.5	40.3%	250,386.1	5.3%	4,684,125.8
2016	Jan	197,057.9	47.8%	193,581.9	47.0%	21,671.0	5.3%	412,310.8
2016	Feb	190,660.0	49.7%	173,440.5	45.2%	19,546.0	5.1%	383,646.6
2016	Mar	196,173.9	49.5%	178,413.1	45.0%	22,017.0	5.6%	396,604.0
2016	Apr	192,872.3	50.1%	173,661.5	45.2%	18,058.0	4.7%	384,591.8
2016	May	185,673.4	47.5%	185,240.7	47.4%	20,221.0	5.2%	391,135.2
2016	Jun	177,041.1	46.7%	180,678.3	47.7%	21,295.5	5.6%	379,014.9
Total		1,139,478.7	48.5%	1,085,016.1	46.2%	122,808.5	5.2%	2,347,303.3

Table 10-37 Regulation sources by year: 2011 through 2016

Year (Jan-Jun)	Spot Market Regulation (Unadjusted MW)	Spot Market Percent of Total	Self Scheduled Regulation (Unadjusted MW)	Self Scheduled Percent of Total	Bilateral Regulation (Unadjusted MW)	Bilateral Percent of Total	Total Regulation (Unadjusted MW)
2011	2,980,385.8	80.8%	596,417.4	16.2%	112,432.0	3.0%	3,689,235.2
2012	3,065,069.1	76.0%	847,576.2	21.0%	122,641.0	3.0%	4,035,286.2
2013	1,740,438.6	64.9%	849,955.3	31.7%	92,120.0	3.4%	2,682,513.9
2014	1,370,386.4	57.9%	889,917.5	37.6%	106,365.5	4.5%	2,366,669.4
2015	1,282,300.1	55.7%	894,595.8	38.8%	126,408.6	5.5%	2,303,304.4
2016	1,139,478.7	48.5%	1,085,016.1	46.2%	122,808.5	5.2%	2,347,303.3

In the first six months of 2016, DR provided an average of 5.6 MW of regulation per hour (3.2 MW of regulation per hour in the same period of 2015). Generating units supplied an average of 611.9 MW of regulation per hour (652.4 MW of regulation per hour in the same period of 2015).

Market Performance

Price

Since the implementation of regulation performance on October 1, 2012, both regulation price and regulation cost per MW are higher than they were prior to October 1, 2012, (Table 10-39). In the first six months of 2016, the price and cost of regulation have remained high relative to prior years with the exception of 2014. The weighted average RMCP for the first six months of 2016 was $15.90 per effective MW. This is a 61.1 percent decrease from the weighted average RMCP of $40.94 per MW in the first six months of 2015. The decrease in the regulation clearing price was the result of a reduction in energy prices and the related reduction in the LOC component of RMCP. The increase in self supply and $0.00 offers from RegD resources in the first six months of 2016 also contributed to lower prices.

Figure 10-30 shows the daily weighted average regulation market clearing price and the opportunity cost component for the marginal units in the PJM Regulation Market on an unadjusted regulation capability MW basis. This data is based on actual five minute interval operational data. As Figure 10-30 illustrates, the LOC component (blue line) is the dominant component of the clearing price.

Figure 10-30 PJM regulation market daily weighted average market-clearing price, marginal unit opportunity cost and offer price (Dollars per MW): January through June 2016

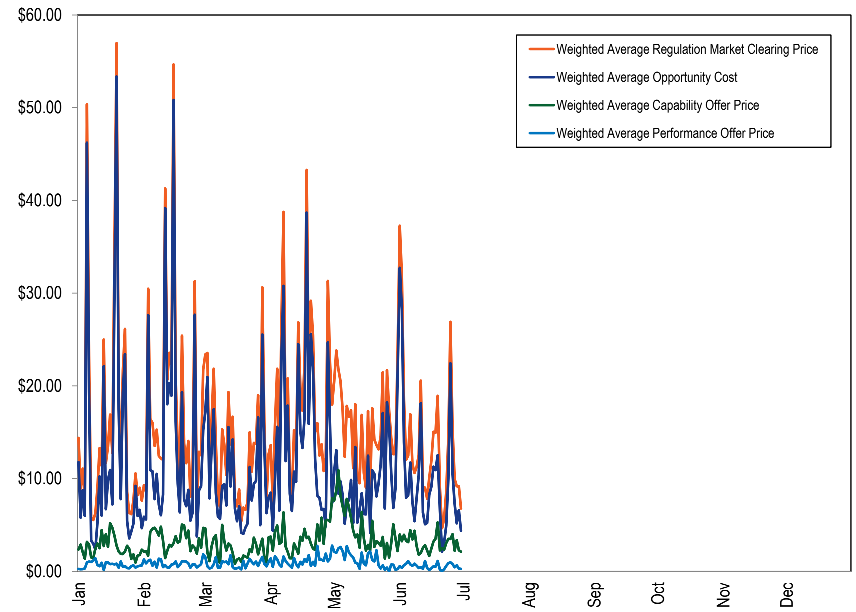


Table 10-38 shows monthly average regulation market clearing price, average marginal unit offer price, and average marginal unit LOC on an unadjusted capability MW basis. This data is based on actual five minute interval operational data.

Table 10-38 PJM regulation market monthly weighted average market-clearing price, marginal unit opportunity cost and offer price from five minute market solution data (Dollars per MW): January through June 2016

Month	Weighted Average Regulation Marginal Unit LOC	Weighted Average Regulation Marginal Unit Capability Offer	Weighted Average Regulation Marginal Unit Performance Offer	Weighted Average Regulation Market Clearing Price
Jan	$12.22	$2.58	$0.67	$15.47
Feb	$13.75	$3.36	$0.85	$17.95
Mar	$10.02	$2.40	$0.83	$13.24
Apr	$14.16	$3.74	$1.18	$19.08
May	$9.76	$4.62	$1.27	$15.65
Jun	$10.05	$3.08	$0.57	$13.70

Monthly and total annual scheduled regulation MW and regulation charges, as well as monthly and monthly average regulation price and regulation cost are shown in Table 10-39. Total scheduled regulation is based on settled (unadjusted capability) MW. The total of all regulation charges for the first six months of 2016 was $43.0 million, compared to $114.2 million for the first six months of 2015.

Table 10-39 Total regulation charges: January 2015 through June 2016[58]

Year	Month	Scheduled Regulation (MW)	Total Regulation Charges ($)	Weighted Average Regulation Market Price ($/MW)	Cost of Regulation ($/MW)	Price as Percent of Cost
2015	Jan	394,350.5	$13,054,006	$27.13	$33.10	81.9%
2015	Feb	356,397.3	$31,757,444	$73.24	$89.11	82.2%
2015	Mar	394,659.0	$21,887,989	$45.79	$55.46	82.6%
2015	Apr	378,682.3	$14,876,920	$32.77	$39.29	83.4%
2015	May	395,717.3	$21,030,737	$43.12	$53.15	81.1%
2015	Jun	382,956.8	$11,544,657	$25.94	$30.15	86.0%
2015	Jul	394,920.8	$11,484,271	$24.40	$29.08	83.9%
2015	Aug	392,404.7	$9,913,785	$20.85	$25.26	82.5%
2015	Sep	379,683.3	$13,639,604	$29.71	$35.92	82.7%
2015	Oct	400,990.0	$10,904,138	$23.12	$27.19	85.0%
2015	Nov	404,303.3	$10,221,684	$21.92	$25.28	86.7%
2015	Dec	408,183.5	$9,323,436	$19.58	$22.84	85.7%
2015 Annual		4,683,248.9	$179,638,672	$32.30	$38.82	83.7%
2016	Jan	412,310.8	$7,589,231	$15.65	$18.41	85.0%
2016	Feb	383,646.6	$7,677,113	$17.63	$20.01	88.1%
2016	Mar	396,604.0	$6,107,773	$13.43	$15.40	87.2%
2016	Apr	384,591.8	$8,367,340	$19.07	$21.76	87.7%
2016	May	391,135.2	$7,217,226	$15.67	$18.45	84.9%
2016	Jun	379,014.9	$5,993,081	$14.03	$15.81	88.7%
2016 YTD		2,347,303.3	$42,951,764	$15.91	$18.31	86.9%

The capability, performance, and opportunity cost components of the cost of regulation are shown in Table 10-40. Total scheduled regulation is based on settled (unadjusted capability) MW.

Table 10-40 Components of regulation cost: January through June, 2016

Month	Scheduled Regulation (MW)	Cost of Regulation Capability ($/MW)	Cost of Regulation Performance ($/MW)	Opportunity Cost ($/MW)	Total Cost ($/MW)
Jan	412,310.8	$14.49	$1.97	$1.95	$18.41
Feb	383,646.6	$16.00	$2.61	$1.40	$20.01
Mar	396,604.0	$12.01	$2.25	$1.14	$15.40
Apr	384,591.8	$17.38	$2.70	$1.67	$21.76
May	391,135.2	$13.56	$3.49	$1.40	$18.45
Jun	379,014.9	$13.33	$1.38	$1.10	$15.81

58 Weighted average market clearing prices presented here are taken from PJM settlements data, and differ from the values reported in Table 10-38, which are from five minute interval operational data. The MMU is investigating the cause of the discrepancies with PJM.

Table 10-41 provides a comparison of the average price and cost for PJM regulation. The ratio of regulation market price to the actual cost of regulation in the first six months of 2016 was 86.9 percent, a 3.5 percent increase from 82.6 percent in the first six months of 2015.

Table 10-41 Comparison of average price and cost for PJM regulation, January through June 2011 through 2016

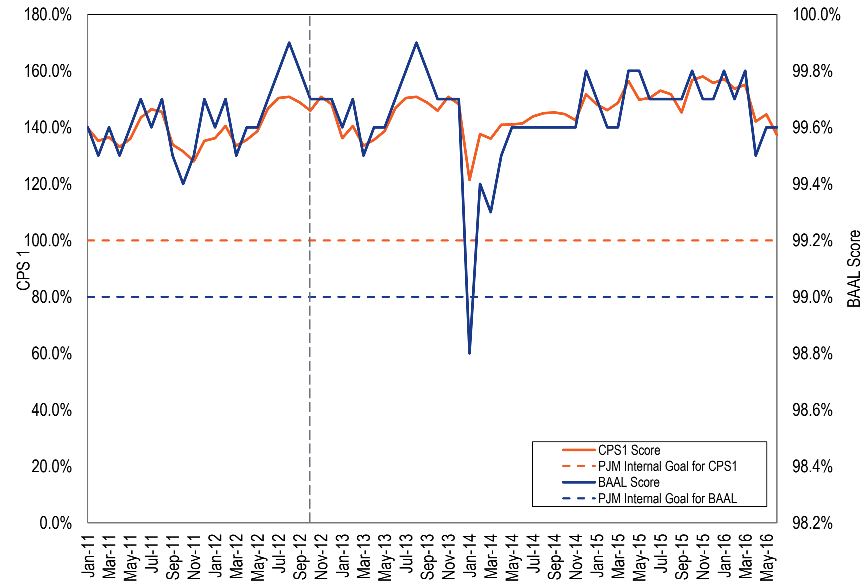
Year (Jan-Jun)	Weighted Regulation Market Price	Weighted Regulation Market Cost	Regulation Price as Percent Cost
2011	$15.31	$31.00	49.4%
2012	$13.89	$18.34	75.7%
2013	$32.04	$37.04	86.5%
2014	$62.71	$75.97	82.5%
2015	$40.94	$49.57	82.6%
2016	$15.90	$18.30	86.9%

Performance Standards

PJM's performance as measured by CPS1 and BAAL standards is shown in Figure 10-31 for every month from January 2011 through March 2016 with the dashed vertical line marking the date (October 1, 2012) of the implementation of the Performance Based Regulation Market design.[59] The horizontal dashed lines represent PJM internal goals for CPS1 and BAAL performance. While PJM did not meet its internal goal for BAAL performance in January 2014, PJM remained in compliance with the applicable NERC standards.

Very cold weather from January 6 through January 8 and from January 17 through January 29, 2014, caused extreme system conditions, including 12 synchronized reserve events, seven RTO-wide shortage pricing events and high forced outage rates. As a result, PJM experienced several frequency excursions of between 10 and 20 minutes which caused PJM's performance on the BAAL metric, a measure of a balancing authority's ability to control ACE and frequency, to decline substantially.

Figure 10-31 PJM monthly CPS1 and BAAL performance: January 2011 through June 2016



Black Start Service

Black start service is necessary to ensure the reliable restoration of the grid following a blackout. Black start service is the ability of a generating unit to start without an outside electrical supply, or the demonstrated ability of a generating unit to automatically remain operating when disconnected from the grid.

PJM does not have a market to provide black start service, but compensates black start resource owners on the basis of an incentive rate or for the costs associated with providing this service.

PJM defines required black start capability zonally and ensures the availability of black start service by charging transmission customers according to their

59 See the *2015 State of the Market Report for PJM*, Appendix F: Ancillary Services.

zonal load ratio share and compensating black start unit owners. Substantial rule changes to the black start restoration and procurement strategy were implemented on February 28, 2013, following a stakeholder process in the System Restoration Strategy Task Force (SRSTF) and the Markets and Reliability Committee (MRC) that approved the PJM and MMU joint proposal for system restoration. These changes give PJM substantial flexibility in procuring black start resources and make PJM responsible for black start resource selection.

On July 1, 2013, PJM initiated its first RTO-wide request for proposals (RFP) under the new rules.[60] [61] PJM set a September 30, 2013, deadline for resources submitting proposals and requested that resources be able to provide black start by April 1, 2015. PJM identified zones with black start shortages, prioritized its selection process accordingly, and began awarding proposals on January 14, 2014. PJM and the MMU coordinated closely during the selection process.

PJM issued two incremental RFPs in 2014. On April 11, 2014, PJM sought additional black start in the AEP Zone and one proposal was selected. On November 24, 2014, PJM sought additional black start in northeastern Ohio and western Pennsylvania, but no proposals were selected because they did not meet the bid requirements. On July 28, 2015, PJM issued two Incremental Request for Proposals, one for northeastern Ohio and another for western Pennsylvania. The bids are currently under review.

Black start payments are nontransparent payments made to units by load to maintain adequate reliability to restart the system in case of a blackout. Current rules appear to prevent publishing detailed data regarding these black start resources, hindering transparency and competitive replacement RFPs. The MMU recommends that the current confidentiality rules be revised to allow disclosure of information regarding black start resources and their associated payments.

Total black start charges are the sum of black start revenue requirement charges and black start operating reserve charges. Black start revenue requirements for black start units consist of fixed black start service costs, variable black start service costs, training costs, fuel storage costs, and an incentive factor. Section 18 of Schedule 6A of the OATT specifies how to calculate each component of the revenue requirement formula. Black start resources can choose to recover fixed costs under a formula rate based on zonal Net CONE and unit ICAP rating, a cost recovery rate based on incremental black start NERC-CIP compliance capital costs, or a cost recovery rate based on incremental black start equipment capital costs. Black start operating reserve charges are paid to units scheduled in the Day-Ahead Energy Market or committed in real time to provide black start service under the automatic load rejection (ALR) option or for black start testing. Total black start charges are allocated monthly to PJM customers proportionally to their zone and nonzone peak transmission use and point to point transmission reservations.

In the first six months of 2016, total black start charges were $31.7 million, a -$3.4 million (12.2 percent) increase from the same period of 2015 level of $28.2 million. Operating reserve charges for black start service declined from $5.0 million in 2015 to $140.5 thousand in 2016. Table 10-42 shows total revenue requirement charges from 2010 through 2016. (Prior to December 2012, PJM did not define a black start operating reserve category. Prior to December 2012, operating reserve charges resulting from units providing black start service were allocated as operating reserve charges for reliability in the western region.)

Table 10-42 Black start revenue requirement charges: 2010 through 2016

Year	Revenue Requirement Charges	Operating Reserves Charges	Total
2010	$5,481,206	$0	$5,481,206
2011	$5,968,676	$0	$5,968,676
2012	$7,873,702	$0	$7,873,702
2013	$10,584,683	$48,075,584	$58,660,267
2014	$10,874,608	$14,336,821	$25,211,429
2015	$23,190,886	$5,036,053	$28,226,939
2016	$31,532,715	$140,504	$31,673,218

60 See PJM. "RTO-Wide Five-Year Selection Process Request for Proposal for Black Start Service," (July 1, 2013).
61 RFPs issued can be found on the PJM website. See PJM. <http://www.pjm.com/markets-and-operations/ancillary-services.aspx>.

Black start zonal charges in the first six months of 2016 ranged from $0.05 per MW-day in the DLCO Zone (total charges were $25,618) to $4.22 per MW-day in the PENELEC Zone (total charges were $2,324,797). For each zone, Table 10-43 shows black start charges, the sum of monthly zonal peak loads multiplied by the number of days of the month in which the peak load occurred, and black start rates (calculated as charges per MW-day). For black start service, point-to-point transmission customers paid on average $0.0354 per MW of reserve capacity during the first six months of 2016.

Table 10-44 provides a revenue requirement estimate by zone for the 2016/2017, 2017/2018 and 2018/2019 delivery years. Revenue requirement values are rounded up to the nearest $50,000 to reflect uncertainty about future black start revenue requirement costs. These values are illustrative only. The estimates are based on the best available data including current black start unit revenue requirements, expected black start unit termination and in-service dates, and owner provided cost estimates of incoming black start units, at the time of publication and may change significantly.

Table 10-43 Black start zonal charges for network transmission use: 2015 and 2016

	2015 (Jan - Jun)					2016 (Jan - Jun)				
Zone	Revenue Requirement Charges	Operating Reserve Charges	Total Charges	Peak Load (MW-day)	Black Start Rate ($/MW-day)	Revenue Requirement Charges	Operating Reserve Charges	Total Charges	Peak Load (MW-day)	Black Start Rate ($/MW-day)
AECO	$225,363	$0	$225,363	442,274	$0.51	$166,658	$6,210	$172,869	464,610	$0.37
AEP	$6,015,630	$4,526,548	$10,542,178	4,417,866	$2.39	$6,468,397	$22,540	$6,490,936	4,499,968	$1.44
AP	$477,209	$69,722	$546,931	1,692,223	$0.32	$2,064,246	$2,304	$2,066,550	1,746,035	$1.18
ATSI	$1,276,351	$13,206	$1,289,557	2,237,540	$0.58	$1,506,341	$1,974	$1,508,315	2,248,865	$0.67
BGE	$5,246,763	$2,496	$5,249,259	1,206,401	$4.35	$3,909,296	$2,379	$3,911,675	1,221,566	$3.20
ComEd	$2,178,109	$28,968	$2,207,077	3,569,537	$0.62	$2,429,443	$24,735	$2,454,178	3,669,539	$0.67
DAY	$117,977	$7,929	$125,907	579,888	$0.22	$118,740	$8,784	$127,524	597,106	$0.21
DEOK	$577,766	$12,531	$590,297	924,005	$0.64	$581,637	$0	$581,637	932,386	$0.62
Dominion	$663,338	$10,434	$673,772	3,580,904	$0.19	$1,468,754	$20,361	$1,489,115	3,940,464	$0.38
DPL	$288,273	$1,417	$289,690	701,375	$0.41	$648,492	$1,206	$649,698	748,748	$0.87
DLCO	$39,546	$0	$39,546	487,379	$0.08	$25,618	$0	$25,618	510,328	$0.05
EKPC	$205,397	$0	$205,397	619,925	$0.33	$179,183	$0	$179,183	635,235	$0.28
JCPL	$1,314,569	$27,382	$1,341,951	1,020,279	$1.32	$3,438,710	$0	$3,438,710	1,058,894	$3.25
Met-Ed	$354,515	$11,185	$365,700	509,841	$0.72	$293,888	$28,493	$322,381	509,309	$0.63
PECO	$786,916	$23,957	$810,873	1,494,608	$0.54	$808,148	$1,253	$809,401	1,473,181	$0.55
PENELEC	$624,875	$0	$624,875	552,340	$1.13	$2,324,797	$0	$2,324,797	550,423	$4.22
Pepco	$154,999	$10,932	$165,930	1,148,463	$0.14	$1,274,317	$12,998	$1,287,315	1,140,721	$1.13
PPL	$59,801	$8,931	$68,732	1,454,878	$0.05	$547,829	$0	$547,829	1,465,992	$0.37
PSEG	$1,485,611	$12,058	$1,497,669	1,722,251	$0.87	$2,121,795	$2,303	$2,124,099	1,746,272	$1.22
RECO	$0	$0	$0	NA	NA	$0	$0	$0	NA	NA
(Imp/Exp/Wheels)	$1,097,878	$268,358	$1,366,236	1,427,846	$0.96	$1,156,425	$4,964	$1,161,389	1,111,241	$1.05
Total	$23,190,886	$5,036,053	$28,226,939	29,789,822	$0.95	$31,532,715	$140,504	$31,673,218	30,270,881	$1.05

NERC – CIP

Currently, there is one black start resource recovering capital costs related to NERC – CIP requirements. During 2015 and 2016 there have been no requests for black start units to recover capital costs under NERC – CIP.

Table 10-44 Black start zonal revenue requirement estimate: 2016/2017 through 2018/2019 delivery years

Zone	2016 / 2017 Revenue Requirement	2017 / 2018 Revenue Requirement	2018 / 2019 Revenue Requirement
AECO	$2,850,000	$2,850,000	$2,800,000
AEP	$19,150,000	$19,200,000	$18,950,000
AP	$4,150,000	$4,150,000	$4,150,000
ATSI	$3,100,000	$3,100,000	$3,100,000
BGE	$8,400,000	$3,650,000	$3,550,000
ComEd	$5,100,000	$5,200,000	$4,750,000
DAY	$250,000	$300,000	$250,000
DEOK	$1,250,000	$1,250,000	$1,200,000
DLCO	$100,000	$100,000	$1,800,000
Dominion	$5,400,000	$5,400,000	$5,400,000
DPL	$2,600,000	$2,600,000	$2,500,000
EKPC	$450,000	$450,000	$300,000
JCPL	$7,200,000	$7,200,000	$7,150,000
Met-Ed	$700,000	$750,000	$600,000
PECO	$1,750,000	$1,900,000	$1,550,000
PENELEC	$4,700,000	$4,750,000	$4,500,000
Pepco	$2,700,000	$2,700,000	$2,650,000
PPL	$800,000	$800,000	$750,000
PSEG	$4,450,000	$4,500,000	$4,450,000
RECO	$0	$0	$0
Total	$75,100,000	$70,850,000	$70,400,000

Reactive Service

Suppliers of reactive power are compensated separately for reactive capability, day-ahead operating reserves, and for real-time lost opportunity costs. Reactive capability compensation must be approved by FERC. Generators may file a request with FERC to have a portion of their fixed costs and the costs of heating losses associated with the provision of reactive power compensated by a FERC approved revenue requirement, the reactive capability payment.[62]

62 See PJM. "Manual 27: Open Access Transmission Tariff Accounting," Revision 85, (July 15, 2015); p. 15

Any reactive service provided operationally that involves a MW reduction outside of its normal operating range or a startup for reactive power will be logged by PJM operators and awarded uplift or LOC credits.

Reactive Service, Reactive Supply and Voltage Control are provided by generation and other sources of reactive power (such as static VAR compensators and capacitor banks).[63] While a fixed requirement for reactive power is not established, reactive power helps maintain appropriate voltages on the transmission system.

Total reactive capability charges are the sum of FERC-approved reactive supply revenue requirements. These requirements are posted monthly on the PJM website.[64] Reactive supply revenue requirement charges are allocated monthly to PJM customers.

Reactive capability charges have followed the AEP method.[65] The AEP method defines the approach for calculating the revenue requirement associated with the provision of reactive power. The AEP method is based on the assumption that a defined share of the total generating plant investment can be allocated to the provision of reactive power based on the nameplate range of reactive power capability. Since the same equipment used to provide reactive power is used to provide real power, an allocator is used to assign costs to reactive.

In recent months, the FERC has begun to reexamine its policies on reactive compensation.[66] Changes in the manufacture of generators, disparities between nameplate values and tested values and questions about the way the allocation factors have been calculated have called continued reliance on the AEP method into question.

63 PJM OATT. Schedule 2 "Reactive Supply and Voltage Control from Generation Sources Service," (Effective Date: February 18, 2012).
64 See PJM. Markets & Operations: Billing, Settlements & Credit <http://www.pjm.com/~/media/markets-ops/settlements/reactive-revenue-requirements-table-may-2016.ashx> (June 8, 2016).
65 Federal Energy Regulatory Commission "Payment for Reactive Power," Apr. 22, 2014, p. 12 <http://www.ferc.gov/legal/staff-reports/2014/04-11-14-reactive-power.pdf>.
66 *See, e.g., Reactive Supply Compensation in Markets Operated by Regional Transmission Organizations and Independent System Operators*, Docket No. AD16-17-000 (March 17, 2016) (Notice of Workshop).

Recommended Market Approach to Reactive Costs

The best approach for recovering reactive capability costs is through markets when markets are available as they are in RTOs/ISOs. The best approach for recovering reactive capability costs in PJM is through the capacity market. The capacity market already incorporates reactive costs and reactive revenues. The treatment of reactive costs in the PJM market needs to be modified so that the capacity market incorporates reactive costs and revenues in a more efficient manner.

Reactive capability is an integral part of all generating units; no generating unit is built without reactive capability.[67] There is no support for the assertion that the fixed costs of reactive capability either can be or should be separated from the total fixed costs of a generating unit. There is no support for the assertion that reactive capability should be compensated outside the markets when the units participate in organized markets. Reactive capability is a precondition for participating in organized markets. Resources must invest in the equipment needed to have minimum reactive capability as a condition of receiving interconnection service from PJM and other markets.[68] PJM requires a power factor of at least 0.95 leading to 0.90 lagging for synchronous units and at least 0.95 leading to 0.95 lagging for non-synchronous units.[69] The regulations specify a minimum power factor range of 0.95 leading and 0.95 lagging power factor unless the market operators' rules specify otherwise.[70] The Commission has recently extended the interconnection service requirement to have reactive capability to wind and solar units, which previously had been exempt.[71] Reactive capability is a requirement for participating in organized markets and is therefore appropriately treated as part of the gross Cost of New Entry in organized markets.

There are two ways to address the cost of reactive in the PJM market design.

Under the current capacity market rules, the gross costs of the entire plant, including any reactive costs, are included in the gross Cost of New Entry (CONE) and the revenues from reactive service capability rates are an offset to the gross CONE. The result is that, conceptually, the cost of reactive is not part of net CONE.[72] This is logically consistent with the separate collection of reactive costs through a cost of service rate in that there is no double counting if the revenue offset is done accurately. Under this approach there is a separate collection of reactive capability costs.

An alternative approach to the current treatment of reactive costs in the capacity market would be to include the gross costs of the entire plant including any reactive costs in the gross Cost of New Entry (CONE) but to calculate net CONE without a reactive revenue offset for reactive service capability rates. The result of this approach would be that the cost of reactive is part of net CONE. This is logically consistent with the elimination of the separate collection of reactive costs through a cost of service rate in that there is no double counting if done accurately. Under this approach there would be no separate collection of reactive capability costs.

PJM currently uses the first approach. There is no reason that PJM could not easily implement the second approach.

The second approach is preferable. The second approach relies on competitive markets to provide incentives to provide energy, both real and reactive, at the lowest possible cost. The second approach does not require the use of arbitrary, approximate and generally inaccurate allocators to determine the cost of providing reactive. The second approach does not require the use of estimated, average and inaccurate net reactive revenue offsets to calculate Net CONE. It is critical in the PJM Capacity Market that Net CONE be as accurate as possible. Only the second approach assures this.

67 *See Reactive Power Requirements for Non-Synchronous Generation*, Order No. 827, 155 FERC ¶ 61,277 at 9 (2016) ("[T]he equipment needed for a wind generator to provide reactive power has become more commercially available and less costly, such that the cost of installing equipment that is capable of providing reactive power is comparable to the costs of a traditional generator.").

68 *See* 18 CFR § 35.28(f)(1); *Standardization of Generator Interconnection Agreements and Procedures*, Order No. 2003, FERC Stats. & Regs. ¶ 31,146, Appendix G (Large Generator Interconnection Agreement (LGIA)), *order on reh'g*, Order No. 2003-A, FERC Stats. & Regs. ¶ 31,160, *order on reh'g*, Order No. 2003-B, FERC Stats. & Regs. ¶ 31,171 (2004), *order on reh'g*, Order No. 2003-C, FERC Stats. & Regs. ¶ 31,190 (2005), *aff'd sub nom.* Nat'l Ass'n of Regulatory Util. Comm'rs v. FERC, 475 F.3d 1277 (D.C. Cir. 2007), *cert. denied*, 552 U.S. 1230 (2008); *Standardization of Small Generator Interconnection Agreements and Procedures*, Order No. 2006, FERC Stats. & Regs. ¶ 31,180, Attachment F (Small Generator Interconnection Agreement), *order on reh'g*, Order No. 2006-A, FERC Stats. & Regs. ¶ 31,196 (2005), *order granting clarification*, Order No. 2006-B, FERC Stats. & Regs. ¶ 31,221 (2006).

69 *See* OATT Attachment O Appendix 2 § 4.7.

70 *See, e.g., id.* LGIA Article 9.6.1 ("Interconnection Customer shall design the Large Generating Facility to maintain a composite power delivery at continuous rated power output at the Point of Interconnection at a power factor within the range of 0.95 leading to 0.95 lagging, unless Transmission Provider has established different requirements that apply to all generators in the Control Area on a comparable basis.").

71 *Reactive Power Requirements for Non-Synchronous Generation*, Order No. 827, 155 FERC ¶ 61,277 (2016); *see also PJM Interconnection, L.L.C.*, 151 FERC ¶ 61,097 at P 28 (2015).

72 *See* OATT Attachment DD § 5.10(a)(iv).

Units are compensated for reactive capability costs under the second approach. But the compensation is based on the outcome of a competitive capacity market rather than based on current or historical cost of service filings for units or fleets of units.

The first approach, although internally logically consistent, relies on unnecessary and inaccurate approximations. The reactive allocator is such an approximation. The reactive revenue offset is an inaccurate estimate based on historical data from reactive revenue requirement filings. The reactive revenues used in the net CONE calculation are based on an average of reactive filings over the three years from 2005 through 2007 and therefore do not reflect even the allocated reactive costs and revenues for a new unit, as would be required to be consistent with the CONE logic.[73] To the extent that the reactive portion of the Net Energy and Ancillary Services Offset is inaccurate, the net CONE is inaccurate.

The reactive revenue offset is set equal to $ 2,199/MW-year in the PJM OATT.[74] This figure is the average annual reactive revenue for combustion turbines from 2005 through 2007, based on the actual costs reported to the Commission in reactive service filings of CTs, as developed by the Market Monitor.

The Net Cost of New Entry is a key parameter in the PJM Capacity Market as it affects the location of the VRR or demand curve and thus has a direct impact on capacity market prices.[75]

If revenues for reactive capacity were removed from the Net Energy and Ancillary Services Revenue Offset, then the fixed costs for investment in reactive capability would be recoverable through the capacity market. By employing a simple and direct approach using CONE with no offset, the rules for cost of service compensation included in Schedule 2 could be eliminated and the requirement for cost of service filings would be eliminated.

As a result of the nature of reactive filings, it is not possible to identify the reactive capability revenues for all individual units that receive reactive capability revenues. As a result, the offer caps in the capacity market are not as accurate as they should be.

Relying on capacity markets instead of cost of service allocations would enhance competition and efficient pricing.

Actual experience with the cost of service approach suggests that customers would be better off under a competition based approach. The Commission's recent investigations into particular rates raises questions about the accuracy and basis of rates currently charged for reactive capability.

Cost of service ratemaking creates unnecessary monitoring difficulties. Because service providers do not have to file rates periodically, suppliers have no incentive to adjust reactive capability rates except when they increase. Suppliers have direct access to information about the costs for their own units; the Commission and other parties do not have such access. When rates are established on a fleet basis or result from a black box settlement, the ability of parties to review and challenge rates is further reduced.

The current FERC review provides an excellent opportunity to discard an anachronistic cost of service approach that has not been working well and that is inconsistent with markets and is unnecessary in organized markets. Increased reliance on markets for the recovery of reactive capability costs would promote efficiency and consistency. Customers, market administrators and regulators will be better served by a simpler and more effective competition based approach.

73 OATT Attachment DD § 5.10(a)(v)(A) ("The Office of the Interconnection shall determine the Net Energy and Ancillary Services Revenue Offset each year for the PJM Region as (A) the annual average of the revenues that would have been received by the Reference Resource from the PJM energy markets during a period of three consecutive calendar years preceding the time of the determination, based on (1) the heat rate and other characteristics of such Reference Resource; (2) fuel prices reported during such period at an appropriate pricing point for the PJM Region with a fuel transmission adder appropriate for such region, as set forth in the PJM Manuals, assumed variable operation and maintenance expenses for such resource of $6.47 per MWh, and actual PJM hourly average Locational Marginal Prices recorded in the PJM Region during such period; and (3) an assumption that the Reference Resource would be dispatched for both the Day-Ahead and Real-Time Energy Markets on a Peak-Hour Dispatch basis; plus (B) ancillary service revenues of $2,199 per MW-year.").

74 *Id.*

75 *Id.*

Improvements to Current Approach

If Schedule 2 payments are not eliminated, then the MMU recommends, at a minimum, that steps be taken to ensure that payments are based on capability that is measured in tests performed by PJM or demonstrated in market data showing actual reactive output and based on capability levels that are useful to PJM system operators to maintain system stability. The FERC recently has initiated a number of investigations into the basis for reactive rates, and the Market Monitor has intervened in and is participating in those proceedings.[76]

Under the *AEP* method, units must establish their MVAR rating based on "the capability of the generators to produce VArs."[77] Typically this has meant reliance on manufacturers' specified nameplate power factor.[78] The Commission has noted a difference between tested reactive MVAR ratings and nameplate MVAR ratings and has, in a number of cases, set the issue of MVAR rating degradation for hearing.[79] The Commission has identified a significant issue. There is no reason to use the nameplate MVAR rating to develop a reactive allocation and there is no basis in the *AEP* order for reliance on the nameplate MVAR rating. Nameplate reactive power ratings are generally higher than the actual ratings as defined by the PJM mandated tests of capability because nameplate power ratings are generally calculated using leading and lagging power factors that are lower than are achievable in real world operation. Although this issue is characterized as degradation, the difference between nameplate and tested capability exists when units are new. Testing will reveal whether the tested capability degrades further. Reliance on tested results would address both the issue of degradation and the issue of theoretical versus actual MVAR ratings.

The estimated capability costs also include estimated heating losses relative to MVAR output.[80] Heating losses are variable costs and not fixed costs and should not be included in the definition of reactive capability costs.[81] Heating losses can be accurately calculated for each hour of operation if each unit had an accurate, recent D-curve test.

Cost of service rates are established under Schedule 2 of the OATT and may cover rates for single units or a fleet of units.[82] Until the Commission took corrective action, fleet rates remained in place in PJM even when the actual units in the fleet changed as a result of unit retirements or sales of units.[83] New rules require unit owners to give notice of fleet changes in an informational filing or to file a new rate based on the remaining units, but do not yet require unit specific reactive rates.[84] Fleet rates should be eliminated. Compensation should be based on unit specific costs. Fleet rates make it almost impossible to monitor whether compensation for reactive capability is based on actual unit specific performance and costs.

To the extent that the Commission decides that PJM and other markets should continue to rely on a cost of service method to compensate reactive capability, the rules should be modified to improve the accuracy of the calculations of reactive capability cost. Rates that do not accurately reflect the cost of the service provided are not just and reasonable.

Manufacturers' nameplate MVAR ratings and the corresponding theoretical power factors should not be relied upon to define the allocator used to calculate the costs of reactive capability. Current performance and testing show significant disparities between nameplate MVAR output and actual output. This is significant regardless of whether the cause is degradation of power factors or simply the difference between theoretical and tested power factors.[85] PJM determined in 1999 that nameplate MVAR and power factor ratings do not reflect the value to the system operator of a units' reactive output after it

76 *See* FERC Dockets Nos. EL16-32, EL16-44, EL16-51, EL16-54, EL16-65, EL16-66, EL16-90, EL16-72, EL16-1004 and ER16-1456.
77 *AEP mimeo* at 31.
78 *See, e.g., id.*
79 *See, e.g., Talen Energy Marketing, LLC*, 154 FERC ¶ 61,087 at P 10 (2016) ("The Informational Filing contains information that raises concerns about the justness and reasonableness of Ironwood's reactive power rate, including, but not limited to, the degradation of the Facility's current MVAR capability as compared with the MVAR capability that was originally used to calculate the revenue requirement for Reactive Service included in Ironwood's reactive power rate.").
80 *See, e.g., id.* at P 10 n12 citing PPL Energy Plus, LLC, Letter Order, Docket No. ER08-1462-000 (Sept. 24, 2008); *Dynegy Midwest Generation, Inc.*, 125 FERC ¶ 61,280, at P 35 (2008).
81 *See* Transcript, *Reactive Supply Compensation in Markets Operated by Regional Transmission System Operators Workshop*, AD16-17-000 (June 30, 2016) at 26:21–27:23.
82 *See, e.g.*, OATT Schedule 2; *Virginia Electric and Power Company*, 114 FERC ¶ 61,318 (2006).
83 *See PJM Interconnection, L.L.C.*, 149 FERC ¶ 61,132 (2014); 151 FERC ¶ 61,224 (2015); OATT Schedule 2.
84 *Id.*
85 In response to a 1999 low voltage event, PJM performed a root cause analysis. The analysis concluded that "PJM narrowly avoided a voltage collapse" and the "if PJM had realized that the MVAR reserves that the EMS indicated were available were not realistic, other action could have been take [sic] to stabilize the system." PJM State & Member Training Dept., Slides, Reactive Reserves and Generator D-Curves at 13 (included as an Attachment), which can be accessed at: <http://www.pjm.com/~/media/training/nerc-certifications/gen-exam-materials/gof/20160104-reactive-reserves-and-d-curve.ashx>

is interconnected at a specific location.[86] Only operator evaluation of reactive capability can provide a meaningful measure of reactive capability.

The information for MVAR ratings should come from data on the MVAR output provided. System operators can evaluate the usefulness and value of reactive capacity based on the actual availability and use of such capability.

Data from periodic testing for reactive capability is another approach to measuring MVAR output. Testing at relatively long intervals is not likely to be as accurate as actual market operations data, but it is more reliable than an untested and dated manufacturers' nameplate rating.

Fleet rates should be eliminated. Compensation should be based on unit specific costs. Fleet rates make it almost impossible to monitor whether compensation for reactive capability is based on actual unit specific performance and costs.

Heating losses are variable costs and should not be included in the cost of reactive capability. The production of reactive power slightly reduces the MWh output of the generator as the generator follows its D-curve. The value of this heating loss component is generally estimated based on estimated operation and associated estimated losses and estimated market prices, treated as a fixed cost, and included in the cost of reactive capability. Losses are minimal and occur during normal operations and should not be treated as a fixed cost. Losses can be better and more accurately accounted for as a variable cost based on actual unit operations and market conditions.

Reactive service is supplied during normal operation as needed and directed by PJM dispatchers. Most reactive service is provided with no impact to operational dispatch. When a need for reactive service requires that a unit's MW output be reduced outside of its normal operational range, or when a unit is started to provide reactive power, it is logged by PJM dispatchers and will be paid reactive service credits in the zone or zones where the reactive service was provided proportionally to their zone and nonzone peak transmission use and point to point transmission reservations.

86 *Id.*, including Attachment.

Reactive Costs

In the first six months of 2016, total reactive capability charges were $151.3 million, a 9.2 percent increase from the 2015 level of $138.6 million in the first six months.[87] Reactive service charges decreased in the first six months of 2016 to $626,217 from $9,251,482 in the first six months of 2015. All $626,217 in January through June 2016 were paid for reactive service provided by 22 units in 197 hours. The reason for the sharp decline in reactive service from the first six months of 2015 to the first six months of 2016 is primarily milder weather in real time. In January through June of 2015, there were $7.4M in charges for reactive service from the day-ahead market. In January through June of 2016, there were $0.0 in reactive service charges from the day ahead market.

For the first six months in each zone in 2015 and 2016, Table 10-45 shows reactive service charges (day-ahead and real time charges are added), reactive capability revenue requirement charges and total charges.

87 See the *2015 State of the Market Report for PJM*, Volume II, Section 4, "Energy Uplift."

Table 10-45 Reactive zonal charges for network transmission use: January through June 2015 and 2016

	2015 (Jan - Jun)			2016 (Jan - Jun)		
Zone	Reactive Service Charges	Reactive Capability Revenue Requirement Charges	Total Charges	Reactive Service Charges	Reactive Capability Revenue Requirement Charges	Total Charges
AECO	$13,275	$3,400,666	$3,413,941	$0	$2,714,981	$2,714,981
AEP	$394,417	$19,909,878	$20,304,295	$14,106	$18,494,486	$18,508,592
AP	$77,321	$8,295,318	$8,372,639	$0	$8,390,866	$8,390,866
ATSI	$3,816,737	$7,240,958	$11,057,695	$0	$12,690,250	$12,690,250
BGE	$51,621	$3,894,668	$3,946,289	$0	$3,827,063	$3,827,063
ComEd	$132,791	$12,890,930	$13,023,721	$1,091	$13,169,277	$13,170,368
DAY	$26,391	$4,224,345	$4,250,736	$0	$4,273,003	$4,273,003
DEOK	$41,305	$2,564,735	$2,606,040	$0	$2,876,239	$2,876,239
Dominion	$2,596,924	$14,862,225	$17,459,149	$0	$15,021,534	$15,021,534
DPL	$1,466,224	$5,463,658	$6,929,882	$570,320	$6,471,457	$7,041,777
DLCO	$19,567	$0	$19,567	$0	$0	$0
EKPC	$24,173	$1,072,573	$1,096,746	$0	$1,084,927	$1,084,927
JCPL	$30,717	$3,571,360	$3,602,077	$0	$4,871,900	$4,871,900
Met-Ed	$57,165	$3,847,767	$3,904,932	$15,071	$3,892,087	$3,907,158
PECO	$57,655	$8,831,645	$8,889,300	$0	$8,933,370	$8,933,370
PENELEC	$264,859	$3,584,469	$3,849,328	$10,366	$4,006,158	$4,016,524
Pepco	$56,930	$2,634,863	$2,691,793	$0	$3,307,039	$3,307,039
PPL	$65,909	$9,441,234	$9,507,143	$15,263	$9,735,841	$9,751,104
PSEG	$55,641	$13,664,947	$13,720,588	$0	$18,512,827	$18,512,827
RECO	$1,860	$0	$1,860	$0	$0	$0
(Imp/Exp/Wheels)	$0	$9,232,178	$9,232,178	$0	$8,415,863	$8,415,863
Total	$9,251,482	$138,628,417	$147,879,899	$626,217	$150,689,168	$151,315,385