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 incentive rates or cost.

The Market Monitoring Unit (MMU) analyzed measures of market structure, conduct and performance for the PJM Regulation Market, the two regional Synchronized Reserve and Non-Synchronized Reserve Markets, and the PJM DASR Market for 2015.

Table 10-1 The Regulation Market results were competitive

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

- The Regulation Market structure was evaluated as not competitive for the year because the Regulation Market had one or more pivotal suppliers which failed PJM's three pivotal supplier (TPS) test in 97 percent of the hours in the first three months of 2015.
- Participant behavior in the Regulation Market was evaluated as competitive for 2015 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, after the introduction of the new market design, despite significant issues with the market design.
- Market design was evaluated as flawed. 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. Further, the market design has failed to correctly incorporate a consistent implementation of the marginal benefit factor in optimization, pricing and settlement. In addition, the market results indicate that PJM's current marginal benefit function is, in some hours, overvaluing RegD as a substitute for RegA in the optimization.

Table 10-2 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 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.
- 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 non-zero price.

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

Table 10-3 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 did not fail the three pivotal supplier test.
- Participant behavior was evaluated as mixed because while most offers appeared consistent with marginal costs, a significant proportion of offers reflected economic withholding.
- Market performance was evaluated as competitive because there were adequate offers at reasonable levels in every hour to satisfy the requirement and the clearing price reflected those offers.
- Market design was evaluated as mixed because while the market is functioning effectively to provide DASR, the three pivotal supplier test, and cost-based offer capping when the test is failed, should be added to the market to ensure that market power cannot be exercised at times of system stress.

Overview

Primary Reserve

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

Market Structure

- **Supply.** Primary reserve is satisfied by both synchronized reserve (generation or demand response currently synchronized to the grid and available within ten minutes), and non-synchronized reserve (generation currently off-line but can be started and provide energy within ten minutes).
- **Demand.** The PJM primary reserve requirement is 150 percent of the largest contingency. The primary reserve requirement in the RTO Reserve 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 in January through March 2015 was 2,299.5 MW. The actual demand for primary reserve in the MAD subzone in January through March 2015 was 1,714.4 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 ten minutes. Synchronized reserve is of two distinct types, tier 1 and tier 2. Tier 1 synchronized reserve counts as part of PJM's primary reserve requirement and is the capability of on-line resources following economic dispatch to ramp up in ten minutes from their current output in response to a synchronized reserve event.

- **Supply.** No offers are made for tier 1 synchronized reserve. The market solution calculates tier 1 synchronized reserve as available 10-minute ramp from the energy dispatch. In the first three months of 2015, there was an average hourly supply of 1,433.0 MW of tier 1 for the RTO synchronized reserve zone, and an average hourly supply of 601.9 MW of tier 1 in the Mid-Atlantic Dominion subzone.
- **Demand.** The default hourly required synchronized reserve requirement is 1,700 MW in the RTO Reserve Zone and 1,450 MW for the Mid-Atlantic Dominion Reserve subzone.
- **Tier 1 Synchronized Reserve Event Response.** Tier 1 synchronized reserve is paid when a synchronized reserve event occurs and it responds. The 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.

Of tier 1 synchronized reserve eligible for payment in Settlements, 66.3 percent actually responded during the seven distinct synchronized reserve events 10 minutes or longer in the first three months of 2015. PJM made changes to the way it calculated tier 1 MW for settlements in July 2014. These changes improved the response rate.

- **Issues.** The competitive price 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. 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 $26,576,359 to tier 1 resources in 2014, and $17,877,658 in the first three months of 2015.

Tier 2 Synchronized Reserve Market

Tier 2 synchronized reserve is part of primary reserve (ten minute availability) 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 filled with tier 1 synchronized reserve, PJM conducts a market to satisfy 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 three months of 2015, the supply of offered and eligible synchronized reserve was sufficient to cover the requirement in both the RTO Reserve Zone and the Mid-Atlantic Dominion Reserve subzone.
- **Demand.** The default hourly required synchronized reserve requirement was 1,450 MW in both the RTO Reserve Zone and the Mid-Atlantic Dominion Reserve subzone.
- **Market Concentration.** In the first three months of 2015, the weighted average HHI for cleared tier 2 synchronized reserve in the Mid-Atlantic Dominion subzone was 4357 which is classified as highly concentrated. The MMU calculates that 56.2 percent of hours would have failed a three pivotal supplier test in the Mid-Atlantic Dominion subzone.

  In the first three months of 2015, the weighted average HHI for cleared tier 2 synchronized reserve in the RTO Synchronized Reserve Zone was 5123 which is classified as highly concentrated. The MMU calculates that 35.0 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 three months of 2015.

Market Conduct

- **Offers.** 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 $16.34 per MW in the first three months of 2015, a decrease of $10.12 (40 percent) from the first three months of 2014.

The weighted average price for tier 2 synchronized reserve for all cleared hours in the RTO Synchronized Reserve Zone was $16.53 per MW in the first three months of 2015, a decrease of $34.37 from January through March 2014.

Non-Synchronized Reserve Market

Non-synchronized reserve is part of primary reserve and includes the same two markets, the RTO Reserve Zone and the Mid-Atlantic Dominion Reserve subzone (MAD). Non-synchronized reserve is comprised of non-emergency energy resources not currently synchronized to the grid that can provide energy within ten minutes. Non-synchronized reserve is available to fill the primary reserve requirement above the synchronized reserve requirement.

Market Structure

- **Supply.** In the first three months of 2015, the supply of eligible non-synchronized reserve was 3,764.3 MW in MAD and 6,721.0 in the RTO. This supply was sufficient to cover the primary reserve requirement in both the RTO Reserve Zone and the Mid-Atlantic Dominion Reserve subzone.
- **Demand.** In the RTO Zone, the market cleared an hourly average of 537.1 MW of non-synchronized reserve in the first three months of 2015. In the MAD subzone, the market cleared an hourly average of 490.0 MW of non-synchronized reserve.

Market Conduct

- **Offers.** No offers are made for non-synchronized reserve. Non-emergency 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.

Market Performance

- **Price.** There are no offers for non-synchronized reserve. 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 in the RTO Reserve Zone was $3.25 per MW in the first three months of 2015 and in 76.8 percent of hours the market clearing price was $0. The non-synchronized reserve weighted average price for all cleared hours in the Mid-Atlantic Dominion (MAD) subzone was $2.76 and in 75.7 percent of hours the market clearing price was $0.

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.[3] The DASR Market has no performance obligations.

Market Structure

- **Concentration.** In the first three months of 2015, zero hours in the DASR Market would have failed the three pivotal supplier test.
- **Supply.** The DASR Market is a must offer market. Any resources that do not make an offer have their offer set to $0 per MW. DASR is calculated by the day-ahead market solution as the lesser of the thirty minute energy ramp rate or the emergency maximum MW minus the day-ahead dispatch point for all on-line units. In the first three months of 2015, the average available hourly DASR was 38,116 MW.
- **Demand.** The DASR requirement in 2015 is 5.93 percent of peak load forecast, down from 6.27 percent in 2014. The average DASR MW purchased was 6,303 MW per hour in the first three months of 2015.

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

Market Conduct

- **Withholding.** Economic withholding remains an issue in the DASR Market. The direct marginal cost of providing DASR is zero. All offers greater than zero constitute economic withholding. As of March 31, 2015, 9.6 percent of resources offered DASR at levels above $5 per MW.
- **DR.** Demand resources are eligible to participate in the DASR Market. Six demand resources entered offers for DASR.

Market Performance

- **Price.** The weighted average DASR market clearing price in January through March 2015 was $0.76 per MW. This is a significant increase from the $0.06 per MW of the first three months of 2014.

Regulation Market

The PJM Regulation Market is a single RT market. Regulation is provided by demand response and generation 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 or RMCCP, performance or RMPCP, and lost opportunity cost or LOC), the rate of substitution between RegA and RegD resources (marginal benefit factor) and a measure of the quality of response (performance score) by a regulation resource to a regulation signal. The marginal benefit factor and performance score translate a resource's capability (actual) MW into effective MW.

Market Structure

- **Supply.** In the first three months of 2015, the average hourly eligible supply of regulation was 1,154 actual MW (898 effective MW). This is a decrease of 224 actual MW (117 effective MW) from the same period of 2014, when the average hourly eligible supply of regulation was 1,377 actual MW (1,016 effective MW).
- **Demand.** The average hourly regulation demand was 648 actual MW in the first three months of 2015. This is a 37 actual MW (0 effective MW) decrease in the average hourly regulation demand of 685 actual MW (664 effective MW) from the same period of 2014.
- **Supply and Demand.** The ratio of offered and eligible regulation to regulation required averaged 1.78. This is an 11.5 percent decrease from the same period of 2014 when the ratio was 2.01.
- **Market Concentration.** In the first three months of 2015, the PJM Regulation Market had a weighted average Herfindahl-Hirschman Index (HHI) of 1545 which is classified as moderately concentrated. In the first three months of 2015, the three pivotal supplier test was failed in 97 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 offer along with cost parameters to verify the offer, and may optionally submit a price 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.[4] In the first three months of 2015, there were 231 resources following the RegA signal and 42 resources following the RegD signal.

Market Performance

- **Price and Cost.** The weighted average clearing price for regulation was $48.66 per MW of regulation in the first three months of 2015, a decrease of $43.28 per MW of regulation, or 47.1 percent, from the same period of 2014. The cost of regulation in the first three months of 2015 was $59.15 per MW of regulation, a decrease of $51.87 per MW of regulation, or 46.7 percent, from the same period of 2014. The decreases in regulation price and regulation cost resulted primarily from high prices and costs in the first three months of 2014, particularly in January.

4 See the *2014 State of the Market Report for PJM*, Volume II, Appendix F "Ancillary Services Markets."

- **RMCP Credits.** RegD resources continue to be incorrectly 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 equally per effective MW.
- **Marginal Benefit Factor Function.** The marginal benefit factor measures the substitutability of RegD resources for RegA resources in satisfying the regulation requirement. The regulation market's effectiveness and efficiency depends on the marginal benefit factor function being properly defined based on the actual tradeoff between RegA and RegD MW in providing regulation. Current regulation performance indicates that the marginal benefit factor function used by PJM is incorrectly describing the operational relationship between RegA and RegD for purposes of providing regulation service.
- **Inconsistent accounting of RegD effective MW.** The IMM has determined that the current market optimization/market solution does not correctly account for the amount of effective MW being provided by RegD. Rather than calculating the total effective MW contribution of RegD MW on the basis of the area under the marginal benefit function curve, the current regulation market optimization assigns all RegD resources with the same effective price the lowest marginal benefit factor associated with last RegD MW at that price. The incorrect accounting of effective MW within the optimization construct will result in the purchase of more than the efficient level of RegD necessary to meet PJM's regulation requirement.

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 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.[5]

In the first three months of 2015, total black start charges were $15.0 million with $10.3 million in revenue requirement charges and $4.7 million 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 automatic load rejection (ALR) option or for black start testing. Black start zonal charges in the first three months of 2015 ranged from $0.04 per MW-day in the PPL Zone (total charges were $31,710) to $4.55 per MW-day in the BGE Zone (total charges were $2,727,337).

Reactive

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

In the first three months of 2015, total reactive service charges were $76.1 million, a 2.2 percent decrease from the first three months of 2014 level of $77.8 million. Revenue requirement charges decreased from $70.3 million to $69.9 million and operating reserve charges fell from $7.5 million to $6.3 million. Total charges in the first three months of 2015 ranged from $1.8 thousand in the RECO Zone to $10.4 million in the AEP Zone. Reactive service revenue requirements are based on FERC-approved filings. Reactive service operating reserve charges are paid for scheduling in the Day-Ahead Energy Market and committing in real time units that provide reactive service.

Ancillary Services Costs per MWh of Load: 2004 through 2015

Table 10-4 shows PJM ancillary services costs for 2004 through 2015, on a per MWh of load basis. The rates are calculated as the total charges for the specified ancillary service divided by the total PJM real time load in MWh.

5 OATT Schedule 1 § 1.3BB.

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. Supplementary operating reserve includes day-ahead operating reserve; balancing operating reserve; and synchronous condensing. 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 also changes in total load.

Table 10-4 History of ancillary services costs per MWh of Load: January through March, 2004 through 2015

Year (Jan-Mar)	Regulation	Scheduling, Dispatch, and System Control	Reactive	Synchronized Reserve	Supplementary Operating Reserve	Total
2004	$0.53	$0.63	$0.26	$0.17	$0.89	$2.48
2005	$0.46	$0.51	$0.25	$0.07	$0.57	$1.86
2006	$0.48	$0.46	$0.28	$0.09	$0.32	$1.62
2007	$0.58	$0.46	$0.30	$0.11	$0.50	$1.95
2008	$0.59	$0.47	$0.29	$0.07	$0.52	$1.94
2009	$0.37	$0.37	$0.34	$0.16	$0.56	$1.80
2010	$0.34	$0.38	$0.35	$0.05	$0.68	$1.80
2011	$0.27	$0.33	$0.39	$0.12	$0.84	$1.95
2012	$0.18	$0.41	$0.49	$0.03	$0.53	$1.64
2013	$0.28	$0.41	$0.63	$0.04	$0.94	$2.30
2014	$0.63	$0.38	$0.37	$0.56	$3.55	$5.49
2015	$0.32	$0.41	$0.36	$0.20	$0.82	$2.11

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 2013. Status: Not 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. (Priority: High. First reported Q3, 2014. Status: Adopted July 2014.)
- The MMU recommends that the tier 2 synchronized reserve must-offer provision of scarcity pricing be enforced. As of the end of December 31, 2014 compliance with the tier 2 must-offer provision was 99.5 percent. (Priority: Medium. First reported 2013. Status: Adopted partially.)
- 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 calculating 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. (Priority: Low. First reported 2013. Status: Not adopted.)
- The MMU recommends that PJM determine why secondary reserve was either unavailable or not dispatched on September 10, 2013, January 6, 2014, and January 7, 2014, and 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: Not adopted.)
- The MMU recommends that the three pivotal supplier test be incorporated in the DASR Market. (Priority: Low. First reported 2012. 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. Further, the market design has failed to correctly incorporate the marginal benefit factor in optimization, pricing and settlement. Instead, the market design makes use of the marginal benefit factor in the optimization and pricing, but a mileage ratio multiplier in settlement. This failure to correctly incorporate marginal benefit factor into the current Regulation Market design is causing effective MW provided by RegD resources to be underpaid per effective MW. These issues have led to the MMU's conclusion that the Regulation Market design, as currently implemented, 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. Compliance with calls to respond to actual synchronized reserve events has been an issue. Compliance with the synchronized reserve must-offer requirement has also been an issue.

The shortage pricing rule that requires market participants to pay tier 1 synchronized reserve the tier 2 synchronized reserve price when the nonsynchronized reserve price is greater than zero, is inefficient and results in a 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. Such resources are not tier 2 resources, although they have the option to offer as tier 2, to take on tier 2 obligations and to be paid as tier 2. Application of this rule added $80.0 million to the cost of primary reserve in 2014.

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 new 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.

Primary Reserve

Primary reserve is to ensure reliability in the event of contingencies. Primary reserve is PJM's implementation of the NERC 15-minute contingency reserve requirement.[6] 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.[7] PJM implements the NERC requirement conservatively as primary reserve available within ten minutes.

Market Structure

Supply

In 2015, PJM's primary reserve requirement was 2,063 MW for the RTO Zone, and 1,700 MW for the MAD subzone. 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. Effective January 1, 2015 the synchronized reserve requirement was increased to 1,342 MW in the Mid-Atlantic Dominion subzone, and remained at 1,375 MW in the RTO Zone. Effective January 8, 2015, the

6 PJM. OATT (effective 2/5/2014), p.1740; 1.3.29F Primary Reserve.
7 NERC, IVGTF Task 2.4 Report; Operating Practices, Procedures, and Tools, March 2011, p. 20.

synchronized reserve requirement was increased to 1,450 MW in both the Mid-Atlantic Dominion subzone, and the RTO Zone. After the synchronized reserve requirement is satisfied, the remainder of primary reserves can come from non-synchronized reserves.

Estimated tier 1 is credited against PJM's primary reserve requirement. In the MAD subzone an average of 570.2 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. There was enough tier 1 to satisfy the MAD subzone synchronized reserve requirement in 76 hours in the first three months of 2015. In the RTO Zone, an average of 1,431.7 MW of tier 1 was available (Table 10-6). The RTO Zone synchronized reserve requirement was satisfied by tier 1 in 43.9 percent of all hours.

Regardless of online/offline state, all non-emergency generation capacity resources must submit a daily offer for Tier 2 Synchronized Reserve in eMKT 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, and batteries, are expected to have zero MW Tier 2 Synchronized Reserve offer quantities.[8]

There is usually enough tier 2 synchronized reserve to fulfill the synchronized reserve requirement. In the MAD subzone, there was an average of 3,764.3 MW of eligible tier 2 synchronized reserve available (Figure 10-11) to meet the average tier 2 hourly demand of 265.7 MW (Table 10-5). In the RTO Zone, there was an average of 6,721 MW of eligible Tier 2 supply available to meet the average hourly demand of 389.9 MW (Table 10-6).

In the MAD subzone, there was an average of 1,955.0 MW of eligible non-synchronized reserve supply available to meet the average hourly demand of 488.8 MW (Table 10-6). In the RTO Zone, an hourly average of 2,793.5 MW supply was available to meet the average hourly demand of 971.8 MW (Table 10-5).

Demand

PJM requires that 150 percent of the largest contingency on the system be maintained as primary reserve. On January 8, 2015, the primary reserve requirement in the RTO Reserve Zone was raised from 2,063 MW to 2,175 MW. Adjustments to this value can occur when grid maintenance or outages change the largest contingency (Figure 10-1).

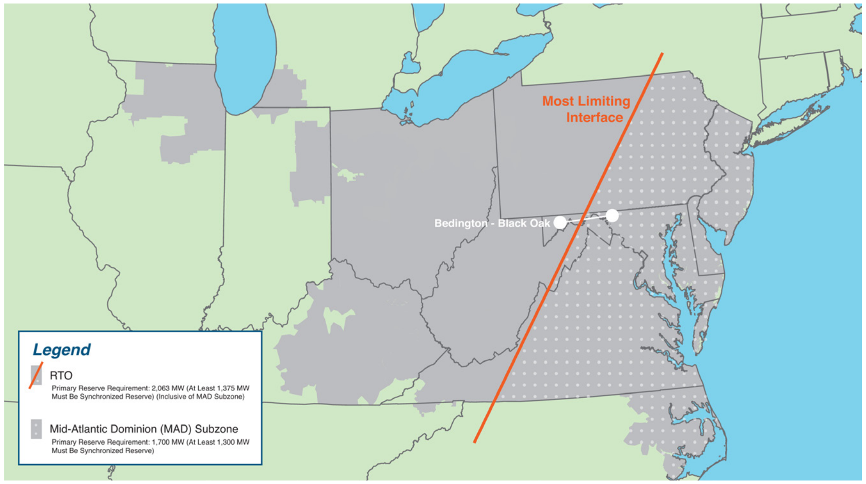
In 29.6 percent of hours in 2015, PJM increased the primary reserve requirement for the RTO Zone. The actual hourly average RTO primary reserve requirement was 2,299.5 MW in the first three months of 2015. In 38 hours during the first three months of 2015, PJM increased the primary reserve requirement for the MAD subzone. The actual hourly average demand for primary reserve in the MAD subzone in the first three months of 2015 was 1,714.4 MW.

Transmission constraints limit the deliverability of reserves within the RTO, requiring the definition of the Mid-Atlantic Dominion (MAD) subzone.[9] Of the 2,175 MW RTO primary reserve requirement, 1,700 MW (Table 10-16) must be deliverable to the MAD subzone (Figure 10-1).

8 See PJM, "Manual 11, Energy and Ancillary Services Market Operations," Revision 72 (January 16, 2015), p. 63, 64.

9 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 and Ancillary Services Market Operations," Revision 722 (January 16, 2015), p. 66.

Figure 10-1 PJM RTO geography and primary reserve requirement: 2015



The Mid-Atlantic Dominion Reserve (MAD) subzone is defined dynamically by the most limiting constraint separating MAD from the PJM RTO Reserve Zone. In 63.3 percent of hours in 2015, that constraint was the Bedington – Black Oak Interface. The AP South transfer interface constraint was the limiting constraint in 36.8 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 March 2015

Year	Month	Tier 1 Total MW	Tier 2 Synchronized Reserve MW	Non-Synchronized Reserve MW
2015	Jan	1,222.0	206.9	629.7
2015	Feb	1,176.7	305.1	437.4
2015	Mar	1,200.6	288.7	394.6
2015	Average	1,199.8	266.9	487.2

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 March 2015

Year	Month	Tier 1 Total MW	Tier 2 Synchronized Reserve MW	Non-Synchronized Reserve MW
2015	Jan	1,582.7	331.7	1,074.4
2015	Feb	1,469.1	415.7	906.3
2015	Mar	1,247.2	424.8	928.5
2015	Average	1,433.0	390.7	969.7

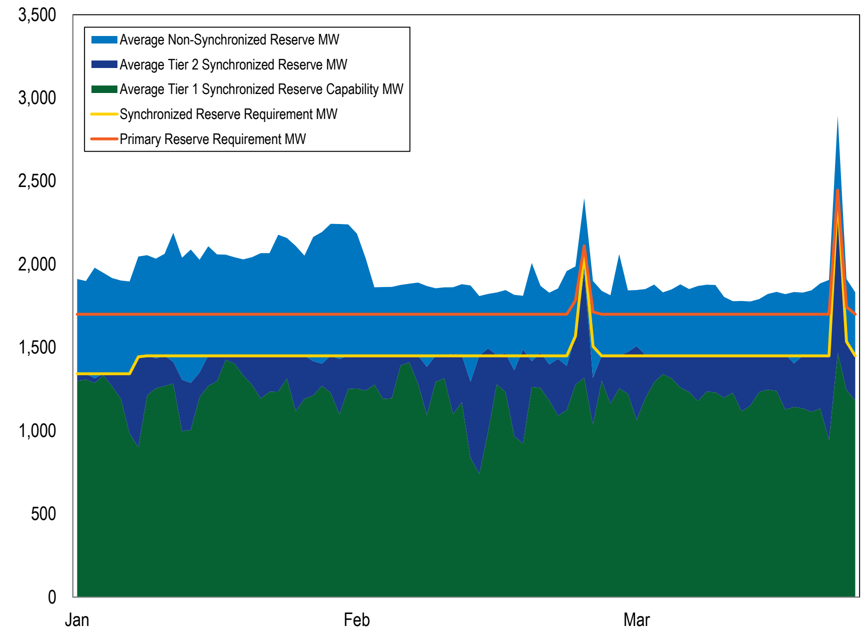
Supply and Demand

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, non-synchronized reserves, and regulation 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 March 2015



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

10 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 10-3 RTO subzone primary reserve MW by source (Daily Averages): January through March 2015

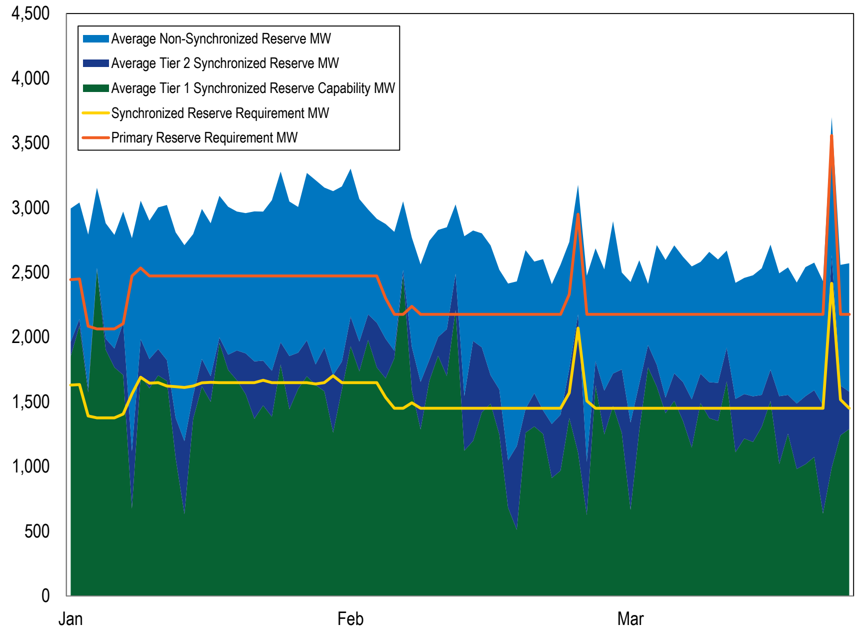


Figure 10-2 and Figure 10-3 show that tier 1 synchronized reserve remains the major contributor to satisfying the synchronized reserve requirements both in the RTO Zone and the Mid-Atlantic Dominion (MAD) subzone.

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. From June 1, 2013, through May 31, 2014, the penalty factor was $400 per MW for both tier 2 synchronized reserve and non-synchronized reserve. Effective June 1, 2014, through May 31, 2015, the penalty factor for both products is $550 per MW. In January 2014, cold weather resulted in high loads which, combined with unit outages, contributed to volatility and high prices in the primary reserve (synchronized and non-synchronized) markets.

Figure 10-4 shows daily average synchronized and non-synchronized market clearing prices in the first three months of 2015.

Figure 10-4 Daily average market clearing prices ($/MW) for synchronized reserve and non-synchronized reserve: January through March 2015

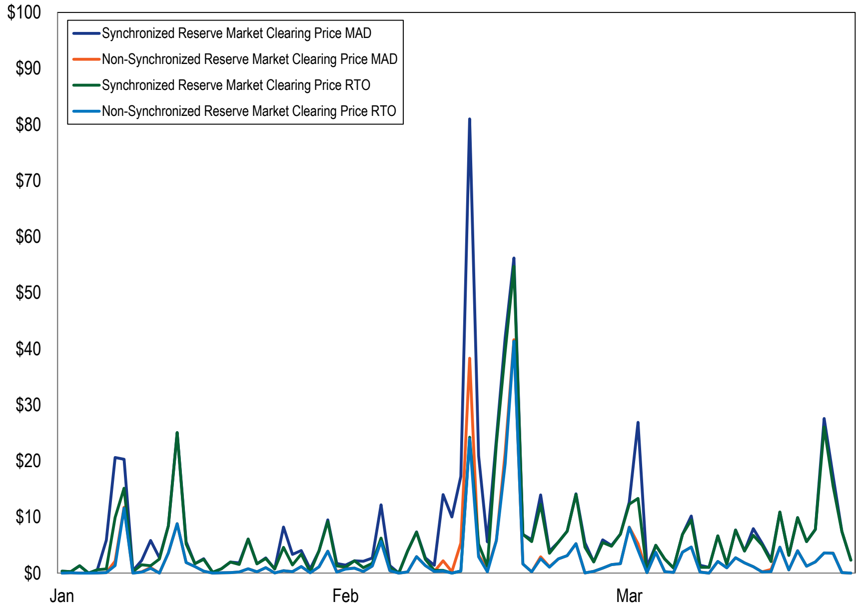


Table 10-7 MW credited, price, cost, and all-in price for primary reserve and its component products, full RTO Reserve Zone, 2015

Product	Share of Primary Reserve Requirement	MW Credited	Credits Paid	Price Per MW	Cost Per MW	All-In Cost
Tier 1 Synchronized Reserve Response	NA	3,061	$123,337	NA	$35.97	$0.00
Tier 1 Synchronized Reserve	28.9%	950,074	$17,877,658	$18.82	$18.82	$0.08
Tier 2 Synchronized Reserve	24.3%	799,676	$24,479,277	$16.53	$30.61	$0.12
Non-synchronized Reserve	46.8%	1,541,171	$3,190,382	$2.10	$3.82	$0.02
Primary Reserve	100.0%	3,290,921	$45,547,317	$10.43	$13.84	$0.22

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 (light blue area in Figure 10-2 and Figure 10-3) and tier 1 synchronized reserve (green area in Figure 10-2 and Figure 10-3). 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.

Tier 1 Synchronized Reserve

Tier 1 synchronized reserve is a component of primary reserve comprised of all on-line 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 ten 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 ten 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.

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 three months of 2015, in the RTO Reserve Zone the average hourly estimated tier 1 synchronized reserve was 1,433.0 MW (Table 10-6). In 195 hours (9.0 percent) 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 three months of 2015, in the MAD reserve subzone the average hour ahead estimated tier 1 synchronized reserve was 1199.8 MW (Table 10-5). In seven hours the estimated tier 1 synchronized reserve was zero. In 8 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 March 2015

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
2015	Jan	622.8	599.2	1,222.0	410.4	1,450.0
2015	Feb	608.4	568.4	1,176.7	0.0	2,252.6
2015	Mar	483.1	717.5	1,200.6	163.7	2,344.6
2015	Average	571.4	628.3	1,199.8	191.4	2,015.7

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
2015	Jan	1,582.7	N/A	1,582.7	0.0	3,240.4
2015	Feb	1,469.1	N/A	1,469.1	0.0	2,980.4
2015	Mar	1,247.2	N/A	1,247.2	0.0	2,727.6
2015	Average	1,433.0	N/A	1,433.0	0.0	2,982.8

Demand

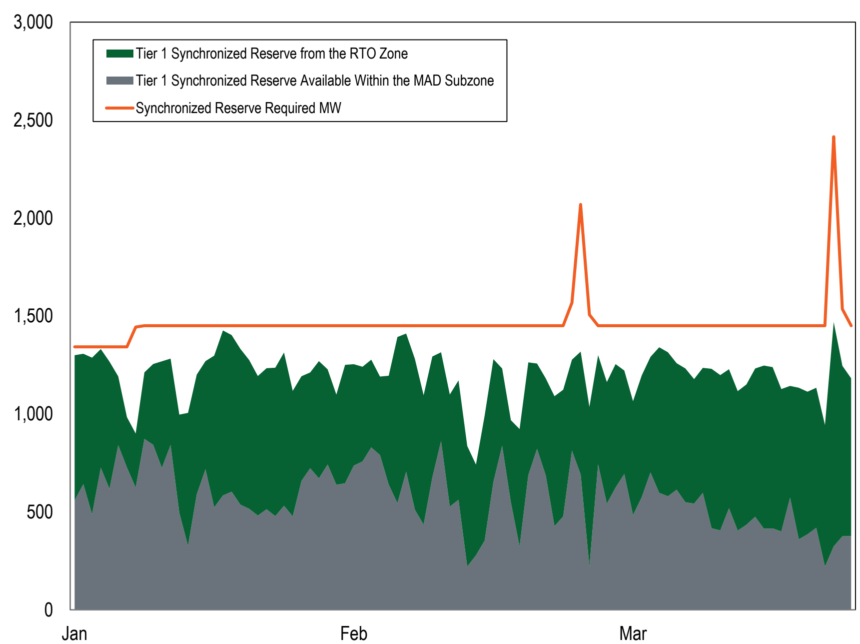
There is no fixed required amount of tier 1 synchronized reserve. Tier 1 synchronized reserve is estimated as part of each market solution and not assigned. Given estimated tier 1, the market software (ASO) completes the primary reserve assignments under the assumption that the estimated tier 1 will 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.

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.

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).

Figure 10-5 Daily average tier 1 synchronized reserve supply (MW) in the MAD subzone: January through March 2015[11]



11 Hours in which the tier 1 estimate was biased by PJM dispatch are excluded from this graph.

Demand for synchronized reserve in the RTO Zone increased 18.1 percent from the first quarter of 2014 primarily because the hourly synchronized reserve requirement was increased from 1,375 MW to 1,450 MW. In addition, there was a temporary increase to 2,688 MW on February 28, 2015 and to 2,615 MW on March 29, 2015 because of emergency outages. Usually, the synchronized reserve requirement is increased because of planned outages in the spring and fall for periods of 10 to 14 days.

Tier 1 Issues

The MMU has identified two issues with PJM's current rules for the compensation of tier 1 resources. PJM inappropriately pays tier 1 MW the tier 2 SRMCP when the non-synchronized reserve market clearing price (NSRMCP) is above $0. Until July, 2014, PJM had been paying the SRMCP to resources that are deselected from Tier 1 in the market solution because they are not capable of providing tier 1 synchronized reserves based on PJM's evaluation. PJM plans to refund to loads the credits erroneously paid for deselected tier 1 synchronized reserves.

Paying Tier 1 the Tier 2 Price

The market solutions correctly treat tier 1 synchronized reserve as having zero cost. The price for tier 1 synchronized reserves is zero unless tier 1 is called on to respond, as there is no incremental cost associated with providing the ability to ramp up from the current economic dispatch point. 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 in 541 hours in 2014. For those 541 hours tier 1 synchronized reserve resources were paid a weighted synchronized reserve market clearing price of $30.67 per MW and earned $89,719,045 in credits (Table 10-14). Of the $89,719,045, $9,687,288 was for tier 1 actually estimated by the PJM market solution and $80,031,757 was mistakenly paid because deselected tier 1 MW were paid when they should not have been (see Table 10-10). The issue of paying for tier 1 from deselected units was corrected in July, 2014. PJM continues however to pay tier 1 synchronized reserve the SRMCP when the non-synchronized reserve market clearing price is above $0. In the first three months of 2015, PJM paid $17,877,658 in credits for tier 1 estimated during hours when the non-synchronized reserve market clearing price was above $0.

Table 10-9 Weighted price of tier 1 synchronized reserve attributable to a non-synchronized reserve price above zero: January 2014 to March 2015

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
2014	Jan	155	$93.26	706,479	$64,956,018	4,557.9
2014	Feb	15	$40.18	65,332	$2,625,303	4,355.4
2014	Mar	67	$44.56	240,625	$10,665,198	3,591.4
2014	Apr	99	$16.07	308,759	$4,959,232	3,118.8
2014	May	61	$15.85	253,076	$4,012,285	4,148.8
2014	Jun	4	$35.46	15,970	$566,292	3,992.4
2014	Jul	5	$17.02	9,150	$155,744	1,829.9
2014	Aug	0	NA	NA	NA	NA
2014	Sep	0	NA	NA	NA	NA
2014	Oct	3	$21.59	2,146	$46,319	715.2
2014	Nov	28	$15.73	38,188	$599,147	1,363.8
2014	Dec	104	$6.93	163,552	$1,133,507	1,739.9
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
Total		1,064	$29.92	2,753,349	$107,596,703	2,681.9

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. Only 31.0 percent of the market solution's estimated tier 1 resource MW actually responded during synchronized reserve events in the first three months of 2015. Thus, 69.0 percent of tier 1 resources do not respond but are paid when the non-synchronized reserve price is 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 effective price of all tier 1 MW increases significantly. The optimization does not reflect the actual cost of the incremental MW of non-synchronized reserve.

In the first three months of 2015, tier 1 MW were paid $123,337 for responding to synchronized reserve events and were paid $17.8 million simply because the NSRMCP was greater than $0 (Table 10-11).

Table 10-10 Dollar impact of paying Tier 1 Synchronized Reserve the SRMCP when the NSRMCP goes above $0: January 2014 through March 2015

		Synchronized Reserve Events			Hours When NSRMCP > $0		
Year	Month	Total MW	Total Credits	Average MW Per Event	Total MW	Total Credits	Average MW Per Hour
2014	Jan	7,828	$965,846	522	706,479	$64,956,018	4,558
2014	Feb	273	$11,153	273	65,332	$2,625,303	4,355
2014	Mar	3,030	$175,902	606	240,625	$10,665,198	3,591
2014	Apr	389	$6,378	195	308,759	$4,959,232	3,119
2014	May	717	$34,906	239	253,076	$4,012,285	4,149
2014	Jun	0	$0	0	15,970	$566,292	3,992
2014	Jul	616	$35,179	308	9,150	$155,744	1,830
2014	Aug	0	$0	0	0	$0	0
2014	Sep	1,936	$143,574	645	0	$0	0
2014	Oct	1,132	$83,901	566	2,146	$46,319	715
2014	Nov	1,350	$38,895	337	38,188	$599,147	1,364
2014	Dec	258	$12,897	129	163,552	$1,133,507	1,740
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
Total		20,590	$1,631,968	380	2,753,349	$107,596,703	2,682

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. 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 plus $50/MW, termed the Synchronized Energy Premium Price.

A summary of PJM's current tier 1 compensation rules are presented in Table 10-11.

Table 10-11 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 MW
NSRMCP>$0	T1 credits = T2 SRMCP * calculated tier 1 MW	T1 credits = T2 SRMCP * min(calculated tier 1 MW, actual response MW)

The MMU's recommended compensation rules for tier 1 MW are in Table 10-12.

Table 10-12 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 MW
NSRMCP>$0	T1 credits = $0	T1 credits = Synchronized Energy Premium Price * actual response MW

Paying for Too Much Tier 1 When NSR Price Is Greater Than Zero

To ensure sufficient synchronized reserves are realized in real time operations, PJM routinely deselects tier 1 resources from the tier 2 market solution that cannot reliably provide tier 1 reserve during synchronized reserve events. The market solution deselects many generation units based on unit type, location, and daily grid conditions. The amount of tier 1 MW that PJM pays in settlements was larger than the amount of tier 1 MW estimates in the PJM market solution, which determines how much tier 2 synchronized reserve will be cleared, through July 2014. PJM paid both the units selected as capable of providing tier 1 and the units deselected as not capable of providing tier 1. If more tier 1 had actually been available for the market solution it would have resulted in a lower price for tier 2 resources. When tier 1 is paid the NSRMCP, the result is, under the tariff rules providing for such payment, overpayment of tier 1 because the price is paid to too many MW. The MMU believes that this is an error. In effect, PJM paid twice for the deselected tier 1 resources, once as the deselected MW and again as the tier 2 MW that were purchased because the deselected MW were not actually available.

As of July 2014, PJM has taken steps to ensure that deselected resources are no longer paid as tier 1 when NSRMCP was above $0 and is collecting the overpayments from those who received them.

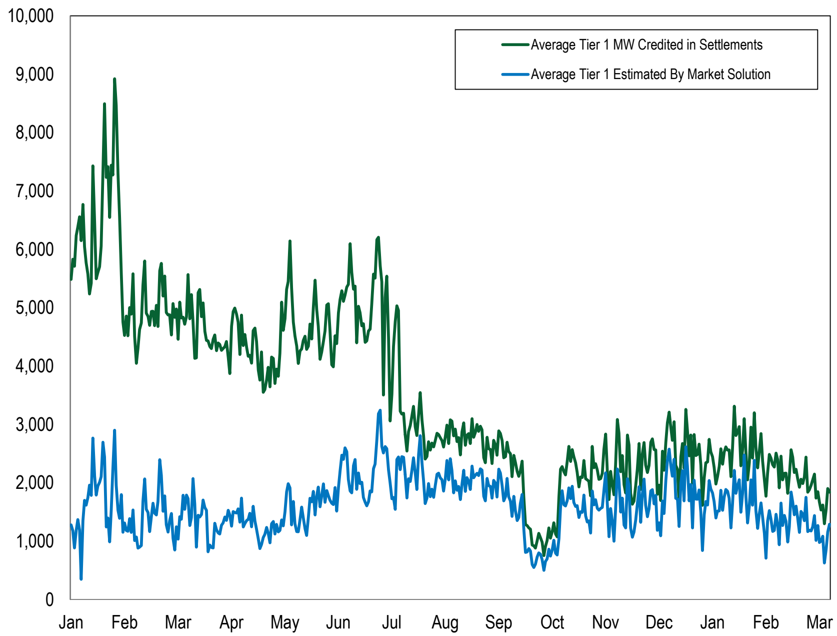
Table 10-13 shows the actual dollars paid to deselected tier 1 resources in error, $99.5 million from October 2012 through March, 2015.

Table 10-13 Actual payments made to tier 1 resources compared with correct tier 1 payments: October 2012 through December 2014

Year	Month	MAD Tier 1 Credits	Correct MAD Tier 1 Credits	RTO Tier 1 Credits	Correct RTO Tier 1 Credits	Total Tier 1 Credits	Correct Total Tier 1 Credits	Overpayments
2012	Oct	$655,253	$233,764	$1,605	$458	$656,858	$234,223	$422,635
2012	Nov	$3,865,695	$1,277,896	$140,128	$45,751	$4,005,822	$1,323,646	$2,682,176
2012	Dec	$439,238	$209,864	$0	$0	$439,238	$209,864	$229,373
2013	Jan	$1,099,271	$254,695	$0	$0	$1,099,271	$254,695	$844,576
2013	Feb	$180,211	$73,781	$0	$0	$180,211	$73,781	$106,430
2013	Mar	$2,408,969	$952,776	$0	$0	$2,408,969	$952,776	$1,456,193
2013	Apr	$1,163,189	$479,173	$70,079	$14,773	$1,233,268	$493,946	$739,321
2013	May	$657,281	$215,651	$40,765	$5,260	$698,046	$220,910	$477,135
2013	Jun	$246,604	$61,479	$2,104	$321	$248,707	$61,800	$186,907
2013	Jul	$2,118,870	$421,124	$77,578	$3,367	$2,196,447	$424,491	$1,771,956
2013	Aug	$910,544	$278,125	$884,473	$110,764	$1,795,017	$388,888	$1,406,129
2013	Sep	$2,043,500	$216,591	$292,218	$52,282	$2,335,717	$268,873	$2,066,844
2013	Oct	$85,905	$20,083	$12,998	$2,147	$98,903	$22,229	$76,673
2013	Nov	$2,531	$1,216	$7,233	$1,471	$9,763	$2,687	$7,076
2013	Dec	$91,677	$9,219	$78,981	$8,915	$170,658	$18,134	$152,524
2014	Jan	$39,963,435	$3,568,087	$22,353,116	$1,306,227	$62,316,551	$4,874,314	$57,442,237
2014	Feb	$1,705,210	$228,579	$920,093	$109,324	$2,625,303	$337,903	$2,287,400
2014	Mar	$7,791,630	$1,188,555	$2,648,458	$325,081	$10,440,088	$1,513,636	$8,926,452
2014	Apr	$2,648,456	$525,691	$2,304,403	$390,583	$4,952,859	$916,275	$4,036,584
2014	May	$1,659,372	$483,967	$2,352,913	$315,944	$4,012,285	$799,911	$3,212,374
2014	Jun	$227,198	$73,258	$339,094	$45,015	$566,292	$118,273	$448,019
2014	Jul	$65,760	$37,224	$89,985	$29,854	$155,744	$67,078	$88,667
2014	Oct	$18,596	$17,636	$27,722	$4,700	$46,319	$22,336	$23,983
2014	Nov	$212,960	$122,832	$383,377	$183,679	$596,337	$306,511	$289,827
2014	Dec	$489,294	$377,915	$796,041	$353,137	$1,285,335	$731,052	$554,283
2015	Jan	$1,457,434	$959,319	$2,217,223	$907,259	$3,674,657	$1,866,578	$1,808,079
2015	Feb	$4,181,418	$2,220,539	$4,980,794	$1,721,693	$9,162,212	$3,942,232	$5,219,980
2015	Mar	$1,860,635	$1,144,575	$3,071,628	$1,259,422	$4,932,263	$2,403,997	$2,528,267
Total		$78,250,132	$15,653,612	$44,093,008	$7,197,428	$122,343,140	$22,851,041	$99,492,099

Figure 10-6 illustrates the impact of PJM's change effective in July 2014. Beginning January 2015, a new metric DGP (Degree of Generator Performance) was introduced to improve the accuracy of the tier 1 MW estimate used by the market solution.

Figure 10-6 Daily average tier 1 actual MW (credited) vs daily average estimated tier 1 MW, January 2014 through March 2015



Tier 1 Estimate Bias

PJM dispatch can apply tier 1 estimate bias to each element of the market solution software (ASO, IT-SCED, and RT-SCED). 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.

In 2015, PJM used tier 1 estimate biasing in the MAD subzone ASO and the RTO Zone ASO (Table 10-14). Tier 1 biasing is not used in any IT-SCED solutions.

Table 10-14 MAD subzone ASO tier 1 estimate biasing, January 2014 through March, 2015

Year	Month	Number of Hours Biased Negatively	Average Negative Bias (MW)	Number of Hours Biased Positively	Average Positive Bias (MW)
2014	Jan	13	(1,419.2)	2	250.0
2014	Feb	36	(1,036.1)	1	100.0
2014	Mar	37	(1,281.1)	4	500.0
2014	Apr	32	(1,387.5)	0	NA
2014	May	23	(909.8)	0	NA
2014	Jun	17	(1,179.4)	3	666.7
2014	Jul	36	(1,011.1)	0	NA
2014	Aug	31	(891.9)	1	750.0
2014	Sep	15	(1,206.7)	0	NA
2014	Oct	67	(1,285.8)	1	500.0
2014	Nov	193	(1,125.4)	6	475.0
2014	Dec	163	(1,238.9)	1	300.0
2015	Jan	51	(1,731.4)	6	600.0
2015	Feb	62	(1,641.1)	0	NA
2015	Mar	25	(794.0)	3	1,000.0
Total		801	(1,209.3)	28	514.2

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.

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 calculating 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 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 of consumption for demand resources) for each five minute interval times the five minute LMP plus $50 per MW.

In the first three months of 2015, tier 1 synchronized reserve synchronized reserve event response credits (Table 10-15) were paid during the seven spinning events. In the first three months of 2015, $123,337 was paid for 3,061 MW of tier 1 response at a cost per MW of $40.29.

Table 10-15 Tier 1 synchronized reserve event response costs: January 2014 through March 2015

Year	Month	Synchronized Reserve Event Response Hours	Total Tier 1 Synchronized Reserve Event Response MW	Total Tier 1 Synchronized Reserve Event Response Credits	Tier 1 Synchronized Reserve Event Response Cost	Average Tier 1 MW Response Per Event
2014	Jan	12	7,827.8	$965,846	$123.39	521.9
2014	Feb	1	273.2	$11,153	$40.82	273.2
2014	Mar	5	3,029.6	$175,902	$58.06	605.9
2014	Apr	2	389.1	$6,378	$16.39	194.5
2014	May	3	717.1	$34,906	$48.68	239.0
2014	Jun	0	NA	NA	NA	NA
2014	Jul	2	615.6	$35,179	$57.15	307.8
2014	Aug	0	NA	NA	NA	NA
2014	Sep	3	1,936.2	$143,574	$74.15	645.4
2014	Oct	2	1,131.7	$83,901	$74.14	565.8
2014	Nov	4	1,349.8	$38,895	$28.81	337.5
2014	Dec	3	692.0	$35,245	$50.96	230.5
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
All		44	21,023.5	$1,654,316	$78.69	477.8

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 ten minutes. Synchronized reserve is of two distinct types, tier 1 and tier 2. Tier 2 synchronized reserve is primary reserve (ten 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 energy price based 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 on-line resources, either synchronized to the grid but not producing energy, or dispatched to provide synchronized reserve at an operating point below their economic dispatch. 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

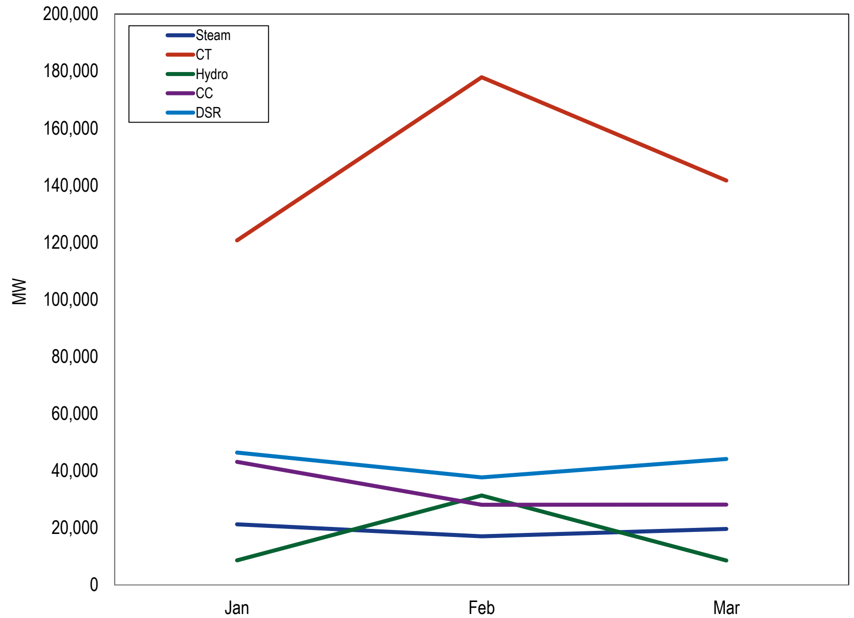
All non-emergency generating resources are required to submit tier 2 synchronized reserve offers. All online, non-emergency generating resources are deemed available to provide both tier 1 and tier 2 synchronized reserve. If PJM issues a primary reserve warning, voltage reduction warning, or manual load dump warning, all off line non-emergency generation capacity resources available to provide energy must submit an offer for tier 2 synchronized reserve.[12] This rule is intended to increase the accuracy of estimates of available synchronized reserve and primary reserve.

In the first three months of 2015, the Mid Atlantic Dominion subzone averaged 3,764.3 MW in synchronized reserve offers, and the RTO Zone averaged 10,488.8 MW of synchronized reserve offers (Figure 10-11).

The supply of tier 2 synchronized reserve in the first three months of 2015 was sufficient to cover the requirement in both the RTO Reserve Zone and the Mid-Atlantic Dominion Reserve subzone. In addition the availability of on-line resources was sufficient to meet the synchronized reserve requirement and shortage pricing was not reached.

The largest portion of cleared tier 2 synchronized reserve in the first three months of 2015 is from CTs, 58.8 percent of all tier 2 synchronized reserve MW. Demand resources remain a significant part of market scheduled tier 2 synchronized reserve. Although demand resources are limited to 33 percent of the 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 12.4 percent in the first three months of 2015.[13] This is a reduction of 29.9 percent from the DR MW share of 17.7 percent of all cleared tier 2 synchronized reserve in the first three months of 2014.

Figure 10-7 Cleared Tier 2 Synchronized Reserve by unit type, full RTO Zone: January through March 2015



Demand

Effective January 1, 2015, the synchronized reserve requirement was increased to 1,342 MW in the Mid-Atlantic Dominion subzone, and remained at 1,375 MW in the RTO Zone. Effective January 8, 2015, the synchronized reserve requirement was increased to 1,450 MW in both the Mid-Atlantic Dominion subzone and the RTO Zone (Table 10-16). There are two circumstances in

12 See PJM. "Manual 11: Energy and Ancillary Services Market Operations" Revision 73, (April 1, 2015), p. 63.

13 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.

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 13: Emergency Operations) 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.[14] In January through March 2015 PJM declared 27 Cold Weather Alerts raising the synchronized reserve requirement from 1,450 MW to 1,700 for 606 hours.

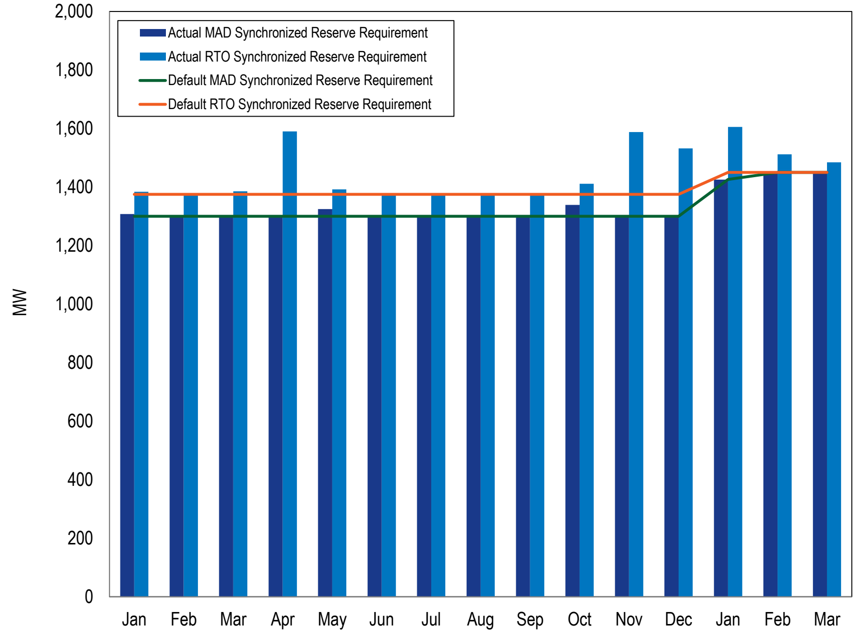
Table 10-16 Default Tier 2 Synchronized Reserve Markets required MW, RTO Zone and Mid-Atlantic Dominion Subzone

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 change the synchronized reserve requirement from its default value (Figure 10-1) when grid maintenance or outages change the largest contingency. In the first three months of 2015, PJM increased the synchronized reserve requirement in 38 hours in the RTO Reserve Zone (Figure 10-8) because of grid outages. The average actual synchronized reserve requirement in the MAD subzone was 1,460.4 MW. The average actual synchronized reserve requirement in the RTO Reserve Zone was 1,534.7 MW.

14 PJM Manual 13 Emergency Operations, Rev 56 June 1, 2014, p. 57.

Figure 10-8 Monthly average actual vs default synchronized reserve requirements, RTO and MAD: January 2014 through March 2015



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.

In the RTO Reserve Zone, 44.4 percent of hours cleared a Tier 2 Synchronized Reserve Market in the first three months of 2015 averaging 389.9 MW. This compares with 20.3 percent of hours averaging 714.2 MW in the first three months of 2014. In the MAD Reserve Subzone, 53.6 percent of hours cleared a Tier 2 Synchronized Reserve Market in the first three months of 2015 averaging 265.7 MW. This compares with 65.4 percent of hours cleared, averaging 631.9 MW in 2013.

Figure 10-9 and Figure 10-10 show the average monthly synchronized reserve required and the average monthly tier 2 synchronized reserve MW scheduled in from January 2014 through March 2015, for the RTO Zone and MAD subzone. The month of January 2014 was unusual in that much more tier 2 synchronized reserve was cleared than prior years. As a result of the extreme weather and reserve shortages on the cold weather days, which reduced the tier 1 available, the dispatchers biased the tier 1 estimate down. The hour ahead tier 1 estimate was biased in 147 hours between the first three months of 2015, with an average negative bias of (1,389) MW per hour. This compares with 93 hours in the first three months of 2014 and an average negative bias of 1,246 MW.

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

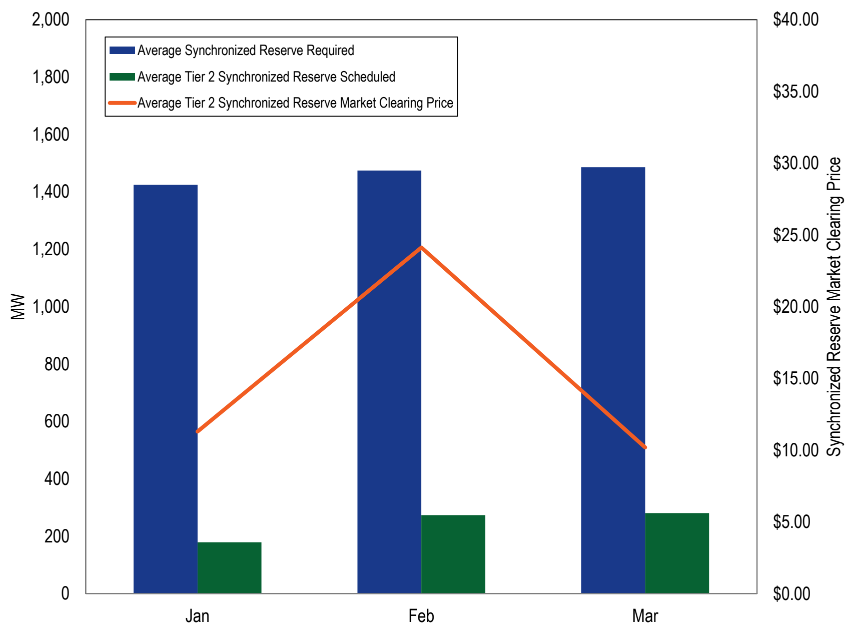
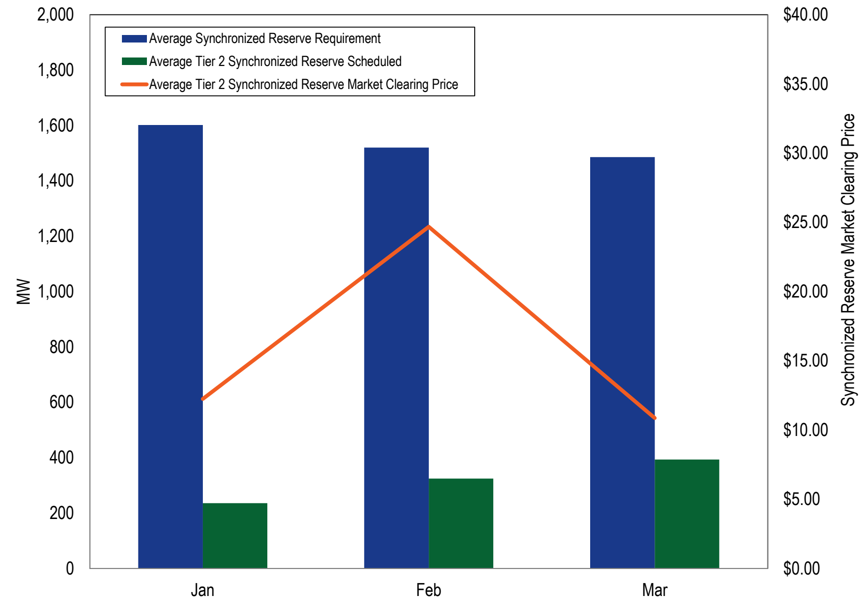


Figure 10-10 RTO Reserve zone monthly average synchronized reserve required vs. tier 2 synchronized reserve scheduled MW: January 2015 through March 2015



Market Concentration

The HHI for all settled tier 2 synchronized reserve during cleared hours of the Mid-Atlantic Dominion subzone Tier 2 Synchronized Reserve Market from the first three months of 2015 was 4357, which is defined as highly concentrated. This is a slight increase from the 4236 HHI of the first three months of 2014. The largest hourly market share was 100 percent and 62.3 percent of all 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 three months of 2015 was 5123, which is defined as highly concentrated. The largest hourly market share was 100 percent and 77.6 percent of hours had a maximum market share greater than or equal to 40 percent.

In the MAD subzone, flexible synchronized reserve was 9.4 percent of all tier 2 synchronized reserve in the first three months of 2015. In the RTO Zone, flexible synchronized reserve assigned was 9.0 percent of all tier 2 synchronized reserve in the first three months of 2015.

The MMU calculates that 56.2 percent of hours failed the three pivotal supplier test in the MAD subzone from January through March 2015 for the inflexible synchronized reserve market (excluding self-scheduled synchronized reserve) in the hour ahead market (Table 10-17) and 35.0 percent of hours failed a three pivotal supplier test in the RTO Zone from the first three months of 2015.

Table 10-17 Three Pivotal Supplier Test Results for the RTO Zone and MAD Subzone: January 2014 through March 2015

Year	Month	Mid Atlantic Dominion Reserve Subzone Pivotal Supplier Hours	RTO Reserve Zone Pivotal Supplier Hours
2014	Jan	90.7%	72.7%
2014	Feb	46.6%	22.6%
2014	Mar	37.9%	17.3%
2014	Apr	31.9%	51.6%
2014	May	22.3%	44.0%
2014	Jun	31.5%	31.3%
2014	Jul	41.6%	16.2%
2014	Aug	21.2%	17.6%
2014	Sep	25.0%	24.5%
2014	Oct	53.2%	71.8%
2014	Nov	56.4%	51.7%
2014	Dec	37.5%	48.6%
2015	Jan	43.2%	33.3%
2015	Feb	85.6%	28.2%
2015	Mar	39.8%	43.4%
	Average	44.3%	38.3%

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

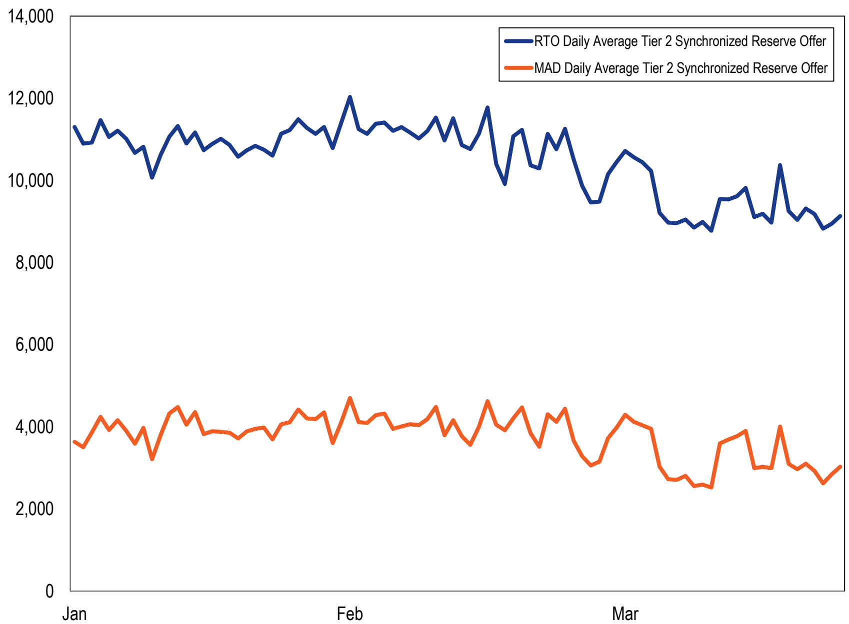
Offers

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 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 includes the synchronized reserve offer quantity (MW). The offer quantity is limited to the economic maximum or less if a spin maximum value 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 ten 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, 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 three months of 2015, the ratio of on-line and eligible tier 2 synchronized reserve to synchronized reserve required in the Mid-Atlantic Dominion subzone was 2.58 averaged over all hours. For the RTO Synchronized Reserve Zone the ratio was 6.84.

After October 1, 2012, PJM adopted a new rule creating a must offer requirement for synchronized reserve for all generation that is online, non-emergency, and available to produce energy. Changes to hourly and daily offer levels are the result of on-line status, minimum/maximum runtimes, minimum notification times, maintenance status and grid conditions including constraints.

Figure 10-11 Tier 2 synchronized reserve daily average offer and eligible volume (MW): January through March 2015



Synchronized reserve is offered by steam, CT, CC, hydroelectric and DR resources. 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 March, 2013 through 2015

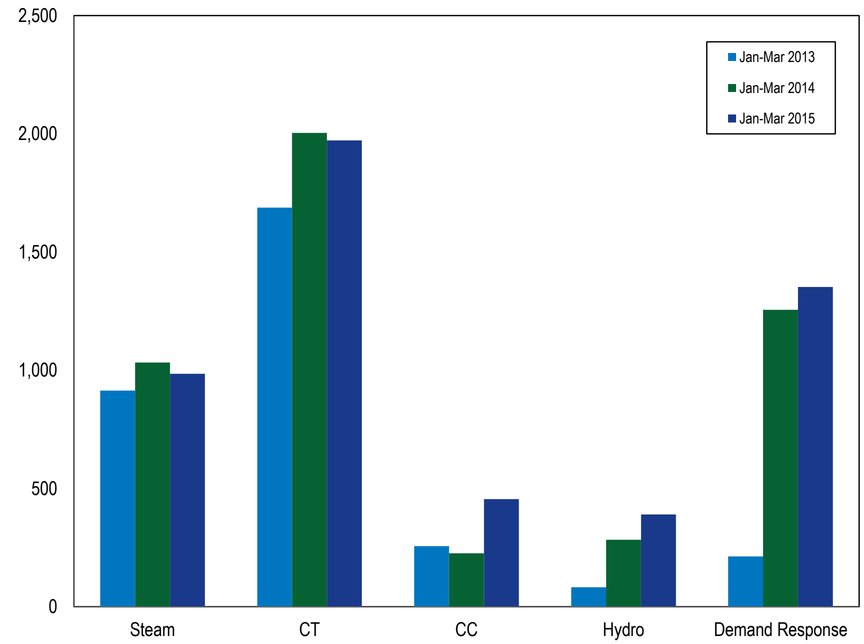
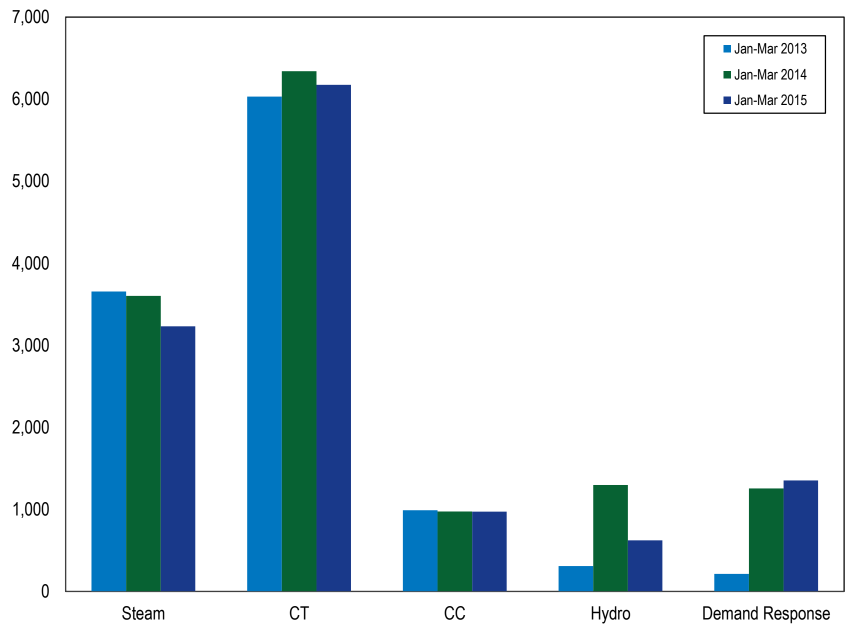


Figure 10-13 RTO Zone average daily tier 2 synchronized reserve offer by unit type (MW): January through March 2013 through 2015



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.

The MAD subzone cleared a Tier 2 Synchronized Reserve Market averaging 314.1 MW (including self-scheduled) with a price greater than $0 in 59.8 percent of hours in the first three months of 2015, compared to 74.1 percent of hours in the first three months of 2014.

The RTO Zone cleared a Tier 2 Synchronized Reserve Market averaging 173.7 MW (including self-scheduled) with a price greater than $0 in 52.3 percent of hours in the first three months of 2015.

In the first three months of 2015, the weighted average Tier 2 synchronized reserve market clearing price in the MAD subzone for all cleared hours was $16.34. In the first three months of 2014, the weighted average synchronized reserve market clearing price in the MAD subzone was $25.33.

In the first three months of 2015, the weighted average Tier 2 Synchronized Reserve Market clearing price in the full RTO Zone for all cleared hours was $16.53. In the first three months of 2014, the weighted average synchronized reserve market clearing price in the RTO Zone was $44.67.

Supply, performance, and demand are reflected in the price of synchronized reserve (Figure 10-9 and Figure 10-10). In February 2015, cold weather meant that on-line resources which are jointly optimized with synchronized reserve were generating at or near their economic maximum. As a result, tier 2 synchronized reserve was more expensive.

Table 10-18 Mid-Atlantic Dominion Subzone, weighted SRMCP and cleared MW (excludes self-scheduled): January through March 2015

Year	Month	Weighted Average Tier 2 Synchronized Reserve Market Clearing Price	Average Hourly Tier 1 Synchronized Reserve Estimated Hour Ahead (MW)	Average Hourly Demand Response Cleared (MW)	Average Tier 2 Generation Synchronized Reserve Cleared (MW)
2015	Jan	$11.29	1,218.9	63.7	142.8
2015	Feb	$24.12	1,179.5	46.3	224.3
2015	Mar	$11.81	1,196.2	60.8	228.7

Table 10-19 RTO zone weighted SRMCP and cleared MW (excludes self-scheduled): January through March 2015

Year	Month	Weighted Average Tier 2 Synchronized Reserve Market Clearing Price	Average Hourly Tier 1 Synchronized Reserve Estimated Hour Ahead (MW)	Average Hourly Demand Response Cleared (MW)	Average Tier 2 Generation Synchronized Reserve Cleared (MW)
2015	Jan	$12.24	1,417.5	63.7	123.7
2015	Feb	$24.68	1,618.3	46.3	35.4
2015	Mar	$12.37	1,285.0	60.8	140.0

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 three months of 2015, the price to cost ratio of the full RTO Zone Tier 2 Synchronized Reserve Market averaged 54.0 percent (Table 10-20); the price to cost ratio of the RTO Zone excluding MAD averaged 54.2 percent; the price to cost ratio of the MAD subzone averaged 53.9 percent.

Table 10-20 Full RTO, RTO, Mid-Atlantic Subzone Tier 2 synchronized reserve MW, credits, price, and cost: January through March 2015

Tier 2 Synchronized Reserve Market	Year	Month	Total MW	Total Credits	Weighted Synchronized Reserve Market Clearing Price	Cost	Price / Cost Ratio
Full RTO Zone	2015	Jan	225,741	$5,090,077	$12.24	$22.55	54.3%
Full RTO Zone	2015	Feb	272,371	$12,065,569	$24.68	$44.30	55.7%
Full RTO Zone	2015	Mar	301,564	$7,323,630	$12.37	$24.29	50.9%
Full RTO Zone	2015	Total	799,676	$24,479,277	$16.53	$30.61	54.0%
RTO Only	2015	Jan	81,527	$1,635,137	$13.91	$20.06	69.4%
RTO Only	2015	Feb	63,834	$3,324,613	$26.51	$52.08	50.9%
RTO Only	2015	Mar	104,025	$2,835,300	$13.44	$27.26	49.3%
RTO Only	2015	Total	249,386	$7,795,050	$16.94	$31.26	54.2%
MAD Subzone	2015	Jan	144,214	$3,454,940	$11.29	$23.96	47.1%
MAD Subzone	2015	Feb	208,536	$8,740,957	$24.12	$41.92	57.5%
MAD Subzone	2015	Mar	197,540	$4,488,330	$11.81	$22.72	52.0%
MAD Subzone	2015	Total	550,290	$16,684,227	$16.34	$30.32	53.9%

Compliance

The MMU has identified and quantified the failure of scheduled tier 2 synchronized reserve resources to deliver during synchronized reserve events since 2011.[15] 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 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.[16] Tier 2 resources are obligated to sustain their final output for the shorter of the length of the event or 30 minutes.[17]

The MMU has reported the wide range of synchronized reserve event response levels and recommended that PJM take action to increase compliance rates. An enhanced penalty structure became effective January 1, 2014. Penalties

15 See the *2011 State of the Market Report for PJM*, Volume II, Section 9, "Ancillary Services" at pg. 250.
16 See PJM, "Manual 11, Energy & Ancillary Services Market Operations," Rev. 73, April 1, 2015 4.2.12 Non-Performance, p. 76.
17 See PJM, "Manual 11, Energy & Ancillary Services Market Operations," Rev. 73, April 1, 2015 4.2.11 Non-Performance, p. 76.

can be assessed for any synchronized reserve event greater than 10 minutes during which flexible or inflexible synchronized reserve was scheduled either by the resource owner or by PJM. In 2014, 20 synchronized reserve events occurred that met these criteria.

Table 10-21 Synchronized reserve events greater than 10 minutes, Tier 2 Response Compliance, RTO Reserve Zone: January through March 2015

2015 Qualifying Synchronized Reserve Event (DD-Mon-YYYY HR)	Event Duration (Minutes)	Total Scheduled Tier 2 MW	Tier 2 Response MW	Percent T2 Compliance
03-Mar-2015 17	11	88.1	49.9	56.6%
16-Mar-2015 10	24	99.2	72.1	72.7%
17-Mar-2015 23	17	70.0	66.0	94.3%
23-Mar-2015 23	15	68.4	51.5	75.3%

Tier 1 resource owners are credited for the amount of synchronized reserve they provide in response to a synchronized reserve event.[18] 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 ten minutes or longer that occurred in the first three months of 2015, 26.5 percent of all scheduled tier 2 synchronized reserve MW were not delivered and were penalized (Table 10-21). In addition, a 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.[19] Resource owners are permitted to aggregate the response of multiple units to offset an underresponse from one unit with an overresponse from a different unit for the purpose of reducing an underresponse penalty. The average number of days between events calculated by PJM Performance Compliance for 2015 is 13 days.[20]

History of Synchronized Reserve Events

Synchronized reserve is designed to provide relief for disturbances.[21] 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. The 56 minute synchronized reserve event of March 27, 2014 was to supply reactive transfer voltage support. Long spinning events of 49, 56 and 68 minutes in 2014 are indicative of either an inadequate supply of primary reserve or the use of primary reserve when secondary reserve would be more appropriate. 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. The risk of using synchronized reserves for energy or any non-disturbance 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 a secondary reserve is the appropriate response.

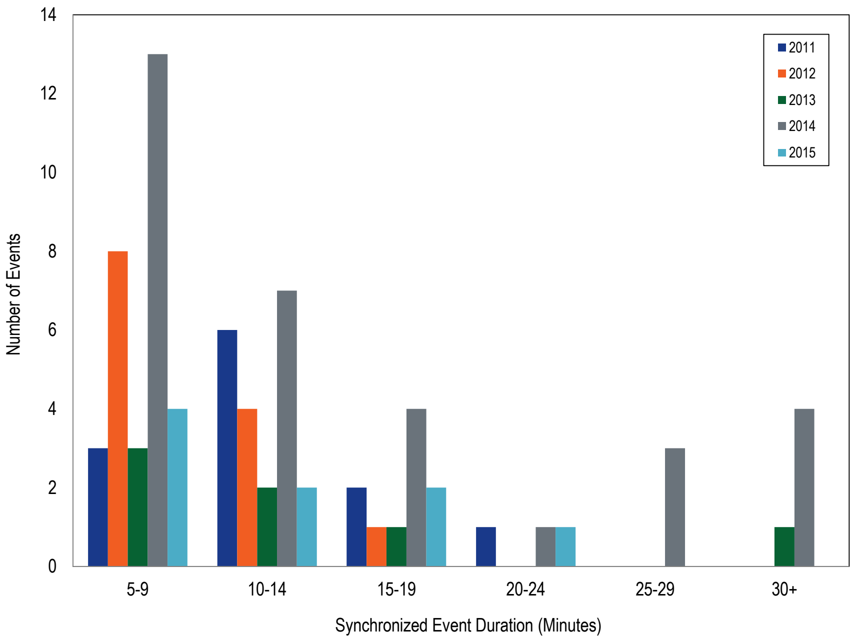
Synchronized reserve events (Table 10-22) are usually caused by a sudden generation outage or transmission disruption (disturbance) requiring PJM to load synchronized reserve.[22] PJM also calls synchronized reserve events for non-disturbance events, which it characterizes as "low ACE." The reserve remains loaded until system balance is recovered. From January 2010 through March 2015, PJM experienced 159 synchronized reserve events, approximately three events per month. Synchronized reserve events had an average length of 13 minutes.

18 See PJM, "Manual 11, Energy & Ancillary Services Market Operations," Rev. 73, April 1, 2015 4.2.12 Non Performance, p. 76.
19 See PJM "M-28 Operating Agreement Accounting," Rev. 67, January 1, 2015, p. 44. See also "Manual 11, Energy & Ancillary Services Market Operations," Rev. 71, January 1, 2015 4.2.12 Non-Performance, p. 76.
20 Report to PJM Operating Committee, "Synchronized Reserve Event Performance and Penalty Days," Dec 3, 2014
21 *2013 State of the Market Report for PJM*, Appendix F – PJM's DCS Performance, pp 451-452.
22 See PJM, "Manual 12, Balancing Operations," Revision 31 (August 21, 2014), 4.1.2 Loading Reserves pp. 36.

Table 10-22 Synchronized reserve events, January 2010 through March 2015

Effective Time	Region	Duration (Minutes)	Effective Time	Region	Duration (Minutes)	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	JAN-06-2014 22:01	RTO	68	JAN-07-2015 22:36	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	JAN-07-2014 02:20	RTO	25	FEB-24-2015 02:51	RTO	5
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	JAN-07-2014 04:18	RTO	34	FEB-26-2015 15:20	RTO	6
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	JAN-07-2014 11:27	RTO	11	MAR-03-2015 17:02	RTO	11
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	JAN-07-2014 13:20	RTO	41	MAR-16-2015 10:25	RTO	24
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	JAN-10-2014 16:46	RTO	12	MAR-17-2015 23:34	RTO	17
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	JAN-21-2014 18:52	RTO	6	MAR-23-2015 23:44	RTO	15
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	JAN-22-2014 02:26	RTO	7			
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	JAN-22-2014 22:54	RTO	8			
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	JAN-25-2014 05:22	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	JAN-26-2014 17:11	RTO	6			
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	JAN-31-2014 15:05	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	FEB-02-2014 14:03	Dominion	8			
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	FEB-08-2014 06:05	Dominion	18			
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	FEB-22-2014 23:05	RTO	7			
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	MAR-01-2014 05:18	RTO	26			
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	MAR-05-2014 21:25	RTO	8			
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	MAR-13-2014 20:39	RTO	8			
SEP-15-2010 11:20	RFC	13	MAY-31-2011 16:36	RFC	27	OCT-30-2012 05:12	RTO	14				MAR-27-2014 10:37	RTO	56			
SEP-22-2010 15:28	Mid-Atlantic	24	JUN-03-2011 14:23	RFC	7	NOV-25-2012 16:32	RTO	12				APR-14-2014 01:16	RTO	10			
OCT-05-2010 17:20	RFC	10	JUN-06-2011 22:02	Mid-Atlantic	9	DEC-16-2012 07:01	RTO	9				APR-25-2014 17:33	RTO	6			
OCT-16-2010 03:22	Mid-Atlantic	10	JUN-23-2011 23:26	RFC	8	DEC-21-2012 05:51	RTO	7				MAY-01-2014 14:18	RTO	13			
OCT-16-2010 03:25	RFCNonMA	7	JUN-26-2011 22:03	Mid-Atlantic	10	DEC-21-2012 10:29	RTO	5				MAY-03-2014 17:11	RTO	13			
OCT-27-2010 10:35	RFC	7	JUL-10-2011 11:20	RFC	10							MAY-14-2014 01:36	RTO	5			
OCT-27-2010 12:50	Mid-Atlantic	10	JUL-28-2011 18:49	RFC	12							JUL-08-2014 03:07	RTO	9			
NOV-26-2010 14:24	RFC	13	AUG-02-2011 01:08	RFC	6							JUL-25-2014 19:19	RTO	7			
NOV-27-2010 11:34	RFC	8	AUG-18-2011 06:45	Mid-Atlantic	6							SEP-06-2014 13:32	RTO	18			
DEC-08-2010 01:19	RFC	11	AUG-19-2011 14:49	RFC	5							SEP-20-2014 23:42	RTO	14			
DEC-09-2010 20:07	RFC	5	AUG-23-2011 17:52	RFC	7							SEP-29-2014 10:08	RTO	15			
DEC-14-2010 12:02	Mid-Atlantic	24	SEP-24-2011 15:48	RFC	8							OCT-20-2014 06:35	RTO	15			
DEC-16-2010 18:40	Mid-Atlantic	20	SEP-27-2011 14:20	RFC	7							OCT-23-2014 11:03	RTO	27			
DEC-17-2010 22:09	Mid-Atlantic	6	SEP-27-2011 16:47	RFC	9							NOV-01-2014 06:50	RTO	9			
DEC-29-2010 19:01	Mid-Atlantic	15	OCT-30-2011 22:39	Mid-Atlantic	10							NOV-08-2014 02:08	RTO	8			
			DEC-15-2011 14:35	Mid-Atlantic	8							NOV-22-2014 05:27	RTO	21			
			DEC-21-2011 14:26	RFC	18							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 2015



Non-Synchronized Reserve Market

Non-synchronized reserve is reserve MW available within ten 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.

There are no offers for non-synchronized reserve. The market solution software evaluates all eligible resources and schedules them economically.

Startup time for non-synchronized reserve resources is not subject to testing. There is no non-synchronized reserve offer MW or offer price. 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 ten 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 software evaluates all eligible resources and schedules them economically. Examples of equipment that generally qualifies as non-synchronized reserve are run of river hydro, pumped hydro, combustion turbines, combined cycles and diesels.[23] In the first three months of 2015, an average of 490.0 MW of non-synchronized reserve was scheduled hourly as part of the primary reserve requirement in the Mid-Atlantic Dominion subzone. In the first three months of 2015, an

23 See PJM. "Manual 11, Energy & Ancillary Services Market Operations" Revision 73 (April 1, 2015), p. 79.

average of 537.1 MW of non-synchronized reserve was scheduled hourly in the RTO Zone.

CTs provided 35.4 percent and hydro 60.5 percent of cleared non-synchronized reserve MW in the first three months of 2015. The remaining 4.1 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 was highly concentrated. The supply of non-synchronized reserves in the RTO Zone was also highly concentrated.

Table 10-23 Non-synchronized reserve market HHIs: January through March 2015

Year	Month	Mid Atlantic Dominion HHI	RTO HHI
2015	Jan	3455	2232
2015	Feb	3749	2201
2015	Mar	3382	3754
2015	Average	3529	2729

Table 10-24 Non-synchronized reserve market pivotal supply test: January through March 2015

Year	Month	Mid Atlantic Dominion Three Pivotal Supplier Hours	RTO Three Pivotal Supplier Hours
2015	Jan	100.0%	98.0%
2015	Feb	95.0%	98.9%
2015	Mar	100.0%	95.8%
2015	Average	98.3%	97.6%

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 MAD subzone. The MAD subzone non-synchronized reserve market had a clearing price greater than zero in 523 (24.3 percent) hours in the first three months of 2015, at an average price of $11.39 per MW. The weighted non-synchronized reserve market clearing price for all hours in the MAD subzone, including cleared hours when the price was zero, was $2.76 per MW. The maximum clearing price was the shortage pricing non-synchronized reserve maximum of $189.24 per MW for four consecutive hours on February 20, 2015. Figure 10-16 shows the daily average hour ahead non-synchronized reserve market clearing price and average scheduled MW for the RTO Zone. The RTO Zone non-synchronized reserve market had a clearing price greater than zero in 501 (23.2 percent) hours in the first three months of 2015, at an average price of $10.66. The weighted non-synchronized reserve market clearing price for all hours in the RTO Zone including cleared hours when the price was zero, was $3.25.

Figure 10-15 Daily average MAD subzone Non-synchronized Reserve Market clearing price and MW purchased: January through March 2015

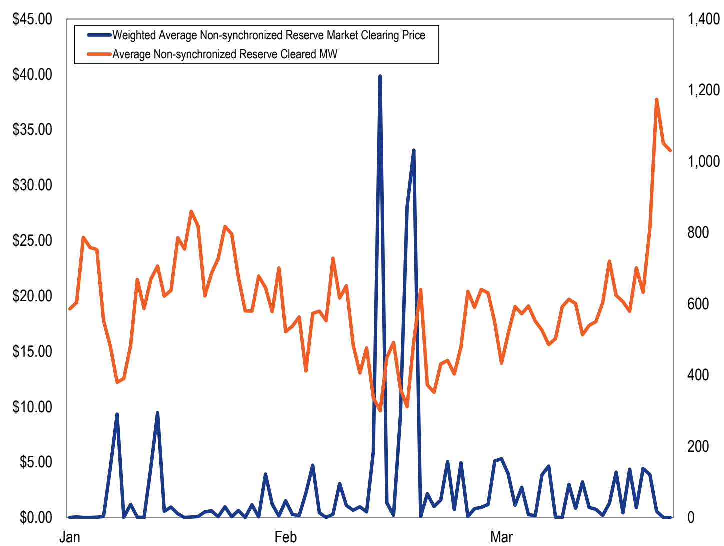
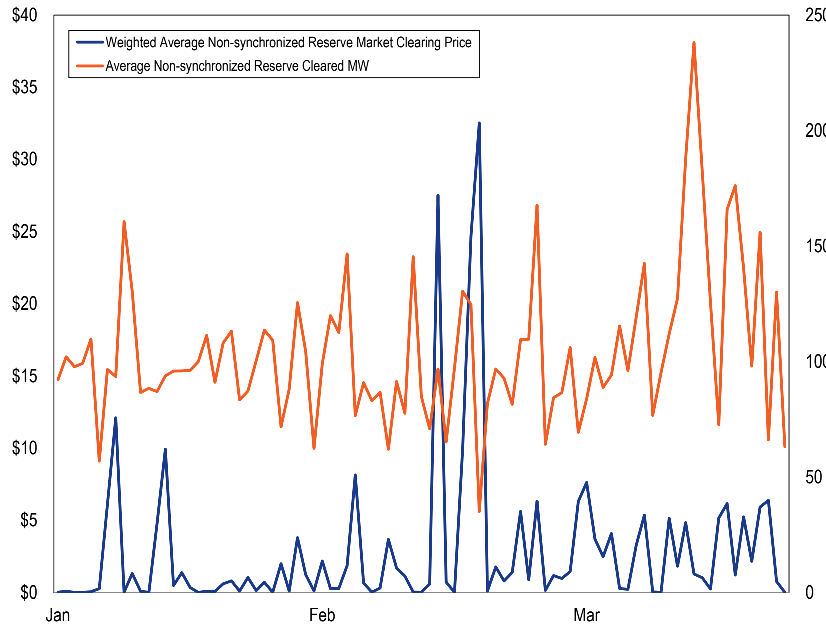


Figure 10-16 Daily average RTO Zone Non-synchronized Reserve Market clearing price and MW purchased: January through March 2015



Price and Cost

In satisfying the primary reserve requirement there is often a large supply of non-synchronized reserve available at zero cost. When the most economic next MW of primary reserve can be met by backing down a resource from its economic operating point for energy, the non-synchronized reserve market price is equal to the LOC of that resource and is greater than zero.

As a result of changing grid conditions, load forecasts, and unexpected generator performance, prices sometimes do not cover the full cost and final LOC for 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 10-25). 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 three months of 2015, the price to cost ratio of the full RTO Zone non-synchronized reserve market averaged 55.1 percent; the price to cost ratio of the RTO Zone excluding MAD averaged 60.3 percent; the price to cost ratio of the MAD subzone averaged 57.6 percent.

Table 10-25 Full RTO, RTO, Mid-Atlantic Subzone non-synchronized reserve MW, credits, price, and cost: January through March 2015

Market	Year	Month	Total Non-Synchronized Reserve MW	Total Non-Synchronized Reserve Charges	Weighted Non-Synchronized Reserve Market Clearing Price	Cost	Price/Cost Ratio
Full RTO Zone	2015	Jan	576,783	$669,152	$1.12	$2.13	52.7%
Full RTO Zone	2015	Feb	412,562	$1,688,422	$3.71	$6.81	54.5%
Full RTO Zone	2015	Mar	551,827	$832,808	$1.48	$2.51	58.7%
Total	2015		1,541,171	$3,190,382	$2.10	$3.82	55.1%
RTO Only	2015	Jan	347,716	$384,275	$1.11	$1.99	55.5%
RTO Only	2015	Feb	242,618	$857,026	$3.53	$5.66	62.4%
RTO Only	2015	Mar	331,903	$482,694	$1.45	$2.45	59.5%
Total	2015		922,237	$1,723,995	$2.03	$3.37	60.3%
MAD Subzone	2015	Jan	229,067	$284,877	$1.24	$2.34	53.2%
MAD Subzone	2015	Feb	169,944	$831,396	$4.89	$8.46	57.8%
MAD Subzone	2015	Mar	219,924	$350,114	$1.59	$2.62	60.9%
Total	2015		618,934	$1,466,387	$2.58	$4.47	57.6%

Secondary Reserve (DASR)

PJM maintains a day-ahead, offer based market for 30-minute secondary reserve.[24] The Day Ahead Scheduling Reserves Market (DASR) has no performance obligations. The MMU recommends elimination of the Day-Ahead Scheduling Reserve Market and its replacement with a Real-Time Market for a dispatchable reserve product beyond the 30-minute limit for primary reserves.

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

DASR 30-minute reserve requirements are determined by PJM for each reliability region.[25] In the Reliability*First* (RFC) region, secondary reserve requirements are calculated based on historical under-forecasted load rates and generator forced outage rates.[26] The RFC and Dominion secondary reserve requirements are added together to form a single RTO DASR requirement defined as a percentage of the daily peak load forecast, currently 5.93 percent. The requirement is applicable for all hours of the operating day. If the DASR Market does not result in procuring adequate scheduling reserves, PJM is required to schedule additional operating reserves.[27]

Market Structure

Supply

The amount of DASR available is the lesser of the energy ramp rate for all on-line units times thirty minutes, or the economic maximum minus the day-ahead dispatch point. For off-line resources capable of being online in thirty minutes, the DASR quantity is economic maximum. In the first three months of 2015, the average available hourly DASR was 38,116 MW. This is an 8.8 percent reduction from 41,787 MW of the first three months of 2014. On January 1, 2015 PJM began using economic maximum minus dispatch to calculate DASR. Before January 1, 2015 PJM had used emergency maximum minus dispatch to calculate DASR. The DASR MW purchased averaged 6,303 MW per hour for the first three months of 2015, a one percent increase from 6,245 MW per hour in the first three months of 2014. Although there was no shortage of DASR in the market solution, the market does not guarantee the availability of scheduled reserve during real time hours. Spinning events longer than 30 minutes while rare do occur (September 10, 2013, and March 27, 2014) when secondary reserve was needed but not enough was available in real time.

Market Concentration

In the first three months of 2015, no hours would have failed a three pivotal supplier test in the DASR Market. No hours would have failed the three pivotal supplier test in the first three months of 2014.

All generation resources are required to offer DASR.[28] 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 three months of 2015, six demand resources offered into the DASR Market.

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.[29] Units that do not offer have their offers set to $0.00 per MW.

Economic withholding remains an issue in the DASR Market. The direct marginal cost of providing DASR is zero. All offers greater than zero constitute economic withholding. As of March 31, 2015, 9.6 percent of resources offered DASR at levels above $5 per MW.

Market Performance

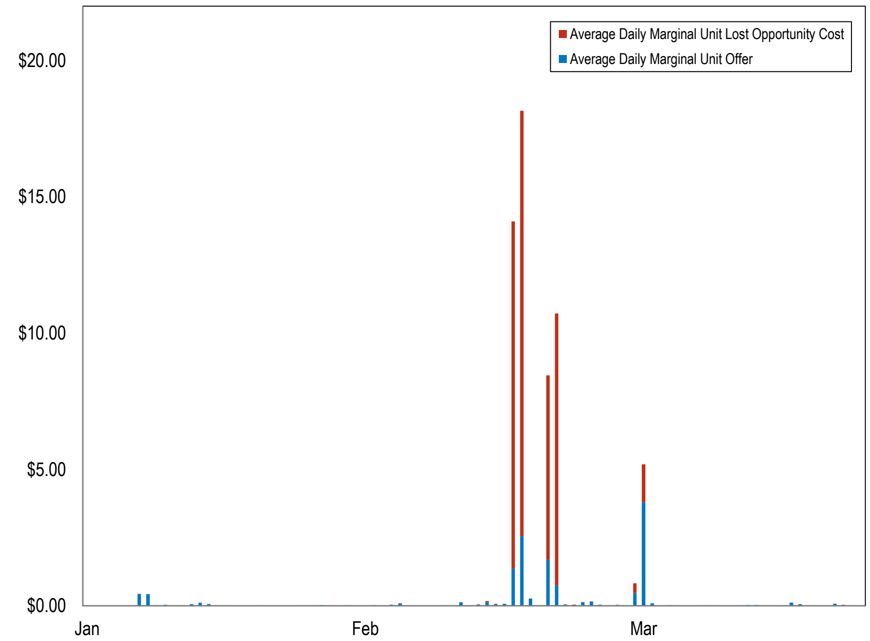
For 64.0 percent of hours in the first three months of 2015, DASR cleared at a price of $0.00 per MWh (Figure 10-17). This is a significant reduction from the 84.0 percent of hours that the DASR market cleared at $0 in the first three months of 2014. This change in the DASR offer MW from dispatch to emergency maximum to dispatch to economic maximum significantly reduced the amount of DASR offered by each resource. In the first three months of2015, the weighted average DASR price in all cleared hours was $0.76. The highest DASR price was $199.83 on February 19, 2015. DASR prices are calculated as the sum of the offer price plus the opportunity cost.

25 See PJM. "Manual 13, Emergency Requirements," Revision 57 (January 1, 2015), p. 11.
26 See PJM. "Manual 13, Emergency Requirements," Revision 57 (January 1, 2015), p. 11.
27 PJM uses the terms "supplemental operating reserves" and "scheduling operating reserves" interchangeably.
28 See PJM "Manual 11," Revision 71, (January 1, 2015) p. 142 at 11.2.3 Day-Ahead Scheduling Reserve Market Rules.
29 See PJM. "Manual 11, Emergency and Ancillary Services Operations," Revision 71 (January 1, 2015), p. 141.

Table 10-26 PJM Day-Ahead Scheduling Reserve Market MW and clearing prices: 2012 through March 2015

Year	Month	Average Required Hourly DASR (MW)	Minimum Clearing Price	Maximum Clearing Price	Weighted Average Clearing Price	Total DASR MW Purchased	Total DASR Credits
2012	Jan	6,944	$0.00	$0.02	$0.00	5,166,216	$604
2012	Feb	6,777	$0.00	$0.02	$0.00	4,716,710	$2,037
2012	Mar	6,180	$0.00	$0.05	$0.00	4,591,937	$5,031
2012	Apr	5,854	$0.00	$0.10	$0.00	4,214,993	$5,572
2012	May	6,491	$0.00	$5.00	$0.05	4,829,220	$226,881
2012	Jun	7,454	$0.00	$156.29	$2.39	5,366,935	$11,422,377
2012	Jul	8,811	$0.00	$155.15	$3.69	6,520,522	$20,723,970
2012	Aug	8,007	$0.00	$55.55	$0.51	5,956,318	$2,601,271
2012	Sep	6,656	$0.00	$7.80	$0.12	4,805,769	$540,586
2012	Oct	6,022	$0.00	$0.04	$0.00	4,454,997	$5,878
2012	Nov	6,371	$0.00	$1.00	$0.02	4,584,792	$75,561
2012	Dec	6,526	$0.00	$0.05	$0.00	5,179,876	$5,975
2013	Jan	6,965	$0.00	$2.00	$0.01	5,182,020	$45,337
2013	Feb	6,955	$0.00	$0.75	$0.00	4,673,491	$20,062
2013	Mar	6,543	$0.00	$1.00	$0.02	4,861,811	$75,071
2013	Apr	5,859	$0.00	$0.05	$0.00	4,218,720	$8,863
2013	May	6,129	$0.00	$23.37	$0.20	4,560,238	$873,943
2013	Jun	7,262	$0.00	$15.88	$0.12	5,228,554	$615,557
2013	Jul	8,129	$0.00	$230.10	$6.76	6,015,476	$37,265,364
2013	Aug	7,559	$0.00	$1.00	$0.01	5,623,824	$55,766
2013	Sep	6,652	$0.00	$119.62	$1.23	4,789,728	$5,245,835
2013	Oct	6,077	$0.00	$0.05	$0.00	4,497,258	$2,363
2013	Nov	6,479	$0.00	$0.10	$0.00	4,665,156	$5,123
2013	Dec	7,033	$0.00	$0.80	$0.01	5,232,625	$25,192
2014	Jan	6,218	$0.00	$534.66	$8.30	4,257,558	$35,349,968
2014	Feb	5,804	$0.00	$5.00	$0.05	3,604,087	$188,937
2014	Mar	5,303	$0.00	$3.00	$0.01	3,590,159	$47,749
2014	Apr	4,465	$0.00	$0.05	$0.00	3,304,943	$1,241
2014	May	5,531	$0.00	$0.10	$0.00	3,717,767	$7,386
2014	Jun	6,901	$0.00	$7.80	$0.04	4,236,399	$163,326
2014	Jul	6,865	$0.00	$0.25	$0.00	4,453,376	$9,358
2014	Aug	6,426	$0.00	$0.01	$0.00	1,631,617	$302
2014	Sep	6,596	$0.00	$0.04	$0.00	3,651,911	$2,444
2014	Oct	4,252	$0.00	$0.00	$0.00	3,163,787	$0
2014	Nov	4,803	$0.00	$0.01	$0.00	3,137,595	$577
2014	Dec	4,455	$0.00	$0.01	$0.00	3,314,871	$58
2015	Jan	4,636	$0.00	$10.00	$0.19	3,449,332	$141,561
2015	Feb	4,802	$0.00	$199.83	$3.92	3,226,918	$6,430,235
2015	Mar	3,972	$0.00	$24.82	$0.52	2,954,922	$730,429

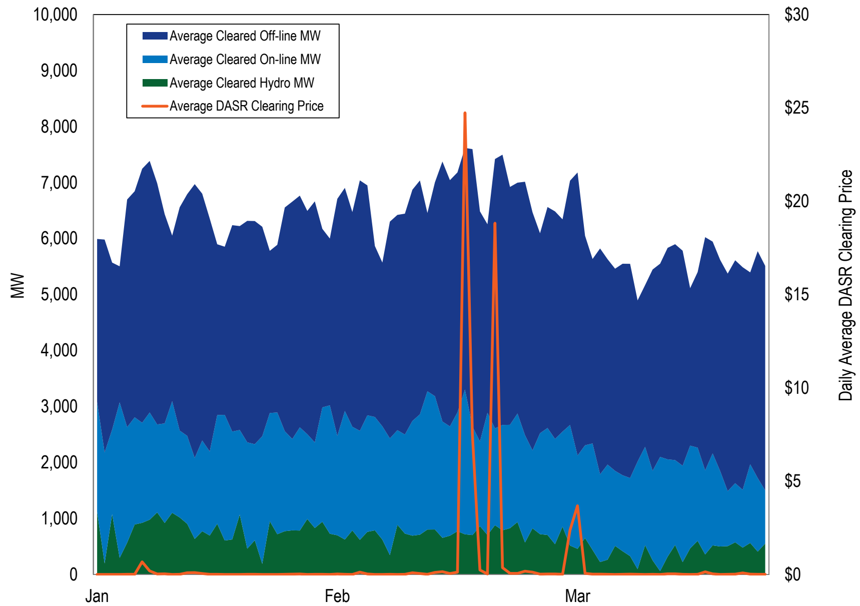
Figure 10-17 Daily average components of DASR clearing price ($/MW), marginal unit offer and LOC: January through March 2015



When energy demand is high the reserve requirement cannot be filled without redispatching online resources which significantly affects the price. Figure 10-17 shows the impact of LOC on price when online resources must be redispatched to satisfy the DASR requirement. DASR prices increase very suddenly at peak loads as a result of high LOCs.

DASR is filled by on-line, off-line, and hydro resources in a consistent proportion regardless of price (Figure 10-18).

Figure 10-18 Daily average DASR prices and MW by classification: January through March 2015



On September 10, 2013, a 68-minute synchronized reserve event was declared as a result of low ACE. On January 6, 2014, another 68-minute synchronized reserve event was declared, this time as the result of a unit trip. Different classes of reserve exist for different classes of imbalance. A 68-minute inability to bring ACE into balance with or without a sudden generator outage is the type of imbalance that 30-minute secondary reserve was created to recover from. On January 6, 2014, the average required DASR was 7,162 MW. On September 10, 2013, the 30-minute reserve requirement was 8,893 MW. Those required amounts of DASR were cleared day-ahead.

It is not clear why secondary reserve (DASR) was either unavailable to the dispatchers or was never called on the operating day when it was needed. PJM dispatch called on tier 1, tier 2, and non-synchronized reserve and was unable to restore balance for 68 minutes. It is not clear why the secondary reserve, already paid for, was not called or not callable.

The MMU recommends that PJM determine why secondary reserve was either unavailable or not dispatched on September 10, 2013, and January 6, 2014, and that PJM evaluate replacing the DASR Market with a real time secondary reserve product that is available and dispatchable in real time. PJM has conducted months of discussion, study, and analysis and proposed several changes to the DASR Market through its Energy/Reserve Pricing and Interchange Volatility (MIC) meeting. Those changes are scheduled to be implemented in Q2, 2015.

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 market. Significant technical and structural changes were made to the Regulation Market in 2012.[30]

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 function defining the substitutability between RegA and RegD must be correctly defined and consistently applied throughout the market construct, from optimization to settlement. That is not the case in PJM's current regulation market design.

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, but with limited ramp rates. RegD is PJM's fast-oscillation regulation signal and is designed for resources with the ability to quickly adjust energy output,

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

but with limited ability to sustain energy output for long periods of time. Resources must qualify to follow the RegA and RegD signals. Resources must qualify for one signal or both signals, but will be assigned by the market clearing engine to follow only one signal within a given market hour. The PJM Regulation Market design includes three clearing price components (capability, performance, and lost opportunity cost), the rate of substitution between RegA and RegD resources (marginal benefit factor) and a measure of the quality of response (performance score) by a regulation resource to a regulation signal.

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 ten 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.[31]

Performance scores measure the regulating response of individual resources, regardless of whether they were originally assigned or replaced (with notification) by a fleet owner. 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 designed 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 resources into a common unit of measure via a marginal benefit factor (MBF).[32] The marginal benefit factor is a measure of the substitutability of RegD resources for RegA resources in satisfying the regulation requirement. The marginal benefit factor and the performance score of the resource are used to convert RegA and RegD resource regulation capability MW into comparable units, termed effective MW. Resource-specific marginal benefit factors are defined for each resource separately while the market marginal benefit factor is the marginal benefit factor of the last RegD resource cleared in the market. Effective MW, supplied from RegA or RegD resources, are defined in terms of RegA MW. 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.

The marginal benefit factor defines the substitutability between RegA and RegD resources in meeting the regulation requirement. The effectiveness and efficiency of the regulation market depends on the marginal benefit factor function being defined by the actual tradeoff between RegA and RegD MW in providing regulation. If the marginal benefit factor function is incorrectly defined the resulting combinations of RegA and RegD would not represent the least cost solution.

PJM has stated that in 30 percent of peak hours in 2014, the proportion of RegD regulation being carried by PJM has negatively affected the provision

31 PJM "Manual 12: Balancing Operations" Rev. 31 (August 21, 2014); 4.5.6, p 52.

32 See the *2013 State of the Market Report for PJM*, Volume II, Section 10, "Issues Related to the Marginal Benefits Factor", pp. 294-8.

of regulation service.[33] PJM has observed issues with regulation performance when the proportion of effective MW from RegD resources exceeds 42 percent (equivalent to RegD of 23 percent or more of actual MW based on the current marginal benefit function).[34] The system issues are a result of PJM buying too much RegD as a proportion of total regulation. The issues also indicate that the marginal benefit factor function used by PJM is incorrectly describing the operational relationship between RegA and RegD. PJM's current marginal benefit factor function is, at least in some hours, overvaluing RegD as a substitute for RegA in the optimization.

The MMU recommends that the marginal benefit factor function used in the regulation market be reviewed as part of incorporating a consistent application of the marginal benefit factor in the regulation market.

The IMM has determined that the current market optimization/market solution does not correctly account for the amount of effective MW being provided by RegD. Rather than calculating the total effective MW contribution of RegD MW on the basis of the area under the marginal benefit function curve, the current regulation market optimization assigns all RegD resources with the same effective price the lowest marginal benefit factor associated with last RegD MW at that price.

The incorrect accounting of effective MW within the optimization construct will result in an inefficient combination of RegA and RegD and a purchase of more than the efficient level of RegD than necessary to meet PJM's defined regulation requirement.

This effect of this market flaw is exacerbated by a marginal benefit factor function that assigns too high a marginal benefit factor to RegD resources. Such a high marginal benefit factor will tend to make incremental effective MW from RegD resources look less expensive than incremental effective MW from RegA resources and the optimization will choose what appears to be the cheapest incremental effective MW for any additional MW required.

33 Fast Response Regulation (RegD) Resources Operational Impact Problem Statement, Presented at the May 5, 2015 Operating Committee. See <http://www.pjm.com/committees-and-groups/committees/oc.aspx>, accessed May 4, 2015.
34 Fast Response Regulation (RegD) Resources Operational Impact Problem Statement, Presented at the May 5, 2015 Operating Committee. See <http://www.pjm.com/committees-and-groups/committees/oc.aspx> , accessed May 4, 2015.

The effect of this market flaw on the amount of Reg D 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 appears as the cheapest source of incremental effective regulation MW.

The MMU recommends that PJM, as part of incorporating a consistent application of the marginal benefit factor in the regulation market, also correct the calculation of effective MW attributed to RegD MW in the regulation market solution.[35]

Figure 10-19 shows, by month, the average cleared RegD MW, the average cleared RegD MW with an effective price of $0.00 and average self scheduled RegD MW. The figure shows 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 2014 and March 2015.

35 See Fast Response Regulation (RegD) Resources Operational Impact Problem Statement and the IMM's Regulation Market Review presentation which were presented at the May 5, 2015 Operating Committee. See <http://www.pjm.com/committees-and-groups/committees/oc.aspx> , accessed May 4, 2015.

Figure 10-19 Average cleared RegD MW and average cleared RegD with an effective price of $0.00 by month: January 2014 through March 2015

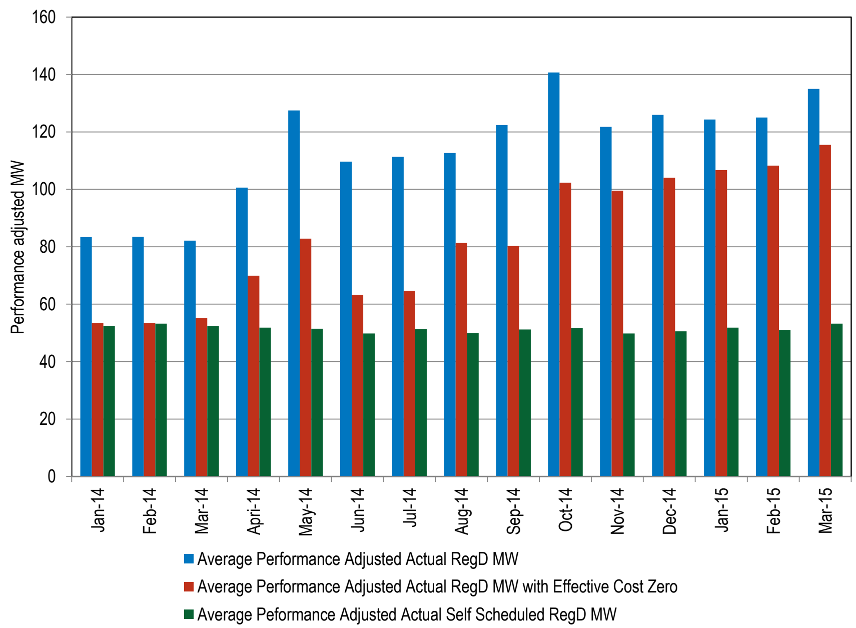


Figure 10-20 Average monthly peak effective MW: PJM market calculated versus benefit factor based

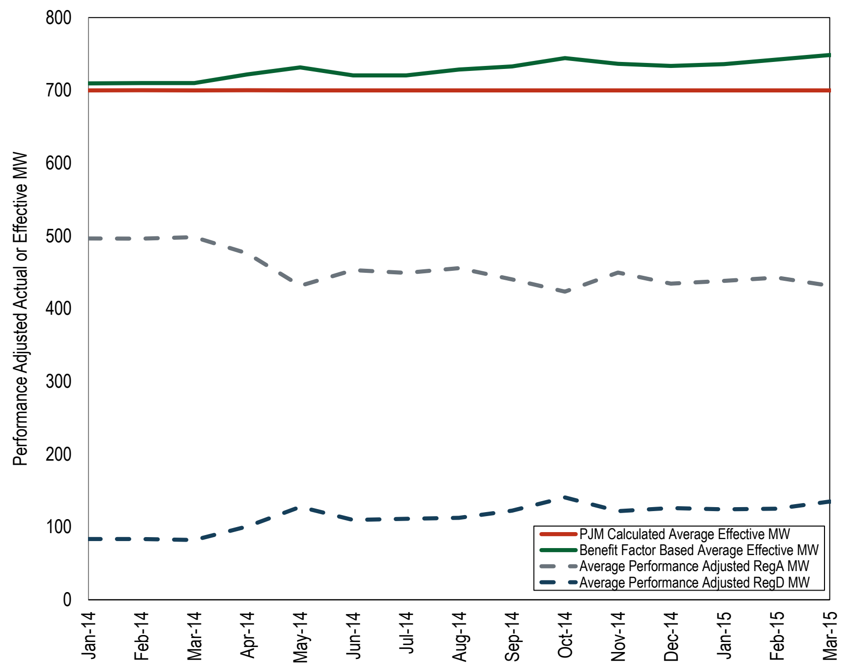
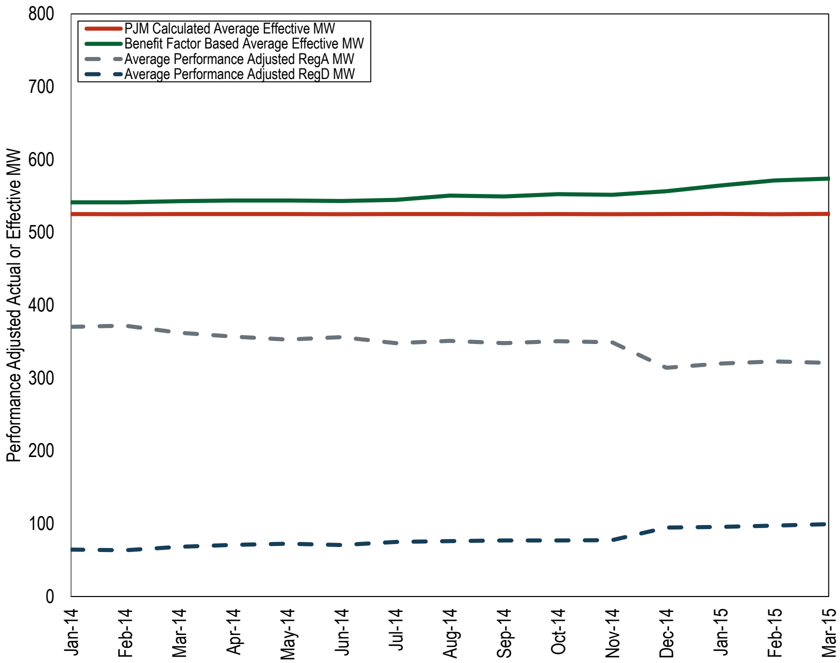


Figure 10-20 and Figure 10-21 show the average monthly peak (Figure 10-20) and off-peak (Figure 10-21) total effective MW as calculated by PJM's incorrect accounting method and total effective MW as calculated by a correctly applied marginal benefit factor function based method for the January 2014 through March 2015 period. The two figures also show the monthly average actual (performance adjusted) RegA MW and RegD cleared in the regulation market for the period. Based on the assumption that the current marginal benefit factor is correct, the figures show that due to PJM's calculation of effective MW from RegD resources, PJM has been clearing an increasing surplus of total effective MW. As shown in Figure 10-19 above, this has been caused by an increasing proportion of RegD MW supply with an effective price of $0.00 in the PJM market.

Figure 10-21 Off peak regulation summary statistics

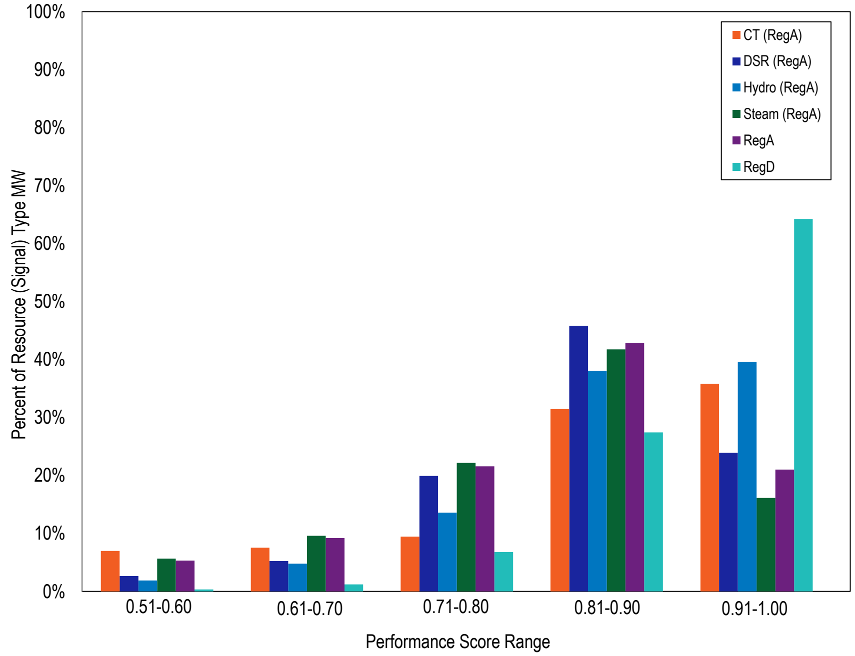


PJM posts clearing prices for the Regulation Market (RMCCP, RMPCP and RMCP) in dollars per unadjusted regulation capability MW. The regulation market clearing price (RMCP) for the hour is the simple average of the twelve five-minute RMCPs within the hour. The five-minute RMCP is the sum of the performance clearing price (RMPCP) and the capability clearing price (RMCCP). The performance clearing price ($/MW) is equal to the most expensive performance offer cleared for the hour. The capability clearing price ($/MW) is equal to the difference between the RMCP for the hour and the RMPCP for the hour.

Resources are paid by RMCP credits (the sum of RMCCP credits and RMPCP credits) and lost opportunity cost credits. RMCCP credits are calculated as MW of regulation capability times performance score times RMCCP. RMPCP credits are calculated as MW of regulation capability times performance score times RegD to RegA mileage ratio (RegD resources only) times RMPCP. RMCP credits are calculated as RMCCP credits plus RMPCP 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 10-22 shows the average performance score by resource type and signal followed for the first three months of 2015. In this figure, the MW used are unadjusted regulation capability MW and the performance score is the actual within hour (as opposed to the historic 100-hour moving average) performance score of the regulation resource. Each category (color bar) adds up to 100 percent so that the full performance score distribution for each resource (or signal) type is shown. Resources following the RegD signal tend to follow the RegD signal more closely than resources following the RegA signal follow the RegA signal. That is, RegD resources tend to have higher performance scores. As the figure shows, 64.3 percent of RegD resources have average performance scores within the 0.91-1.00 range, whereas only 21.0 percent of RegA resources have average performance scores within that range.

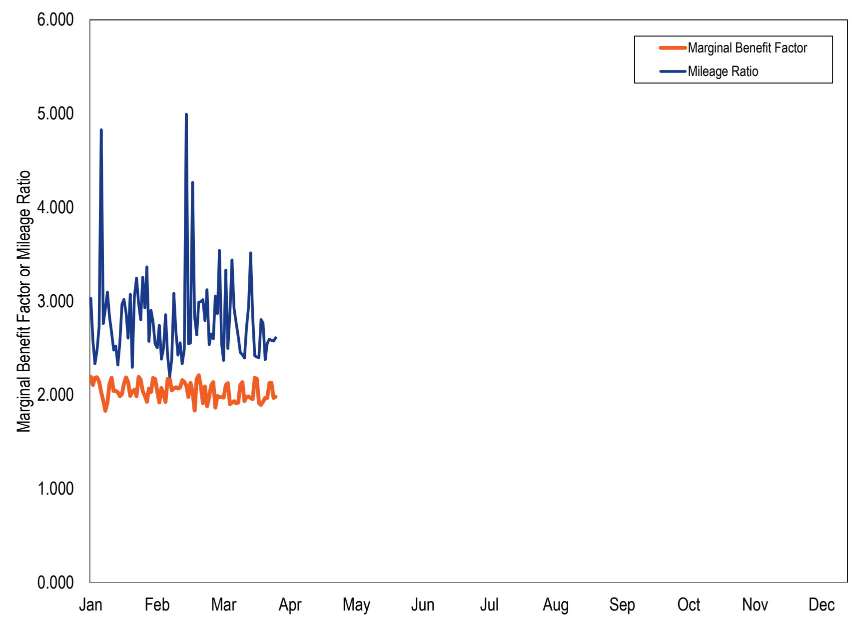
Figure 10-22 Hourly average performance score by unit type and regulation signal type: January through March 2015



From October 1, 2012, through October 31, 2013, PJM adhered to a FERC order that required the marginal benefit factor be fixed at one for settlement calculations only. As Figure 10-23 shows, the actual marginal benefit factor, as used in the optimization and commitment process for regulation in 2014, was always higher than one. The result of using a fixed marginal benefit factor of one was that resources following the RegD signal were underpaid relative to their value in the optimization. Resources following the RegD signal should have been paid the actual market marginal benefit factor times the amount that they were actually paid. The market marginal benefit factor should have been applied to the capability and the performance payments of RegD resources.

On October 2, 2013, 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 RegD to RegA mileage ratio in the performance credit paid to RegD resources, effective November 1, 2013, and retroactively to October 1, 2012.[36] As Figure 10-23 demonstrates, the RegD to RegA mileage ratio is generally higher than the actual marginal benefit factor and much more variable. In Figure 10-23 the mileage ratio is the actual hourly mileage ratio, calculated as the mileage provided by RegD resources divided by the mileage provided by RegA resources. The mileage multiplier has not brought total payment of RegD resources in line with RegA resources on a dollar per effective MW basis. This is, in part, due to the fact that the performance related price per MW of capability, which is the only part multiplied by the mileage ratio, is a relatively small portion of the total price per MW of capability.

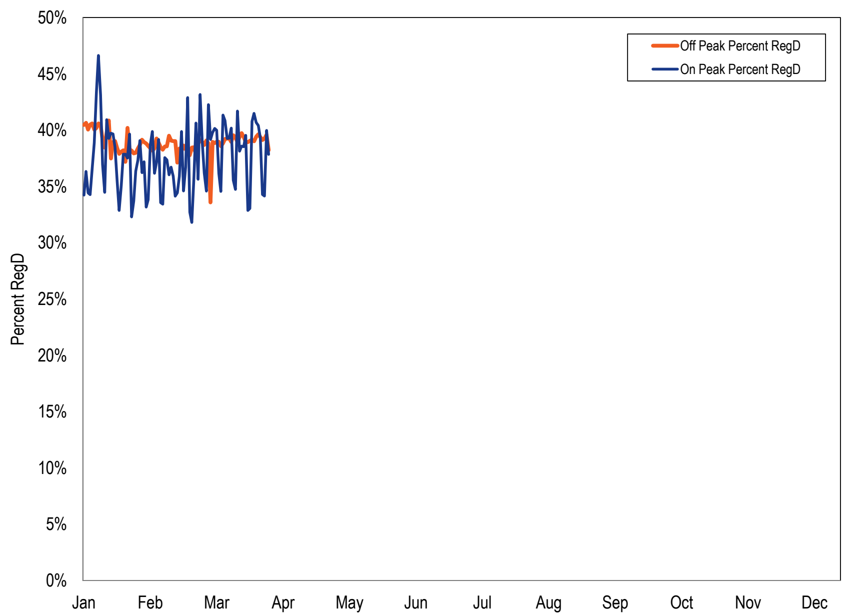
Figure 10-23 Daily average marginal benefit factor and mileage ratio: 2015



36 145 FERC ¶ 61,011 (2013).

The proportion of RegD resources used to satisfy the on peak regulation requirement (700 effective MW) has varied, as shown in Figure 10-24.

Figure 10-24 Daily average percent of RegD effective MW by peak: 2015



Market Structure

Supply

Table 10-27 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 2014. In this table, 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. A resource must be either generation or demand. But a resource can (and several resources currently do) choose to follow both signals. For that reason, the sum of each signal type's capability can exceed the full regulation capability.

Table 10-27 PJM regulation capability, daily offer and hourly eligible: 2015[37,38]

		By Resource Type		By Signal Type	
Metric	All Regulation	Generating Resources	Demand Resources	RegA Following Resources	RegD Following Resources
Capability MW	8,175.3	8,160.5	14.8	8,089.6	403.9
Offered MW	5,749.0	5,741.7	7.4	5,594.8	154.3
Actual Eligible MW	1,153.9	1,147.7	6.2	959.5	194.4
Effective Eligible MW	898.0	890.0	8.1	642.4	255.7
Actual Cleared MW	647.8	644.0	3.8	513.9	133.8
Effective Cleared MW	663.7	656.5	7.2	413.1	250.6

Total regulation capability MW provided by coal units increased slightly from 173,842 MW in the first three months of 2014 to 175,692 MW in the first three months of 2015, and the proportion of regulation provided by coal increased slightly from 17.1 percent of regulation in the first three months of 2014 to 17.9 percent of regulation in the first three months of 2015. Coal unit revenues were $12.8 million in the first three months of 2015, 46.7 percent of the $27.3 million in revenues in the first three months of 2014. The decrease in coal unit revenues was a result of the high regulation market clearing prices and out of market opportunity cost credits in January 2014. Table 10-28 provides monthly data on the number of coal units providing regulation, the scheduled regulation in MW provided by coal units, the total scheduled regulation in MW provided by all resources, the percent of scheduled regulation provided by coal units, and the total credits received by coal units. In Table 10-28, the MW have been adjusted by the actual within hour performance score since this adjustment forms the basis of payment for coal units providing regulation.

37 Average Daily Offer MW excludes units that have offers but are unavailable for the day.
38 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 10-28 PJM regulation provided by coal units

Year	Period	Number of Coal Units Providing Regulation	Adjusted Settled Regulation from Coal Units (MW)	Adjusted Settled Regulation from All Resources (MW)	Percent of Scheduled Regulation from Coal Units	Total Coal Unit Regulation Credits
2014	Jan	109	70,441	360,513	19.5%	$15,782,562
2014	Feb	102	51,033	309,976	16.5%	$4,690,694
2014	Mar	101	52,368	341,089	15.4%	$6,860,625
2015	Jan	81	49,199	343,557	14.3%	$2,052,287
2015	Feb	86	72,485	308,646	23.5%	$6,536,068
2015	Mar	69	54,008	342,961	15.7%	$4,171,676

The supply of regulation can be affected by regulating units retiring from service. Table 10-29 shows what the impact on the Regulation Market would be if all units retire that are requesting retirement through the end of 2015. These retirements will reduce the supply of regulation in PJM by less than one percent. The MW in Table 10-29 have been adjusted by the actual within-hour performance score.

Table 10-29 Impact on PJM Regulation Market of currently regulating units scheduled to retire through 2015

Current Regulation Units, 2015	Adjusted Settled MW, 2015	Units Scheduled To Retire Through 2015	Adjusted Settled MW of Units Scheduled To Retire Through 2015	Percent Of Regulation MW To Retire Through 2015
242	995,164	18	6,554	0.66%

Although the marginal benefit factor for slow (RegA) resources is 1.0, the effective MW of RegA following resources was lower than the offered MW in the first three months of 2015, because the average performance score was less than 1.00 (Figure 10-25). For the first three months of 2015, the MW-weighted average RegA performance score was 0.80 and there were 231 resources following the RegA signal.

In Figure 10-25 and Figure 10-26, effective MW are adjusted for the historic 100-hour moving average performance score and the resource-specific benefit factor and actual MW are unadjusted for either performance score or benefit factor. Whereas Figure 10-25 shows the results for effective MW, Figure 10-26 shows the results for actual MW. The MW values in both figures are monthly averages and the area for RegA is stacked on top of that for RegD such that the top of the stacked area is the monthly average clearing amount. The performance score values in both figures are monthly averages weighted by actual MW.

Figure 10-25 Monthly cleared effective MW and performance score by signal: 2015

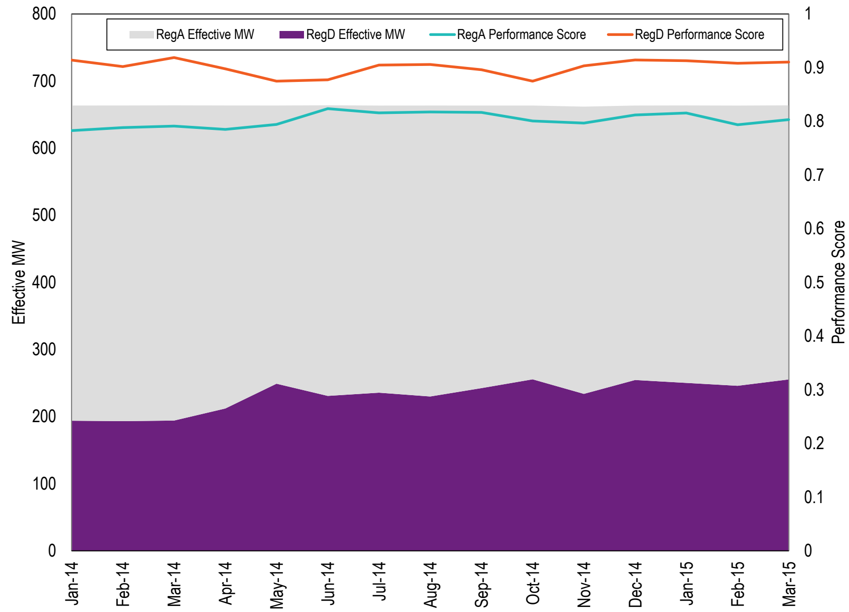
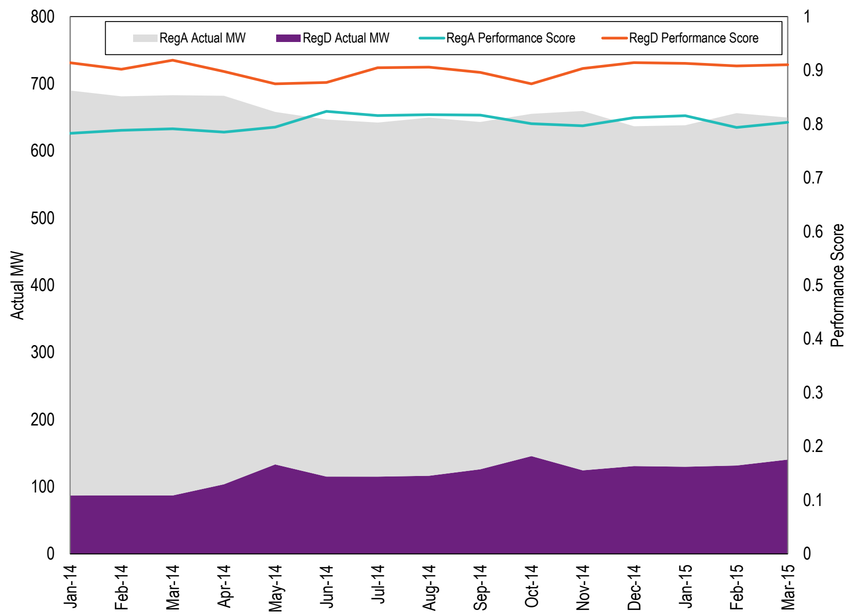


Figure 10-26 Monthly cleared actual MW and performance score by signal: 2015



For RegD resources, the effective MW are higher than the actual MW because their marginal benefit factor at current participation levels is greater than 1.0. In the first three months of 2015, the marginal benefit factor for cleared RegD following resources ranged from 0.895 to 2.441 with an average over all hours of 2.041. In the first three months of 2015, the MW-weighted average RegD resource performance score was 0.90 and there were 42 resources following the RegD signal.

The cost of each unit is calculated using its offer price, lost opportunity cost, capability MW, and the miles to MW ratio of the signal type offered, modified by resource marginal benefit factor and historic performance score. (The miles to MW ratio of the signal type offered is the historic 30-day moving average of requested mileage for that signal type per unadjusted regulation capability MW.)

As of October 1, 2012, a regulation resource's total offer is equal to the sum of its capability offer ($/MW) and performance offer ($/MW) and its estimated lost opportunity cost ($/MW). As of October 1, 2012, the within hour five minute clearing price for regulation is determined by the total offer, including the actual opportunity cost and any applicable benefit factor, of the most expensive cleared regulation resource in each interval.

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 10-37). In the first three months of 2015, the price and cost of regulation have remained high relative to prior years with the exception of 2014. The weighted average regulation price for the first three months of 2015 was $48.66/MW. The regulation cost for the first three months of 2015 was $59.15/MW. The ratio of price to cost is slightly lower (82 percent) than in the same period in 2014 (83 percent).

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 1, 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 the first three months of 2015.

Table 10-30 PJM Regulation Market required MW and ratio of eligible supply to requirement: January through March 2014 and 2015

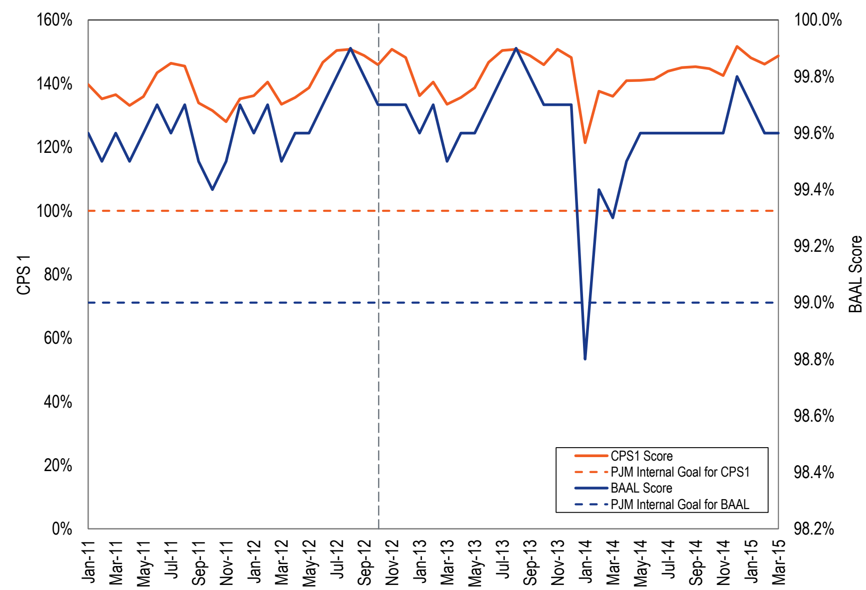
Month	Average Required Regulation (MW), 2014	Average Required Regulation (MW), 2015	Average Required Regulation (Effective MW), 2014	Average Required Regulation (Effective MW), 2015	Ratio of Supply MW to MW Requirement, 2014	Ratio of Supply MW to MW Requirement, 2015	Ratio of Supply Effective MW to Effective MW Requirement, 2014	Ratio of Supply Effective MW to Effective MW Requirement, 2015
Jan	690	638	664	664	2.05	1.86	1.60	1.35
Feb	681	656	664	663	2.00	1.75	1.51	1.37
Mar	683	650	664	664	1.99	1.73	1.48	1.35

Table 10-30 shows the average hourly required regulation by month and its relationship to the supply of regulation for both actual (unadjusted) and effective MW. The average hourly required regulation by month is an average across all of the hours in that month. The average hourly required effective MW of regulation is a weighted average of the requirement of 700 effective MW during peak hours and the requirement of 525 effective MW during off peak hours.

PJM's performance as measured by CPS1 and BAAL standards is shown in Figure 10-27 for every month from January 2011 through March 2015 with the dashed vertical line marking the date (October 1, 2012) of the implementation of the Performance Based Regulation Market design.[39] 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 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 10-27 PJM monthly CPS1 and BAAL performance: January 2011 through March 2015



39 See the *2014 State of the Market Report for PJM*, Appendix F: Ancillary Services.

Market Concentration

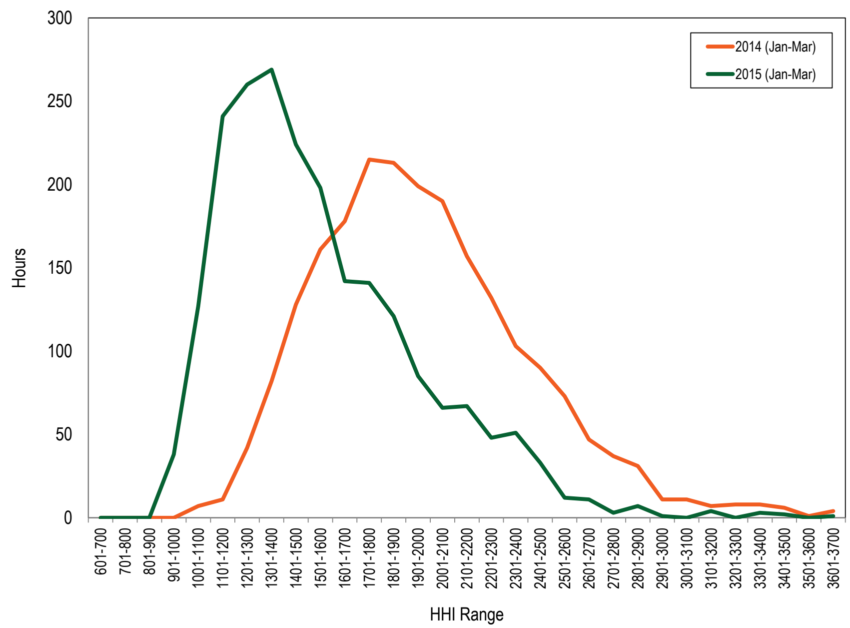
Table 10-31 shows Herfindahl-Hirschman Index (HHI) results for January through March 2014 and 2015, based on market shares of effective MW, defined as regulation capability MW adjusted by performance score and resource-specific benefit factor, consistent with the metrics used to clear the regulation market. The weighted average HHI of 1545 is classified as moderately concentrated and is lower than the HHI for the same period in 2014 of 1954. For the first three months of 2015, the weighted average HHI of RegA resources was 2508 (highly concentrated, but lower than the January through March 2014 value of 2859) and the weighted average HHI of RegD resources was 3073 (highly concentrated, but lower than the January through March 2014 value of 5280). The HHI of RegA resources and the HHI of RegD resources are both substantially higher than the HHI of the Regulation Market as a result of the fact that different owners have large market shares in the RegA and RegD markets.

Table 10-31 PJM cleared regulation HHI: 2014 and 2015

Year (Jan-Mar)	Minimum HHI	Weighted Average HHI	Maximum HHI
2014	1014	1954	3813
2015	909	1545	3656

Figure 10-28 compares the frequency distribution of HHI for January through March 2014 and 2015.

Figure 10-28 PJM Regulation Market HHI distribution: 2014 and 2015



The Regulation Market TPS test is calculated for each market hour. If an owner is pivotal, its resources are offer capped at the lower of their cost based or price based regulation offers.

Table 10-32 includes a monthly summary of three pivotal supplier results. In the first three months of 2015, 97 percent of hours had three or fewer pivotal suppliers. The impact of offer capping in the regulation market is limited because of the role of LOC in price formation (Figure 10-30).The MMU concludes from these results that the PJM Regulation Market in the first three months of 2015 was characterized by structural market power in 97 percent of hours.

Table 10-32 Regulation market monthly three pivotal supplier results: 2013 through 2015

Month	2013 Percent of Hours Pivotal	2014 Percent of Hours Pivotal	2015 Percent of Hours Pivotal
Jan	83%	97%	98%
Feb	82%	99%	96%
Mar	97%	95%	97%
Average	88%	97%	97%

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 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 non-steady state. For batteries and flywheels only, there is zero cost for lower efficiency. Instead, batteries and flywheels calculate an energy storage unit loss reflecting the net energy consumed to provide regulation service.[40]

Up until one hour before the operating hour, the regulating resource must input or, if already inputted, may change the following: 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.[41]

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 10-34).[42] 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.[43] Self scheduled regulation during on peak and off peak hours varies from hour to hour and comprises a large portion of total effective regulation per hour (on average 37.3 percent during on peak and 49.0 percent during off peak hours in the first three months of 2015).

40 See PJM. "Manual 11: Energy & Ancillary Services Market Operations," Revision 72, (January 16, 2015); para 3.2.1, p 47.

41 See PJM. "Manual 11: Energy & Ancillary Services Market Operations," Revision 72, (January 16, 2015); para 3.2.2, pp 48.

42 See PJM. "Manual 28: Operating Agreement Accounting," Revision 68, (January 16, 2015); para 4.1, p 15.

43 See PJM. "Manual 11: Energy & Ancillary Services Market Operations," Revision 72, (January 16, 2015); para 3.2.9, p 59.

Figure 10-29 Off peak and on peak regulation levels: 2015

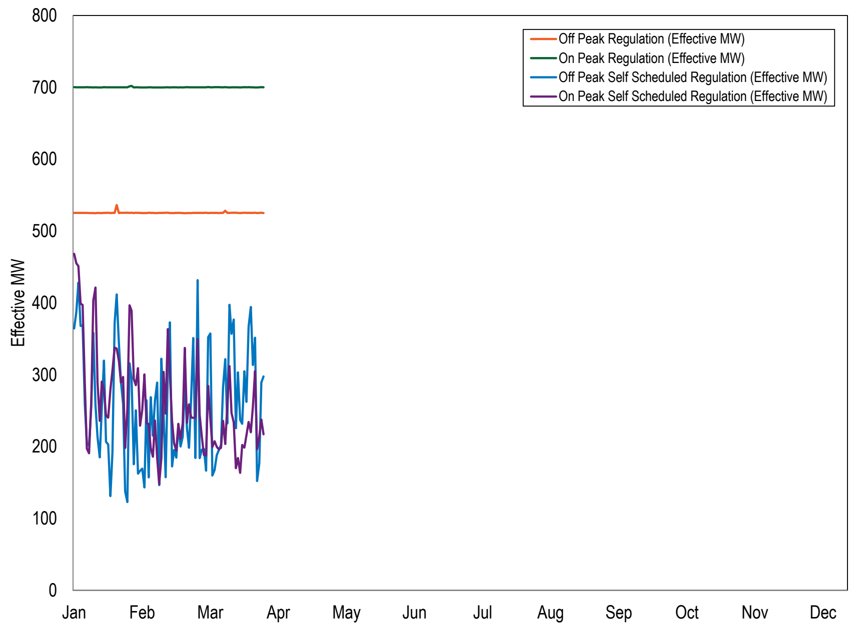


Table 10-33 shows how RegD resources have impacted the Regulation Market. RegD resources are both a growing proportion of the market (11 percent at the start of the Performance Based Regulation Market design in October 2012 versus 38 percent in March 2015) and a growing proportion of resources that self schedule (10 percent in October 2012 versus 17 percent in March 2015). This has resulted in an increase in the proportion of the regulation requirement that is self scheduled.

Table 10-33 RegD self scheduled regulation by month, October 2012 through March 2015

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	72	265	658	40%	10%	11%
2012	Nov	74	88	197	716	27%	10%	12%
2012	Dec	83	89	189	701	27%	12%	13%
2013	Jan	36	82	134	720	19%	5%	11%
2013	Feb	85	90	212	724	29%	12%	12%
2013	Mar	80	119	280	681	41%	12%	18%
2013	Apr	82	107	266	594	45%	14%	18%
2013	May	74	109	268	616	44%	12%	18%
2013	Jun	80	123	335	731	46%	11%	17%
2013	Jul	78	120	304	823	37%	9%	15%
2013	Aug	84	128	366	757	48%	11%	17%
2013	Sep	112	152	382	670	57%	17%	23%
2013	Oct	120	164	350	613	57%	20%	27%
2013	Nov	134	176	397	663	60%	20%	26%
2013	Dec	137	181	314	664	47%	21%	27%
2014	Jan	133	194	261	664	39%	20%	29%
2014	Feb	134	193	291	664	44%	20%	29%
2014	Mar	132	194	287	664	43%	20%	29%
2014	Apr	127	212	270	664	41%	19%	32%
2014	May	122	249	265	664	40%	18%	38%
2014	Jun	123	231	366	664	55%	19%	35%
2014	Jul	127	236	352	664	53%	19%	36%
2014	Aug	117	230	369	664	56%	18%	35%
2014	Sep	121	242	394	664	59%	18%	37%
2014	Oct	116	255	353	664	53%	17%	38%
2014	Nov	114	235	348	664	52%	17%	35%
2014	Dec	117	254	352	664	53%	18%	38%
2015	Jan	116	250	306	664	46%	18%	38%
2015	Feb	111	246	242	663	36%	17%	37%
2015	Mar	114	255	231	664	35%	17%	38%
Average		105	176	298	676	44%	16%	26%

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 three months of 2015, 58.4 percent was purchased in the PJM market, 36.0 percent was self-scheduled, and 5.5 percent was purchased bilaterally (Table 10-34). Table 10-35 shows the total regulation by market regulation, self-scheduled regulation, and bilateral regulation for the first three months of each year. These tables are based on settled (purchased) MW, but are not adjusted for either performance score or benefit factor to maintain consistency with years 2010 through 2012 when these constructs were not part of the Regulation Market.

Table 10-34 Regulation sources: spot market, self-scheduled, bilateral purchases: 2014 and 2015

Year	Month	Spot Market Regulation (MW)	Spot Market Percent of Total	Self-Scheduled Regulation (MW)	Self-Scheduled Percent of Total	Bilateral Regulation (MW)	Bilateral Percent of Total	Total Regulation (MW)	RegA Regulation (MW)	RegA Percent of Total	RegD Regulation (MW)	RegD Percent of Total
2014	Jan	259,686	63.7%	125,234	30.7%	22,737	5.6%	407,656	381,313	93.5%	26,343	6.5%
2014	Feb	217,755	59.4%	132,385	36.1%	16,530	4.5%	366,670	342,929	93.5%	23,741	6.5%
2014	Mar	245,991	59.8%	148,162	36.0%	17,524	4.3%	411,677	384,312	93.4%	27,365	6.6%
2014	Apr	248,323	62.8%	135,399	34.2%	11,890	3.0%	395,612	367,207	92.8%	28,405	7.2%
2014	May	242,328	61.0%	141,443	35.6%	13,641	3.4%	397,411	359,344	90.4%	38,067	9.6%
2014	Jun	155,366	40.1%	207,856	53.7%	23,881	6.2%	387,102	343,882	88.8%	43,220	11.2%
2014	Jul	172,095	43.5%	203,841	51.5%	19,930	5.0%	395,865	353,551	89.3%	42,314	10.7%
2014	Aug	162,399	40.4%	221,373	55.1%	17,901	4.5%	401,673	357,482	89.0%	44,191	11.0%
2014	Sep	131,860	34.5%	227,657	59.6%	22,690	5.9%	382,207	332,208	86.9%	49,999	13.1%
2014	Oct	165,032	41.8%	210,543	53.3%	19,499	4.9%	395,073	340,314	86.1%	54,759	13.9%
2014	Nov	165,252	42.8%	200,239	51.9%	20,322	5.3%	385,812	340,518	88.3%	45,294	11.7%
2014	Dec	160,526	40.9%	207,454	52.9%	24,490	6.2%	392,470	344,123	87.7%	48,347	12.3%
2015	Jan	197,191	50.0%	174,054	44.1%	23,058	5.8%	394,304	352,448	89.4%	41,856	10.6%
2015	Feb	220,139	61.8%	116,199	32.6%	20,039	5.6%	356,377	323,745	90.8%	32,631	9.2%
2015	Mar	252,275	63.8%	122,594	31.0%	20,341	5.1%	395,210	356,186	90.1%	39,025	9.9%

Table 10-35 Regulation sources by year: 2011 through 2015

Year (Jan-Mar)	Spot Market Regulation (MW)	Spot Market Percent of Total	Self-Scheduled Regulation (MW)	Self-Scheduled Percent of Total	Bilateral Regulation (MW)	Bilateral Percent of Total	Total Regulation (MW)
2011	1,502,757	78.9%	338,972	17.8%	62,720	3.3%	1,904,449
2012	1,512,307	73.5%	484,971	23.6%	61,400	3.0%	2,058,678
2013	1,029,412	73.1%	341,164	24.2%	38,432	2.7%	1,409,008
2014	723,432	61.0%	405,781	34.2%	56,790	4.8%	1,186,003
2015	669,606	58.4%	412,847	36.0%	63,438	5.5%	1,145,891

In the first three months of 2015, DR provided an average of 3.77 MW of regulation per hour (3.84 MW of regulation per hour in the same period of 2014). Generating units supplied an average of 644.00 MW of regulation per hour (680.95 MW of regulation per hour in the same period of 2014).

Market Performance

Price

The weighted average RMCP for January through March 2015 was $48.66 per MW. This is the average price per unadjusted capability MW. This is a 47.1 percent decrease from the weighted average RMCP of $91.94/MW in the same period of 2014. The decrease in regulation price resulted primarily from very high prices in the first three months of 2014. Figure 10-30 shows the daily 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.

Figure 10-30 PJM Regulation Market daily weighted average market-clearing price, marginal unit opportunity cost and offer price (Dollars per MW): 2015

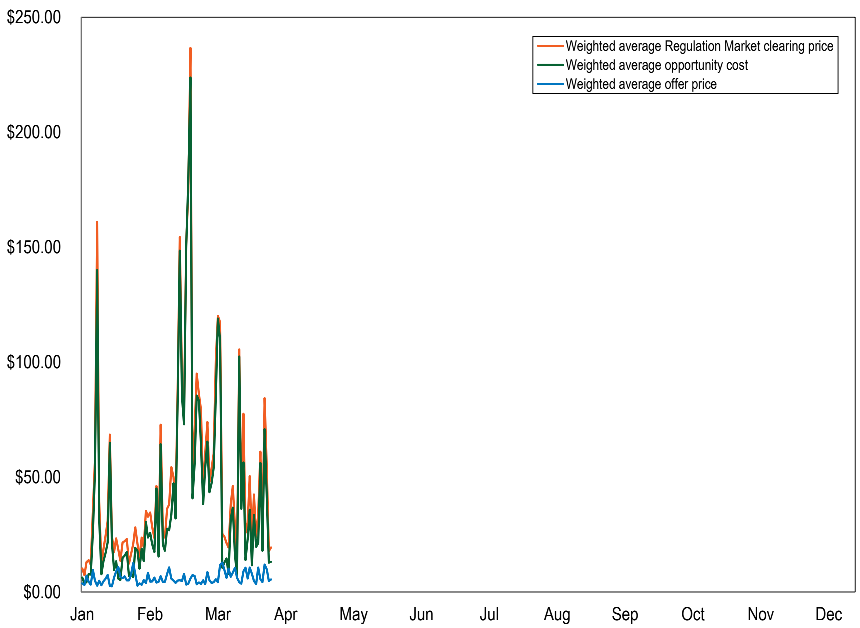


Table 10-36 shows monthly average regulation market clearing price, average marginal unit offer price, and average marginal unit LOC on an unadjusted capability MW basis.

Table 10-36 PJM Regulation Market monthly weighted average market-clearing price, marginal unit opportunity cost and offer price (Dollars per MW): 2015

Month	Weighted Average Regulation Market Clearing Price	Weighted Average Regulation Marginal Unit Offer	Weighted Average Regulation Marginal Unit LOC
Jan	$27.04	$5.58	$22.64
Feb	$73.07	$5.41	$56.98
Mar	$45.86	$7.09	$41.88

Total scheduled regulation MW, total regulation charges, regulation price and regulation cost are shown in Table 10-37. Total scheduled regulation is based on settled (unadjusted capability) MW.

Table 10-37 Total regulation charges: 2014 and 2015

Year	Month	Scheduled Regulation (MW)	Total Regulation Charges ($)	Weighted Average Regulation Market Price ($/MW)	Cost of Regulation ($/MW)	Price as Percent of Cost
2014	Jan	407,656	$65,714,049	$132.49	$161.20	82.2%
2014	Feb	366,670	$27,293,638	$62.61	$74.44	84.1%
2014	Mar	411,677	$40,110,074	$80.75	$97.43	82.9%
2014	Apr	395,612	$15,241,038	$31.80	$38.53	82.5%
2014	May	397,411	$16,952,817	$34.47	$42.66	80.8%
2014	Jun	387,102	$14,312,991	$30.43	$36.97	82.3%
2014	Jul	395,865	$14,482,844	$29.80	$36.59	81.5%
2014	Aug	401,673	$10,006,979	$20.54	$24.91	82.5%
2014	Sep	382,207	$11,888,482	$25.06	$31.10	80.6%
2014	Oct	395,073	$15,481,225	$32.98	$39.19	84.2%
2014	Nov	385,812	$12,606,811	$27.56	$32.68	84.3%
2014	Dec	392,470	$9,907,252	$21.33	$25.24	84.5%
2015	Jan	394,304	$13,015,918	$27.04	$33.01	81.9%
2015	Feb	356,377	$31,675,690	$73.07	$88.88	82.2%
2015	Mar	395,210	$21,958,495	$45.86	$55.56	82.5%

The capability, performance, and opportunity cost components of the cost of regulation are shown in Table 10-38. Total scheduled regulation is based on settled (unadjusted capability) MW.

Table 10-38 Components of regulation cost: 2015

Month	Scheduled Regulation (MW)	Cost of Regulation Capability ($/MW)	Cost of Regulation Performance ($/MW)	Opportunity Cost ($/MW)	Total Cost ($/MW)
Jan	394,304	$24.27	$3.80	$4.94	$33.01
Feb	356,377	$68.96	$5.98	$13.94	$88.88
Mar	395,210	$41.50	$6.17	$7.90	$55.56

A comparison of monthly average RMCP credits per effective MW earned by RegA and RegD resources from October 1, 2012, (the implementation date of the performance-based Regulation Market) through 2014 is shown in Figure 10-31. On November 1, 2013, FERC instructed PJM to remove the marginal benefit factor from all settlement calculations.[44] In its place, PJM inserted the mileage ratio for the RMPCP credit of RegD resources only. The RMPCP credit of RegA resources does not have a mileage ratio multiplier. Figure 10-31 shows RMCP credits earned by RegD resources before (yellow bar) and after (red bar) the November 1, 2013, change on a per effective MW basis. Figure 10-31 also shows RMCP credits earned by RegA resources (green bar) on a per effective MW basis. RMCP credits earned by RegA resources were not affected by the November 1, 2013, change. In Figure 10-31, the RegA RMCP Credit per effective MW is, on average, 1.9 times higher than the RegD RMCP Credit per effective MW from October 2012 through March 2015. Were the marginal benefit factor correctly applied to settlements, the average RegD RMCP Credit per effective MW would be higher and equal to the RegA RMCP Credit per effective MW. That is, RegD resources are currently underpaid for the service they provide to the Regulation Market. The underpayment calculations are based on PJM's current marginal benefit function.

Figure 10-31 Comparison of monthly average RegA and RegD RMCP Credits per Effective MW: October 2012 through March 2015

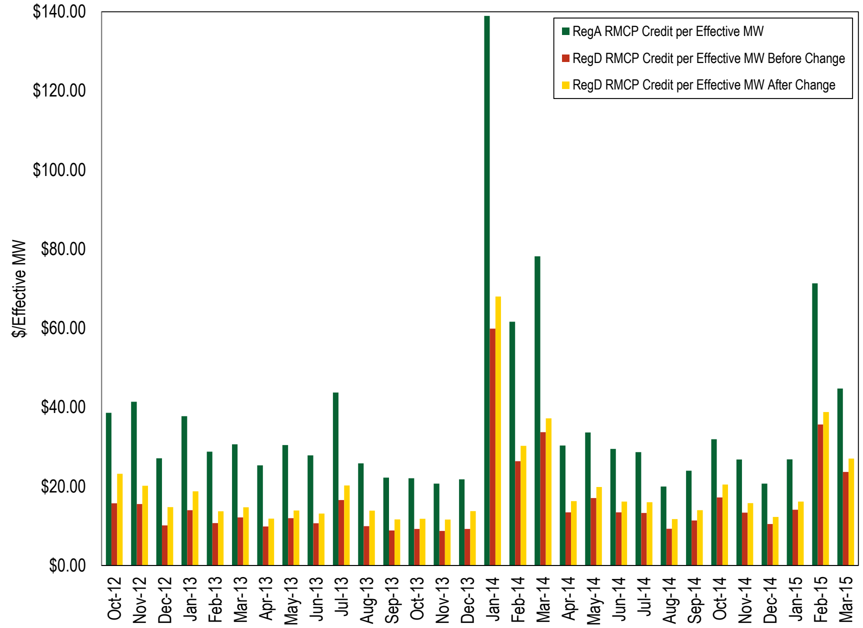


Table 10-39 provides the information from Figure 10-31, along with the percentage of underpayment of RegD resources both before and after the November 1, 2013, change. Table 10-40 provides an estimate (to the nearest thousand dollars) of the total dollar value of the underpayment of RegD resources both before and after the November 1, 2013, change.

44 145 FERC ¶ 61,011 (2013).

Table 10-39 Comparison of monthly average RegA and RegD RMCP credits per effective MW: October 2012 through March 2015

Year	Month	RegA RMCP Credit per Effective MW	RegD RMCP Credit per Effective MW Before Change	RegD RMCP Credit per Effective MW After Change	RegD RMCP Credit per Effective MW Should Be	RegD Underpayment Before Change	RegD Underpayment After Change	Percent RegD Underpayment Before Change	Percent RegD Underpayment After Change
2012	Oct	$38.61	$15.72	$23.16	$38.61	$22.89	$15.44	59%	40%
2012	Nov	$41.41	$15.54	$20.14	$41.41	$25.88	$21.27	62%	51%
2012	Dec	$27.11	$10.14	$14.77	$27.11	$16.97	$12.34	63%	46%
2013	Jan	$37.76	$13.98	$18.75	$37.76	$23.78	$19.02	63%	50%
2013	Feb	$28.79	$10.72	$13.72	$28.79	$18.07	$15.07	63%	52%
2013	Mar	$30.64	$12.15	$14.71	$30.64	$18.49	$15.93	60%	52%
2013	Apr	$25.31	$9.85	$11.84	$25.31	$15.45	$13.47	61%	53%
2013	May	$30.46	$11.94	$13.88	$30.46	$18.52	$16.58	61%	54%
2013	Jun	$27.84	$10.68	$13.13	$27.84	$17.15	$14.71	62%	53%
2013	Jul	$43.72	$16.56	$20.22	$43.72	$27.16	$23.49	62%	54%
2013	Aug	$25.81	$9.93	$13.86	$25.81	$15.88	$11.96	62%	46%
2013	Sep	$22.21	$8.87	$11.64	$22.21	$13.34	$10.56	60%	48%
2013	Oct	$22.07	$9.22	$11.81	$22.07	$12.85	$10.26	58%	46%
2013	Nov	$20.71	$8.72	$11.62	$20.71	$11.99	$9.08	58%	44%
2013	Dec	$21.77	$9.22	$13.74	$21.77	$12.55	$8.03	58%	37%
2014	Jan	$138.94	$59.88	$68.01	$138.94	$79.06	$70.93	57%	51%
2014	Feb	$61.64	$26.35	$30.24	$61.64	$35.29	$31.40	57%	51%
2014	Mar	$78.16	$33.72	$37.20	$78.16	$44.44	$40.96	57%	52%
2014	Apr	$30.33	$13.45	$16.28	$30.33	$16.89	$14.05	56%	46%
2014	May	$33.62	$17.03	$19.85	$33.62	$16.58	$13.76	49%	41%
2014	Jun	$29.45	$13.45	$16.16	$29.45	$16.00	$13.29	54%	45%
2014	Jul	$28.64	$13.29	$16.01	$28.64	$15.36	$12.63	54%	44%
2014	Aug	$19.96	$9.29	$11.73	$19.96	$10.67	$8.23	53%	41%
2014	Sep	$23.97	$11.35	$13.96	$23.97	$12.62	$10.02	53%	42%
2014	Oct	$31.91	$17.21	$20.45	$31.91	$14.70	$11.46	46%	36%
2014	Nov	$26.79	$13.34	$15.75	$26.79	$13.45	$11.03	50%	41%
2014	Dec	$20.70	$10.46	$12.28	$20.70	$10.24	$8.42	49%	41%
2015	Jan	$26.81	$14.08	$16.14	$26.81	$12.73	$10.67	47%	40%
2015	Feb	$71.32	$35.66	$38.80	$71.32	$35.66	$32.52	50%	46%
2015	Mar	$44.74	$23.65	$27.02	$44.74	$21.09	$17.72	47%	40%
Average		$37.04	$16.18	$19.56	$37.04	$20.86	$17.48	56%	46%

Table 10-40 Comparison of monthly average RegA and RegD RMCP credits: October 2012 through March 2015

Year	Month	RegA RMCP Credits	RegD RMCP Credits Before Change	RegD RMCP Credits After Change	RegD RMCP Credits Should Be	RegD Underpayment Before Change	RegD Underpayment After Change	Percent RegD Underpayment Before Change	Percent RegD Underpayment After Change
2012	Oct	$17,212,000	$495,000	$729,000	$1,215,000	$720,000	$486,000	59%	40%
2012	Nov	$19,541,000	$724,000	$938,000	$1,930,000	$1,206,000	$991,000	62%	51%
2012	Dec	$12,661,000	$488,000	$711,000	$1,306,000	$817,000	$594,000	63%	45%
2013	Jan	$18,681,000	$799,000	$1,072,000	$2,159,000	$1,360,000	$1,087,000	63%	50%
2013	Feb	$12,505,000	$702,000	$899,000	$1,886,000	$1,184,000	$987,000	63%	52%
2013	Mar	$13,464,000	$922,000	$1,117,000	$2,326,000	$1,404,000	$1,209,000	60%	52%
2013	Apr	$9,308,000	$684,000	$822,000	$1,756,000	$1,072,000	$934,000	61%	53%
2013	May	$12,277,000	$954,000	$1,109,000	$2,434,000	$1,480,000	$1,325,000	61%	54%
2013	Jun	$13,215,000	$812,000	$998,000	$2,116,000	$1,304,000	$1,118,000	62%	53%
2013	Jul	$25,905,000	$1,497,000	$1,828,000	$3,953,000	$2,456,000	$2,124,000	62%	54%
2013	Aug	$13,067,000	$756,000	$1,054,000	$1,964,000	$1,208,000	$910,000	62%	46%
2013	Sep	$9,818,000	$733,000	$962,000	$1,835,000	$1,102,000	$873,000	60%	48%
2013	Oct	$7,773,000	$871,000	$1,115,000	$2,084,000	$1,213,000	$969,000	58%	46%
2013	Nov	$7,513,000	$1,111,000	$1,481,000	$2,639,000	$1,528,000	$1,157,000	58%	44%
2013	Dec	$8,024,000	$1,260,000	$1,878,000	$2,976,000	$1,715,000	$1,097,000	58%	37%
2014	Jan	$45,616,000	$8,606,000	$9,774,000	$19,967,000	$11,362,000	$10,193,000	57%	51%
2014	Feb	$19,277,000	$3,664,000	$4,204,000	$8,570,000	$4,906,000	$4,366,000	57%	51%
2014	Mar	$26,515,000	$6,671,000	$7,360,000	$15,465,000	$8,794,000	$8,105,000	57%	52%
2014	Apr	$10,750,000	$1,878,000	$2,275,000	$4,238,000	$2,359,000	$1,963,000	56%	46%
2014	May	$10,712,000	$3,022,000	$3,521,000	$5,963,000	$2,941,000	$2,442,000	49%	41%
2014	Jun	$9,657,000	$2,117,000	$2,544,000	$4,637,000	$2,519,000	$2,092,000	54%	45%
2014	Jul	$9,073,000	$2,640,000	$3,182,000	$5,692,000	$3,052,000	$2,510,000	54%	44%
2014	Aug	$6,582,000	$1,632,000	$2,061,000	$3,506,000	$1,875,000	$1,445,000	53%	41%
2014	Sep	$7,569,000	$1,995,000	$2,453,000	$4,213,000	$2,217,000	$1,760,000	53%	42%
2014	Oct	$10,052,000	$2,973,000	$3,532,000	$5,511,000	$2,538,000	$1,980,000	46%	36%
2014	Nov	$8,138,000	$2,443,000	$2,885,000	$4,906,000	$2,463,000	$2,020,000	50%	41%
2014	Dec	$6,348,000	$2,011,000	$2,360,000	$3,979,000	$1,968,000	$1,619,000	49%	41%
2015	Jan	$7,661,000	$2,972,000	$3,408,000	$5,660,000	$2,688,000	$2,252,000	47%	40%
2015	Feb	$19,132,000	$6,962,000	$7,574,000	$13,924,000	$6,962,000	$6,350,000	50%	46%
2015	Mar	$13,517,000	$4,658,000	$5,320,000	$8,809,000	$4,152,000	$3,489,000	47%	40%
Total		$411,563,000	$67,052,000	$79,166,000	$147,619,000	$80,565,000	$68,447,000	56%	46%

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 decreased to 82 percent in the first three months of 2015 from 83 percent in the same period of 2014.

Table 10-41 Comparison of average price and cost for PJM Regulation, January through March, 2009 through 2015

Year (Jan-Mar)	Weighted Regulation Market Price	Weighted Regulation Market Cost	Regulation Price as Percent Cost
2009	$23.56	$29.87	79%
2010	$18.05	$30.67	59%
2011	$11.51	$24.83	46%
2012	$12.61	$16.76	75%
2013	$33.87	$38.95	87%
2014	$91.94	$111.02	83%
2015	$48.66	$59.15	82%

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 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.[45] 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. (The selection process was completed in the first half of 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 have been selected yet.

Black start payments are non-transparent 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 is 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 non-zone peak transmission use and point to point transmission reservations.

In the first three months of 2015, total black start charges were $15.0 million, a $2.3 million (18.1 percent) increase from the same period of 2014 level of

45 See PJM. "RTO-Wide Five-Year Selection Process Request for Proposal for Black Start Service," (July 1, 2013).

$12.7 million. Operating reserve charges for black start service declined from $7.6 million in 2014 to $4.7 million in 2015. Table 10-42 shows total revenue requirement charges from 2009 through 2014. (Prior to December 2012, PJM did not define a black start operating reserve category.)

Table 10-42 Black start revenue requirement charges: 2010 through 2015

Year (Jan-Mar)	Revenue Requirement Charges
2010	$2,673,689
2011	$2,793,709
2012	$3,864,301
2013	$5,412,855
2014	$5,104,104
2015	$10,276,712

Table 10-43 Black start zonal charges for network transmission use: 2014 and 2015

	2014 (Jan - Mar)					2015 (Jan - Mar)				
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	$153,360	$0	$153,360	246,528	$0.62	$145,824	$0	$145,824	219,915	$0.66
AEP	$166,432	$7,036,425	$7,202,857	2,056,167	$3.50	$2,753,539	$4,413,733	$7,167,272	2,196,729	$3.26
APS	$68,326	$0	$68,326	780,966	$0.09	$72,613	$0	$72,613	841,437	$0.09
ATSI	$28,280	$0	$28,280	1,182,699	$0.02	$633,587	$0	$633,587	1,112,589	$0.57
BGE	$1,139,947	$0	$1,139,947	614,727	$1.85	$2,727,337	$0	$2,727,337	599,868	$4.55
ComEd	$1,021,927	$0	$1,021,927	2,004,210	$0.51	$1,080,851	$0	$1,080,851	1,774,908	$0.61
DAY	$60,441	$6,511	$66,951	306,837	$0.22	$58,587	$7,929	$66,517	288,342	$0.23
DEOK	$281,806	$0	$281,806	463,140	$0.61	$286,689	$0	$286,689	459,450	$0.62
Dominion	$248,851	$0	$248,851	1,688,670	$0.15	$249,919	$0	$249,919	1,780,560	$0.14
DPL	$136,765	$1,357	$138,122	361,683	$0.38	$145,352	$0	$145,352	348,750	$0.42
DLCO	$14,378	$0	$14,378	265,635	$0.05	$15,215	$0	$15,215	242,343	$0.06
EKPC	$90,113	$0	$90,113	227,934	$0.40	$92,420	$0	$92,420	308,250	$0.30
JCPL	$119,801	$0	$119,801	574,101	$0.21	$132,826	$0	$132,826	507,321	$0.26
Met-Ed	$208,834	$0	$208,834	271,107	$0.77	$183,108	$0	$183,108	253,512	$0.72
PECO	$360,442	$4,838	$365,280	775,656	$0.47	$388,580	$2,129	$390,709	743,175	$0.53
PENELEC	$122,181	$0	$122,181	277,857	$0.44	$136,878	$0	$136,878	274,644	$0.50
Pepco	$75,854	$0	$75,854	588,006	$0.13	$80,590	$0	$80,590	571,059	$0.14
PPL	$35,102	$0	$35,102	665,298	$0.05	$31,710	$0	$31,710	723,420	$0.04
PSEG	$418,230	$0	$418,230	937,296	$0.45	$488,392	$0	$488,392	856,368	$0.57
RECO	$0	$0	$0	NA	NA	$0	$0	$0	NA	NA
(Imp/Exp/Wheels)	$353,034	$510,050	$863,083	1,062,418	$0.81	$572,694	$253,822	$826,516	828,964	$1.00
Total	$5,104,104	$7,559,180	$12,663,284	15,350,935	$0.82	$10,276,712	$4,677,613	$14,954,325	14,931,604	$1.00

Black start zonal charges in the first three months of 2015 ranged from $0.04 per MW-day in the PPL Zone (total charges were $31,710) to $4.55 per MW-day in the BGE Zone (total charges were $2,727,337). 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 $0.05 per MW of reserve capacity during the first three months of 2015.

Table 10-44 provides a revenue requirement estimate by zone for the 2015-2016, 2016-2017, and 2017-2018 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. They are based on the best available data (i.e. 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 in either direction as actual costs become known and finalized.

Table 10-44 Black start zonal revenue requirement estimate: 2015/2016 through 2017/2018 delivery years

Zone	2015-2016 Revenue Requirement	2016-2017 Revenue Requirement	2017-2018 Revenue Requirement
AECO	$1,600,000	$2,200,000	$2,150,000
AEP	$17,100,000	$20,600,000	$20,850,000
APS	$4,200,000	$4,400,000	$4,450,000
ATSI	$2,550,000	$2,500,000	$2,500,000
BGE	$8,450,000	$9,300,000	$9,400,000
ComEd	$4,250,000	$3,600,000	$3,750,000
DAY	$250,000	$300,000	$300,000
DEOK	$1,250,000	$1,250,000	$1,250,000
DLCO	$150,000	$100,000	$100,000
Dominion	$4,300,000	$5,700,000	$6,000,000
DPL	$1,750,000	$2,600,000	$2,600,000
EKPC	$450,000	$450,000	$500,000
JCPL	$6,950,000	$7,000,000	$7,000,000
Met-Ed	$850,000	$900,000	$950,000
PECO	$1,800,000	$1,900,000	$2,050,000
PENELEC	$4,700,000	$4,750,000	$4,900,000
Pepco	$2,400,000	$2,650,000	$2,700,000
PPL	$700,000	$800,000	$800,000
PSEG	$7,600,000	$7,800,000	$7,800,000
RECO	$0	$0	$0
Total	$71,300,000	$78,800,000	$80,050,000

Table 10-45 shows new black start NERC critical infrastructure protection (CIP) capital costs being recovered by black start units in PJM. These costs were located in multiple zones, including ComEd, DEOK, DLCO, JCPL, Met-Ed, PENELEC and Pepco. These costs are recoverable through Schedule 6A of the tariff, and include both physical security and cyber security investments in order to protect black start units deemed critical. This included equipment necessary to restrict access to both physical sites, as well as firewall and software upgrades necessary protect cyber assets and monitor unit operations.

Table 10-45 NERC CIP Costs: 2015

Capital Cost Requested	Cost Recovered in Jan-Mar 2015	Number of Units	MW
$1,736,971	$157,630	33	678

Reactive Service

Reactive Service, Reactive Supply and Voltage Control from Generation or Other Sources Service, is provided by generation and other sources (such as static VAR compensators and capacitor banks) of reactive power (measured in VAR).[46] Reactive power helps maintain appropriate voltages on the transmission system and is essential to the flow of real power (measured in MW). Without Reactive Service in the necessary amounts across the RTO footprint, transmission system voltages fall, generating units and transmission lines shut down, and no real power flows.

Total reactive service charges are the sum of reactive service revenue requirement charges and reactive service operating reserve charges. Reactive service revenue requirements are based on FERC-approved filings. Reactive service revenue requirement charges are allocated monthly to PJM customers in the zone or zones where the reactive service was provided proportionally to their zone and non-zone peak transmission use and point to point transmission reservations. Reactive service operating reserve charges are paid for scheduling in the Day-Ahead Energy Market and committing in real time units that provide reactive service. These operating reserve charges are allocated daily to the zone or zones where the reactive service was provided.

In the first three months of 2015, total reactive service charges were $76.1 million, a 2.2 percent decrease from the first three months of 2014 level of $77.8 million.[47] Revenue requirement charges decreased from $70.3 million to $69.9 million and operating reserve charges fell from $7.5 million to $6.3 million. Total charges in the first three months of 2015 ranged from $1.8 thousand in the RECO Zone to $10.4 million in the AEP Zone.

46 PJM OATT. Schedule 2 "Reactive Supply and Voltage Control from Generation Sources Service," (Effective Date: February 18, 2012).

47 See the *2014 State of the Market Report for PJM*, Volume II, Section 4, "Energy Uplift."

For each zone in the first three months of 2014 and 2015, Table 10-46 shows Reactive Service operating reserve charges, revenue requirement charges and total charges (the sum of operating reserve and revenue requirement charges).

Table 10-46 Reactive zonal charges for network transmission use: January through March, 2014 and 2015

	2014 (Jan - Mar)			2015 (Jan - Mar)		
Zone	Operating Reserve Charges	Revenue Requirement Charges	Total Charges	Operating Reserve Charges	Revenue Requirement Charges	Total Charges
AECO	$81,431	$1,255,482	$1,336,913	$13,309	$1,945,614	$1,958,922
AEP	$183,570	$9,857,657	$10,041,227	$395,554	$10,016,846	$10,412,400
APS	$249,479	$5,312,075	$5,561,553	$77,563	$4,114,087	$4,191,651
ATSI	$3,389,443	$3,963,356	$7,352,799	$2,170,693	$3,690,235	$5,860,928
BGE	$33,662	$1,900,875	$1,934,537	$51,599	$1,931,572	$1,983,171
ComEd	$34,089	$6,009,518	$6,043,607	$132,500	$6,106,564	$6,239,064
DAY	$5,699	$2,063,768	$2,069,468	$25,676	$2,097,095	$2,122,771
DEOK	$9,035	$1,408,663	$1,417,698	$40,372	$1,431,411	$1,471,783
Dominion	$4,883	$7,319,846	$7,324,729	$19,374	$7,438,053	$7,457,426
DPL	$33,131	$2,636,968	$2,670,099	$2,598,813	$2,709,938	$5,308,752
DLCO	$1,416,426	$0	$1,416,426	$193,151	$0	$193,151
EKPC	$4,764	$523,492	$528,256	$24,773	$531,946	$556,719
JCPL	$7,964	$1,743,078	$1,751,042	$30,381	$1,771,227	$1,801,608
Met-Ed	$15,074	$1,829,559	$1,844,633	$57,025	$1,908,311	$1,965,337
PECO	$259,820	$4,310,471	$4,570,292	$57,165	$4,380,080	$4,437,245
PENELEC	$1,339,940	$1,282,269	$2,622,209	$197,694	$1,848,486	$2,046,180
Pepco	$29,749	$1,286,001	$1,315,750	$47,128	$1,306,768	$1,353,896
PPL	$15,867	$4,710,500	$4,726,367	$63,701	$4,682,408	$4,746,109
PSEG	$357,998	$6,669,467	$7,027,465	$55,175	$6,777,170	$6,832,345
RECO	$487	$0	$487	$1,813	$0	$1,813
(Imp/Exp/Wheels)	$0	$6,249,391	$6,249,391	$0	$5,178,835	$5,178,835
Total	$7,472,512	$70,332,436	$77,804,949	$6,253,458	$69,866,646	$76,120,104