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 2014.

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 2014.
- Participant behavior in the Regulation Market was evaluated as competitive for 2014 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.

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.

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

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

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 is currently 2,063 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 2014 was 2,130 MW. The actual demand for primary reserve in the MAD subzone in 2014 was 1,705 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 2014, there was an average hourly supply of 1,357.4 MW of tier 1 for the RTO synchronized reserve zone, and an average hourly supply of 642.6 MW of tier 1 for the Mid-Atlantic Dominion subzone.
- **Demand.** The default hourly required synchronized reserve requirement is 1,375 MW in the RTO Reserve Zone and 1,300 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.

  Only 18.2 percent of tier 1 synchronized reserve eligible for payment in Settlements actually responded during the 23 distinct synchronized reserve hours (synchronized reserve events 10 minutes or longer) in 2014. After July 2014, this response rate improved to 37.1 percent.
- **Issues.** The 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 $89,997,054 to tier 1 resources in 2014. 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.

  PJM paid both the units selected as capable of providing tier 1 and the units deselected as not capable of providing tier 1. 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.

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 2014, 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, except for two hours on January 6, 2014, and eight hours on January 7, 2014.
- **Demand.** The default hourly required synchronized reserve requirement is 1,375 MW in the RTO Reserve Zone and 1,300 MW for the Mid-Atlantic Dominion Reserve subzone.
- **Market Concentration.** In 2014, the weighted average HHI for cleared tier 2 synchronized reserve in the Mid-Atlantic Dominion subzone was 5143 which is classified as highly concentrated. The MMU calculates that in 2014, 41.3 percent of hours would have failed a three pivotal supplier test in the Mid-Atlantic Dominion subzone.

  In 2014, the weighted average HHI for cleared tier 2 synchronized reserve in the RTO Synchronized Reserve Zone was 5825 which is classified as highly concentrated. The MMU calculates that in 2014 39.2 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 2014.

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. As of December 31, 2014, 0.5 percent of eligible resources had no tier 2 synchronized reserve offer. This is an improvement over the same period in 2013 when 13.7 percent of eligible resources had no tier 2 synchronized reserve offer.

Market Performance

- **Price.** The weighted average price for tier 2 synchronized reserve for all cleared hours in the Mid-Atlantic Dominion (MAD) subzone was $15.50 per MW in 2014, an increase of $8.52 (104 percent) over 2013.

  The weighted average price for tier 2 synchronized reserve for all cleared hours in the RTO Synchronized Reserve Zone was $12.94 per MW in 2014, an increase of $7.47 (85.9 percent) over 2013.

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.

Market Structure

- **Supply.** In 2014, the supply of eligible non-synchronized reserve was sufficient to cover the primary reserve requirement in both the RTO Reserve Zone and the Mid-Atlantic Dominion Reserve subzone, except for two hours on January 6, 2014, and eight hours on January 7, 2014.
- **Demand.** In the RTO Zone, the market cleared an hourly average of 731.7 MW of non-synchronized reserve during 2014. In 95.5 percent of hours the market clearing price was $0. In the MAD subzone, the market cleared an hourly average of 733.1 MW of non-synchronized reserve. In 93.8 percent of hours the market clearing price was $0.

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 $0.76 per MW in 2014, compared to $1.81 for 2013. The non-synchronized reserve weighted average price for all cleared hours in the Mid-Atlantic Dominion (MAD) subzone was $1.23 per MW, compared to $0.41 in 2013.

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 2014, 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 2014, the average available hourly DASR was 42,017 MW.
- **Demand.** The DASR requirement in 2014 was 6.27 percent of peak load forecast, down from 6.91 percent in 2013. The average DASR MW purchased was 6,245 MW per hour in 2014.

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 December 31, 2014, 9.6 percent of resources offered DASR at levels above $5 per MW, compared to 11.9 percent of resources offering above $5.00 at the same time in 2013.
- **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 2014 was $0.63 per MW. This is a $0.07 per MW (10.0 percent) decrease from 2013, which had a weighted price of $0.70 per MW.

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 2014, the average hourly eligible supply of regulation was 1,281 actual MW (918 effective MW). This is a decrease of 216 actual MW (230 effective MW) from 2013, when the average hourly eligible supply of regulation was 1,497 actual MW (1,148 effective MW).
- **Demand.** The average hourly regulation demand was 663 actual MW in 2014. This is a 98 actual MW (24 effective MW) decrease in the average hourly

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

regulation demand of 759 actual MW (688 effective MW) from 2013.

- **Supply and Demand.** The ratio of offered and eligible regulation to regulation required averaged 1.94. This is a 2.9 percent decrease from 2013 when the ratio was 2.00.
- **Market Concentration.** In 2014, the PJM Regulation Market had a weighted average Herfindahl-Hirschman Index (HHI) of 1960 which is classified as highly concentrated. In 2014, 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 2014, there were 296 resources following the RegA signal and 52 resources following the RegD signal.

Market Performance

- **Price and Cost.** The weighted average clearing price for regulation was $44.15 per MW of regulation in 2014, an increase of $14.01 per MW of regulation, or 46.5 percent, from 2013. The cost of regulation in 2014 was $53.41 per MW of regulation, an increase of $18.84 per MW of regulation, or 54.5 percent, from 2013. The increases in regulation price and regulation cost resulted primarily from high prices and costs in the first three months of 2014, particularly in January, when PJM experienced record winter load, high LMPs, high levels of generation outages, several hours of shortage pricing, and several synchronized reserve events.
- **RMCP Credits.** RegD resources continue to be underpaid 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.

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 2014, total black start charges were $59.9 million with $26.9 million in revenue requirement charges and $33.0 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 for scheduling in the Day-Ahead Energy Market or committing in real time units that provide black start service. Black start zonal charges in 2014 ranged from $0.07 per MW-day in the DLCO Zone (total charges were $72,263) to $3.90 per MW-day in the AEP Zone (total charges were $32,513,935).

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 2014, total reactive service charges were $309.7 million with $280.3 million in revenue requirement charges and $29.4 million in operating reserve charges. 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. Total charges in 2014 ranged from $1,700 in the RECO Zone to $40.8 million in the AEP Zone.

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

5 OATT Schedule 1 § 1.3BB.

Ancillary Services Costs per MWh of Load: 2003 through 2014

Table 10-4 shows PJM ancillary services costs for 2003 through 2014, 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. 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 ReliabilityFirst 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. For example, the regulation market clearing price increased 46.5 percent (from $30.14 to $44.15 per MW of regulation capability) while the cost of regulation per MWh of real-time load increased only 29.2 percent, from $0.24 to $0.31 per MWh of real time load.

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.)
- 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.)

Table 10-4 History of ancillary services costs per MWh of Load: 2003 through 2014

Year	Regulation	Scheduling, Dispatch, and System Control	Reactive	Synchronized Reserve	Supplementary Operating Reserve	Total
2003	$0.50	$0.61	$0.24	$0.14	$0.83	$2.32
2004	$0.50	$0.60	$0.25	$0.13	$0.90	$2.38
2005	$0.79	$0.47	$0.26	$0.11	$0.93	$2.57
2006	$0.53	$0.48	$0.29	$0.08	$0.43	$1.81
2007	$0.63	$0.47	$0.29	$0.06	$0.58	$2.02
2008	$0.68	$0.40	$0.31	$0.08	$0.59	$2.06
2009	$0.34	$0.32	$0.37	$0.05	$0.48	$1.56
2010	$0.34	$0.38	$0.41	$0.07	$0.73	$1.93
2011	$0.32	$0.34	$0.42	$0.10	$0.77	$1.95
2012	$0.26	$0.40	$0.43	$0.04	$0.79	$1.92
2013	$0.24	$0.39	$0.80	$0.04	$0.59	$2.08
2014	$0.31	$0.37	$0.37	$0.20	$1.16	$2.41

- 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 2014, 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, currently 1,300 MW in the Mid-Atlantic Dominion subzone, and 1,375 MW in 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 529.3 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 57 hours in 2014. In the RTO Zone, an average of 1,358.8 MW of tier 1 was available (Table 10-6). The RTO Zone synchronized reserve requirement was satisfied by tier 1 in 45.1 percent of all hours.

There is usually enough tier 2 synchronized reserve (all resources capable of supplying tier 2 must make a tier 2 synchronized reserve offer) to fulfill the synchronized reserve requirement. In the MAD subzone, there was an average of 2,743 MW of eligible tier 2 synchronized reserve available (Figure 10-11) to meet the average tier 2 hourly demand of 364.5 MW (Table 10-5). In the RTO Zone, there was an average of 3,033 MW of eligible Tier 2 supply available to meet the average hourly demand of 529.8 MW (Table 10-6).

In the MAD subzone, there was an average of 1,531.6 MW of eligible non-synchronized reserve supply available to meet the average hourly demand of 604.1 MW (Table 10-6). In the RTO Zone, an hourly average of 2,241 MW supply was available to meet the average hourly demand of 985.1 MW (Table 10-5).

Demand

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

In 15.0 percent of hours in 2014, PJM increased the primary reserve requirement for the RTO Zone. The actual hourly average RTO primary reserve requirement was 2,215.1 MW in 2014. In 78 hours during 2014, PJM increased the primary reserve requirement for the MAD subzone. The actual hourly average demand for primary reserve in the MAD subzone in 2014 was 1, 1,712.7 MW.

Transmission constraints limit the deliverability of reserves within the RTO, requiring the definition of the Mid-Atlantic Dominion (MAD) subzone.[9] Of the 2,063 MW RTO primary reserve requirement, 1,700 MW (Table 10-16) must be deliverable to the MAD subzone (Figure 10-1).

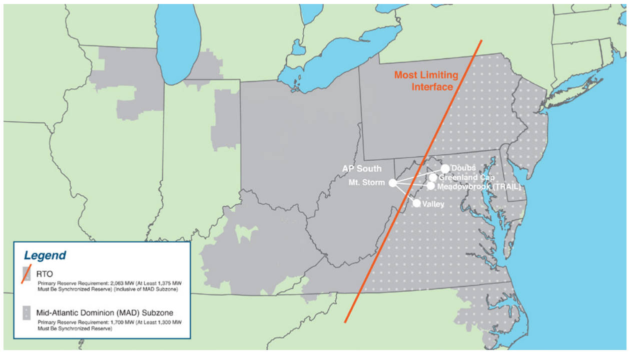
6 PJM. OATT (effective 2/5/2014), p.1740; 1.3.29F Primary Reserve.

7 NERC, IVGTF Task 2.4 Report; Operating Practices, Procedures, and Tools, March 2011, p. 20.

8 See PJM, "Manual 11, Energy and Ancillary Services Market Operations," Revision 71 (January 1, 2015), p. 66, 67. PJM's Markets and Reliability Committee approved a temporary rule change effective June 1, 2014, allowing operators to increase the primary reserve requirement when a Hot or Cold Weather Alert, Maximum Emergency Generation Alert, or Load Management Alert is issued. This rule was in effect until September 30, 2014. Between January 1 and June 30, 2014, no changes were made to the synchronized reserve requirement based on this rule change.

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 71 (January 1, 2015), p. 67.

Figure 10-1 PJM RTO geography and primary reserve requirement: 2014



The Mid-Atlantic Dominion Reserve (MAD) subzone is defined dynamically by the most limiting constraint separating MAD from the PJM RTO Reserve Zone.[10] In 74.7 percent of hours in 2014, that constraint was the Bedington – Black Oak Interface. The AP South transfer interface constraint was the limiting constraint in 54.3 percent of hours.

PJM requires that synchronized reserves equal at least 100 percent of the largest contingency. For the RTO Reserve Zone, this means that 1,375 MW of the primary reserve requirement must be synchronized reserve and for the Mid Atlantic Dominion Reserve subzone that means that 1,300 MW must be synchronized reserve.

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: 2014

Year	Month	Tier 1 Total MW	Tier 2 Synchronized Reserve MW	Non-synchronized Reserve MW
2014	Jan	242.6	1,079.1	508.2
2014	Feb	841.5	467.9	643.2
2014	Mar	974.0	333.6	639.5
2014	Apr	877.4	510.2	522.6
2014	May	1,049.4	282.3	621.3
2014	Jun	1,089.0	219.0	626.8
2014	Jul	1,215.9	91.6	701.8
2014	Aug	1,055.5	247.1	696.4
2014	Sep	1,019.1	282.9	592.9
2014	Oct	1,042.5	344.4	533.3
2014	Nov	1,017.2	288.3	591.2
2014	Dec	1,087.4	227.8	571.9
2014	Average	959.3	364.5	604.1

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: 2014

Year	Month	Tier 1 Total MW	Tier 2 Synchronized Reserve MW	Non-synchronized Reserve MW
2014	Jan	388.7	1,237.0	888.8
2014	Feb	1,203.2	502.2	931.4
2014	Mar	1,343.4	383.5	1,095.6
2014	Apr	1,139.8	853.1	980.3
2014	May	1,341.5	394.3	1,052.7
2014	Jun	1,768.7	316.5	984.1
2014	Jul	2,230.7	127.1	949.2
2014	Aug	1,910.2	292.1	972.3
2014	Sep	1,636.3	352.5	909.0
2014	Oct	825.9	732.6	939.6
2014	Nov	1,173.8	638.3	1,078.4
2014	Dec	1,326.1	528.4	1,039.4
2014	Average	1,357.4	529.8	985.1

After experiencing periods of reserve shortage (both synchronized reserve and non-synchronized reserve) during the cold weather of January 6 through 8, 2014, the PJM Market Implementation Committee (MIC) convened an Energy/Reserve Pricing and Interchange Volatility (ERPIV) subcommittee to study the shortages and recommend solutions. Several changes to reserve requirement determination were proposed and agreed upon by the MIC. During periods of Hot Weather Alert, Cold Weather Alert, Max Emergency Gen Alert, Weather / Environmental Emergency, or Sabotage/Terrorism Emergency PJM dispatchers may extend the primary reserve requirement during on-peak hours. The primary reserve requirement will be extended in an amount equal to the existing reserve requirement plus any additional MW brought online for that hour by PJM Dispatch to account for operational uncertainty. This change became effective on January 1, 2015.

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.

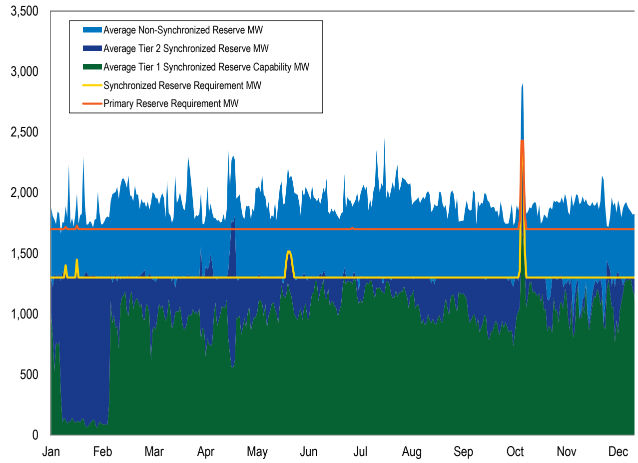
The ASO jointly optimizes energy, synchronized reserves, non-synchronized reserves, and regulation based on forecast system conditions to determine the

10 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 71 (January 1, 2015), p. 67. No additional subzones were defined in 2014.

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 within hour flexible tier 2 resources if its forecasts indicate 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 1,300 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 1,300 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 1,300 MW of tier 1 then the remaining synchronized reserve requirement up to 1,300 MW is filled with tier 2 synchronized reserve (dark blue area). After 1,300 MW of synchronized reserve are assigned, the remaining 400 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 1,300 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): 2014



The solution methodology is similar for the RTO Reserve Zone (Figure 10-3) except that the required synchronized reserve is 1,375 MW and the required primary reserve MW is 2,063 MW.[11] Figure 10-3 shows how the hour ahead ASO satisfies the primary reserve requirement for the RTO Zone.

Figure 10-3 RTO subzone primary reserve MW by source (Daily Averages): 2014

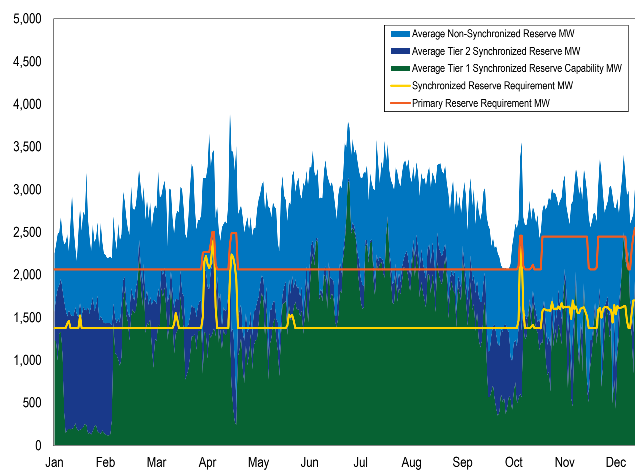


Figure 10-2 and Figure 10-3 show that tier 1 synchronized reserve remains the major contributor to satisfying the synchronized reserve requirements both in the RTO Zone and the Mid-Atlantic Dominion (MAD) subzone.

11 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.

Price and Cost

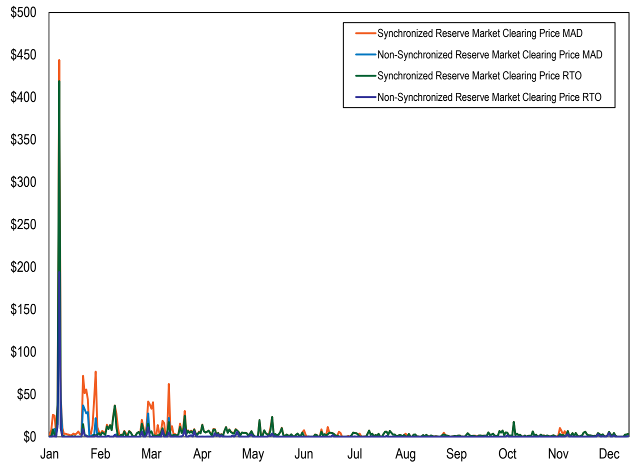
There is a separate price and cost for each component of primary reserve. In the market solution, the cost of tier 1 synchronized reserves is zero except in defined circumstances, as there is no incremental cost associated with the ability to ramp up from the current economic dispatch point nor is there 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 2014.

Figure 10-4 Daily average market clearing prices ($/MW) for synchronized reserve and non-synchronized reserve: 2014



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.

Table 10-7 MW credited, price, cost, and all-in price for primary reserve and its component products, full RTO Reserve Zone, 2014

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	17,962	$1,530,978	NA	$85.23	$0.00
Tier 1 Synchronized Reserve	19.3%	2,356,785	$89,719,045	$38.07	$38.07	$0.11
Tier 2 Synchronized Reserve	28.6%	3,485,894	$69,733,658	$12.94	$20.00	$0.09
Non-synchronized Reserve	52.1%	6,357,945	$13,515,036	$0.87	$2.13	$0.02
Primary Reserve	100.0%	12,200,624	$172,967,739	$11.50	$14.18	$0.22

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 2014, in the RTO Reserve Zone the average hourly estimated tier 1 synchronized reserve was 1,357.4 MW (Table 10-8). In 1,825 hours the estimated tier 1 synchronized reserve was greater than the primary reserve requirement, meaning that the primary reserve requirement was met entirely by tier 1 synchronized reserve.

Table 10-8 Monthly average market solution Tier 1 Synchronized Reserve (MW) identified hourly, 2014

		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
2014	Jan	149.5	93.2	242.6	0.0	1,117.7
2014	Feb	582.5	259.0	841.5	0.0	1,383.4
2014	Mar	515.7	458.3	974.0	90.5	1,411.5
2014	Apr	523.9	353.4	877.4	162.2	1,195.0
2014	May	698.2	351.1	1,049.4	461.2	1,550.9
2014	Jun	713.9	375.1	1,089.0	302.6	1,637.2
2014	Jul	808.3	407.7	1,215.9	0.0	1,734.0
2014	Aug	605.4	450.1	1,055.5	443.1	1,398.7
2014	Sep	522.5	496.6	1,019.1	401.0	1,298.8
2014	Oct	391.8	650.8	1,042.5	399.0	2,211.9
2014	Nov	376.9	640.3	1,017.2	0.0	1,306.4
2014	Dec	468.8	618.6	1,087.4	0.0	1,462.4
2014	Average	529.8	429.5	959.3	188.3	1,475.7
		RTO Reserve Zone				
Year	Month	Average Hourly Tier 1 Local to RTO	Synchronized Reserve Available from RTO	Average Hourly Tier 1 Used	Minimum Hourly Tier 1 Used	Maximum Hourly Tier 1 Used
2014	Jan	388.7	0.0	388.7	0.0	2,081.9
2014	Feb	1,203.2	0.0	1,203.2	38.2	2,963.8
2014	Mar	1,343.4	0.0	1,343.4	88.6	3,202.9
2014	Apr	1,139.8	0.0	1,139.8	0.0	2,711.1
2014	May	1,341.5	0.0	1,341.5	0.0	3,166.8
2014	Jun	1,768.7	0.0	1,768.7	0.0	3,839.9
2014	Jul	2,230.7	0.0	2,230.7	0.0	4,209.3
2014	Aug	1,910.2	0.0	1,910.2	0.0	3,783.8
2014	Sep	1,636.3	0.0	1,636.3	0.0	3,974.6
2014	Oct	825.9	0.0	825.9	0.0	2,712.8
2014	Nov	1,173.8	0.0	1,173.8	0.0	3,222.1
2014	Dec	1,326.1	0.0	1,326.1	0.0	2,962.0
2014	Average	1,357.4	0.0	1,357.4	10.6	3,235.9

In 2014, in the MAD reserve subzone the average hour ahead estimated tier 1 synchronized reserve was 959.3 MW (Table 10-8). In seven hours the estimated tier 1 synchronized reserve was zero. In 81 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. In two hours the estimated tier 1 synchronized reserve was greater than the subzone primary reserve requirement.

Demand

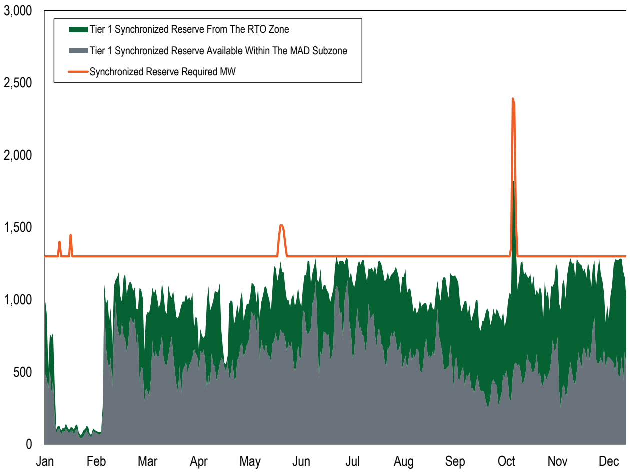
There is no fixed required amount of tier 1 synchronized reserve. Tier 1 synchronized reserve is estimated as part of each market solution and not assigned. Given estimated tier 1, the market software (ASO) completes the primary reserve assignments under the assumption that the estimated tier 1 will 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: 2014[12]



Demand for synchronized reserve in the RTO Zone increased significantly because of an extended outage beginning in November. Usually, the synchronized reserve requirement is increased because of outages for periods of 10 to 14 days. Originally, an 11 day outage had been scheduled beginning November 3. This was increased to 18 days and then further increased to 30 days. The result was a synchronized reserve requirement of 1,700 MW that remained in place from November 3, 2014 through December 3, 2014.

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. PJM also pays the SRMCP to resources that are deselected because they are not capable of providing tier 1 synchronized reserves based on PJM's evaluation.

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

12 Hours in which the tier 1 estimate was biased by PJM dispatch are excluded from this graph. Tier 1 estimate biasing was used in 244 hours for the MAD subzone and 682 hours in the RTO Zone in all of 2014.

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 10-9). 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 10-12).

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. Tier 1 resources are not obligated to respond to synchronized reserve events. Only 35.3 percent of the market solution's estimated tier 1 resource MW actually responded during synchronized reserve events in 2014. Thus, 64.7 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 2014, tier 1 MW was paid $1,508,631 for its response to synchronized reserve events and it was paid $89.7 million for being identified as having ramp available during hours when the NSRMCP was greater than $0. (Table 10-10)

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

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
2014		541	$30.67	177,497	89,719,045	2,941.4

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

		Synchronized Reserve Events			Hours When NSRMCP > $0		
Year	Month	Total MW	Total Credits	Average MWs Per Event	Total MW	Total Credits	Average MWs 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
2014	Total	17,528	$1,508,631	318	1,803,275	$89,719,045	2,451

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 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.

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 June 24, 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 June 24, 2014, PJM has taken steps to ensure that deselected resources are no longer paid as tier 1 when NSRMCP was above $0.

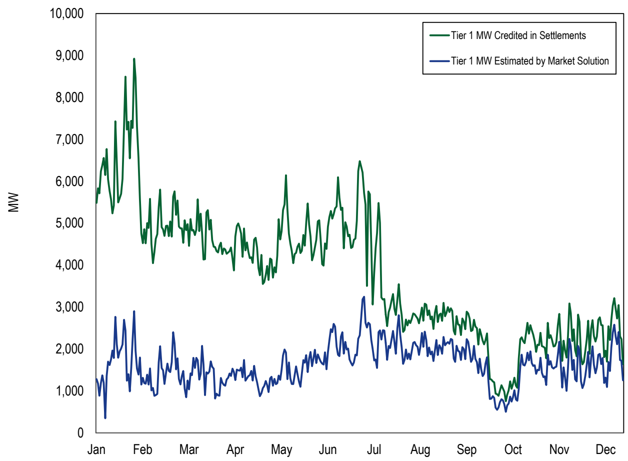
Table 10-13 shows the actual dollars paid to deselected tier 1 resources in error, $92.7 million from October 2012 through December 2014.

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	$655,254	$233,764	$1,603	$458	$656,858	$234,223	$422,635
2012	Nov	$3,865,259	$1,277,486	$140,128	$45,751	$4,005,387	$1,323,237	$2,682,150
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	$1,185,455	$479,173	$47,812	$14,773	$1,233,268	$493,946	$739,321
2013	May	$681,357	$215,651	$16,688	$5,260	$698,046	$220,910	$477,135
2013	Jun	$247,188	$61,479	$1,520	$321	$248,707	$61,800	$186,907
2013	Jul	$2,178,731	$421,124	$17,716	$3,367	$2,196,447	$424,491	$1,771,956
2013	Aug	$1,213,299	$278,125	$581,718	$110,764	$1,795,017	$388,888	$1,406,129
2013	Sep	$2,056,147	$216,591	$279,570	$52,282	$2,335,717	$268,873	$2,066,844
2013	Oct	$84,208	$20,083	$14,695	$2,147	$98,903	$22,229	$76,673
2013	Nov	$6,459	$1,216	$3,304	$1,471	$9,763	$2,687	$7,076
2013	Dec	$100,461	$9,219	$70,197	$8,915	$170,658	$18,134	$152,524
2014	Jan	$43,637,118	$3,568,087	$18,679,375	$1,306,227	$64,956,018	$4,874,314	$60,081,704
2014	Feb	$1,766,397	$228,579	$858,906	$109,324	$2,625,303	$337,903	$2,287,400
2014	Mar	$7,800,331	$1,188,555	$2,639,757	$325,081	$10,665,198	$1,513,636	$9,151,562
2014	Apr	$2,648,456	$525,691	$2,304,403	$390,583	$4,959,232	$916,275	$4,042,957
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	$599,147	$306,511	$292,636
2014	Dec	$489,294	$377,915	$796,041	$353,137	$1,133,507	$731,052	$402,455
	Total	$74,926,989	$11,328,771	$29,646,524	$3,309,054	$107,295,504	$14,637,824	$92,657,680

Figure 10-6 illustrates the impact of PJM's change effective in July 2014. Beginning January 2015, additional changes are intended to eliminate the discrepancy between market solution estimated tier 1 MW and the tier 1 MW paid by PJM.

Figure 10-6 Average hourly tier 1 actual MW vs average hourly estimated tier 1 MW, 2014



The MMU recommends that no payments be made to tier 1 resources if they are deselected in the PJM market solution.

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 2014, 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. Tier 1 biasing was used in the RT-SCED solution in 244 five-minute periods in amounts between -100 MW and -400 MW. All of the periods were on the days of extreme cold, January 7 and January 8.

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

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
2014	All	663	(1,164.4)	19	442.7

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.

Tier 1 biasing is generally done on a short-term basis. In January 2014, PJM dispatch found that the amount of tier 1 estimated by the ASO was not actually available when needed during the cold weather on January 6 and 7. As a result, PJM dispatch reset the tier 1 estimate value used by the ASO to be ten percent of the value estimated by the ASO for the entire period of January 7 through February 7. The effect of this change can be seen in Figure 0-2 and Figure 0-3. The dip in the grey area is the reduction of tier 1, forcing the ASO to fill the synchronized reserve requirement (yellow line) with tier 2 (green area).

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 2014, tier 1 synchronized reserve synchronized reserve event response credits (Table 10-15) were paid during 39 hours (in 15 of those hours the non-synchronized reserve market clearing price was also greater than zero). In 2014, $1,530,978 was paid for 17,962 MW of tier 1 response during 37 hours at a cost per MW of $85.23.

Table 10-15 Tier 1 synchronized reserve event response costs: 2014

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
2014	Jan	12	7,828	$965,846	$123.39	521.9
2014	Feb	1	273	$11,153	$40.82	273.2
2014	Mar	5	3,030	$175,902	$58.06	605.9
2014	Apr	2	389	$6,378	$16.39	194.5
2014	May	3	717	$34,906	$48.68	239.0
2014	Jun	0	NA	NA	NA	NA
2014	Jul	2	616	$35,179	$57.15	307.8
2014	Aug	0	NA	NA	NA	NA
2014	Sep	3	1,936	$143,574	$74.15	645.4
2014	Oct	2	1,132	$83,901	$74.14	565.8
2014	Nov	4	1,350	$38,895	$28.81	337.5
2014	Dec	3	692	$35,245	$50.96	230.5
2014	All	37	17,962	$1,530,978	$85.23	485.5

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 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

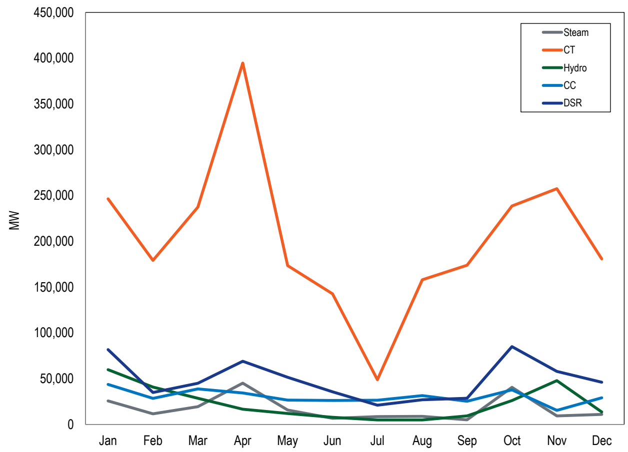
All non-emergency generating resources are required to submit tier 2 synchronized reserve offers. All online, non-emergency generating resources are deemed available to provide both tier 1 and tier 2 synchronized reserve. If PJM issues a primary reserve warning, voltage reduction warning, or manual load dump warning, all off line non-emergency generation capacity resources available to provide energy must submit an offer for tier 2 synchronized reserve.[13] This rule is intended to increase the accuracy of estimates of available synchronized reserve and primary reserve.

In 2014, the Mid Atlantic Dominion subzone averaged 3,720 MW in synchronized reserve offers, and the RTO Zone averaged 10,213 MW of synchronized reserve offers (Figure 10-11).

With the exception of several hours on January 6 and 7, the supply of tier 2 synchronized reserve in 2014 was sufficient to cover the requirement in both the RTO Reserve Zone and the Mid-Atlantic Dominion Reserve subzone. On January 6, hours 19 and 20, an RTO-wide shortage pricing event was triggered by a Voltage Reduction Action implemented in response to RTO-wide synchronized reserve levels falling below the 1,375 MW synchronized reserve requirement. On January 7, deficient synchronized reserves in the RTO Reserve Zone caused shortage pricing in hours 7 through 11. On January 7, deficient synchronized reserves in the Mid-Atlantic Dominion Reserve subzone caused shortage pricing in hours 7 through 12, 17 and 18.

Demand resources remain a significant part of market scheduled tier 2 synchronized reserve. The DR MW share of the total cleared MAD subzone Tier 2 Synchronized Reserve Market was 15.1 percent in 2014.[14] This is a reduction of 22.9 percentage points from the DR MW share of 38.0 percent of all cleared MAD tier 2 synchronized reserve in 2013.

Figure 10-7 Cleared Tier 2 Synchronized Reserve by unit type, full RTO Zone: 2014



Demand

The default hourly required synchronized reserve requirement is 1,375 MW in the RTO Reserve Zone and 1,300 MW for the Mid-Atlantic Dominion Reserve subzone (Table 10-16). There are two circumstances in which PJM may alter the synchronized reserve requirement from its default value. Between June 1, 2014, and September 30, 2014, PJM reserved the right to change the requirement in either the MAD subzone or the RTO Zone in the event of a Hot or Cold Weather Alert, Maximum Emergency Generation Alert, or Load Management Alert.[15] In 2014, PJM did not change the synchronized reserve requirement for this reason.

PJM may also change the synchronized reserve requirement from its default value (Figure 10-1) when grid maintenance or outages change the largest contingency. All changes to the synchronized reserve requirements in 2014 were for this reason. In 2014, PJM increased the synchronized reserve requirement in 145 hours in the MAD subzone and 1,445 hours in the RTO Reserve Zone (Figure 10-8). The average actual synchronized reserve requirement in the MAD subzone was 1,306.5 MW. The

13 See PJM. "Manual 11: Energy and Ancillary Services Market Operations" Revision 71, (January 1, 2015), p. 64.

14 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.

15 See PJM, "Manual 11, Energy and Ancillary Services Market Operations," Revision 71 (January 1, 2015), p. 68.

average actual synchronized reserve requirement in the RTO Reserve Zone was 1,454.4 MW.

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.

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	Dec 31, 2012	1,300	Mar 15, 2010	Nov 12, 2012	1,350
			Nov 12, 2012		1,375

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

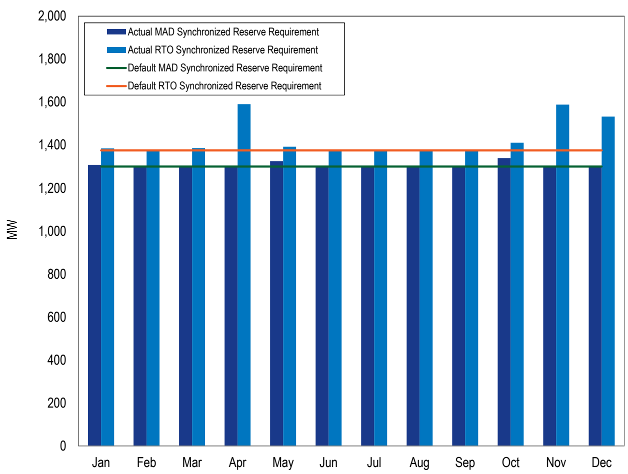


Figure 10-9 Mid-Atlantic Dominion Reserve subzone monthly average synchronized reserve required vs. tier 2 synchronized reserve scheduled MW: 2014

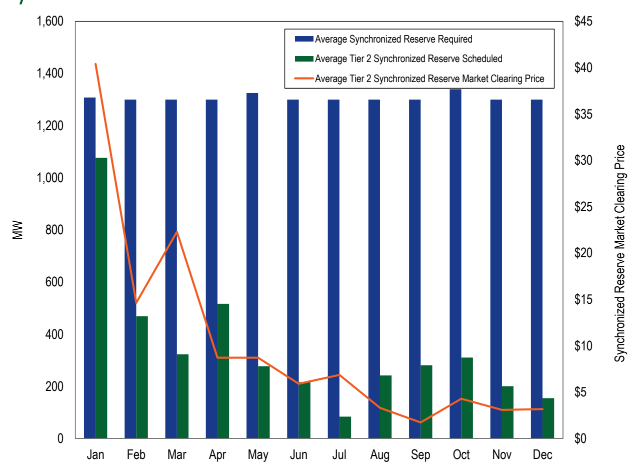
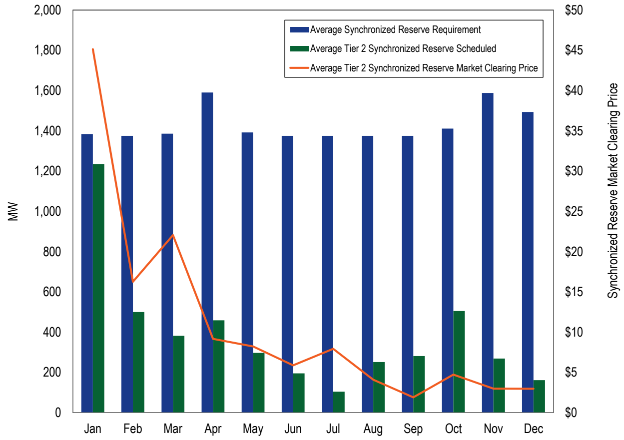


Figure 10-10 RTO Reserve zone monthly average synchronized reserve required vs. tier 2 synchronized reserve scheduled MW: 2014



In the RTO Reserve Zone, 37.4 percent of hours cleared a Tier 2 Synchronized Reserve Market in 2014 averaging 194.4 MW. This compares with 14.5 percent of hours averaging 251.6 MW in 2013. In the MAD Reserve Subzone, 48.6 percent of hours cleared a Tier 2 Synchronized Reserve Market in 2014 averaging 352.6 MW. This compares with 45.9 percent of hours cleared, averaging 153.8 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 2014, 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 295 hours in 2014 with an average negative bias below (1,169) MW per hour.

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 in 2014 was 5163, which is defined as highly concentrated. The largest hourly market share was 100 percent and 70.9 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 all of 2014 was 5639, which is defined as highly concentrated. The largest hourly market share was 100 percent and 79.7 percent of hours had a maximum market share greater than or equal to 40 percent.

In the MAD subzone, flexible synchronized reserve was 16.6 percent of all tier 2 synchronized reserve in 2014. In the RTO Zone, flexible synchronized reserve assigned was 24.6 percent of all tier 2 synchronized reserve in 2014. For flexible resources only, the hourly average HHI in 2014 in the MAD subzone was 8697. For flexible resources only the hourly average HHI in 2014 in the RTO Zone was 9104.

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

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%
2014	Total	41.3%	39.2%

The MMU calculates that 41.3 percent of hours failed the three pivotal supplier test in the MAD subzone in 2014 for the inflexible synchronized reserve market (excluding self-scheduled synchronized reserve) in the hour ahead market (Table 10-17) and 39.2 percent of hours failed a three pivotal supplier test in the RTO Zone in 2014.

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

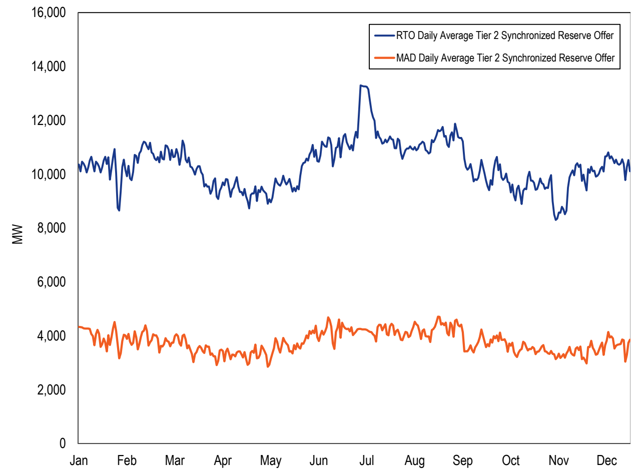
Offers

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 2014, the ratio of on-line and eligible tier 2 synchronized reserve to synchronized reserve required in the Mid-Atlantic Dominion subzone was 2.91 averaged over all hours. For the RTO Synchronized Reserve Zone the ratio was 7.52.

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): 2014



Synchronized reserve is offered by steam, CT, CC, hydroelectric and DR resources. Figure 0-12 shows average offer MW volume by market and unit type for the MAD subzone and Figure 0-13 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): 2012 through 2014

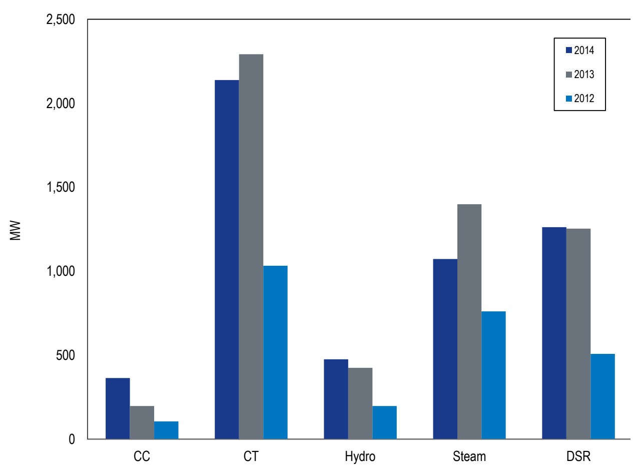
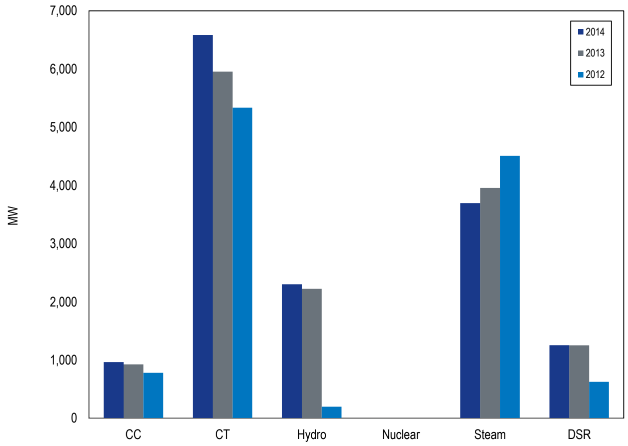


Figure 10-13 RTO Zone average daily tier 2 synchronized reserve offer by unit type (MW): 2012 through 2014



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 with a price greater than $0 in 48.6 percent of hours in 2014, compared to 55.5 percent of hours in 2013.

In 2014, the weighted average Tier 2 Synchronized Reserve Market clearing price in the RTO Zone only for all cleared hours was $12.94. In 2013, the weighted average synchronized reserve market clearing price in the RTO Zone was $6.98.

In 2014, the weighted average Tier 2 synchronized reserve market clearing price in the MAD subzone for all cleared hours was $15.50. In 2013, the weighted average synchronized reserve market clearing price in the MAD subzone was $7.11.

Both the RTO Zone and the MAD subzone experienced a primary reserve shortage and resulting shortage pricing event on January 6 in hour 19 and 20 and on January 7 in hours 7 through 12, 17 and 18. Shortage pricing for synchronized reserve was triggered on January 6 and 7. On January 6, hours 19 and 20, an RTO-wide shortage pricing event was triggered by a Voltage Reduction Action implemented in response to RTO-wide synchronized reserve levels falling below 1,375 MW synchronized reserve requirement. On January 7 deficient synchronized reserves in the RTO Reserve Zone caused shortage pricing in hours 7 through 11. On January 7, deficient synchronized reserves in the Mid-Atlantic Dominion Reserve Subzone caused Shortage Pricing in hours 7 through 12, 17 and 18.

Supply, performance, and demand are reflected in the price of synchronized reserve (Figure 10-9 and Figure 10-10). In January 2014, cold weather meant that on-line resources were generating at or near their economic maximum. As a result, there was little tier 1 synchronized reserve available and more tier 2 synchronized reserve were required.

Table 10-18 Mid-Atlantic Dominion Subzone, weighted SRMCP and cleared MW: 2014

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)
2014	Jan	$40.39	231	114	964
2014	Feb	$14.64	827	53	419
2014	Mar	$22.30	966	61	273
2014	Apr	$8.73	789	98	413
2014	May	$8.73	1,044	71	212
2014	Jun	$5.91	1,081	50	169
2014	Jul	$6.86	1,207	28	65
2014	Aug	$3.31	1,053	38	209
2014	Sep	$1.74	1,018	40	242
2014	Oct	$4.30	1,038	117	229
2014	Nov	$3.09	1,012	82	205
2014	Dec	$3.18	1,040	79	181
	Average	$15.50	942	69	299

Table 10-19 RTO zone weighted SRMCP and cleared MW: 2014

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)
2014	Jan	$45.14	1,111.9	113.7	158.5
2014	Feb	$16.25	1,287.2	53.2	34.5
2014	Mar	$22.04	1,276.3	61.5	48.1
2014	Apr	$9.16	1,351.5	97.8	341.2
2014	May	$8.22	1,208.7	70.9	115.2
2014	Jun	$5.88	1,227.3	50.4	97.3
2014	Jul	$7.93	1,309.4	28.1	37.5
2014	Aug	$4.09	1,292.1	37.7	45.2
2014	Sep	$1.89	1,266.9	40.1	68.0
2014	Oct	$4.72	948.0	117.2	389.6
2014	Nov	$2.98	1,181.3	82.4	349.3
2014	Dec	$3.30	1,188.9	60.3	300.2
	Average	$12.94	1,220.8	67.8	165.4

The RTO Zone cleared a Tier 2 Synchronized Reserve Market at a price above $0 in 39.1 percent of hours in 2014 compared to 14.3 percent in 2013. For all cleared hours, the average amount of tier 2 synchronized reserve cleared was 165.4 MW at a weighted average SRMCP of $12.94 (compared with $6.86 in 2013).

In the MAD subzone, in 2014 (Table 10-18), an average of 299.0 MW of tier 2 synchronized reserve was cleared at a weighted average price $15.50. In 2013, the weighted average price for tier 2 synchronized reserve in the MAD Reserve Zone was $7.11.

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 2014, the price to cost ratio of the full RTO Zone Tier 2 Synchronized Reserve Market averaged 64.7 percent (Table 10-20); the price to cost ratio of the RTO Zone excluding MAD averaged 52.9 percent; the price to cost ratio of the MAD subzone averaged 69.1 percent.

Table 10-20 Full RTO, RTO, Mid-Atlantic Subzone Tier 2 synchronized reserve MW, credits, price, and cost: 2014

Tier 2 Synchronized Reserve Market	Year	Month	Total MW	Total Credits	Weighted Synchronized Reserve Market Clearing Price	Cost	Price / Cost Ratio
Full RTO Zone	2014	Jan	445,496	$23,844,697	$45.14	$53.52	84.3%
Full RTO Zone	2014	Feb	258,309	$5,821,713	$16.25	$22.54	72.1%
Full RTO Zone	2014	Mar	331,076	$10,886,718	$22.04	$32.88	67.0%
Full RTO Zone	2014	Apr	523,600	$6,802,832	$9.16	$12.99	70.5%
Full RTO Zone	2014	May	222,982	$3,040,617	$8.22	$13.64	60.3%
Full RTO Zone	2014	Jun	173,110	$2,098,749	$5.88	$12.12	48.5%
Full RTO Zone	2014	Jul	105,641	$2,073,770	$7.93	$19.63	40.4%
Full RTO Zone	2014	Aug	162,348	$2,351,274	$4.09	$14.48	28.2%
Full RTO Zone	2014	Sep	190,382	$1,831,339	$1.89	$9.62	19.6%
Full RTO Zone	2014	Oct	410,778	$3,940,793	$4.72	$9.59	49.2%
Full RTO Zone	2014	Nov	383,082	$3,738,744	$2.98	$9.76	30.6%
Full RTO Zone	2014	Dec	279,091	$3,302,412	$3.30	$11.83	27.9%
Full RTO Zone	2014	Total	3,485,894	$69,733,658	$12.94	$20.00	64.7%
RTO Only	2014	Jan	20,161	$4,625,280	$145.29	$229.42	63.3%
RTO Only	2014	Feb	24,106	$1,005,403	$31.97	$41.71	76.7%
RTO Only	2014	Mar	49,150	$1,483,557	$20.55	$30.18	68.1%
RTO Only	2014	Apr	189,103	$2,651,007	$9.93	$14.02	70.8%
RTO Only	2014	May	64,474	$1,263,484	$6.97	$19.60	35.6%
RTO Only	2014	Jun	59,849	$802,216	$5.82	$13.40	43.4%
RTO Only	2014	Jul	36,502	$568,835	$9.95	$15.58	63.9%
RTO Only	2014	Aug	46,264	$903,706	$6.04	$19.53	30.9%
RTO Only	2014	Sep	38,492	$667,505	$2.49	$17.34	14.4%
RTO Only	2014	Oct	183,203	$1,894,664	$5.25	$10.34	50.8%
RTO Only	2014	Nov	182,400	$1,628,322	$2.86	$8.93	32.0%
RTO Only	2014	Dec	135,027	$1,521,211	$3.31	$11.27	29.4%
RTO Only	2014	Total	1,028,731	$19,015,190	$9.77	$18.48	52.9%
MAD Subzone	2014	Jan	425,336	$19,219,418	$40.39	$45.19	89.4%
MAD Subzone	2014	Feb	234,203	$4,816,310	$14.64	$20.56	71.2%
MAD Subzone	2014	Mar	281,925	$9,403,161	$22.30	$33.35	66.9%
MAD Subzone	2014	Apr	334,497	$4,151,824	$8.73	$12.41	70.3%
MAD Subzone	2014	May	158,507	$1,777,133	$8.73	$11.21	77.8%
MAD Subzone	2014	Jun	113,261	$1,296,534	$5.91	$11.45	51.6%
MAD Subzone	2014	Jul	69,139	$1,504,934	$6.86	$21.77	31.5%
MAD Subzone	2014	Aug	116,084	$1,447,568	$3.31	$12.47	26.6%
MAD Subzone	2014	Sep	151,890	$1,163,834	$1.74	$7.66	22.7%
MAD Subzone	2014	Oct	227,575	$2,046,129	$4.30	$8.99	47.8%
MAD Subzone	2014	Nov	200,682	$2,110,423	$3.09	$10.52	29.4%
MAD Subzone	2014	Dec	144,064	$1,781,201	$3.18	$12.36	26.6%
MAD Subzone	2014	Total	2,457,163	$50,718,468	$15.50	$20.64	69.1%

Compliance

Synchronized reserve non-compliance has two components: failure to deliver scheduled tier 2 Synchronized Reserve MW during synchronized reserve events; and failure of non-emergency, generation resources capable of providing energy to provide a daily synchronized reserve offer.

The MMU has identified and quantified the failure of scheduled tier 2 synchronized reserve resources to deliver during synchronized reserve events since 2011.[16] 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

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

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.[17] Tier 2 resources are obligated to sustain their final output for the shorter of the length of the event or 30 minutes.[18]

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 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: 2014

2014 Qualifying Synchronized Reserve Event (DD-Mon-YYYY HR)	Event Duration (Minutes)	Total Scheduled Tier 2 MW	Tier 2 Response Shortfall MW	Percent Compliance
06-Jan-2014 22	68	759	180	76.3%
07-Jan-2014 02	25	209	94	55.1%
07-Jan-2014 04	34	604	525	13.2%
07-Jan-2014 11	11	95	61	35.6%
07-Jan-2014 13	41	151	129	14.7%
10-Jan-2014 16	12	103	13	87.4%
31-Jan-2014 15	13	87	11	87.4%
08-Feb-2014 06	18	54	0	100.0%
01-Mar-2014 05	26	78	12	84.7%
27-Mar-2014 10	56	512	170	66.8%
01-May-2014 14	13	58	6	90.4%
03-May-2014 17	13	55	14	74.2%
06-Sep-2014 13	18	80	60	24.9%
20-Sep-2014 23	14	92	36	60.9%
29-Sep-2014 10	15	73	39	47.2%
20-Oct-2014 06	15	7	2	68.6%
23-Oct-2014 11	27	96	42	55.7%
22-Nov-2014 05	21	147	80	45.4%
31-Dec-2014 21	12	58	18	69.0%

Tier 1 resource owners are credited for the amount of synchronized reserve they provide in response to a synchronized reserve event.[19] 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 2014, 39.1 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.[20] 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 2014 is 15 days.

A second compliance issue is the failure to comply with the must offer requirement. The shortage pricing rules include a must offer requirement for tier 2 synchronized reserve for most generators under normal conditions, and an expanded set of generators under defined conditions related to peak load. For all hours, all on-line, non-emergency, generating resources that are providing energy and are capable of providing synchronized reserve are deemed available for tier 1 and tier 2 synchronized reserve and they must have a tier 2 offer and be available for reserve. When PJM issues a primary reserve warning, voltage reduction warning, or manual load dump warning, all other non-emergency, off-line available generation capacity resources must have a tier 2 offer and be available for

17 See PJM, "Manual 11, Energy & Ancillary Services Market Operations," Rev. 71, January 1, 2015 4.2.12 Non-Performance, p. 76.

18 See PJM, "Manual 11, Energy & Ancillary Services Market Operations," Rev. 71, January 1, 2015 4.2.11 Non-Performance, p. 76.

19 See PJM, "Manual 11, Energy & Ancillary Services Market Operations," Rev. 71, January 1, 2015 4.2.12 Non Performance, p. 76.

20 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.

reserve. As of December 28, 2014, the MMU estimates that all but 0.5 percent of eligible energy resources are in compliance with the synchronized reserve must-offer requirement.

PJM is to monitor every generator subject to the must offer requirement to ensure that it has submitted a tier 2 synchronized reserve offer greater than or equal to ninety percent of its ramp rate time 10 minutes.[21]

History of Synchronized Reserve Events

Synchronized reserve is designed to provide relief for disturbances.[22] 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.[23] 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 2010 through 2014, PJM experienced 151 synchronized reserve events, approximately three events per month. Synchronized reserve events had an average length of 13 minutes.

21 See PJM, "Manual 11, Energy & Ancillary Services Market Operations," Rev. 71, January 1, 2014 Section 4.2.1, p. 63.
22 2013 State of the Market Report for PJM, Appendix F – PJM's DCS Performance, pp 451-452.
23 See PJM, "Manual 12, Balancing Operations," Revision 31 (August 21, 2014), 4.1.2 Loading Reserves pp. 36.

Table 10-22 Synchronized reserve events, 2010 through 2014

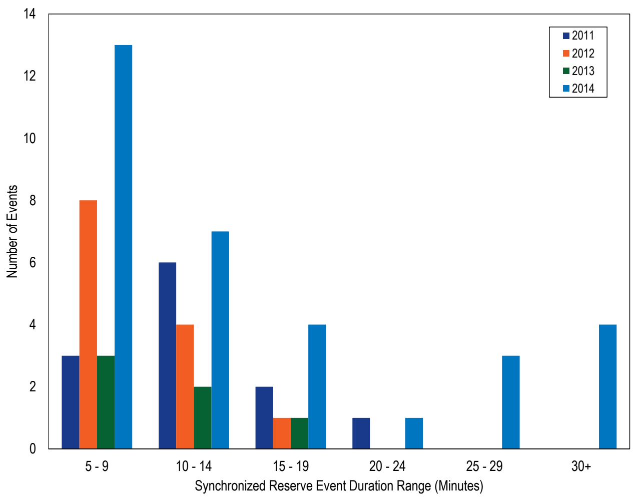
Effective Time	Region	Duration (Minutes)	Effective Time	Region	Duration (Minutes)	Effective Time	Region	Duration (Minutes)
FEB-18-2010 13:27	Mid-Atlantic	19	JAN-11-2011 15:10	Mid-Atlantic	6	JAN-03-2012 16:51	RFC	9
MAR-18-2010 11:02	RFC	27	FEB-02-2011 01:21	RFC	5	JAN-06-2012 23:25	RFC	8
MAR-23-2010 20:14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

Table 10-22 Synchronized reserve events, 2010 through 2014 *(continued)*

Effective Time	Region	Duration (Minutes)	Effective Time	Region	Duration (Minutes)
JAN-22-2013 08:34	RTO	8	JAN-06-2014 22:01	RTO	68
JAN-25-2013 15:01	RTO	19	JAN-07-2014 02:20	RTO	25
FEB-09-2013 22:55	RTO	10	JAN-07-2014 04:18	RTO	34
FEB-17-2013 23:10	RTO	13	JAN-07-2014 11:27	RTO	11
APR-17-2013 01:11	RTO	11	JAN-07-2014 13:20	RTO	41
APR-17-2013 20:01	RTO	9	JAN-10-2014 16:46	RTO	12
MAY-07-2013 17:33	RTO	8	JAN-21-2014 18:52	RTO	6
JUN-05-2013 18:54	RTO	20	JAN-22-2014 02:26	RTO	7
JUN-08-2013 15:19	RTO	9	JAN-22-2014 22:54	RTO	8
JUN-12-2013 17:35	RTO	10	JAN-25-2014 05:22	RTO	10
JUN-30-2013 01:22	RTO	10	JAN-26-2014 17:11	RTO	6
JUL-03-2013 20:40	RTO	13	JAN-31-2014 15:05	RTO	13
JUL-15-2013 18:43	RTO	29	FEB-02-2014 14:03	Dominion	8
JUL-28-2013 14:20	RTO	10	FEB-08-2014 06:05	Dominion	18
SEP-10-2013 19:48	RTO	68	FEB-22-2014 23:05	RTO	7
OCT-28-2013 10:44	RTO	33	MAR-01-2014 05:18	RTO	26
DEC-01-2013 11:17	RTO	9	MAR-05-2014 21:25	RTO	8
DEC-07-2013 19:44	RTO	7	MAR-13-2014 20:39	RTO	8
			MAR-27-2014 10:37	RTO	56
			APR-14-2014 01:16	RTO	10
			APR-25-2014 17:33	RTO	6
			MAY-01-2014 14:18	RTO	13
			MAY-03-2014 17:11	RTO	13
			MAY-14-2014 01:36	RTO	5
			JUL-08-2014 03:07	RTO	9
			JUL-25-2014 19:19	RTO	7
			SEP-06-2014 13:32	RTO	18
			SEP-20-2014 23:42	RTO	14
			SEP-29-2014 10:08	RTO	15
			OCT-20-2014 06:35	RTO	15
			OCT-23-2014 11:03	RTO	27
			NOV-01-2014 06:50	RTO	9
			NOV-08-2014 02:08	RTO	8
			NOV-22-2014 05:27	RTO	21
			NOV-22-2014 08:19	RTO	10
			DEC-10-2014 18:58	RTO	8
			DEC-31-2014 21:42	RTO	12

Compliance by tier 2 synchronized reserve to the 68 minute synchronized reserve event of January 6 was very poor (Table 10-21) at 45.4 percent non-compliance among MAD subzone resources and 29.7 percent non-compliance overall.

Figure 10-14 Synchronized reserve events duration distribution curve: 2011 through 2014



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 1,300 MW must be synchronized reserve, and that 2,063 MW of ten minute primary reserve must be available in the RTO Reserve Zone of which 1,375 MW must be synchronized reserve (Figure 10-2). 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). Except for four hours on January 7, 2014 there was always enough non-synchronized reserve available to meet the primary reserve requirement.

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.[24] In 2014, an average of 622.2 MW of non-synchronized reserve was scheduled hourly as part of the primary reserve requirement in the Mid-Atlantic Dominion subzone. In 2014, an average of 1,112.0 MW of non-synchronized reserve was scheduled hourly in the RTO Zone.

CTs provided 50.0 percent and hydro 47.9 percent of cleared non-synchronized reserve MW in 2014. The remaining 2.1 percent of cleared non-synchronized reserve was provided by diesel resources.

24 See PJM. "Manual 11, Energy & Ancillary Services Market Operations" Revision 71 (January 1, 2015), p. 79.

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: 2014

Year	Month	Mid Atlantic Dominion HHI	RTO HHI
2014	Jan	3034	3468
2014	Feb	2703	3610
2014	Mar	2859	2396
2014	Apr	4366	5333
2014	May	3784	6445
2014	Jun	3470	4054
2014	Jul	2927	6230
2014	Aug	4348	7761
2014	Sep	5349	3122
2014	Oct	5105	1327
2014	Nov	3652	2431
2014	Dec	3957	1703
2014	Average	3796	3990

Table 10-24 Non-synchronized reserve market pivotal supply test: 2014

Year	Month	Mid Atlantic Dominion Three Pivotal Supplier Hours	RTO Three Pivotal Supplier Hours
2014	Jan	97.2%	88.8%
2014	Feb	100.0%	95.7%
2014	Mar	99.2%	93.3%
2014	Apr	100.0%	92.6%
2014	May	100.0%	90.8%
2014	Jun	100.0%	95.5%
2014	Jul	99.7%	99.6%
2014	Aug	100.0%	98.0%
2014	Sep	100.0%	86.8%
2014	Oct	99.3%	99.9%
2014	Nov	100.0%	95.8%
2014	Dec	92.6%	98.3%
2014	Average	99.0%	94.6%

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 541 (6.2 percent) hours in 2014, at an average price of $26.20 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 $1.23 per MW. The maximum clearing price was the shortage pricing non-synchronized reserve maximum of $400 per MW for four consecutive hours on January 7, 2014. Figure 10-15 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 379 (4.4 percent) hours in 2014 at an average price of $21.82. The weighted non-synchronized reserve market clearing price for all hours in the RTO Zone including cleared hours when the price was zero, was $0.76. The maximum clearing price was the shortage pricing non-synchronized reserve maximum of $400 for four consecutive hours on January 7, 2014.

Figure 10-15 Daily average MAD subzone Non-synchronized Reserve Market clearing price and MW purchased: January through December 2014

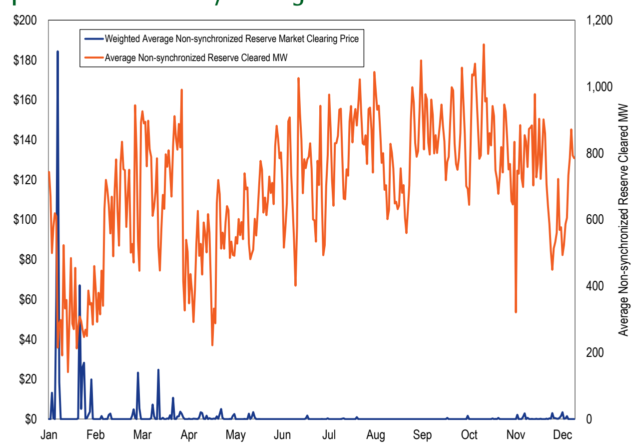
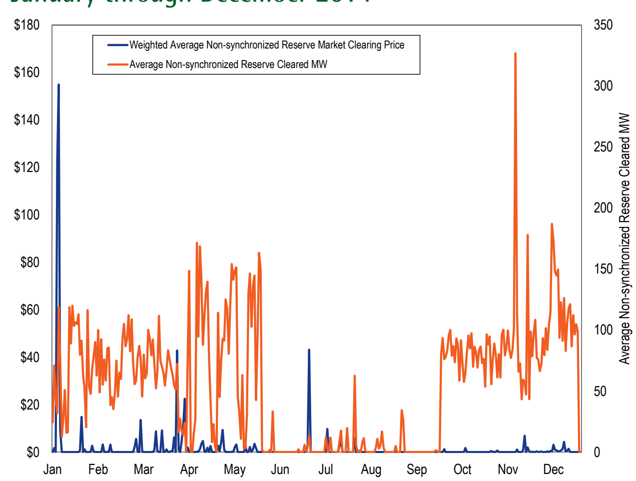


Figure 10-16 Daily average RTO Zone Non-synchronized Reserve Market clearing price and MW purchased: January through December 2014



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.

Table 10-25 Full RTO, RTO, Mid-Atlantic Subzone non-synchronized reserve MW, credits, price, and cost: 2014

Market	Year	Month	Total Non-Synchronized Reserve MW	Total Charges	Weighted Non-Synchronized Reserve Market Clearing Price	Cost	Price/Cost Ratio
Full RTO Zone	2014	Jan	291,938	$5,756,058	$7.16	$19.72	36.3%
Full RTO Zone	2014	Feb	416,613	$871,881	$0.30	$2.09	14.5%
Full RTO Zone	2014	Mar	582,741	$2,771,506	$0.95	$4.76	19.9%
Full RTO Zone	2014	Apr	392,105	$464,952	$0.93	$1.19	78.4%
Full RTO Zone	2014	May	478,527	$1,015,507	$0.36	$2.12	16.9%
Full RTO Zone	2014	Jun	532,890	$227,613	$0.05	$0.43	11.9%
Full RTO Zone	2014	Jul	573,581	$553,232	$0.07	$0.96	6.9%
Full RTO Zone	2014	Aug	600,291	$158,759	$0.00	$0.26	0.0%
Full RTO Zone	2014	Sep	609,047	$92,560	$0.00	$0.15	0.0%
Full RTO Zone	2014	Oct	704,373	$425,527	$0.04	$0.60	7.0%
Full RTO Zone	2014	Nov	626,155	$718,511	$0.20	$1.15	17.7%
Full RTO Zone	2014	Dec	604,420	$509,074	$0.40	$0.84	47.9%
Total	2014		6,412,683	$13,565,182	$0.87	$2.12	41.2%
RTO Only	2014	Jan	158,922	$1,945,725	$5.45	$12.24	44.5%
RTO Only	2014	Feb	253,255	$406,812	$0.25	$1.61	15.8%
RTO Only	2014	Mar	345,732	$1,011,285	$0.70	$2.93	23.8%
RTO Only	2014	Apr	233,686	$246,437	$0.87	$1.05	82.7%
RTO Only	2014	May	295,479	$603,341	$0.34	$2.04	16.6%
RTO Only	2014	Jun	322,662	$135,670	$0.05	$0.42	12.2%
RTO Only	2014	Jul	335,334	$308,849	$0.07	$0.92	7.3%
RTO Only	2014	Aug	365,874	$95,544	$0.00	$0.26	0.0%
RTO Only	2014	Sep	368,081	$52,482	$0.00	$0.14	0.0%
RTO Only	2014	Oct	435,381	$260,324	$0.04	$0.60	6.8%
RTO Only	2014	Nov	389,949	$428,735	$0.19	$1.10	17.4%
RTO Only	2014	Dec	369,022	$308,660	$0.40	$0.84	47.9%
Total	2014		3,873,379	$5,803,863	$0.70	$1.50	46.5%
MAD Subzone	2014	Jan	133,016	$3,810,333	$14.30	$28.65	49.9%
MAD Subzone	2014	Feb	163,358	$465,070	$0.64	$2.85	22.4%
MAD Subzone	2014	Mar	237,009	$1,760,222	$2.63	$7.43	35.4%
MAD Subzone	2014	Apr	158,419	$218,515	$1.14	$1.38	82.4%
MAD Subzone	2014	May	183,048	$412,166	$0.49	$2.25	21.6%
MAD Subzone	2014	Jun	210,228	$91,944	$0.05	$0.44	11.5%
MAD Subzone	2014	Jul	238,247	$244,383	$0.06	$1.03	6.3%
MAD Subzone	2014	Aug	234,417	$63,215	$0.00	$0.27	0.0%
MAD Subzone	2014	Sep	240,966	$40,078	$0.00	$0.17	0.0%
MAD Subzone	2014	Oct	268,992	$165,203	$0.04	$0.61	7.2%
MAD Subzone	2014	Nov	236,206	$289,776	$0.27	$1.23	22.1%
MAD Subzone	2014	Dec	235,398	$200,414	$0.41	$0.85	47.8%
Total	2014		2,539,305	$7,761,320	$1.67	$3.06	54.6%

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 0-25). The closer the price to cost ratio comes to one, the more the market price reflects the full cost of non-synchronized reserve.

In 2014, the price to cost ratio of the full RTO Zone non-synchronized reserve market averaged 41.2 percent; the price to cost ratio of the RTO Zone excluding MAD averaged 46.5 percent; the price to cost ratio of the MAD subzone averaged 54.6 percent.

Secondary Reserve (DASR)

PJM maintains a day-ahead, offer based market for 30-minute secondary reserve.[25] 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.

DASR 30-minute reserve requirements are determined by PJM for each reliability region.[26] In the ReliabilityFirst (RFC) region, secondary reserve requirements are calculated based on historical under-forecasted load rates and generator forced outage rates.[27] 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 6.27 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.[28]

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 emergency maximum minus the day-ahead dispatch point. Beginning January 1, 2015, the economic maximum will be used instead of emergency maximum. For off-line resources capable of being online in thirty minutes, the DASR quantity is emergency maximum (economic maximum beginning January 1, 2015). In 2014, the average available hourly DASR was 42,017 MW. The DASR MW purchased averaged 6,245 MW per hour for 2014, a decrease from 6,805 MW per hour in 2013. 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. There were several hours in September 2013 and January 2014 when secondary reserve was needed but was not available in real time.

Market Concentration

In 2014, 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 2013.

All generation resources are required to offer DASR.[29] Load response resources which are registered in PJM's Economic Load Response and are dispatchable by PJM are eligible to provide DASR. In 2014, 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.[30] 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 December 31, 2014, 9.6 percent of resources offered DASR at levels above $5 per MW.

Market Performance

For 94.1 percent of hours in 2014, DASR cleared at a price of $0.00 per MWh (Figure 10-17). In 2014, the weighted average DASR price was $0.63. The highest DASR price was $534.66 on January 8, 2014. DASR prices are calculated as the sum of the offer price plus the opportunity cost.

25 See PJM. "Manual 35, Definitions and Acronyms," Revision 35, (April 11, 2014), p. 89.
26 See PJM. "Manual 13, Emergency Requirements," Revision 57 (January 1, 2015), p. 11.
27 See PJM. "Manual 13, Emergency Requirements," Revision 57 (January 1, 2015), p. 11.
28 PJM uses the terms "supplemental operating reserves" and "scheduling operating reserves" interchangeably.
29 See PJM "Manual 11," Revision 71, (January 1, 2015) p. 142 at 11.2.3 Day-Ahead Scheduling Reserve Market Rules.
30 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 2014

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

When energy demand is high the reserve requirement cannot be filled without redispatching online resources which significantly affects the price. Figure 0-17 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 10-17 Daily average components of DASR clearing price ($/MW), marginal unit offer and LOC: 2014

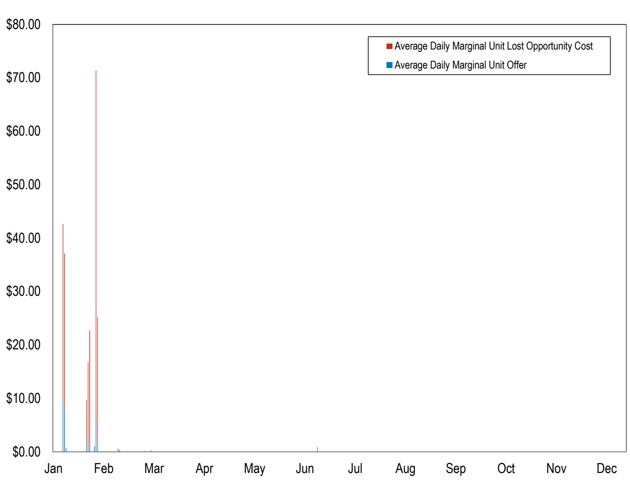
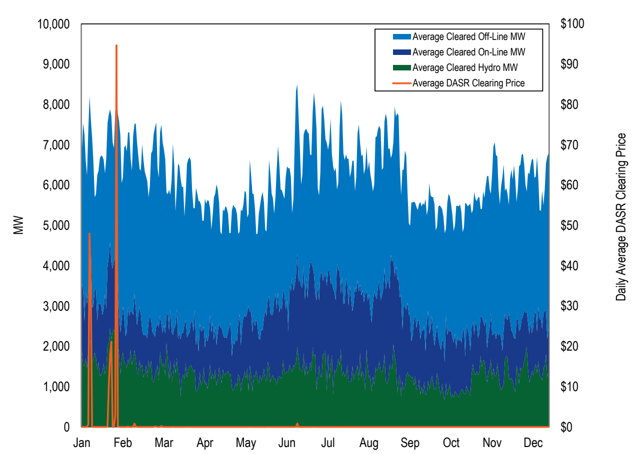


Figure 10-18 Daily average DASR prices and MW by classification: 2014



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.[31]

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, 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

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

between the regulation response and the regulation requested.[32]

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).[33] 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 expressly referred to as effective MW or effective regulation MW, MW means regulation capability MW unadjusted for either marginal benefit factor or performance factor.

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.

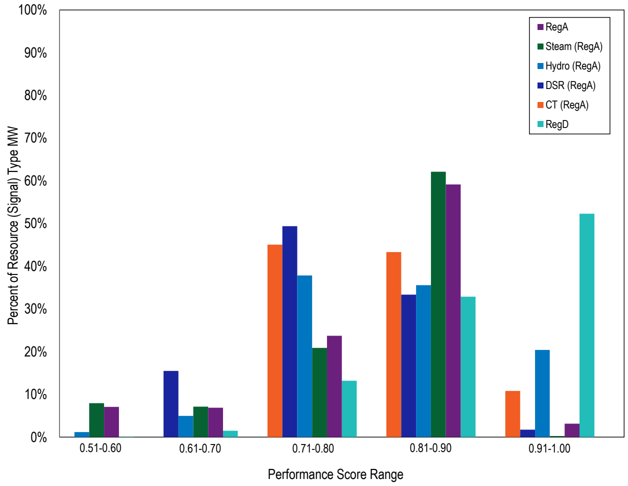
Resources are paid by RMCP credits (the sum of RMCCP credits and RMPCP credits) and lost opportunity cost credits. RMCCP credits are calculated as MW of regulation capability times performance score times RMCCP. RMPCP credits are calculated as MW of regulation capability times performance score times 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 10-19 shows the average performance score by resource type and signal followed for 2014. 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, 52.3 percent of RegD resources have average performance scores within the 0.91-1.00 range, whereas only 3.1 percent of RegA resources have average performance scores within that range.

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

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

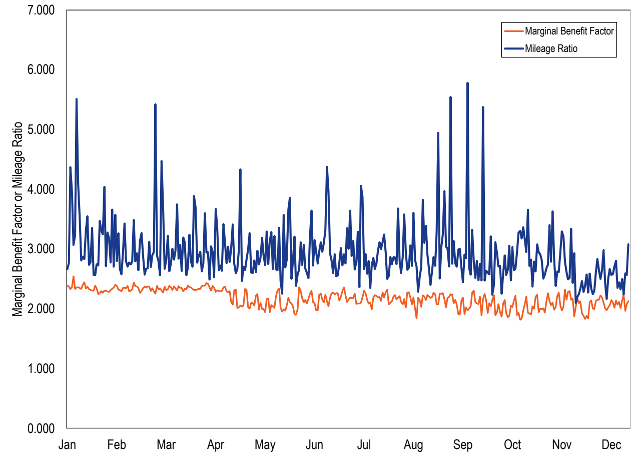
Figure 10-19 Hourly average performance score by unit type and regulation signal type: 2014



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 0-20 shows, the true marginal benefit factor, as used in the optimization and commitment process for regulation in 2014, was always higher than one. This caused resources following the RegD signal to be underpaid. Resources following the RegD signal should have been paid the true 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.

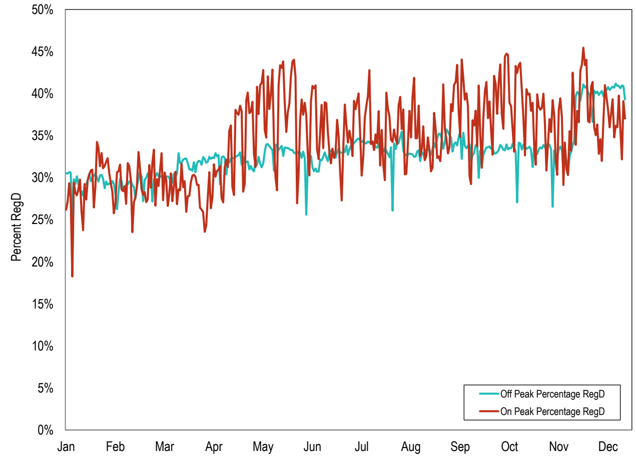
On October 2, 2013, FERC directed PJM to eliminate the use of the marginal benefit factor completely from settlement calculations of the capability and performance credits and replace it with RegD to RegA mileage ratio in the performance credit paid to RegD resources, effective November 1, 2013, and retroactively to October 1, 2012.[34] As Figure 0-20 demonstrates, the RegD to RegA mileage ratio is generally higher than the actual marginal benefit factor and much more variable. In this figure 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 10-20 Daily average marginal benefit factor and mileage ratio: 2014



Starting in April 2014, the proportion of RegD resources used to satisfy the on peak regulation requirement (700 effective MW) has varied considerably, as shown in Figure 10-21. This, in turn, has caused the marginal benefit factor, which is directly related to the proportion of RegD, to vary significantly since April 2014.

Figure 10-21 Daily average percentage of RegD effective MW by peak: 2014



34 145 FERC ¶ 61,011 (2013).

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.

Total regulation capability MW provided by coal units decreased from 563,665 MW in 2013 to 543,249 MW in 2014, but the proportion of regulation provided by coal increased, from 12.6 percent of regulation in 2013 to 13.2 percent of regulation in 2014. Coal unit revenues were $44.7 million in 2014, 1.4 times the $31.4 million in revenues in 2013. The increase in coal unit revenues was a result of the high regulation market clearing prices and out of market opportunity cost credits in January. 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.

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 10-27 PJM regulation capability, daily offer and hourly eligible: 2014[35 36]

		By Resource Type		By Signal Type	
Metric	All Regulation	Generating Resources	Demand Resources	RegA Following Resources	RegD Following Resources
Capability MW	8,388.2	8,373.4	14.8	8,304.2	402.2
Offered MW	3,468.9	3,462.3	6.6	3,411.7	57.2
Actual Eligible MW	1,280.3	1,275.2	5.1	1,104.1	176.4
Effective Eligible MW	917.4	910.0	7.4	680.3	237.3
Actual Cleared MW	660.7	657.6	3.1	546.2	114.3
Effective Cleared MW	663.7	657.6	6.1	436.3	227.2

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
2013	Jan	117	80,766	401,101	20.1%	$5,376,060
2013	Feb	101	64,164	365,249	17.6%	$3,071,878
2013	Mar	96	44,443	372,154	11.9%	$2,473,951
2013	Apr	80	26,964	297,782	9.1%	$1,559,309
2013	May	97	27,970	307,455	9.1%	$1,856,919
2013	Jun	106	42,345	387,670	10.9%	$2,332,995
2013	Jul	109	73,068	447,273	16.3%	$5,659,884
2013	Aug	95	56,657	430,879	13.1%	$2,651,943
2013	Sep	89	41,021	358,971	11.4%	$2,118,200
2013	Oct	62	35,088	321,080	10.9%	$1,688,471
2013	Nov	67	37,872	378,946	10.0%	$1,370,984
2013	Dec	81	33,309	388,691	8.6%	$1,208,075
2013	Average	92	46,972	371,438	12.4%	$2,614,056
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
2014	Apr	76	52,780	351,763	15.0%	$2,805,943
2014	May	76	36,989	324,871	11.4%	$2,023,258
2014	Jun	82	31,369	330,372	9.5%	$1,591,779
2014	Jul	88	42,754	336,232	12.7%	$1,765,050
2014	Aug	77	37,950	352,366	10.8%	$1,276,055
2014	Sep	78	35,271	345,852	10.2%	$2,012,589
2014	Oct	63	44,963	350,894	12.8%	$2,563,178
2014	Nov	80	50,282	345,190	14.6%	$2,045,081
2014	Dec	69	37,048	355,081	10.4%	$1,307,848
2014	Average	83	45,271	342,017	13.2%	$3,727,055

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

Current Regulation Units, 2014	Adjusted Settled MW, 2014	Units Scheduled To Retire Through 2015	Adjusted Settled MW of Units Scheduled To Retire Through 2015	Percent Of Regulation MW To Retire Through 2015
301	4,104,200	35	33,749	0.82%

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

36 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.

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 2014 because the average performance score was less than 1.00 (Figure 10-22). For 2014, the MW-weighted average RegA performance score was 0.80 and in 2014, there were 296 resources following the RegA signal.

In Figure 10-22 and Figure 10-23, 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 10-22 shows the results for effective MW, Figure 10-23 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.

For RegD resources, the effective MW are higher than the actual MW because their marginal benefit factor at current participation levels is significantly greater than 1.0. In 2014, the marginal benefit factor for cleared RegD following resources ranged from 0.477 to 2.751 with an average over all hours of 2.179. In 2014, the MW-weighted average RegD resource performance score was 0.90 and there were 52 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.

Figure 10-22 Monthly cleared effective MW and performance score by signal: 2014

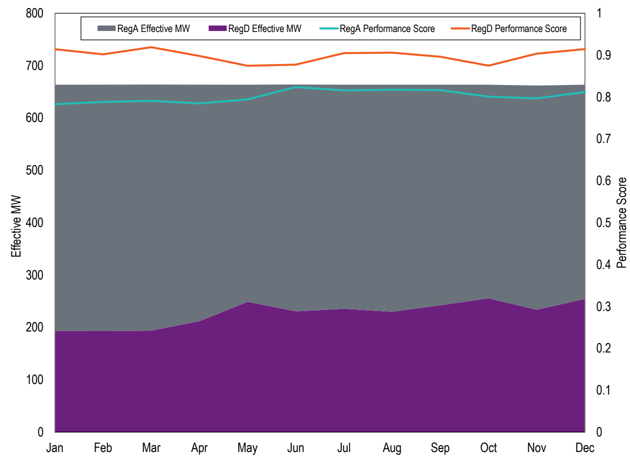
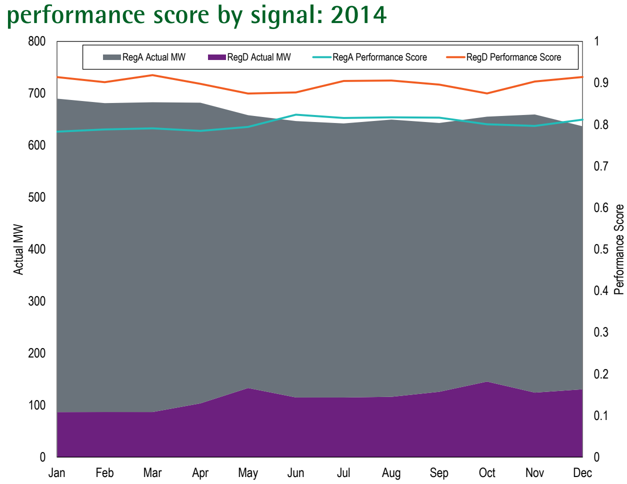


Figure 10-23 Monthly cleared actual MW and performance score by signal: 2014



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). Throughout 2014, the price and cost of regulation have remained high relative to prior years. The weighted average regulation price for 2014 was $44.15/MW. The regulation cost for 2014 was $53.41/MW. The ratio of price to cost is lower (83 percent) than in the same period in 2013 (87 percent) due to the extreme market conditions in January that resulted in increased out of market payments based on lost opportunity costs.

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 through all of 2014.

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 10-24 for every month from January 2011 through 2014 with the dashed vertical line marking the date (October 1, 2012) of the implementation of the Performance Based Regulation Market design.37 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 10-24 PJM monthly CPS1 and BAAL performance: January 2011 through 2014

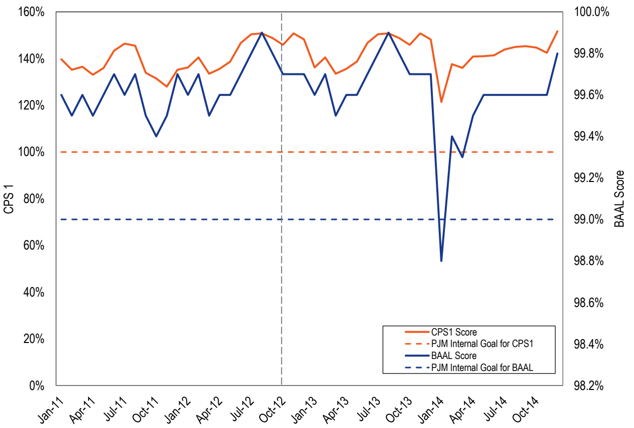


Table 10-30 PJM Regulation Market required MW and ratio of eligible supply to requirement: 2013 and 2014

Month	Average Required Regulation (MW), 2013	Average Required Regulation (MW), 2014	Average Required Regulation (Effective MW), 2013	Average Required Regulation (Effective MW), 2014	Ratio of Supply MW to MW Requirement, 2013	Ratio of Supply MW to MW Requirement, 2014	Ratio of Supply Effective MW to Effective MW Requirement, 2013	Ratio of Supply Effective MW to Effective MW Requirement, 2014
Jan	862	690	720	664	1.80	2.05	1.72	1.60
Feb	875	681	724	664	1.85	2.00	1.73	1.51
Mar	774	683	681	664	1.67	1.99	1.56	1.48
Apr	663	682	594	664	1.75	2.04	1.64	1.54
May	683	658	616	664	1.67	1.93	1.57	1.44
Jun	808	647	731	664	1.76	1.89	1.65	1.29
Jul	920	642	823	664	1.69	1.88	1.62	1.29
Aug	835	650	757	664	2.11	1.93	1.66	1.30
Sep	697	643	670	664	2.25	1.91	1.60	1.26
Oct	633	655	613	664	2.50	1.83	1.79	1.26
Nov	677	659	661	664	2.62	1.85	1.84	1.28
Dec	677	637	664	664	2.27	1.96	1.67	1.34

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

Market Concentration

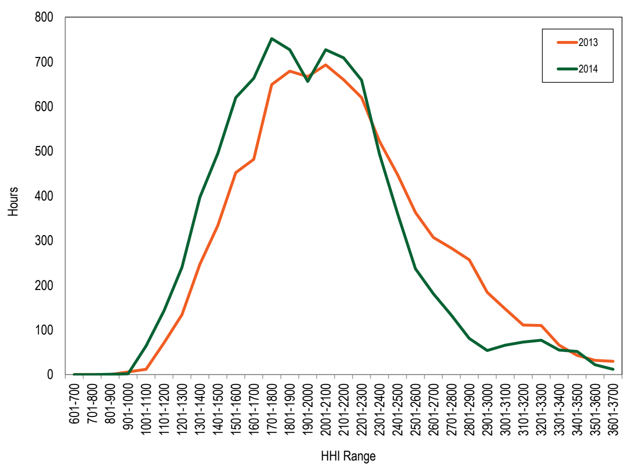
Table 10-31 shows Herfindahl-Hirschman Index (HHI) results for 2013 and 2014, based on market shares of effective MW, defined as regulation capability MW adjusted by performance score and resource-specific benefit factor, consistent with the metrics used to clear the regulation market. The weighted average HHI of 1960 is classified as highly concentrated, but is lower than the HHI for the same period in 2013 of 2102. For 2014, the weighted average HHI of RegA resources was 3141 (highly concentrated and higher than the 2013 value of 2751) and the weighted average HHI of RegD resources was 4329 (highly concentrated and lower than the 2013 value of 6784). 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: 2013 and 2014

Period	Minimum HHI	Weighted Average HHI	Maximum HHI
2013	966	2102	9616
2014	877	1960	3943

Figure 10-25 compares the frequency distribution of HHI for 2014 with 2013.

Figure 10-25 PJM Regulation Market HHI distribution: 2013 and 2014



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 2014, 97 percent of hours had one or more pivotal suppliers. The impact of offer capping in the regulation market is limited because of the role of LOC in price formation (Figure 10-27).The MMU concludes from these results that the PJM Regulation Market in 2014 was characterized by structural market power in 97 percent of hours.

Table 10-32 Regulation market monthly three pivotal supplier results: 2012 through 2014

	2012	2013	2014
Month	Percent of Hours Pivotal	Percent of Hours Pivotal	Percent of Hours Pivotal
Jan	71%	83%	97%
Feb	67%	82%	99%
Mar	64%	97%	95%
Apr	41%	88%	89%
May	37%	93%	96%
Jun	40%	95%	99%
Jul	13%	94%	100%
Aug	32%	92%	100%
Sep	35%	90%	99%
Oct	19%	83%	99%
Nov	18%	89%	99%
Dec	40%	95%	98%
Average	40%	90%	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.[38]

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.[39]

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).[40] Figure 10-26 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.41 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 46.3 percent during on peak and 62.7 percent during off peak hours in 2014).

Figure 10-26 Off peak and on peak regulation levels: 2014

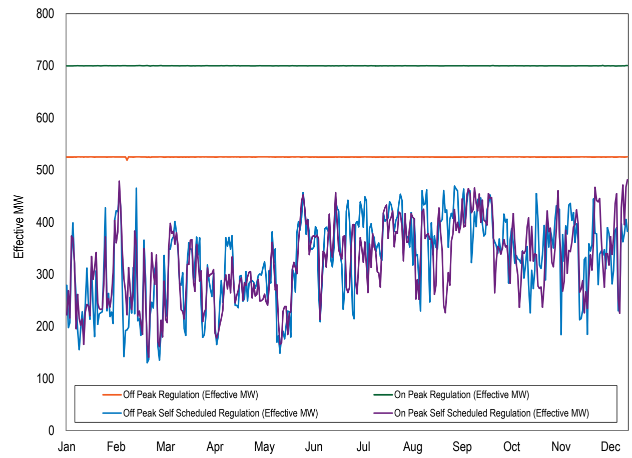


Table 10-33 shows how RegD resources have impacted the Regulation Market. RegD resources are both a growing proportion of the market (11 percent at the start of the Performance Based Regulation Market design in October 2012 versus 38 percent in October 2014) and a growing proportion of resources that self schedule (10 percent in October 2012 versus 17 percent in October 2014). This has resulted in an increase in the proportion of the regulation requirement that is self scheduled.

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

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

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

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

Table 10-33 RegD self scheduled regulation by month, October 2012 through December 2014

Year	Month	RegA Self Scheduled Effective MW	RegA Effective MW	Percent of RegA Self Scheduled	RegD Self Scheduled Effective MW	RegD Effective MW	Percent of RegD Self Scheduled	Total Self Scheduled Effective MW	Total Effective MW	RegA Percent of Total Self Scheduled	Percent of Total Self Scheduled	RegD Percent of Total Self Scheduled	Percent of Total Self Scheduled	RegA Percent of Total Effective MW	RegD Percent of Total Effective MW
2012	Oct	198	586	34%	66	72	92%	265	658	30%	40%	10%	40%	89%	11%
2012	Nov	122	628	19%	74	88	84%	197	716	17%	27%	10%	27%	88%	12%
2012	Dec	106	612	17%	83	89	93%	189	701	15%	27%	12%	27%	87%	13%
2013	Jan	98	638	15%	36	82	43%	134	720	14%	19%	5%	19%	89%	11%
2013	Feb	127	634	20%	85	90	94%	212	724	18%	29%	12%	29%	88%	12%
2013	Mar	200	561	36%	80	119	67%	280	681	29%	41%	12%	41%	82%	18%
2013	Apr	184	487	38%	82	107	77%	266	594	31%	45%	14%	45%	82%	18%
2013	May	194	507	38%	74	109	68%	268	616	32%	44%	12%	44%	82%	18%
2013	Jun	255	608	42%	80	123	65%	335	731	35%	46%	11%	46%	83%	17%
2013	Jul	226	703	32%	78	120	64%	304	823	27%	37%	9%	37%	85%	15%
2013	Aug	282	629	45%	84	128	66%	366	757	37%	48%	11%	48%	83%	17%
2013	Sep	269	518	52%	112	152	74%	382	670	40%	57%	17%	57%	77%	23%
2013	Oct	229	450	51%	120	164	73%	350	613	37%	57%	20%	57%	73%	27%
2013	Nov	263	488	54%	134	176	76%	397	663	40%	60%	20%	60%	74%	26%
2013	Dec	177	483	37%	137	181	76%	314	664	27%	47%	21%	47%	73%	27%
2014	Jan	128	470	27%	133	194	69%	261	664	19%	39%	20%	39%	71%	29%
2014	Feb	156	471	33%	134	193	70%	291	664	24%	44%	20%	44%	71%	29%
2014	Mar	156	470	33%	132	194	68%	287	664	23%	43%	20%	43%	71%	29%
2014	Apr	143	452	32%	127	212	60%	270	664	22%	41%	19%	41%	68%	32%
2014	May	143	415	35%	122	249	49%	265	664	22%	40%	18%	40%	62%	38%
2014	Jun	243	433	56%	123	231	53%	366	664	37%	55%	19%	55%	65%	35%
2014	Jul	225	428	53%	127	236	54%	352	664	34%	53%	19%	53%	64%	36%
2014	Aug	251	434	58%	117	230	51%	369	664	38%	56%	18%	56%	65%	35%
2014	Sep	272	421	65%	121	242	50%	394	664	41%	59%	18%	59%	63%	37%
2014	Oct	237	408	58%	116	255	45%	353	664	36%	53%	17%	53%	62%	38%
2014	Nov	235	429	55%	114	235	48%	348	664	35%	52%	17%	52%	65%	35%
2014	Dec	235	409	57%	117	254	46%	352	664	35%	53%	18%	53%	62%	38%
Average		198	510	40%	104	168	66%	302	678	29%	45%	15%	45%	75%	25%

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 2014, 49.3 percent was purchased in the PJM market, 45.8 percent was self-scheduled, and 4.9 percent was purchased bilaterally (Table 10-34). From 2010 through 2014, Table 10-35 shows the total regulation by market regulation, self-scheduled regulation, and bilateral regulation. 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: 2013 and 2014

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
2013	Jan	413,304	83.6%	72,880	14.7%	8,070	1.6%	494,253	486,993	98.5%	7,261	1.5%
2013	Feb	338,990	74.7%	102,005	22.5%	12,808	2.8%	453,803	444,761	98.0%	9,042	2.0%
2013	Mar	275,880	60.0%	165,987	36.1%	17,554	3.8%	459,421	441,104	96.0%	18,317	4.0%
2013	Apr	219,793	57.6%	147,858	38.8%	13,860	3.6%	381,510	365,735	95.9%	15,775	4.1%
2013	May	235,849	57.0%	161,270	38.9%	16,934	4.1%	414,053	397,086	95.9%	16,967	4.1%
2013	Jun	254,215	53.4%	198,617	41.8%	22,816	4.8%	475,647	456,515	96.0%	19,133	4.0%
2013	Jul	349,047	63.2%	182,452	33.0%	21,201	3.8%	552,699	536,209	97.0%	16,490	3.0%
2013	Aug	258,550	50.7%	230,441	45.2%	21,351	4.2%	510,342	488,981	95.8%	21,360	4.2%
2013	Sep	181,609	43.8%	214,932	51.9%	17,647	4.3%	414,187	387,443	93.5%	26,745	6.5%
2013	Oct	167,857	44.1%	200,079	52.5%	13,073	3.4%	381,009	351,951	92.4%	29,058	7.6%
2013	Nov	161,126	40.1%	221,180	55.1%	19,248	4.8%	401,553	370,938	92.4%	30,616	7.6%
2013	Dec	229,345	55.5%	164,070	39.7%	19,699	4.8%	413,114	387,443	93.8%	25,671	6.2%
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%

Table 10-35 Regulation sources by year: 2010 through 2014

Year	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)
2010	6,192,042	82.2%	1,161,581	15.4%	175,590	2.3%	7,529,214
2011	6,433,062	81.8%	1,226,633	15.6%	207,682	2.6%	7,867,377
2012	6,154,298	78.6%	1,484,768	19.0%	193,408	2.5%	7,832,474
2013	3,085,563	57.7%	2,061,770	38.5%	204,259	3.8%	5,351,592
2014	2,326,612	49.3%	2,161,585	45.8%	231,031	4.9%	4,719,227

In 2014, DR provided an average of 3.05 MW of regulation per hour (2.46 MW of regulation per hour in 2013). Generating units supplied an average of 657.61 MW of regulation per hour (804.36 MW of regulation per hour in 2013).

Market Performance

Price

The weighted average RMCP for 2014 was $44.15 per MW. This is the average price per unadjusted capability MW. This is a 46.5 percent increase from the weighted average RMCP of $30.14/MW in 2013. The increase in regulation price resulted primarily from very high prices in the first three months of 2014. Figure 10-27 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 10-27 PJM Regulation Market daily weighted average market-clearing price, marginal unit opportunity cost and offer price (Dollars per MW): 2014

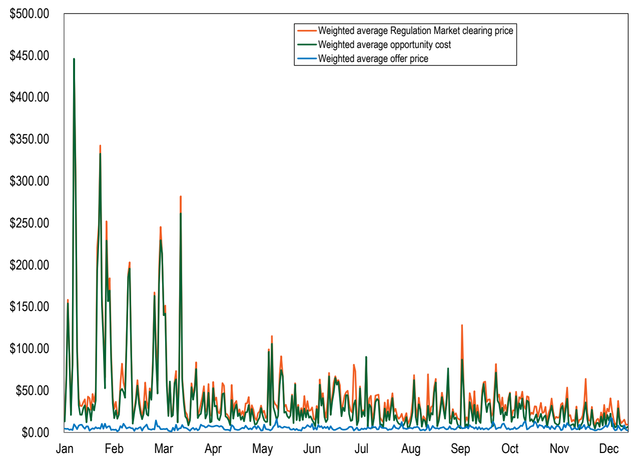


Table 10-36 shows monthly average regulation market clearing price, average marginal unit offer price, and average marginal unit LOC on an unadjusted capability MW basis.

Table 10-36 PJM Regulation Market monthly weighted average market-clearing price, marginal unit opportunity cost and offer price (Dollars per MW): 2014

Month	Weighted Average Regulation Market Clearing Price	Weighted Average Regulation Marginal Unit Offer	Weighted Average Regulation Marginal Unit LOC
Jan	$132.49	$5.44	$101.27
Feb	$62.61	$4.72	$60.76
Mar	$80.75	$4.79	$71.35
Apr	$31.80	$5.56	$25.58
May	$34.47	$5.22	$31.94
Jun	$30.43	$5.23	$31.54
Jul	$29.80	$4.71	$27.84
Aug	$20.54	$5.27	$20.41
Sep	$25.06	$5.31	$30.35
Oct	$32.98	$6.36	$28.21
Nov	$27.56	$6.59	$16.74
Dec	$21.33	$5.74	$13.18

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: 2013 and 2014

Year	Month	Scheduled Regulation (MW)	Total Regulation Charges ($)	Weighted Average Regulation Market Price ($/MW)	Cost of Regulation ($/MW)	Price as Percentage of Cost
2013	Jan	494,253	$22,870,690	$39.94	$46.27	86.3%
2013	Feb	453,803	$15,273,604	$29.51	$33.66	87.7%
2013	Mar	459,421	$16,678,410	$31.64	$36.30	87.2%
2013	Apr	381,510	$11,930,098	$26.49	$31.27	84.7%
2013	May	414,053	$15,599,491	$33.42	$37.68	88.7%
2013	Jun	475,647	$15,999,677	$29.81	$33.64	88.6%
2013	Jul	552,699	$31,386,733	$50.12	$56.79	88.3%
2013	Aug	510,342	$15,866,117	$27.60	$31.09	88.8%
2013	Sep	414,187	$12,203,764	$25.98	$29.46	88.2%
2013	Oct	381,009	$10,155,471	$23.30	$26.65	87.4%
2013	Nov	401,553	$10,008,092	$21.45	$24.92	86.1%
2013	Dec	413,114	$11,188,339	$22.43	$27.08	82.8%
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%

Table 10-38 Components of regulation cost: 2014

Month	Scheduled Regulation (MW)	Cost of Regulation Capability ($/MW)	Cost of Regulation Performance ($/MW)	Opportunity Cost ($/MW)	Total Cost ($/MW)
Jan	407,656	$124.57	$11.60	$25.03	$161.20
Feb	366,670	$57.80	$6.41	$10.23	$74.44
Mar	411,677	$76.76	$5.71	$14.96	$97.43
Apr	395,612	$28.50	$4.49	$5.54	$38.53
May	397,411	$31.24	$4.64	$6.78	$42.66
Jun	387,102	$26.96	$4.57	$5.44	$36.97
Jul	395,865	$26.23	$4.74	$5.62	$36.59
Aug	401,673	$17.19	$4.34	$3.39	$24.91
Sep	382,207	$21.79	$4.45	$4.87	$31.10
Oct	395,073	$28.96	$5.47	$4.76	$39.19
Nov	385,812	$24.14	$4.45	$4.09	$32.68
Dec	392,470	$18.62	$3.58	$3.04	$25.24

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.

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 10-28. On November 1, 2013, FERC instructed PJM to remove the marginal benefit factor from all settlement calculations.[42] 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 10-28 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 10-28 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 10-28, the RegA RMCP

42 145 FERC ¶ 61,011 (2013).

Credit per effective MW is, on average, 1.9 times higher than the RegD RMCP Credit per effective MW from October 2012 through 2014. 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.

Table 10-39 provides the information from Figure 10-28, 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.

Figure 10-28 Comparison of monthly average RegA and RegD RMCP Credits per Effective MW: October 2012 through 2014

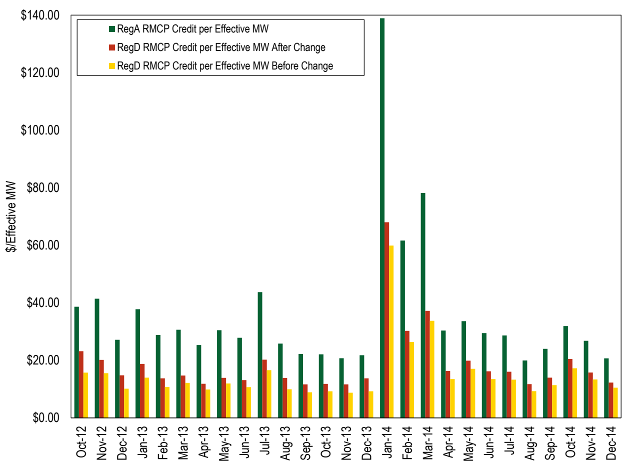


Table 10-39 Comparison of monthly average RegA and RegD RMCP Credits per Effective MW: October 2012 through 2014

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%
Average		$35.86	$15.26	$18.70	$35.86	$20.60	$17.16	57%	47%

Table 10-40 Comparison of monthly average RegA and RegD RMCP Credits: October 2012 through 2014

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%
Total		$371,253,000	$52,460,000	$62,864,000	$119,226,000	$66,763,000	$56,356,000	57%	47%

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 83 percent in from 87 percent in 2013. This was in part a result of extreme market conditions in January.

Table 10-41 Comparison of average price and cost for PJM Regulation, 2008 through 2014

Year	Weighted Regulation Market Price	Weighted Regulation Market Cost	Regulation Price as Percent Cost
2008	$42.09	$64.43	65%
2009	$23.56	$29.87	79%
2010	$18.08	$32.07	56%
2011	$16.21	$29.28	55%
2012	$20.35	$26.41	77%
2013	$30.14	$34.57	87%
2014	$44.15	$53.41	83%

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.[43] 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 for scheduling in the Day-Ahead Energy Market or committing in real time units that provide black start service. 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.

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

In 2014, total black start charges were $59.9 million, a $47.7 million (44.3 percent) decrease from the 2013 level of $107.6 million. Operating reserve charges for black start service declined from $86.7 million in 2013 to $33.0 million in 2014. This decrease was due to higher LMPs that caused more ALR black start units to run economically rather than out of merit. 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: 2009 through 2014

Year	Revenue Requirement Charges
2009	$14,264,163
2010	$11,490,379
2011	$13,695,331
2012	$18,749,617
2013	$20,939,804
2014	$26,931,890

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 2014.

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 10-43 Black start zonal charges for network transmission use: 2013 and 2014

Zone	2013 Revenue Requirement Charges	2013 Operating Reserve Charges	2013 Total Charges	2013 Peak Load (MW-day)	2013 Black Start Rate ($/MW-day)	2014 Revenue Requirement Charges	2014 Operating Reserve Charges	2014 Total Charges	2014 Peak Load (MW-day)	2014 Black Start Rate ($/MW-day)
AECO	$581,124	$41,138	$622,262	1,025,285	$0.61	$641,714	$33,266	$674,979	999,808	$0.68
AEP	$649,333	$82,041,349	$82,690,682	8,507,639	$9.72	$1,703,556	$30,810,379	$32,513,935	8,338,900	$3.90
APS	$267,202	$3,063	$270,264	3,111,370	$0.09	$284,629	$3,027	$287,656	3,167,251	$0.09
ATSI	$124,525	$2,119	$126,644	4,932,938	$0.03	$1,117,362	$32,487	$1,149,849	4,796,501	$0.24
BGE	$6,095,115	$10,301	$6,105,416	2,555,730	$2.39	$8,298,743	$5,049	$8,303,792	2,493,060	$3.33
ComEd	$4,097,259	$56,996	$4,154,255	8,614,329	$0.48	$4,244,937	$44,049	$4,288,986	8,128,185	$0.53
DAY	$241,080	$5,252	$246,332	1,280,092	$0.19	$238,561	$6,511	$245,071	1,244,395	$0.20
DEOK	$667,936	$8,662	$676,599	1,988,923	$0.34	$1,143,965	$15,022	$1,158,987	1,878,290	$0.62
Dominion	$508,734	$21,152	$529,886	4,138,535	$0.13	$1,002,588	$4,599	$1,007,188	6,848,495	$0.15
DPL	$558,101	$31,314	$589,415	1,501,647	$0.39	$569,743	$39,708	$609,451	1,466,826	$0.42
DLCO	$58,154	$7,928	$66,082	1,114,747	$0.06	$59,743	$12,520	$72,263	1,077,298	$0.07
EKPC	$214,758	$8,380	$223,138	509,919	$0.44	$414,902	$4,438	$419,341	924,399	$0.45
JCPL	$554,197	$14,945	$569,142	2,270,081	$0.25	$511,961	$6,257	$518,218	2,328,299	$0.22
Met-Ed	$789,692	$55,639	$845,330	1,108,286	$0.76	$841,635	$66,769	$908,404	1,099,490	$0.83
PECO	$1,405,096	$28,121	$1,433,217	3,120,385	$0.46	$1,514,449	$13,614	$1,528,063	3,145,716	$0.49
PENELEC	$510,881	$6,835	$517,716	1,061,420	$0.49	$525,443	$3,497	$528,940	1,126,865	$0.47
Pepco	$300,675	$24,095	$324,770	2,453,056	$0.13	$315,935	$17,347	$333,282	2,384,691	$0.14
PPL	$184,305	$0	$184,305	2,694,248	$0.07	$219,982	$0	$219,982	2,698,153	$0.08
PSEG	$2,094,342	$32,992	$2,127,334	3,821,477	$0.56	$1,776,610	$32,643	$1,809,253	3,801,256	$0.48
RECO	$0	$0	$0	NA	NA	$0	$0	$0	NA	NA
(Imp/Exp/Wheels)	$1,037,296	$4,301,281	$5,338,577	2,905,037	$1.84	$1,505,432	$1,843,801	$3,349,233	3,497,621	$0.96
Total	$20,939,804	$86,701,561	$107,641,365	58,715,141	$1.83	$26,931,890	$32,994,983	$59,926,873	61,445,495	$0.98

Black start zonal charges in 2014 ranged from $0.07 per MW-day in the DLCO Zone (total charges were $72,263) to $3.90 per MW-day in the AEP Zone (total charges were $32,513,935). 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

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: 2014

Capital Cost Requested	Cost Recovered in 2014	Number of Units	MW
$1,736,971	$630,521	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).[44] 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 2014, total reactive service charges were $309.7 million, a 49.8 percent decrease from the 2013 level of $616.4 million.[45] While revenue requirement charges increased from $276.9 million to $280.3 million, operating reserve charges fell from $339.4 million to $29.4 million. The decrease in operating reserve charges was due to higher LMPs that caused more units that provide reactive service to be run economically rather than out of merit. Total charges in 2014 ranged from $1.7 thousand in the RECO Zone to $40.8 million in the AEP Zone. For each zone in 2013 and 2014 Table 10-46 shows Reactive Service operating reserve charges, revenue requirement charges and total charges (the sum of operating reserve and revenue requirement charges).

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

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

Table 10-46 Reactive zonal charges for network transmission use: 2013 and 2014

Zone	2013 Operating Reserve Charges	2013 Revenue Requirement Charges	2013 Total Charges	2014 Operating Reserve Charges	2014 Revenue Requirement Charges	2014 Total Charges
AECO	$4,673,542	$5,132,697	$9,806,239	$106,703	$6,619,096	$6,725,798
AEP	$36,194,483	$40,300,353	$76,494,836	$865,627	$39,948,775	$40,814,402
APS	$10,688,148	$21,716,973	$32,405,121	$282,914	$18,526,181	$18,809,095
ATSI	$61,085,799	$15,741,841	$76,827,641	$12,057,987	$15,273,585	$27,331,572
BGE	$16,976,343	$7,771,212	$24,747,555	$55,339	$7,703,416	$7,758,755
ComEd	$22,192,595	$24,568,280	$46,760,875	$146,570	$24,353,948	$24,500,518
DAY	$3,759,513	$8,437,155	$12,196,668	$29,971	$8,363,550	$8,393,522
DEOK	$5,964,175	$5,758,935	$11,723,110	$29,413	$5,708,694	$5,738,107
Dominion	$22,979,048	$29,925,202	$52,904,250	$4,327,880	$29,664,137	$33,992,016
DPL	$50,938,709	$10,051,706	$60,990,415	$7,278,450	$10,767,688	$18,046,138
DLCO	$3,267,018	$0	$3,267,018	$15,712	$0	$15,712
EKPC	$2,387,655	$1,069,929	$3,457,584	$12,873	$2,121,484	$2,134,358
JCPL	$13,049,937	$6,257,533	$19,307,471	$38,699	$7,063,933	$7,102,632
Met-Ed	$3,709,406	$7,479,654	$11,189,060	$46,087	$7,529,444	$7,575,531
PECO	$10,155,174	$17,622,191	$27,777,365	$369,729	$17,468,456	$17,838,185
PENELEC	$36,562,731	$4,650,339	$41,213,069	$3,218,978	$6,505,000	$9,723,978
Pepco	$7,080,243	$5,257,464	$12,337,707	$50,913	$5,211,599	$5,262,512
PPL	$9,753,227	$18,872,215	$28,625,443	$45,115	$18,899,819	$18,944,934
PSEG	$17,688,214	$27,266,302	$44,954,516	$402,849	$27,028,433	$27,431,281
RECO	$339,964	$0	$339,964	$1,679	$0	$1,679
(Imp/Exp/Wheels)	$0	$19,038,717	$19,038,717	$0	$21,551,743	$21,551,743
Total	$339,445,925	$276,918,698	$616,364,623	$29,383,487	$280,308,980	$309,692,468