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 the first six months of 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

- 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 96 percent of the hours in the first six months of 2014.
- Participant behavior in the Regulation Market was evaluated as competitive for the first six months of 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 Synchronized Reserve Markets 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

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

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

Overview

Primary Reserve

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

Market Structure

- **Supply.** Primary reserve is satisfied by both synchronized reserve (energy or demand response currently synchronized to the grid and available within ten minutes), and non-synchronized reserve (energy 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 for the first six months of 2014 was 2,087 MW. The actual demand for primary reserve in the MAD subzone in the first six months of 2014 was 1,700 MW.

Tier 1 Synchronized Reserve

Tier 1 synchronized reserve is part 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.

- **Supply.** In the first six months of 2014, an average supply of 1,083 MW of tier 1 was identified hourly for the entire RTO synchronized reserve, and an average supply of 846 MW of tier 1 was identified hourly for the Mid-Atlantic Dominion subzone.
- **Demand.** There is no fixed required amount of tier 1 synchronized reserve. Tier 1 synchronized reserve is estimated and not assigned.
- **Price and Cost.** The price for synchronized reserves is typically zero, as there is no incremental cost associated with providing the ability to ramp up from the current economic dispatch point. However, a tariff change included in the shortage pricing tariff changes (October 1, 2012) modified the pricing of tier 1 so that tier 1 synchronized reserve is paid the tier 2 synchronized reserve market clearing price whenever the non-synchronized reserve market clearing price rises above zero. The rationale for this change was and is unclear but it has had a significant impact on the cost of tier 1 synchronized reserves, resulting in a windfall payment of $75,248,584.

  The additional payments to tier 1 synchronized reserves can be considered a windfall because the additional payment does not create an incentive to provide more tier 1 synchronized reserves and the additional payment is not a payment for performance as all estimated tier 1 synchronized reserves receive the payment regardless of whether they provided any response.

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- **Tier 1 Synchronized Reserve Spinning Event Response.** Tier 1 synchronized reserve is awarded credits when a spinning event occurs and it responds. These spinning 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.

  The MMU analysis shows that only 27.0 percent of tier 1 synchronized reserve identified hour ahead as available for both synchronized reserve and primary reserve actually responded to spinning events.

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 conducts a market to satisfy the requirement with tier 2 synchronized reserve. The Tier 2 Synchronized Reserve Market includes the PJM RTO Reserve Zone and a subzone, the Mid-Atlantic Dominion Reserve subzone (MAD).

Market Structure

- **Supply.** In the first six months of 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 the first six months of 2014, the weighted average HHI for cleared inflexible tier 2 synchronized reserve in the Mid-Atlantic Dominion subzone was 4406 which is classified as highly concentrated. The HHI for flexible synchronized reserve cleared during real-time market solutions (which was only 12.6 percent of all tier 2 synchronized reserve) was 8650. The MMU calculates that during the first six months of 2014, 43.2 percent of hours would have failed a three pivotal supplier test in the Mid-Atlantic Dominion subzone and 38.3 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, in the first six months of 2014, were characterized by structural market power.

Market Conduct

- **Offers.** 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. Compliance with the must-offer rule for tier 2 synchronized reserve is greatly improved.

Market Performance

- **Price.** The cleared synchronized reserve weighted average price for tier 2 synchronized reserve in the Mid-Atlantic Dominion (MAD) subzone was $15.18 per MW in the first six months of 2014, a $7.73 increase from the first six months of 2013.

  The cleared synchronized reserve weighted average price for tier 2 synchronized reserve in the RTO Synchronized Reserve Zone was $18.15 per MW in the first six months of 2014.

Non-Synchronized Reserve Market

Non-synchronized reserve is a component of primary reserve and shares its market definitions including the RTO Reserve Zone and the Mid-Atlantic Dominion Reserve subzone (MAD). After the hour ahead market solution satisfies the requirement for synchronized reserve the remainder of the primary reserve requirement is satisfied with non-synchronized reserve. Non-synchronized reserve is non-emergency energy resources not currently synchronized to the grid that can provide energy within ten minutes at the direction of PJM dispatch.

Market Structure

- **Supply.** In the first six months of 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 396.9 MW of non-synchronized reserve during the first six months of 2014. In 93.9 percent of hours the market clearing price was $0. In the MAD subzone, the market cleared an hourly average of 593.0 MW of non-synchronized reserve. In 90.7 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.** Prices are a function of the opportunity costs of any resources taken for non-synchronized reserves. The cleared non-synchronized reserve weighted average price in the RTO Reserve Zone was $0.93 per MW for the first six months of 2014. The cleared non-synchronized reserve weighted average price in the Mid-Atlantic Dominion (MAD) subzone was $2.68 per MW.

Secondary Reserve

PJM maintains a day-ahead, offer based market for 30-minute secondary reserve.[3] It is designed to provide price signals that encourage resources to provide 30-minute reserve. The DASR market has no performance obligations.

Market Structure

- **Concentration.** The MMU calculates that in the first six months of 2014, zero hours in the DASR Market 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. For the first six months of 2014, the average available hourly DASR was 40,768 MW.
- **Demand.** The DASR requirement in 2014 is 6.27 percent of peak load forecast, down from 6.91 percent in 2013. The DASR MW purchased averaged 5,951 MW per hour for the first six months of 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. On June 30, 2014, 11.2 percent of resources offered DASR at levels above $5 per MW.
- **DR.** Demand resources are eligible to participate in the DASR Market. As of June 30, 2014, six demand resources have entered offers for DASR.

Market Performance

- **Price.** The weighted average DASR market clearing price in the first six months of 2014 was $1.63 per MW. This is a $1.57 per MW increase from the first six months of 2013, which had a weighted price of $0.06.

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

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Regulation Market

The PJM Regulation Market is a single market for the RTO. Regulation is provided by demand response and generation resources that must qualify to follow a regulation signal (RegA or RegD). PJM jointly optimizes regulation with synchronized reserve and energy to provide all three of these services at least cost. 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. The marginal benefit factor and performance score translate a resource's capability (actual) MW into effective MW.

Market Structure

- **Supply.** In the first six months of 2014, the average hourly eligible supply of regulation was 1,336 actual MW (980 effective MW). This is a decrease of 30 actual MW (137 effective MW) from the first six months of 2013, when the average hourly eligible supply of regulation was 1,366 actual MW (1,118 effective MW).
- **Demand.** The average hourly regulation demand was 674 actual MW (664 effective MW) in the first six months of 2014. This is a 104 actual MW (14 effective MW) decrease in the average hourly regulation demand of 777 actual MW (678 effective MW) in the same period of the first six months of 2013.
- **Supply and Demand.** The ratio of offered and eligible regulation to regulation required averaged 1.98. This is a 13.1 percent increase over the first six months of 2013 when the ratio was 1.75.
- **Market Concentration.** In the first six months of 2014, the PJM Regulation Market had a weighted average Herfindahl-Hirschman Index (HHI) of 1901 which is classified as highly concentrated. In the first six months of 2014, the three pivotal supplier test was failed in 96 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] As of June 30, 2014, there were 277 resources following the RegA signal and 41 resources following the RegD signal.

Market Performance

- **Price and Cost.** The weighted average clearing price for regulation was $62.09 per MW of regulation in the first six months of 2014, an increase of $30.29 per MW of regulation, or 106.2 percent, from the first six months of 2013. The cost of regulation in the first six months of 2014 was $75.20 per MW of regulation, a $38.73 per MW of regulation, or 106.2 percent, increase from the first six months of 2013.
- **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. In the first six months of 2014, RegA resources received RMCP credits per effective MW on average 1.9 times higher than RegD resources. If the Regulation Market were functioning correctly, 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]

4 See the *2012 State of the Market Report for PJM*, Volume II, Appendix F "Ancillary Services Markets."
5 OATT Schedule 1 § 1.3BB.

In the first six months of 2014, total black start charges were $25.2 million with $10.9 million in revenue requirement charges and $14.3 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 the first six months of 2014 ranged from $0.02 per MW-day in the ATSI Zone (total charges were $58,250) to $3.32 per MW-day in the AEP Zone (total charges were $13,714,398).

Reactive

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

In the first six months of 2014, total reactive service charges were $163.0 million with $140.8 million in revenue requirement charges and $22.2 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 the first six months of 2014 ranged from $1.7 thousand in the RECO Zone to $20.3 million in the AEP Zone.

Ancillary Services Costs per MWh of Load: January through June, 2003 through 2014

Table 10-4 shows PJM ancillary services costs for the first six months of years 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 real time load in MWh for the first six months of 2014 (393.2 million MWh). The scheduling, system control, and dispatch category of costs is comprised of PJM scheduling, PJM system control and PJM dispatch; owner scheduling, owner system control and owner dispatch; other supporting facilities; black start services; direct assignment facilities; and Reliability*First* Corporation charges. 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 the volume of each ancillary service purchased. As an example, the regulation market clearing price increased 106.2 percent (from $31.80 to $62.09 per MW of regulation capability), the cost of regulation per MWh of real time load increased only 76.9 percent, from $0.26 to $0.46 per MWh of real time load.

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

Year	Regulation	Scheduling, Dispatch, and System Control	Reactive	Synchronized Reserve	Supplementary Operating Reserve	Total
2003	$0.57	$0.61	$0.24	$0.14	$0.81	$2.37
2004	$0.53	$0.66	$0.26	$0.16	$0.93	$2.53
2005	$0.57	$0.51	$0.27	$0.11	$0.60	$2.05
2006	$0.48	$0.48	$0.29	$0.08	$0.32	$1.65
2007	$0.61	$0.46	$0.30	$0.09	$0.50	$1.95
2008	$0.73	$0.37	$0.30	$0.08	$0.66	$2.14
2009	$0.37	$0.43	$0.37	$0.04	$0.50	$1.71
2010	$0.37	$0.38	$0.36	$0.06	$0.75	$1.92
2011	$0.33	$0.38	$0.41	$0.11	$0.80	$2.03
2012	$0.20	$0.44	$0.47	$0.03	$0.65	$1.79
2013	$0.26	$0.41	$0.65	$0.03	$0.73	$2.09
2014	$0.46	$0.41	$0.42	$0.36	$2.07	$3.71

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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.
- The MMU recommends that the rule requiring the payment of the tier 2 price to tier 1 synchronized reserve resources when the non-synchronized reserve price is above zero be eliminated immediately.
- The MMU recommends that the tier 2 synchronized reserve must-offer provision of scarcity pricing be enforced. As of the end of June, 2014 compliance with the tier 2 must-offer provision reached 96.7 percent.
- 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.
- 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.
- 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.
- The MMU recommends that the three pivotal supplier test be incorporated in the DASR Market.

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 a consistent implementation of 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 spinning events has been an issue. Compliance with the synchronized reserve must-offer requirement has also been an issue.

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.

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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. 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. PJM implements the NERC requirement conservatively as primary reserve available within ten minutes.

Market Structure

Supply

PJM's primary reserve requirement is satisfied by synchronized tier 1 reserves, synchronized tier 2 reserves and non-synchronized reserves, subject to the requirement that synchronized reserve equal 100 percent of the largest contingency.

In the first six months of 2014, in the RTO Zone, an average of 1,083 MW of tier 1 synchronized reserve was estimated hourly; an average of 10,199 MW of tier 2 synchronized reserve was offered; an average of 273 MW of tier 2 was scheduled; an average of 1,168.7 MW of non-synchronized reserve was available; and an average of 396.9 MW of non-synchronized reserve was scheduled.

In the first six months of 2014, in the MAD subzone, an average of 846 MW of tier 1 synchronized reserve was estimated hourly; an average of 3,749 MW of tier 2 synchronized reserve was offered; an average of 441 MW of tier 2 was scheduled; an average of 2,304 MW of non-synchronized reserve was available; and an average of 593.0 MW of non-synchronized reserve was scheduled.

With the exception of several hours on January 6 and 7, the supply of primary reserve in the first six months of 2014 was sufficient to cover the requirement in both the RTO Reserve Zone and the MAD subzone. On January 6, hours 19 and 20, deficient primary reserves resulted in a voltage reduction action which resulted in an RTO-wide shortage pricing event. On January 7, deficient primary reserves in the RTO Zone caused shortage pricing in hours 7 through 11. On January 7, deficient primary reserves in the MAD subzone caused shortage pricing in hours 7 through 12, 17 and 18.

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).[6]

In two hours between January 1 and June 30, 2014, PJM increased the primary reserve requirement for the RTO Zone. The actual hourly average RTO primary reserve requirement was 2,087 MW in January through June, 2014. In 14 hours between January 1 and June 30, 2014, PJM increased the primary reserve requirement for the MAD subzone. The actual hourly demand for primary reserve in the MAD subzone in the first six months of 2014 was 1,702 MW.

Transmission constraints limit the deliverability of reserves within the RTO, requiring the definition of the Mid-Atlantic Dominion (MAD) subzone.[7] Of the 2,063 MW RTO primary reserve requirement, 1,700 MW (Table 10-10) must be deliverable to the MAD subzone (Figure 10-1). The actual hourly average MAD primary reserve requirement was 1,700 MW in the first six months of 2014.

6 See PJM, "Manual 11, Energy and Ancillary Services Market Operations," Revision 67 (June 1, 2014), 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 will sunset on September 30, 2014. Between January 1 and June 30, 2014, no changes were made to the synchronized reserve requirement based on this rule change.

7 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 67 (June 1, 2014), p. 66.

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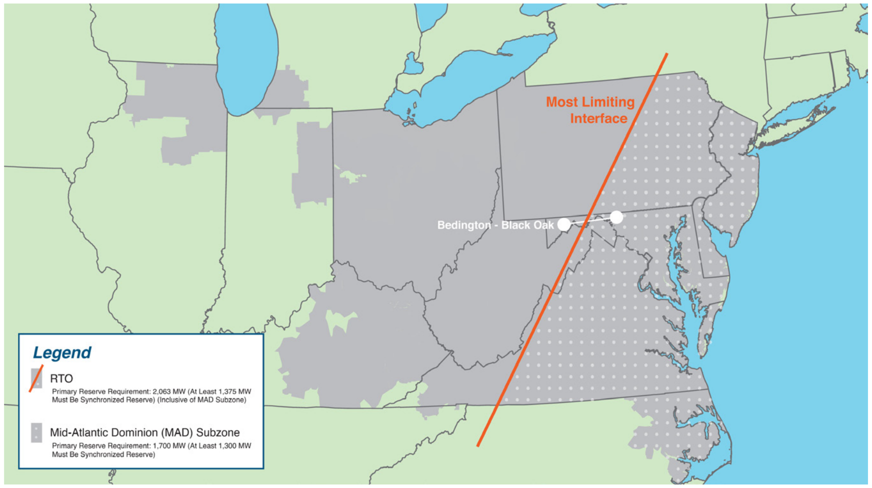
Figure 10-1 PJM RTO geography and primary reserve requirement: January through June 2014



The Mid-Atlantic Dominion Reserve (MAD) subzone is defined dynamically by the most limiting constraint separating MAD from the PJM RTO Reserve Zone.[8] In 88.6 percent of hours in January through June, 2014, that constraint was the Bedington – Black Oak transfer interface constraint.

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.

Supply and Demand

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

The ASO jointly optimizes energy, synchronized reserves, non-synchronized reserves, and regulation based on forecast system conditions to determine the most economic set of reserve resources to commit for the upcoming operating hour (before the hour commitments). IT-SCED runs at 15 minute intervals and jointly optimizes energy and reserves given the ASO's inflexible unit commitments. IT-SCED is used to estimate available tier 1 synchronized reserve and to provide a load forecast and ancillary services solutions. RT-SCED runs at five minute intervals and jointly optimizes energy and reserves given inflexible unit commitment. 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.

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 tier 1 synchronized reserve has a price of zero, ASO first estimates how much tier 1 synchronized reserve (gray 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 green 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 or equal to synchronized reserve, almost all primary reserve between 1,300 MW and 1,700 MW is filled by non-synchronized reserve. 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.[9]

8 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 67 (June 1, 2014), p. 66.

9 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

Figure 10-2 Mid-Atlantic Dominion subzone primary reserve MW by source (Daily Averages): January through June 2014

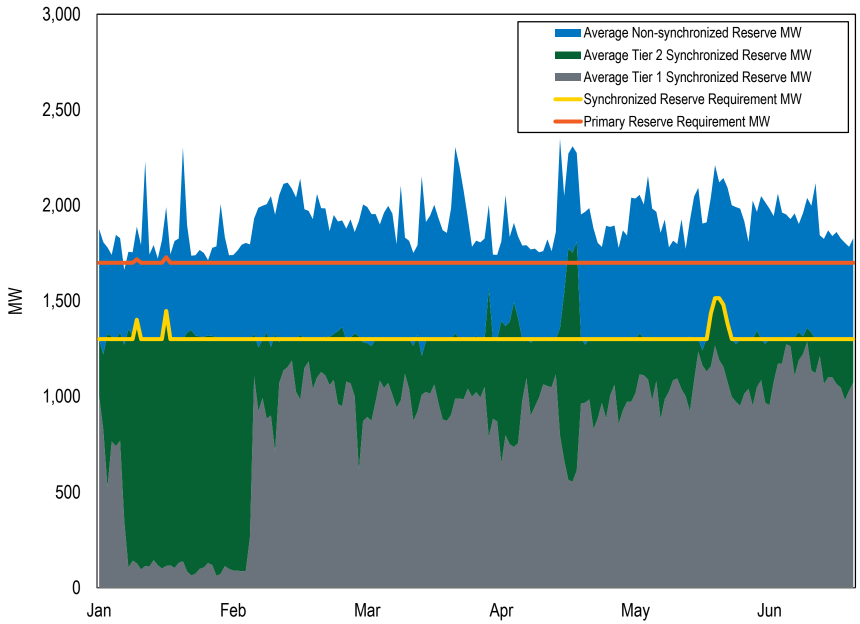


Figure 10-3 shows how the hour ahead ASO satisfies the primary reserve requirement for the RTO Zone.

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

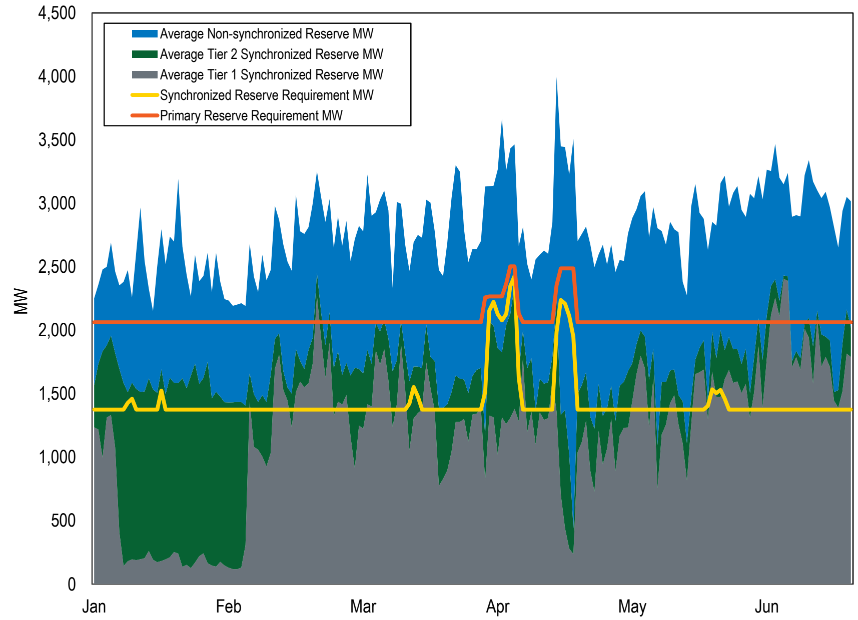


Figure 10-3 shows that tier 1 synchronized reserve remains the major contributor to satisfying the synchronized reserve requirements both in the RTO Zone and the Mid-Atlantic Dominion (MAD) subzone.

Price and Cost

Tier 1 synchronized reserves are on line resources able to ramp up from their existing economic dispatch. The price for 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. The price for tier 1 synchronized reserves is positive when they respond to a call. In addition, in any hour that the non-synchronized reserve market clears with a price above $0, the tier 1 synchronized reserves are paid the tier 2

solutions which assumes zero cost.

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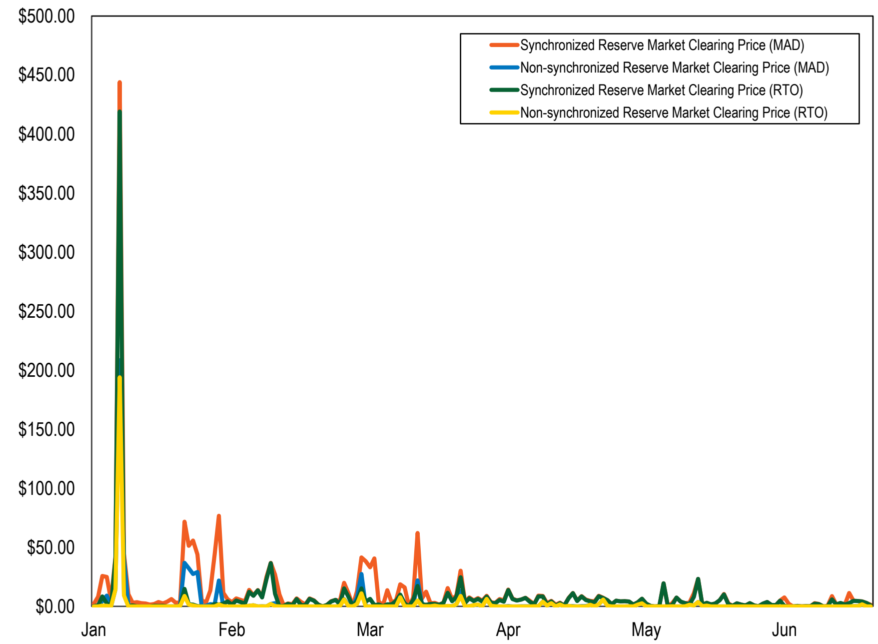
synchronized reserve market price. As available primary reserve approaches the primary reserve requirement the cost to serve the next MW of primary reserve is the non-synchronized reserve market clearing price (the blue area).

The non-synchronized reserve market clearing price was above $0 in 401 hours during the first six months of 2014. For those 401 hours, tier 1 synchronized reserve resources were paid the weighted synchronized reserve market clearing price of $8.62 per MW and earned $75,248,584 in credits.

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 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 from January 1, 2014, through June 30, 2014.

Figure 10-4 Daily average market clearing prices for Synchronized Reserve and Non-synchronized Reserve: January through June 2014



The cost of meeting PJM's primary reserve requirement (displayed in Figure 10-3) is shown by component in Table 10-5. Under most market conditions, most primary reserve identified by the hour ahead market solution is provided at no incremental cost by non-synchronized reserve (blue area in Figure 10-3) and tier 1 synchronized reserve (gray area in Figure 10-3). Column 6 (Cost per MW) is the total credits divided by the total MW of reserves. Column 7 (All-In Cost) is the total credits paid divided by the load, or the total cost per MWh of energy to satisfy the primary reserve requirement.

Table 10-5 MW credited, price, cost, and all-in price for primary reserve and its component products, RTO Reserve Zone, January through June, 2014

(1) Product	(2) Share of Primary Reserve Requirement	(3) MW Credited	(4) Credits Paid	(5) Price Per MW	(6) Cost Per MW	(7) All-In Cost
Tier 1 Synchronized Reserve Response	NA	12,228	$1,050,954	NA	$85.95	$0.00
Tier 1 Synchronized Reserve	42.7%	757,038	$75,248,584	$8.62	$99.40	$0.19
Tier 2 Synchronized Reserve	18.6%	1,954,573	$52,495,326	$20.08	$26.86	$0.13
Non-synchronized Reserve	38.8%	2,694,815	$11,107,519	$1.63	$4.12	$0.03
Primary Reserve	142.0%	5,418,654	$139,902,383	$9.28	$25.82	$0.36

If the unnecessary payments for tier 1 were removed per the MMUs recommendation the cost for primary reserve would have been reduced by $75,248,584 for the first six months of 2014.

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 (grey 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 or unless the non-synchronized reserve market clearing price is above $0.

The tier 1 estimate used by the market solution can be biased by PJM dispatch to make the solution solve for more or less tier 2 synchronized reserve than the market solution.

The MMU has recommended that instead of using tier 1 biasing, PJM improve the accuracy of the tier 1 estimates. The MMU recommends that PJM provide a reason for every use of tier 1 biasing, to provide increased transparency and facilitate analysis designed to improve the estimation methodology.

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.

For the first six months of 2014, in the RTO Reserve Zone the average hour ahead estimated tier 1 synchronized reserve was 1,083 MW (Table 10-6). In 118 hours the estimated tier 1 was zero. In 1,667 hours the estimated tier 1 synchronized reserve was greater than the synchronized reserve zone requirement of 1,375 and no tier 2 synchronize reserve was needed. In 659 hours the estimated tier 1 synchronized reserve was greater than 2,063 MW primary reserve requirement, meaning that the primary reserve requirement was met by tier 1 synchronized reserve.

For the first six months of 2014, in the MAD reserve subzone the average hour ahead estimated tier 1 synchronized reserve was 846 MW (Table 10-6). In four hours the estimated tier 1 synchronized reserve was zero. In 51 hours the estimated tier 1 synchronized reserve was greater than the synchronized reserve zone requirement of 1,300 MW and no tier 2 synchronized reserve market was needed. The estimated tier 1 synchronized reserve was never greater than the 1,700 MW primary reserve requirement.

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Table 10-6 Monthly average market solution Tier 1 Synchronized Reserve identified hourly, January through June, 2014

Year	Month	Average Hourly Tier 1 Local to MAD	Average Hourly Tier 1 Imported from RTO	Average Hourly Tier 1 Used	Minimum Hourly Tier 1 Used	Maximum Hourly Tier 1 Used
Mid-Atlantic Dominion Reserve Subzone						
2014	Jan	149	93	243	0	1,118
2014	Feb	583	259	842	0	1,383
2014	Mar	516	458	974	91	1,412
2014	Apr	524	353	877	162	1,195
2014	May	698	351	1,049	461	1,551
2014	Jun	714	375	1,089	303	1,637
RTO Reserve Zone						
Year	Month	Average Hourly Tier 1 Local to MAD	Average Hourly Tier 1 Imported from RTO	Average Hourly Tier 1 Used	Minimum Hourly Tier 1 Used	Maximum Hourly Tier 1 Used
2014	Jan	389	0	389	0	2,082
2014	Feb	1,203	0	1,203	38	2,964
2014	Mar	1,343	0	1,343	89	3,203
2014	Apr	1,140	0	1,140	0	2,711
2014	May	1,342	0	1,342	0	3,167
2014	Jun	1,769	0	1,769	0	3,840

Demand

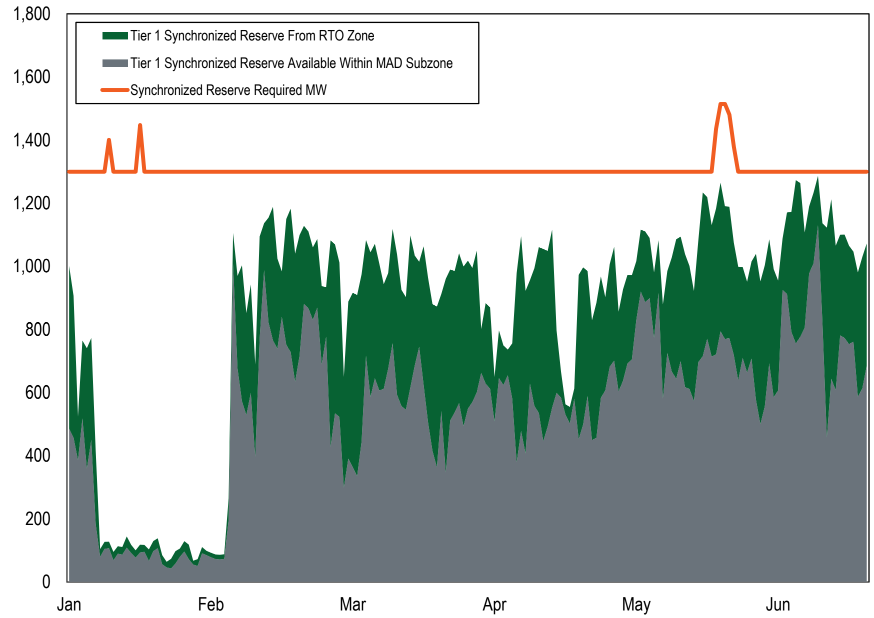
There is no fixed required amount of tier 1 synchronized reserve. Tier 1 synchronized reserve is estimated and not assigned. Given estimated tier 1, the market software completes the primary reserve assignments under the assumption that the estimated tier 1 will be available if needed. The ancillary services market solution was designed on the assumption that the market price of tier 1 synchronized reserve is $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 in the MAD subzone: January through June, 2014[10]



10 Hours in which the tier 1 estimate was biased by PJM dispatch are excluded from this graph. Tier 1 estimate biasing was used in 148 hours for the MAD subzone and 335 hours in the RTO zone in the first six months of 2014.

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From January through June 2014, the average amount of tier 1 synchronized reserve MW used in the hour-ahead market solution for the MAD subzone was 846 MW, compared to the average synchronized reserve requirement of 1,306 MW. In four hours the market solution used no tier 1 synchronized reserve to satisfy the synchronized reserve requirement and in 51 hours the market solution used tier 1 synchronized reserve for the entire synchronized reserve requirement.

From January through June 2014, the average amount of tier 1 synchronized reserve MW used in the hour-ahead market solution for the RTO zone was 1,083 MW, compared to the average synchronized reserve requirement of 1,450 MW. In 118 hours the market solution used no tier 1 synchronized reserve to satisfy the synchronized reserve requirement and in 37.4 percent of hours the market solution used tier 1 synchronized reserve for the entire synchronized reserve requirement.

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.

During the first six months of 2014, PJM used tier 1 estimate biasing in the MAD subzone ASO (Table 10-7) and RT-SCED market solutions, and in the RTO Zone ASO and RT-SCED market solutions. Tier 1 biasing was 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.[11]

Table 10-7 MAD subzone ASO tier 1 estimate biasing, January through June, 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	250
2014	Feb	36	(1,036)	1	100
2014	Mar	37	(1,281)	4	500
2014	Apr	32	(1,388)	0	NA
2014	May	23	(910)	0	NA
2014	Jun	17	(1,179)	3	667

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

The accuracy of the tier 1 estimate increases as the market solution gets closer to real time Figure 10-6. The tier 1 estimate from the hour ahead solution differs from the actual value by 134 MW. The tier 1 estimate from the intermediate term solution differs from the actual value by 122 MW. The tier 1 estimate from the real time solution differs from the actual value by 102 MW. Figure 10-6 also shows that the accuracy of the tier 1 estimate decreases during hours when the demand for energy is increasing or decreasing rapidly, e.g. hours 6, 7, 8, 19, 20, 21.

11 The number of five minute periods was reported incorrectly as 328 in the *2014 Quarterly State of the Market Report for PJM: January through March, p 318.*

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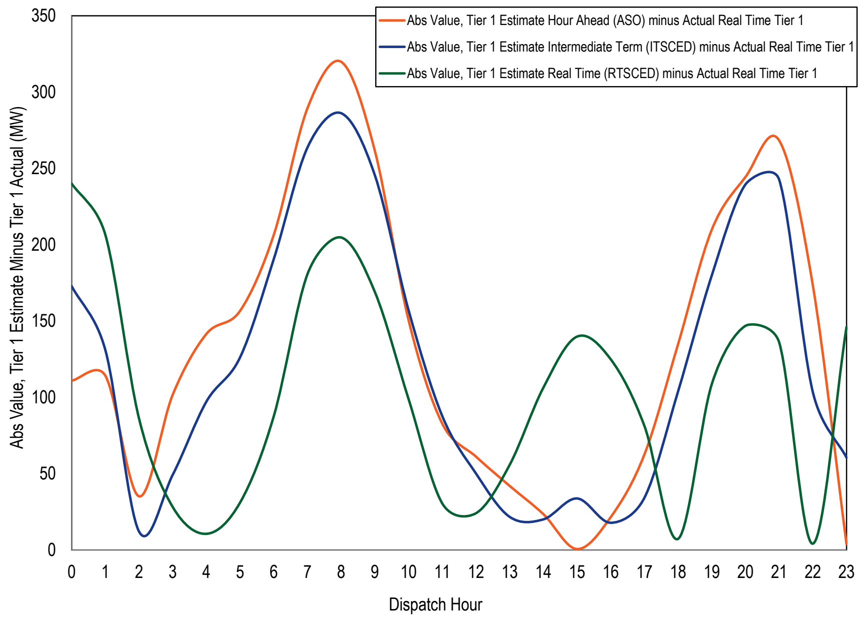
Figure 10-6 Absolute value of the tier 1 estimate minus the actual value by market hour, January through June 2014



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 period of 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 10-2 and Figure 10-3. The dip in the gray area is the reduction of tier 1, forcing the ASO to fill the synchronized reserve requirement (yellow line) with tier 2 (green area).

Price and Cost

The price for synchronized reserves is typically zero, as there is no incremental cost associated with providing the ability to ramp up from the current economic dispatch point. However, a tariff change included in the shortage pricing tariff changes (October 1, 2012) modified the pricing of tier 1 so that tier 1 synchronized reserve is paid the tier 2 synchronized reserve market clearing price whenever the non-synchronized reserve market clearing price rises above zero. The rationale for this change was and is unclear but it has had a significant impact on the cost of tier 1 synchronized reserves. The non-synchronized reserve market clearing price was above $0 in 401 hours during the first six months of 2014. For those 401 hours tier 1 synchronized reserve resources were paid the weighted synchronized reserve market clearing price of $8.62 per MW and earned $75,248,584 in credits for an average cost of $99.40 per MW (Table 10-8).

Table 10-8 Price and cost of tier 1 synchronized reserve attributable to a non-synchronized reserve price above zero; January through June, 2014

Year	Month	Number of Hours When NSRMCP Greater Than $0	Weighted SRMCP for Hours When NSRMCP Greater Than $0	Total Tier 1 MW Credited for Hours When NSRMCP Greater Than $0	Total Tier 1 Credits for Hours When NSRMCP Greater Than $0	Cost of Tier 1 When NSRMCP Greater Than $0
2014	Jan	155	$10.15	339,888	$53,984,582	$158.83
2014	Feb	15	$7.81	33,392	$2,447,582	$73.30
2014	Mar	67	$7.29	116,820	$10,071,711	$86.22
2014	Apr	99	$7.73	142,990	$4,594,030	$32.13
2014	May	61	$6.95	116,079	$3,604,644	$31.05
2014	Jun	4	$6.56	7,869	$546,036	$69.39
2014	Total	401	$8.62	757,038	$75,248,584	$99.40

Tier 1 resources are not obligated to respond to spinning events. The ratio of tier 1 MW actually responding to spinning events to the tier 1 MW estimate is 27.0 percent.

The additional payments to tier 1 synchronized reserves 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

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for performance as all estimated tier 1 receives the payment regardless of whether they provided any response. Thus, 73.0 percent of tier 1 resources do not respond but are paid when the non-synchronized reserve price is greater than zero. Tier 2 synchronized reserve resources are paid the market clearing price for tier 2 because they stand ready to respond and incur costs to do so, have an obligation to perform and pay penalties for nonperformance. The MMU recommends that the additional payments to tier 1 be eliminated.

Tier 1 Synchronized Reserve Spinning Event Response

Tier 1 synchronized reserve is awarded credits when a spinning event occurs and it responds. These spinning 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.

For January through June, 2014, Tier 1 synchronized reserve spinning event response credits (Table 10-9) were paid during 26 hours (in 15 of those hours the non-synchronized reserve market clearing price was also greater than zero). For January through June, 2014, $1,050,954 was paid for 12,228 MW of tier 1 response during 26 hours at an average cost per MW of $53.75.

Table 10-9 Tier 1 synchronized reserve spinning event response costs, January through June, 2014

Year	Month	Spinning Event Response Hours	Total Tier 1 Spinning Event Response MW	Total Tier 1 Spinning Event Response Credits	Tier 1 Spinning Event Response Cost
2014	Jan	15	7,821	$823,972	$105.36
2014	Feb	1	273	$11,147	$40.80
2014	Mar	5	3,029	$174,612	$57.65
2014	Apr	2	388	$6,322	$16.29
2014	May	3	717	$34,900	$48.67
2014	Jun	0	0	$0	$0.00
2014	Total	26	12,228	$1,050,954	$85.95

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 conducts 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 commitments guarantee that the Tier 2 MW will be available in the event of a synchronized reserve event.

Tier 2 synchronized reserve committed by the hour ahead market solution is inflexible. 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).

During the operating hour the IT-SCED and the RT-SCED market solutions have the ability to dispatch additional resources inflexibly or flexibly depending on the current forecast need for synchronized reserve. A flexible commitment is one in which the IT-SCED or RT-SCED redispatches online generating resources to meet the synchronized reserve requirement. Such resources can be recommitted to generation by subsequent market solutions or kept as synchronized reserve depending on market conditions.

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Market Structure

Supply

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

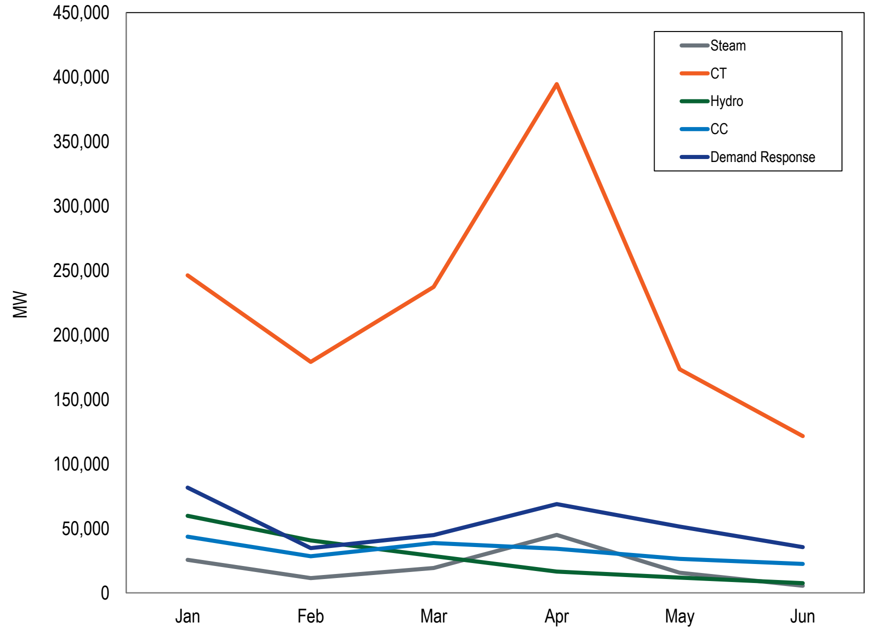
For January through June, 2014, the Mid Atlantic Dominion subzone averaged 3,749 MW in synchronized reserve offers, and the RTO Zone averaged 10,199 MW of synchronized reserve offers (Figure 10-11).

With the exception of several hours on January 6 and 7, the supply of tier 2 synchronized reserve the first six months of 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 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 synchronized reserve although their share of total cleared synchronized reserve declined significantly as the amount of tier 2 has increased. The DR MW share of the total cleared MAD subzone Tier 2 Synchronized Reserve Market was 17.5 percent in the first six months of 2014.[13] This is a reduction of 26.1 percentage points from the DR MW share of 43.6 percent of all cleared MAD tier 2 synchronized reserve for the first six months of 2013.

12 See PJM. "Manual 11: Energy and Ancillary Services Market Operations" Revision 64, (January 6, 2014), p. 63.
13 The cap on demand response participation is defined in MW terms. There is no cap on the proportion of cleared demand response consistent with the MW cap.

Figure 10-7 Cleared Tier 2 Synchronized Reserve by Unit Type, Full RTO Zone, January through June, 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 10-10). 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 reserves 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.[14] In the first six months of 2014, PJM has not changed the synchronized reserve requirement for this reason.

14 See PJM, "Manual 11, Energy and Ancillary Services Market Operations," Revision 67 (June 1, 2014), p. 66, 67.

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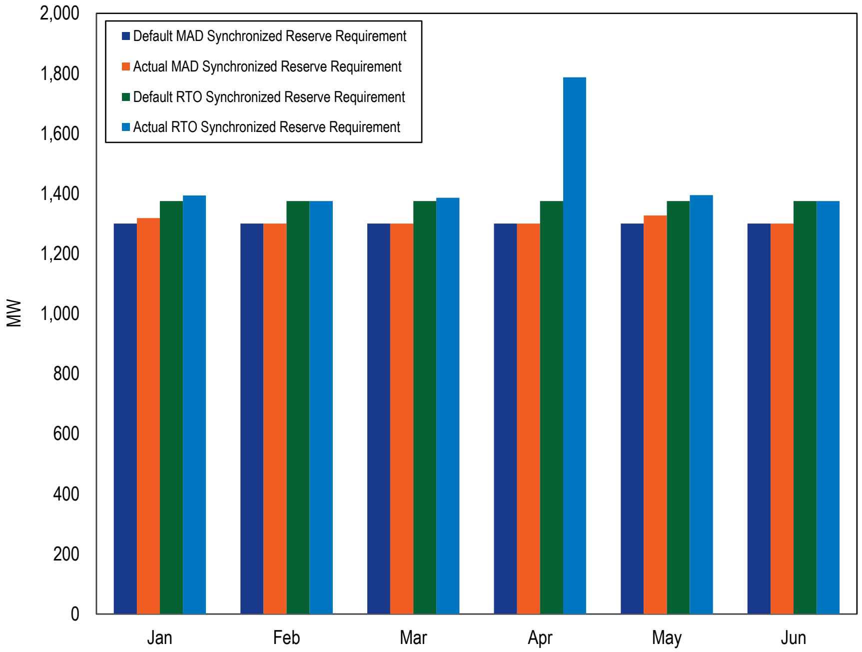
Table 10-10 Default Tier 2 Synchronized Reserve Markets required MW, RTO Zone and Mid-Atlantic Dominion Subzone

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: January through June, 2014



PJM may also change the synchronized reserve requirement from its default value when grid maintenance or outages change the largest contingency (Figure 10-1). All changes to the synchronized reserve requirements during the first six months of 2014 were for this reason. In the first six months of 2014, PJM increased the synchronized reserve requirement in 98 hours in both the MAD subzone and the RTO Reserve Zone (Figure 10-8). The average actual synchronized reserve requirement in the MAD subzone was 1,309 MW. The average actual synchronized reserve requirement in the RTO Reserve Zone was 1,461 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.

Between October 1, 2013 and December 31, 2013, PJM implemented several changes in the way tier 1 available MW is estimated in order to improve the accuracy of the estimates.[15] The effect of these changes in both the RTO Zone and MAD subzone was to reduce the estimates of tier 1 and to increase the amount of tier 2 MW cleared (Figure 10-2). The changes included capping the tier 1 estimate at the lesser of a generator's economic maximum or its spinning maximum value. Some hydro units were excluded from tier 1 estimates because most hydro units do not respond to spin events. Combined cycle units are excluded from tier 1 estimates because combined cycles often require additional equipment or operator intervention to respond to spinning events. Units that are assigned to provide regulation and units that are backed down for constraint control are excluded from tier 1 estimates.

These changes reduced the amount of tier 1 estimated and significantly increased the amount of tier 2 synchronized reserve required. In the RTO Reserve Zone, 56.8 percent of hours cleared a Tier 2 Synchronized Reserve Market in the first six months of 2014 averaging 272.5 MW compared to less than one percent of hours in the first six months of 2013.

Figure 10-7 and Figure 10-8 and show the average monthly synchronized reserve required and the average monthly Tier 2 synchronized reserve MW scheduled in the first six months of 2014, for the RTO Zone and MAD

15 PJM Operating Committee Meeting, November 5, 2013, <http://www.pjm.com/~/media/committees-groups/committees/oc/20131105/20131105-item-10-oc-tier-1-changes.ashx>.

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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 168 hours during the first six months of 2014 with an average bias of over 1,000 MW per hour.

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

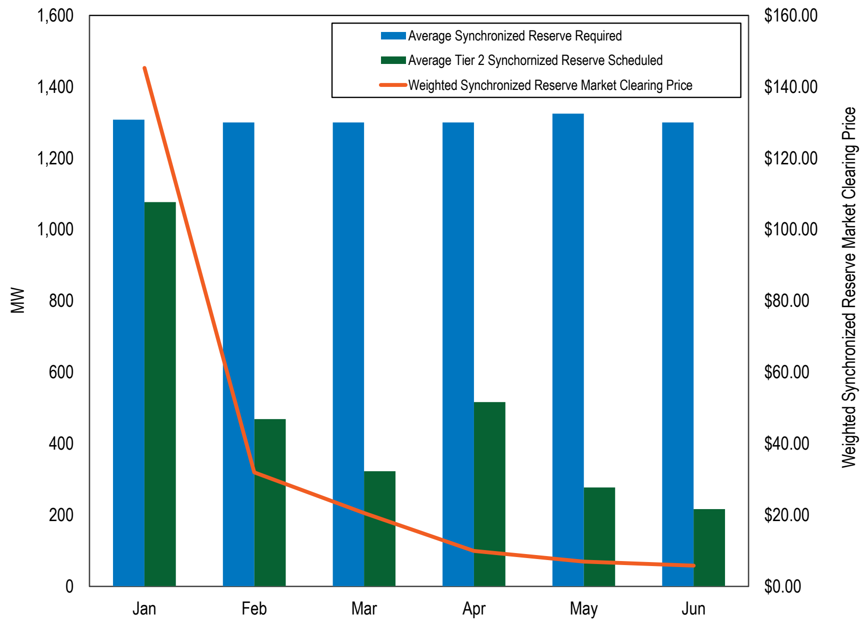
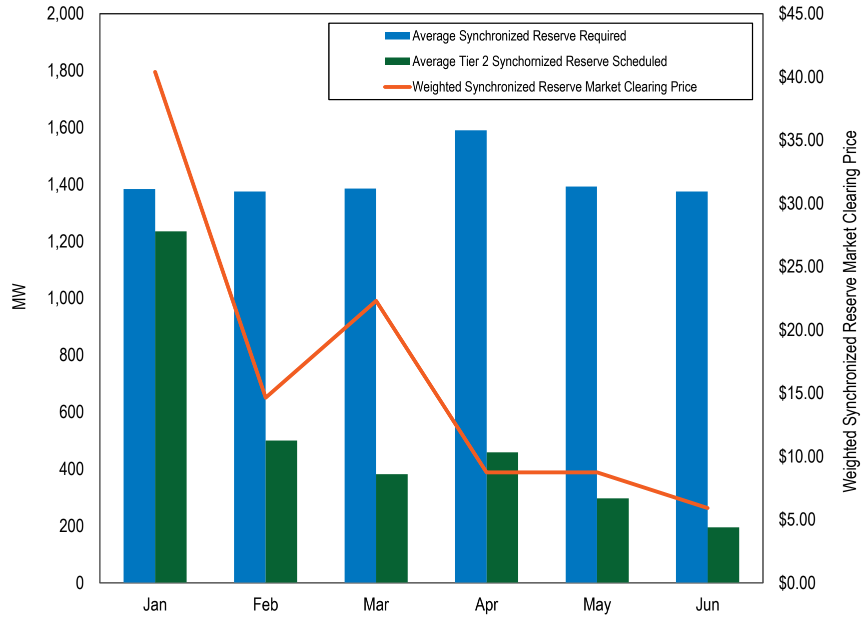


Figure 10-10 RTO Reserve zone monthly average synchronized reserve required vs. tier 2 synchronized reserve scheduled MW: January through June 2014



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 for the first six months of 2014 was 4406, which is defined as highly concentrated. The largest hourly market share was 100 percent and 68.3 percent of all hours had a maximum market share greater than or equal to 40 percent.

The HHI for settled tier 2 synchronized reserve during cleared hours of the RTO Zone Tier 2 Synchronized Reserve Market for the first six months of 2014 was 5495, which is defined as highly concentrated. The largest hourly market share was 100 percent and 76.3 percent of hours had a maximum market share greater than or equal to 40 percent.

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In the MAD subzone, flexible synchronized reserve was 12.6 percent of all tier 2 synchronized reserve in the first six months of 2014. In the RTO Zone, flexible synchronized reserve assigned was 15.5 percent of all tier 2 synchronized reserve in the first six months of 2014. For flexible resources only, the hourly average HHI in the first six months of 2014 in the MAD subzone was 8650. For flexible resources only the hourly average HHI in the first six months of 2014 in the RTO Zone was 9235.

The MMU calculates that 43.2 percent of hours failed the three pivotal supplier test in the MAD subzone in the first six months of 2014 for the inflexible synchronized reserve market (excluding self-scheduled synchronized reserve) in the hour ahead market (Table 10-11) and 38.3 percent of hours failed a three pivotal supplier test in the RTO Zone in the first six months of 2014.

Table 10-11 Three Pivotal Supplier Test Results for the RTO Zone and MAD Subzone, January through June, 2014

Year	Month	Mid Atlantic Dominion Reserve Subzone Pivotal Supplier Hours	RTO Reserve Zone Pivotal Supplier Hours
2014	Jan	90.7%	72.6%
2014	Feb	46.1%	22.4%
2014	Mar	36.6%	14.5%
2014	Apr	31.9%	45.6%
2014	May	22.3%	43.7%
2014	Jun	31.5%	31.1%
	Average	43.2%	38.3%

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

Market Behavior

Offers

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

Figure 10-11 shows the daily average of hourly offered tier 2 synchronized reserve MW for both the RTO Synchronized Reserve Zone and the Mid-Atlantic Dominion Synchronized Reserve subzone. In the first six months of 2014, the ratio of on-line tier 2 synchronized reserve to synchronized reserve required in the Mid-Atlantic Dominion subzone was 2.85 averaged over all hours. For the RTO Synchronized Reserve Zone the ratio was 7.35.

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

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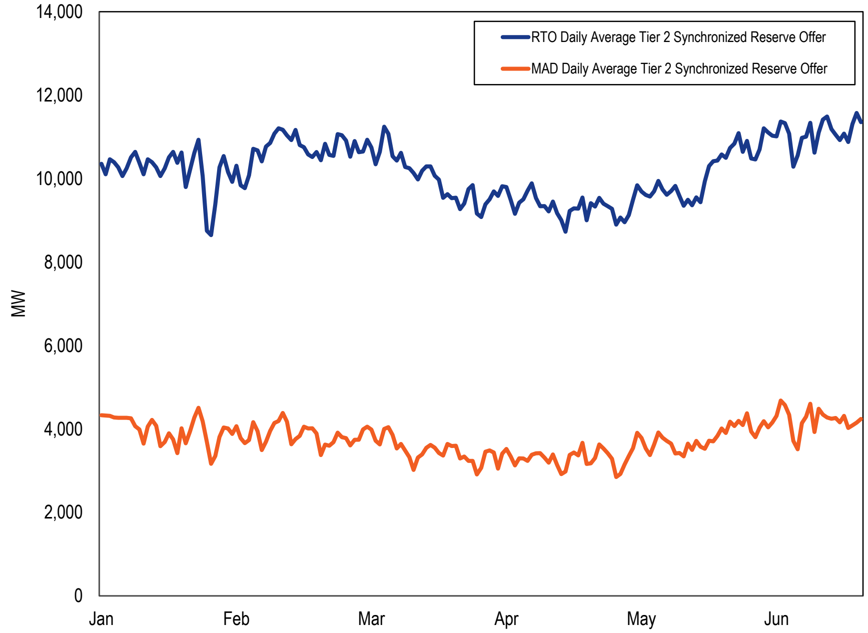
result of on-line status, minimum/maximum runtimes, minimum notification times, maintenance status and grid conditions including constraints.

Figure 10-11 Tier 2 synchronized reserve daily average offer and eligible volume (MW): January through March 2014



Synchronized reserve is offered by steam, CT, CC, hydroelectric and DR resources. Figure 10-12 shows average offer MW volume by market and unit type for the MAD subzone and Figure 10-13 shows average offer MW volume by market and unit type for the RTO Zone.

Figure 10-12 Mid-Atlantic Dominion Subzone average daily tier 2 synchronized reserve offer by unit type (MW): January through June 2012 – 2014

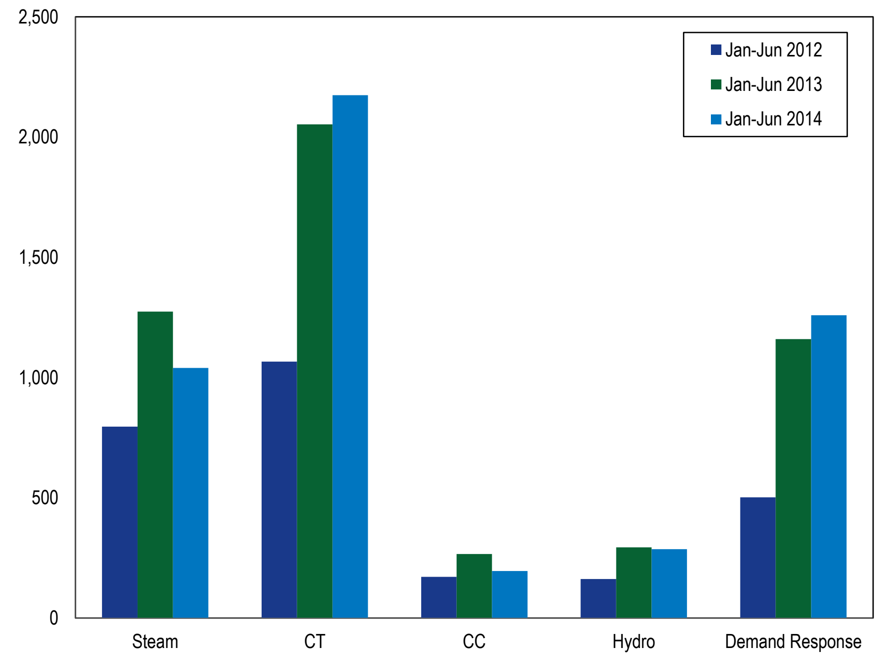


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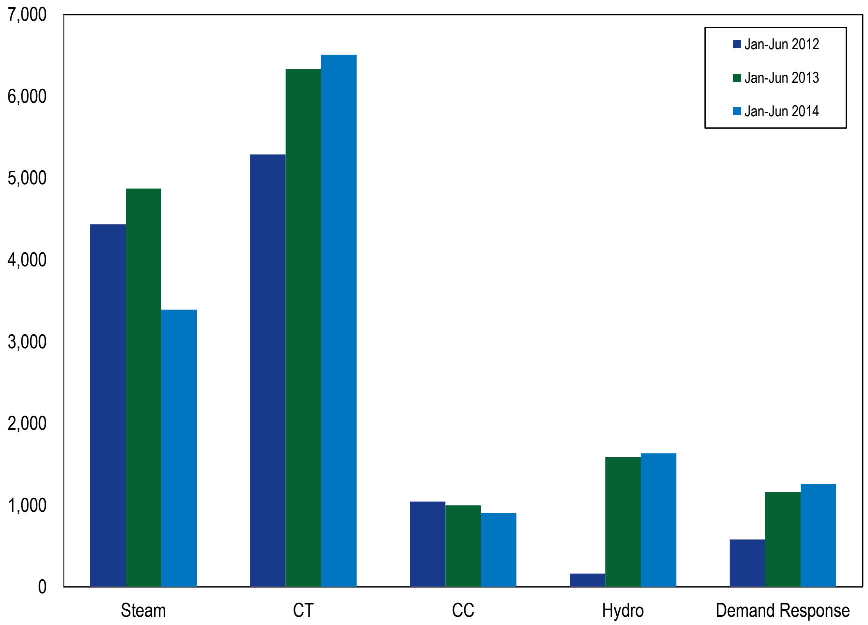
Figure 10-13 RTO Zone average daily tier 2 synchronized reserve offer by unit type (MW): January through June 2012 – 2014



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 in 96.4 percent of hours in the first six months of 2014 compared to 31.0 percent of hours in the first six months of 2013.

In the first six months of 2014, the weighted average Tier 2 Synchronized Reserve Market Clearing Price in the RTO Zone only for all cleared hours was $18.15. In the first six months of 2013, the weighted average Synchronized Reserve Market clearing price in the RTO Zone (only cleared in 33 hours) was $7.17.

In the first six months of 2014, the weighted average Tier 2 synchronized reserve market clearing price in the MAD subzone for all cleared hours was $15.18. In the first six months of 2013, the weighted average Synchronized Reserve Market clearing price in the MAD subzone was $7.45.

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 and demand are reflected in the price of synchronized reserve (Figure 10-7and Figure 10-8). 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.

The Tier 2 Synchronized Reserve Market for the MAD subzone (Table 10-12) cleared an hourly average 418.3 MW with a weighted average SRMCP of $15.18 in the first six months of 2014. This is an increase of $7.73 over the weighted average SRMCP of $7.45 for the first six months of 2013.

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Table 10-12 Mid-Atlantic Dominion Subzone, weighted SRMCP and cleared MW: January through June 2014

Year	Month	Weighted Average Tier 2 Synchronized Reserve Market Clearing Price	Average Tier 1 Synchronized Reserve Estimated Hour Ahead	Average Demand Response Cleared (MW)	Average Tier 2 Generation Synchronized Reserve Cleared (MW)
2014	Jan	$40.39	230.2	113.7	964.7
2014	Feb	$14.64	826.9	53.2	419.9
2014	Mar	$22.30	965.5	61.5	273.1
2014	Apr	$8.73	789.3	97.8	412.9
2014	May	$8.73	1,044.2	70.9	212.3
2014	Jun	$5.91	1,030.7	42.3	227.0

The RTO Zone cleared a Tier 2 Synchronized Reserve Market in 56.8 percent of hours in the first six months of 2014 compared to less than one percent of hours in the first six months of 2013.

The Tier 2 Synchronized Reserve Market for the RTO Zone (Table 10-13) cleared an hourly average 123.0 MW with a weighted average SRMCP of $18.15 for the first six months of 2014.

For the first six months of 2014 (Table 10-13), the weighted average price for tier 2 synchronized reserve in the RTO Reserve Zone was $18.15. For the first six months of 2013, the weighted average price for tier 2 synchronized reserve in the RTO Reserve Zone was $7.17 (note that a tier 2 synchronized reserve market was cleared in only 33 hours in the first six months of 2013).

Table 10-13 RTO zone weighted SRMCP and cleared MW: January through June, 2014

Year	Month	Weighted Average Tier 2 Synchronized Reserve Market Clearing Price	Average Tier 1 Synchronized Reserve Estimated Hour Ahead	Average Demand Response Cleared (MW)	Average Tier 2 Generation Synchronized Reserve Cleared (MW)
2014	Jan	$145.29	389.8	113.7	1,234.7
2014	Feb	$31.97	1,203.2	53.2	497.6
2014	Mar	$20.55	1,343.4	61.5	382.0
2014	Apr	$9.93	1,139.8	97.8	503.6
2014	May	$6.97	1,341.5	70.9	296.2
2014	Jun	$5.82	1,770.0	42.3	192.4

Price and 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.

For the first six months of 2014, the price to cost ratio of the full RTO Zone Tier 2 Synchronized Reserve Market averaged 74.8 percent; the price to cost ratio of the RTO Zone excluding MAD averaged 62.4 percent; the price to cost ratio of the MAD subzone averaged 78.4 percent.

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Table 10-14 Full RTO, RTO, Mid-Atlantic Subzone Tier 2 synchronized reserve MW, credits, price, and cost: January through June, 2014

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	Total		1,954,573	$52,495,326	$20.08	$26.86	74.8%
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	Total		406,843	$11,830,946	$18.15	$29.08	62.4%
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	77.9%
MAD Subzone	2014	Jun	113,261	$1,296,534	$5.91	$11.45	51.6%
MAD Subzone	Total		1,547,729	$40,664,379	$20.59	$26.27	78.4%

Compliance

Synchronized reserve non-compliance has two components: failure to deliver scheduled tier 2 Synchronized Reserve MW during spinning 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 spinning 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 spinning event. Actual spinning 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.

The MMU has reported the wide range of spinning 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 spinning event greater than 10 minutes during which flexible or inflexible synchronized reserve was scheduled either by the resource owner or by PJM. In the first six months of 2014, 12 spinning events occurred that met these criteria. The response from tier 2 synchronized reserve resources to spinning events has improved during the first six months of 2014.

Table 10-15 Synchronized reserve events greater than 10 minutes, Tier 2 Response Compliance, RTO Reserve Zone, January through June 2014

2014 Qualifying Spinning Events (DD-MON-YYYY HR)	Event Duration (Minutes)	Total Scheduled Tier 2 MW	Tier 2 Response Shortfall MW	Percent Compliance
06-JAN-2014 22	68	1,190	353	70.3%
07-JAN-2014 02	25	1,170	94	92.0%
07-JAN-2014 04	34	1,205	235	80.5%
07-JAN-2014 11	11	548	79	85.6%
07-JAN-2014 13	41	1,472	327	77.8%
10-JAN-2014 16	12	550	43	92.1%
31-JAN-2014 15	13	410	46	88.8%
01-MAR-2014 05	26	196	28	85.7%
27-MAR-2014 10	56	511	75	85.4%
01-MAY-2014 10	13	549	104	81.0%
01-MAY-2014 15	13	487	100	79.5%
03-MAY-2014 17	13	304	57	81.5%

For the qualifying spinning events that occurred in the first six months of 2014, 17.9 percent of all scheduled synchronized reserve MW were not delivered and were penalized.

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

17 See PJM, "Manual 11, Energy & Ancillary Services Market Operations," Rev. 67, June 1, 2014 Settlements, p. 75.

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Resource owners are credited for the amount of tier 2 synchronized reserve they provide in response to a spinning event.[18] Resource 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. The average number of days between events calculated by PJM Performance Compliance for 2014 is 15 days. 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 spinning event.[19] Resource owners are permitted to aggregate the response of multiple units to offset an underresponse from one unit with an overresponse from a different unit for the purpose of reducing an underresponse penalty.

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 reserve. Compliance with this requirement has improved since the end of March, 2014. As of June 30, 2014, the MMU estimates that 3.6 percent of eligible energy resources are not 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.[20]

18 See PJM, "Manual 11, Energy & Ancillary Services Market Operations," Rev. 67, June 1, 2014 Non Performance, p. 76.
19 See PJM "M-28 Operating Agreement Accounting," Rev. 64, April 11, 2014, p. 42. See also "Manual 11, Energy & Ancillary Services Market Operations," Rev. 67, June 1, 2014 Non Performance, p. 76.
20 See PJM, "Manual 11, Energy & Ancillary Services Market Operations," Rev. 67, June 1, 2014 Section 4.2.1, p. 62.

History of Spinning Events

Synchronized reserve is designed to provide relief for disturbances.[21] In the absence of a disturbance, PJM dispatchers have used synchronized reserve as a source of energy to provide relief from low ACE. Such an event occurred on January 6, 2014. Three extended (68, 25, and 34 minutes) spinning events were declared during afternoon and evening hours of January 6 for low ACE. The 56 minute spinning event of March 27, 2014 was to supply reactive transfer voltage support. All other spinning events during the first six months of 2014 were for disturbances. Spinning events of 56 and 68 minutes are indicative of either an inadequate supply of primary reserve or the use of primary reserve when secondary reserve would be more appropriate. 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.

Spinning events (Table 10-16) are usually caused by a sudden generation outage or transmission disruption (disturbance) requiring PJM to load synchronized reserve.[22] PJM also calls spinning events for non-disturbance events, which it characterizes as low ACE. The reserve remains loaded until system balance is recovered. From 2011 through the first six months of 2014, PJM experienced 100 spinning events, between two and three events per month. Spinning events had an average length of 13 minutes.

Compliance by tier 2 synchronized reserve to the 68 minute spinning event of January 6 was very poor (Table 10-15) at 45.4 percent non-compliance among MAD subzone resources and 29.7 percent non-compliance overall.

21 2013 State of the Market Report for PJM, Appendix F – PJM's DCS Performance, pp 451-452.
22 See PJM, "Manual 12, Balancing Operations," Revision 30 (December 1, 2013), pp. 36-37.

Table 10-16 Spinning events, 2011 through 2014

Effective Time	Region	Duration (Minutes)	Effective Time	Region	Duration (Minutes)	Effective Time	Region	Duration (Minutes)	Effective Time	Region	Duration (Minutes)
JAN-11-2011 15:10	Mid-Atlantic	6	JAN-03-2012 16:51	RFC	9	JAN-22-2013 08:34	RTO	8	JAN-06-2014 22:01	RTO	68
FEB-02-2011 01:21	RFC	5	JAN-06-2012 23:25	RFC	8	JAN-25-2013 15:01	RTO	19	JAN-07-2014 02:20	RTO	25
FEB-08-2011 22:41	Mid-Atlantic	11	JAN-23-2012 15:02	Mid-Atlantic	8	FEB-09-2013 22:55	RTO	10	JAN-07-2014 04:18	RTO	34
FEB-09-2011 11:40	Mid-Atlantic	16	MAR-02-2012 19:54	RFC	9	FEB-17-2013 23:10	RTO	13	JAN-07-2014 11:27	RTO	11
FEB-13-2011 15:35	Mid-Atlantic	14	MAR-08-2012 17:04	RFC	6	APR-17-2013 01:11	RTO	11	JAN-07-2014 13:20	RTO	41
FEB-24-2011 11:35	Mid-Atlantic	14	MAR-19-2012 10:14	RFC	10	APR-17-2013 20:01	RTO	9	JAN-10-2014 16:46	RTO	12
FEB-25-2011 14:12	RFC	10	APR-16-2012 00:20	Mid-Atlantic	9	MAY-07-2013 17:33	RTO	8	JAN-21-2014 18:52	RTO	6
MAR-30-2011 19:13	RFC	12	APR-16-2012 11:18	RFC	8	JUN-05-2013 18:54	RTO	20	JAN-22-2014 02:26	RTO	7
APR-02-2011 13:13	Mid-Atlantic	11	APR-19-2012 11:54	RFC	16	JUN-08-2013 15:19	RTO	9	JAN-22-2014 22:54	RTO	8
APR-11-2011 00:28	RFC	6	APR-20-2012 11:08	Mid-Atlantic	7	JUN-12-2013 17:35	RTO	10	JAN-25-2014 05:22	RTO	10
APR-16-2011 22:51	RFC	9	JUN-20-2012 13:35	RFC	7	JUN-30-2013 01:22	RTO	10	JAN-26-2014 17:11	RTO	6
APR-21-2011 20:02	Mid-Atlantic	6	JUN-26-2012 17:51	RFC	7	JUL-03-2013 20:40	RTO	13	JAN-31-2014 15:05	RTO	13
APR-27-2011 01:22	RFC	8	JUL-23-2012 21:45	RFC	18	JUL-15-2013 18:43	RTO	29	FEB-02-2014 14:03	RTO	8
MAY-02-2011 00:05	Mid-Atlantic	21	AUG-03-2012 12:44	RFC	10	JUL-28-2013 14:20	RTO	10	FEB-08-2014 06:05	RTO	18
MAY-12-2011 19:39	RFC	9	SEP-08-2012 04:34	RFC	12	SEP-10-2013 19:48	RTO	68	FEB-22-2014 23:05	RTO	7
MAY-26-2011 17:17	Mid-Atlantic	20	SEP-27-2012 17:19	Mid-Atlantic	7	OCT-28-2013 10:44	RTO	33	MAR-01-2014 05:18	RTO	26
MAY-27-2011 12:51	RFC	6	OCT-17-2012 10:48	RTO	10	DEC-01-2013 11:17	RTO	9	MAR-05-2014 21:25	RTO	8
MAY-29-2011 09:04	RFC	7	OCT-23-2012 22:29	RTO	19	DEC-07-2013 19:44	RTO	7	MAR-13-2014 20:39	RTO	8
MAY-31-2011 16:36	RFC	27	OCT-30-2012 05:12	RTO	14				MAR-27-2014 10:37	RTO	56
JUN-03-2011 14:23	RFC	7	NOV-25-2012 16:32	RTO	12				APR-14-2014 01:16	RTO	10
JUN-06-2011 22:02	Mid-Atlantic	9	DEC-16-2012 07:01	RTO	9				APR-25-2014 17:33	RTO	6
JUN-23-2011 23:26	RFC	8	DEC-21-2012 05:51	RTO	7				MAY-01-2014 14:18	RTO	13
JUN-26-2011 22:03	Mid-Atlantic	10	DEC-21-2012 10:29	RTO	5				MAY-03-2014 17:11	RTO	13
JUL-10-2011 11:20	RFC	10							MAY-14-2014 01:36	RTO	5
JUL-28-2011 18:49	RFC	12									
AUG-02-2011 01:08	RFC	6									
AUG-18-2011 06:45	Mid-Atlantic	6									
AUG-19-2011 14:49	RFC	5									
AUG-23-2011 17:52	RFC	7									
SEP-24-2011 15:48	RFC	8									
SEP-27-2011 14:20	RFC	7									
SEP-27-2011 16:47	RFC	9									
OCT-30-2011 22:39	Mid-Atlantic	10									
DEC-15-2011 14:35	Mid-Atlantic	8									
DEC-21-2011 14:26	RFC	18									

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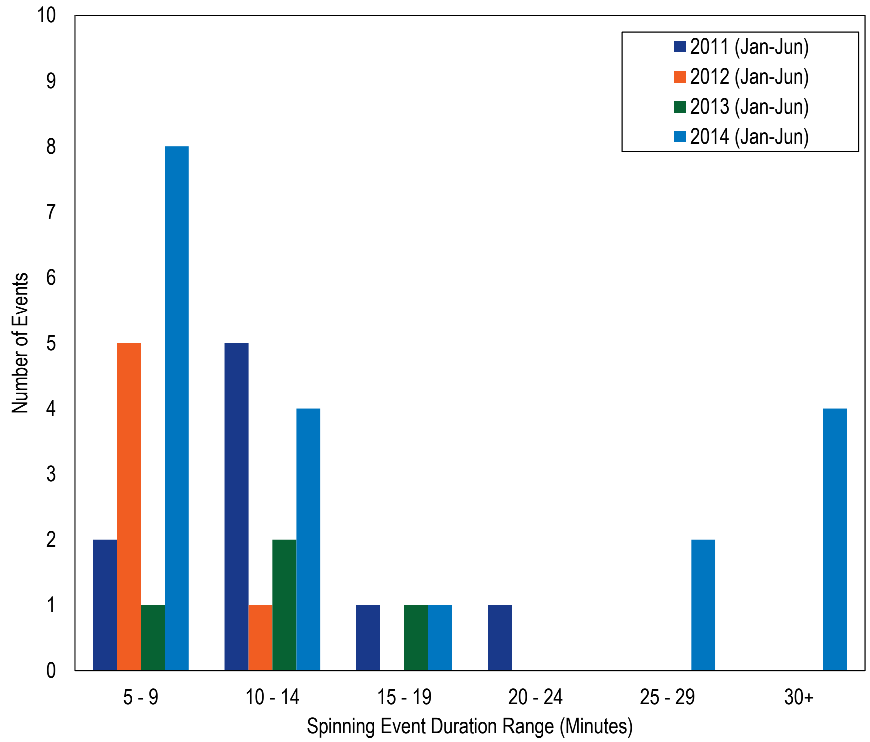
Figure 10-14 Spinning events duration distribution curve, January through June 2011 through 2014



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 (yellow line) in excess of the synchronized reserve requirement (red 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. The market solution software evaluates all eligible resources and schedules them economically. Examples of equipment that generally qualifies as non-synchronized reserve are run of river hydro, pumped hydro, combustion turbines, combined cycles and diesels.[23] For the first six months of 2014 an average of 602.6 MW of non-

23 See PJM. "Manual 11, Energy & Ancillary Services Market Operations" Revision 67 (June 1, 2014), p. 79.

synchronized reserve was scheduled hourly in the Mid-Atlantic Dominion subzone. For the first six months of 2014, an average of 624.2 MW of non-synchronized reserve was scheduled hourly in the RTO Zone.

CTs provided 57.9 percent and hydro 39.2 percent of cleared non-synchronized reserve MW in the first six months of 2014. The remaining cleared non-synchronized reserve was provided by diesel resources.

Market Concentration

The supply of non-synchronized reserves in the Mid-Atlantic Dominion subzone was highly concentrated. The supply of non-synchronized reserves in the RTO Zone was also highly concentrated.

Table 10-17 Non-synchronized reserve market HHIs, January through June 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

Table 10-18 Non-synchronized reserve market pivotal supply test, January through June 2014

Year	Month	Mid Atlantic Dominion Three Pivotal Supplier Hours	RTO Three Pivotal Supplier Hours
2014	Jan	97.2%	89.3%
2014	Feb	100.0%	95.7%
2014	Mar	99.2%	93.7%
2014	Apr	100.0%	100.0%
2014	May	100.0%	95.3%
2014	Jun	100.0%	95.6%

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 401 (8.9 percent) hours in the first six months of 2014, at an average price of $33.73 per MW. The weighted non-synchronized reserve market clearing price for all hours in the MAD subzone, including cleared hours when the price was zero, was $2.68 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 257 (6.0 percent) hours in the first six months of 2014 at an average price of $29.93. The weighted non-synchronized reserve market clearing price for all hours in the RTO Zone including cleared hours when the price was zero, was $0.93. The maximum clearing price was the shortage pricing non-synchronized reserve maximum of $400 for four consecutive hours on January 7, 2014.

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

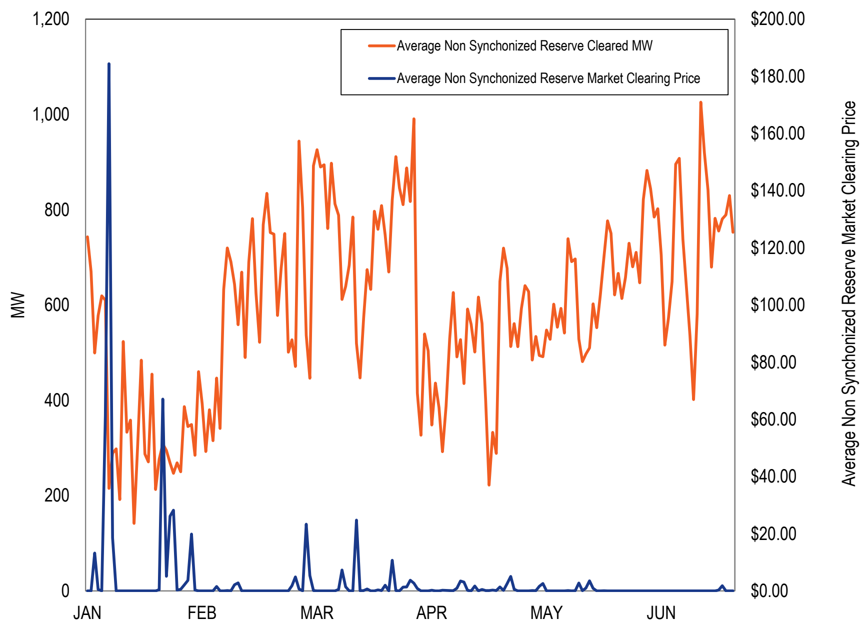
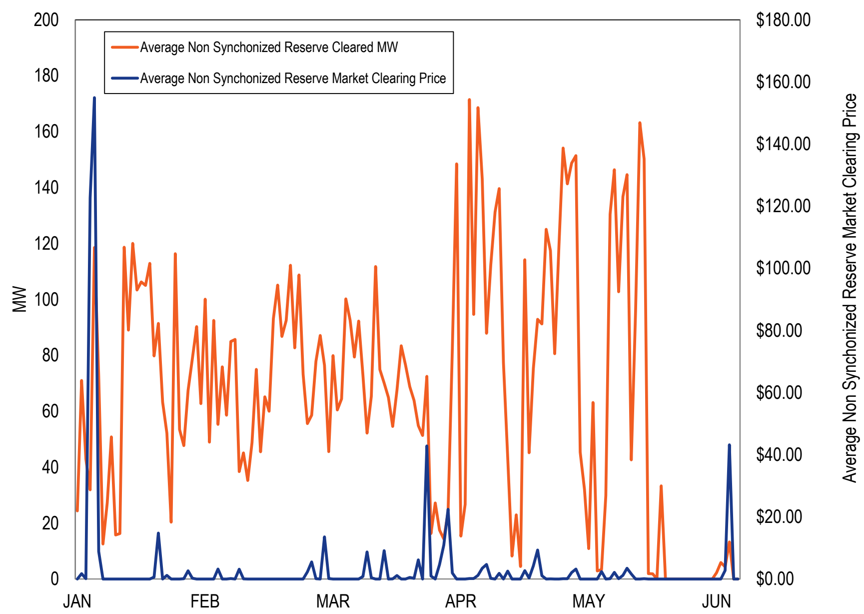


Figure 10-16 Daily average RTO Zone Non-Synchronized Reserve Market clearing price and MW purchased: January through June 2014



Price and Cost

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 SRMCP does not fully compensate them.

The full cost of non-synchronized reserve including payments for the clearing price and uplift costs is calculated and compared to the price (Table 10-19). The closer the price to cost ratio comes to one, the more the market price reflects the full cost of non-synchronized reserve.

For the first six months of 2014, the price to cost ratio of the full RTO Zone non-synchronized reserve market averaged 39.4 percent; the price to cost ratio of the RTO Zone excluding MAD averaged 47.3 percent; the price to cost ratio of the MAD subzone averaged 51.5 percent.

Table 10-19 Full RTO, RTO, Mid-Atlantic Subzone non-synchronized reserve MW, credits, price, and cost: January through June, 2014

Market	Year	Month	Total Non-Synchronized Reserve MW	Total Charges	Weighted Non-Synchronized Reserve Market Clearing Price	Cost
Full RTO Zone	2014	Jan	291,938	$5,756,058	$7.16	$19.72
Full RTO Zone	2014	Feb	416,613	$871,881	$0.30	$2.09
Full RTO Zone	2014	Mar	582,741	$2,771,506	$0.95	$4.76
Full RTO Zone	2014	Apr	392,105	$464,952	$0.93	$1.19
Full RTO Zone	2014	May	478,527	$1,015,507	$0.36	$2.12
Full RTO Zone	2014	Jun	532,890	$227,613	$0.05	$0.43
Total	2014		2,694,815	$11,107,519	$1.63	$4.12
RTO Only	2014	Jan	158,922	$1,945,725	$5.45	$12.24
RTO Only	2014	Feb	253,255	$406,812	$0.25	$1.61
RTO Only	2014	Mar	345,732	$1,011,285	$0.70	$2.93
RTO Only	2014	Apr	233,686	$246,437	$0.87	$1.05
RTO Only	2014	May	295,479	$603,341	$0.34	$2.04
RTO Only	2014	Jun	322,662	$135,670	$0.05	$0.42
Total	2014		1,609,736	$4,349,269	$1.28	$2.70
MAD Subzone	2014	Jan	133,016	$3,810,333	$14.30	$28.65
MAD Subzone	2014	Feb	163,358	$465,070	$0.64	$2.85
MAD Subzone	2014	Mar	237,009	$1,760,222	$2.63	$7.43
MAD Subzone	2014	Apr	158,419	$218,515	$1.14	$1.38
MAD Subzone	2014	May	183,048	$412,166	$0.49	$2.25
MAD Subzone	2014	Jun	210,228	$91,944	$0.05	$0.44
Total	2014		1,085,078	$6,758,250	$3.21	$6.23

Secondary Reserve (DASR)

PJM maintains a day-ahead, offer based market for 30-minute secondary reserve.[24] It is designed to provide price signals that encourage resources to provide 30-minute reserve. The DASR market has no performance obligations. The MMU recommends elimination of the day-ahead market and its replacement with a real-time market for a dispatchable reserve product beyond the 30-minute limit for primary reserves is needed.

DASR 30-minute reserve requirements are determined by PJM for each reliability region.[25] In the Reliability*First* (RFC) region, secondary reserve requirements are calculated based on historical under-forecasted load rates and generator forced outage rates.[26] The RFC and Dominion secondary reserve requirements are added together to form a single RTO DASR requirement defined as a percentage of the daily peak load forecast, currently 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. [27]

Market Structure

Supply

The amount of DASR available is the lesser of the energy ramp rate for all on-line units times thirty minutes, or the emergency maximum minus the day-ahead dispatch point. For off-line resources capable of being online in thirty minutes, the DASR quantity is emergency maximum. For the first six months of 2014, the average available hourly DASR was 40,768 MW. The DASR MW purchased averaged 5,951 MW per hour for the first six months of 2014, a decrease from 6,614 MW per hour in the first six months of 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 the first six months of 2014, no hours would have failed a three pivotal supplier test in the DASR Market. No hours failed the three pivotal supplier test in the first six months of 2013.

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

25 See PJM. "Manual 13, Emergency Requirements," Revision 56 (June 1, 2014), p. 11.

26 See PJM. "Manual 13, Emergency Requirements," Revision 56 (June 1, 2014), p. 11.

27 PJM uses the terms "supplemental operating reserves" and "scheduling operating reserves" interchangeably.

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All generation resources are required to offer DASR.[28] Load response resources which are registered in PJM's Economic Load Response and are dispatchable by PJM are eligible to provide DASR. No demand resources offered in the DASR Market in the first six months of 2014.

Market Conduct

PJM rules allow any unit with reserve capability that can be converted into energy within 30 minutes to offer into the DASR Market.[29] Units that do not offer have their offers set to $0.00 per MW.

Economic withholding remains an issue in the DASR Market. The direct marginal cost of providing DASR is zero. All offers greater than zero constitute economic withholding. On June 30, 2014, 11.2 percent of resources offered DASR at levels above $5 per MW.

Market Performance

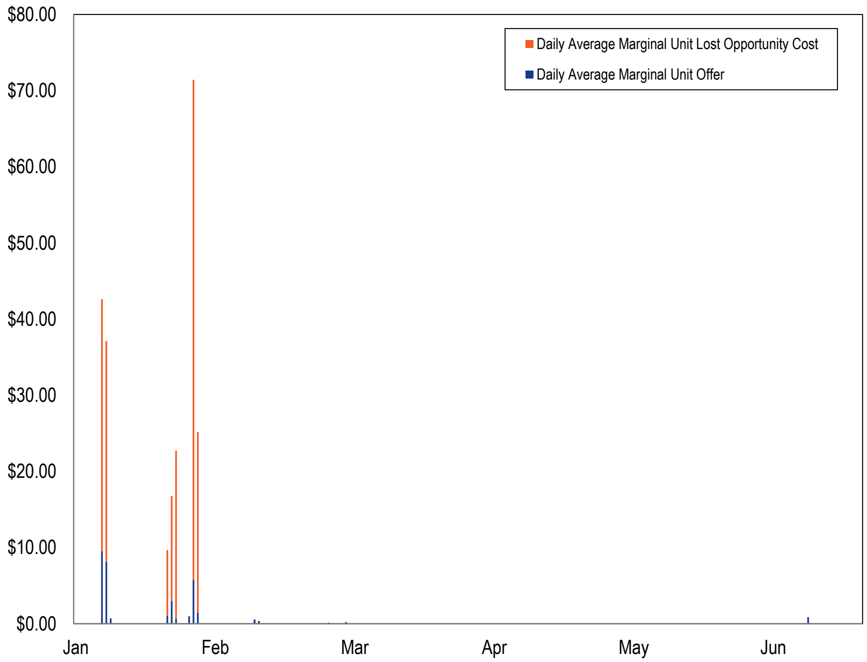
For 90.0 percent of hours in the first six months of 2014, DASR cleared at a price of $0.00 per MWh (Figure 10-17). For the first six months of 2014, the weighted average DASR price was $1.63. The highest DASR price was $534.66 on January 8, 2014. DASR prices are calculated as the sum of the offer price plus the opportunity cost. For most hours the price is comprised entirely of the offer price. During the first six months of 2014, when the clearing price was above $0.00, 85.2 percent of the price is LOC.

Table 10-20 PJM Day-Ahead Scheduling Reserve Market MW and clearing prices: January 2012 Through June 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	5,212,272	$35,349,968
2014	Feb	5,804	$0.00	$5.00	$0.05	4,541,860	$188,937
2014	Mar	5,303	$0.00	$3.00	$0.01	4,647,607	$47,749
2014	Apr	4465	$0.00	$0.05	$0.00	3,894,178	$1,241
2014	May	5531	$0.00	$0.10	$0.00	4,105,788	$7,386
2014	Jun	6901	$0.00	$7.80	$0.04	4,795,078	$163,325

28 See PJM "Manual 11," Revision 67, (June 1, 2014) p. 144 at Day-ahead Scheduling Reserves Market Rules.
29 See PJM. "Manual 11, Emergency and Ancillary Services Operations," Revision 67 (June 1,, 2014), p. 142.

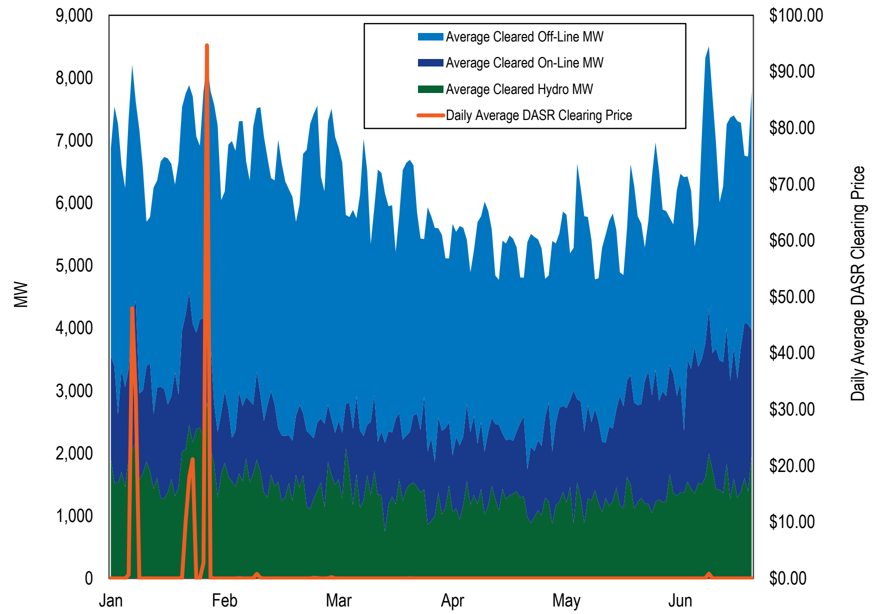
Figure 10-17 Daily average components of DASR clearing price, marginal unit offer and LOC: January through June 2014



When energy demand is high the reserve requirement cannot be filled without redispatching online resources which significantly affects the price. Figure 10-17 shows the impact of LOC on price when online resources must be redispatched to satisfy the DASR requirement.

Figure 10-18 illustrates the sensitivity of DASR prices to high energy dispatch and the resource types (on-line, off-line, and hydro) used for secondary reserve. DASR prices remain very low even at high energy dispatch levels. DASR prices increase very suddenly at peak loads as a result of high LOCs (Figure 10-17).

Figure 10-18 Daily average DASR prices and MW by classification: January through June, 2014



On September 10, 2013, a 68-minute spinning event was declared as a result of low ACE. On January 6, 2014 another 68-minute spinning 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

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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.

Regulation Market

Regulation matches generation with very short term changes in load by moving the output of selected resources up and down via an automatic control signal. Regulation is provided by generators with a short-term response capability (less than five minutes) or by demand response (DR). The PJM Regulation Market is operated as a single market. Significant technical and structural changes were made to the Regulation Market in 2012.[30]

Market Design

The Regulation Market includes resources following two signals: RegA and RegD. Resources responding to either signal help control ACE. 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 generally provided by fleets of resources rather than by individual units. The regulation signals (RegA or RegD) are sent every two seconds to the fleet local control centers. A fleet is a set of resources owned or operated by a common entity. Fleet owners may allocate their assigned regulating capability to individual resources as they wish as long as the total allocated RegA capability and total allocated RegD capability match the totals assigned to them. Fleet local control centers report to PJM every two seconds the fleet response to the RegA and RegD signals.

There is no clear reason why PJM should continue to procure regulation on a fleet basis rather than on an individual unit basis, comparable to the energy market.

Regulation performance scores (0.0 to 1.0) measure the response of a regulating resource to its chosen regulation signal (RegA or RegD) every ten seconds by measuring: delay, the time delay of the regulation response to a change in the regulation signal; correlation, the correlation between the regulating resource output and the regulation signal; and precision, the difference between the regulation response and the regulation requested.[31]

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). 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

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

31 PJM "Manual 12: Balancing Operations" Rev. 30 (December 1, 2013); 4.5.6, p 52.

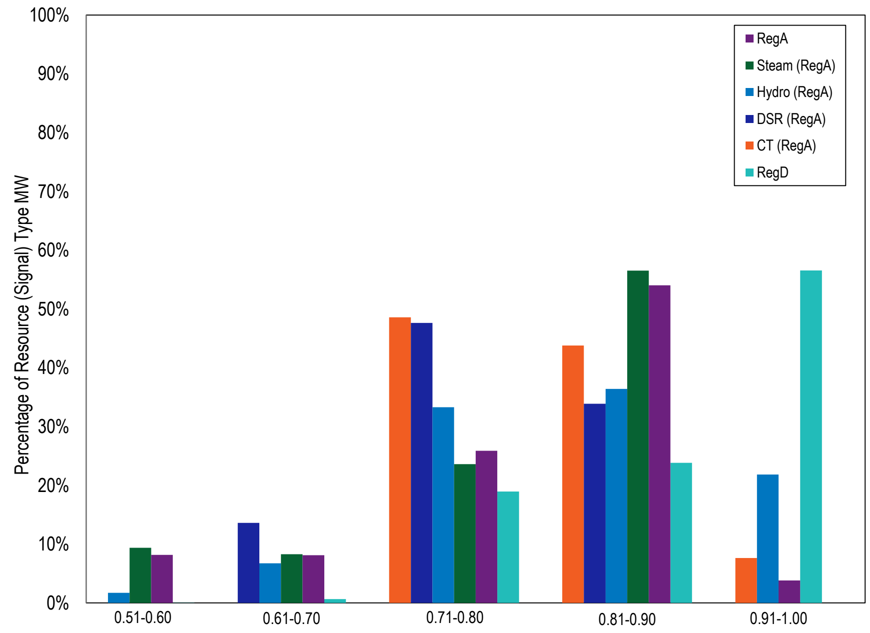
regulation MW, MW means regulation capability MW unadjusted for either marginal benefit factor or performance factor.

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 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 the first six months of 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, 56.6 percent of RegD resources have average performance scores within the 0.91-1.00 range, whereas only 3.8 percent of RegA resources have average performance scores within that range.

Figure 10-19 Hourly average performance score by unit type and regulation signal type: January through June 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 10-20 shows, the true marginal benefit factor, as used in the optimization and commitment process for regulation in the first three months of 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

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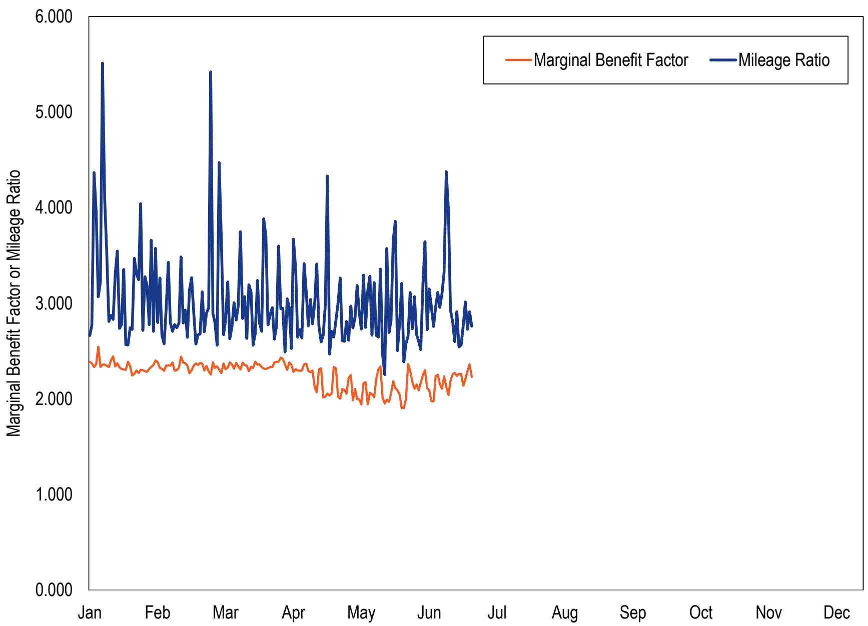
performance credits and replace it with RegD to RegA mileage ratio in the performance credit paid to RegD resources, effective November 1, 2013, and retroactively to October 1, 2012.[32] As Figure 10-20 demonstrates, the RegD to RegA mileage ratio is generally higher than the actual marginal benefit 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: January through June 2014



32 145 FERC ¶ 61,011 (2013).

Market Structure

Supply

Table 10-21 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 January through June 2014. In this table, actual MW are unadjusted regulation capability MW and effective MW are adjusted by the historic 100-hour moving average performance score and resource-specific benefit factor. A resource must be either generation or demand. But a resource can (and several resources currently do) choose to follow both signals. For that reason the sum of each signal type's capability can exceed the full regulation capability.

Table 10-21 PJM regulation capability, daily offer and hourly eligible: January through June 2014[33] [34]

		By Resource Type		By Signal Type	
Metric	All Regulation	Generating Resources	Demand Resources	RegA Following Resources	RegD Following Resources
Capability MW	8,537.4	8,524.5	12.9	8,484.6	518.7
Offered MW	5,852.1	5,843.1	9.0	5,661.1	191.1
Actual Eligible MW	1,335.6	1,329.6	6.0	1,173.6	162.0
Effective Eligible MW	980.4	972.0	8.5	761.2	219.2
Actual Cleared MW	673.5	670.1	3.4	571.3	102.2
Effective Cleared MW	663.7	656.7	7.0	451.4	212.3

Total regulation capability MW provided by coal units increased from 286,651 MW in the first six months of 2013 to 294,981 MW in the first six months of 2014 and the proportion of regulation provided by coal increased, from 13.1 percent of regulation in the first six months of 2013 to 14.5 percent of regulation in the first six months of 2014. Coal unit revenues in the first six months of 2014 were 2.0 times the revenues in the first six months of 2013 ($33.8 million in the first six months of 2014, versus $16.7 million in the first six months of 2013). The increase was a result of the high regulation market clearing prices and out of market opportunity cost credits in January. Table 10-22 provides monthly data on the number of coal units providing

33 Average Daily Offer MW excludes units that have offers but are unavailable for the day.
34 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.

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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 10-22, 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.

Table 10-22 PJM regulation provided by coal units

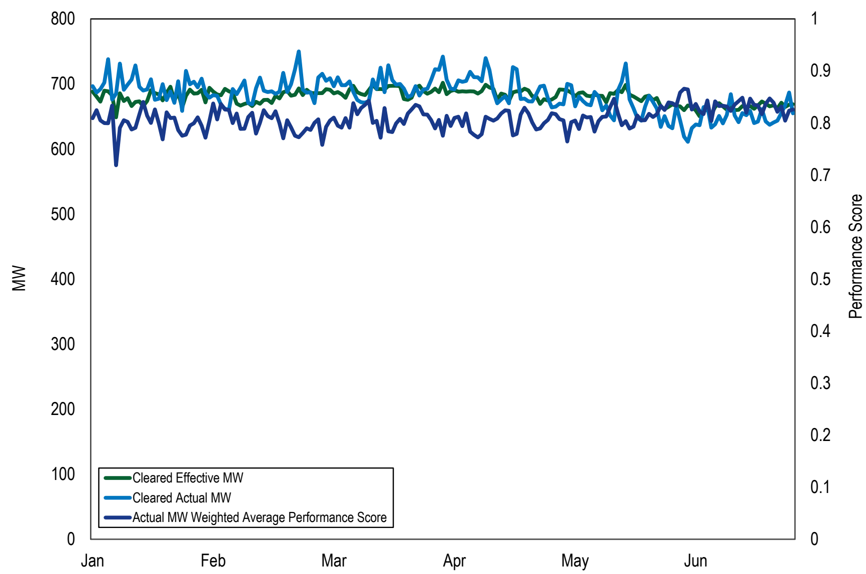
Year	Period	Number of Coal Units Providing Regulation	Adjusted Settled Regulation from Coal Units (MW)	Adjusted Settled Regulation from All Resources (MW)	Percent of Scheduled Regulation from Coal Units	Total Coal Unit Regulation Credits
2013	Jan	117	80,766	401,101	20.1%	$5,376,060
2013	Feb	101	64,164	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	Average	100	47,775	355,235	13.1%	$2,778,519
2014	Jan	109	70,441	360,513	19.5%	$15,780,551
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	330,376	9.5%	$1,591,779
2014	Average	91	49,163	336,431	14.5%	$5,625,475

The supply of regulation can be affected by regulating units retiring from service. Table 10-23 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 10-23 have been adjusted by the actual within-hour performance score.

Table 10-23 Impact on PJM Regulation Market of currently regulating units scheduled to retire through 2015

Current Regulation Units, January through June 2014	Adjusted Settled MW, January through June 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
281	2,018,585	30	19,713	0.98%

Figure 10-21 All (RegA and RegD) cleared regulation: Daily average actual cleared MW of regulation, effective cleared MW of regulation, and average performance score: January through June 2014



Although the marginal benefit factor for slow (RegA) resources is 1.0, the effective MW of RegA following resources was lower than the offered MW in the first six months of 2014 because the average performance score was less than 1.00 (Figure 10-21). For the first six months of 2014, the MW-weighted average RegA performance score was 0.80 and from January through June 2014, there were 277 resources following the RegA signal.

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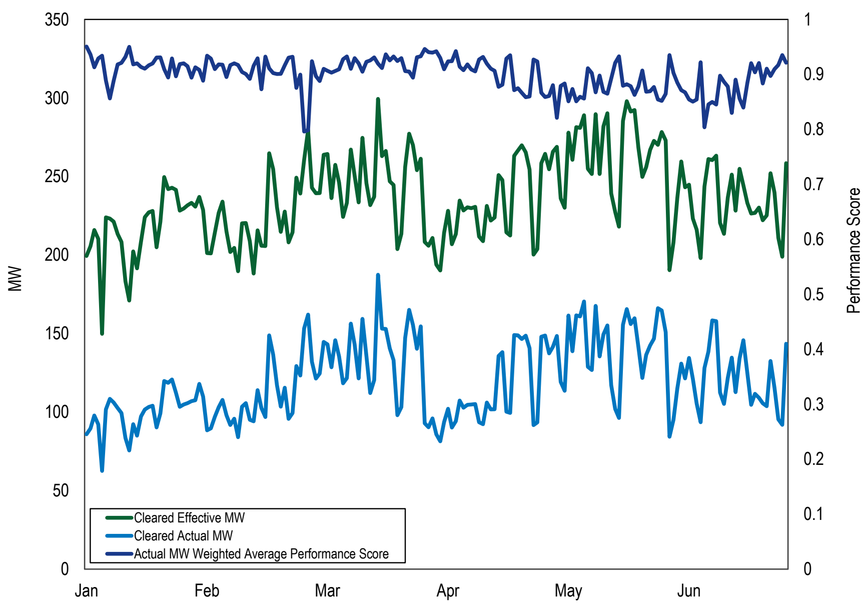
In Figure 10-21 and Figure 10-22, actual MW are unadjusted for either performance score or benefit factor and effective MW are adjusted for the historic 100-hour moving average performance score and the resource-specific benefit factor.

Figure 10-22 Only RegD cleared regulation: Daily average actual cleared MW of regulation, effective cleared MW of regulation, and average performance score; RegD units: January through June 2014



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

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

Since the implementation of regulation performance on October 1, 2012, both regulation price and regulation cost per MW are higher than they were prior to October 1, 2012, (Table 10-30). Throughout the first six months of 2014, the price and cost of regulation have remained high relative to prior years. The weighted average regulation price for the first six months of 2014 was $62.09/MW. The regulation cost for the first six months of 2014 was $75.20/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.

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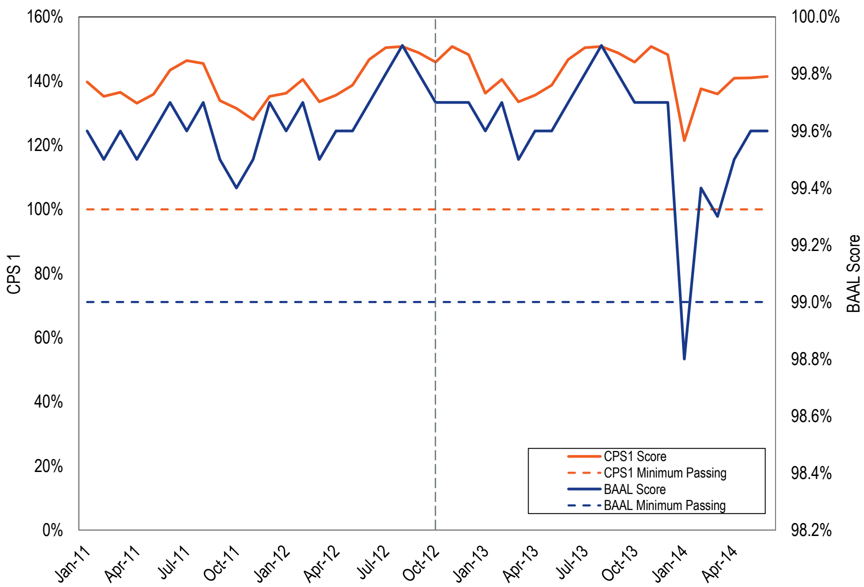
Table 10-24 PJM Regulation Market required MW and ratio of eligible supply to requirement: January through June, 2013 and 2014

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

Table 10-24 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 10-23 for every month from January 2011 through June 2014 with the dashed vertical line marking the date (October 1, 2012) of the implementation of the Performance Based Regulation Market design.[35] 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, PJM remained in compliance with the applicable NERC standards.

Figure 10-23 PJM monthly CPS1 and BAAL performance: January 2011 through June 2014



35 See the *2013 State of the Market Report for PJM*, Appendix F: Ancillary Services.

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Market Concentration

Table 10-25 shows Herfindahl-Hirschman Index (HHI) results for the first six months of 2013 and the first six months of 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 1901 is classified as highly concentrated, but is lower than the HHI for the same period in the first six months of 2013 of 2083. For the first six months of 2014, the weighted average HHI of RegA resources was 2845 (highly concentrated) and the weighted average HHI of RegD resources was 4795 (highly concentrated). 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 market.

Table 10-25 PJM cleared regulation HHI: January through June 2013 and 2014

Period	Minimum HHI	Weighted Average HHI	Maximum HHI
2013 (Jan-Jun)	953	2083	9616
2014 (Jan-Jun)	977	1901	3943

Figure 10-24 compares the frequency distribution of HHI for the first six months of 2014 with the first six months of 2013.

Table 10-26 includes a monthly summary of three pivotal supplier results. In the first six months of 2014, 96 percent of hours had one or more pivotal suppliers which failed PJM's three pivotal supplier test. The impact of offer capping in the regulation market is limited because of the role of LOC in price formation (Figure 10-26).

The MMU concludes from these results that the PJM Regulation Market in the first six months of 2014 was characterized by structural market power in 96 percent of hours.

Figure 10-24 PJM Regulation Market HHI distribution: January through June 2013 and 2014

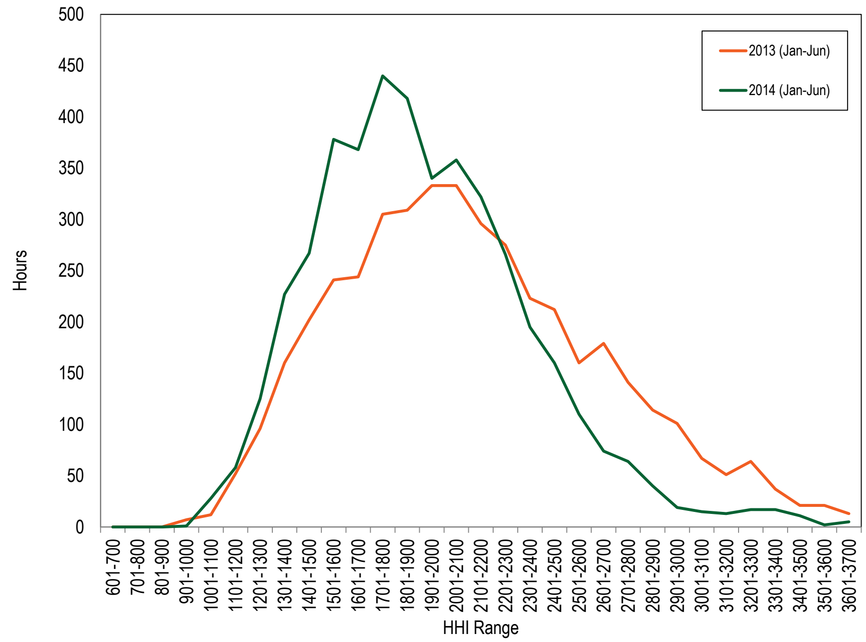


Table 10-26 Regulation market monthly three pivotal supplier results: January through June, 2012 through 2014

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%
Average	53%	90%	96%

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.

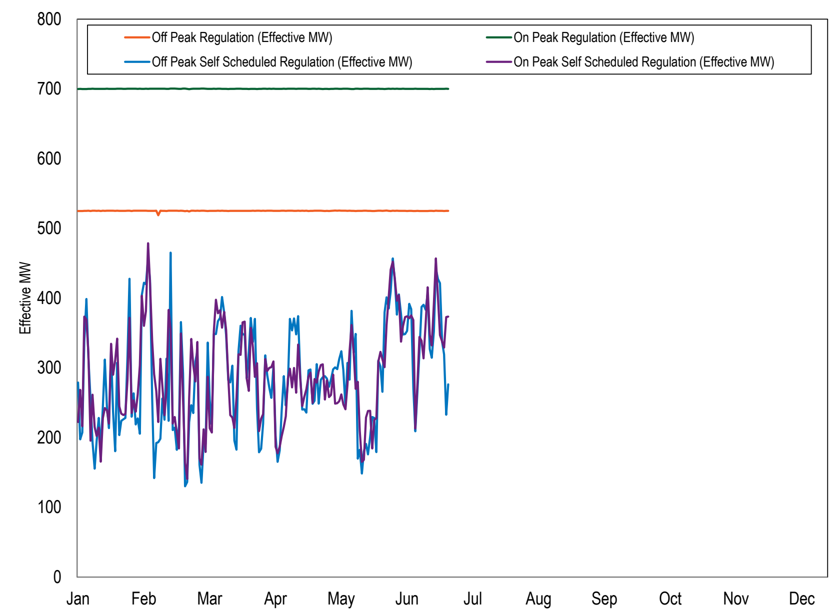
Offers in the Regulation Market consist of a capability component for the MW of regulation capability provided and a performance component for the miles (ΔMW of regulation movement) provided. The capability component for cost offers is not to exceed the increased costs (specifically, increased fuel costs 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.[36]

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.[37]

36 See PJM. "Manual 11: Energy & Ancillary Services Market Operations," Revision 67, (June 1, 2014); para 3.2.1, p 47.
37 See PJM. "Manual 11: Energy & Ancillary Services Market Operations," Revision 67, (June 1, 2014); para 3.2.2, pp 48.

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 10-27).[38] Figure 10-25 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. This value may not always equal the regulation requirement because PJM maintains regulation capabilities within a two percent band around the requirement.[39] 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 41.5 percent during on peak and 54.6 percent during off peak hours in the first six months of 2014).

Figure 10-25 Off peak and on peak regulation levels: January through June 2014



38 See PJM. "Manual 28: Operating Agreement Accounting," Revision 65, (April 24, 2014); para 4.1, p 15.
39 See PJM. "Manual 11: Energy & Ancillary Services Market Operations," Revision 67, (June 1, 2014); para 3.2.9, p 59.

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Increased self-scheduled regulation lowers the requirement for cleared regulation, resulting in fewer MW cleared in the market and lower clearing prices. Of the LSEs' obligation to provide regulation in the first six months of 2014, 57.9 percent was purchased in the PJM market, 37.6 percent was self-scheduled, and 4.5 percent was purchased bilaterally (Table 10-27). From 2010 through the first six months of 2014, Table 10-28 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 January through June in years 2010 through 2012 when these constructs were not part of the Regulation Market.

In the first six months of 2014, DR provided an average of 3.35 MW of regulation per hour (1.89 MW of regulation per hour in the first six months of 2013). Generating units supplied an average of 673.65 MW of regulation per hour (772.60 MW of regulation per hour in the first six months of 2013).

Table 10-27 Regulation sources: spot market, self-scheduled, bilateral purchases: January through June 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	484,937	98.1%	9,317	1.9%
2013	Feb	338,990	74.7%	102,005	22.5%	12,808	2.8%	453,803	443,118	97.6%	10,685	2.4%
2013	Mar	275,880	60.0%	165,987	36.1%	17,554	3.8%	459,421	445,518	97.0%	13,903	3.0%
2013	Apr	219,793	57.6%	147,858	38.8%	13,860	3.6%	381,510	369,556	96.9%	11,954	3.1%
2013	May	235,849	57.0%	161,270	38.9%	16,934	4.1%	414,053	401,277	96.9%	12,776	3.1%
2013	Jun	254,215	53.4%	198,617	41.8%	22,816	4.8%	475,647	460,222	96.8%	15,425	3.2%
2014	Jan	259,686	63.7%	125,234	30.7%	22,737	5.6%	407,656	395,755	97.1%	11,900	2.9%
2014	Feb	217,755	59.4%	132,385	36.1%	16,530	4.5%	366,670	355,909	97.1%	10,761	2.9%
2014	Mar	245,991	59.8%	148,162	36.0%	17,524	4.3%	411,677	399,207	97.0%	12,470	3.0%
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	343,855	88.8%	43,247	11.2%

Table 10-28 Regulation sources by year: January through June, 2010 through 2014

Year (Jan-Jun)	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	3,001,635	81.3%	607,813	16.5%	84,626	2.3%	3,694,074
2011	2,977,317	80.8%	596,653	16.2%	111,710	3.0%	3,685,680
2012	3,063,481	75.9%	848,065	21.0%	122,641	3.0%	4,034,187
2013	1,738,030	64.9%	848,617	31.7%	92,041	3.4%	2,678,688
2014	1,369,448	57.9%	890,479	37.6%	106,201	4.5%	2,366,128

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Market Performance

Price

The weighted average RMCP for the first six months of 2014 was $62.09 per MW. This is the average price per unadjusted capability MW. This is a 106.2 percent increase from the weighted average RMCP of $31.80/MW in first six months of 2013. Figure 10-26 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.

Table 10-29 shows monthly average regulation market clearing price, average marginal unit offer price, and average marginal unit LOC on an unadjusted capability MW basis.

Table 10-29 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	$80.73	$4.79	$71.35
Apr	$31.80	$5.56	$25.58
May	$34.47	$5.22	$31.94
Jun	$30.44	$5.23	$31.54

Total scheduled regulation MW, total regulation charges, regulation price and regulation cost are shown in Table 10-30. Total scheduled regulation is based on settled (unadjusted capability) MW.

Figure 10-26 PJM Regulation Market daily weighted average market-clearing price, marginal unit opportunity cost and offer price (Dollars per MW): 2014

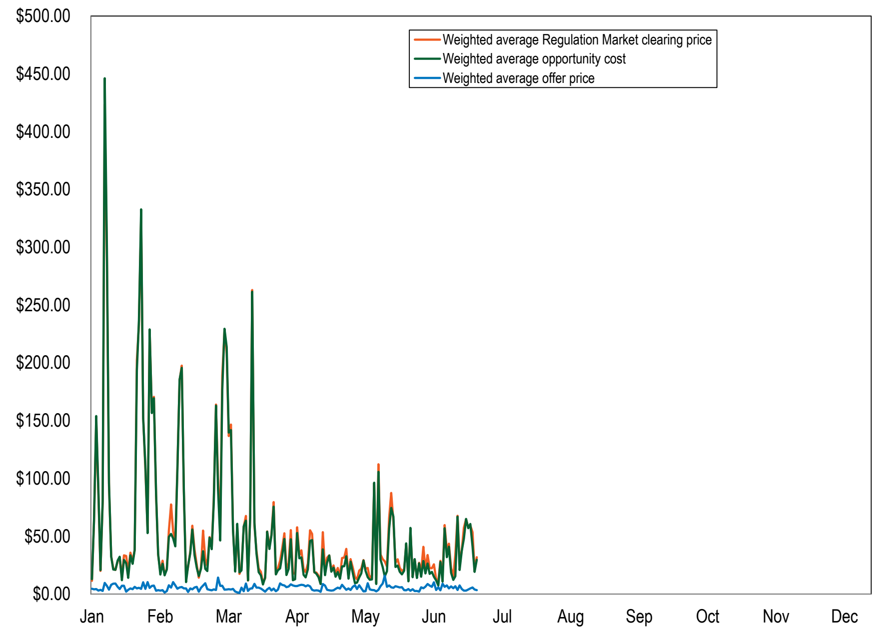

Table 10-30 Total regulation charges: January through June, 2013 and 2014

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%
2013	Feb	453,803	$15,273,604	$29.51	$33.66	88%
2013	Mar	459,421	$16,678,410	$31.64	$36.30	87%
2013	Apr	381,510	$11,930,098	$26.49	$31.27	85%
2013	May	414,053	$15,599,491	$33.42	$37.68	89%
2013	Jun	475,647	$15,999,677	$29.81	$33.64	89%
2014	Jan	407,656	$65,714,049	$132.49	$161.20	82%
2014	Feb	366,670	$27,293,638	$62.61	$74.44	84%
2014	Mar	411,667	$40,104,102	$80.73	$97.42	83%
2014	Apr	395,612	$15,241,038	$31.80	$38.53	83%
2014	May	397,411	$16,952,817	$34.47	$42.66	81%
2014	Jun	387,102	$14,312,991	$30.44	$36.97	82%

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The capability, performance, and opportunity cost components of the cost of regulation are shown in Table 10-31. Total scheduled regulation is based on settled (unadjusted capability) MW.

Table 10-31 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	411,667	$76.75	$5.71	$14.96	$97.42
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

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 the first six months of 2014 is shown in Figure 10-27. On November 1, 2013, PJM removed the marginal benefit factor from all settlement calculations. In its place, PJM inserted the mileage ratio for the performance credit only. In Figure 10-27, the RegA RMCP Credit per effective MW is, on average, 2.6 times higher than the RegD RMCP Credit per effective MW from October 2012 through October 2013. However, since November 1, 2013, the RegA RMCP Credit per effective MW is only, on average, 1.9 times higher than the RegD RMCP Credit per effective MW. 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.

Table 10-32 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 the first six months of 2014 from 87 percent in the first six months of 2013. This was in part a result of extreme market conditions in January.

Figure 10-27 Comparison of monthly average RegA and RegD RMCP Credits per Effective MW: October 2012 through June 2014[40]

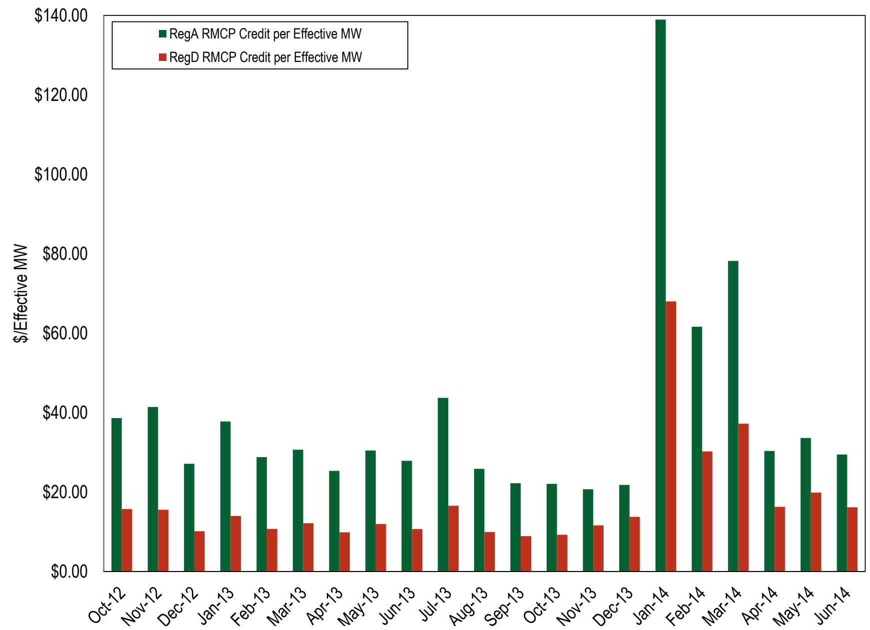

Table 10-32 Comparison of average price and cost for PJM Regulation, January through June, 2008 through 2014

Year (Jan-Jun)	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	$15.53	$30.89	50%
2012	$13.90	$18.35	76%
2013	$31.80	$36.47	87%
2014	$62.09	$75.20	83%

40 These values are credits before PJM makes its retroactive adjustments to RMCP credits.

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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.[41] 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 will be completed in the first half of 2014.) PJM and the MMU have coordinated closely during the selection process.

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.

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

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.

In the first six months of 2014, total black start charges were $25.2 million, a $33.5 million (57.1 percent) decrease from the January through June 2013 level of $58.7 million. Operating reserve charges for black start service declined from $48.1 million in the first six months of 2013 to $14.3 million in the first six months of 2014. This decrease was due to higher LMPs that caused more ALR black start units to run economically rather than out of merit. Table 10-33 shows total revenue requirement charges from the first six months of years 2009 through 2014. (Prior to December 2012, PJM did not define a black start operating reserve category.)

Table 10-33 Black start revenue requirement charges: January through June, 2009 through 2014

Year (Jan-Jun)	Revenue Requirement Charges
2009	$7,141,944
2010	$5,481,206
2011	$5,968,676
2012	$7,873,702
2013	$10,606,439
2014	$10,874,608

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Table 10-34 Black start zonal charges for network transmission use: January through June, 2013 and 2014

Zone	Jan-Jun 2013 Revenue Requirement Charges	Jan-Jun 2013 Operating Reserve Charges	Jan-Jun 2013 Total Charges	Jan-Jun 2013 Peak Load (MW-day)	Jan-Jun 2013 Black Start Rate ($/MW-day)	Jan-Jun 2014 Revenue Requirement Charges	Jan-Jun 2014 Operating Reserve Charges	Jan-Jun 2014 Total Charges	Jan-Jun 2014 Peak Load (MW-day)	Jan-Jun 2014 Black Start Rate ($/MW-day)
AECO	$267,605	$10,060	$277,666	508,429	$0.55	$311,952	$5,772	$317,725	495,795	$0.64
AEP	$310,508	$45,457,250	$45,767,758	4,218,857	$10.85	$397,225	$13,317,173	$13,714,398	4,135,180	$3.32
APS	$127,521	$3,063	$130,584	1,542,898	$0.08	$138,802	$3,027	$141,829	1,570,609	$0.09
ATSI	$66,710	$0	$66,710	2,446,197	$0.03	$58,250	$0	$58,250	2,378,539	$0.02
BGE	$3,665,240	$10,301	$3,675,541	1,267,362	$2.90	$2,821,475	$2,462	$2,823,936	1,236,284	$2.28
ComEd	$2,006,801	$12,677	$2,019,478	4,271,763	$0.47	$2,074,281	$20,220	$2,094,502	4,030,689	$0.52
DAY	$117,519	$5,252	$122,771	634,785	$0.19	$120,900	$6,511	$127,411	617,083	$0.21
DEOK	$159,453	$2,481	$161,933	985,755	$0.16	$568,211	$15,022	$583,233	931,426	$0.63
Dominion	$0	$21,152	$21,152	596,719	$0.04	$500,681	$0	$500,681	3,396,103	$0.15
DPL	$280,163	$2,833	$282,996	744,652	$0.38	$277,835	$3,255	$281,091	727,385	$0.39
DLCO	$28,760	$0	$28,760	552,792	$0.05	$29,187	$0	$29,187	534,222	$0.05
EKPC	$30,536	$0	$30,536	71,484	$0.43	$188,691	$0	$188,691	458,401	$0.41
JCPL	$279,581	$14,945	$294,526	1,125,711	$0.26	$245,209	$0	$245,209	1,154,581	$0.21
Met-Ed	$362,766	$22,151	$384,917	549,588	$0.70	$423,275	$3,816	$427,091	545,226	$0.78
PECO	$668,233	$28,121	$696,354	1,547,369	$0.45	$734,070	$13,614	$747,684	1,559,930	$0.48
PENELEC	$261,103	$2,445	$263,548	526,348	$0.50	$250,552	$0	$250,552	558,801	$0.45
Pepco	$145,604	$21,574	$167,177	1,216,447	$0.14	$154,088	$15,053	$169,141	1,182,545	$0.14
PPL	$87,003	$0	$87,003	1,336,052	$0.07	$99,043	$0	$99,043	1,337,988	$0.07
PSEG	$1,205,893	$32,992	$1,238,885	1,895,034	$0.65	$811,203	$31,135	$842,339	1,885,006	$0.45
RECO	$0	$0	$0	0	NA	$0	$0	$0	0	NA
(Imp/Exp/Wheels)	$535,440	$2,428,287	$2,963,728	1,385,075	$2.14	$669,677	$885,546	$1,555,223	1,900,931	$0.82
Total	$10,606,439	$48,075,584	$58,682,023	27,423,317	$2.14	$10,874,608	$14,322,606	$25,197,214	30,636,726	$0.82

Black start zonal charges in the first six months of 2014 ranged from $0.02 per MW-day in the ATSI Zone (total charges were $58,250) to $3.32 per MW-day in the AEP Zone (total charges were $13,714,398). For each zone, Table 10-34 shows black start charges, the sum of monthly zonal peak loads multiplied by the number of days of the month in which the peak load occurred, and black start rates (calculated as charges per MW-day). For black start service, point-to-point transmission customers paid on average $0.06 per MW of reserve capacity during the first six months of 2014.

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Table 10-35 shows estimated black start revenue requirements by zone for delivery years 2014-2015 through 2016-2017 based on current, incoming, and outgoing black start resources.

Table 10-35 Revenue Requirement Estimate: Delivery Years 2014-2015 through 2016-2017

Zone	2014-2015 Revenue Requirement	2015-2016 Revenue Requirement	2016-2017 Revenue Requirement
AECO	$881,923	$2,422,980	$2,712,515
AEP	$10,739,321	$18,054,481	$18,070,565
APS	$309,424	$4,253,581	$4,256,090
ATSI	$2,592,447	$3,084,911	$3,086,491
BGE	$2,009,693	$1,488,297	$1,538,482
ComEd	$4,672,575	$5,292,902	$3,721,520
DAY	$272,203	$271,052	$274,403
DEOK	$1,224,221	$1,223,003	$1,226,548
Dominion	$1,606,732	$4,293,407	$5,985,460
DPL	$857,173	$2,160,879	$2,715,141
DLCO	$63,794	$185,467	$187,744
EKPC	$408,714	$406,733	$412,501
JCPL	$2,270,287	$7,428,656	$7,449,817
Met-Ed	$856,576	$812,061	$858,183
PECO	$1,613,435	$1,796,320	$1,873,591
PENELEC	$543,679	$4,629,185	$4,679,970
Pepco	$1,086,225	$2,604,867	$2,611,127
PPL	$199,874	$851,869	$859,863
PSEG	$7,085,539	$9,780,520	$9,802,397
RECO	$0	$0	$0
Total	$39,293,835	$71,041,172	$72,322,407

Table 10-36 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 10-36 NERC CIP Costs: January through June 2014

Capital Cost Requested	Cost Recovered in Jan-Jun 2014	Number of Units	MW
$1,736,971	$315,260	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).[42] Reactive power helps maintain appropriate voltages on the transmission system and is essential to the flow of real power (measured in MW). Without Reactive Service in the necessary amounts across the RTO footprint, transmission system voltages fall, generating units and transmission lines shut down, and no real power flows.

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

In the first six months of 2014, total reactive service charges were $163.0 million, a 33.7 percent decrease from the January through June 2013 level of $245.9 million.[43] While revenue requirement charges increased from $137.5 million to $140.8 million, operating reserve charges fell from $108.5 million to $22.2 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 the first six months of 2014 ranged from $1.7 thousand in the RECO Zone to $20.3 million in

42 PJM OATT. Schedule 2 "Reactive Supply and Voltage Control from Generation Sources Service," (Effective Date: February 18, 2012).
43 See the *2013 State of the Market Report for PJM*, Volume II, Section 4, "Energy Uplift."

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the AEP Zone. For each zone in the first six months of 2013 and 2014 Table 10-37 shows Reactive Service operating reserve charges, revenue requirement charges and total charges (the sum of operating reserve and revenue requirement charges).

Table 10-37 Reactive zonal charges for network transmission use: January through June 2013 and 2014

Zone	Jan-Jun 2013 Operating Reserve Charges	Jan-Jun 2013 Revenue Requirement Charges	Jan-Jun 2013 Total Charges	Jan-Jun 2014 Operating Reserve Charges	Jan-Jun 2014 Revenue Requirement Charges	Jan-Jun 2014 Total Charges
AECO	$2,683,893	$2,566,704	$5,250,597	$88,275	$2,788,429	$2,876,704
AEP	$8,153,186	$20,152,965	$28,306,151	$437,548	$19,866,380	$20,303,929
APS	$2,488,889	$10,972,769	$13,461,658	$301,299	$10,389,180	$10,690,479
ATSI	$27,244,415	$7,641,410	$34,885,824	$9,617,533	$7,875,173	$17,492,706
BGE	$1,989,309	$3,886,144	$5,875,452	$55,339	$3,830,881	$3,886,220
ComEd	$5,067,119	$12,285,840	$17,352,959	$146,570	$12,111,130	$12,257,700
DAY	$861,802	$4,219,161	$5,080,963	$29,971	$4,159,163	$4,189,134
DEOK	$1,381,668	$2,879,866	$4,261,534	$29,413	$2,838,913	$2,868,326
Dominion	$754,824	$14,964,671	$15,719,496	$15,712	$14,751,867	$14,767,579
DPL	$5,485,503	$4,936,218	$10,421,721	$1,337,912	$5,334,635	$6,672,547
DLCO	$16,250,781	$0	$16,250,781	$6,728,321	$1,055,006	$7,783,328
EKPC	$223,710	NA	$223,710	$12,873	$0	$12,873
JCPL	$8,674,519	$3,129,200	$11,803,719	$24,412	$3,512,868	$3,537,280
Met-Ed	$1,053,902	$3,740,344	$4,794,246	$46,087	$3,703,543	$3,749,630
PECO	$2,337,734	$8,812,315	$11,150,049	$369,729	$8,686,999	$9,056,728
PENELEC	$10,613,972	$2,325,491	$12,939,463	$2,452,238	$2,881,674	$5,333,913
Pepco	$1,747,773	$2,629,096	$4,376,869	$50,913	$2,591,709	$2,642,622
PPL	$2,287,888	$9,244,748	$11,532,636	$45,115	$9,493,188	$9,538,303
PSEG	$9,103,258	$13,635,038	$22,738,296	$389,325	$13,441,141	$13,830,466
RECO	$79,979	$0	$79,979	$1,679	$0	$1,679
(Imp/Exp/Wheels)	$0	$9,433,877	$9,433,877	$0	$11,529,066	$11,529,066
Total	$108,484,126	$137,455,855	$245,939,981	$22,180,267	$140,840,945	$163,021,212

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