Ancillary Service Markets

The United States Federal Energy Regulatory Commission (FERC) defined six ancillary services in Order No. 888: 1) scheduling, system control and dispatch; 2) reactive supply and voltage control from generation service; 3) regulation and frequency response service; 4) energy imbalance service; 5) operating reserve – synchronized reserve service; and 6) operating reserve – supplemental reserve service.[1] Of these, PJM currently provides regulation, energy imbalance, synchronized reserve, and operating reserve – supplemental reserve services through market-based mechanisms. PJM provides energy imbalance service through the Real-Time Energy Market. PJM provides the remaining ancillary services on a cost basis. 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.[2]

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 nine months of 2013.

Table 10-1 The Regulation Market results were indeterminate for January through September, 2013

	January through September 2013	
Market Element	Evaluation	Market Design
Market Structure	Not Competitive	
Participant Behavior	Competitive	
Market Performance	To Be Determined	To Be Determined

- The Regulation Market structure was evaluated as not competitive for the year because the Regulation Market had one or more pivotal suppliers which failed PJM's three pivotal supplier (TPS) test in 91 percent of the hours in January through September, 2013.
- Participant behavior in the Regulation Market was evaluated as competitive for January through September, 2013 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 indeterminate, after the introduction of the new market design. It is too early to reach a definitive conclusion about performance under the new market design because important parts of the design are inefficient and because there is not yet enough information on performance.
- Market design was evaluated as indeterminate, after the introduction of the new market design. While the market design continues to include the incorrect definition of opportunity cost, overall the changes were positive. The market design also includes the incorrect definition of the marginal benefits factor for purposes of settlement.[3] It is too early to reach a definitive conclusion about the new market design because there is not yet enough information about actual implementation of the design.

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	Effective

- The Synchronized Reserve Market structure was evaluated as not competitive because of high levels of supplier concentration. The MMU estimates that the Synchronized Reserve Market had one or more pivotal suppliers which failed the three pivotal supplier test in 5.6 percent of the hours in January through September, 2013.
- Participant behavior was evaluated as competitive because the market rules require competitive, cost based offers.

1 75 FERC ¶ 61,080 (1996).
2 For more details, see the *2012 State of the Market Report for PJM*, Volume II, Section 9, "Ancillary Service Markets."
3 On October 2, 2013 FERC issued an order directing PJM to compensate regulating resources (the portion of each resource's compensation based on performance) based on a mileage ratio multiplier. This ratio will be the hourly mileage of the RegD signal / mileage of the RegA signal. This ratio increases the regulation performance compensation paid to high performing resources compared with regular resources. Between October 2012 and September 2013 the average mileage ratio has been 3.11 compared to an average marginal benefit factor of 2.63. PJM will begin to settle the regulation market (performance segment) using the mileage ratio on November 1, 2013. PJM will then recalculate performance regulation settlement for the purpose of adjusting the credits from October 1, 2012, through October 31, 2013. The regulation performance clearing price will not change.

- Market performance was evaluated as competitive because the interaction of the participant behavior with the market design results in competitive prices.
- Market design was evaluated as effective because market power mitigation rules result in competitive outcomes despite high levels of supplier concentration.

Table 10-3 The Day-Ahead Scheduling Reserve Market results were competitive

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

- The Day-Ahead Scheduling Reserve Market structure was evaluated as competitive because market participants did not fail the three pivotal supplier test.
- Participant behavior was evaluated as mixed because while most offers appeared consistent with marginal costs (zero), 15 percent 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

Regulation Market

The PJM Regulation Market continues to be operated as a single market.

Market Structure

- **Supply.** In January through September 2013, the supply of offered and eligible regulation in PJM was both stable and adequate. The ratio of offered and eligible regulation to regulation required averaged 3.67. This is a 14.7 percent increase over January through September 2012 when the ratio was 3.20.
- **Demand.** The on-peak regulation requirement is equal to 0.70 percent of the forecast peak load for the PJM RTO for the day and the off-peak requirement is equal to 0.70 percent of the forecast valley load for the PJM RTO for the day. The average hourly regulation demand in January through September, 2013, was 784 MW. This is a 214 MW decrease in the average hourly regulation demand of 998 MW in the same period of 2012.
- **Market Concentration.** In January through September 2013, the PJM Regulation Market had a weighted average Herfindahl-Hirschman Index (HHI) of 2063 which is classified as highly concentrated.[4] In January through September 2013, 91 percent of hours had one or more pivotal suppliers which failed PJM's three pivotal supplier test (44 percent of hours failed the three pivotal supplier test in January through September 2012).

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. Under the new market design, offers include both a capability offer and a performance offer. The performance offer is converted to $/MW by multiplying the MW offer by the ΔMW/MW value of the signal type

4 See the *2012 State of the Market Report for PJM*, Volume II, Section 2, "Energy Market," at "Market Concentration" for a more complete discussion of concentration ratios and the Herfindahl-Hirschman Index (HHI). Consistent with common application, the market share and HHI calculations presented in the SOM are based on supply that is cleared in the market in every hour, not on measures of available capacity.

of the unit. Owners must also specify which signal type the unit will be following, RegA or RegD.[5] As of September 30, 2013, there were 22 resources offering performance regulation and following the RegD signal.

- **Price and Cost.** The weighted average Regulation Market Clearing Price for the PJM Regulation Market for January through September 2013 was $32.72. This is an increase of $17.80, or 119.3 percent, from the weighted average price for regulation in January through September 2012. The cost of regulation from January through September 2013 was $37.35. This is a $16.77 (81.5 percent) increase from the same time period in 2012.

Synchronized Reserve Market

Although PJM has retained the two synchronized reserve markets it implemented on February 1, 2007, their definition has changed. The RFC Synchronized Reserve Zone has incorporated the former Southern Synchronized Reserve Zone into the RTO Reserve Zone. The former Mid-Atlantic Synchronized Reserve Zone has incorporated the Dominion Zone to become the Mid-Atlantic Dominion Reserve Zone. PJM has the right to define new zones or subzones "as needed for system reliability."[6]

Market Structure

- **Supply.** In January through September, 2013, the supply of offered and eligible synchronized reserve was both stable and adequate. The contribution of Demand Response (DR) to the Synchronized Reserve Market remains significant. Demand resources are relatively low cost, and their participation in this market lowers overall Synchronized Reserve prices.
- **Demand.** PJM made a minor change to the default hourly required synchronized reserve requirements on October 1, 2012. When the RFC Zone became the RTO Zone on October 1, 2012, the synchronized reserve requirement increased from 1,350 MW to 1,375 MW. Although the Mid-Atlantic Subzone became the Mid-Atlantic Dominion Subzone on October 1, 2012, the requirement remained at 1,300 MW. The integration of East Kentucky Power Cooperative (EKPC) into PJM on June 1, 2013, had no impact on the Synchronized Reserve Market requirement because the largest contingencies remain in the Mid-Atlantic Dominion Subzone. The EKPC integration did, however, increase the availability of both Tier 1 and Tier 2 MW available throughout the RTO.

  In early June 2013, PJM implemented a modification to the way the transfer interface defines the Mid-Atlantic Dominion Subzone within the RTO Zone. The change makes calculations of the unit distribution factor (DFAX) values across the interface consistent with the way these values are calculated in the energy market. Additionally, PJM calculates the most limiting interface in real time for each market optimization, ASO, IT-SCED and RT-SCED. For most hours it is Bedington – Black Oak. The second most common limiting interface is AP South.

- **Market Concentration.** For January through September 2013, the average weighted HHI for cleared synchronized reserve in the Mid-Atlantic Dominion Subzone was 4372 which is classified as highly concentrated. The average weighted cleared Synchronized Reserve Market HHI for the Mid-Atlantic Subzone in January through September, 2012, was 3202, which is classified as "highly concentrated."[7] In January through September, 2013, 58 percent of hours had a maximum market share greater than 40 percent, compared to 45 percent of hours in January through September, 2012.

  In the Mid-Atlantic Dominion Subzone, in January through September, 2013, the MMU estimates that 5.6 percent of hours that cleared a synchronized reserve market had three or fewer pivotal suppliers. In January through September, 2012, the MMU estimates that 24 percent of hours had three or fewer pivotal suppliers. The MMU concludes from these TPS results that the Mid-Atlantic Dominion Subzone Synchronized Reserve Market in January through September 2013 was characterized by structural market power.

5 See the *2012 State of the Market Report for PJM*, Volume II, Appendix F "Ancillary Services Markets."
6 See PJM. "Manual 11, Energy and Ancillary Services Market Operations," Revision 61 (June 27, 2013), p. 66.
7 See Section 3, "Energy Market" at "Market Concentration" for a more complete discussion of concentration ratios and the Herfindahl-Hirschman Index (HHI).

Market Conduct

- **Offers.** Daily cost based offer prices are submitted for each unit by the unit owner, and PJM adds opportunity cost calculated using the average of 5-minute LMPs, which together comprise the total offer for each unit to the Synchronized Reserve Market. The synchronized reserve offer made by the unit owner is subject to an offer cap of marginal cost plus $7.50 per MW, plus lost opportunity cost. All suppliers are paid the higher of the market clearing price or their offer plus their unit specific opportunity cost.

Market Performance

- **Price.** The weighted average price for Tier 2 synchronized reserve in the Mid-Atlantic Dominion Subzone was $6.86 per MW in January through September, 2013, a decrease of three percent over January through September 2012. The total cost of synchronized reserves per MW in January through September 2013 was $14.82, a 35 percent increase from the $10.92 cost of synchronized reserve in January through September 2012. The market clearing price was 51 percent of the total synchronized reserve cost per MW in January through September 2013, down from 64 percent in January through September 2012.
- **Adequacy.** A synchronized reserve deficit occurs when the combination of Tier 1 and Tier 2 synchronized reserve is not adequate to meet the synchronized reserve requirement. Neither PJM Synchronized Reserve Market experienced a deficit in January through September period of 2013. Although supplies were always adequate to meet demand, an extended spinning event on September 10 raised concerns that the current method for estimating Tier 1 is incorrect. PJM has initiated studies designed to improve the accuracy of Tier 1 estimation. It is expected that by January 1, 2014, the amount of Tier 1 estimated, especially during periods of high demand, will decrease as a result of changes to the estimation method.

DASR

The purpose of the DASR Market is to satisfy supplemental (30-minute) reserve requirements with a market-based mechanism that allows generation resources to offer their reserve energy at a price and compensates cleared supply at a single market clearing price. The DASR 30-minute reserve requirements are determined for each reliability region.[8] If the DASR Market does not result in procuring adequate scheduling reserves, PJM is required to schedule additional operating reserves.

Market Structure

- **Concentration.** The MMU calculates that in January through September, 2013, zero hours in the DASR market would have failed the three pivotal supplier test. The current structure of PJM's DASR Market does not include the three pivotal supplier test. The MMU recommends that the three pivotal supplier test be incorporated in the DASR market.
- **Demand.** In 2013, the required DASR is 6.91 percent of peak load forecast, down from 7.03 percent in 2012.

Market Conduct

- **Withholding.** Economic withholding remains an issue in the DASR Market. The direct marginal cost of providing DASR is zero, but there is an opportunity cost associated with providing DASR. As of September 30, 2013, 15 percent of offers reflected economic withholding. PJM rules require that all units with reserve capability that can be converted into energy within 30 minutes offer into the DASR Market.[9] Units that do not offer have their offers set to zero.
- **DR.** Demand resources are eligible to participate in the DASR Market, but no demand resource cleared the DASR Market in January through September, 2013.

8 See PJM. "Manual 13: Emergency Operations," Revision 53, (June 1, 2013); pp 11-12.
9 See PJM. "Manual 11, Energy and Ancillary Services Market Operations," Revision 60 (June 1, 2013), p. 144.

Market Performance

- **Price.** The weighted DASR market clearing price in January through September 2013 was $0.93 per MW. In January through September 2012, the weighted price of DASR was $0.75 per MW.

Black Start Service

Black start service is necessary to help 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 is the demonstrated ability of a generating unit to automatically remain operating at reduced levels when disconnected from the grid.[10]

In January through September 2013 black start charges were $80.3 million. Black start zonal charges in January through September 2013 ranged from $0.03 per MW-day in the ATSI zone (total charges were $95,492) to $10.30 per MW-day in the AEP zone (total charges were $65,557,476). For each zone, Table 10-23 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 $0.08 per MW.

Ancillary services costs per MW of load: January through September 2002 - 2013

Table 10-4 shows PJM ancillary services costs for January through September 2002 through 2013, on a per MW of load basis. 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.

10 OATT Schedule 1 § 1.3BB.

Table 10-4 History of ancillary services costs per MW of Load: January through September 2002 through 2013

Year	Regulation	Scheduling, Dispatch, and System Control	Reactive	Synchronized Reserve	Supplementary Operating Reserve	Total
2002	$0.47	$0.52	$0.21	$0.00	$0.66	$1.86
2003	$0.53	$0.59	$0.23	$0.09	$0.88	$2.32
2004	$0.50	$0.64	$0.25	$0.14	$0.90	$2.43
2005	$0.78	$0.47	$0.25	$0.11	$0.88	$2.49
2006	$0.55	$0.48	$0.28	$0.07	$0.44	$1.82
2007	$0.65	$0.47	$0.29	$0.06	$0.58	$2.05
2008	$0.75	$0.34	$0.29	$0.07	$0.55	$2.00
2009	$0.36	$0.36	$0.36	$0.05	$0.47	$1.60
2010	$0.37	$0.38	$0.36	$0.06	$0.75	$1.92
2011	$0.35	$0.36	$0.39	$0.09	$0.87	$2.06
2012	$0.23	$0.44	$0.44	$0.03	$0.75	$1.89
2013	$0.27	$0.41	$0.69	$0.04	$0.66	$2.07

Conclusion

The design of the Regulation Market changed significantly effective October 1, 2012. While the market design continues to include the incorrect definition of opportunity cost, overall the changes were positive. It is too early to reach a definitive conclusion about performance under the new market design because there is not yet enough information on performance. It is essential that the Regulation Market incorporate the consistent implementation of the marginal benefit factor in optimization, pricing and settlement. But the experience of the last quarter of 2012 and the first three quarters of 2013 is cause for optimism with respect the performance of the Regulation Market under the new market design.

The structure of each 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. (The term Synchronized Reserve Market refers only to Tier 2 synchronized reserve.) 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 MMU concludes that the structure of the DASR Market was competitive in the first nine months of 2013, although concerns remain about economic withholding and the absence of the three pivotal supplier test in this market.

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.

Overall, the MMU concludes that it is not yet possible to reach a definitive conclusion about the new Regulation Market design, but there is reason for optimism. The MMU concludes that the Synchronized Reserve Market results were competitive in the first nine months of 2013. The MMU concludes that the DASR Market results were competitive in the first nine months of 2013.

Regulation Market

The PJM Regulation Market continues to be operated as a single market. Significant technical and structural changes were made to the Regulation Market in 2012. On May 7, 2012, PJM switched to an improved optimizer called the Ancillary Services Optimizer (ASO). On October 1, 2012, PJM made additional technical changes to the optimized solution and, to comply with FERC Order No. 755, implemented Performance Based Regulation.[11] On November 16, 2012, FERC modified the PJM market design that was introduced on October 1, 2012.[12]

11 For a description of the full history of the changes to the tariff provisions governing the Regulation Market, see the *2011 State of the Market Report for PJM*, Volume II, Section 9, Ancillary Service Markets."

12 *PJM Interconnection, L.L.C.*, 139 FERC ¶ 141,134 (November 16, 2012)

Regulation Market Changes for Performance Based Regulation

Regulation is a key part of PJM's effort to minimize ACE in order to keep the reportable metrics CPS1 and BAAL within acceptable limits. On October 20, 2011, FERC issued Order No. 755 directing PJM and other RTOs/ISOs to modify their regulation market rules to make use of and properly compensate a mix of fast and traditional response regulation resources."[13] Order No. 755 also sought to correct "certain practices of some RTOs and ISOs result in economically inefficient economic dispatch of frequency regulation resources."[14]

A rationale for the new market design was the assumption that new, fast response technologies could be used, in combination with traditional resources, to reduce the total amount of resources needed to meet regulation requirements and thereby reduce the cost of regulation. Order No. 755 required that the new and traditional resources be purchased in a single market, with compensation for both capacity (MW) and miles (total MW per minute measured in ΔMW/MW) provided.[15] Prior to October 1, 2012, regulation consisted of energy that could be added or removed within five minutes following a traditional (RegA) signal. On October 1, 2012, the PJM introduced a single market that included two distinct types of frequency response: RegA (traditional and slower oscillation signal) and RegD (faster oscillation signal). Within this new market design, resources can choose to follow RegA or RegD.

In a market defined in terms of units of RegA equivalent regulation service, the marginal benefits factor of all units following the RegA signal is one, while the marginal benefits factor of units following the RegD signal depends on how much RegD following resources are used. Under PJM's August 15, 2012, proposal, the benefits factor can be as high as 2.9 but never lower than zero. Effective regulation is a function of two components, the benefits factor, which itself is a function of the amount of RegD regulation already committed; and the historical performance of the unit as measured by the 100-hour average of performance scores. A unit's regulation capability MW

13 Order No. 755 at P 3. FERC ordered PJM "to compensate frequency regulation resources based on the actual service provided, including a capacity payment that includes the marginal unit's opportunity costs and a payment for performance that reflects the quantity of frequency regulation service provided by a resource when the resource is accurately following the dispatch signal."

14 *Id.* at P 2.

15 *Id.* at PP 99, 131 & 177

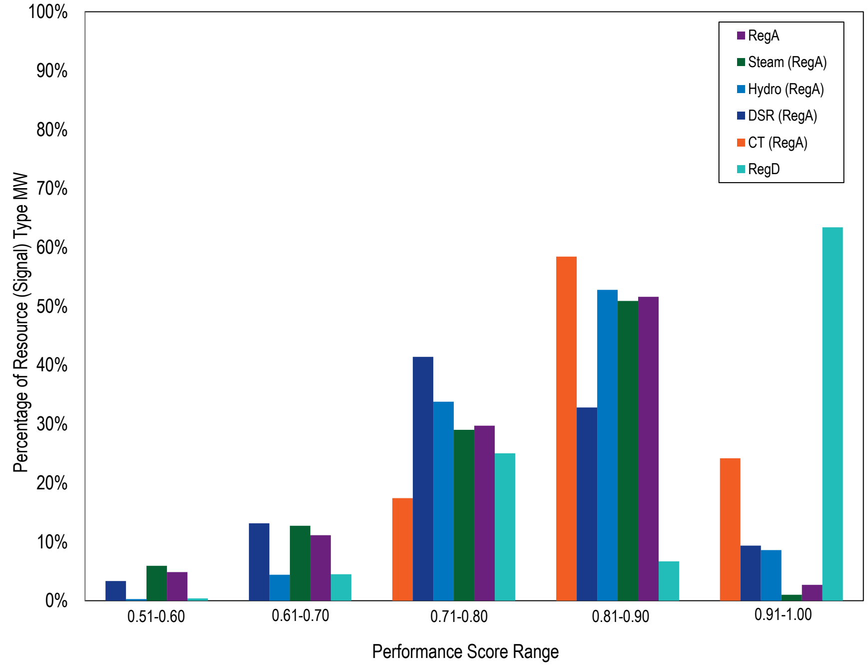
multiplied by its benefits factor, and modified by its performance score, results in that unit's effective RegA signal following regulation MW.

FERC's November 16, 2012 order only partially accepted the market design in PJM's August 15, 2012, filing. FERC's November 16, 2012, order fixed the marginal benefits factor for RegD resources at a value of 1.0 for purposes of payment. This created a dichotomy in the PJM regulation market between the marginal value of RegD resources in the dispatch, and the resulting market price and payments to resources in the settlement process in PJM's regulation market through the first quarter of 2013.

Performance tracking is an essential element of the performance based Regulation Market. Regulation performance scores (0.0 to 1.0) measure the response of a regulating unit 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 relationship between the regulating resource output and the regulation signal; and precision, the difference in energy provided from the difference in energy requested.[16] An hourly performance score is calculated and multiplied by the MW cleared when calculating payment. Additionally, hourly scores are stored and used as part of a 100 hour rolling average historical performance score to obtain an effective capability MW and performance MW used in clearing. Figure 10-1 shows the average performance score by unit type and signal followed.

16 A full specification of each of the three criteria used in the performance score is presented in PJM "Manual 12: Balancing Operations" Rev. 27 (December 20, 2012); 4.5.6, p 52.

Figure 10-1 Average performance score grouped by unit type and regulation signal type: January through September 2013



Using a performance score to measure the accuracy of a regulating resource, a mileage ratio to compare the effective MW of differing types of resources, and effective MW as a means of translating the value of actual MW for high performance units are the reasons that the required regulation has been lowered from 1.0 percent to 0.7 percent of forecast peak load.

The performance based Regulation Market requires that unit owners provide two-part offers for their regulation resources, an offer for regulation capability in terms of \$/MW and a regulation performance offer in terms of \$/ΔMW. In addition, unit owners must enter the regulation signal type the unit will follow, RegA or RegD. Owners may enter price based offers subject to a combined offer cap of \$100/MW.

Market Structure

Supply

Table 10-5 shows capability, average daily offer and average hourly eligible MW for all hours. The hourly regulation capability decreased in January through September 2013, to 8,411 MW from 9,413 MW during the same time period of 2012.

Table 10-5 PJM regulation capability, daily offer[17] and hourly eligible: January through September 2012 and 2013[18]

Period	Regulation Capability (MW)	Average Daily Offer (MW)	Percent of Capability Offered	Average Hourly Eligible (MW)	Percent of Capability Eligible
2013 (Jan-Sep)	8,441	3,981	47%	1,716	20%
2012 (Jan-Sep)	9,413	6,656	71%	3,089	33%

The supply of regulation can be affected by regulating units retiring from service. Table 10-6 shows what the impact on the Regulation Market would be if all units retire that are requesting retirement through the end of 2015.

Table 10-6 Impact on PJM Regulation Market of currently regulating units scheduled to retire through 2015

Current Regulation Units, January through September 2013	Settled MW, January through September 2013	Units Scheduled To Retire Through 2015	Settled MW of Units Scheduled To Retire Through 2015	Percent Of Regulation MW To Retire Through 2015
306	5,125,625	33	54,484	1.06%

The cost of each unit is calculated in market clearing using its offer price, lost opportunity cost, capability MW, and the miles to MW ratio of the signal type they choose to follow, modified by resource benefit factor and historic performance score. As of October 1, 2012, a regulation resource's total offer is equal to the sum of its total capability ($/MW) and performance offer ($/MW). As of October 1, 2012, the within hour five minute clearing price for regulation is determined by the total offer, including the actual within hour lost opportunity cost, of the most expensive cleared regulation resource in each interval. The total clearing price for the hour is the simple average of the twelve interval prices within the hour. The total clearing price for the hour (RMCP) is in two parts, 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 total clearing price for the hour and the performance clearing price for the hour.

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 10-12). Since the implementation of shortage pricing and changing the regulation requirement to 0.70 percent of peak load forecast (from one percent of peak load forecast prior to October 1) the price and cost of regulation have remained high. The weighted average regulation price for January through September 2013 was $32.72. The regulation cost for January through June 2013 was $37.35. The ratio of price to cost is significantly higher at 88 percent (compared with 72 percent in Q3 of 2012), meaning that more of the costs are now part of the price.

As of September 30, 2013, there were 22 resources following the RegD signal. For January through September 2013, the weighted-average HHI of the set of RegD resources was 5494 (highly concentrated).

In the period from January 1, 2013, through September 30, 2013, the marginal benefit factor for cleared RegD following resources has ranged from 1.743 to 2.899 with an average over all hours of 2.595. For purposes of market settlement and payments, FERC has required PJM to set the marginal benefit factor at 1.000. Figure 10-2 shows the disparity between the actual marginal benefit factor used in clearing the Regulation Market and the FERC required marginal benefit factor used in settling the Regulation Market.

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

18 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.

Figure 10-2 Daily (simple) average marginal benefit factor; January through September 2013

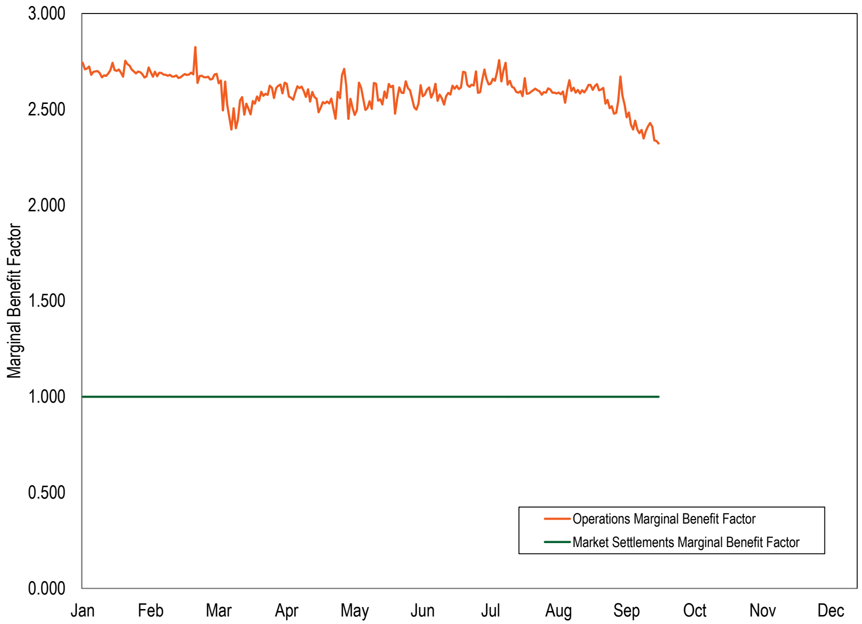
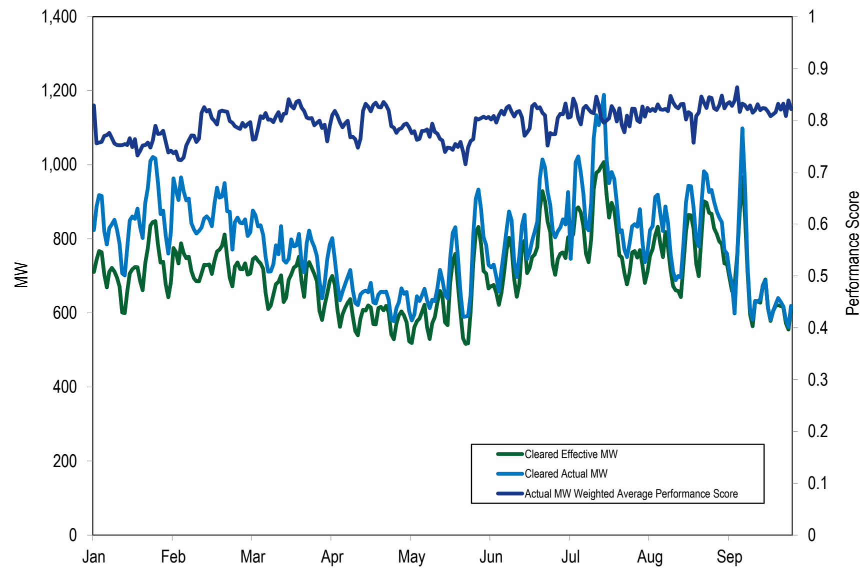
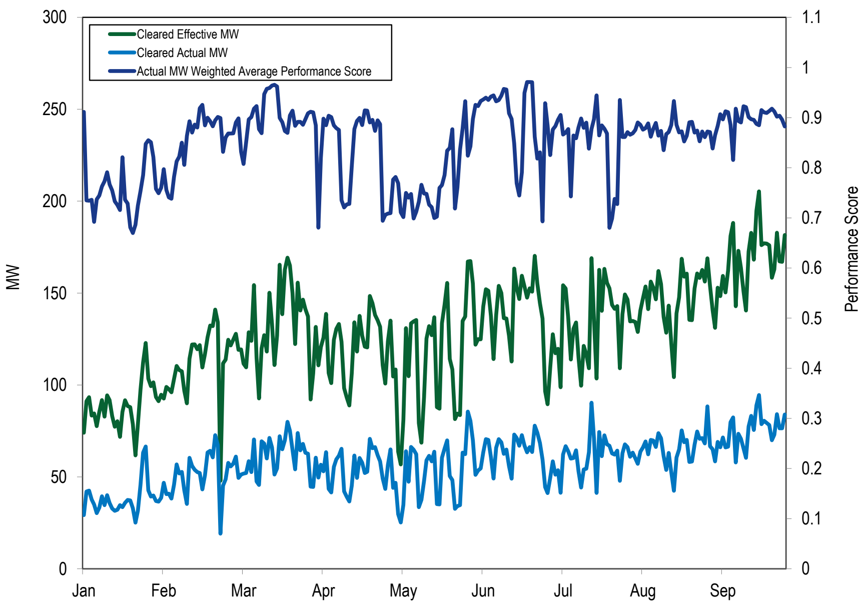


Figure 10-3 Daily average actual cleared MW of regulation, effective cleared MW of regulation, and average performance score; all cleared regulation; January through September 2013



Although the benefits factor for traditional (RegA following) resources is 1.0, the effective MW of RegA following resources is lower than the offered MW because the performance score is less than 1 (Figure 9-2). For January through September, 2013, the MW-weighted average RegA performance score was 0.80.

Figure 10-4 Daily average actual cleared MW of regulation, effective cleared MW of regulation, and average performance score; RegD units only; January through September 2013



For RegD resources, the effective MW are higher than the actual MW because their benefits factor at current participant levels is significantly greater than 1.0 (Figure 9-3). For January through September, 2013, the MW-weighted average RegD resource performance score was 0.89.

Demand

Demand for regulation does not change with price. The regulation requirement is set by PJM in accordance with NERC control standards, based on reliability objectives and forecast load. 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 one percent of peak load forecast to 0.9 percent on October 1, 2012, but instead it was changed from 1 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. Then it was reduced to its current value of 0.70 percent of peak load forecast on December 18, 2012.

Table 10-7 shows the average hourly required regulation by month and its relationship to the supply of regulation.

Table 10-7 PJM Regulation Market required MW and ratio of eligible supply to requirement: January through September 2012 and 2013

Month	Average Required Regulation (MW), 2012	Average Required Regulation (MW), 2013	Ratio of Supply to Requirement, 2012	Ratio of Supply to Requirement, 2013
Jan	1,005	851	3.29	3.66
Feb	979	870	3.45	4.65
Mar	876	766	3.14	4.86
Apr	826	656	3.19	2.55
May	918	678	3.26	3.91
Jun	1,055	801	3.21	4.34
Jul	1,246	911	2.94	1.66
Aug	1,134	832	2.97	2.60
Sep	941	693	3.33	4.80

PJM's performance as measured by CPS and BAAL standards has not declined as a result of the lower regulation requirement.[19]

19 See the *2012 State of the Market Report for PJM*, Appendix F: Ancillary Services.

Market Concentration

Table 10-8 shows Herfindahl-Hirschman Index (HHI) results for January through September of 2012 and 2013. The average HHI of 2063 is classified as highly concentrated and is higher than the HHI for the same period in 2012.

Table 10-8 PJM cleared regulation HHI: January through September 2012 and 2013

Period	Minimum HHI	Weighted Average HHI	Maximum HHI
2013 (Jan-Sep)	730	2063	5650
2012 (Jan-Sep)	810	1529	4962

Figure 10-5 compares the 2013 HHI distribution curves with distribution curves for the same periods of 2012 and 2011.

Figure 10-5 PJM Regulation Market HHI distribution: January through September 2011, 2012, and 2013

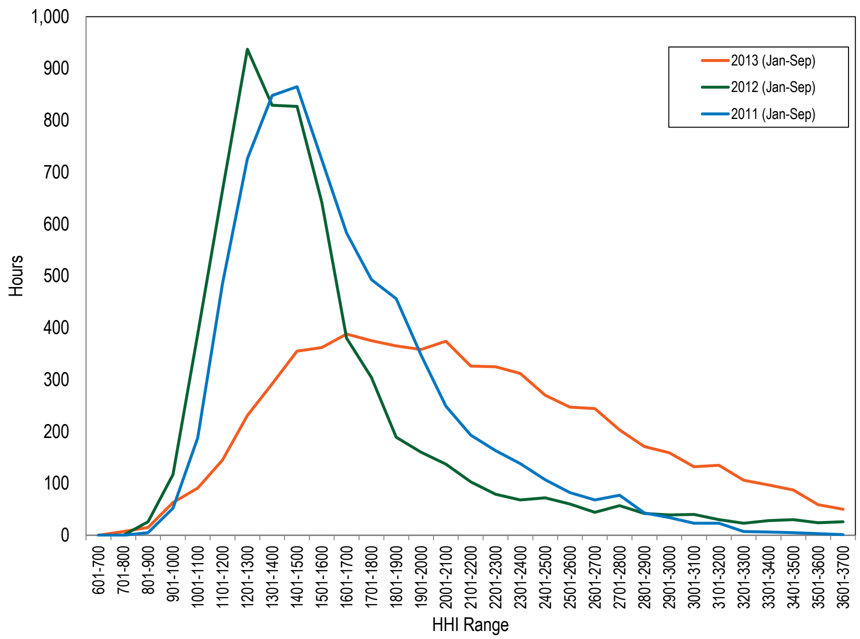


Table 10-9 includes a monthly summary of three pivotal supplier results. In January through September 2013, 91 percent of hours had one or more pivotal suppliers which failed PJM's three pivotal supplier test.[20] Offer capping in the regulation market has little impact on prices because offers are a smaller component of price than is LOC (Figure 10-7).

The MMU concludes from these results that the PJM Regulation Market in January through September 2013 was characterized by structural market power in 91 percent of hours.

Table 10-9 Regulation market monthly three pivotal supplier results: January through September 2011, 2012 and 2013

	2013	2012	2011
Month	Percent of Hours Pivotal	Percent of Hours Pivotal	Percent of Hours Pivotal
Jan	83%	71%	95%
Feb	82%	67%	93%
Mar	97%	64%	94%
Apr	88%	41%	97%
May	93%	37%	95%
Jun	95%	40%	89%
Jul	94%	13%	89%
Aug	92%	32%	83%
Sep	90%	35%	87%

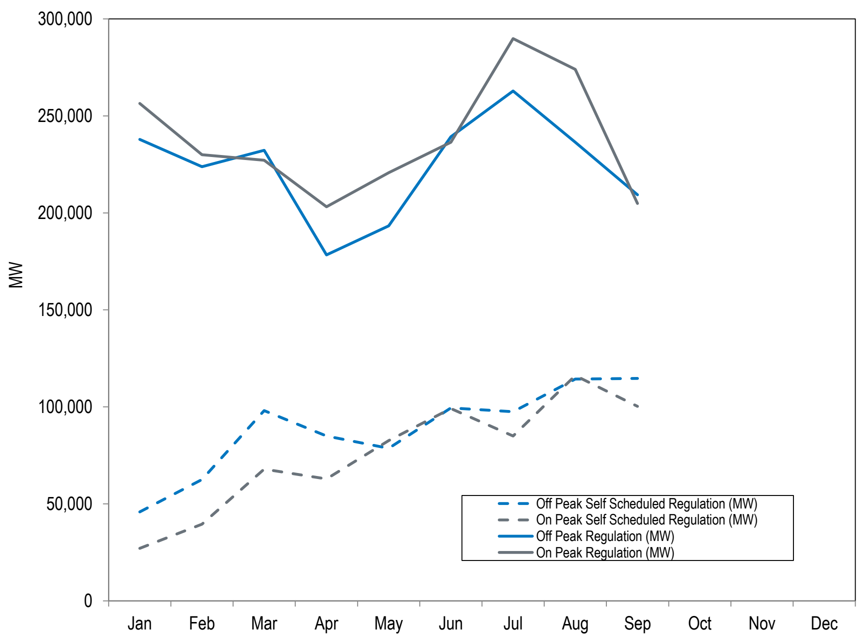
20 The MMU monitors the application of the TPS test by PJM and brings any issues to the attention of PJM.

Market Conduct

Offers

Regulation Market participation is a function of the obligation of all LSEs 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 10-10).[21]

Figure 10-6 Off peak and on peak regulation levels: January through September 2013



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 January through September of 2013, 60.8 percent was purchased in the spot market, 35.5 percent was self-scheduled, and 3.7 percent was purchased bilaterally (Table 10-10).

Table 10-10 Regulation sources: spot market, self-scheduled, bilateral purchases: January through September 2012 and 2013

Year	Month	Spot Regulation (MW)	Self-Scheduled Regulation (MW)	Bilateral Regulation (MW)	Total Regulation (MW)	RegA Regulation (MW)	RegD Regulation (MW)
2013	Jan	413,304	72,880	8,070	494,253	486,959	7,294
2013	Feb	338,990	102,005	12,808	453,803	444,689	9,113
2013	Mar	275,880	165,987	17,554	459,421	441,000	18,421
2013	Apr	219,793	147,858	13,860	381,510	365,856	15,654
2013	May	235,849	161,270	16,934	414,053	397,020	17,033
2013	Jun	254,215	198,617	22,816	475,647	456,494	19,153
2013	Jul	349,047	182,452	21,201	552,699	536,188	16,512
2013	Aug	258,550	230,441	21,351	510,342	488,951	21,391
2013	Sep	181,609	214,945	17,647	414,200	387,397	26,803
2012	Jan	553,686	164,806	21,261	739,753	NA	NA
2012	Feb	481,004	175,757	20,456	677,217	NA	NA
2012	Mar	477,564	144,408	19,683	641,655	NA	NA
2012	Apr	426,564	124,750	21,083	572,397	NA	NA
2012	May	542,585	97,574	17,849	658,008	NA	NA
2012	Jun	582,078	140,769	22,309	745,156	NA	NA
2012	Jul	819,897	63,415	19,711	903,024	NA	NA
2012	Aug	710,715	95,949	17,687	824,350	NA	NA
2012	Sep	515,732	113,351	19,726	648,809	NA	NA

Demand resources (DR) offered and cleared regulation for the first time in November 2011. In April 2012, a tariff change allowing DR to offer 0.1 MW facilitated participation by DR. In January through September 2013 DR provided an average of 1,439 MW of regulation per month.

21 See PJM. "Manual 28: Operating Agreement Accounting," Revision 60, (June 1, 2013); para 4.1, pp 15.

Market Performance

Price

The weighted average RMCP for January through September 2013, was $32.72. This is a 119.3 percent increase from the January through September 2012 weighted average RMCP of $14.92. Figure 10-7 shows the daily average Regulation Market clearing price and the opportunity cost component for the marginal units in the PJM Regulation Market.

Figure 10-7 PJM Regulation Market daily weighted average market-clearing price, marginal unit opportunity cost and offer price (Dollars per MWh): January through September 2013

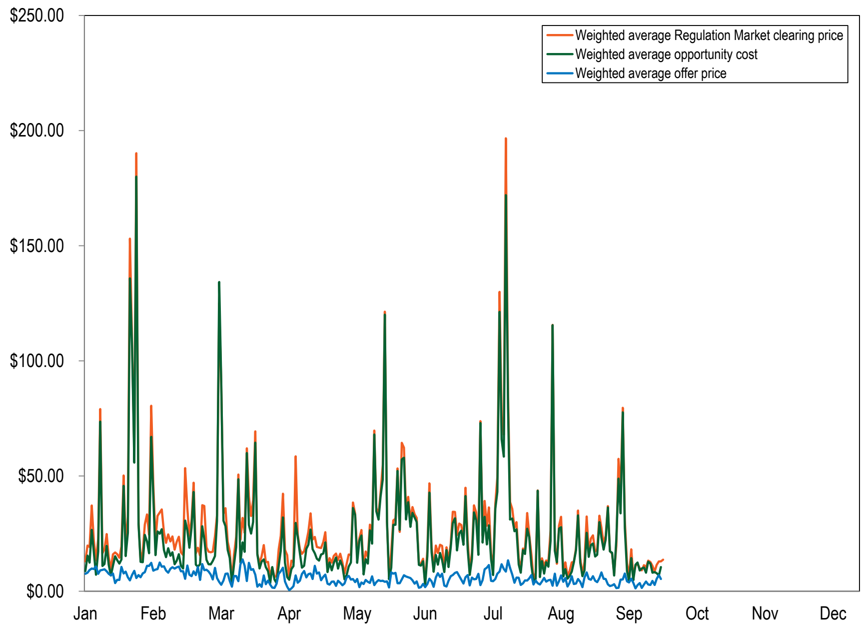


Table 10-11 shows monthly average regulation market clearing price, average marginal unit offer price, and average marginal unit LOC.

Table 10-11 PJM Regulation Market monthly weighted average market-clearing price, marginal unit opportunity cost and offer price (Dollars per MWh): January through September 2013

Month	Weighted Average Regulation Market Clearing Price	Weighted Average Regulation Marginal Unit Offer	Weighted Average Regulation Marginal Unit LOC
Jan	$39.94	$7.72	$39.62
Feb	$29.51	$9.37	$23.01
Mar	$31.64	$5.02	$27.10
Apr	$26.49	$5.07	$14.48
May	$33.42	$4.32	$30.52
Jun	$29.81	$4.41	$20.18
Jul	$50.12	$5.97	$32.98
Aug	$27.60	$4.30	$20.75
Sep	$25.98	$3.71	$17.44

Total scheduled regulation MW, total regulation charges, regulation price and regulation cost are shown in Table 10-12.

Table 10-12 Total regulation charges: January through September 2013 and 2012

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%
2013	Jul	552,699	$31,386,733	$50.12	$56.79	88%
2013	Aug	510,342	$15,866,117	$27.60	$31.09	89%
2013	Sep	414,200	$12,203,834	$25.98	$29.46	88%
2012	Jan	739,753	$13,338,201	$13.41	$18.03	74%
2012	Feb	677,217	$10,108,296	$11.89	$14.93	80%
2012	Mar	641,655	$11,109,763	$12.61	$17.31	73%
2012	Apr	572,397	$9,038,430	$13.01	$15.79	82%
2012	May	658,008	$16,248,950	$17.44	$24.69	71%
2012	Jun	745,156	$14,181,461	$14.91	$19.03	78%
2012	Jul	903,024	$29,228,039	$20.73	$32.37	64%
2012	Aug	824,350	$18,273,264	$15.86	$22.17	72%
2012	Sep	648,809	$13,593,245	$14.41	$20.95	69%

A breakdown of the cost of regulation into its capability, performance, and opportunity cost components is shown in Table 10-13 and a comparison of monthly average RMCP credits per Effective MW earned by RegA and RegD resources is shown in Figure 10-8.

Table 10-13 Components of regulation cost: January through September 2013

Month	Scheduled Regulation (MW)	Cost of Regulation Capability ($/MW)	Cost of Regulation Performance ($/MW)	Opportunity Cost ($/MW)	Total Cost ($/MW)
Jan	494,253	$33.74	$6.25	$6.28	$46.27
Feb	453,803	$25.50	$4.10	$4.06	$33.66
Mar	459,421	$28.31	$3.46	$4.53	$36.30
Apr	381,510	$23.21	$3.36	$4.69	$31.27
May	414,053	$30.44	$3.01	$4.22	$37.68
Jun	475,647	$26.80	$3.09	$3.74	$33.64
Jul	552,699	$46.08	$4.11	$6.59	$56.79
Aug	510,342	$22.93	$4.76	$3.40	$31.09
Sep	414,200	$22.02	$4.05	$3.40	$29.46

Figure 10-8 Comparison of monthly average RegA and RegD RMCP Credits per Effective MW: January through September 2013

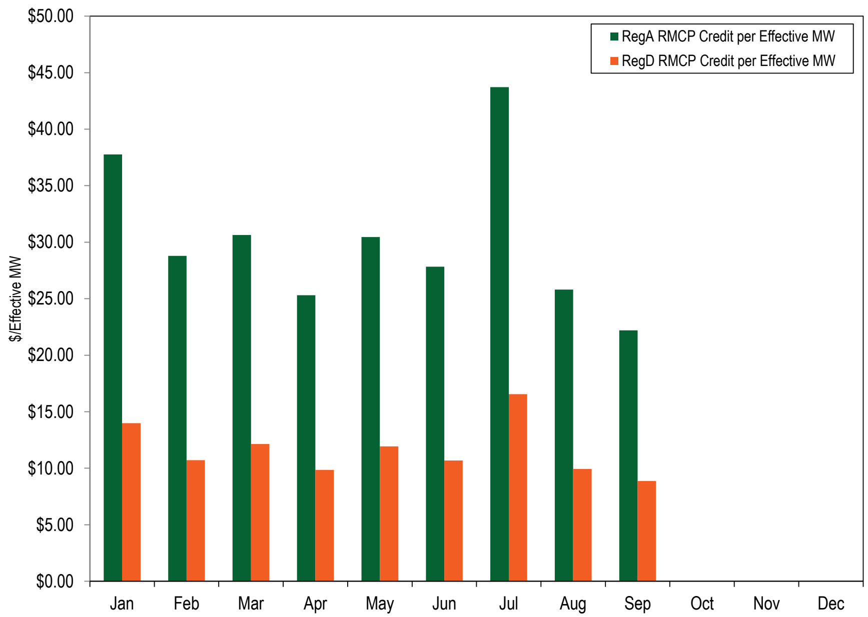


Table 10-14 provides a comparison of the average price and cost for PJM Regulation. The difference between the Regulation Market price and the actual cost of regulation was less in January through September 2013 than it was in January through September 2012. This is an improvement which resulted from the use of pricing based on real-time LMP instead of forecast LMP as had been done prior to shortage pricing in October 1, 2012.

Table 10-14 Comparison of average price and cost for PJM Regulation, January through September 2007 through 2013

Period	Weighted Regulation Market Price	Weighted Regulation Market Cost	Regulation Price as Percent Cost
2007	$36.86	$52.91	70%
2008	$42.09	$64.43	65%
2009	$23.56	$29.87	79%
2010	$18.08	$32.07	56%
2011	$17.03	$32.71	52%
2012	$14.92	$20.58	72%
2013	$32.72	$37.35	88%

Primary Reserve

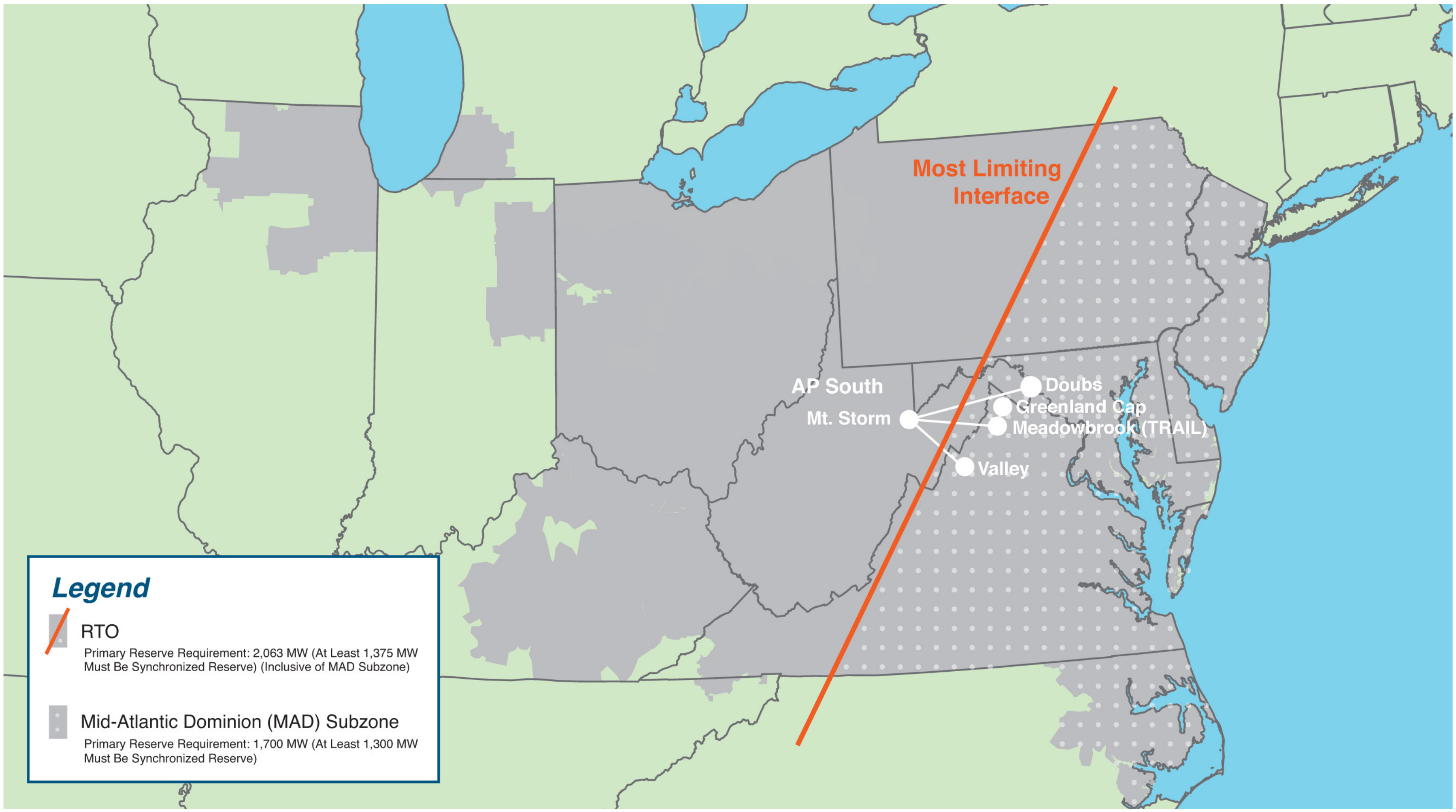
Reserves are provided by generating capability that is standing by ready for service if an unforeseen event causes a need for it. NERC defines reporting and response requirements for disturbance events in "NERC Performance Standard BAL-002-0, Disturbance Control Performance" and PJM defines its corresponding obligations in Manual M-12.[22] NERC defines contingency reserves as energy available in 15 minutes. PJM calls this Primary Reserve and specifies it as energy available within 10 minutes. Units in a shutdown state may satisfy the primary reserve requirement if they can start within 10 minutes. PJM retains a separate ten minute synchronized reserve requirement.

22 See PJM. "Manual 12: Balancing Operations" Revision 27, Attachment D, "Disturbance Control Performance/Standard" (December 20, 2012), p. 84.

Requirements

PJM must satisfy the contingency reserve requirements specifications of the Reliability*First* Corporation and VACAR. For the RTO reserve zone the primary reserve requirement is 150 percent of the largest contingency in the PJM footprint, currently 2,063 MW. Of that 2,063 MW, PJM requires that at least 1,375 MW be on line and synchronized to the grid (Figure 10-9).

Figure 10-9 PJM RTO geography and primary reserve requirement: January through June 2013



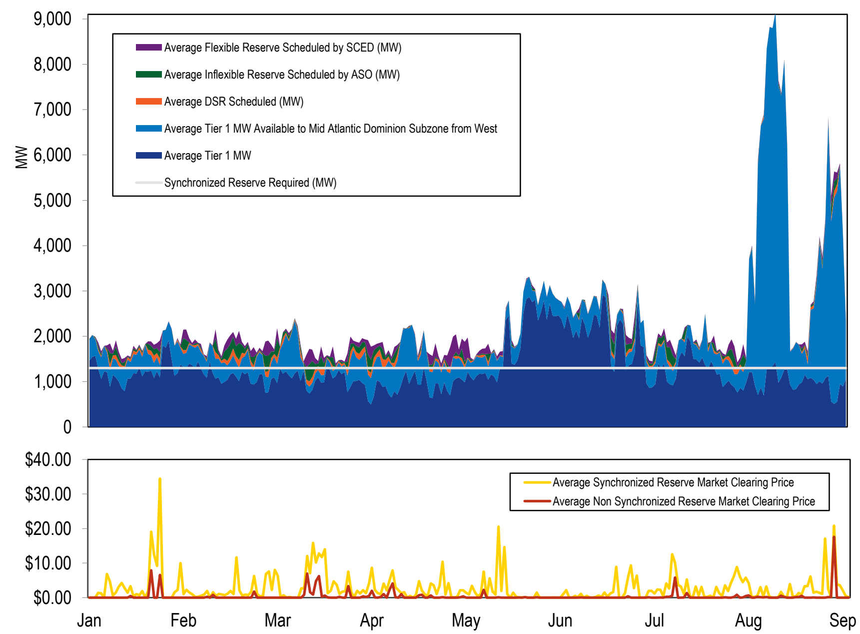
PJM recognizes that transmission constraints limit the deliverability of reserves within the RTO, and therefore creates a sub-zone within the RTO called the Mid-Atlantic Dominion Subzone. Of the 2,063 MW requirement for primary reserve in the RTO, 1,700 MW must be deliverable to the Mid-Atlantic Dominion Subzone. Of the 1,375 MW of synchronized reserve in the RTO, 1,300 MW must be deliverable to the Mid-Atlantic Dominion Subzone.

The primary reserve requirement is satisfied with both synchronized reserve and non-synchronized reserve, both of which are reserves available within ten minutes. Synchronized reserve is on-line and synchronized to the grid. Non-synchronized reserve is any unit not synchronized to the grid but capable of providing energy within ten minutes (examples of this are shutdown run-of-the-river hydro, pumped hydro, CTs, some CCs and diesels).

The Mid-Atlantic Dominion Subzone is defined dynamically by the most limiting constraint. In approximately 99 percent of ASO, RT-SCED, and IT-SCED cases, that constraint is Bedington - Black Oak (Figure 10-9). Between January 1, 2013, and May 31 2013, the reserve interface had been defined by the set of all resources with a three percent or greater DFAX raise help on the constrained side of the Bedington - Black Oak constraint. From June 1, 2013, through September 30, 2013, PJM determined the most limiting interface in real time and used that constraint to determine which resources were deliverable within the constrained area.[23] The effect of these changes to the reserve interface has been to significantly increase the supply of Tier 1 synchronized reserve available in the Mid-Atlantic Dominion Subzone thereby decreasing the amount of Tier 2 synchronized reserve required (Figure 10-10). On June 1, 2013, PJM integrated the East Kentucky Power Cooperative transmission system. This is on the unconstrained side of the AP South constraint.

The primary reserves requirement is not satisfied by a single market but by several products across the RTO Zone and Mid-Atlantic Dominion Subzone. The two requirements of the Mid-Atlantic Dominion Reserve Zone, primary reserve (1,700 MW) and synchronized reserve (1,300 MW) are satisfied by a set of products optimized to minimize total cost (Figure 10-10). The components of the Mid-Atlantic Dominion Primary Reserve Zone in order of increasing cost are: Tier 1 synchronized reserve available within the Mid-Atlantic Dominion Primary Reserve zone which is priced at $0 unless there is a shortage event, a spinning event or the price of non-synchronized reserve rises above zero; Tier 1 synchronized reserve available across the most limiting constraint from the west as seen by the RT-SCED which is also priced at $0; Demand Response which is always inflexible Tier 2 synchronized reserve and cleared by the ASO; inflexible Tier 2 generation reserve scheduled and priced economically by ASO; and flexible synchronized reserve scheduled by the RT-SCED.

Figure 10-10 Components of Mid-Atlantic Dominion Subzone Primary Reserve (Daily Averages): January through September, 2013



23 The specific constrained interface may be revised by PJM to meet system reliability needs. 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 60 (June 1, 2013), p. 78.

Figure 10-10 shows that Tier 1 Synchronized Reserve remains the major contributor to satisfying the reserve requirements. Tier 1 synchronized reserve available inside the subzone from the RTO Zone is also a major contributor to satisfying the Mid-Atlantic Dominion (MAD) subzone synchronized reserve requirement. Both of these components have a price of $0.00 unless a Tier 2 Synchronized Reserve or Non-Synchronized Reserve market is cleared in the RTO Zone. Non-synchronized reserve clears a separate market less frequently because (like DASR) it is available without redispatch from CTs, diesels and some hydro units (Ref. Non-Synchronized Reserve Market). Tier 2 synchronized reserve is dispatched at a market clearing price.

In 206 hours between January 1 and September 30, 2013, the Non-Synchronized Reserve Market for the Mid-Atlantic Dominion Subzone cleared at greater than $0.00, averaging $10.17 with a maximum clearing price of $210.07 on September 11. Non-synchronized reserve only clears when synchronized reserve also clears.

Scarcity Pricing

On October 1, 2012 PJM introduced shortage pricing, scarcity pricing, which made major changes to the structure and operation of the PJM reserve markets. PJM now has two markets to satisfy the primary reserve requirement; the Synchronized Reserve Market (Tier 2), and the new Non-Synchronized Reserve Market. The Synchronized Reserve Market dispatches Tier 2 synchronized reserve plus demand response to satisfy the synchronized reserve requirement minus the Tier 1 MW available. Both Tier 1 and Tier 2 consist of units on-line synchronized to the grid. Units offering synchronized reserve which clear the Synchronized Reserve Market are Tier 2 units. The primary reserve requirement is then satisfied by Tier 1 plus Tier 2 plus Non-Synchronized reserve.

If IT SCED and RT SCED forecast a primary reserve or synchronized reserve shortage, then PJM will implement shortage pricing through the inclusion of primary reserve or synchronized reserve penalty factors.[24]

With shortage pricing, PJM began specifying that all on-line, non-emergency, generation capacity resources must offer Tier 2 synchronized reserve in accordance with the resources' capability to provide these reserves. As of the end of September 2013 PJM through its Operations Committee is still finalizing the penalty structure for not complying with a Tier 2 commitment, as well as final manual language for the must offer provisions.

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.[25] This rule ensures that IT-SCED and RT-SCED will be able to make accurate estimates of the amount of Primary Reserve available.

From January through September 2013 no reserve zone or sub-zone experienced a reserve shortage as determined by the reserve market software. However, during the September 10 spinning event an apparent real-time shortage was observed. PJM is studying this event to determine if the shortage was compliance related or if there was an actual shortage of Tier 1 MW as determined by ASO and SCED.

Synchronized Reserve Market

Prior to October 1, 2012, PJM operated two synchronized reserve markets because of differing synchronized reserve requirements specified by two different reliability regional authorities, Reliability*First* Corporation and VACAR. Those two synchronized reserve zones (Southern and RFC) are now combined into one zone, the RTO Synchronized Reserve Zone, with its requirements structured to satisfy both regional specifications.[26] Tier 2 synchronized reserve can be scheduled flexibly or inflexibly. Inflexible units are scheduled by the ASO sixty minutes before the operating hour. Inflexible units are committed to provide synchronized reserve for the entire hour and will be paid the higher of the SRMCP or their offer price plus LOC (except for demand response resources which will be paid SRMCP). Flexible units can be allocated to either synchronized reserve or to energy depending on

24 See the *2012 State of the Market Report for PJM*, Volume II, "Ancillary Service Markets" for more details on the impact of shortage pricing on the Reserve Markets.

25 See PJM. "Manual 11: Energy and Ancillary Services Market Operations" Revision 60, (June 1, 2013), p. 72.

26 See the *2012 State of the Market Report for PJM*, Volume II, "Ancillary Service Markets" for more details on the impact of shortage pricing on the Synchronized Reserve Markets.

their optimal economic solution. Flexible units are assigned or re-assigned by either the IT-SCED or the RT-SCED.

Market Structure

Supply

For the first nine months of 2013, the supply of offered and eligible synchronized reserve was stable and adequate in both the RTO Zone and the Mid-Atlantic Dominion Subzone. The contribution of demand resources to the Synchronized Reserve Market remains significant. Demand resources (DR) are relatively low cost, and their participation lowers overall Synchronized Reserve prices. PJM has limited the amount of DR to 25 percent of the synchronized reserve requirement since it was introduced into the market in August 2006. On December 6, 2012, PJM increased this amount to 33 percent of the synchronized reserve requirement.

Total MW of cleared and scheduled synchronized reserve in January through September 2013 was 747,660 MW, a significant reduction from January through September of 2012, 2,097,584 MW. The DR share of the total Synchronized Reserve Market increased from 36 percent in January through September of 2012 to 42 percent in the same time period of 2013. The merging of the former Mid-Atlantic subzone with Dominion into the new Mid-Atlantic Dominion subzone, plus the changes made in June, 2013 has made more Tier 1 reserve available to the subzone (Figure 10-10). The former Dominion Zone had an excess of Tier 1, reducing the number of hours when the subzone has to clear a Tier 2 market. The ratio of offered and eligible synchronized reserve MW to the synchronized reserve required (1,300 MW) was 1.39 for the Mid-Atlantic Dominion Subzone from January through September 2013 an increase from the 1.26 ratio of offered and eligible reserve MW to required in January through September 2012.[27]

Demand

In late May and early June, PJM made several changes, both geographic and procedural, to the Synchronized Reserve Market. The reserve interface (defined by the most limiting constraint) was made dynamic with the most limiting constraint calculated in real time. In practice the result is almost always Bedington – Black Oak. In addition, the limitation of the interface was changed from calculating the effect of all units with a three percent or greater raise help on the constrained side of the interface to calculating the effect from all units. Additionally, the EKPC region was integrated into the RTO zone. These changes greatly increased the reserve available in the RTO Zone, the T1 available across the interface into the Mid-Atlantic Dominion Subzone (MAD), and the available T2 inside of MAD.

Because there is a large amount of Tier 1 available in the non-Mid-Atlantic Dominion regions of the RTO, a Synchronized Reserve Market usually does not have to be cleared in the RTO Synchronized Reserve Zone. In January through September 2013 in the RTO Synchronized Reserve Zone a Synchronized Reserve Market was cleared in less than three percent of hours (168 hours). From January through September 2013 in the Mid-Atlantic Dominion Subzone a Tier 2 Synchronized Reserve Market was cleared in 33 percent of hours at an average of 267 MW. This is a reduction from the average of 388 MW cleared in January through September 2012. It is important to note that with shortage pricing a Synchronized Reserve Market can clear at $0. The MAD Synchronized Reserve Market cleared at $0 but assigned synchronized reserve in 25 percent of hours during January through September 2013 clearing an average of 38 MW.

As of September 30, 2013, the synchronized reserve requirement for the RTO synchronized reserve zone is 1,375 MW. The Mid-Atlantic Dominion synchronized reserve zone requirement is 1,300 MW.

27 The Synchronized Reserve Market in the Southern Region between January and September, 2012 cleared in so few hours that related data for that market are not meaningful.

Table 10-15 Synchronized Reserve Market required MW, RTO Zone and Mid-Atlantic Dominion Subzone, December 2008 through June 2013

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

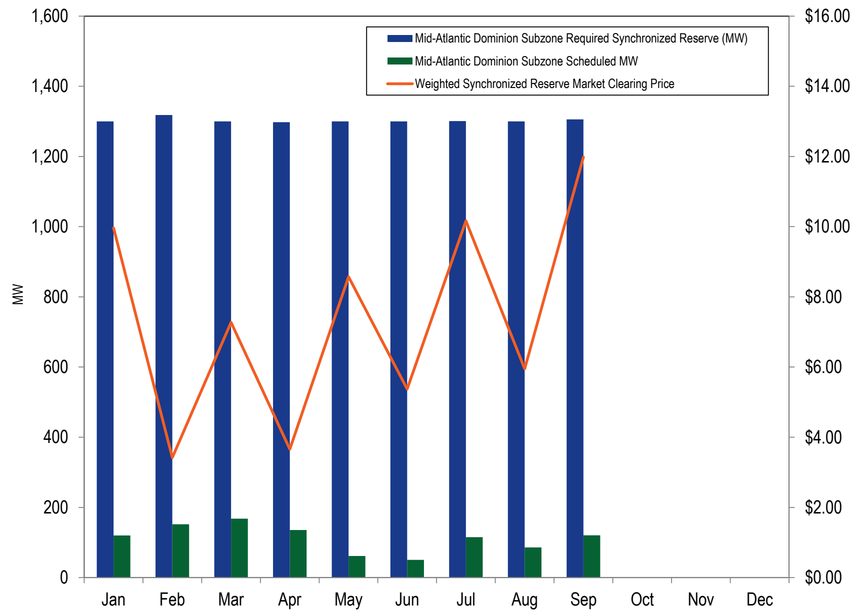
The market demand for Tier 2 synchronized reserve in the Mid-Atlantic Dominion sub-zone is determined by subtracting the amount of forecast Tier 1 synchronized reserve available plus the amount of Tier 1 available from the RTO Zone across the most limiting constraint (currently AP South) from the synchronized reserve zone's requirement each 5-minute period. Market demand is further reduced by subtracting the amount of self-scheduled Tier 2 resources.

Exceptions to this requirement can occur when grid maintenance or outages change the largest contingency. The requirement for both the RTO Zone and the Mid-Atlantic Dominion Subzone was raised to 1,780 MW for eight hours on February 2, 2013. The requirement for the RTO Zone was raised to 1,650 MW for 5 days from September 4 through September 8.

Figure 10-11 shows the average monthly synchronized reserve required and the average monthly Tier 2 synchronized reserve MW scheduled during January through September of 2013, for the Mid-Atlantic Dominion Synchronized Reserve Market.

The RTO Synchronized Reserve Zone almost always has enough Tier 1 to cover its synchronized reserve requirement. Available Tier 1 in the western and southern part of the RTO Synchronized Reserve Zone generally exceeds the total synchronized reserve requirement. In January through September 2013, the RTO Synchronized Reserve Zone cleared a Tier 2 Synchronized Reserve Market at a price greater than $0 in 198 hours with an unweighted average SRMCP of $3.29. The Mid-Atlantic Dominion Subzone cleared a separate Tier 2 market at a price greater than $0 in 33 percent of all hours during January through September of 2013 with an unweighted SRMCP of $8.33.

Figure 10-11 Mid-Atlantic Dominion Synchronized Reserve Subzone average hourly synchronized reserve required vs. synchronized reserve scheduled MW: January through September 2013



The former Southern Synchronized Reserve Zone (integrated into the Mid-Atlantic Dominion Synchronized Reserve Zone on October 1, 2012) is part of the Virginia and Carolinas Area (VACAR) subregion of SERC. VACAR specifies that available, 15 minute quick start reserve can be subtracted from Dominion's share of the largest contingency to determine synchronized reserve requirements.[28] The amount of 15 minute quick start reserve available in VACAR is sufficient to eliminate Tier 2 synchronized reserve demand for most hours. The VACAR requirement for the former Southern Synchronized

28 See PJM. "Manual 11: Energy & Ancillary Services Market Operations," Revision 60 (June 1, 2013), p. 73.

Reserve Zone is now satisfied by the Synchronized Reserve requirement for the Mid-Atlantic Dominion Synchronized Reserve Subzone.

Market Concentration

The HHI from January through September 2012 for the Mid-Atlantic Subzone was 3202, which is defined as highly concentrated. The HHI for the Mid-Atlantic Dominion Subzone from January through September 2013 was 4372, which is defined as highly concentrated. Note that the HHI for 2013 includes both inflexible and flexible assigned MW. The largest hourly market share was 100 percent and 58 percent of all hours had a maximum market share greater than or equal to 40 percent (compared to 45 percent of all hours January through September 2012). Most synchronized reserve is provided by inflexible scheduled Tier 2 resources.[29] When there is not enough Tier 2 or when the IT SCED or RT SCED sees a need, flexible reserve units are assigned spinning. Flexible synchronized reserve is a much smaller market. Looking at the flexible unit sector of the synchronized reserve market from January through September, 2013, the hourly average HHI (among all resources cleared as flexible) was 8916.

The MMU estimates that in January through September, 2013, 5.6 percent of hours in the Mid-Atlantic Dominion Subzone would have failed a three pivotal supplier test (Table 9-12). This is lower than the 24 percent that the MMU calculates would have failed the three pivotal supplier test in January through September, 2012. The reason for the decline is the increasing significance of demand response in the supply of synchronized Demand response MW were 42.0 percent of the settled synchronized reserve Tier 2 MW in January through September, 2013. These results indicate that the Mid-Atlantic Dominion Sub-zone, the only synchronized reserve market that clears on a regular basis, is not structurally competitive.

29 See the *2012 State of the Market Report for PJM*, Volume II, Appendix F, Ancillary Service Markets, Synchronized Reserve Market Clearing. With shortage pricing, PJM divided synchronized reserve into flexible and inflexible. A synchronized reserve resource can be either flexible or inflexible, but not both. Inflexible resources must be dispatched, which means incurring lost opportunity costs and/or startup and fuel costs associated with their synchronized reserve dispatch point. Flexible units can respond more quickly to a spinning event and need not be moved from their economic dispatch at the time the ASO or IT SCED runs.

Table 10-16 Mid-Atlantic Dominion Subzone[30] Synchronized Reserve Market monthly three pivotal supplier results: 2010, 2011, 2012, and 2013

Month	2013 Percent of Hours Pivotal	2012 Percent of Hours Pivotal	2011 Percent of Hours Pivotal	2010 Percent of Hours Pivotal
Jan	1%	45%	92%	64%
Feb	11%	40%	99%	49%
Mar	7%	38%	74%	65%
Apr	8%	33%	83%	31%
May	10%	15%	46%	45%
Jun	0%	29%	14%	10%
Jul	6%	10%	19%	23%
Aug	5%	3%	25%	18%
Sep	3%	4%	56%	17%
Oct		9%	73%	54%
Nov		17%	84%	83%
Dec		25%	88%	40%

Market Conduct

Offers

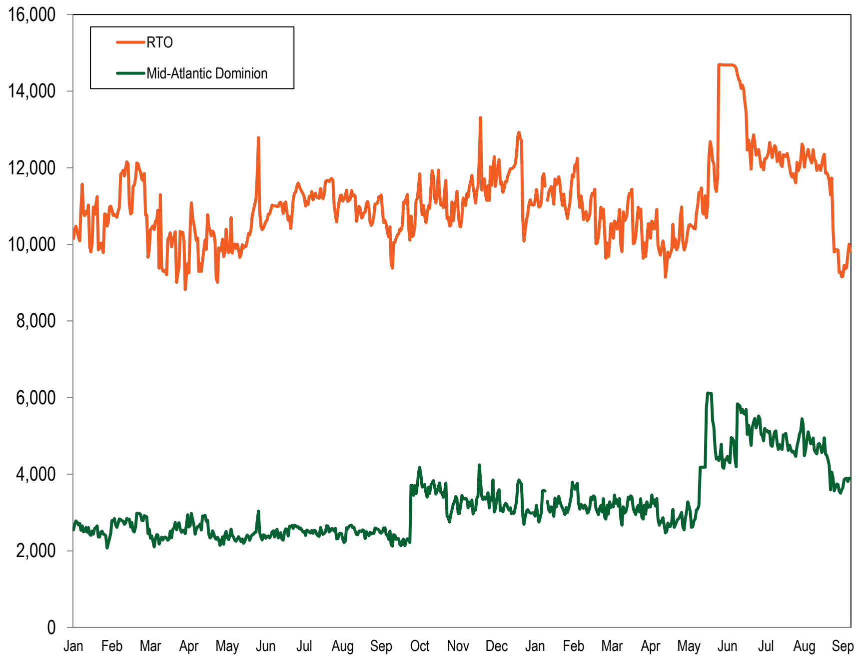
Daily cost based offer prices are submitted for each unit by the unit owner, and PJM adds opportunity cost calculated using the average of 5-minute LMPs, which together comprise the total offer for each unit to the Synchronized Reserve Market. The synchronized reserve offer made by the unit owner is subject to an offer cap of marginal cost plus $7.50 per MW, plus lost opportunity cost. All suppliers are paid the higher of the market clearing price or their offer plus their unit specific opportunity cost. Figure 10-12 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 Sub-zone. Note that the geography of the RTO zone and the Mid-Atlantic subzone changed on October 1 with shortage pricing.

While offer volumes increased after October 1, 2012, because PJM adopted a new rule making synchronized reserve a must-offer for all generation that are on-line, non-emergency, and available for energy, compliance with this rule has been slow and subject to confusion. Beginning in late May 2013 PJM and the MMU have been reminding participants in the PJM Operating Committee

30 Note that the market expanded in October 2012 with the addition of Dominion.

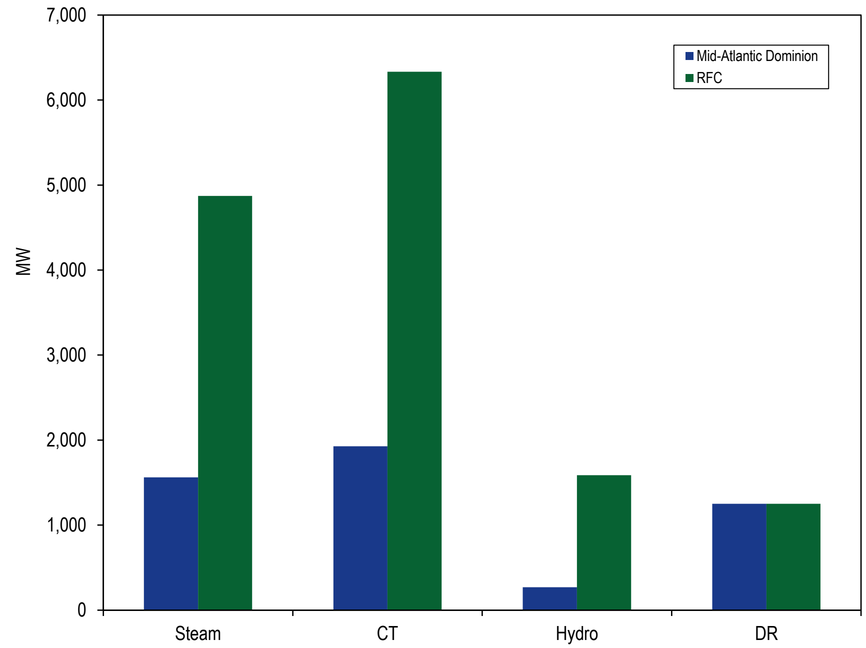
that non-emergency resources capable of providing synchronized reserve are obligated by tariff to offer their daily capability. The MMU and PJM have begun efforts to clarify the must offer rules and to make participants aware of this requirement.

Figure 10-12 Tier 2 synchronized reserve daily average offer volume (MW): January 2012 through September 2013



Synchronized reserve is offered by steam, CT, hydroelectric and DR resources. Figure 10-13 shows average offer MW volume by market and unit type.

Figure 10-13 Average daily Tier 2 synchronized reserve offer by unit type (MW): June through September 2013



DR

Demand resources were permitted to participate in the Synchronized Reserve Markets effective August 2006. DR has a significant impact on the Synchronized Reserve Market. As currently implemented in the Synchronized Reserve Market, DR is always an inflexible resource. In January through September 2013, DR was 42.3 percent of all cleared Tier 2 synchronized reserves, compared to 36 percent for the same period in 2012. In 9.4 percent of the hours in which synchronized reserve was cleared, all cleared MW was DR (Table 10-17). In the hours when all cleared MW was DR, the simple average SRMCP was $0.21. The weighted average SRMCP for all cleared hours was $6.86.

Table 10-17 Weighted average SRMCP, weighted average SRMCP when all cleared synchronized reserve is DR, and percent of all cleared hours that all cleared synchronized reserve is DR: January through September 2013 for Mid-Atlantic Dominion Sub-zone

Year	Month	Average SRMCP	Average SRMCP when all cleared synchronized reserve is DR	Percent of cleared hours all synchronized reserve is DR
2012	Oct	$16.15	$1.69	2%
2012	Nov	$11.44	$0.72	4%
2012	Dec	$5.06	$0.40	5%
2013	Jan	$9.96	$0.13	7%
2013	Feb	$3.42	$0.07	5%
2013	Mar	$7.27	$0.05	12%
2013	Apr	$3.66	$0.00	11%
2013	May	$8.57	$0.25	8%
2013	Jun	$5.37	$0.00	1%
2013	Jul	$10.17	$0.07	2%
2013	Aug	$5.95	$0.67	17%
2013	Sep	$9.27	$1.49	22%

Market Performance

Price

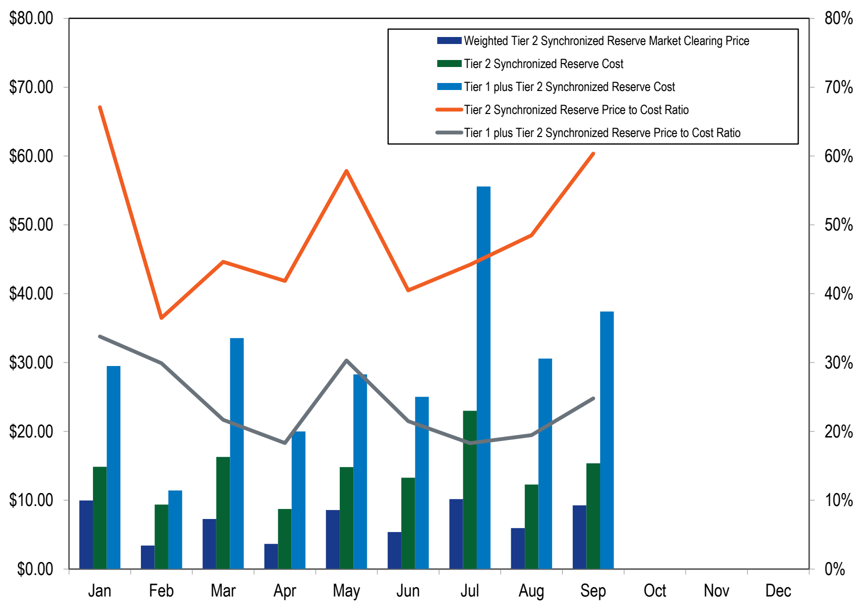
Figure 10-14 shows the weighted average Tier 2 price and the cost per MW associated with meeting synchronized reserve demand in the Mid-Atlantic Dominion Sub-zone. The price of Tier 2 synchronized reserve is the Synchronized Reserve Market Clearing Price (SRMCP).

Table 10-18 shows the monthly weighted average SRMCP, all credits including LOC credits, MW scheduled by PJM, and MW added by either the IT SCED or RT SCED for the Mid-Atlantic Dominion subzone. The weighted average price for synchronized reserve in the Mid-Atlantic Dominion Subzone in January through September 2013 was $6.86 while the corresponding cost of synchronized reserve was $14.26. The price for synchronized reserve in January through September 2012 was $7.06 while the cost was $10.96.

Table 10-18 Mid-Atlantic Dominion Sub-zone weighted synchronized reserve market clearing prices, credits, and MWs: January through September 2013

Year	Month	Weighted Synchronized Reserve Market Clearing Price	Synchronized Reserve Credits	Tier 1 Credits When NSR Prices Above $0	PJM Tier 2 and DSR Scheduled Synchronized Reserve MW	Flexible Synchronized Reserve Added by SCED (MW)	Self Scheduled MW
2013	Jan	$9.96	$1,217,854	$1,201,252	66,632	15,270	102
2013	Feb	$3.42	$1,203,289	$264,087	86,561	41,251	598
2013	Mar	$7.27	$2,275,995	$2,408,969	124,913	14,727	0
2013	Apr	$3.66	$938,914	$1,208,482	103,892	3,362	165
2013	May	$8.57	$766,400	$696,039	45,746	5,815	140
2013	Jun	$5.37	$341,359	$293,787	25,006	2,988	0
2013	Jul	$10.17	$1,781,381	$2,523,518	70,423	7,029	0
2013	Aug	$5.95	$813,309	$1,213,299	61,359	4,649	291
2013	Sep	$9.27	$1,443,551	$2,071,443	79,412	13,660	892
Total		$6.86	$10,782,052	$11,880,875	663,944	108,751	2,188

Figure 10-14 Comparison of Mid-Atlantic Dominion Subzone Tier 2 synchronized reserve weighted average price and cost (Dollars per MW): January through September 2013



The RTO Reserve Zone synchronized reserve requirement was satisfied by Tier 1 in all but 198 hours of January through September 2013. In the MAD sub-zone the Synchronized Reserve and Primary Reserve Requirements were satisfied by a combination of Tier 1 and non-synchronized reserve in 67 percent of hours from January through September 2013. In the 33 percent of hours when synchronized reserve was needed to fill the synchronized reserve and/or primary reserve requirement the maximum clearing price was $210.07 and the weighted average clearing price was $6.86.

Although Tier 1 synchronized reserve adds no cost in most hours, the change to the shortage pricing rule resulted in extremely large charges for Tier 1 reserves for a small number of hours. The rule change requires the payment of all Tier 1 reserves the full Tier 2 synchronized reserve clearing price in the hours when the non synchronized reserve market has a price greater than zero. More credits were paid to Tier 1 reserves during the 206 hours when the non-synchronized reserve price was above zero ($11.8M) than was paid to Tier 2 synchronized reserve ($10.8M) (Table 10-18) for the entire first three quarters of 2013. This is a windfall payment to Tier 1 reserves without any logical rationale.

Price and Cost

A price to cost ratio close to 1.0 is an indicator of an efficient market design. In the Mid-Atlantic Subzone of the RFC Synchronized Reserve Market for January through September 2013, the price of Tier 2 synchronized reserves was 49 percent of the cost. In January through September 2012, the price to cost ratio was 64 percent.

Since the implementation of shortage pricing, the price of synchronized reserve has declined slightly. The exception to this occurs when the non-synchronized reserve price is greater than $0. In that case, the shortage pricing rules require that Tier 1 synchronized reserve is paid the Tier 2 synchronized reserve clearing price. Tier 1 synchronized reserve has always been available to respond optionally to spinning events, but now it is also paid when the non-synchronized reserve price rises above zero. Payment for Tier 1 synchronized reserve that responds to a spinning event is compensated at the average of the 5-minute energy LMPs plus $50/MWh.[31] This rule significantly increases the cost of Tier 1 synchronized reserves with no operational or economic reason to do so. PJM is not actually reserving any Tier 1, but simply paying substantially more for the same product without any additional performance requirements. The MMU recommends that the rule requiring the payment of Tier 1 synchronized reserve resources when the non-synchronized reserve price is above zero be eliminated immediately. Table 10-19 shows the price and cost history of the Tier 2 Synchronized Reserve Market since 2005.

31 See PJM M-28: Operating Agreement Accounting, rev.62, 10/1/2012, p. 62.

Table 10-19 Comparison of yearly weighted average price and cost for PJM Tier 2 Synchronized Reserve, January through September 2005 through 2013

Year	Weighted Average Tier 2 Synchronized Reserve Price	Weighted Average Tier 2 Synchronized Reserve Cost	Tier 2 Synchronized Reserve Price as Percent of Cost
2005 (Jan-Sep)	$12.81	$17.01	75%
2006 (Jan-Sep)	$14.40	$27.78	52%
2007 (Jan-Sep)	$18.24	$21.27	86%
2008 (Jan-Sep)	$10.87	$16.76	65%
2009 (Jan-Sep)	$6.38	$10.41	61%
2010 (Jan-Sep)	$11.51	$16.54	70%
2011 (Jan-Sep)	$12.00	$14.21	84%
2012 (Jan-Sep)	$7.06	$10.96	64%
2013 (Jan-Sep)	$6.86	$14.26	48%

Before shortage pricing the reason for relatively low actual price to cost ratio was the difference in opportunity cost calculated using the forecast LMP and the actual LMP. In addition, the low price to cost ratio was in part a result of out of market purchases of Tier 2 synchronized reserve when PJM dispatchers needed the reserves for reliability reasons (Table 10-18). The problem of lower forecast LMPs than real-time LMPs was solved by the use of real-time pricing.

Beginning with shortage pricing on October 1, 2012, PJM expanded its use of Tier 1 estimate biasing. Each market clearing engine (ASO, IT SCED, and RT SCED) can have its Tier 1 estimate manually biased. Negative Tier 1 estimate biasing refers to the manual subtraction from the Tier 1 estimate that the market clearing engines uses to determine how much Tier 2 MW to schedule. A negative bias reduces the amount of Tier 1 estimated to be available and therefore increases the amount of inflexible Tier 2 which must be purchased. PJM has reduced, but not eliminated, the use of Tier 1 estimate biasing. From July through September 2013, Tier 1 estimate was biased in 36 hours. In thirty hours of the thirty-six hours it was biased negatively averaging -236 MW. In the remaining six hours it was biased positively averaging 47 MW. The negative bias was applied entirely during several hours of the hot days of July 9 through July 19, also September 11 and September 26. During the hours of negative bias the SRMCP averaged $30.61. The average SRMCP was $2.60 during all hours between July 1 and September 30.

A negative Tier 1 bias means purchasing more inflexible Tier 2 MW than the market clearing software estimates it needs before the hour. The increased inflexible Tier 2 resources need to be compensated for their LOC and they must be paid even if they are not needed in real-time. This leads to Tier 2 synchronized reserves being assigned and paid when they are not needed or when the price is zero. A price of zero means that the Tier 2 synchronized reserve requirement was determined to be zero because there was enough Tier 1 during the hour. From January through September 2013, a total of 202,434 MW of Tier 2 synchronized reserve was purchased for hours when the price was later calculated to be $0. The charges (to compensate for lost opportunity costs) for this synchronized reserve were $986,166.

Figure 10-14 shows by month the percentage of all hours ASO had its Tier 1 estimate biased. IT SCED biasing did not occur in Q3, 2013. RT SCED Tier 1 biasing occurred in July for a total of 114 hours, averaging -305 MW and September for 147 hours averaging 317 MW. In every hour which RT SCED Tier 1 biasing was used between July and September, 2013, it was used to subtract Tier 1 from the estimate, thereby increasing the need to schedule additional Tier 2 synchronized reserve.

Figure 10-15 Impact of flexible Tier 2 synchronized reserve added by IT SCED and RT SCED to the Mid-Atlantic Dominion Subzone: January through September 2013

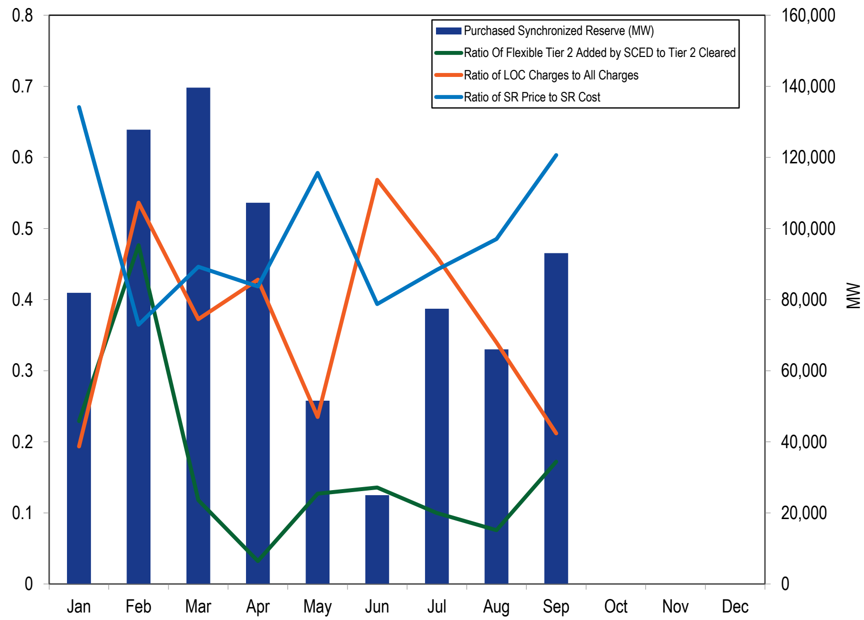
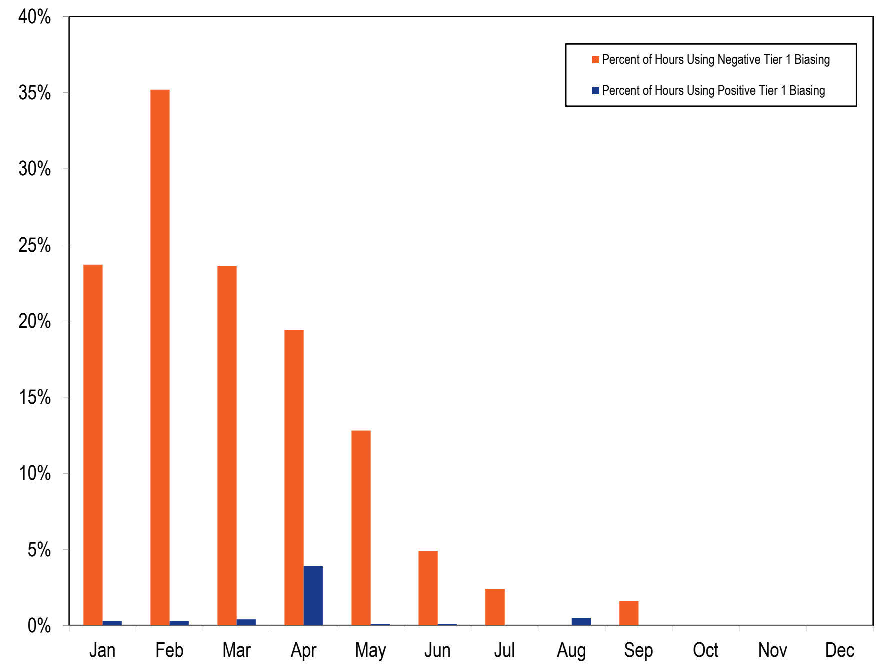


Figure 10-16 Use of ASO Tier 1 Estimate Biasing in the Middle Atlantic Dominion sub-zone: January through September 2013



PJM gives several reasons for Tier 1 estimate biasing: sometimes units do not achieve the ramp rate they have bid, sometimes units fail to follow PJM dispatch, and sometimes system conditions change rapidly during the hour between a market solution and the actual hour. But these situations occur routinely, regardless of overall system conditions. In the third quarter of 2013, Tier 1 estimate biasing was used almost exclusively during the hot days of July 10-19 and on September 11 to compensate for inaccurate estimates of Tier 1 by ASO and SCED during periods of high energy use.

The MMU recommends that PJM be more explicit about why Tier 1 biasing is used. 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.

Compliance

Non-compliance in the Synchronized Reserve Market remains a problem. Non-compliance has two major 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.

Table 10-20 Synchronized reserve events greater than 10 minutes, July – September, 2013[32]

Q3 Qualifying Spinning Events (Hour)	Event Duration (minutes)	MAD Synchronized Reserve Market Clearing Price	Tier 2 plus DR Cleared MW	Tier 2 plus DR Added MW	Percent Tier 2 Penalized for Non Compliance	Percent of DR Penalized for Non Compliance	Overall Percent of Synchronized Reserve Penalty for Non Compliance
03-JUL-2013 20	13	$11.79	476	264	38%	49%	41%
15-JUL-2013 18	29	$7.49	361	0	14%	62%	35%
10-SEP-2013 19	68	$0.00	65	0	98%		100%

The MMU has expressed concern over noncompliance by Tier 2 synchronized reserve resources during spinning events since 2011.[33] When synchronized reserve resources clear the Synchronized Reserve Market they are obligated to provide their full cleared Tier 2 MW in a spinning event. The MMU has observed a wide range of spinning event response levels, presented its data to PJM and urged PJM to take action to increase compliance rates. In May 2013, PJM initiated an effort to increase the penalty for non-compliance of scheduled synchronized reserve resources during spinning events. As of September 30, 2013, an enhanced penalty structure was approved by the Operations Committee. The increased penalties will be implemented after FERC approval. 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. Between July 1, 2013 and September 30, 2013, three spinning events occurred that met these criteria.

For the three spinning events that occurred between July 1 and September 30, 2013, a total of 41 percent of all scheduled Tier 2 synchronized reserve MW was not delivered and therefore penalized. Of the 1,166 MW of scheduled reserve, 483 MW of failed to perform during spinning events.

32 Additional analysis of the synchronized reserve event of 10-Sep-2013 Hour 19 is available in the History of Spinning Events section.

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

The shortage pricing changes introduced on October 1, 2012, included a must offer of Tier 2 Synchronized Reserve requirement for most generators under normal conditions, and an expanded set of generators under well-defined abnormal 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 an 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, generation capacity resources must have an offer and be available for reserve.As of September 30, the MMU estimates that at least 14 percent of eligible energy resources are not in compliance with the synchronized reserve must-offer requirement.

History of Spinning Events

Spinning events (Table 10-21) are usually caused by a sudden generation outage or transmission disruption requiring PJM to load synchronized reserve.[34] The reserve remains loaded until system balance is recovered. From

34 See PJM. "Manual 12, Balancing Operations," Revision 27 (December 20, 2012), pp. 36-37.

January 2010 through September 2013, PJM experienced 113 spinning events, or between two and three events per month. Spinning events had an average length of 13.2 minutes.

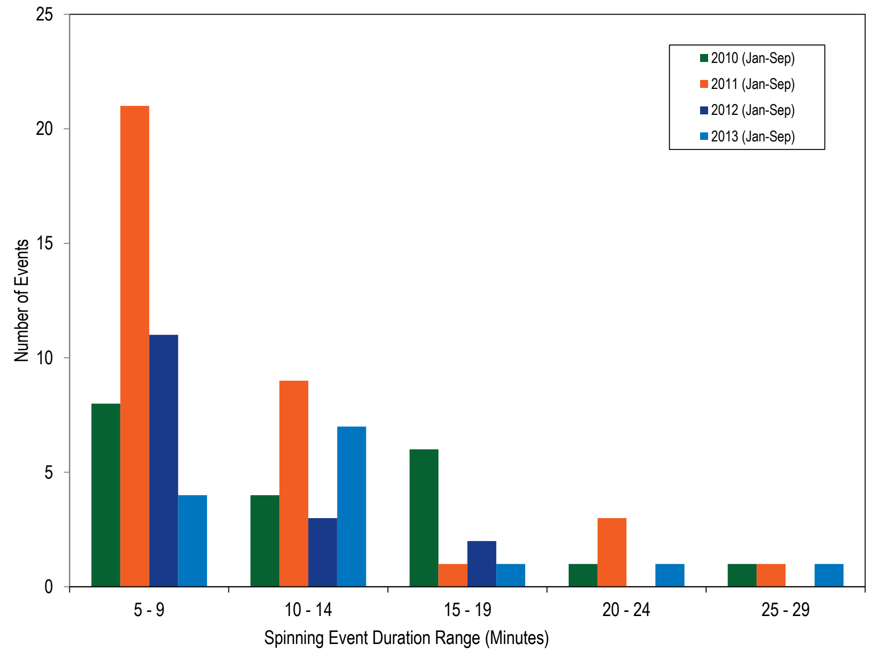
Table 10-21 Spinning Events, January 2010 through September 2013

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

The spinning event of September 10, called by PJM due to low ACE, lasted 68 minutes, which is the longest spinning event in at least the last five years. PJM's systems did not anticipate the event, clearing low levels of Tier 2 synchronized reserve as a result of overestimating the amount of Tier 1 available. When the event was called, resources estimated to have available Tier 1 did not respond as expected and did not resolve the imbalance. During the day of September 10, Tier 2 synchronized reserve and non-synchronized reserve prices were $0.00 for 22 hours and $3.18 and $1.53 for hours 1600 and 1700. Low ACE that is not the result of a generator outage or transmission interruption indicates a problem with short-term load forecasting, dispatch solution, reserve measurement and/or generator compliance with instructions.

September 10 was part of a three-day period of high demand for energy and reserves, September 9 through September 11. The day following the spinning event, September 11, 2013, was also a hot day. Although PJM Dispatch used Tier 1 estimate biasing in only 1.5 percent of hours from July 1 through September 30, on September 11 PJM Dispatch used it for 9 contiguous hours from 1200 to 2000 inclusive, averaging -241 MW. During this period, prices for both Tier 2 synchronized reserve and non-synchronized reserve increased to $210.07, prices for Tier 2 synchronized reserve averaged $50.83, and prices for non-synchronized reserve averaged $46.89.

Figure 10-17 Spinning events duration distribution curve, January through September 2010 to 2013



Adequacy

A synchronized reserve deficit occurs when the combination of Tier 1 and Tier 2 synchronized reserve is not adequate to meet the synchronized reserve requirement. No primary reserve shortages were identified by PJM between January 1, 2013, and September 30, 2013.

Non-Synchronized Reserve Market

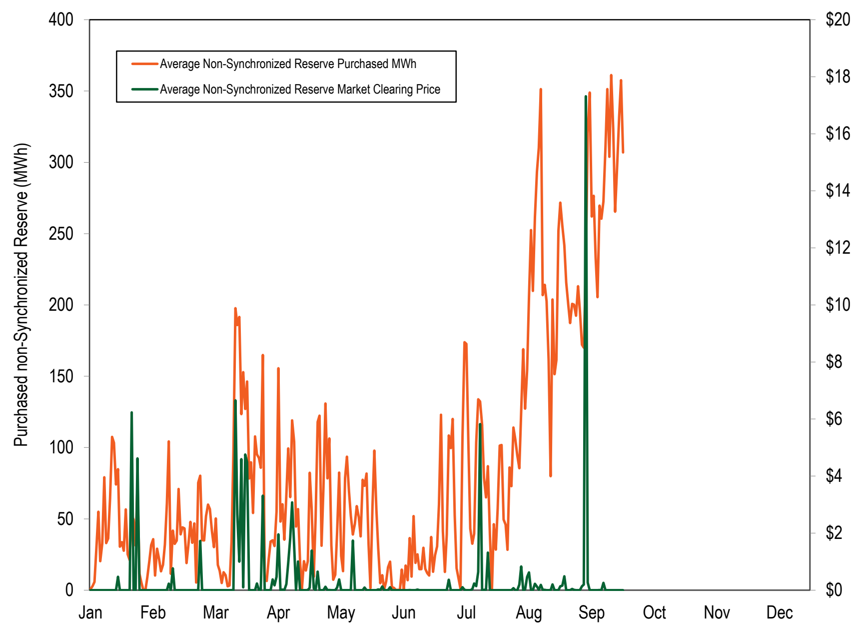
The primary reserve requirement is 150 percent of the largest contingency. For the RTO Reserve Zone this is 2,063 MW. For the Mid-Atlantic Dominion Reserve Zone this is 1,700 MW. The primary reserve requirement can be filled with Tier 1 synchronized reserve, Tier 2 synchronized reserve, or non-synchronized reserve subject to the requirement that there be 1,300 MW of synchronized reserve in the Mid-Atlantic Dominion Reserve Zone. The Ancillary Services Optimizer determines the most economic combination of these products to fill the balance of the primary reserve requirement. As such there is no pre-defined hourly requirement for non-synchronized reserve.

Non-synchronized reserve is reserve MW available within ten minutes but not synchronized to the grid. PJM specifies that 1,300 MW of synchronized reserve must be available in the Mid-Atlantic Dominion Reserve Zone. The remainder can be made up of non-synchronized reserve. Examples of equipment that generally qualify in this category are shutdown run-of-river, pumped hydro, industrial combustion turbines, jet engine/expander turbines, combined cycle and diesels.[35]

As for Tier 1 synchronized reserve, PJM calculates the amount of non-synchronized reserve available each hour and every five minutes within the hour. The calculation is based upon a unit's startup and notification time, energy ramp rate, and economic minimum. Almost all non-synchronized reserve enabled resources are CTs, with some Diesel. Startup time for these units is not subject to testing. There is no non-synchronized reserve offer price. Prices are determined by the lost opportunity cost created by any deviation from economic merit order required to maintain the non-synchronized reserve commitment. In most hours the non-synchronized reserve clearing price is zero.

Figure 10-18 shows the daily average non-synchronized reserve market clearing price and average scheduled MW. The Mid-Atlantic Dominion Reserve Zone non-synchronized reserve market cleared with a clearing price greater than zero in 206 hours from January through September of 2013 with a maximum of $210.07 on September 11, 2013. The non-synchronized reserve market clearing price for the RTO Reserve Zone cleared in 64 hours with a maximum clearing price of $9.22 on August 31, 2013.

Figure 10-18 Daily average Non-Synchronized Reserve Market clearing price and MW purchased: January through September 2013



While the overall impact of non-synchronized reserve on Primary Reserve costs remains low (with an average price of $10.17 for the 206 hours when it cleared above $0 between January and September) the non-synchronized reserve market includes a tariff change that significantly increases the cost and does so in an uneconomic way. Whenever non-synchronized reserve clears at a price above $0.00, all Tier 1 resources is paid the synchronized reserve market clearing price.[36] This new rule added $11,880,825 to the total cost of primary reserve during the January through September, 2013 period, more that the full cost of synchronized reserve for the entire period ($10,782,052).

35 See PJM. "Manual 11, Energy & Ancillary Services Market Operations" Revision 60 (June 1, 2013), p. 85.

36 See PJM. "Manual 28, Operating Agreement Accounting," Revision 60 (June 1, 2013), p. 37.

Day Ahead Scheduling Reserve (DASR)

The Day-Ahead Scheduling Reserve Market is a market based mechanism for the procurement of supplemental, 30-minute reserves on the PJM System.[37]

The DASR 30-minute reserve requirements are determined by the reliability region.[38] In the Reliability*First* (RFC) region, reserve requirements are calculated based on historical under-forecasted load rates and generator forced outage rates.[39] The RFC and Dominion DASR requirements are added together to form a single RTO DASR requirement which is obtained via the DASR Market. 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.

Market Structure

In 2013, the required DASR is 6.91 percent of peak load forecast, down from 7.03 percent in 2012.[40] The DASR requirement is a sum of the load forecast error and the forced outage rate. From 2012 the load forecast error increased from 1.97 percent to 2.13 percent. The forced outage rate decreased from 4.93 percent to 4.66 percent. Added together, the 2013 DASR requirement is 6.91 percent. The DASR MW purchased averaged 6,895 MW per hour for January through September 2013, a slight decrease from 7,019 MW per hour in the same period of 2012.

In January through September, 2013, no hours failed the three pivotal supplier test in the DASR Market. No hours failed the three pivotal supplier test, calculated by the MMU, in January through September, 2012.

Load response resources which are registered in PJM's Economic Load Response and are dispatchable by PJM are also eligible to provide DASR. No demand side resources cleared the DASR market in January through June, 2013.

37 PJM uses the terms "supplemental operating reserves" and "scheduling operating reserves" interchangeably.
38 See PJM. "Manual 13, Emergency Requirements," Revision 53 (June 1, 2013), p. 11.
39 See PJM. "Manual 10, Pre-Scheduling Operations," Revision 27 (February 28, 2013), pp. 18-19.
40 See the *2012 State of the Market Report for PJM*, Volume II, Section 9, "Ancillary Services" at Day Ahead Scheduling Reserve (DASR).

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.[41] 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. However, there is a positive opportunity cost in addition to this direct marginal cost, which is not part of the offer price but calculated by PJM. As of September 30, 2013, 15 percent of all units offered DASR at levels above $5 per MW. The impact on DASR prices of high offers was minor as a result of a favorable balance between supply and demand.

Market Performance

For 89 percent of hours in January through September, 2013, DASR cleared at a price of $0.00 (Figure 10-19). For January through September 2013, the weighted DASR price was $0.93. The highest price was $230.10 on July 17, 2013. DASR prices are calculated as the sum of the offer price plus the opportunity cost. For most hours the price is comprised entirely of offer price. When the DASR clearing price is greater than $0, 66 percent of the time the price consists solely of the offer price. The breakdown of price into offer and LOC is in Figure 10-19.

41 See PJM. "Manual 11, Emergency and Ancillary Services Operations," Revision 60 (June 1, 2013), p. 143.

Table 10-22 PJM Day-Ahead Scheduling Reserve Market MW and clearing prices: January through September 2012 and 2013

Year	Month	Average Required Hourly DASR (MW)	Minimum Clearing Price	Maximum Clearing Price	Weighted Average Clearing Price	Total DASR MW Purchased	Total DASR Credits
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
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

The secondary reserve requirement (DASR) is usually satisfied at no cost and with no need to redispatch energy resources. The amount of reserve available from hydro and off-line resources is relatively static. But when energy demand is high there is less hydro and fewer offline resources available. In that case the reserve requirement cannot be filled without redispatching online resources which significantly affects the price. Figure 10-19 shows the impact on price when online resources must be redispatched to satisfy the DASR requirement. Figure 10-20 illustrates the relationship between DASR prices and high energy dispatch and the use of off-line resources for secondary reserve.

Figure 10-19 Hourly components of DASR clearing price: January through September 2013

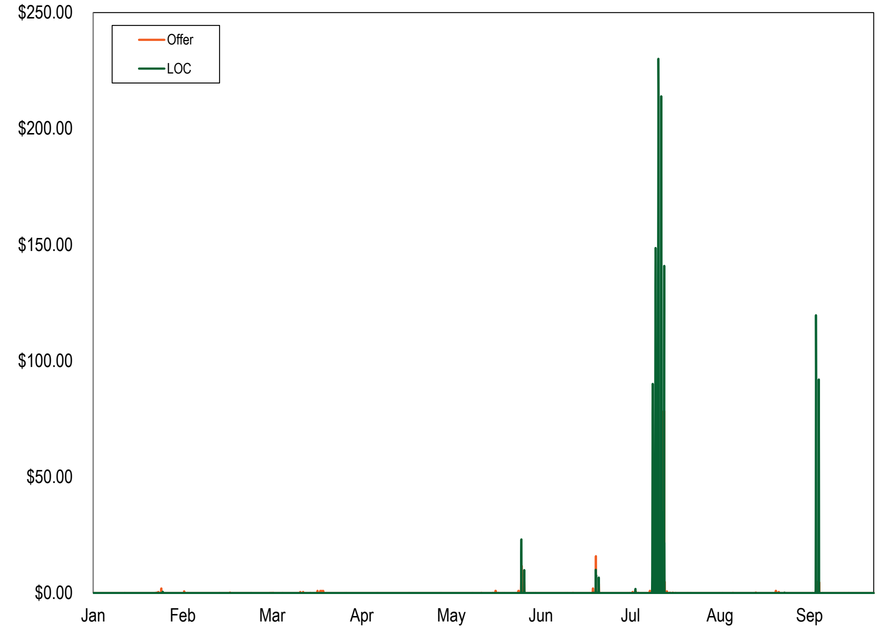
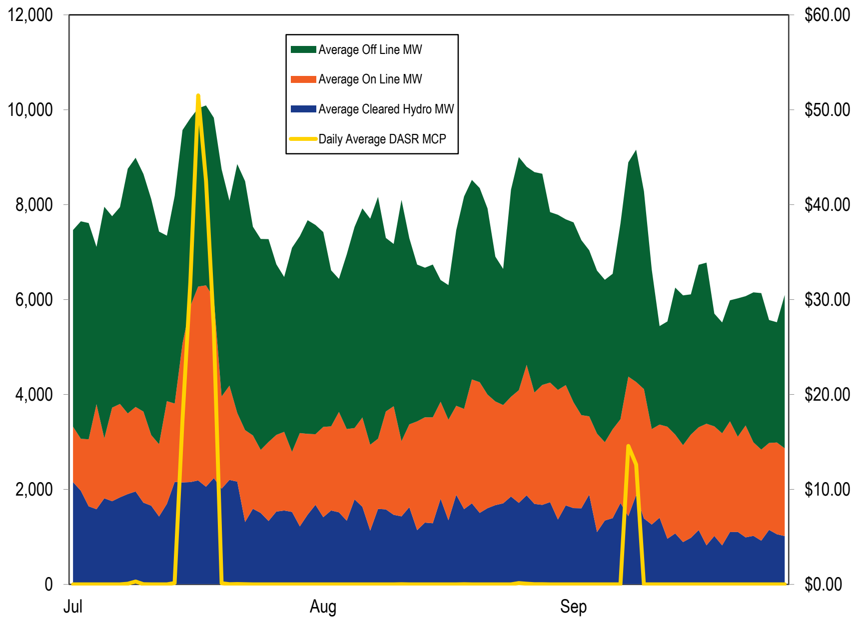


Figure 10-20 Price impact of dispatched online resources



Black Start Service

Black start service is necessary to help 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.

Individual transmission owners, with PJM, identify the black start units included in each transmission owner's system restoration plan. 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. (Table 10-23)

Following a stakeholder process in the System Restoration Strategy Task Force (SRSTF), substantial changes to the black start restoration and procurement strategy were introduced. The PJM and MMU proposal for system restoration was approved at the February 28, 2013, Markets and Reliability Committee (MRC).

The proposed changes include allowing PJM more flexibility in procuring black start resources by allowing cross zonal coordination between transmission zones, clarifying the responsibility for black start resources selection, revising the timing requirement for black start from 90 minutes to three hours, and implementing a process to revise black start plans on a five year basis in order to ensure system restoration needs are met. This proposal is a substantial improvement to current system restoration strategy, which does not give PJM adequate flexibility in procuring black start resources. This proposal also clarifies that PJM is the entity responsible for selecting the appropriate black start resources for each transmission zone based on system restoration requirements.

Black start payments are non-transparent payments made to units on the behalf of load to maintain adequate reliability to restart the system in case of a blackout. Current rules appear to prevent the publishing detailed data regarding these black start resources, hindering transparency and competitive replacement RFPs. The MMU recommends 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.

In January through September 2013, black start charges were $80.3 million. Black start zonal charges in January through September 2013 ranged from $0.03 per MW-day in the ATSI zone (total charges were $95,492) to $10.30 per MW-day in the AEP zone (total charges were $65,557,476). For each zone, Table 10-23 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 $0.08 per MW of reserve capacity.

Table 10-23 Black start zonal charges for network transmission use: January through September 2013

Zone	Charges	Peak Load (MW-day)	Black Start Rate ($/MW-day)
AECO	$464,890	766,857	$0.61
AEP	$65,557,476	6,363,248	$10.30
AP	$182,452	2,327,134	$0.08
ATSI	$95,492	3,689,568	$0.03
BGE	$4,905,081	1,911,546	$2.57
ComEd	$3,060,666	6,443,046	$0.48
DAY	$184,311	957,438	$0.19
DEOK	$388,067	1,487,339	$0.26
DLCO	$51,327	833,769	$0.06
DOM	$254,195	1,770,908	$0.14
DPL	$433,745	1,123,149	$0.39
EKPC	$122,585	290,702	$0.42
JCPL	$423,749	1,697,896	$0.25
Met-Ed	$611,005	828,937	$0.74
PECO	$1,063,357	2,333,877	$0.46
PENELEC	$389,848	793,884	$0.49
Pepco	$236,474	1,834,751	$0.13
PPL	$146,763	2,015,150	$0.07
PSEG	$1,680,463	2,858,255	$0.59
RECO	$0	NA	NA