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 three months of 2013.

Table 9-1 The Regulation Market results were indeterminate for January through March, 2013

	January through March 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 three months of 2013.
- Participant behavior in the Regulation Market was evaluated as competitive for January through March, 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 remain to be decided by FERC 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. It is too early to reach a definitive conclusion about the new market design because important parts of the design remain to be decided by FERC and because there is not yet enough information about actual implementation of the design.

Table 9-2 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 Synchronized Reserve Market had one or more pivotal suppliers which failed the three pivotal supplier test in 6.3 percent of the hours in January through March, 2013.
- Participant behavior was evaluated as competitive because the market rules require competitive, cost based offers.
- Market performance was evaluated as competitive because the interaction of 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.

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."

Table 9-3 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), about 12 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 March 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 4.39. This is 33.4 percent increase over January through March 2012 when the ratio was 3.29, was the result of the decrease in demand.
- **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 March, 2013, was 829 MW. This is a 124 MW decrease in the average hourly regulation demand of 953 MW in the same period of 2012.
- **Market Concentration.** In January through March 2013, the PJM Regulation Market had a weighted average Herfindahl-Hirschman Index (HHI) of 1995 (1611 in January through March 2012), which is classified as "highly concentrated."[3] In January through March 2013, 88 percent of hours had one or more pivotal suppliers which failed PJM's three pivotal supplier test (67 percent of hours failed the three pivotal supplier test in January through March 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 costs 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 of the unit. Owners must also specify which signal type the unit will be following, RegA or RegD.[4] As of March 31, 2013, there were 14 distinct resources (five generation and nine demand response) offering performance regulation and following the RegD signal.
- **Price and Cost.** The weighted Regulation Market Clearing Price for the PJM Regulation Market for January through March 2013 was $33.87. This is an increase of $21.26, or 168.6 percent, from the weighted average price for regulation in January through March 2012. The cost of regulation from January through March 2013 was $38.95. This is a $22.19 (132.4 percent) increase from the same time period in 2012.

3 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.

4 See the *2012 State of the Market Report for PJM*, Volume II, Appendix F "Ancillary Services Markets."

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 now merged with the former Southern Synchronized Reserve Zone into the RTO Reserve Zone. The former Mid-Atlantic Synchronized Reserve Zone has incorporated Dominion to become the Mid-Atlantic Dominion Reserve Zone. PJM further retains the right to define new zones or subzones "as needed for system reliability."[5]

Market Structure

- **Supply.** In January through March, 2013, the supply of offered and eligible synchronized reserve was both stable and adequate. The contribution of DSR to the Synchronized Reserve Market remains significant. Demand side 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 Sub-zone became the Mid-Atlantic Dominion Sub-zone on October 1, 2012, the requirement remained at 1,300 MW.
- **Market Concentration.** For January through March, 2013, the average weighted HHI for cleared synchronized reserve in the Mid-Atlantic Dominion Subzone was 4161 which is classified as highly concentrated. The average weighted cleared Synchronized Reserve Market HHI for the Mid-Atlantic Subzone in January through March, 2012, was 2638, which is classified as "highly concentrated."[6] In January through March, 2013, 35 percent of hours had a maximum market share greater than 40 percent, compared to 43 percent of hours in January through March, 2012.
- In the Mid-Atlantic Subzone, in January through March, 2013, 6.3 percent of hours that cleared a synchronized reserve market had three or fewer pivotal suppliers. In January through March, 2012, 49 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 March 2013 was characterized by structural market power.

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 Subzone was $7.35 per MW in January through March, 2013, an increase of $1.29 per MW over January through March, 2012. The total cost of synchronized reserves per MW in January through March 2013 was $12.58, a $4.82 increase from the $7.76 cost of synchronized reserve in January through March 2012. The market clearing price was 58 percent of the total synchronized reserve cost per MW in January through March, 2013, down from 78 percent in January through March, 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 the first quarter of 2013.

DASR

On June 1, 2008, PJM introduced the Day-Ahead Scheduling Reserve Market (DASR), as required by the RPM settlement.[7] The purpose of this market is to

5 See PJM, "Manual 11, Energy and Ancillary Services Market Operations," Revision 59 (April 1, 2013), p. 75.
6 See Section 2, "Energy Market" at "Market Concentration" for a more complete discussion of concentration ratios and the Herfindahl-Hirschman Index (HHI).
7 See 117 FERC ¶ 61,331 (2006).

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 March, 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 this direct marginal cost. As of March 31, 2013, thirteen percent of offers reflected economic withholding. PJM rules require all units with reserve capability that can be converted into energy within 30 minutes to offer into the DASR Market.[9] Units that do not offer have their offers set to zero.
- **DSR.** Demand side resources are eligible to participate in the DASR Market, but no demand resource cleared the DASR Market in January through March, 2013.

Market Performance

- **Price.** The weighted DASR market clearing price in January through March, 2013 was $0.01 per MW. In January through March, 2012, the weighted price of DASR was $0.01 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]

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 all costs associated with providing this service, as defined in the tariff. In January through March, 2013, black start credits were $27.6 million. Black start zonal credits in January through March 2013 ranged from $0.03 per MW in the ATSI zone (total credits of $38,980) to $10.66 per MW in the AEP zone (total credits of $22,352,763).

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

Table 9-4 shows PJM ancillary services costs for January through March, 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.

8 See PJM. "Manual 13: Emergency Operations," Revision 52, (February 1, 2013); pp 11-12.
9 PJM. "Manual 11, Energy and Ancillary Services Market Operations," Revision 59 (April 1, 2013), p. 145.
10 OATT Schedule 1 § 1.3BB.

Table 9-4 History of ancillary services costs per MW of Load[11]: January through March 2002 through 2013

Year	Regulation	Scheduling, Dispatch, and System Control	Reactive	Synchronized Reserve	Supplementary Operating Reserve	Total
2002	$0.37	$0.59	$0.24	$0.00	$0.56	$1.76
2003	$0.65	$0.59	$0.22	$0.00	$0.98	$2.43
2004	$0.53	$0.63	$0.26	$0.17	$0.89	$2.48
2005	$0.46	$0.51	$0.25	$0.07	$0.57	$1.86
2006	$0.48	$0.46	$0.28	$0.09	$0.32	$1.62
2007	$0.58	$0.46	$0.30	$0.11	$0.50	$1.95
2008	$0.59	$0.47	$0.29	$0.07	$0.52	$1.94
2009	$0.37	$0.37	$0.34	$0.16	$0.56	$1.80
2010	$0.34	$0.38	$0.35	$0.05	$0.68	$1.80
2011	$0.27	$0.33	$0.39	$0.12	$0.84	$1.95
2012	$0.18	$0.41	$0.49	$0.03	$0.53	$1.64
2013	$0.28	$0.41	$0.63	$0.04	$0.94	$2.30

Conclusion

The design of the Regulation Market changed very 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 important parts of the design remain to be decided by FERC and 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 quarter 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. However, compliance with calls to respond to actual spinning events has been an issue. As a result, the MMU recommends that the rules for compliance be reevaluated.

The MMU concludes that the structure of the DASR Market was competitive in the first three 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 three months of 2013. The MMU concludes that the DASR Market results were competitive in the first three 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.[12] On

11 Results in this table differ slightly from the results reported previously because accounting load is used in the denominator in this table.

12 All existing PJM tariffs, and any changes to these tariffs, are approved by FERC. The MMU describes the full history of the changes to the tariff provisions governing the Regulation Market in the *2011 State of the Market Report for PJM*, Volume II, Section 9, "Ancillary Service Markets."

November 16, 2012, FERC modified the PJM market design that was introduced on October 1, 2012.[13]

Regulation Market Changes for Performance Based Regulation

Regulation is a key part of PJM's effort to minimize ACE so as to keep the reportable metrics CPS1 and BAAL within acceptable limits.[14] On October 20, 2011, FERC issued Order No. 755 directing PJM and other RTOs/ISOs to modify their regulation markets to make use of and properly compensate a mix of fast and traditional response regulation resources.[15] A driver 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. FERC directed 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. 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.[16]

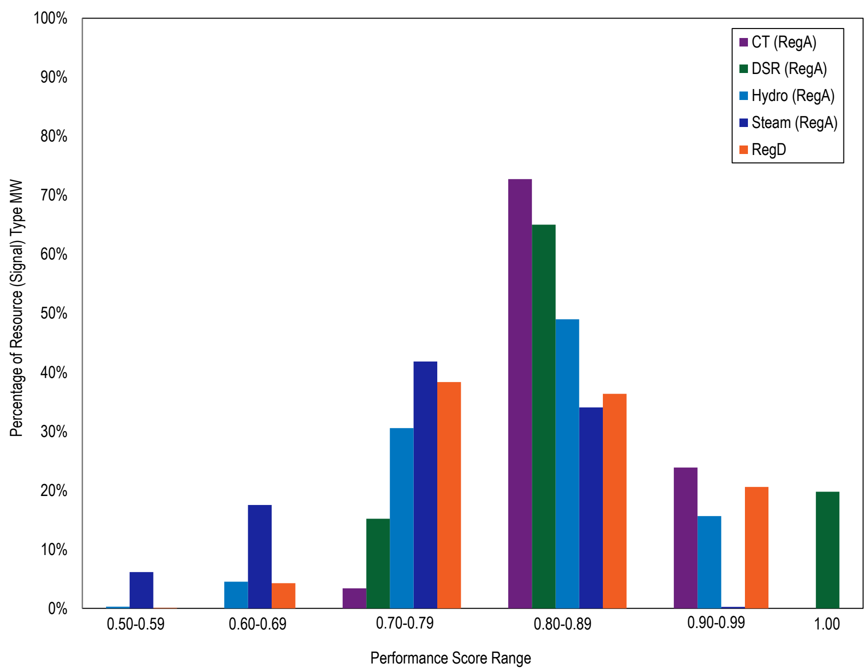
In a market defined in terms of units of RegA equivalent regulation service, the marginal benefits factor of all units following the RegA signal is one, while the marginal benefits factor of units following the RegD signal depends on how much RegD following resources are used. Under PJM's August 15, 2012, proposal, the benefits factor can be as high as 2.9 but never lower than zero. Between January 1, 2013, and March 31, 2013, the lowest actual marginal benefit factor was 1.58. The highest marginal benefit factor was 2.899. The average marginal benefit factor was 2.655. 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 100-hour average of performance scores. A unit's regulation capability MW multiplied by its benefits factor, and modified by its performance score, results in that unit's effective RegA signal following regulation MW.[17]

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. Every regulating unit for every hour has its performance tracked, measured, and recorded. An hourly performance score (0.0 to 1.0) 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. Units are cleared and compensated for their effective MW. Regulation performance score measures 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.[18] Figure 9-1 shows the average performance score by unit type and signal followed.

13 *PJM Interconnection, L.L.C.*, 139 FERC ¶ 61,130 (2012)
14 See the *2012 State of the Market Report for PJM*, Appendix F: Ancillary Services, p.1
15 *Frequency Regulation Compensation in the Organized Wholesale Power Markets*, 137 FERC ¶ 61,064 (2011) ("Order No. 755").
16 For more details, see the *2012 State of the Market Report for PJM*, Volume II, Section 9, "Ancillary Service Markets."
17 See PJM "Manual 11: Energy & Ancillary Services Market Operations," Revision 59, (April 1, 2013); pps 61-62.
18 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 9-1 Average performance score grouped by unit type and regulation signal type: January through March 2013



The use of a performance score to measure the accuracy of a regulating resource is the primary reason 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 $/MW. 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 9-5 shows capability, average daily offer and average hourly eligible MW for all hours. The hourly regulation capability decreased in January through March 2013, to 8,149 MW from 9,257 MW during the same time period of 2012. Eligible regulation as a percentage of capability increased by nine percent over the same period in 2012.

Table 9-5 PJM regulation capability, daily offer[19] and hourly eligible: January through March 2012 and 2013[20]

Period	Regulation Capability (MW)	Average Daily Offer (MW)	Percent of Capability Offered	Average Hourly Eligible (MW)	Percent of Capability Eligible
2013 (Jan-Mar)	8,149	6,211	76%	3,551	44%
2012 (Jan-Mar)	9,257	6,878	74%	3,209	35%

The supply of regulation can be affected by regulating units retiring from service. Table 9-6 shows what the impact on the Regulation Market would be if all units retire that are requesting retirement through the end of 2015.

Table 9-6 Impact on PJM Regulation Market of currently regulating units scheduled to retire through 2015

Current Regulation Units, January through March 2013	Settled MW, January through March 2013	Units Scheduled To Retire Through 2015	Settled MW of Units Scheduled To Retire Through 2015	Percent Of Regulation MW To Retire Through 2015
252	1,797,570	30	20,741	1.15%

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

19 Average Daily Offer MW excludes units that have offers but are unavailable for the day.
20 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.

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 of 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. 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 March, 2013 was $33.87. The regulation cost for January through March, 2013, was $38.95. The ratio of price to cost is significantly higher at 87 percent (compared with 76 percent in Q1 of 2012), meaning that more of the costs which used to come from LOC as a result of low load forecasts are now part of the price.

Since October 1, a number of resources have offered and cleared the regulation market following the RegD signal. As of March 31, 2013, there were 14 distinct resources (five generation and nine demand response) offering performance regulation and following the RegD signal.

In the period from January 1, 2013 through March 31, 2013, the marginal benefits factor (contribution to ACE correction) for cleared RegD following resources has ranged from 1.58 to 2.899 with an average over all hours of 2.66.

If the set of resources that follow the RegD signal were to be considered as a separate market, the HHI in that market from January through March 2013 was 5823.

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 March, 2013, the MW-weighted average RegA performance score was 0.79.

Figure 9-2 Daily average actual cleared MW of regulation, effective cleared MW of regulation, and average performance score; all cleared regulation; January through March 2013

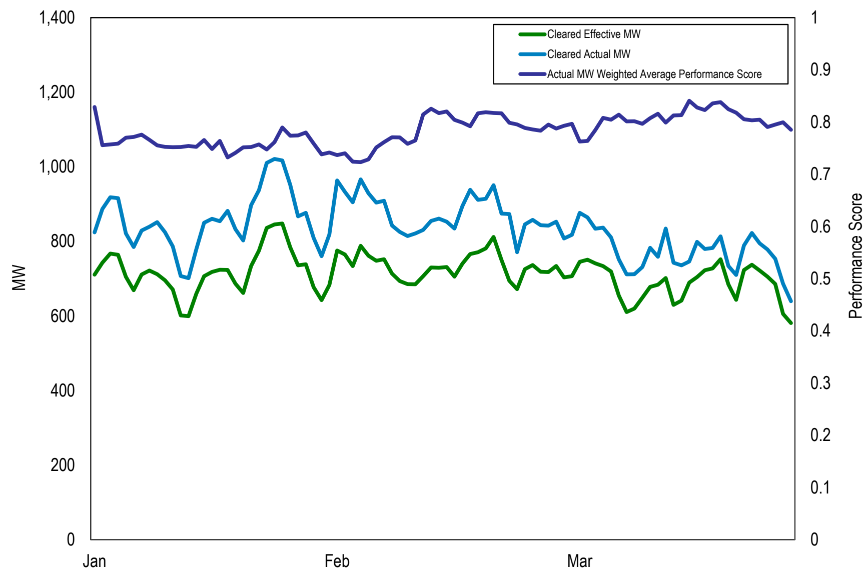
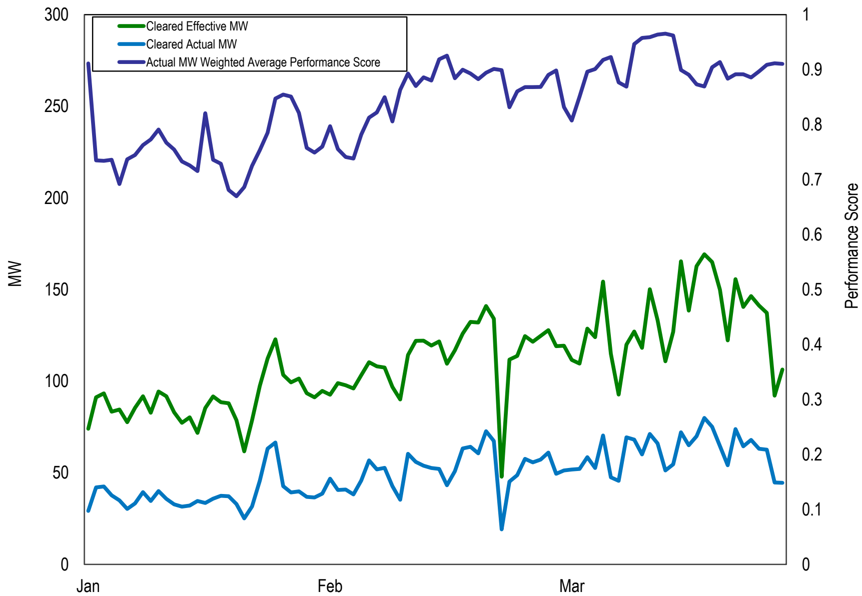


Figure 9-3 Daily average actual cleared MW of regulation, effective cleared MW of regulation, and average performance score; RegD units only; January through March 2013



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 March, 2013, the MW-weighted average RegD resource performance score was 0.86.

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 9-7 shows the required regulation and its relationship to the supply of regulation.

Table 9-7 PJM Regulation Market required MW and ratio of eligible supply to requirement: January through March 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

PJM's performance as measured by CPS and BAAL standards has not been reduced as a result of the lower regulation requirement.[21]

Market Concentration

Table 9-8 shows Herfindahl-Hirschman Index (HHI) results for January through March of 2012 and 2013. The average HHI of 1995 is classified as moderately concentrated and is higher than the HHI for the same period in 2012.

Table 9-8 PJM cleared regulation HHI: January through March 2012 and 2013

Period	Minimum HHI	Weighted Average HHI	Maximum HHI
2013 (Jan-Mar)	757	1995	5449
2012 (Jan-Mar)	814	1611	4429

21 *2012 State of the Market Report for PJM*, Appendix F: Ancillary Services.

Figure 9-4 compares the 2013 HHI distribution curves with distribution curves for the same periods of 2012 and 2011.

Figure 9-4 PJM Regulation Market HHI distribution: January through March 2011, 2012, and 2013

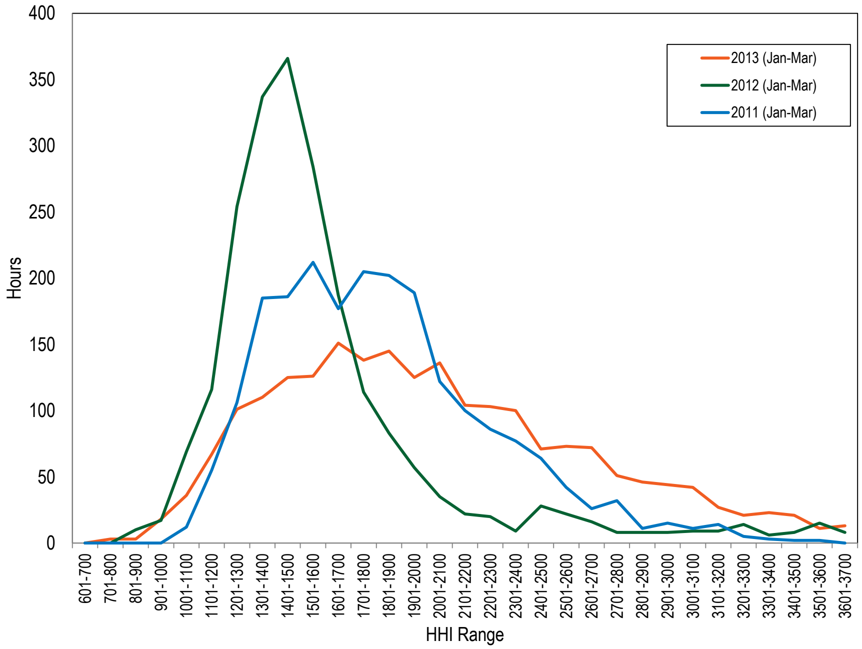


Table 9-9 includes a monthly summary of three pivotal supplier results. In January through March 2013, 88 percent of hours had one or more pivotal suppliers which failed or should have failed PJM's three pivotal supplier test.[22] In March, 2013, 97 percent of hours had one or more pivotal supplier and in 78 percent of hours all suppliers were pivotal. Offer capping in the regulation market has little impact on prices because offers are a smaller component of price than is LOC (Figure 9-6).

The MMU concludes from these results that the PJM Regulation Market in January through March 2013 was characterized by structural market power in 88 percent of the hours.

Table 9-9 Regulation market monthly three pivotal supplier results: January through March 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%

Market Conduct

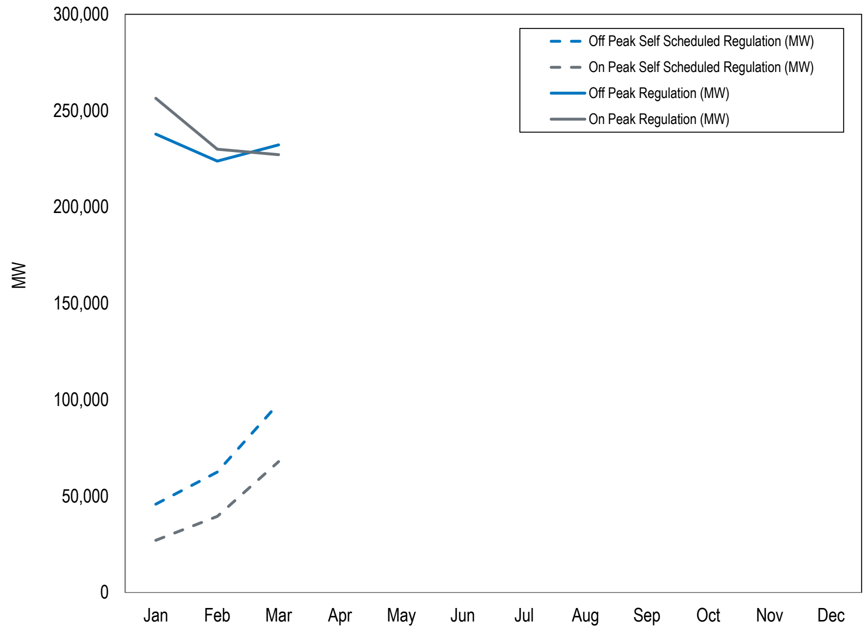
Offers

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 9-10).[23]

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

23 See PJM "Manual 28: Operating Agreement Accounting," Revision 59, (April 22, 2013); para 4.1, pp 14.

Figure 9-5 Off peak and on peak regulation levels: January through March 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 Q1 of 2013, 73 percent was purchased in the spot market, 24.0 percent was self scheduled, and 2.8 percent was purchased bilaterally (Table 9-10).

Table 9-10 Regulation sources: spot market, self-scheduled, bilateral purchases: January through March 2012 and 2013

Year	Month	Spot Regulation (MW)	Self-Scheduled Regulation (MW)	Bilateral Regulation (MW)	Total Regulation (MW)
2013	Jan	413,304	72,880	8,070	494,253
2013	Feb	338,990	102,005	12,808	453,803
2013	Mar	275,880	165,987	17,554	459,421
2012	Jan	553,686	164,806	21,261	739,753
2012	Feb	481,004	175,757	20,456	677,217
2012	Mar	477,564	144,408	19,683	641,655

Demand resources offered and cleared regulation for the first time in November 2011. In April 2012, a tariff change allowing demand resources to offer 0.1 MW facilitated participation by demand resources. Although their impact remains small the participation of demand resources in regulation is growing. For January through March, 2013, approximately fifty percent of hours cleared some DSR regulation.

The Minimum Regulation MW parameter was reintroduced in 2012. This parameter allows regulation owners to specify a minimum amount of regulation that can be cleared, which imposes a constraint on the ASO's three product optimization. For the marginal unit, the ASO may need to clear less than an individual unit's offered amount of regulation in order to meet the regulation requirement. As a result of this parameter, there are a significant number of hours in which the ASO will have to clear more MW than is optimal or skip the marginal unit and clear a more expensive unit resulting in a higher Regulation Market Clearing Price.

Market Performance

Price

The weighted average RMCP for January through March, 2013, was $33.87. This is a 166.6 percent increase from the January through March 2012 weighted average RMCP of $12.64. Figure 9-6 shows the daily average Regulation Market clearing price and the opportunity cost component for the marginal units in the PJM Regulation Market.

Figure 9-6 PJM Regulation Market daily weighted average market-clearing price, marginal unit opportunity cost and offer price (Dollars per MWh): January through March 2013

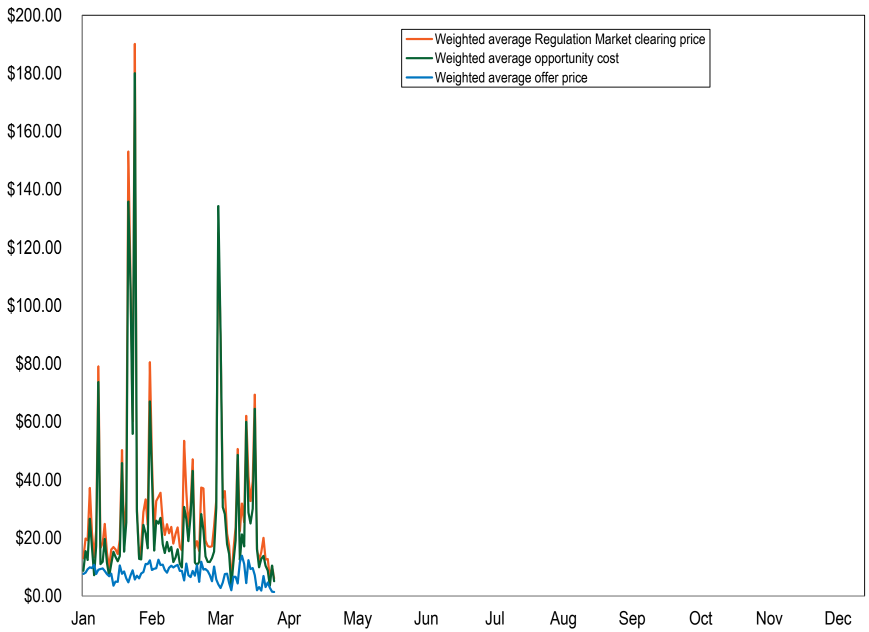


Table 9-11 shows monthly average regulation market clearing price, average marginal unit offer price, and average marginal unit LOC.

There were several hourly price spikes in the ancillary services markets during the second half of January (Figure 9-7). The spikes were driven entirely by LOC costs resulting from high LMPs. The spikes were most acute in the capability regulation market. The LOC component of capability regulation is the most volatile component of regulation prices. The RMCP reached $228.87 and $448.26 in hours 11 and 12 of January 22, 2013. Prices reached $479.22 and $571.19 in hours 14 and 15 of January 25, 2013. In all there were 39 hours in January where the RMCP was over $100.

Figure 9-7 Ancillary Services Price spikes; January 20-January 29, 2013

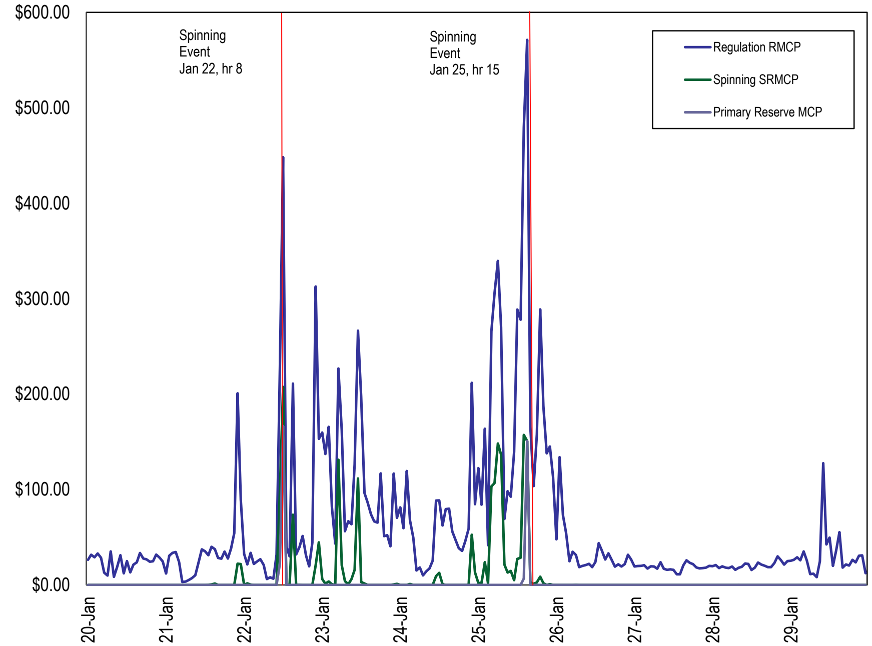


Table 9-11 PJM Regulation Market monthly weighted average market-clearing price, marginal unit opportunity cost and offer price (Dollars per MWh): January through March 2013

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

Total scheduled regulation MW, total regulation charges, regulation price and regulation cost are shown in Table 9-12.

Table 9-12 Total regulation charges: January through March 2013 and 2012

Year	Month	Scheduled Regulation (MW)	Total Regulation Charges ($/MW)	Weighted Average Regulation Market Price ($/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%
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%

A breakdown of the cost of regulation into its capability, performance, and opportunity cost components is shown in Table 9-13.

Table 9-13 Components of regulation cost: January through March 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

Table 9-14 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 March 2013 than it was in January through March 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 9-14 Comparison of average price and cost for PJM Regulation, January through March 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	$18.05	$30.67	59%
2011	$11.51	$24.83	46%
2012	$12.61	$16.76	75%
2013	$33.87	$38.95	87%

Primary Reserve

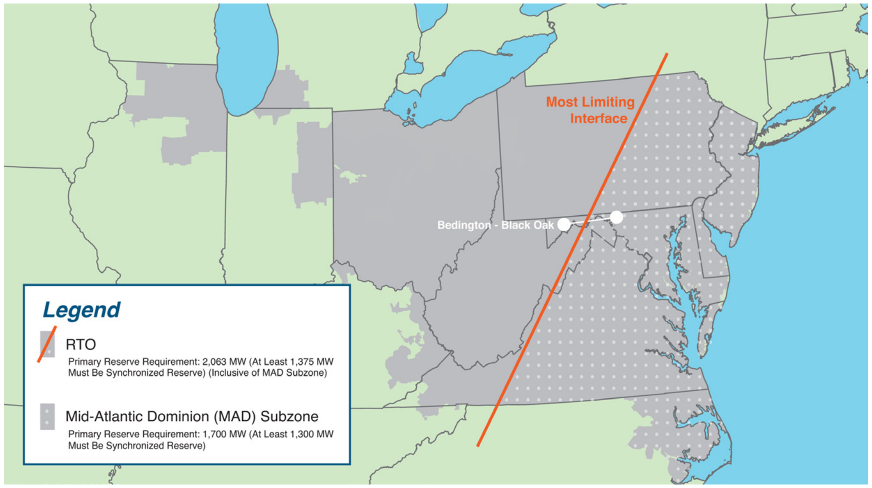
Reserves are provided by generating capability that is standing by ready for service if an unforeseen event causes a need for it. The need can be short-term and critical in the event of a disturbance or generator outage or longer term. NERC defines such losses and defines reporting requirements in “NERC Performance Standard BAL-002-0, Disturbance Control Performance.” PJM defines its obligation in M-12.[24] NERC calls short-term reserve contingency reserve and specifies it as energy available in 15 minutes. PJM satisfies this requirement and calls it Primary Reserve. PJM 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 synchronized reserve requirement.

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 9-8).

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

Figure 9-8 PJM RTO geography and primary reserve requirement: January through March 2013



Because of constrained deliverability within the RTO, PJM imposes a further restriction by creating a sub-zone within the RTO called the Mid-Atlantic Dominion sub-zone. Of the 2,063 MW requirement for primary reserve in the RTO, 1,700 MW must be deliverable to the Mid-Atlantic Dominion sub-zone. Of the 1,375 MW of synchronized reserve in the RTO, 1,300 MW must be deliverable to the Mid-Atlantic Dominion sub-zone. The Mid-Atlantic Dominion sub-zone is defined approximately by the geography in Figure 9-8. It is defined exactly by the set of all resources with a three percent or greater DFAX raise help on the constrained side of the most limiting constraint, currently Bedington-Black Oak.[25]

The primary reserves requirement is not satisfied by a single market but by several products across the RTO Zone and Mid-Atlantic Dominion Sub-zone. 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 energy products optimized to minimize total cost (Figure 9-9). The components of the Mid-Atlantic Dominion Primary Reserve Zone are Tier 1 synchronized reserve which is priced at $0 unless there is a shortage event or a spinning event, Tier 2 synchronized reserve which is satisfied by the Synchronized Reserve Market and priced economically, Demand Response (DSR) which is priced at the Synchronized Reserve Market clearing price, non-synchronized reserve (limited to no more than 50 percent of the primary reserve requirement) which is priced only when it must be dispatched at an optimized clearing price by the ASO, and synchronized reserve available in the Mid-Atlantic Dominion Reserve Zone from the RTO Reserve Zone across the most limiting constraint (usually Bedington-Black Oak).

25 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 59 (April 1, 2013), p. 75.

Figure 9-9 Components of Mid-Atlantic Dominion Subzone Primary Reserve (Daily Averages): January through March, 2013

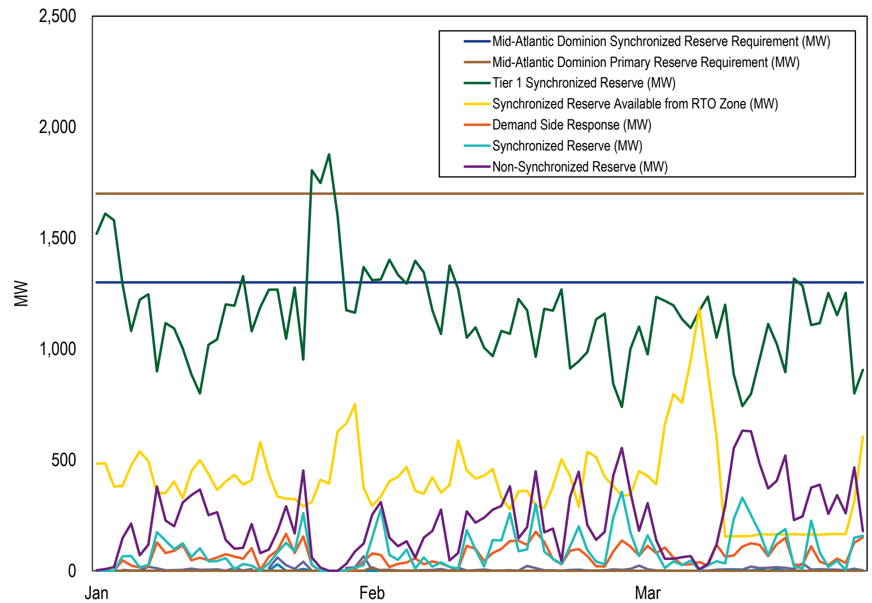


Figure 9-9 shows that Tier 1 Synchronized Reserve remains the major contributor to satisfying the reserve requirements. Synchronized reserve available inside the sub-zone from the RTO Zone is also a major contributor.

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 and some hydro units. Tier 2 synchronized reserve is dispatched at a market clearing price.

In 43 hours between January 1 and March 31, 2013 the Non-Synchronized Reserve Market cleared at greater than $0.00. Non-synchronized reserve only clears when synchronized reserve also clears.

Shortage Pricing

On October 1, 2012 PJM introduced shortage 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.[26]

From January through March, 2013 no location experienced a reserve shortage.

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 merged into one zone, the RTO Synchronized Reserve Zone, with its requirements structured to satisfy both regional specifications.[27]

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 Reserve Markets.

Market Structure

Supply

For the first three months of 2013, the supply of offered and eligible synchronized reserve was both stable and adequate. The contribution of DSR to the Synchronized Reserve Market remained significant. Demand side resources are relatively low cost, and their participation lowers overall Synchronized Reserve prices. PJM has limited the amount of DSR 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 demand side resources decreased in January through March of 2013 over 2012 (from 172,745 MW to 129,646 MW). The DSR share of the total Synchronized Reserve Market increased from 38 percent in January through March of 2012 to 48.0 percent in the same time period of 2013. Demand side resources satisfied 100 percent of the Tier 2 Synchronized Reserve market in 8.5 percent of hours in January through March of 2013 compared to 14 percent of hours in during the same time period of 2012. The merging of the former Mid-Atlantic subzone with Dominion into the new Mid-Atlantic Dominion subzone has made more Tier 1 reserve available to the subzone. The former Dominion Zone had an excess of Tier 1 lessening 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 1.3 for the Mid-Atlantic Dominion Subzone.[28] This is a 20.4 percent increase from January through March 2012 when the ratio was 1.08. Much of the required synchronized reserve is supplied from on-line (Tier 1) synchronized reserve resources. It is important to note however that the Mid-Atlantic Dominion Subzone is bigger than the Mid-Atlantic Subzone which was the basis for the Q1 2012 metric. For the RTO Zone the offered and

27 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.

28 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.

eligible excess supply ratio is determined using the administratively required level of synchronized reserve. The requirement for Tier 2 synchronized reserve is lower than the required reserve level for synchronized reserve because there is usually a significant amount of Tier 1 synchronized reserve available.

Demand

With Shortage Pricing on October 1, 2012, PJM made a geographic change to the Synchronized Reserve Market footprint. The previous Southern Zone (Dominion) was merged into the previous Mid-Atlantic Sub-zone to become the Mid-Atlantic Dominion Sub-zone. The Synchronized Reserve requirement remains 1,300 MW but the primary reserve requirement (a combination of 10-minute synchronized reserve and 10-minute non-synchronized reserve) is set to 1,700 MW.

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 March, 2013, in the RTO Synchronized Reserve Zone a Synchronized Reserve Market was cleared in less than one percent of hours. From January through March 2013 in the Mid-Atlantic Dominion Subzone a Tier 2 Synchronized Reserve Market was cleared in 38 percent of hours at an average of 306 MW. Note that there is more Tier 1 MW available in the Mid-Atlantic Dominion Subzone during the first quarter of 2013 than there was in the Mid-Atlantic Subzone in 2012, not only because of its integration with Dominion, but also because the transfer capability for Tier 1 from the RTO Zone into the Mid-Atlantic Subzone is now set to 100 percent.

As of March 31, 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.

Table 9-15 Synchronized Reserve Market required MW, RTO Zone and Mid-Atlantic Dominion Subzone, December 2008 through March 2013

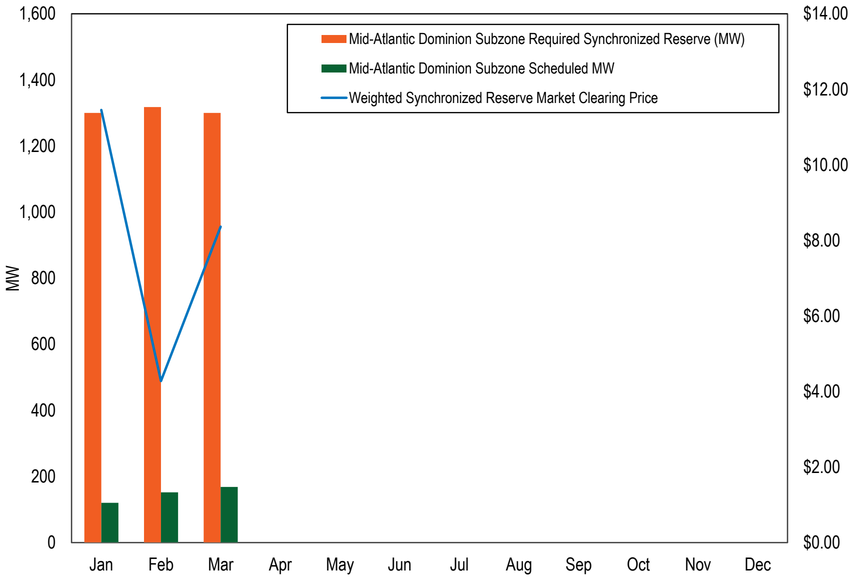
Mid-Atlantic Dominion Subzone			RTO Synchronized Reserve Zone		
From Date	To Date	Required MW	From Date	To Date	Required MW
May 10, 2008	May 8, 2010	1,150	May 10, 2008	Jan 1, 2009	1,305
May 8, 2010	Jul 13, 2010	1,200	Jan 1, 2009	Mar 15, 2010	1,320
July 13, 2010		1,300	Mar 15, 2010	Nov 12, 2012	1,350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

Figure 9-10 shows the average monthly synchronized reserve required and the average monthly Tier 2 synchronized reserve MW scheduled during January through March of 2013, for the Mid-Atlantic Dominion Synchronized Reserve Market.

Figure 9-10 Mid-Atlantic Dominion Synchronized Reserve Subzone monthly average synchronized reserve required vs. Tier 2 scheduled MW: January through March 2013



The RTO Synchronized Reserve Zone almost always has enough Tier 1 to cover its synchronized reserve requirement. Available Tier 1 in the western part of the RTO Synchronized Reserve Zone generally exceeds the total synchronized reserve requirement. In January through March 2013, the RTO Synchronized Reserve Zone cleared a Tier 2 Synchronized Reserve Market in 8 hours with an average SRMCP of $0.64. The Mid-Atlantic Dominion Subzone cleared a separate Tier 2 market in 38 percent of all hours during January through March of 2013 at a weighted SRMCP of $8.03.

For the Mid-Atlantic Dominion Subzone from January through March 2013 the requirement is 1,300 MW. The difference between the level of required synchronized reserve and the level of Tier 2 synchronized reserve scheduled is the amount of Tier 1 synchronized reserve available on the system. 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.[29] 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 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 March 2012 for the Mid-Atlantic Subzone was 2638, which is defined as highly concentrated. The HHI for the Mid-Atlantic Dominion Subzone from January through March 2013 was 4161, 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 35 percent of all hours had a maximum market share greater than or equal to 40 percent (compared to 43 percent of all hours Q1 2012). Most synchronized reserve is provided by inflexible scheduled Tier 2 resources.[30] 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 March, 2013, the hourly average HHI (all hours in which a market was cleared and flexible units were part of the market) was 8936.

The MMU estimates that in January through March, 2013, 6.3 percent of hours in the Mid-Atlantic Dominion Subzone would have failed a three pivotal supplier test (Table 9-12). This is significantly lower than the 49 percent that the MMU calculates would have failed the three pivotal supplier test in January through March, 2012. The reason for the decline is the increasing significance

29 See PJM. "Manual 11: Energy & Ancillary Services Market Operations," Revision 54 (October 1, 2012), p. 71.

30 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.

of demand response in the supply of synchronized reserve. Demand response MW were 49 percent of the settled synchronized reserve tier 2 MW in January through March, 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.

Table 9-16 Mid-Atlantic Dominion Sub-zone[31] Synchronized Reserve Market monthly three pivotal supplier results: 2010, 2011, 2012, and 2013

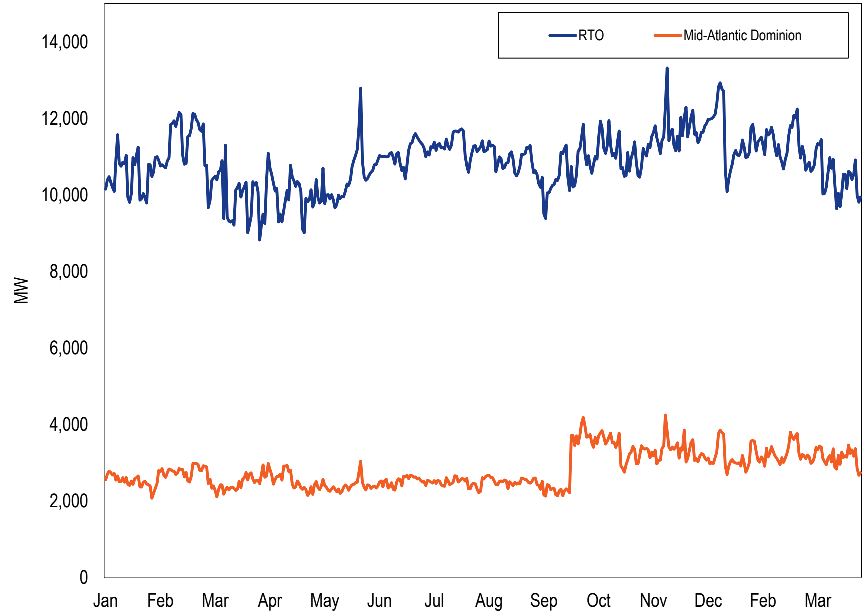
Month	2013 Percent of Hours Pivotal	2012 Percent of Hours Pivotal	2011 Percent of Hours Pivotal	2010 Percent of Hours Pivotal
Jan	1%	45%	92%	64%
Feb	11%	40%	99%	49%
Mar	7%	38%	74%	65%
Apr		33%	83%	31%
May		15%	46%	45%
Jun		29%	14%	10%
Jul		10%	19%	23%
Aug		3%	25%	18%
Sep		4%	56%	17%
Oct		9%	73%	54%
Nov		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 9-11 shows the daily average of hourly offered Tier 2 synchronized reserve MW for both the RTO Synchronized Reserve Zone and the Mid-Atlantic Dominion Synchronized Reserve Sub-zone. Note that the geography of the RTO zone and the Mid-Atlantic subzone changed on October 1 with shortage pricing.

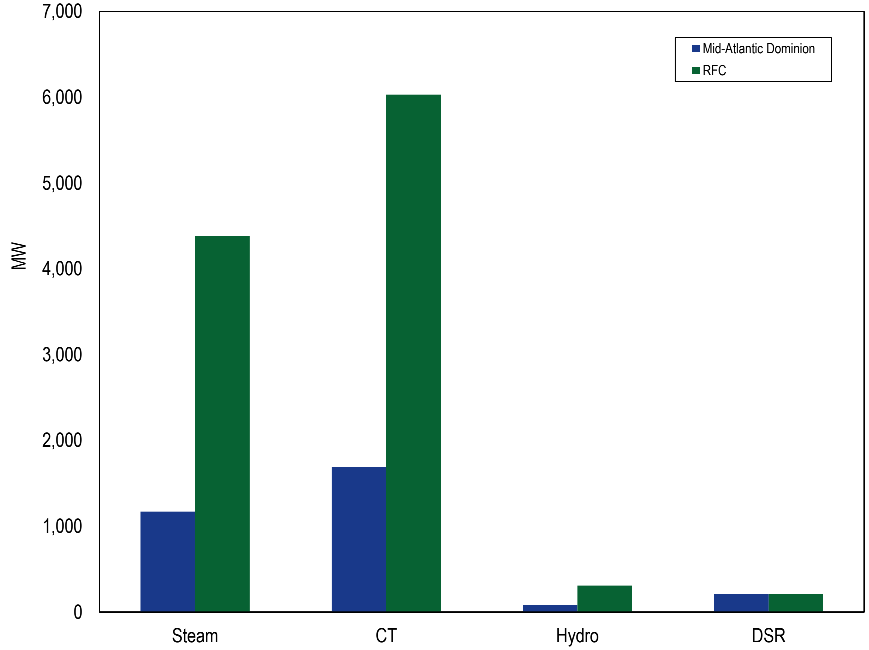
Figure 9-11 Tier 2 synchronized reserve average hourly offer volume (MW): January 2012 through March 2013



Synchronized reserve is offered by steam, CT, hydroelectric and DSR resources. Figure 9-12 shows average offer MW volume by market and unit type.

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

Figure 9-12 Average daily Tier 2 synchronized reserve offer by unit type (MW): January through March 2013



DSR

Demand-side resources were permitted to participate in the Synchronized Reserve Markets effective August, 2006. DSR has a significant impact on the Synchronized Reserve Market. As currently implemented in the Synchronized Reserve Market, DSR is always an inflexible resource. In January through March 2013, DSR was 49 percent of all cleared Tier 2 synchronized reserves, compared to 38 percent for the same period in 2012. In 16 percent of the hours in which synchronized reserve was cleared, all cleared MW were DSR (Table 9-17). In the hours when all cleared MW were DSR, the simple average SRMCP was $0.11. The simple average SRMCP for all cleared hours was $6.97.

Table 9-17 Average RFC SRMCP when all cleared synchronized reserve is DSR, average SRMCP, and percent of all cleared hours that all cleared synchronized reserve is DSR: October through December 2012, and January through March 2013

Year	Month	Average SRMCP	Average SRMCP when all cleared synchronized reserve is DSR	Percent of cleared hours all synchronized reserve is DSR
2012	Oct	$16.15	$1.69	2%
2012	Nov	$11.44	$0.72	4%
2012	Dec	$5.06	$0.40	5%
2013	Jan	$10.05	$0.06	7%
2013	Feb	$3.16	$0.06	5%
2013	Mar	$8.57	$0.16	12%

Market Performance

Price

Figure 9-13 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 9-18 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 March 2013 was $7.35 while the corresponding cost of synchronized reserve was $12.58. The price for synchronized reserve in January through March 2012 was $6.06 while the cost was $7.76. Although the price of synchronized reserve rose slightly from Q1 of 2012, the cost rose significantly.

Table 9-18 Mid-Atlantic Dominion Sub-zone weighted synchronized reserve market clearing prices, credits, and MWs: January through March 2013

Year	Month	Weighted Synchronized Reserve Market Clearing Price	Synchronized Reserve Credits	PJM Tier 2 and DSR Scheduled Synchronized Reserve MW	Flexible Synchronized Reserve Added by SCED (MW)	Self Scheduled MW
2013	Jan	$12.48	$1,224,123	68,540	15,270	102
2013	Feb	$3.70	$1,140,543	102,141	41,251	598
2013	Mar	$8.02	$2,250,953	124,863	14,727	0

The RTO Reserve Zone requirement was satisfied by Tier 1 in all but eight hours of January through March 2013. On October 1, 2012, the RFC Synchronized Reserve Zone became the RTO Reserve Zone. The Synchronized Reserve and Primary Reserve Requirements were satisfied by a combination of Tier 1 and non-synchronized reserve in all but 58 hours from January through March 2013. In the 58 hours when synchronized reserve was needed to fill the synchronized reserve and/or primary reserve requirement the maximum clearing price was $128.70 and the weighted average clearing price was $1.41.

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 March 2013, the price of Tier 2 synchronized reserves was 58 percent of the cost. In January through March 2012, the price to cost ratio was 70 percent.

Figure 9-13 Comparison of Mid-Atlantic Dominion Subzone Tier 2 synchronized reserve weighted average price and cost (Dollars per MW): January through March 2013

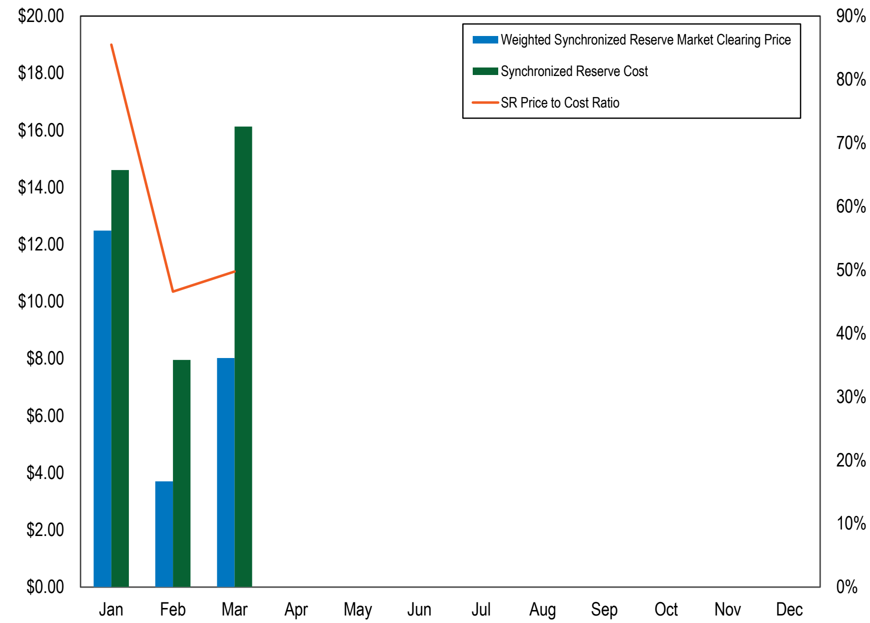


Table 9-19 shows the price and cost history of the Synchronized Reserve Market since 2005.

Table 9-19 Comparison of yearly weighted average price and cost for PJM Synchronized Reserve, January through March 2005 through 2013

Year	Weighted Synchronized Reserve Market Price	Weighted Synchronized Reserve Cost	Synchronized Reserve Price as Percent of Cost
2005 (Jan-Mar)	$13.29	$17.59	76%
2006 (Jan-Mar)	$14.57	$21.65	67%
2007 (Jan-Mar)	$11.22	$16.26	69%
2008 (Jan-Mar)	$10.65	$16.43	65%
2009 (Jan-Mar)	$7.75	$9.77	79%
2010 (Jan-Mar)	$10.55	$14.41	73%
2011 (Jan-Mar)	$10.96	$13.22	83%
2012 (Jan-Mar)	$6.06	$7.76	78%
2013 (Jan-Mar)	$8.07	$12.90	63%

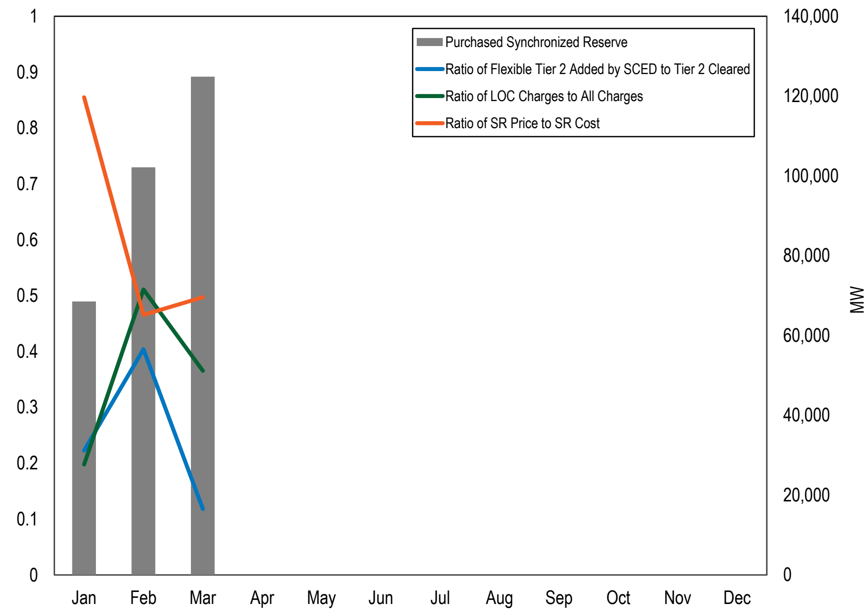
Before shortage pricing the reason for relatively low actual price to cost ratio was the difference in opportunity cost calculated using the forecast LMP and the actual LMP. In addition, the low price to cost ratio was in part a result of out of market purchases of Tier 2 synchronized reserve when PJM dispatchers needed the reserves for reliability reasons (Table 9-18). 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 biasing (a technical term). Negative Tier 1 biasing refers to the manual subtraction from the Tier 1 estimate that the market clearing engines use to determine how much Tier 2 MW to schedule. A negative bias reduces the amount of Tier 1 estimated and therefore increases the amount of inflexible Tier 2 which must be purchased. A negative bias means purchasing more inflexible Tier 2 MW than the market clearing software estimates it needs before the hour. This reduces the likelihood that the IT SCED and/or RT SCED will add flexible Tier 2 MW during the market hour.

PJM can bias the Tier 1 synchronized reserve estimate that the ASO uses when it determines the amount of synchronized reserve to buy. The bias forces the ASO to clear more (or less) inflexible Tier 2 synchronized reserve than it would otherwise procure. Most of the bias adjustments reduce the amount of Tier 1 estimated thereby increasing the amount of inflexible Tier 2 procured. 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 a significant amount of Tier 2 synchronized reserves being paid when they are not needed or when the price is zero. A price of $0 means that the Tier 2 synchronized reserve requirement was determined to be zero because there was enough Tier 1.

From January through March, 2013, a total of 48,867 MWH 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 $294,064.

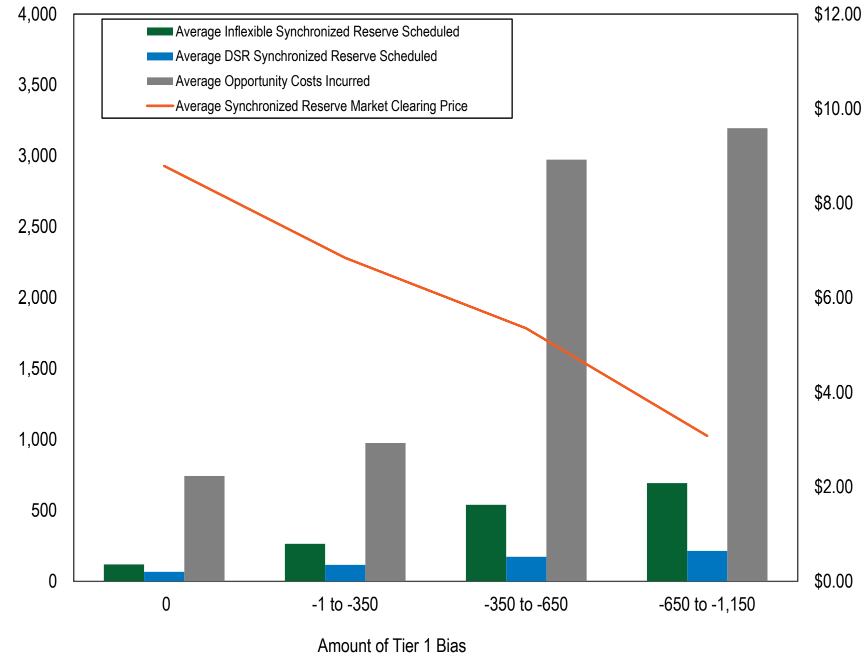
Figure 9-14 Impact of flexible Tier 2 synchronized reserve added by IT SCED and RT SCED to the Mid-Atlantic Dominion Sub-Zone: January through March 2013



Each market clearing engine (ASO, IT SCED, and RT SCED) can have its Tier 1 estimate manually biased. ASO Tier 1 biasing was used in 590 hours. In 585 hours the biasing was negative, ranging from -2,000 MW to -100 MW, with an average of -577 MW. IT SCED Tier 1 biasing was not used for the first quarter of 2013. RT SCED Tier 1 biasing occurred between January 22 and February 1 (with one hour in March 2) for a total of 48 hours, averaging 530 MW. In every hour which RT SCED Tier 1 biasing was used, it was used to add Tier 1 to the estimate, thereby lessening the need to schedule additional Tier 2 synchronized reserve.

PJM gives several reasons for Tier 1 biasing. Sometimes units do not achieve the ramp rate they have bid, sometimes units fail to follow PJM dispatch, sometimes system conditions change rapidly during the hour between a market solution and the actual hour.

Figure 9-15 Impact of Tier 1 Bias the ASO solution on SRMCP, MW Scheduled, and LOC Charges: January – March 2013



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.

History of Spinning Events

Spinning events (Table 9-20) are usually caused by a sudden generation outage or transmission disruption requiring PJM to load synchronized reserve.[32] The

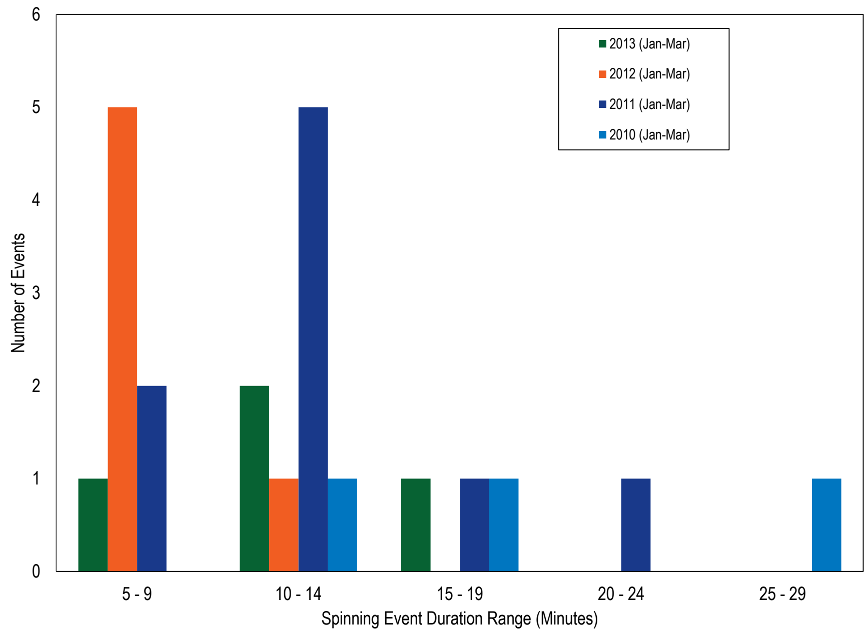
32 See PJM. "Manual 12, Balancing Operations," Revision 27 (December 20, 2012), pp. 36-37.

reserve remains loaded until system balance is recovered. From January 2010 through March 2013, PJM experienced 95 spinning events, or between two and three events per month. Spinning events generally lasted between 7 minutes and 20 minutes with an average length of 11.2 minutes.

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

Figure 9-16 Spinning events duration distribution curve, January through March 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 occurred between January 1, 2013 and March 31, 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.

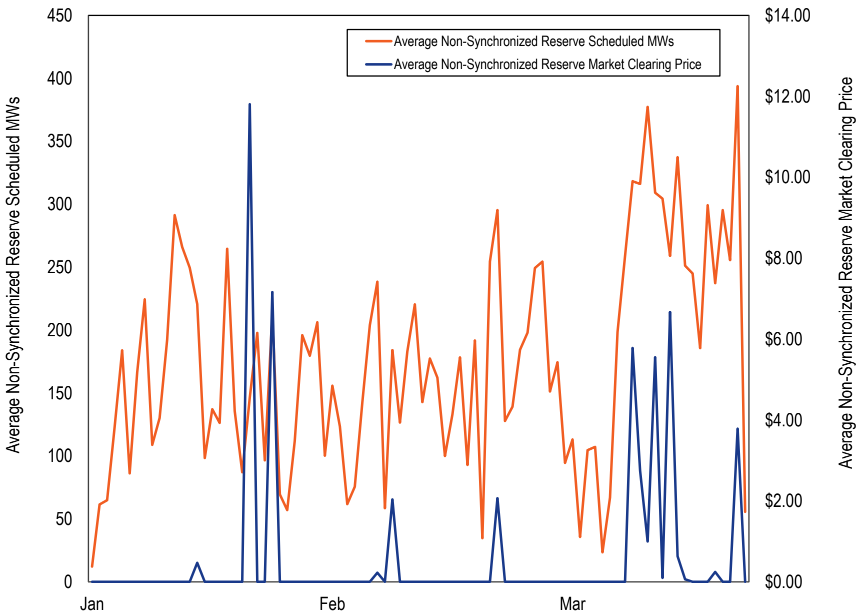
Non-synchronized reserve is reserve MW available within ten minutes but not synchronized to the grid. PJM specifies that 1,300 MW of synchronized reserve must be available in the Mid-Atlantic Dominion Reserve Zone. The remainder can be made up of non-synchronized reserve. Examples of equipment that generally qualify in this category are shutdown run-of-river, pumped hydro, industrial combustion turbines, jet engine/expander turbines, combined cycle and diesels.[33]

Like Tier 1 synchronized reserve PJM calculates the amount of non-synchronized reserve available each hour. The calculation is based upon a unit's startup and notification time, energy ramp rate, and economic minimum. 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 9-17 shows the daily average non-synchronized reserve market clearing price and average scheduled MW. The Mid-Atlantic Dominion Reserve Zone non-synchronized reserve market clearing price was greater than zero in 58 hours (five percent of all hours) from January through March of 2013 with a maximum of $128.70 on January 22, 2013.The non-synchronized reserve market clearing price for the RTO Reserve Zone never cleared for greater than $0.

33 PJM. "Manual 11, Energy & Ancillary Services Market Operations" Revision 59 (April 1, 2013), p. 86.

Figure 9-17 Daily average Non-Synchronized Reserve Market clearing price and MW cleared: January through March 2013



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.[34]

The DASR 30-minute reserve requirements are determined by the reliability region.[35] In the Reliability*First* (RFC) region, reserve requirements are calculated based on historical under-forecasted load rates and generator forced outage rates.[36] 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.

34 PJM uses the terms "supplemental operating reserves" and "scheduling operating reserves" interchangeably.
35 PJM. "Manual 13, Emergency Requirements," Revision 52 (February 1, 2013), pp. 12-13.
36 PJM. "Manual 10, Pre-Scheduling Operations," Revision 27 (February 28, 2013), pp. 18-19.

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.[37] 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 6,817 MW per hour for January through March 2013, a slight decrease from 6,841 MW per hour in 2012.

In January through March, 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 March, 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 March, 2013.

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.[38] 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 March 31, 2013, 13 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.

37 See the *2012 State of the Market Report for PJM*, Volume II, Section 9, "Ancillary Services" at Day Ahead Scheduling Reserve (DASR).
38 PJM. "Manual 11, Emergency and Ancillary Services Operations," Revision 59 (April 1, 2013), p. 144-145.

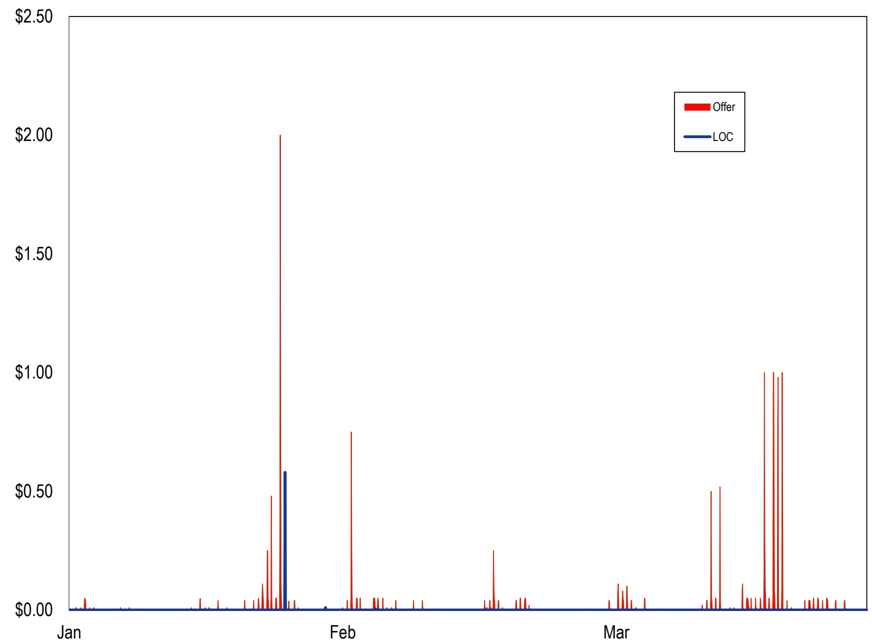
Market Performance

For 90 percent of hours in January through March, 2013, DASR cleared at a price of $0.00 (Figure 9-18). From January through March 2013, the weighted DASR price was $0.01. The highest price was $2.00 on January 24, 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. Most (93 percent) DASR clearing prices consist solely of the offer price. The breakdown of price into offer and LOC is in Figure 9 17.

Table 9-21 PJM Day-Ahead Scheduling Reserve Market MW and clearing prices: January 2011 through March 2013

Year	Month	Average Required Hourly DASR (MW)	Minimum Clearing Price	Maximum Clearing Price	Weighted Average Clearing Price	Total DASR Credits
2011	Jan	6,536	$0.00	$1.00	$0.03	$127,837
2011	Feb	6,180	$0.00	$1.00	$0.02	$61,682
2011	Mar	5,720	$0.00	$1.00	$0.01	$45,885
2011	Apr	5,265	$0.00	$0.05	$0.01	$24,463
2011	May	5,554	$0.00	$25.52	$0.29	$894,607
2011	Jun	7,305	$0.00	$193.97	$2.26	$9,653,815
2011	Jul	8,647	$0.00	$217.12	$4.21	$22,880,723
2011	Aug	7,787	$0.00	$61.91	$0.75	$3,577,433
2011	Sep	6,535	$0.00	$5.00	$0.07	$292,252
2011	Oct	5,874	$0.00	$0.04	$0.00	$3,655
2011	Nov	6,067	$0.00	$0.04	$0.00	$6,155
2011	Dec	6,532	$0.00	$0.21	$0.00	$6,181
2012	Jan	6,944	$0.00	$0.02	$0.00	$604
2012	Feb	6,777	$0.00	$0.02	$0.00	$2,037
2012	Mar	6,180	$0.00	$0.05	$0.00	$5,031
2012	Apr	5,854	$0.00	$0.10	$0.00	$5,572
2012	May	6,491	$0.00	$5.00	$0.05	$226,881
2012	Jun	7,454	$0.00	$156.29	$2.39	$11,422,377
2012	Jul	8,811	$0.00	$155.15	$3.69	$20,723,970
2012	Aug	8,007	$0.00	$55.55	$0.51	$2,601,271
2012	Sep	6,656	$0.00	$7.80	$0.12	$540,586
2012	Oct	6,022	$0.00	$0.04	$0.00	$5,878
2012	Nov	6,371	$0.00	$1.00	$0.02	$75,561
2012	Dec	6,526	$0.00	$0.05	$0.00	$5,975
2013	Jan	6,963	$0.00	$2.00	$0.01	$45,337
2013	Feb	6,957	$0.00	$0.75	$0.00	$20,062
2013	Mar	6,552	$0.00	$1.00	$0.02	$75,071

Figure 9-18 Hourly components of DASR clearing price: January through March 2013



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 9-22)

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 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 March 2013, black start credits were $27.6 million. Black start zonal credits in January through March 2013 ranged from $0.03 per MW in the ATSI zone (total credits: $38,980) to $10.66 per MW in the AEP zone (total credits: $22,352,763). For each zone, Table 9-22 shows black start revenue requirement credits, black start operating reserve credits, and the black start rate (calculated as credits per MW).

Table 9-22 Black start zonal credits for network transmission use: January through March 2013

Zone	Revenue Requirement Credits	Operating Reserve Credits	Black Start Rate ($/MW)
AECO	$136,178		$0.54
AEP	$160,578	$22,192,186	$10.66
AP	$51,913		$0.07
ATSI	$38,980		$0.03
BGE	$2,055,089	$2,500	$3.27
ComEd	$1,048,471		$0.49
DAY	$61,281	$5,530	$0.21
DEOK	$82,925		$0.17
DLCO	$15,085		$0.05
DPL	$147,659	$1,915	$0.40
JCPL	$146,258		$0.26
Met-Ed	$184,402		$0.67
PECO	$344,865	$8,515	$0.46
PENELEC	$138,744		$0.53
Pepco	$75,718		$0.13
PPL	$42,395		$0.06
PSEG	$668,315		$0.71