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.

Regulation matches generation with very short-term changes in load by moving the output of selected resources up and down via an automatic control signal. Regulation is provided, independent of economic signal, by generators with a short-term response capability (less than five minutes) or by demand-side response (DSR). Longer-term deviations between system load and generation are met via primary and secondary reserve and generation responses to economic signals. Synchronized reserve is a form of primary reserve. To provide synchronized reserve a generator must be synchronized to the system and capable of providing output within 10 minutes. Synchronized reserve can also be provided by DSR. The term, Synchronized Reserve Market, refers only to supply of and demand for Tier 2 synchronized reserve. Beginning October 1, 2012 with the implementation of Shortage Pricing, primary reserve is also satisfied by non-synchronized reserve subject to the restriction that at least 50 percent of primary reserve must be synchronized reserve.

The Regulation, Synchronized Reserve, and Non-Synchronized Reserve Markets are cleared, prior to the market hour, and supplementally within the hour, on a real-time basis. The Regulation, Synchronized Reserve, and Non-Synchronized Reserve Markets are cleared and priced interactively with the Energy Market and operating reserve requirements to minimize the cost of the combined products, subject to reactive limits, resource constraints, unscheduled power flows, inter area transfer limits, resource distribution factors, self-scheduled resources, limited fuel resources, bilateral transactions, hydrological constraints, generation requirements and reserve requirements, and prior to the hour assignments for regulation and reserves.

The purpose of the Day-Ahead Scheduling Reserve (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 the market clearing price.[2]

PJM does not provide a market for reactive power, but does ensure its adequacy through member requirements and scheduling. Generation owners are paid according to FERC-approved, reactive revenue requirements. Charges are allocated to network customers based on their percentage of load, as well as to point-to-point customers based on their monthly peak usage.

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 all of 2012.

Table 9-1 The Regulation Market results were not competitive for the first three quarters and were indeterminate for the fourth quarter[3]

	January through September, 2012		October through December, 2012	
Market Element	Evaluation	Market Design	Evaluation	Market Design
Market Structure	Not Competitive		Not Competitive	
Participant Behavior	Competitive		Competitive	
Market Performance	**Not Competitive**	**Flawed**	**To Be Determined**	**To Be Determined**

1 75 FERC ¶ 61,080 (1996).

2 See 117 FERC ¶ 61,331 at P 29 n32 (2006).

3 As Table 9-1 indicates, the Regulation Market results are not the result of the offer behavior of market participants, which was competitive as a result of the application of the three pivotal supplier test. The Regulation Market results are not competitive because the market rules, in particular the calculation of the opportunity cost, resulted in a price greater than the competitive price in some hours, resulted in a price less than the competitive price in some hours, and because the market rules are inconsistent with basic economic logic. The competitive price is the actual marginal cost of the marginal resource in the market. The competitive price in the Regulation Market is the price that would have resulted from a combination of the competitive offers from market participants and the application of the prior, correct approach to the calculation of the opportunity cost. The correct way to calculate opportunity cost and maintain incentives across both regulation and energy markets is to treat the offer on which the unit is dispatched for energy as the measure of its marginal costs for the energy market. To do otherwise is to impute a lower marginal cost to the unit than its owner does and therefore impute a higher or lower opportunity cost than its owner does, depending on the direction the unit was dispatched to provide regulation. If the market rules and/or their implementation produce inefficient outcomes, then no amount of competitive behavior will produce a competitive outcome.

- 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 43 percent of the hours in 2012.[4]
- Participant behavior in the Regulation Market was evaluated as competitive for the year 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 not competitive for the first three quarters, despite competitive participant behavior, because prior changes in market rules, in particular the changes to the calculation of the opportunity cost, resulted in a price greater than the competitive price in some hours, resulted in a price less than the competitive price in some hours, and because the revised market rules are inconsistent with basic economic logic.[5]
- Market performance was evaluated as indeterminate for the fourth quarter, 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 flawed for the first three quarters because while PJM has improved the market by modifying the schedule switch determination, the lost opportunity cost calculation is inconsistent with economic logic and there were additional issues with the order of operation in the assignment of units to provide regulation prior to market clearing.
- Market design was evaluated as indeterminate for the fourth quarter, 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.

4 These TPS results reflect MMU estimates for the period between May 6 and July 21, 2012, when the TPS test was not correctly applied by PJM.

5 PJM agrees that the definition of opportunity cost should be consistent across all markets and should, in all markets, be based on the offer schedule accepted in the market. This would require a change to the definition of opportunity cost in the Regulation Market which is the change that the MMU has recommended. The MMU also agrees that the definition of opportunity cost should be consistent across all markets.

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 22 percent of the hours in 2012.
- 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 prices that reflect marginal costs.
- Market design was evaluated as effective because market power mitigation rules result in competitive outcomes despite high levels of supplier concentration.

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

In 2012, the PJM Regulation Market continued 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, the Ancillary Services Optimizer (ASO). On October 1, 2012, PJM implemented Performance Based Regulation, to comply with FERC Order No. 755.[6] On November 16, 2012, FERC modified the PJM market design that was introduced on October 1, 2012.[7]

Market Structure

- **Supply.** In 2012, 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 3.61 for 2012. This is a 20.3 percent increase over 2011 when the ratio was 3.00.
- **Demand.** The on-peak regulation requirement, as of December 31, 2012, 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. In 2011, the on-peak regulation requirement was equal to 1.0 percent of the forecast peak load for the PJM RTO for the day and the off-peak requirement was equal to 1.0 percent of the forecast valley load for the PJM RTO for the day. The average hourly regulation demand in 2012 was 921 MW (840 MW off peak, and 1,015 MW on peak). This is a 4 MW decrease in the average hourly regulation demand of 925 MW in 2011 (842 MW off peak, and 1,071 MW on peak).

  Of the LSEs' obligation to provide regulation during 2012, 78.6 percent was purchased in the spot market (81.8 percent in 2011), 19.0 percent was self scheduled (15.6 percent in 2011), and 2.5 percent was purchased bilaterally (2.6 percent in 2011).[8]
- **Market Concentration.** In 2012, the PJM Regulation Market had a weighted, average Herfindahl-Hirschman Index (HHI) of 1,735 which is classified as "moderately concentrated."[9] The minimum hourly HHI was 788 and the maximum hourly HHI was 4962.[10] In 2012, 43 percent of hours had one or more pivotal suppliers which failed PJM's three pivotal supplier test (82.1 percent of hours failed the three pivotal supplier test in 2011). The MMU concludes from these results that the PJM Regulation Market in 2012 was characterized by structural market power in 43 percent of the hours.

Market Conduct

- **Offers.** Daily regulation offer prices are submitted for each unit by the unit owner. Owners are required to submit a cost offer along with 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.[11] As of December 31, 2012, there were seven distinct resources (three generation and four demand response) offering performance regulation and following the RegD signal.
- **Price.** The weighted Regulation Market clearing price for the PJM Regulation Market for January through September, 2012 was $14.92 per MWh. This was a decrease of $2.11, or 12.4 percent, from the

6 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."

7 *PJM Interconnection, L.L.C.*, 139 FERC ¶ 61,130 (2012)

8 Due to rounding, percentages might not sum to 100 percent.

9 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.

10 HHI and market share are commonly used but potentially misleading metrics for structural market power. Traditional HHI and market share analyses tend to assume homogeneity in the costs of suppliers. It is often assumed, for example, that small suppliers have the highest costs and that the largest suppliers have the lowest costs. This assumption leads to the conclusion that small suppliers compete among themselves at the margin, and therefore participants with small market share do not have market power. This assumption and related conclusion are not generally correct in electricity markets, like the Regulation Market, where location and unit specific parameters are significant determinants of the costs to provide service, not the relative market share of the participant. The three pivotal supplier test provides a more accurate metric for structural market power because it measures, for the relevant time period, the relationship between demand in a given market and the relative importance of individual suppliers in meeting that demand. The MMU uses the results of the three pivotal supplier tests, not HHI or market share measures, as the basis for conclusions regarding structural market power.

11 See Appendix F "Ancillary Services Markets."

weighted average price for regulation in January through September, 2011. The cost of regulation from January through September, 2012 was $20.59 per MWh. This is an $11.64 (36.1 percent) decrease from the same time period in 2011.

The Regulation Market changed significantly on October 1, 2012, with the introduction of Performance Regulation. For October through December 2012, the weighted average market clearing price was $36.52 per MWh. This is a 148.2 percent increase from the weighted average market clearing price of $14.71 for the same period in 2011. The total cost of regulation from October through December 2012, was $43.86 per MWh. This is a $23.40 per MWh increase (114.3 percent) over the cost of regulation during the same time period of 2011.

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."[12]

Market Structure

- **Supply.** In 2012, 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, 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, the requirement remained at 1,300 MW.
- **Market Concentration.** For all of 2012, the average weighted HHI for cleared synchronized reserve in the Mid-Atlantic Dominion Subzone was 3570 which is classified as highly concentrated. The average weighted cleared Synchronized Reserve Market HHI for the Mid-Atlantic Subzone in 2011 was 2637, which is classified as "highly concentrated."[13] In 2012, 56 percent of hours had a maximum market share greater than 40 percent, compared to 46 percent of hours in 2011.

  In the Mid-Atlantic Subzone, in 2012, 22 percent of hours that cleared a synchronized reserve market had three or fewer pivotal suppliers. In 2011, 63 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 2012 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 $8.02 per MW in 2012, a $3.79 per MW decrease from 2011. The total cost of synchronized reserves per MWh in 2012 was $12.71, a $2.77 decrease (17.9 percent) from the $15.48 cost of synchronized reserve in 2011. The market clearing price was 65 percent of the total synchronized reserve cost per MW in 2012, down from 76 percent in 2011.

  One goal of shortage pricing is to have the synchronized reserve price reflect the total cost of synchronized reserve. Although both price and cost

12 See PJM, "Manual 11, Energy and Ancillary Services Market Operations," Revision 57 (December 1, 2012), p. 74.

13 See Section 2, "Energy Market" at "Market Concentration" for a more complete discussion of concentration ratios and the Herfindahl-Hirschman Index (HHI).

are lower in 2012, the price/cost ratio was high from October through December, 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 2012.

DASR

On June 1, 2008, PJM introduced the Day-Ahead Scheduling Reserve Market (DASR), as required by the RPM settlement.[14] The purpose of this 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.[15] 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 2012, 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 2012, the required DASR was 7.03 percent of peak load forecast, down from 7.11 percent in 2011.

Market Conduct

- **Withholding.** Economic withholding remains an issue in the DASR Market. The direct marginal cost of providing DASR is zero; however, there is an opportunity cost associated with this direct marginal cost. As of December 31, 2012, twelve 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.[16] Units that do not offer have their offers set to zero.
- **DSR.** Demand side resources do participate in the DASR Market, but no demand resource cleared the DASR Market in 2012.

Market Performance

- **Price.** The weighted DASR market clearing price in 2012 was $0.57 per MW. In 2011, the weighted price of DASR was $0.55 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.[17]

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 2012, black start charges were $50.2 million. This is 151 percent higher than 2011, when total black start service charges were $20.0 million. There was substantial zonal variation. Black start zonal charges in 2012 ranged from $0.02 per MW in the ATSI zone (total charges: $119,167) to $3.62 per MW in the AEP zone (total charges: $32,468,706).

Ancillary services costs per MW of load: 2001 - 2012

Table 9-4 shows PJM ancillary services costs for 2001 through 2012 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

14 See 117 FERC ¶ 61,331 (2006).

15 See PJM. "Manual 13: Emergency Operations," Revision 52, (February 1, 2013); pp 11-12.

16 PJM. "Manual 11, Energy and Ancillary Services Market Operations," Revision 57 (December 1, 2012), p. 141.

17 OATT Schedule 1 § 1.3BB.

Operating Reserve; Balancing Operating Reserve; and Synchronous Condensing.

Table 9-4 History of ancillary services costs per MW of Load[18]: 2001 through 2012

Year	Regulation	Scheduling, Dispatch, and System Control	Reactive	Synchronized Reserve	Supplementary Operating Reserve	Total
2001	$0.50	$0.44	$0.22	$0.00	$1.07	$2.23
2002	$0.45	$0.53	$0.21	$0.07	$0.63	$1.90
2003	$0.50	$0.61	$0.24	$0.14	$0.83	$2.32
2004	$0.50	$0.60	$0.25	$0.13	$0.90	$2.38
2005	$0.79	$0.47	$0.26	$0.11	$0.93	$2.57
2006	$0.53	$0.48	$0.29	$0.08	$0.43	$1.81
2007	$0.63	$0.47	$0.29	$0.06	$0.58	$2.02
2008	$0.68	$0.40	$0.31	$0.08	$0.59	$2.06
2009	$0.34	$0.32	$0.37	$0.05	$0.48	$1.56
2010	$0.34	$0.38	$0.41	$0.07	$0.73	$1.93
2011	$0.32	$0.34	$0.42	$0.10	$0.77	$1.95
2012	$0.26	$0.40	$0.43	$0.04	$0.79	$1.92

Conclusion

The MMU continues to conclude that the results of the Regulation Market were not competitive in the first three quarters of 2012.[19] The Regulation Market results were not competitive because the 2008 changes in market rules, in particular the changes to the calculation of the opportunity cost, resulted in a price greater than the competitive price in some hours, resulted in a price less than the competitive price in some hours, and because the revised market rules are inconsistent with basic economic logic and the definition of opportunity cost elsewhere in the PJM tariff. This conclusion is not based on the behavior of market participants, which remains competitive.

PJM agrees that the definition of opportunity cost should be consistent across all markets and should, in all markets, be based on the offer schedule accepted in the market. This would require a change to the definition of opportunity cost in the Regulation Market which is the change that the MMU has recommended. The MMU recommends that the definition of opportunity cost be consistent across all markets.

More importantly for the Regulation Market is that the design of the market was 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 is cause for optimism with respect to 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 DASR Market results were competitive in 2012, 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.

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

19 The *2009 State of the Market Report for PJM* provided the basis for this conclusion. The *2009 State of the Market Report for PJM* summarized the history of the issues related to the Regulation Market. See the *2009 State of the Market Report for PJM*, Volume II, Section 6, "Ancillary Service Markets."

Overall, the MMU concludes that the Regulation Market results were not competitive in the first three quarters of 2012 as a result of the identified market design issues but that although it is not yet possible to reach a definitive conclusion about the new design, there is reason for optimism. The MMU concludes that the Synchronized Reserve Market results were competitive in 2012. The MMU concludes that the DASR Market results were competitive in 2012.

Regulation Market

Throughout 2012, the PJM Regulation Market continued 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.[20] On November 16, 2012, FERC modified the PJM market design that was introduced on October 1, 2012.[21]

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.[22] 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.[23] 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, 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.

As part of the implementation process of the new Regulation Market design, PJM conducted studies that showed that new, fast response technologies could be used, in combination with traditional resources, to reduce the amount of resources needed to meet regulation requirements and thereby reduce the cost of regulation. These studies showed that resources following a fast response signal (RegD) are, up to a point and at a diminishing rate, a substitute for resources following a slow response signal (RegA).

In the study, the rate of substitution between RegA and RegD following resources is dependent on the proportion of RegA to RegD resources employed. The effectiveness (in minimizing ACE) of RegD following resources falls as the proportion of RegD following resources to RegA following resources increases. The PJM Regulation Market, as proposed in its August 15, 2012 filing, seeks to clear an optimal, least cost mix of RegA and RegD following resources, using a single overall clearing price for regulation service.

The clearing of two different resources types in a single market with uniform pricing requires that the two resources be converted into comparable units. A resource following RegA provides regulation service measured in MW of capability and miles of movement per MW of capability. A resource following RegD also provides regulation service, but the amount of regulation service provided is measured in terms of RegA. The conversion of units of RegD into units of RegA occurs through the use of what is termed a benefits factor. The marginal benefits factor describes how much regulation can be provided by the next increment of a RegD resource, measured in terms of equivalent RegA regulation MW. This translation into equivalent RegA MW of regulation is required in order to have an efficient market clearing mechanism with a single price. The marginal benefits factor is based on the physical, engineering characteristics of the system and the resultant relative effectiveness of RegA and RegD resources in meeting the system's need for regulation. The amount of regulation

20 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."

21 *PJM Interconnection, L.L.C.*, 139 FERC ¶ 61,130 (2012)

22 See the *2012 State of the Market Report for PJM*, Appendix F: Ancillary Services, p.1

23 Frequency Regulation Compensation in the Organized Wholesale Power Markets, 137 FERC ¶ 61,064 (2011) ("Order No. 755").

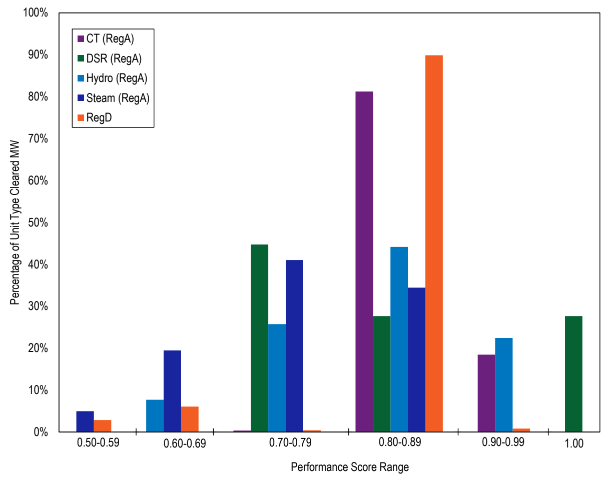
provided by a unit of RegD measured in terms of RegA units depends on these observed system characteristics.

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 October 1, 2012, and December 31, 2012, the lowest actual marginal benefit factor was 2.02. 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.[24] Figure 9-1 shows the performance score distribution of that unit type from October through December, 2012.

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 settlement in PJM's regulation market through the remainder of 2012.

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.[25] Figure 9-1 shows the average performance score by unit type and signal followed.

Figure 9-1 Average performance score grouped by unit type and regulation signal type: October-December 2012



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. Initially, the required regulation was lowered from 1 percent to 0.78 percent of forecast peak load.[26] As of December 31, 2012, the regulation requirement was 0.70 percent of peak load forecast. PJM historically procured regulation MW without performance adjustment. In order to make sure it had enough effective regulation, PJM set its regulation requirement, in terms of regulation MW, equal to 1.0 percent of total expected peak demand. With the introduction of the performance adjustment for regulation MW provided under the new market design, PJM is better able to determine the effective amount of regulation MW it is purchasing from individual resources. The performance adjustment converts raw regulation capability MW into effective regulation capability MW. With a conversion of regulation supply

24 See PJM "Manual 11: Energy & Ancillary Services Market Operations," Revision 57, (December 1, 2012); para 3.2.7, pp 62.

25 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); para. 4.5.6, pp 52.

26 See PJM "Manual 12: Balancing Operations," Revision 27, (December 20, 2012); para 4.4.3, pp 44.

into effective MW, PJM's regulation requirement was similarly converted to units of effective regulation MW, resulting in the reduction in the regulation requirement, measured in effective regulation MW, as a percentage of 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.

The implementation of Shortage Pricing on October 1, 2012 significantly changed the way ancillary services markets are cleared and priced. The Regulation Market is cleared and assignments made hourly through a joint optimization of energy, reserves, and regulation by the Ancillary Service Optimizer (ASO). The ASO performs the regulation three-pivotal supplier test and makes hourly assignment of cleared regulating units. The ASO does not calculate clearing prices. Units that clear and are assigned to regulate for the hour will continue to regulate for that hour but their pricing is recalculated every five minutes by the Locational Pricing Calculator (LPC). Before October 1 the cost of a regulation unit in the regulation market was calculated as the regulation offer plus the lost opportunity cost (as a function of the forecast LMP). After October 1, the adjusted total offer cost of a unit in the regulation market is calculated by the sum of the adjusted regulation performance offer price, the adjusted regulation capability price, and the adjusted LOC. Using the adjusted total offer cost, both the regulation market capability clearing price and the regulation market performance clearing price are computed from the highest adjusted offer for each of those prices among the assigned regulation units. The final regulation market clearing price (calculated in 5-minute intervals and averaged to an hourly RMCP) is the sum of the regulation market capability clearing price (RMCCP) and the regulation market performance clearing price (RMPCP).

Market Structure

Supply

Table 9-5 shows capability, average daily offer and average hourly eligible MW for all hours. The hourly regulation capability increased in 2012, to 9,413 MW from 8,871 MW in 2011. Eligible regulation as a percentage of capability increased by four percent over 2011.

Table 9-5 PJM regulation capability, daily offer[27] and hourly eligible: 2011 and 2012[28]

Period	Regulation Capability (MW)	Average Daily Offer (MW)	Percent of Capability Offered	Average Hourly Eligible (MW)	Percent of Capability Eligible
2011 (Jan-Sep)	8,808	5,970	68%	2,742	31%
2012 (Jan-Sep)	9,413	6,656	71%	3,089	33%
2011 (Oct-Dec)	8,871	6,446	73%	2,680	30%
2012 (Oct-Dec)	8,235	6,224	76%	3,228	39%
2011	8,871	6,083	69%	2,723	31%
2012	9,413	6,551	70%	3,253	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, 2012	Settled MW, 2012	Units Scheduled To Retire Through 2015	Settled MW of Units Scheduled To Retire Through 2015	Percent Of Regulation MW To Retire Through 2015
302	8,225,023	53	206,197	2.51%

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 ($/MW) and performance offer ($/ΔMW). 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

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

28 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.

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 significantly higher than they were prior to October 1, 2012. Since required regulation is now reduced to 0.70 percent of peak load forecast (from one percent of peak load forecast prior to October 1) the overall cost of regulation while high in October and November, returned to historical levels in December. The ratio of price to cost is higher, 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 the end of 2012 the use of the RegD signal was beginning to show wider participation.

In the period from October 1, 2012 through December, 2012, the marginal benefits factor (contribution to ACE correction) for cleared RegD following resources has ranged from 2.2 to 2.7.

If the set of resources that follow RegD were to be considered as a separate market, their HHI from October through December, 2012 would be 8422.

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 October through December, 2012, the average 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; October through December, 2012

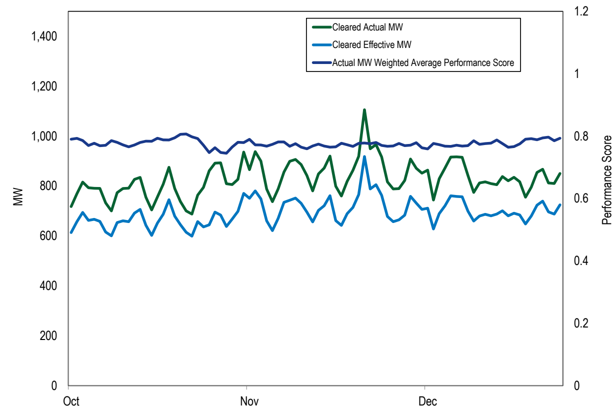
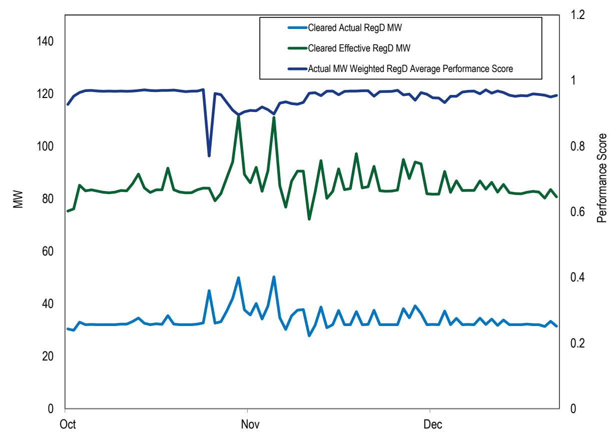


Figure 9-3 Daily average actual cleared MW of regulation, effective cleared MW of regulation, and average performance score; RegD units only; October through December, 2012



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, averaging about 2.6 (Figure 9-3). The average RegD resource performance score was 0.96.

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. 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. Before October 1, the requirement had been 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. 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: Calendar years 2011 and 2012

Month	Average Required Regulation (MW), 2011	Average Required Regulation (MW), 2012	Ratio of Supply to Requirement, 2011	Ratio of Supply to Requirement, 2012
Jan	960	1,005	3.19	3.29
Feb	897	979	3.06	3.45
Mar	823	876	3.02	3.14
Apr	747	826	2.87	3.19
May	786	918	2.84	3.26
Jun	1,037	1,055	2.81	3.21
Jul	1,214	1,246	2.79	2.94
Aug	1,093	1,134	2.83	2.97
Sep	922	941	2.74	3.33
Oct	821	772	3.04	4.28
Nov	855	708	3.01	4.63
Dec	934	701	3.25	5.60

The regulation requirement is designed to ensure that regulation minimizes ACE excursions and time deficits. NERC has establishes several measures of control performance that PJM reports; CPS1, CPS2, and BAAL. PJM's performances as measured by CPS and BAAL standards has not been reduced in spite of the lower regulation requirement.[29]

Market Concentration

Table 9-8 shows Herfindahl-Hirschman Index (HHI) results for 2011 and 2012. The average HHI of 1735 is classified as moderately concentrated.

Table 9-8 PJM cleared regulation HHI: 2011 and 2012

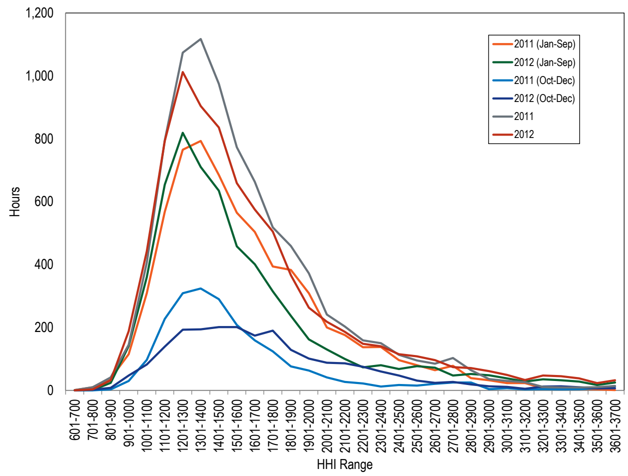
Period	Minimum HHI	Weighted Average HHI	Maximum HHI
2011 (Jan-Sep)	818	1645	3683
2012 (Jan-Sep)	810	1529	4962
2011 (Oct-Dec)	841	1543	4005
2012 (Oct-Dec)	788	1673	4339
2011	818	1630	4005
2012	788	1735	4962

Figure 9-4 compares the 2012 HHI distribution curves with distribution curves for the same periods of 2011 and 2010.

Table 9-9 includes a monthly summary of three pivotal supplier results. In 2012, 43 percent of hours had one or more pivotal suppliers which failed or should have failed PJM's three pivotal supplier test.[30] Pivotal supplier test results improved after October 1, 2012 when Regulation Performance Pricing took effect. The combination of lower required MW (one percent of peak load declining to 0.7 percent of peak load) and higher clearing prices increased the diversity of eligible regulation providers.

The MMU concludes from these results that the PJM Regulation Market in 2012 was characterized by structural market power in 43 percent of the hours.

Figure 9-4 PJM Regulation Market HHI distribution: 2011 and 2012



29 *2012 State of the Market Report for PJM*, Appendix F: Ancillary Services.

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

Table 9-9 Regulation market monthly three pivotal supplier results: 2010, 2011 and 2012[31]

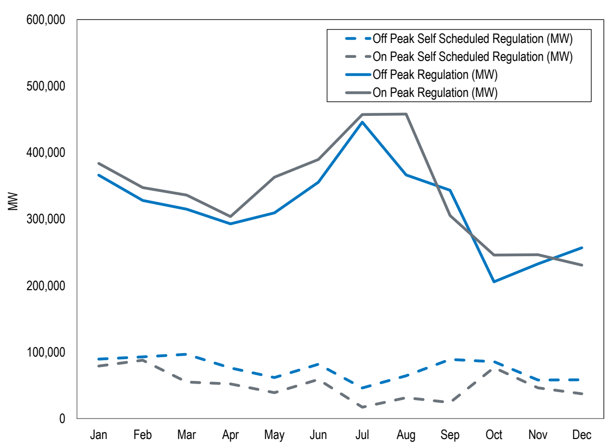
	Percent of Hours Pivotal		
Month	2012	2011	2010
Jan	71%	95%	74%
Feb	67%	93%	70%
Mar	64%	94%	83%
Apr	41%	97%	82%
May	*37%	95%	79%
Jun	*40%	89%	81%
Jul	*13%	89%	75%
Aug	32%	83%	69%
Sep	35%	87%	70%
Oct	19%	67%	47%
Nov	18%	46%	63%
Dec	40%	50%	89%

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).[32]

Figure 9-5 Off peak and on peak regulation levels: 2012



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 during 2012, 78.6 percent was purchased in the spot market (81.8 percent in 2011), 19.0 percent was self scheduled (15.6 percent in 2011), and 2.5 percent was purchased bilaterally (2.6 percent in 2011). (Table 9-10).

Table 9-10 Regulation sources: spot market, self-scheduled, bilateral purchases: 2011 and 2012

Year	Month	Spot Regulation (MW)	Self-Scheduled Regulation (MW)	Bilateral Regulation (MW)	Total Regulation (MW)
2011	Jan	575,975	116,226	16,670	708,871
2011	Feb	462,229	115,250	17,553	595,032
2011	Mar	464,862	107,496	28,107	600,464
2011	Apr	419,449	86,614	18,275	524,338
2011	May	466,780	81,699	15,977	564,456
2011	Jun	588,022	89,368	15,128	692,518
2011	Jul	754,390	39,324	15,647	809,361
2011	Aug	722,598	67,277	14,442	804,318
2011	Sep	566,419	81,607	15,062	663,088
2011	Oct	479,901	113,104	15,063	608,068
2011	Nov	456,942	137,050	16,313	610,304
2011	Dec	475,496	191,618	19,445	686,559
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
2012	Apr	426,564	124,750	21,083	572,397
2012	May	542,585	97,574	17,849	658,008
2012	Jun	582,078	140,769	22,309	745,156
2012	Jul	819,897	63,415	19,711	903,024
2012	Aug	710,715	95,949	17,687	824,350
2012	Sep	518,046	114,495	19,726	652,267
2012	Oct	287,616	162,555	1,539	451,710
2012	Nov	369,075	104,386	5,727	479,188
2012	Dec	385,468	95,903	6,378	487,749

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 October through December every hour cleared some demand resources.

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.

31 The results for May, June and July, 2012 are MMU estimates.

32 See PJM "Manual 28: Operating Agreement Accounting," Revision 57, (December 1, 2012); para 4.2, pp 14.

Market Performance

Price

The weighted average regulation market clearing price for January through September 2012 was $14.92. This is a 12.4 percent decrease from the weighted average market clearing price of $17.03 for the same period in 2011. For October through December 2012, the weighted average market clearing price was $36.52. This is a 148.2 percent increase from the weighted average market clearing price of $14.71 for the same period in 2011. In all of 2012, the weighted average market clearing price was $19.04. This is a 17.5 percent increase from the 2011 weighted average market clearing price of $16.21.

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. Table 9-11 shows monthly average regulation market clearing price, average marginal unit offer price, and average marginal unit LOC. All units chosen to provide regulation received the higher of the clearing price, or the unit's regulation offer plus the individual unit's real-time opportunity cost, based on actual LMP.[33] The purpose of 5-minute pricing using real-time LMPs to shift what had been after-market LOCs into the price so that the price more nearly reflects the full cost of regulation. The implementation of Shortage Pricing and Performance Regulation on October 1, 2012 was followed by several changes of software and market operations procedure between October 1 and December 1. Although regulation prices were historically high from October through December, the December price was closer to the January-September average regulation prices and the ratio of price to cost was at a high level, 89 percent, indicating that the price more closely reflects the cost.

The average capability offer (excluding opportunity cost) of the marginal unit for the PJM Regulation Market during October through December, 2012, was $5.37 per MWh, a decrease from the average offer in October through December 2011 of $11.01 (Table 9-11).

The average opportunity cost of the marginal unit for the PJM Regulation Market in October through December 2012 was $27.67. This is an increase from the average opportunity cost for the marginal unit during the same period of 2012 of $3.47. In the PJM Regulation Market the marginal unit opportunity cost averaged 76 percent of the RMCP. This is a decrease from the October through December, 2011, average of 20 percent.

Figure 9-6 PJM Regulation Market daily weighted average market-clearing price, marginal unit opportunity cost and offer price (Dollars per MWh): 2012

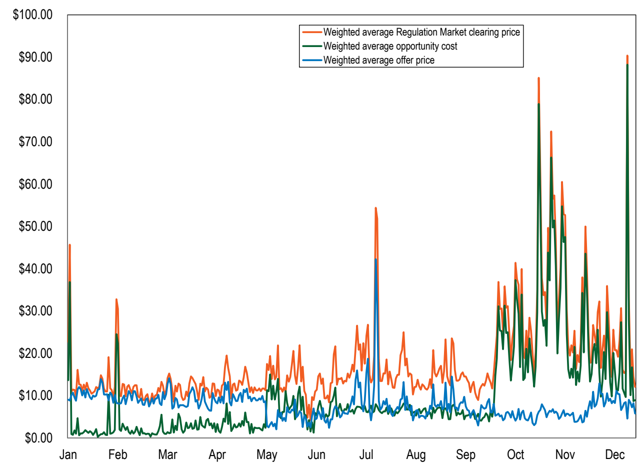


Table 9-11 PJM Regulation Market monthly weighted average market-clearing price, marginal unit opportunity cost and offer price (Dollars per MWh): January through December 2012

Month	Weighted Average Regulation Market Clearing Price	Weighted Average Regulation Marginal Unit Offer	Weighted Average Regulation Marginal Unit LOC
Jan	$13.41	$10.58	$2.70
Feb	$11.89	$8.84	$2.68
Mar	$12.61	$8.82	$3.48
Apr	$13.01	$8.63	$4.07
May	$17.44	$6.52	$9.89
Jun	$14.91	$6.21	$6.94
Jul	$20.73	$6.60	$10.70
Aug	$15.86	$6.50	$7.37
Sep	$14.42	$5.46	$7.16
Oct	$39.80	$5.14	$23.94
Nov	$42.71	$5.58	$32.33
Dec	$27.39	$8.50	$20.19
Average	$20.35	$7.28	$10.95

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

33 See PJM. "Manual 28: Operating Agreement, Accounting," Revision 57, Section 4.2, "Regulation Credits" (December 1, 2012), p. 15. PJM uses estimated opportunity cost to clear the market and actual opportunity cost to compensate generators that provide regulation and synchronized reserve.

Table 9-12 Total regulation charges: 2012 and 2011

Year	Month	Scheduled Regulation (MW)	Total Regulation Charges	Weighted Average Regulation Market Price ($/MW)	Cost of Regulation ($/MW)	Price as Percentage of Cost
2011	Jan	709,121	$20,116,704	$11.77	$28.37	41%
2011	Feb	594,515	$14,551,995	$11.33	$24.48	46%
2011	Mar	599,608	$12,967,924	$11.42	$21.63	53%
2011	Apr	523,565	$15,361,871	$15.56	$29.34	53%
2011	May	566,439	$23,561,565	$17.92	$41.60	43%
2011	Jun	691,666	$27,696,820	$23.38	$40.04	58%
2011	Jul	810,656	$37,375,988	$23.61	$46.11	51%
2011	Aug	803,781	$26,271,979	$19.10	$32.69	58%
2011	Sep	662,237	$17,074,805	$16.07	$25.78	62%
2011	Oct	608,213	$12,437,431	$14.30	$20.45	70%
2011	Nov	637,312	$14,929,690	$17.57	$23.43	75%
2011	Dec	685,895	$11,993,503	$12.48	$17.49	71%
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	$18,285,825	$15.86	$22.18	72%
2012	Sep	652,267	$13,676,276	$14.42	$20.97	69%
2012	Oct	451,710	$22,089,570	$39.80	$48.90	81%
2012	Nov	479,188	$24,908,205	$42.71	$51.98	82%
2012	Dec	487,749	$14,970,348	$27.39	$30.69	89%

Table 9-13 Components of regulation cost: 2012

Month	Scheduled Regulation (MW)	Cost of Regulation Capability ($/MW)	Cost of Regulation Performance ($/MW)	Opportunity Cost ($/MW)	Total Cost ($/MW)
Jan	739,753	$13.41		$4.62	$18.03
Feb	677,217	$11.89		$3.04	$14.93
Mar	641,655	$12.61		$4.70	$17.31
Apr	572,397	$13.01		$2.78	$15.79
May	658,008	$17.44		$7.25	$24.69
Jun	745,156	$14.91		$4.12	$19.03
Jul	903,024	$20.73		$11.64	$32.37
Aug	824,350	$15.88		$6.30	$22.18
Sep	652,267	$14.43		$6.54	$20.97
Oct	451,710	$30.90	$8.95	$9.05	$48.90
Nov	479,188	$36.58	$6.18	$9.22	$51.98
Dec	487,749	$21.23	$6.20	$3.26	$30.69

Table 9-14 Comparison of average price and cost for PJM Regulation, 2006 through 2012

Period	Weighted Regulation Market Price ($/MW)	Weighted Regulation Market Cost ($/MW)	Regulation Price as Percent Cost
2006	$32.69	$44.98	73%
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	$16.21	$29.28	55%
2012	$20.35	$26.41	77%

Table 9-12 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 2012 than it was 2011.

Both regulation prices and costs rose significantly after the implementation of Performance Regulation on October, 1, 2012 (Table 9-12). In December, however, after a software change, the total cost of regulation dropped. Although prices remain high, significantly fewer MW are cleared. Also, since LOC costs that had been paid at settlements time are now shifted into the real-time price calculation, the ratio of price to cost is the highest it has ever been at 89 percent in December.

Primary Reserve

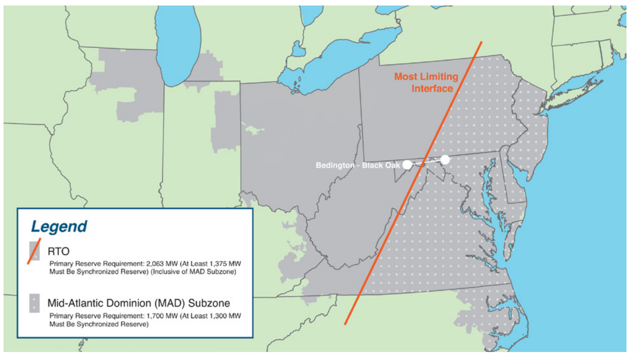
Reserve is generating capability that is standing by ready for service if an unforeseen event causes a sudden need for it. The need can be short-term and critical in the event of a disturbance or generator outage or longer term. NERC defines such losses and defines reporting requirements in "NERC Performance Standard BAL-002-0, Disturbance Control Performance." PJM defines its obligation in M-12[34]. 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 more restrictively as energy available within 10 minutes. Historically PJM has further restricted this by specifying that the energy be on-line and synchronized. This excluded some units (such as hydro and CT units) which could deliver energy within 10 minutes from a shutdown state because shutdown units were considered less reliable. PJM now allows units in a shutdown state to satisfy the primary reserve requirement. PJM still retains a synchronized reserve requirement.

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

Requirements

PJM must satisfy 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 must be on-line and synchronized to the grid (Figure 9-7).

Figure 9-7 PJM RTO primary reserve requirement: October through December 2012



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 9-7. 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.[35]

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 as optimized by the Ancillary Services Optimizer (ASO). 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 ensure their least total price (Figure 9-8). The components of the Mid-Atlantic Dominion Primary Reserve Zone are Tier 1 MW 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).

Figure 9-8 Components of Mid-Atlantic Sub-Zone Primary Reserve (Daily Averages): October through December, 2012

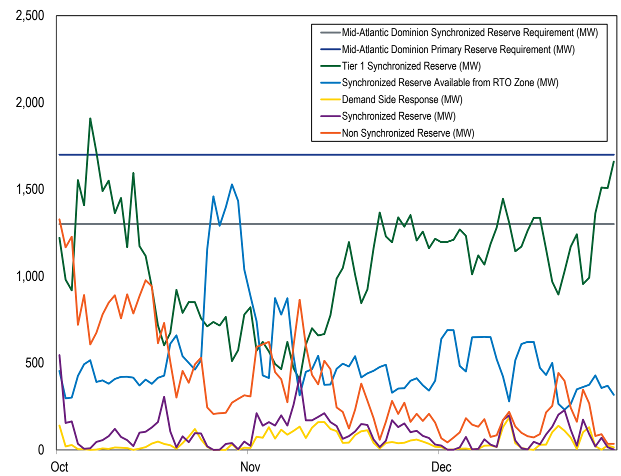


Figure 9-8 shows that Tier 1 Synchronized Reserve remains the major contributor to the reserve requirements. Synchronized reserve available inside the sub-zone from the RTO Zone is also a major contributor. Both of these components usually have a price of $0.00 unless a Tier 2 Synchronized Reserve or Non-Synchronized Reserve market is cleared in the RTO Zone. Non-synchronized reserve is the next most important component of primary reserve. Although it is more often a component of the primary reserve it clears a separate market less frequently because (like DASR) it is available without re-dispatch from CTs and some hydro units. Finally synchronized reserve is dispatched usually at an optimized clearing price as calculated by the LPC.

35 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 57 (December 1, 2012), p. 74.

The ASO must satisfy the primary reserve requirement and the synchronized reserve requirement subject to the constraint that at least 1,300 MW of the 1,700 MW required for primary reserve must be synchronized reserve. In this effort it will select first Tier 1 synchronized reserve which is higher quality than non-synchronized reserve and is priced at $0.00. When all Tier 1 has been identified, if it is enough to satisfy the 1,300 MW synchronized reserve requirement (which it was in about 57 percent of hours in the Mid-Atlantic Dominion Subzone), then ASO begins to assign non-synchronized reserve priced at $0.00. If it is not enough to satisfy the 1,300 MW synchronized reserve requirement, then synchronized reserve and non-zero priced non-synchronized reserve are scheduled at a price dictated by the optimized supply curve. Non-synchronized reserve can often be scheduled at zero price but when scheduled it is constrained to remain off-line and available for the hour. As LMPs rise this could involve LOC. ASO will always choose synchronized reserve over equally priced non-synchronized reserve. In 159 hours between October 1 and December 31, 2012 the Non-Synchronized Reserve Market cleared at greater than $0.00. Figure 9-8 shows that 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.

Geography

As can be seen from Figure 9-7, the geography of the Synchronized Reserve Market has changed with Shortage Pricing. The former Southern Zone (Dominion) and RFC zone are now merged into the RTO Zone. Within the RTO Zone the Mid-Atlantic Dominion Sub-zone is defined by the most restrictive interface to the RTO and includes the former Mid-Atlantic Zone and Dominion.

Operation

In addition to the geographic changes, the market solution methodology changed significantly.[36] Reserves, regulation, and energy are jointly optimized and committed by the new Ancillary Services Optimizer (ASO) 60 minutes before the hour based on least cost using the LMP forecast. No price is calculated by the ASO. In addition to the ASO an Intermediate Term Security Constrained Economic Dispatch (IT SCED) runs with a one to two hour look-ahead optimizing a joint energy and reserves solution for every 15 minute period, commits incremental energy resources (the energy three-pivotal supplier test is run by the IT-SCED), and recommends incremental reserve resources which can be committed by PJM dispatch.

In addition, a Real-Time Security Constrained Economic Dispatch (RT SCED) joint optimizer with a 10-20 minute look-ahead uses the current state estimator solution and forecasts the load during its look-ahead period. Using its calculated Tier 1 and available (flexible) Tier 2 RT SCED redispatches energy and reserves among on-line dispatchable reserves (known as flexible reserves) to minimize the total cost of energy and reserves (both synchronized reserves and non-synchronized reserves).

Finally, a Locational Pricing Calculator (LPC) runs every five minutes and provides real-time pricing based on the currently approved RT-SCED solution. The hourly market clearing price is the simple average of each five-minute LPC-calculated price. According to PJM "In general, re-allocating reserve assignments to where they are most economic allows the most inexpensive generating capacity available to serve load while

36 See the *2012 State of the Market Report for PJM*, Volume II, Ancillary Service Markets Appendix, "Synchronized Reserve Market Clearing" for a more detailed description of the clearing methodology.

the more expensive online generators with lower opportunity costs provide reserves."[37]

Shortage Pricing Penalty Factors

The IT SCED, RT SCED, and LPC contain embedded penalty factors designed to allow them to optimally redispatch flexible reserve resources between energy and reserve and to cap their merit order price at the penalty level for any/all locations where that shortage exists (Table 9-15). The penalty factor will increase each year and remain under review to ensure they allow PJM operators to utilize fully all system assets and they accurately reflect the value of each product and location under shortage conditions.

Table 9-15 Shortage Pricing penalty factors: June 2012 through May 2016

Start Date	End Date	Synchronized Reserve Penalty Factor ($/MWh)	Non-Synchronized Reserve Penalty Factor ($/MWh)
October 1, 2012	May 31, 2013	$250	$250
June 1, 2013	May 31, 2014	$400	$400
June 1, 2014	May 31, 2015	$550	$550
June 1, 2015		$850	$850

When a shortage occurs for a specific reserve product (RTO synchronized, RTO non-synchronized reserves, Mid-Atlantic Dominion synchronized, and/or Mid-Atlantic Dominion non-synchronized reserves) merit order prices for the product/location will be capped at the penalty factor for the duration of the shortage event. If warranted, the resource will be compensated at settlement time for its true cost for providing service. From October through December, 2012 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. As with the former RFC Zone, deliverability across the most limiting constraint (currently Bedington-Black Oak) requires that the RTO Zone maintain a subzone. What had been the Mid-Atlantic subzone before October 1, 2012 is now called the Mid-Atlantic Dominion sub-zone. The Synchronized Reserve requirement remains the same as it did for the previous Mid-Atlantic sub-zone, 1,300 MW. The primary reserve requirements of the new Mid-Atlantic Dominion sub-zone are now 1,700 MW.

PJM has established the RTO Synchronized Reserve Zone hourly requirement to be 150 percent of the largest contingency or 2,063 MW. This requirement can be changed in any hour when conditions (such as outages or maintenance) necessitate. These changes to the Synchronized Reserve requirement (sometimes called double spinning) are detailed below under "Demand." Since Shortage Pricing, PJM has declared the right to create additional zones or sub-zones within the synchronized reserve market with suitable notification of PJM stakeholders.[38]

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 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.

Shortage Pricing introduced another product and market: Non-Synchronized Reserve that can be used to fulfill the Primary Reserve requirement in both the RTO Synchronized Reserve Zone and the Mid-Atlantic Dominion subzone subject to the limitation that at least 50 percent of primary reserve be synchronized.

Market Structure

Supply

For 2012, 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

37 See "Shortage Pricing Update," <http://www.pjm.com/sitecore%20modules/web/~/media/committees-groups/committees/mrc/20121214-shortage/20121214-shortage-pricing-update.ashx>, (December 14, 2012).

38 See PJM, "Manual 11, Energy and Ancillary Services Market Operations," Revision 57 (December 1, 2012), p. 74.

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 2012 over 2011 (from 982,434 MW to 737,951 MW). The DSR share of the total Synchronized Reserve Market increased from 17.7 percent in 2011 to 29.8 percent in 2012. Demand side resources satisfied 100 percent of the Tier 2 Synchronized Reserve market in 5.0 percent of hours in 2012 compared to 6.6 percent of hours in 2011. 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 1.4 for the Mid-Atlantic Dominion Subzone.[39] This is a 29.6 percent increase from 2011 when the ratio was 1.08. Much of the required synchronized reserve is supplied from on-line (Tier 1) synchronized reserve resources. The ratio of offered and eligible synchronized reserve to the required Tier 2 for all cleared Tier 2 hours in 2012 was 5.1 for the Mid-Atlantic Dominion Subzone. This is a 70 percent increase from 2011 when the ratio was 3.00. 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 2011 metric. For the RTO Zone the offered and 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 2012, in the RTO Synchronized Reserve Zone a Synchronized Reserve Market was cleared in two percent of hours. From January through September 2012 in the Mid-Atlantic Subzone a Tier 2 Synchronized Reserve Market was cleared in 69 percent of hours at an average of 448 MW. Between October and December in the Mid-Atlantic Dominion Subzone, a Tier 2 synchronized reserve market was cleared in 43 percent of hours, averaging 305 MW. For all of 2012, in the Mid-Atlantic/Mid-Atlantic Dominion Subzone, a Tier 2 synchronized reserve market was cleared in 62 percent of hours with 429 MW cleared, on average. Note that there is more Tier 1 MW available in the Mid-Atlantic Dominion Subzone after October, 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 set to 100 percent.

As of December 31, 2012, 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 9-16 Synchronized Reserve Market required MW, RTO Zone and Mid-Atlantic Dominion Subzone, December 2008 through December 2012

Mid-Atlantic Dominion Subzone			RTO Synchronized Reserve Zone		
From Date	To Date	Required MW	From Date	To Date	Required MW
May 10, 2008	May 8, 2010	1,150	May 10, 2008	Jan 1, 2009	1,305
May 8, 2010	Jul 13, 2010	1,200	Jan 1, 2009	Mar 15, 2010	1,320
July 13, 2010	Dec 31, 2012	1,300	Mar 15, 2010	Nov 12, 2012	1,350
			Nov 12, 2012	Dec 31, 2012	1,375

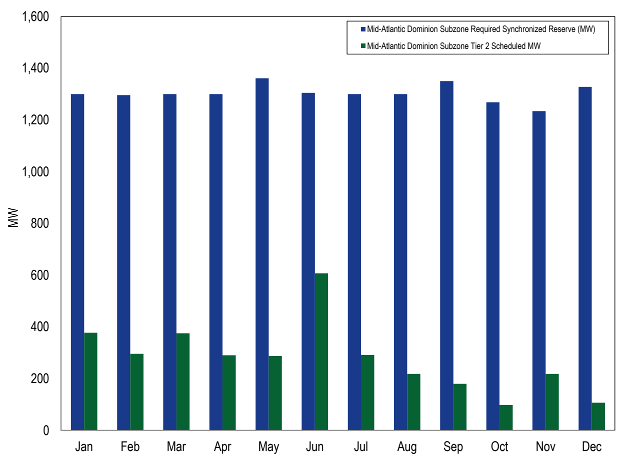
The market demand for Tier 2 synchronized reserve in the Mid-Atlantic Dominion sub-zone is determined by subtracting the amount of forecast Tier 1 synchronized reserve available plus the amount of Tier 1 available from the RTO Zone across the most limiting constraint (currently Bedington-Black Oak) from 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.

39 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.

Exceptions to this requirement can occur when grid maintenance or outages change the largest contingency. The requirement in the Mid-Atlantic Subzone was raised to 1,700 MW for several hours in May and June. The requirement in the Mid-Atlantic Subzone was also raised to 1,350 MW for several hours in May. The requirement in the Mid-Atlantic Subzone was raised to 1,716 MW from September 24 through 28. A generator outage changed the requirement to 1,175 MW from October 24 through November 10. Another outage changed the requirement to 1,220 MW from November 10 through November 19.

Figure 9-9 shows the average monthly synchronized reserve required and the average monthly Tier 2 synchronized reserve MW scheduled during January through December 2012, for the Mid-Atlantic Dominion Synchronized Reserve Market.

Figure 9-9 Mid-Atlantic Dominion Synchronized Reserve Subzone monthly average synchronized reserve required vs. Tier 2 scheduled MW: January through December 2012



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 October through December 2012, the RTO Synchronized Reserve Zone cleared a Tier 2 Synchronized Reserve Market in 46 (2.1 percent) hours with an average SRMCP of $4.46. The Mid-Atlantic Dominion Subzone cleared a separate Tier 2 market in 43 percent of all hours during October through December, 2012 at a weighted SRMCP of $11.99.

For all of 2012, the Mid-Atlantic/Mid-Atlantic Dominion Sub-zone cleared a Tier 2 Synchronized Reserve Market in 62.5 percent of all hours at a weighted SRMCP of $8.02.

The actual synchronized reserve requirement for the Mid-Atlantic Subzone for January through September 2012 was usually 1,300 MW. For the Mid-Atlantic Dominion Subzone from October through December 2012 the requirement was also 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 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.[40] 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 September 2012 for the Mid-Atlantic Subzone was 3202, which is defined as highly concentrated. The HHI for the Mid-Atlantic Dominion Subzone from October through December 2012 was 4672, which is defined as highly concentrated. For all of 2012 the HHI for the Mid-Atlantic/Mid-Atlantic Dominion Subzone was 3570 which is highly concentrated. The HHI for the Mid-Atlantic Subzone for 2011 was 2637. The largest hourly market share was 100 percent and 56 percent of all hours had a maximum market share greater than or equal to 40 percent (compared to 46 percent of all hours in 2011). Looking at flexible unit sector of the synchronized reserve market between October and December, 2012, the hourly average HHI (all hours in which a market was cleared

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

and flexible units were part of the market) was 3651. For units comprising the inflexible sector the HHI was 1185.

In October through December, 2012, 17 percent of hours in the Mid-Atlantic Dominion Subzone failed the three pivotal supplier test (Table 9-17). For all of 2012, 22 percent of hours failed the three pivotal supplier test. For 2011, 63 percent of hours failed the three pivotal supplier test. 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 9-17 Synchronized Reserve market monthly three pivotal supplier results: 2010, 2011 and 2012

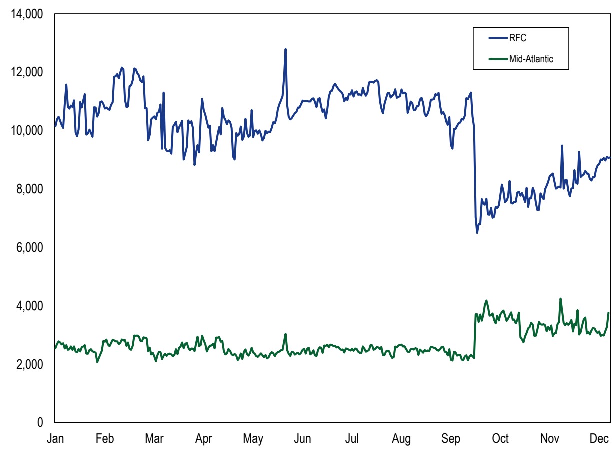
Month	2012 Percent of Hours Pivotal	2011 Percent of Hours Pivotal	2010 Percent of Hours Pivotal
Jan	45%	92%	64%
Feb	40%	99%	49%
Mar	38%	74%	65%
Apr	33%	83%	31%
May	15%	46%	45%
Jun	29%	14%	10%
Jul	10%	19%	23%
Aug	3%	25%	18%
Sep	4%	56%	17%
Oct	9%	73%	54%
Nov	17%	84%	83%
Dec	25%	88%	40%

Market Conduct

Offers

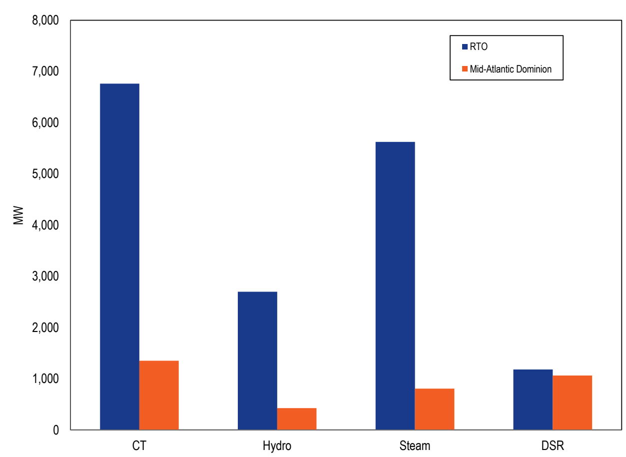
Daily cost based offer prices are submitted for each unit by the unit owner, and PJM adds opportunity cost calculated using the average of 5-minute LMPs, which together comprise the total offer for each unit to the Synchronized Reserve Market. The synchronized reserve offer made by the unit owner is 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 9-10 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 9-10 Tier 2 synchronized reserve average hourly offer volume (MW): October through December 2012



Synchronized reserve is offered by steam, CT, hydroelectric and DSR resources. Figure 9-11 shows average offer MW volume by market and unit type.

Figure 9-11 Average daily Tier 2 synchronized reserve offer by unit type (MW): October through December 2012



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 October through December 2012, DSR was 36 percent of all cleared Tier 2 synchronized reserves, compared to 23 percent for the same period in

2011. In 3.5 percent of the hours in which synchronized reserve was cleared, all cleared MW were DSR (Table 9-18). In the hours when all cleared MW were DSR, the simple average SRMCP was $0.94. The simple average SRMCP for all cleared hours was $9.60.

Table 9-18 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: January through December 2010, 2011, 2012

Year	Month	Average SRMCP	Average SRMCP when all cleared synchronized reserve is DSR	Percent of cleared hours all synchronized reserve is DSR
2010	Jan	$5.84	$2.03	4%
2010	Feb	$5.97	$0.10	1%
2010	Mar	$8.45	$2.01	6%
2010	Apr	$7.84	$1.86	17%
2010	May	$9.98	$1.68	15%
2010	Jun	$9.61	$0.74	9%
2010	Jul	$16.30	$0.79	7%
2010	Aug	$11.17	$0.93	12%
2010	Sep	$10.45	$1.15	12%
2010	Oct	$8.21	$1.06	8%
2010	Nov	$9.59	$0.36	1%
2010	Dec	$12.49	$0.88	4%
2011	Jan	$10.75	$0.10	0%
2011	Feb	$10.91	NA	0%
2011	Mar	$11.34	$2.04	2%
2011	Apr	$16.07	$1.84	10%
2011	May	$10.59	$1.71	14%
2011	Jun	$13.41	$1.18	10%
2011	Jul	$16.99	$0.62	6%
2011	Aug	$10.62	$0.78	7%
2011	Sep	$10.97	$1.73	15%
2011	Oct	$9.65	$1.18	4%
2011	Nov	$10.39	$0.71	3%
2011	Dec	$10.04	$2.24	1%
2012	Jan	$6.25	$1.71	11%
2012	Feb	$5.37	$1.78	24%
2012	Mar	$6.55	$1.40	6%
2012	Apr	$6.62	$0.91	4%
2012	May	$8.24	$0.54	2%
2012	Jun	$4.25	$0.43	1%
2012	Jul	$14.92	$0.10	0%
2012	Aug	$5.63	$0.60	1%
2012	Sep	$5.72	$1.23	2%
2012	Oct	$16.15	$1.69	2%
2012	Nov	$11.44	$0.72	4%
2012	Dec	$5.06	$0.40	5%

Market Performance

Price

Figure 9-12 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 9-19 shows the monthly weighted average SRMCP, credits, and MW for the Mid-Atlantic Dominion subzone. The weighted average price for synchronized reserve in the Mid-Atlantic Dominion Subzone in 2012 was $8.02 while the corresponding cost of synchronized reserve was $12.71. Both price and cost are lower than in 2011, when price was $11.81 and cost was $15.48.

Table 9-19 Mid-Atlantic Dominion Sub-zone weighted synchronized reserve market clearing prices, credits, and MWs: 2012

Month	Weighted Synchronized Reserve Market Clearing Price	Synchronized Reserve Credits	PJM Scheduled MW	PJM Added MW	Self Scheduled MW
Jan	$6.25	$911,823	229,958	12,604	48,393
Feb	$5.37	$676,438	165,304	9,255	36,819
Mar	$6.55	$827,316	238,999	5,126	43,546
Apr	$6.62	$519,409	214,213	4,527	857
May	$8.24	$1,323,561	162,029	10,177	32,673
Jun	$4.25	$926,120	308,701	8,833	62,627
Jul	$14.92	$2,085,816	182,230	24,704	10,497
Aug	$5.63	$1,063,661	117,050	22,156	26,030
Sep	$5.72	$1,027,975	128,290	3,363	1,175
Oct	$16.15	$2,238,592	94,866	NA	7,204
Nov	$11.44	$3,719,841	175,093	NA	974
Dec	$5.06	$1,034,280	84,734	NA	935
Total	$8.02	$16,354,832	2,101,467	100,745	271,730

The RFC Synchronized Reserve requirement was satisfied by Tier 1 in all but six hours of January through September 2012. 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 46 hours from October 1, 2012 through December 31, 2012. In the 46 hours when synchronized reserve was needed to fill the synchronized reserve and/or primary reserve requirement the maximum clearing price was $29.16 and the average clearing price was $4.46.

The Southern Synchronized Reserve Zone cleared a market in 94 hours of January through September 2012 with a weighted average clearing price of $20.47. The Southern Synchronized Reserve Zone was merged into the Mid-Atlantic Dominion Reserve Sub-Zone on October 1, 2012.

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 2012, the price of Tier 2 synchronized reserves was 63 percent of the cost.

Figure 9-12 Comparison of Mid-Atlantic Dominion Subzone Tier 2 synchronized reserve weighted average price and cost (Dollars per MW): January through December 2012

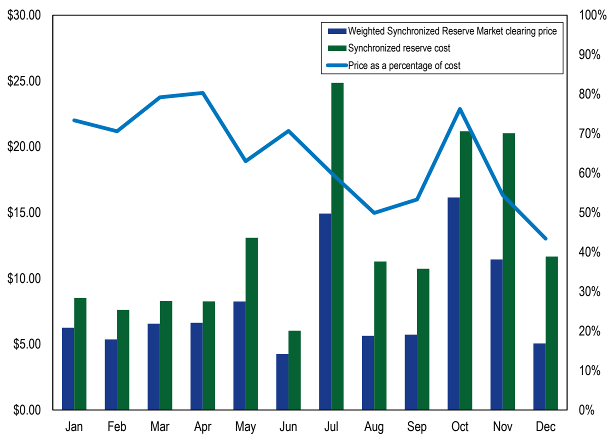


Table 9-20 shows the price and cost history of the Synchronized Reserve Market since 2005.

Table 9-20 Comparison of yearly weighted average price and cost for PJM Synchronized Reserve, 2005 through 2012

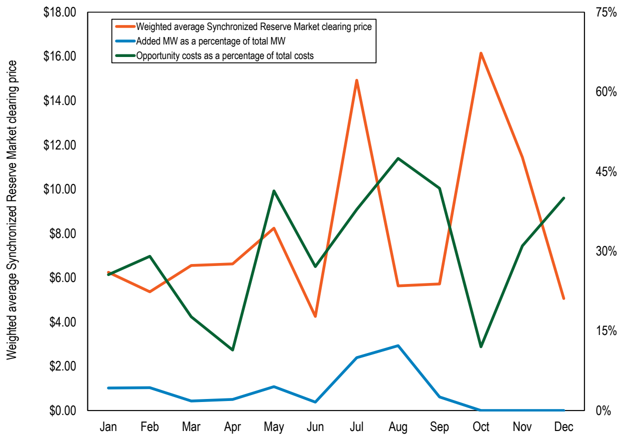
Year	Simple Average Synchronized Reserve Market Price	Weighted Average Synchronized Reserve Market Price	Weighted Average Synchronized Reserve Cost	Synchronized Reserve Price as Percent of Cost
2005	$10.89	$13.29	$17.59	76%
2006	$10.67	$14.57	$21.65	67%
2007	$11.57	$11.22	$16.26	69%
2008	$7.76	$10.65	$16.43	65%
2009	$6.58	$7.75	$9.77	79%
2010	$8.49	$10.55	$14.41	73%
2011	$9.48	$11.81	$15.48	76%
2012	$6.73	$8.02	$12.71	63%

The primary reason for the relatively low actual price to cost ratio is the difference in opportunity cost calculated using the forecast LMP and the actual LMP. In addition, the low price to cost ratio is in part a result of out of market purchases of Tier 2 synchronized reserve when PJM dispatchers need the reserves for reliability reasons (Table 9-13). This practice is changing as a result of shortage pricing. The percentage of settled Tier 2 MW that was added by PJM dispatchers from January through September 2012, after market clearance was 6.4 percent (Table 9-21) (it was 3.2 percent in January through September 2011, 5.2 percent in January through September 2010, 11.6 percent in January through September 2009, and 68.8 percent in January through September 2008).

Table 9-21 Tier 2 synchronized reserve purchases by month for the Mid-Atlantic Dominion Subzone: 2012

Month	Added MW	Self Scheduled MW	Tier 2 Plus DSR Cleared MW
Jan	12,580	47,259	231,919
Feb	9,035	35,176	162,598
Mar	5,126	42,423	240,465
Apr	4,527	1,249	209,288
May	10,177	32,293	162,211
Jun	7,060	63,007	310,072
Jul	23,971	10,307	181,155
Aug	22,536	22,800	117,611
Sep	3,363	1,175	126,659
Oct	NA	7,204	94,866
Nov	NA	974	175,093
Dec	NA	935	84,734

Figure 9-13 Impact of Tier 2 synchronized reserve added MW to the Mid-Atlantic Dominion Sub-Zone: 2012



Tier 1 bias means the manual subtraction from (or addition to) the Tier 1 estimate that the market software uses to determine how much Tier 2 MW to buy. In 2010, PJM significantly increased its use of Tier 1 bias in market solutions. By subtracting from the estimated Tier 1 MW, PJM Market Operations forces the market software to purchase more Tier 2 MW than it estimates it needs. This reduces the need for PJM Dispatch to add Tier 2 MW after market clearance but means purchasing more Tier 2 MW than the market clearing software estimates it needs. There are 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.

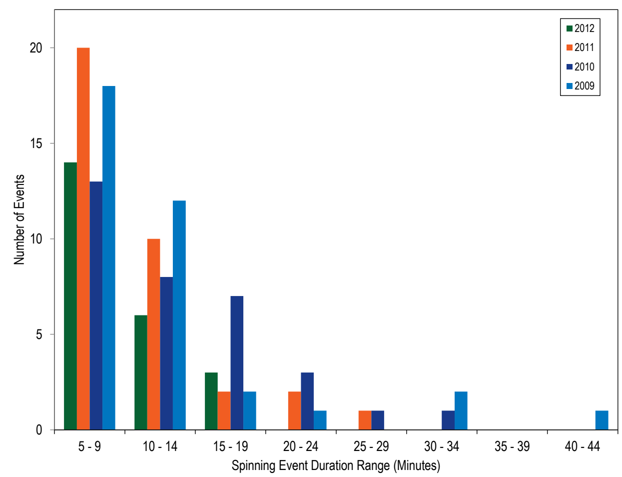
Beginning with Shortage Pricing on October 1, 2012, PJM expanded its use of biasing. Tier 1 biasing can be applied to the intermediate term SCED solution, or the real time SCED solution, to the ASO solution. RT SCED Tier 1 biasing occurred between October 19 and October 26 for a total of 97 hours averaging 220 MW of bias. IT SCHED Tier 1 biasing was used 383 hours between October 19 and December 2 with an average bias of 519 MW. ASO Tier 1 biasing was used 152 hours between November 10 and December 23 with an average ASO Tier 1 bias of 364 MW.

The MMU recommends that PJM define explicit and transparent rules for calculating available Tier 1 MW and for its use of biasing during any phase of the market solution. Additionally, the MMU recommends that PJM publish these rules in Manual 11: Energy and Ancillary Services Market Operations, and associate each instance of biasing with a rule.

History of Spinning Events

Spinning events (Table 9-22) are usually caused by a sudden generation outage or transmission disruption requiring PJM to load synchronized reserve.[41] The reserve remains loaded until system balance is recovered. From January 2009 through December 2012, PJM experienced 127 spinning events, or almost three events per month. Spinning events generally lasted between 7 minutes and 20 minutes with an average length of 11.4 minutes, although several events have lasted longer than 30 minutes.

Figure 9-14 Spinning events duration distribution curve, 2009 to 2012



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

Table 9-22 Spinning Events, January 2009 through December 2012

Effective Time	Region	Duration (Minutes)	Effective Time	Region	Duration (Minutes)	Effective Time	Region	Duration (Minutes)	Effective Time	Region	Duration (Minutes)
JAN-17-2009 09:37	RFC	7	FEB-18-2010 13:27	Mid-Atlantic	19	JAN-11-2011 15:10	Mid-Atlantic	6	JAN-03-2012 16:51	RFC	9
JAN-20-2009 17:33	RFC	10	MAR-18-2010 11:02	RFC	27	FEB-02-2011 01:21	RFC	5	JAN-06-2012 23:25	RFC	8
JAN-21-2009 11:52	RFC	9	MAR-23-2010 20:14	RFC	13	FEB-08-2011 22:41	Mid-Atlantic	11	JAN-23-2012 15:02	Mid-Atlantic	8
FEB-18-2009 18:38	Mid-Atlantic	10	APR-11-2010 13:12	RFC	9	FEB-09-2011 11:40	Mid-Atlantic	16	MAR-02-2012 19:54	RFC	9
FEB-19-2009 11:01	RFC	6	APR-28-2010 15:09	Mid-Atlantic	8	FEB-13-2011 15:35	Mid-Atlantic	14	MAR-08-2012 17:04	RFC	6
FEB-28-2009 06:19	RFC	5	MAY-11-2010 19:57	Mid-Atlantic	9	FEB-24-2011 11:35	Mid-Atlantic	14	MAR-19-2012 10:14	RFC	10
MAR-03-2009 05:20	Mid-Atlantic	11	MAY-15-2010 03:03	RFC	6	FEB-25-2011 14:12	RFC	10	APR-16-2012 00:20	Mid-Atlantic	9
MAR-05-2009 01:30	Mid-Atlantic	43	MAY-28-2010 04:06	Mid-Atlantic	5	MAR-30-2011 19:13	RFC	12	APR-16-2012 11:18	RFC	8
MAR-07-2009 23:22	RFC	11	JUN-15-2010 00:46	RFC	34	APR-02-2011 13:13	Mid-Atlantic	11	APR-19-2012 11:54	RFC	16
MAR-23-2009 23:40	Mid-Atlantic	10	JUN-19-2010 23:49	Mid-Atlantic	9	APR-11-2011 00:28	RFC	6	APR-20-2012 11:08	Mid-Atlantic	7
MAR-23-2009 23:42	RFCNonMA	8	JUN-24-2010 00:56	RFC	15	APR-16-2011 22:51	RFC	9	JUN-20-2012 13:35	RFC	7
MAR-24-2009 13:20	Mid-Atlantic	8	JUN-27-2010 19:33	Mid-Atlantic	15	APR-21-2011 20:02	Mid-Atlantic	6	JUN-26-2012 17:51	RFC	7
MAR-25-2009 02:29	RFC	9	JUL-07-2010 15:20	RFC	8	APR-27-2011 01:22	RFC	8	JUL-23-2012 21:45	RFC	18
MAR-26-2009 13:08	RFC	10	JUL-16-2010 20:45	Mid-Atlantic	19	MAY-02-2011 00:05	Mid-Atlantic	21	AUG-03-2012 12:44	RFC	10
MAR-26-2009 18:30	Mid-Atlantic	20	AUG-11-2010 19:09	RFC	17	MAY-12-2011 19:39	RFC	9	SEP-08-2012 04:34	RFC	12
APR-24-2009 16:43	RFC	11	AUG-13-2010 23:19	RFC	6	MAY-26-2011 17:17	Mid-Atlantic	20	SEP-27-2012 17:19	Mid-Atlantic	7
APR-26-2009 03:04	Mid-Atlantic	5	AUG-16-2010 07:08	RFC	17	MAY-27-2011 12:51	RFC	6	OCT-17-2012 10:48	RTO	10
MAY-03-2009 15:07	RFC	10	AUG-16-2010 19:39	Mid-Atlantic	11	MAY-29-2011 09:04	RFC	7	OCT-23-2012 22:29	RTO	19
MAY-17-2009 07:41	RFC	5	SEP-15-2010 11:20	RFC	13	MAY-31-2011 16:36	RFC	27	OCT-30-2012 05:12	RTO	14
MAY-21-2009 21:37	RFC	13	SEP-22-2010 15:28	Mid-Atlantic	24	JUN-03-2011 14:23	RFC	7	NOV-25-2012 16:32	RTO	12
JUN-18-2009 17:39	RFC	12	OCT-05-2010 17:20	RFC	10	JUN-06-2011 22:02	Mid-Atlantic	9	DEC-16-2012 07:01	RTO	9
JUN-30-2009 00:17	Mid-Atlantic	8	OCT-16-2010 03:22	Mid-Atlantic	10	JUN-23-2011 23:26	RFC	8	DEC-21-2012 05:51	RTO	7
JUL-26-2009 19:07	RFC	18	OCT-16-2010 03:25	RFCNonMA	7	JUN-26-2011 22:03	Mid-Atlantic	10	DEC-21-2012 10:29	RTO	5
JUL-31-2009 02:01	RFC	6	OCT-27-2010 10:35	RFC	7	JUL-10-2011 11:20	RFC	10			
AUG-15-2009 21:07	RFC	17	OCT-27-2010 12:50	Mid-Atlantic	10	JUL-28-2011 18:49	RFC	12			
SEP-08-2009 10:12	Mid-Atlantic	8	NOV-26-2010 14:24	RFC	13	AUG-02-2011 01:08	RFC	6			
SEP-29-2009 16:20	RFC	7	NOV-27-2010 11:34	RFC	8	AUG-18-2011 06:45	Mid-Atlantic	6			
OCT-01-2009 10:13	RFC	11	DEC-08-2010 01:19	RFC	11	AUG-19-2011 14:49	RFC	5			
OCT-18-2009 22:40	Mid-Atlantic	8	DEC-09-2010 20:07	RFC	5	AUG-23-2011 17:52	RFC	7			
OCT-26-2009 01:01	RFC	7	DEC-14-2010 12:02	Mid-Atlantic	24	SEP-24-2011 15:48	RFC	8			
OCT-26-2009 11:05	RFC	13	DEC-16-2010 18:40	Mid-Atlantic	20	SEP-27-2011 14:20	RFC	7			
OCT-26-2009 19:55	RFC	8	DEC-17-2010 22:09	Mid-Atlantic	6	SEP-27-2011 16:47	RFC	9			
NOV-20-2009 15:30	RFC	8	DEC-29-2010 19:01	Mid-Atlantic	15	OCT-30-2011 22:39	Mid-Atlantic	10			
DEC-09-2009 22:34	Mid-Atlantic	34				DEC-15-2011 14:35	Mid-Atlantic	8			
DEC-09-2009 22:37	RFCNonMA	31				DEC-21-2011 14:26	RFC	18			
DEC-14-2009 11:11	Mid-Atlantic	8									

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 deficits in January through September 2012. Since shortage pricing on October 1, 2012, PJM allows some units to transition between synchronized reserve and energy on a five-minute basis within an operating hour. This additional flexibility is designed to minimized overall costs of energy and reserve and reduces the chance of a synchronized reserve shortage. A primary reserve shortage can occur triggering shortage pricing. No primary reserve shortages occurred between October 1, 2012 and December 31, 2012.

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.[42]

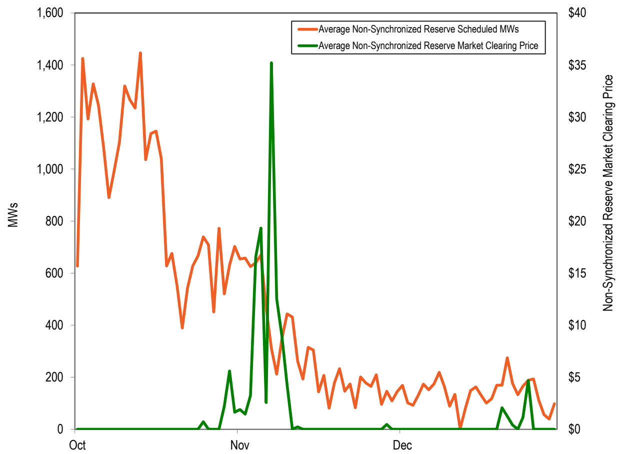
Like Tier 1 synchronized reserve PJM calculates the amount of non-synchronized reserve available each

42 PJM. "Manual 11, Energy & Ancillary Services Market Operations" Revision 57 (December 1, 2012), p. 85.

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 9-15 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 20 hours in October (all after October 24), 121 hours in November, 2012, and 18 hours in December (all between December 22 and December 26). The non-synchronized reserve market clearing price for the RTO Reserve Zone was greater than zero in only three hours in October through December, 2012.

Figure 9-15 Daily average Non-Synchronized Reserve Market clearing price and MW cleared: October through December 2012



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.[43]

The DASR 30-minute reserve requirements are determined by the reliability region.[44] In the Reliability*First* (RFC) region, reserve requirements are calculated based on historical under-forecasted load rates and generator forced outage rates.[45] 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 2012, the required DASR was 7.03 percent of peak load forecast, down from 7.11 percent in 2011.[46] The DASR requirement is a sum of the load forecast error and the forced outage rate. From 2011 the load forecast error increased from 1.90 percent to 1.97 percent. The forced outage rate decreased from 4.98 percent to 4.93 percent. Added together, the 2012 DASR requirement was 7.03 percent. The DASR MW purchased averaged 6,841 MW per hour for 2012, an increase from 6,500 MW per hour in 2011. DASR MW purchased increased by 5.1 percent in 2012 over the 2011, from 57.0 million MW to 59.9 million MW.

In 2012, no hours failed the three pivotal supplier test in the DASR Market. Twenty one hours failed the pivotal supplier test in 2011.

Load response resources which are registered in PJM's Economic Load Response and are dispatchable by PJM are also eligible to provide DASR, but remained insignificant. No demand side resources cleared the DASR market in 2012.

43 PJM uses the terms "supplemental operating reserves" and "scheduling operating reserves" interchangeably.
44 PJM. "Manual 13, Emergency Requirements," Revision 52 (February 1, 2013), pp. 12-13.
45 PJM. "Manual 10, Pre-Scheduling Operations," Revision 27 (February 28, 2013), pp. 18-19.
46 See the *2011 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.[47] 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 December 31, 2012, twelve 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

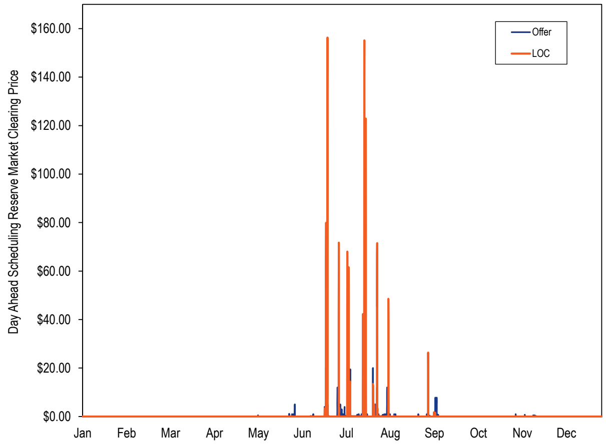
Table 9-23 PJM Day-Ahead Scheduling Reserve Market MW and clearing prices: January through December 2011 and 2012

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

For 82 percent of hours in 2012, DASR cleared at a price of $0.00 (Figure 9-16). For all of 2012, the weighted DASR price was $0.57, a $0.02 increase from the weighted price during 2011. In 82 percent of hours in 2012, the DASR Market Clearing Price was $0.00; however, there were several days of extremely high DASR prices in June, July and August (a maximum price of $156.29 occurred on June 21, 2012). These high prices were primarily the result of high demand and limited supply which created the need for redispatch in the Day-Ahead Energy Market in order to provide DASR. The result was that DASR prices in these hours reflected opportunity costs associated with the redispatch. 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 (98 percent) DASR clearing prices consist solely of the offer price. For a few of the high price hours the price is composed almost entirely of LOC. For the top 0.5 percent (average clearing price = $73.93) of hours, on average 97.2 percent of the price is determined by opportunity cost. On the other hand, for the bottom 99.5 percent (average clearing price = $0.13) of hours, on average 8.8 percent of the price is composed of LOC (Figure 9-16).

47 PJM. "Manual 11, Emergency and Ancillary Services Operations," Revision 57 (December 1, 2012), p. 141-142.

Figure 9-16 Hourly components of DASR clearing price: January through December 2012



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. PJM's goal is to charge transmission customers for black start service according to their zonal load ratio share (Table 9-24).

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.

The MMU has concerns that there is a disconnect between a service that is required for system reliability, the balkanized approach to procuring that service, and the need to secure voluntary participation in the system restoration plans from the relatively few potential providers at the critical locations identified. The current process provides for PJM and transmission owners to jointly develop and administer the black start service plan for each transmission zone. Following a stakeholder process in the System Restoration Strategy Task Force (SRSTF), substantial changes to the black start restoration and procurement strategy were introduced. PJM and the MMU's 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.

In 2012, black start charges were $50.2 million. This is 151 percent higher than 2011, when total black start service charges were $20.0 million. There was substantial zonal variation. Black start zonal charges in 2012 ranged from $0.02 per MW in the ATSI zone (total charges: $119,167) to $3.62 per MW in the AEP zone (total charges: $32,468,706).

The black start charges in Table 9-24 include estimated charges that were allocated to customers as operating reserve charges but that were in fact to pay for the operation of ALR black start units.[48]

48 See the *2012 State of the Market Report for PJM*, Section 3, "Operating Reserves", at "Operating Reserve Charges."

Table 9-24 Black start yearly zonal charges for network transmission use: 2012

Zone	Network Charges	Black Start Rate ($/MW)
AECO	$566,721	$0.52
AEP	$32,468,706	$3.62
AP	$208,617	$0.06
ATSI	$119,167	$0.02
BGE	$5,493,609	$2.07
ComEd	$4,238,804	$0.49
DAY	$199,751	$0.15
DEOK	$278,948	$0.14
DLCO	$45,806	$0.04
DPL	$533,673	$0.34
JCPL	$471,832	$0.20
Met-Ed	$504,209	$0.44
PECO	$1,254,077	$0.38
PENELEC	$453,764	$0.40
Pepco	$280,952	$0.11
PPL	$145,528	$0.05
PSEG	$2,945,488	$0.74

Table 9-25 shows new black start NERC critical infrastructure protection (CIP) capital costs being recovered by black start units in PJM. These costs were located in multiple zones, including ComEd, DEOK, DLCO, JCPL, Met-Ed, PENELEC and Pepco. These costs are recoverable through Schedule 6A of the tariff, and include both physical security and cyber security investments in order to protect black start units deemed critical. This included equipment necessary to restrict access to both physical sites, as well as firewall and software upgrades necessary protect cyber assets and monitor unit operations.

Table 9-25 Black start NERC CIP capital cost recovery in PJM: 2012

Capital Cost Requested	Cost Recovered in 2012	Number of Units	MW
$1,736,971	$150,290	33	678.1