Ancillary Service Markets

The United States Federal Energy Regulatory Commission (FERC) defined six ancillary services in Order No. 888: scheduling, system control and dispatch; reactive supply and voltage control from generation service; regulation and frequency response service; energy imbalance service; operating reserve – synchronized reserve service; and operating reserve – supplemental reserve service.[1] PJM provides scheduling, system control and dispatch and reactive on a cost basis. PJM provides regulation, energy imbalance, synchronized reserve, and supplemental reserve services through market mechanisms.[2] Although not defined by the FERC as an ancillary service, black start service plays a comparable role. Black start service is provided on the basis of incentive rates or cost.

The Market Monitoring Unit (MMU) analyzed measures of market structure, conduct and performance for the PJM Regulation Market, the two regional Synchronized Reserve and Non-Synchronized Reserve Markets, and the PJM DASR Market for 2013.

Table 10-1 The Regulation Market results were competitive for 2013

Market Element	Evaluation	Market Design
Market Structure	Not Competitive	
Participant Behavior	Competitive	
Market Performance	**Competitive**	**Flawed**

- Market structure was evaluated as not competitive for the year because the Regulation Market had one or more pivotal suppliers which failed PJM's three pivotal supplier (TPS) test in 90 percent of the hours in 2013.
- Participant behavior in the Regulation Market was evaluated as competitive for 2013 because market power mitigation requires competitive offers when the three pivotal supplier test is failed and there was no evidence of generation owners engaging in anti-competitive behavior.
- Market performance was evaluated as competitive, after the introduction of the new market design, despite significant issues with the market design.
- Market design was evaluated as flawed. While the design of the Regulation Market was significantly improved with changes introduced October 1, 2012, a number of issues remain. The market results continue to include the incorrect definition of opportunity cost. Further, the market design has failed to correctly incorporate a consistent implementation of the marginal benefit factor in optimization, pricing and settlement.

1 75 FERC ¶ 61,080 (1996).

2 Energy imbalance service refers to the Real-Time Energy Market.

Table 10-2 The Synchronized Reserve Markets results were competitive

Market Element	Evaluation	Market Design
Market Structure: Regional Markets	Not Competitive	
Participant Behavior	Competitive	
Market Performance	**Competitive**	**Mixed**

- The Synchronized Reserve Market structure was evaluated as not competitive because of high levels of supplier concentration.
- Participant behavior was evaluated as competitive because the market rules require competitive, cost based offers.
- Market performance was evaluated as competitive because the interaction of the participant behavior with the market design results in competitive prices.
- Market design was evaluated as mixed. Market power mitigation rules result in competitive outcomes despite high levels of supplier concentration. However, Tier 1 reserves are inappropriately compensated when the non-synchronized reserve market clears with a non-zero price.

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

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

- The Day-Ahead Scheduling Reserve Market structure was evaluated as competitive because market participants did not fail the three pivotal supplier test.
- Participant behavior was evaluated as mixed because while most offers appeared consistent with marginal costs, 12 percent of offers reflected economic withholding.
- Market performance was evaluated as competitive because there were adequate offers at reasonable levels in every hour to satisfy the requirement and the clearing price reflected those offers.

- Market design was evaluated as mixed because while the market is functioning effectively to provide DASR, the three pivotal supplier test, and cost-based offer capping when the test is failed, should be added to the market to ensure that market power cannot be exercised at times of system stress.

Overview

Regulation Market

The PJM Regulation Market is a single market for the RTO. PJM jointly optimizes Regulation with Synchronized Reserve and energy to provide all three of these services at least cost.

Market Structure

- **Supply.** In 2013, the supply of offered and eligible regulation in PJM was stable, but the average daily offer decreased from 6,551 MW in 2012 to 4,166 MW in 2013 (a decrease of 36.4 percent) and the average hourly eligible regulation decreased from 3,253 MW in 2012 to 1,642 MW in 2013 (a decrease of 50.1 percent).
- **Demand.** The average hourly regulation demand was 753 MW in 2013. This is a 177 MW decrease (19.0 percent) in the average hourly regulation demand of 930 MW in the same period of 2012.
- **Supply and Demand.** The ratio of offered and eligible regulation to regulation required averaged 3.40. This is a 5.8 percent decrease from 2012 when the ratio was 3.61.
- **Market Concentration.** In 2013, the PJM Regulation Market had a weighted average Herfindahl-Hirschman Index (HHI) of 2115 which is classified as highly concentrated. In 2013, the three pivotal supplier test was failed in 90 percent of hours. In 2012, the three pivotal supplier test was failed in 40 percent of hours.

Market Conduct

- **Offers.** Daily regulation offer prices are submitted for each unit by the unit owner. Owners are required to submit a cost offer along with cost parameters to verify the offer, and may optionally submit a price offer. Under the new market design, offers include both a capability offer and a performance offer. Owners must specify which signal type the unit will be following, RegA or RegD.[3] As of December 31, 2013, there were 26 resources following the RegD signal.

Market Performance

- **Price and Cost.** The weighted average clearing price for regulation was $30.14/MW of regulation in 2013, an increase of $9.79/MW of regulation, or 48.1 percent, from 2012. The cost of regulation in 2013 was $34.57/MW of regulation, an $8.16/MW of regulation, or 30.9 percent, increase from 2012.

Synchronized Reserve Market

The Tier 2 Synchronized Reserve market includes the PJM RTO Reserve Zone and a subzone, the Mid-Atlantic Dominion Reserve Zone (MAD). The MAD subzone is designed to ensure that transmission constraints will not prevent adequate synchronized reserves from being available in MAD when called. PJM has the right to define new zones or subzones "as needed for system reliability."[4]

Market Structure

- **Supply.** In 2013, the supply of offered and eligible synchronized reserve was both stable and adequate.
- **Demand.** When the RFC Zone became the RTO Zone on October 1, 2012, the synchronized reserve requirement increased from 1,350 MW to 1,375 MW. The Mid-Atlantic Subzone became the Mid-Atlantic Dominion Subzone on October 1, 2012. Requirement synchronized reserve requirement remained at 1,300 MW. The integration of East Kentucky Power Cooperative (EKPC) into PJM on June 1, 2013, had no impact on the Synchronized Reserve Market requirement because the largest contingencies remain in the Mid-Atlantic Dominion Subzone.
- **Supply and Demand.** All on-line generation resources are required to offer synchronized reserve. The 2013 ratio of on-line synchronized reserve to synchronized reserve required was 1.29.
- **Market Concentration.** In 2013, the weighted average HHI for cleared tier 2 synchronized reserve in the Mid-Atlantic Dominion Subzone was 4205

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

4 See PJM. "Manual 11, Energy and Ancillary Services Market Operations," Revision 64 (January 6, 2014), p. 66.

which is classified as highly concentrated. In 2013, 56 percent of hours had a maximum market share greater than 40 percent.

The MMU concludes from these results that the Mid-Atlantic Dominion Subzone Tier 2 Synchronized Reserve Market in 2013 was characterized by structural market power.

Market Conduct

- **Offers.** Daily cost based offer prices are submitted for each generating unit and each demand resource. The offers are subject to an offer cap of marginal cost plus $7.50 per MW, plus opportunity cost, which is calculated by PJM. All suppliers are paid the higher of the market clearing price or their offer plus their unit specific opportunity cost.

Market Performance

- **Price.** The cleared synchronized reserve weighted average price for Tier 2 synchronized reserve in the Mid-Atlantic Dominion (MAD) Subzone was $6.98 per MW in 2013, a $1.04 decrease from 2012. The total cost of tier 2 synchronized reserves per MW in MAD in 2013 was $13.07, a three percent increase from the $12.71 cost of synchronized reserve in 2012. The market clearing price was 53 percent of the total synchronized reserve cost per MW in 2013, down from 63 percent in 2012.
- **Supply and Demand.** A synchronized reserve shortage occurs when the combination of tier 1 and tier 2 synchronized reserve supply is not adequate to meet the synchronized reserve requirement. Neither PJM Synchronized Reserve Market experienced a synchronized reserve shortage in 2013. The spinning event of September 10 raised concerns that the current method for estimating Tier 1 is incorrect leading to an overall synchronized reserve deficit.

Day-Ahead Scheduling Reserve (DASR)

The purpose of the DASR Market is to satisfy secondary 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.[5] If the DASR Market does not result in procuring adequate scheduling reserves, PJM is required to schedule additional operating reserves.

The MMU has identified problems with the definition and dispatchability of DASR and recommends solutions.

Market Structure

- **Concentration.** The MMU calculates that in 2013, zero hours in the DASR market would have failed the three pivotal supplier test. The current structure of PJM's DASR Market does not include the three pivotal supplier test. The MMU recommends that the three pivotal supplier test be incorporated in the DASR market.
- **Supply.** DASR resources comprise of all those resources that can provide reserve capability that can be fully converted into energy within 30 minutes as requested by PJM dispatchers. MMU recommends that scheduling reserve be more definitively defined and satisfied by a real-time market.
- **Demand.** In 2013, the required DASR was 6.91 percent of peak load forecast, down from 7.03 percent in 2012.

Market Conduct

- **Withholding.** Economic withholding remains an issue in the DASR Market. The marginal cost of providing DASR is zero, but there is an opportunity cost associated with providing DASR. As of December 31, 2013, 12 percent of offers reflected economic withholding (defined as cost offers above $5.00). All units with reserve capability that can be converted into energy within 30 minutes are required to offer in the DASR Market.[6] Units that do not offer have their offers set to zero.
- **DR.** Demand resources are eligible to participate in the DASR Market, but no demand resource cleared the DASR Market in 2013.

Market Performance

- **Price.** The weighted DASR market clearing price in 2013 was $0.70 per MW. This is a 23 percent increase from 2012.

5 See PJM. "Manual 13: Emergency Operations," Revision 53, (June 1, 2013); pp 11-12.

6 See PJM. "Manual 11, Energy and Ancillary Services Market Operations," Revision 64 (January 6, 2014), p. 137.

Black Start Service

Black start service is required for the reliable restoration of the grid following a blackout. Black start service is the ability of a generating unit to start without an outside electrical supply, or is the demonstrated ability of a generating unit to automatically remain operating at reduced levels when disconnected from the grid.[7]

In 2013, black start charges were $107.5 million (compared to $50.2 million in 2012). Black start zonal charges in 2013 ranged from $0.03 per MW-day in the ATSI Zone (total charges were $126,644) to $9.71 per MW-day in the AEP Zone (total charges were $82,588,453).

Reactive

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

In 2013, total reactive service charges were $616.6 million compared to $368.3 million in 2012.[8] Total charges in 2013 ranged from $340.0 thousand in the RECO Zone to $76.8 million in the ATSI Zone.

Ancillary Services Costs per MW of Load: 2002 - 2013

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

Year	Regulation	Scheduling, Dispatch, and System Control	Reactive	Synchronized Reserve	Supplementary Operating Reserve	Total
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
2013	$0.24	$0.39	$0.80	$0.04	$0.59	$2.08

Table 10-4 shows PJM ancillary services costs for 2002 through 2013, on a per-MW of load basis. The scheduling, system control, and dispatch category of costs is comprised of PJM scheduling, PJM system control and PJM dispatch; owner scheduling, owner system control and owner dispatch; other supporting facilities; black start services; direct assignment facilities; and Reliability*First* Corporation charges. Supplementary operating reserve includes day-ahead operating reserve; balancing operating reserve; and synchronous condensing.

Recommendations

- The MMU recommends that the Regulation Market be modified to incorporate a consistent application of the marginal benefits factor throughout the optimization, assignment and settlement process.
- The MMU recommends that the rule requiring the payment of tier 1 synchronized reserve resources when the non-synchronized reserve price is above zero be eliminated immediately.
- The MMU recommends that the tier 2 synchronized reserve must-offer provision of scarcity pricing be enforced.
- The MMU recommends that PJM be more explicit about why tier 1 biasing is used in the optimized solution to the Tier 2 Synchronized Reserve Market. The MMU recommends that PJM define rules for calculating available tier 1 MW and for the use of biasing during any phase of the market solution and then identify the relevant rule for each instance of biasing.
    - The MMU recommends that PJM determine why secondary reserve was either unavailable or not dispatched on September 10, 2013 and that PJM evaluate replacing the DASR market with a real time secondary reserve product that is available and dispatchable in real time.
    - The MMU recommends PJM revise the current confidentiality rules in order to specifically allow a more transparent disclosure of information regarding black start resources and their associated payments in PJM.
    - The MMU recommends that the three pivotal supplier test be incorporated in the DASR market.

7 OATT Schedule 1 § 1.3BB.

8 See the *2013 State of the Market Report for PJM*, Volume II, Section 4, "Energy Uplift."

Conclusion

While the design of the Regulation Market was significantly improved with changes introduced October 1, 2012, a number of issues remain. The market results continue to include the incorrect definition of opportunity cost. Further, the market design has failed to correctly incorporate a consistent implementation of the marginal benefit factor in optimization, pricing and settlement. Instead, the market design makes use of the benefits factor in the optimization and pricing, but a mileage ratio multiplier in settlement. This failure to correctly incorporate marginal benefit factor into the current Regulation Market design is causing effective MW provided by RegD resources to be paid a different amount per effective MW than effective MW provided by RegA resources. These issues have led to the MMU's conclusion that the Regulation Market design, as currently implemented, is flawed.

The structure of each Tier 2 Synchronized Reserve Market has been evaluated and the MMU has concluded that these markets are not structurally competitive as they are characterized by high levels of supplier concentration and inelastic demand. As a result, these markets are operated with market-clearing prices and with offers based on the marginal cost of producing the service plus a margin. As a result of these requirements, the conduct of market participants within these market structures has been consistent with competition, and the market performance results have been competitive. Compliance with calls to respond to actual spinning events has been an issue. Compliance with the synchronized reserve must-offer requirement has also been an issue.

The benefits of markets are realized under these approaches to ancillary service markets. Even in the presence of structurally noncompetitive markets, there can be transparent, market clearing prices based on competitive offers that account explicitly and accurately for opportunity cost. This is consistent with the market design goal of ensuring competitive outcomes that provide appropriate incentives without reliance on the exercise of market power and with explicit mechanisms to prevent the exercise of market power.

The MMU concludes that the new Regulation Market results were competitive. The MMU concludes that the Synchronized Reserve Market results were competitive. The MMU concludes that the DASR Market results were competitive.

Regulation Market

Regulation matches generation with very short term changes in load by moving the output of selected resources up and down via an automatic control signal. Regulation is provided, independent of economic signal, by generators with a short-term response capability (less than five minutes) or by demand response (DR). The PJM Regulation Market is operated as a single market. Significant technical and structural changes were made to the Regulation Market in 2012.[9]

Regulation Market Changes for Performance Based Regulation

On October 20, 2011, the FERC issued Order No. 755 directing PJM and other RTOs/ISOs to modify their regulation market rules to include fast and slow response regulation resources."[10]

A rationale for the new market design was the assumption that new, fast response technologies could be used, in combination with slow resources, to reduce the total amount of resources needed to meet regulation requirements and thereby reduce the cost of regulation. Order No. 755 required that the fast and slow resources be purchased in a single market, with compensation for both capacity (MW) and miles (ΔMW).[11] Regulation miles are calculated as the sum of the absolute value of a given regulation resource's movement (up and down) in response to a regulation signal.

The performance based Regulation Market requires that resource owners provide two-part offers for their regulation resources, an offer for regulation capability in terms of $/MW and a regulation performance offer in terms of $/MW (based on $ per ΔMW times ΔMW/MW). The two parts of the offer are combined to provide a total regulation offer in terms of $/MW.

9 See the *2012 State of the Market Report for PJM*, Volume II, Section 9, "Ancillary Services," p. 271.
10 Order No. 755 at P 3. FERC ordered PJM "to compensate frequency regulation resources based on the actual service provided, including a capacity payment that includes the marginal unit's opportunity costs and a payment for performance that reflects the quantity of frequency regulation service provided by a resource when the resource is accurately following the dispatch signal."
11 Id. at PP 99, 131 & 177.

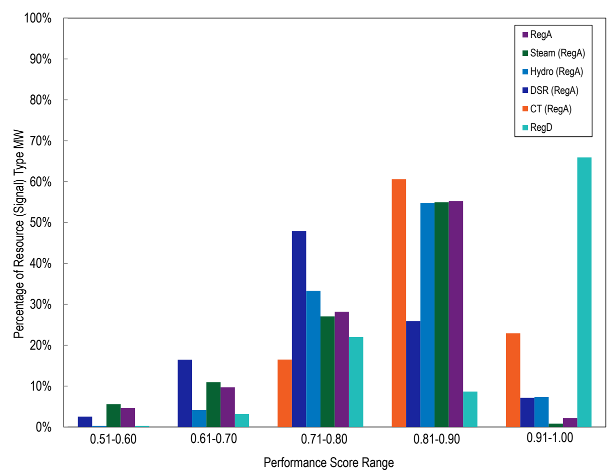
Prior to October 1, 2012, regulation consisted of generation and demand resources responding within five minutes to a single PJM-generated signal (RegA) that directed these resources to increase or decrease output or load. On October 1, 2012, PJM introduced a single market that included resources following two signals: RegA and RegD. Resources responding to either signal help moderate ACE. RegA is PJM's slow-oscillation regulation signal and is designed for resources with the ability to sustain energy output for long periods of time, but with limited ramp rates. RegD is PJM's fast-oscillation regulation signal and is designed for resources with the ability to quickly adjust energy output, but with limited ability to sustain energy output for long periods of time. Resources must qualify to follow the RegA and RegD signals. Resources must qualify for one signal or both signals, but will be assigned by the market clearing engine to follow only one signal within a given market hour.

While resources following RegA and RegD can both provide regulation service in PJM's regulation market, PJM's joint optimization is designed to determine and assign the optimal mix of RegA and RegD MW to meet the hourly regulation requirement. The optimal mix is a function of the relative effectiveness and cost of available RegA and RegD resources. The optimization of RegA and RegD assignments is dependent on the conversion of RegA and RegD resources into common units of measure via a marginal benefits factor (MBF). The marginal benefits factor is a measure of the substitutability of RegD resources for RegA resources in satisfying the regulation requirement. The marginal benefits factor and the performance score of the resource, are used to convert RegA and RegD resource regulation capability MW into comparable units, termed Effective MW. Effective MW, supplied from RegA or RegD resources, are defined in terms of RegA MW. Except where expressly referred to as Effective MW or effective regulation MW, MW means unadjusted regulation capability MW.

Regulation performance scores (0.0 to 1.0) measure the response of a regulating resource to its chosen regulation signal (RegA or RegD) every ten seconds by measuring: delay, the time delay of the regulation response to a change in the regulation signal; correlation, the correlation between the regulating resource output and the regulation signal; and precision, the difference between the regulation response and the regulation requested.[12] An hourly performance score is calculated and multiplied by the MW cleared when calculating payment.

Figure 10-1 shows the average performance score by resource type and signal followed. Each category (color bar) adds up to 100 percent so that the full performance score distribution for each resource (or signal) type is shown. Resources following the RegD signal follow the RegD signal more closely than resources following the RegA signal follow the RegA signal. That is, RegD resources tend to have higher performance scores. As the figure shows, 65.9 percent of RegD resources have average performance scores within the 0.91-1.00 range, whereas only 2.2 percent of RegA resources have average performance scores within that range.

Figure 10-1 Average performance score by unit type and regulation signal type: 2013



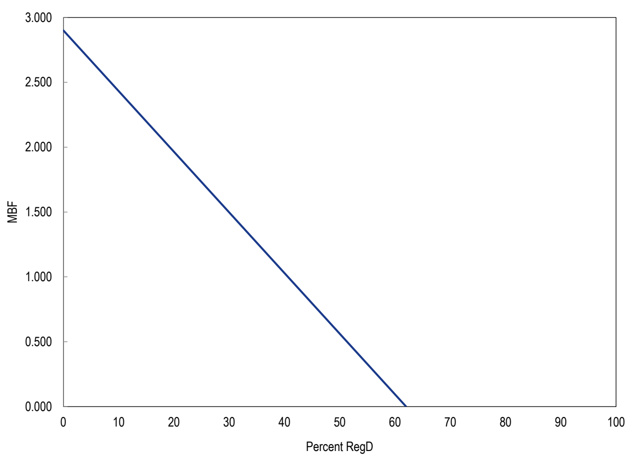
Issues Related to the Marginal Benefits Factor

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 a resource following the RegD signal depends on how much RegD following resources are used. As of December 31, 2013, PJM uses an affine function to determine the marginal benefits factor of RegD resource MW. Two points (percent RegD in Regulation Market, Marginal Benefits Factor) define this

12 PJM "Manual 12: Balancing Operations" Rev. 27 (December 20, 2012); 4.5.6, p 52.

function: (0, 2.9) and (62, 0.0001). Its equation is MBF = 2.9 – 0.05 x (percent of RegD in Regulation Market). The marginal benefits factor is therefore a function of the proportion of RegD and RegA resources employed in the market solution. The greater the proportion of RegD to RegA in the market solution, the lower the marginal benefits factor of the last RegD resource MW in that solution. PJM can modify the function based on the observed effect that RegD resources have on satisfying NERC requirements (CPS and BAAL). The relevant portion of the graph of this function is shown in Figure 10-2. As shown in Figure 10-2, if the regulation requirement were 10 MW and there were one RegD resource providing 1 MW of regulation, then the marginal benefits factor would be 2.432.

Figure 10-2 Marginal benefits factor function graph



The FERC's November 16, 2012, order only partially accepted the market design in PJM's August 15, 2012, filing. The order fixed the marginal benefits factor for RegD resources at a value of 1.0 for purposes of payment, but not for the market clearing and optimization process. This created a dichotomy in the PJM Regulation Market between the marginal value of RegD resources in the dispatch, and the resulting market price and payments to resources in the settlement process in PJM's regulation market through the third quarter of 2013.

On October 2, 2013, the FERC issued an Order Granting Rehearing.[13] The order removed the marginal benefits factor entirely from the performance and capability credit settlements calculation of RegD resources. Instead, the order directed that the mileage ratio be used in place of the marginal benefits factor as a performance multiplier for RegD performance credits. No similar adjustment is to be applied to the capability credits settlement. This change was implemented for all Regulation Market settlements from November 1, 2013, through December 31, 2013. Retroactive adjustments to Regulation Market settlements from October 1, 2012, through October 31, 2013, will be made by PJM in the first half of 2014.

The resulting market design is flawed. The mileage ratio is not a substitute for the marginal benefits factor. Unlike the marginal benefits factor, the mileage ratio of RegD to RegA provides no information regarding the relative value of RegD and RegA resources in the optimized market solution. The failure to use the marginal benefits factor in the performance and capability credit settlements process creates an inconsistency among the marginal value of the regulation resources as acted upon in the joint optimization, the posted prices for regulation and the compensation of the regulation resources.

From October 1, 2012, through October 31, 2013, PJM adhered to a FERC order that required the marginal benefits factor be fixed at one for settlement calculations only. As Figure 10-3 shows, the true marginal benefits factor, as used in the optimization and commitment process for Regulation in 2013, was always higher than one. This caused resources following the RegD signal to be underpaid. Resources following the RegD signal should have been paid the true marginal benefits factor times the amount that they were actually paid. This scalar should have been applied to the capability and the performance payments of RegD resources.

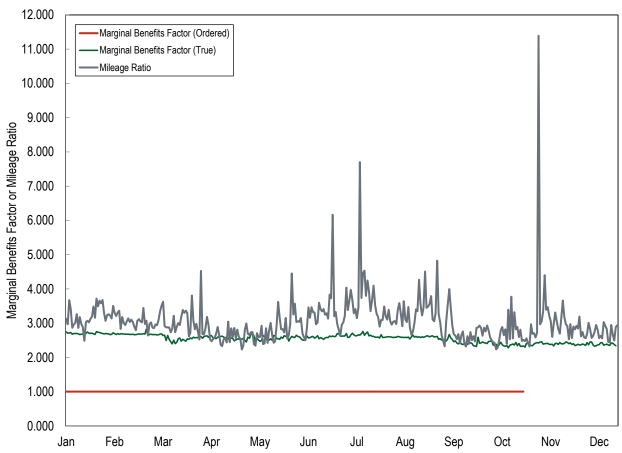
On October 2, 2013, FERC directed PJM to eliminate the use of the marginal benefits factor completely from settlement calculations of the capability and performance credits and replace it with RegD to RegA mileage ratio in the performance credit paid to RegD resources, effective November 1, 2013, and retroactively to October 1, 2012.[14] As Figure 10-3 demonstrates, the RegD to RegA mileage ratio is generally higher than the true marginal benefits factor and much more variable. The mileage multiplier has not brought total payment of RegD resources in line with RegA resources on a dollar per effective MW basis. This is, in part, due to the fact

13 145 FERC ¶ 61,011 (2013).

14 145 FERC ¶ 61,011 (2013).

that the performance related price per MW of capability, which is multiplied by the mileage ratio, is a relatively small portion of the total price per MW of capability. It is also due to the fact that the mileage ratio is not a substitute for the marginal benefits factor.

Figure 10-3 Daily average marginal benefit factor and mileage ratio: 2013



Unlike the marginal benefits factor, the mileage ratio of RegD to RegA provides no information regarding the relative value of RegD and RegA resources in the optimized market solution. A marginal benefits factor of 2.5 for a RegD resource means that for every 1 MW of regulation capability the RegD resource provides, it is replacing 2.5 MW of regulation capability of a RegA resource. The RegD to RegA mileage ratio simply captures how much PJM wanted RegD resources to change their output over time relative to the signal sent to RegA resources and has nothing to do with the rate of substitution between RegD and RegA resources.

The following two examples illustrate the issues caused by the use of the RegD to RegA mileage ratio and the inconsistent application of the marginal benefits factor in PJM's settlement of the regulation market.

Table 10-5 illustrates the issues that resulted when FERC required the marginal benefits factor to be set at one.

Table 10-5 Regulation payment example (1 of 3)

Problem: MBF = 1	RegA Resource	RegD Resource
Regulation MW	4	4
Performance Score	100%	100%
Marginal Benefits Factor (Actual)	2	2
Mileage Ratio (RegD:RegA)	3	3
RMCCP ($/MW)	$5.00	$5.00
RMPCP ($/MW)	$1.00	$1.00
RMCP ($/MW)	$6.00	$6.00
RMCCP Credit ($)	$20.00	$20.00
RMCCP Credit Should Be ($)	$20.00	$40.00
RMPCP Credit ($)	$4.00	$4.00
RMPCP Credit Should Be ($)	$4.00	$8.00
RMCP Credit ($)	$24.00	$24.00
RMCP Credit Should Be ($)	$24.00	$48.00

It is assumed that each resource provides 4 MW of regulation capability, has a 100 percent performance score, the marginal benefits factor is 2.0, the mileage ratio is 3.0, the RMCCP is $5.00/MW, the RMPCP is $1.00/MW and the RMCP is $6.00/MW.

The RMCCP Credit is calculated as MW of regulation capability times performance score times marginal benefits factor times RMCCP. The RMPCP Credit is calculated as MW of regulation capability times performance score times marginal benefits factor times RMPCP. The RMCP Credit is calculated as RMCCP Credit plus RMPCP Credit.

For the RegA resource, the RMCCP Credit is equal to $20.00 (4 MW x 100 percent x $5.00/MW). The RMPCP Credit is equal to $4.00 (4 MW x 100 percent x $1.00/MW). The total RMCP Credit is $24.00. The FERC marginal benefit factor of one does not affect the settlement of the RegA resources, as the benefit factor of a RegA resource is always one by design.

For the RegD resource, the RMCCP Credit is equal to $20.00 (4 MW x 100 percent x 1.0 (FERC MBF) x $5.00/MW). Since the marginal benefits factor is 2.0, the RMCCP Credit should be equal to $40.00 (4 MW x 100 percent x 2.0 (MBF) x $5.00/MW). The impact of using the marginal benefit factor of 1.0 is to provide only half the RMCCP credits awarded in settlement compared to what they should be with the use of the actual marginal benefit factor.

For the RegD resource, the RMPCP Credit is equal to $4.00 (4 MW x 100 percent x 1.0 (FERC MBF) x $1.00/MW). However, since the marginal benefits factor is 2.0, the RMPCP Credit should be equal to $8.00 (4 MW x 100 percent x 2 (MBF) x $1.00/MW). That is, the RMPCP should be 2.0 (the marginal benefits factor) times the erroneous calculation actually used. For the RegD resource, the total RMCP Credit is equal to $24.00 ($20.00 + $4.00). The RMCP Credit should be equal to $48.00 ($40.00 + $8.00). Again, twice as high due to the failure to include the correct marginal benefits factor in settlement.

Table 10-6 illustrates the issues that resulted when FERC required that the RegD to RegA mileage ratio be applied in the calculation of RMPCP Credits instead of the correct application of the marginal benefits factor to the allocation of both the RMCCP and RMPCP Credits.

Table 10-6 Regulation payment example (2 of 3)

Problem: Mileage Ratio	RegA Resource	RegD Resource
Regulation MW	4	4
Performance Score	100%	100%
Marginal Benefits Factor (Actual)	2	2
Mileage Ratio (RegD:RegA)	3	3
RMCCP ($/MW)	$5.00	$5.00
RMPCP ($/MW)	$1.00	$1.00
RMCP ($/MW)	$6.00	$6.00
RMCCP Credit ($)	$20.00	$20.00
RMCCP Credit Should Be ($)	$20.00	$40.00
RMPCP Credit ($)	$4.00	$12.00
RMPCP Credit Should Be ($)	$4.00	$8.00
RMCP Credit ($)	$24.00	$32.00
RMCP Credit Should Be ($)	$24.00	$48.00

In this example, it is assumed that each resource provides 4 MW of regulation capability, has a 100 percent performance score, the marginal benefits factor is actually 2.0, the mileage ratio is 3.0, the RMCCP is $5.00/MW, the RMPCP is $1.00/MW and the RMCP is $6.00/MW.

In this example, the RMCCP Credit is calculated as MW of regulation capability times performance score times RMCCP. The RMPCP Credit is calculated as MW of regulation capability times performance score times RegD to RegA mileage ratio times RMPCP. The RMCP Credit is calculated as RMCCP Credit plus RMPCP Credit.

For the RegA resource, the RMCCP Credit is 4 MW x 100 percent x $5.00/MW = $20.00. The RMPCP Credit is 4 MW x 100 percent x $1.00/MW = $4.00. The total RMCP Credit is $20.00 + $4.00 = $24.00. The assumption does not affect the RegA resources credit calculations.

For the RegD resource, the RMCCP Credit is equal to $20.00 (4 MW x 100 percent x $5.00/MW). However, since the marginal benefits factor is 2.0, the RMCCP Credit should be equal to $40.00 (4 MW x 100 percent x 2 (MBF) x $5.00/MW). That is, the RMCCP should be 2.0 (the marginal benefits factor) times the erroneous calculation actually used. For the RegD resource, the RMPCP Credit is equal to $12.00 (4 MW x 100 percent x 3 (RegD:RegA mileage ratio) x $1.00/MW). However, since the marginal benefits factor is 2.0, the RMPCP Credit should be equal to $8.00 (4 MW x 100 percent x 2 (MBF) x $1.00/MW). That is, the RMPCP should be 2.0 (the marginal benefits factor) divided by 3.0 (the mileage ratio) times the calculation actually used. For the RegD resource, the total RMCP Credit is equal to $32.00 ($20.00 + $12.00). However, the total RMCP Credit should be equal to $48.00 ($40.00 + $8.00).

In this example, the use of the mileage ratio reduces the difference between PJM's current calculation of the RMCP Credit and the correct calculation of RMCP using the consistent application of the marginal benefits factor. But the use of the mileage ratio does not, and it cannot, resolve the issue. The mileage ratio based calculation is incorrect.

The MMU recommends that the current mileage rate based calculation be replaced with the consistent application of the marginal benefits factor.

Posted Regulation Prices Do Not Reflect Actual Clearing Payments

PJM posts clearing prices for the Regulation Market (RMCCP, RMPCP and RMCP) in what are termed to be dollars per unadjusted regulation capability MW. The Regulation Market clearing price (RMCP) for the hour is the simple average of the twelve five-minute RMCPs within the hour. The five-minute RMCP is the sum of the performance clearing price (RMPCP) and the capability clearing price (RMCCP). The performance clearing price ($/MW) is equal to the most expensive performance offer cleared for the hour. The capability clearing price ($/MW) is equal to the difference between the RMCP for the hour and the RMPCP for the hour.

The posted prices for regulation are misleading, as resource payment is not made to resources on an unadjusted capability MW basis. Instead posted prices are adjusted in settlement by multiplying by a resource's regulation capability MW by its performance score. The RMPCP (performance price) paid to RegD resources is further adjusted by multiplying performance related price (RMPCP) by the RegD to RegA mileage ratio for the hour.

Due to the performance score and mileage ratio adjustments, realized regulation payments per capability MW are, on a dollar per capability basis, not the same across resources. The RMCP paid per capability MW, for example, varies by the resource's performance score. The closer a resource's performance score is to 1.0 (100 percent), the closer the realized price is to the posted RMCP per capability MW. Even absent variations in the performance score across resources, the use of the mileage ratio to adjust the realized price of performance (RMPCP) per capability MW of RegD causes the RMPCP price per MW of capability to vary across resource types.

This variation between posted and realized price per MW is problematic because it reduces the transparency of the market. Price transparency is a key feature of efficient markets, as the more reflective the price is of the underlying fundamentals of the market at the margin, the greater the efficiency of the purchase, provision and investment decisions that are dependent on that price. The market design should result in prices that reflect the marginal value and cost of the resource or service being provided, and that price should be provided in a clear and common per unit metric across providers of that product or service.

The hypothetical example in Table 10-7 illustrates the issue.

Table 10-7 Regulation payment example (3 of 3)

Problem: Differing RMCP Credits	Resource 1	Resource 2
Regulation Capability MW	4	4
Performance Score	100%	75%
Marginal Benefits Factor (Actual)	1	1
Mileage Ratio (RegD:RegA)	1	1
Effective MW	$4.00	$3.00
RMCCP ($/MW)	$5.00	$5.00
RMPCP ($/MW)	$1.00	$1.00
RMCP ($/MW)	$6.00	$6.00
RMCCP Credit	$20.00	$15.00
RMPCP Credit	$4.00	$3.00
RMCP Credit	$24.00	$18.00
RMCP Credit per Regulation Capability MW	$6.00	$4.50
RMCP Credit per Effective MW	$6.00	$6.00

In this example, assume that two resources cleared 4 MW of regulation capability, but within the hour, one resource (Resource 1) had a 100 percent performance score and the other (Resource 2) had a 75 percent performance score. Further assume that the RMCCP was $5.00/MW, the RMPCP was $1.00/MW, and the RMCP was $6.00/MW. To simplify, it is also assumed that the marginal benefits factor for the hour was 1.0 and that the mileage ratio was also 1.0. These assumptions limit the differences between the resources in the optimization and the settlement calculations in the example.

Under these assumptions, Resource 1 provided 4 effective MW, due to its 100 percent performance score and Resource 2 supplied only 3 effective MW because it had a performance score of 75 percent. The RMCCP Credit for Resource 1 is equal to $20.00 (4 MW x 100 percent x $5.00/MW) and for Resource 2 is equal to $15.00 (4 MW x 75 percent x $5.00/MW). The RMPCP Credit for Resource 1 is equal to $4.00 (4 MW x 100 percent x $1.00/MW) and for Resource 2 is equal to $3.00 (4 MW x 75 percent x $1.00/MW). Finally, the RMCP Credit for Resource 1 is equal to $24.00 ($20.00 + $4.00) and for Resource 2 is equal to $18.00 ($15.00 + $3.00).

For every 1 MW of regulation capability MW offered and cleared by Resource 1, Resource 1 earned $6.00. However, for every 1 MW of regulation capability offered and cleared by Resource 2, Resource 2 earned only $4.50, due to its 75 percent performance score. As is shown in the last column of Table 10-7, the credit earned per effective MW is $6.00 for both resources.

The MMU recommends that regulation prices be presented in terms of dollars per effective MW, with RegA or RegD resources receiving the same payment per Effective MW. This can only be achieved through the consistent application of the marginal benefits factor throughout the optimization, assignment and settlement process.

Market Structure

Supply

Table 10-8 shows capability, average daily offer and average hourly eligible MW for all hours. The hourly regulation capability decreased in 2013, to 8,617 MW from 9,413 MW in 2012.

Table 10-8 PJM regulation capability, daily offer[15] and hourly eligible: 2012 and 2013[16]

Period	Regulation Capability (MW)	Average Daily Offer (MW)	Percent of Capability Offered	Average Hourly Eligible (MW)	Percent of Capability Eligible
2012	9,413	6,551	70%	3,253	35%
2013	8,617	4,166	48%	1,624	19%

Coal units on average provided only 15.5 percent of regulation in 2013. This is a significant decline from the 30.1 percent of regulation provided by coal units in 2012. Coal unit revenues in 2013 were about half of what they were in 2012 ($31.4 million in 2013 versus $62.3 million in 2012). Table 10-9 provides monthly data of the number of coal units providing regulation, the scheduled regulation in MW provided by coal units, the total scheduled regulation in MW provided by all resources, the percent of scheduled regulation provided by coal units, and the total credits received by coal units.

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

Although the marginal benefits factor for slow (RegA) resources is 1.0, the effective MW of RegA following resources was lower than the offered MW in 2013 because the average performance score was less than 1.00 (Figure 10-4). For 2013, the MW-weighted average RegA performance score was 0.80 and as of December 31, 2013, there were 265 resources following the RegA signal.

Table 10-9 PJM regulation provided by coal units

Year	Month	Number of Coal Units Providing Regulation	Scheduled Regulation from Coal Units (MW)	Scheduled Regulation from All Resources (MW)	Percent of Scheduled Regulation from Coal Units	Total Coal Unit Regulation Credits
2012	Jan	94	256,512	739,753	34.7%	$4,730,792
2012	Feb	93	184,650	677,217	27.3%	$2,868,974
2012	Mar	97	174,768	641,655	27.2%	$3,509,174
2012	Apr	93	195,207	572,397	34.1%	$3,301,602
2012	May	105	198,348	658,008	30.1%	$5,031,604
2012	Jun	127	203,402	745,156	27.3%	$4,211,652
2012	Jul	127	309,048	903,024	34.2%	$10,675,726
2012	Aug	122	258,372	824,350	31.3%	$6,144,214
2012	Sep	106	184,365	648,809	28.4%	$4,657,407
2012	Oct	92	130,970	451,710	29.0%	$6,484,144
2012	Nov	105	156,250	479,188	32.6%	$7,307,279
2012	Dec	93	120,276	487,749	24.7%	$3,378,357
2013	Jan	117	121,466	494,253	24.6%	$5,376,657
2013	Feb	102	99,850	453,803	22.0%	$3,071,883
2013	Mar	96	67,580	459,421	14.7%	$2,473,951
2013	Apr	80	40,636	381,510	10.7%	$1,559,309
2013	May	97	42,190	414,053	10.2%	$1,856,919
2013	Jun	105	62,914	475,647	13.2%	$2,332,995
2013	Jul	109	106,367	552,699	19.2%	$5,659,885
2013	Aug	95	83,448	510,342	16.4%	$2,652,089
2013	Sep	89	60,920	414,200	14.7%	$2,118,200
2013	Oct	62	54,575	381,009	14.3%	$1,688,471
2013	Nov	67	56,945	401,553	14.2%	$1,372,687
2013	Dec	81	50,706	413,104	12.3%	$1,208,075

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

16 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.

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

Current Regulation Units, 2013	Settled MW, 2013	Units Scheduled To Retire Through 2015	Settled MW of Units Scheduled To Retire Through 2015	Percent Of Regulation MW To Retire Through 2015
309	6,583,490	33	66,664	1.01%

Figure 10-4 Daily average actual cleared MW of regulation, effective cleared MW of regulation, and average performance score; all cleared regulation: 2013

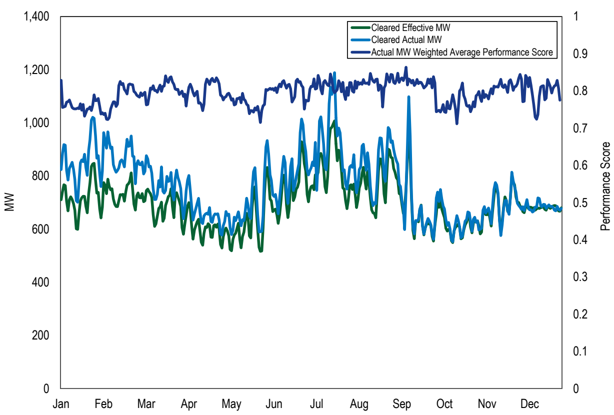
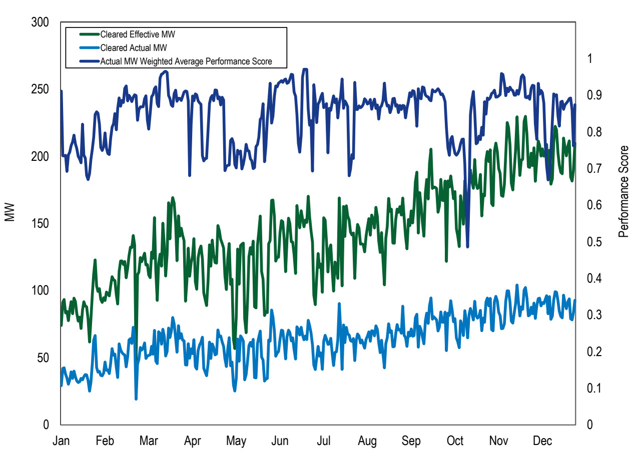


Figure 10-5 Daily average actual cleared MW of regulation, effective cleared MW of regulation, and average performance score; RegD units only: 2013



For RegD resources, the effective MW are higher than the actual MW because their marginal benefits factor at current participation levels is significantly greater than 1.0. In 2013, the marginal benefit factor for cleared RegD following resources ranged from 1.743 to 2.899 with an average over all hours of 2.543. For 2013, the MW-weighted average RegD resource performance score was 0.90 and as of December 31, 2013, there were 26 resources following the RegD signal.

The cost of each unit is calculated using its offer price, lost opportunity cost, capability MW, and the miles to MW ratio of the signal type they choose to follow, modified by resource benefit factor and historic performance score.

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

Since the implementation of regulation performance on October 1, 2012, both regulation price and regulation cost per MW are higher than they were prior to October 1, 2012, (Table 10-17). Throughout 2013, the price and cost of regulation have remained high relative to prior years. The weighted average regulation price for 2013 was $30.14/MW. The regulation cost for 2013 was $34.57/MW. The ratio of price to cost is significantly higher at 87 percent (compared with 77 percent in 2012), meaning that more of the cost of regulation is incorporated in the price.

Figure 10-3 shows the average marginal benefit factor by day compared to the average mileage ratio by day.

Demand

Demand for regulation does not change with price. The regulation requirement is set by PJM in accordance with NERC control standards, based on reliability objectives and forecast load. Prior to October 1, 2012, the regulation requirement was 1.0 percent of the forecast peak load for on peak hours and 1.0 percent of the forecast valley load for off peak hours. Between October 1, 2012, and December 31, 2012, PJM changed the regulation requirement several times. It had been scheduled to be reduced from 1.0 percent of peak load forecast to 0.9 percent on October 1, 2012, but instead it was changed from 1.0 percent of peak load forecast to 0.78 percent of peak load forecast. It was further reduced to 0.74 percent of peak load forecast on November 22, 2012 and reduced again to 0.70 percent of peak load forecast on December 18, 2012. On December 1, 2013, it was reduced to 700 MW of effective regulation during peak hours and 525 effective MW during off peak hours.

Table 10-11 shows the average hourly required regulation by month and its relationship to the supply of regulation.

Table 10-11 PJM Regulation Market required MW and ratio of eligible supply to requirement: 2012 and 2013

Month	Average Required Regulation (MW), 2012	Average Required Regulation (MW), 2013	Ratio of Supply to Requirement, 2012	Ratio of Supply to Requirement, 2013
Jan	1,005	851	3.29	3.66
Feb	979	870	3.45	4.65
Mar	876	766	3.14	4.86
Apr	826	656	3.19	2.55
May	918	678	3.26	3.91
Jun	1,055	801	3.21	4.34
Jul	1,246	911	2.94	1.66
Aug	1,134	832	2.97	2.60
Sep	941	693	3.33	4.80
Oct	772	633	4.28	1.18
Nov	708	674	4.63	2.29
Dec	701	672	5.60	4.31

PJM's performance as measured by CPS and BAAL standards has not declined as a result of the lower regulation requirement.[17]

Market Concentration

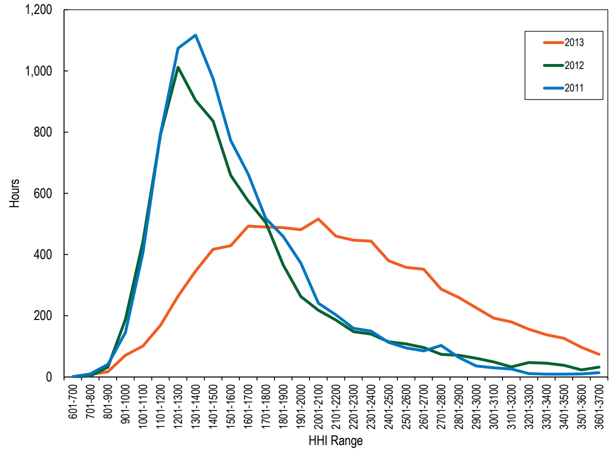
Table 10-12 shows Herfindahl-Hirschman Index (HHI) results for 2012 and 2013. The average HHI of 2115 is classified as highly concentrated and is higher than the HHI for the same period in 2012.

Table 10-12 PJM cleared regulation HHI: 2011 through 2013

Period	Minimum HHI	Weighted Average HHI	Maximum HHI
2011	818	1630	4005
2012	788	1735	4962
2013	650	2115	5650

Figure 10-6 compares the 2013 HHI distribution curves with distribution curves for 2012 and 2011. The weighted average HHI in 2013 of 2115 is 380 points higher than the HHI in 2012 of 1735 and 485 points higher than the HHI in 2011 of 1630.

Figure 10-6 PJM Regulation Market HHI distribution: 2011, 2012, and 2013



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

For 2013, the weighted-average HHI of RegD resources was 4952 (highly concentrated).

Table 10-13 includes a monthly summary of three pivotal supplier results. In 2013, 90 percent of hours had one or more pivotal suppliers which failed PJM's three pivotal supplier test. The impact of offer capping in the regulation market is limited because of the role of LOC in price formation (Figure 10-8).

The MMU concludes from these results that the PJM Regulation Market in 2013 was characterized by structural market power in 90 percent of hours.

Table 10-13 Regulation market monthly three pivotal supplier results: 2011, 2012 and 2013

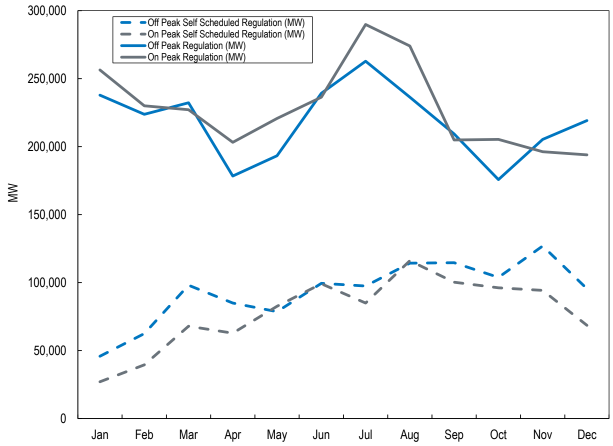
	2011	2012	2013
Month	Percent of Hours Pivotal	Percent of Hours Pivotal	Percent of Hours Pivotal
Jan	95%	71%	83%
Feb	93%	67%	82%
Mar	94%	64%	97%
Apr	97%	41%	88%
May	95%	37%	93%
Jun	89%	40%	95%
Jul	89%	13%	94%
Aug	83%	32%	92%
Sep	87%	35%	90%
Oct	67%	19%	83%
Nov	46%	18%	89%
Dec	50%	40%	95%

Market Conduct

Offers

Regulation Market participation is a function of the obligation of all LSEs to provide regulation in proportion to their load share. LSEs can purchase regulation in the Regulation Market, purchase regulation from other providers bilaterally, or self-schedule regulation to satisfy their obligation (Table 10-14).[18] Figure 10-6 compares total regulation and self-scheduled regulation during on-peak and off-peak hours.

Figure 10-7 Off peak and on peak regulation levels: 2013



Increased self-scheduled regulation lowers the requirement for cleared regulation, resulting in fewer MW cleared in the market and lower clearing prices. Of the LSEs' obligation to provide regulation in 2013, 57.7 percent was purchased in the spot market, 38.5 percent was self-scheduled, and 3.8 percent was purchased bilaterally (Table 10-14). From 2008 through 2013, Table 10-15 shows the yearly total regulation by spot regulation, self-scheduled regulation, and bilateral regulation. Total regulation MW decreased significantly in 2013.

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

Table 10-14 Regulation sources: spot market, self-scheduled, bilateral purchases: 2012 and 2013

Year	Month	Spot Regulation (MW)	Self-Scheduled Regulation (MW)	Bilateral Regulation (MW)	Total Regulation (MW)	RegA Regulation (MW)	RegD Regulation (MW)
2012	Jan	553,686	164,806	21,261	739,753	NA	NA
2012	Feb	481,004	175,757	20,456	677,217	NA	NA
2012	Mar	477,564	144,408	19,683	641,655	NA	NA
2012	Apr	426,564	124,750	21,083	572,397	NA	NA
2012	May	542,585	97,574	17,849	658,008	NA	NA
2012	Jun	582,078	140,769	22,309	745,156	NA	NA
2012	Jul	819,897	63,415	19,711	903,024	NA	NA
2012	Aug	710,715	95,949	17,687	824,350	NA	NA
2012	Sep	515,732	113,351	19,726	648,809	NA	NA
2012	Oct	287,616	162,555	1,539	451,710	435,764	15,946
2012	Nov	369,075	104,386	5,727	479,188	469,343	9,845
2012	Dec	385,468	95,903	6,378	487,749	478,367	9,382
2013	Jan	413,304	72,880	8,070	494,253	486,959	7,294
2013	Feb	338,990	102,005	12,808	453,803	444,689	9,113
2013	Mar	275,880	165,987	17,554	459,421	441,000	18,421
2013	Apr	219,793	147,858	13,860	381,510	365,856	15,654
2013	May	235,849	161,270	16,934	414,053	397,020	17,033
2013	Jun	254,215	198,617	22,816	475,647	456,494	19,153
2013	Jul	349,047	182,452	21,201	552,699	536,188	16,512
2013	Aug	258,550	230,441	21,351	510,342	488,951	21,391
2013	Sep	181,609	214,945	17,647	414,200	387,397	26,803
2013	Oct	167,857	200,079	13,073	381,009	351,915	29,094
2013	Nov	161,126	221,180	19,248	401,553	370,938	30,616
2013	Dec	229,317	164,088	19,699	413,104	387,434	25,671

Table 10-15 Regulation sources by year: 2008 through 2013

Year	Spot Regulation (MW)	Spot Percent of Total	Self-Scheduled Regulation (MW)	Self-Scheduled Percent of Total	Bilateral Regulation (MW)	Bilateral Percent of Total	Total Regulation (MW)
2009	6,437,619	86.6%	885,675	11.9%	112,129	1.5%	7,435,423
2010	6,195,368	82.2%	1,162,072	15.4%	175,489	2.3%	7,532,929
2011	6,433,365	81.8%	1,226,492	15.6%	207,421	2.6%	7,867,278
2012	6,151,984	78.6%	1,483,624	19.0%	193,409	2.5%	7,829,016
2013	3,085,535	57.7%	2,061,801	38.5%	204,259	3.8%	5,351,595

Demand resources (DR) offered and cleared regulation for the first time in November, 2011. In April 2012, a tariff change allowing DR to offer regulation in increments as small as 0.1 MW facilitated participation by DR. In 2013, DR provided an average of 2.46 MW of regulation per hour. Generating units supplied an average of 804.36 MW of regulation per hour.

Market Performance

Price

The weighted average RMCP for 2013 was $30.14/MW. This is the average price per capability MW, not effective MW. This is a 48.1 percent increase from the 2012 weighted average RMCP of $20.35/MW. Figure 10-8 shows the daily average Regulation Market clearing price and the opportunity cost component for the marginal units in the PJM Regulation Market.

Figure 10-8 PJM Regulation Market daily weighted average market-clearing price, marginal unit opportunity cost and offer price (Dollars per MW): 2013

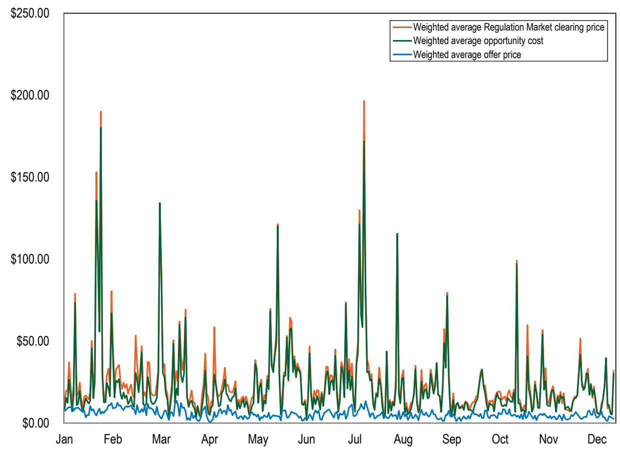


Table 10-16 shows monthly average regulation market clearing price, average marginal unit offer price, and average marginal unit LOC.

Table 10-16 PJM Regulation Market monthly weighted average market-clearing price, marginal unit opportunity cost and offer price (Dollars per MWh): 2013

Month	Weighted Average Regulation Market Clearing Price	Weighted Average Regulation Marginal Unit Offer	Weighted Average Regulation Marginal Unit LOC
Jan	$39.94	$7.72	$39.62
Feb	$29.51	$9.37	$23.01
Mar	$31.64	$5.02	$27.10
Apr	$26.49	$5.07	$14.48
May	$33.42	$4.32	$30.52
Jun	$29.81	$4.41	$20.18
Jul	$50.12	$5.97	$32.98
Aug	$27.60	$4.30	$20.75
Sep	$25.98	$3.71	$17.44
Oct	$23.30	$5.12	$16.99
Nov	$21.45	$3.84	$15.62
Dec	$22.43	$4.20	$18.18

Total scheduled regulation MW, total regulation charges, regulation price and regulation cost are shown in Table 10-17.

Table 10-17 Total regulation charges: 2013 and 2012

Year	Month	Scheduled Regulation (MW)	RegA Charges	RegD Charges	Total Regulation Charges	Weighted Average Regulation Market Price	Cost of Regulation (per MW Regulation)	Price as Percentage of Cost
2012	Jan	739,753	$13,338,201	NA	$13,338,201	$13.41	$18.03	74%
2012	Feb	677,217	$10,108,296	NA	$10,108,296	$11.89	$14.93	80%
2012	Mar	641,655	$11,109,763	NA	$11,109,763	$12.61	$17.31	73%
2012	Apr	572,397	$9,038,430	NA	$9,038,430	$13.01	$15.79	82%
2012	May	658,008	$16,248,950	NA	$16,248,950	$17.44	$24.69	71%
2012	Jun	745,156	$14,181,461	NA	$14,181,461	$14.91	$19.03	78%
2012	Jul	903,024	$29,228,039	NA	$29,228,039	$20.73	$32.37	64%
2012	Aug	824,350	$18,273,264	NA	$18,273,264	$15.86	$22.17	72%
2012	Sep	648,809	$13,593,245	NA	$13,593,245	$14.41	$20.95	69%
2012	Oct	451,710	$21,360,986	$728,584	$22,089,570	$39.80	$48.90	81%
2012	Nov	479,188	$24,103,561	$804,645	$24,908,205	$42.71	$51.98	82%
2012	Dec	487,749	$14,346,214	$624,134	$14,970,348	$27.39	$30.69	89%
2013	Jan	494,253	$22,013,590	$857,101	$22,870,690	$39.94	$46.27	86%
2013	Feb	453,803	$14,668,673	$604,931	$15,273,604	$29.51	$33.66	88%
2013	Mar	459,421	$15,933,732	$744,677	$16,678,410	$31.64	$36.30	87%
2013	Apr	381,510	$11,334,101	$595,998	$11,930,098	$26.49	$31.27	85%
2013	May	414,053	$14,914,435	$685,056	$15,599,491	$33.42	$37.68	89%
2013	Jun	475,647	$15,360,763	$638,914	$15,999,677	$29.81	$33.64	89%
2013	Jul	552,699	$30,411,682	$975,050	$31,386,733	$50.12	$56.79	88%
2013	Aug	510,342	$15,230,247	$635,871	$15,866,117	$27.60	$31.09	89%
2013	Sep	414,200	$11,472,333	$731,501	$12,203,834	$25.98	$29.46	88%
2013	Oct	381,009	$9,279,497	$875,974	$10,155,471	$23.30	$26.65	87%
2013	Nov	401,553	$8,772,784	$1,235,308	$10,008,092	$21.45	$24.92	86%
2013	Dec	413,104	$9,624,420	$1,563,940	$11,188,360	$22.43	$27.08	83%

The capability, performance, and opportunity cost components of the cost of regulation into it are shown in Table 10-18.

Table 10-18 Components of regulation cost: 2013

Month	Scheduled Regulation (MW)	Cost of Regulation Capability ($/MW)	Cost of Regulation Performance ($/MW)	Opportunity Cost ($/MW)	Total Cost ($/MW)
Jan	494,253	$33.74	$6.25	$6.28	$46.27
Feb	453,803	$25.50	$4.10	$4.06	$33.66
Mar	459,421	$28.31	$3.46	$4.53	$36.30
Apr	381,510	$23.21	$3.36	$4.69	$31.27
May	414,053	$30.44	$3.01	$4.22	$37.68
Jun	475,647	$26.80	$3.09	$3.74	$33.64
Jul	552,699	$46.08	$4.11	$6.59	$56.79
Aug	510,342	$22.93	$4.76	$3.40	$31.09
Sep	414,200	$22.02	$4.05	$3.40	$29.46
Oct	381,009	$19.33	$4.02	$3.30	$26.65
Nov	401,553	$17.66	$4.77	$2.49	$24.92
Dec	413,104	$16.43	$7.58	$3.07	$27.08

A comparison of monthly average RMCP credits per Effective MW earned by RegA and RegD resources in 2013 is shown in Figure 10-9. On November 1, 2013, PJM removed the marginal benefits factor from all settlement calculations. In its place, PJM inserted the mileage ratio for the performance credit only. In Figure 10-9, the RegA RMCP Credit per effective MW is, on average, 2.58 times higher than the RegD RMCP Credit per effective MW from January through October 2013. However, in November and December 2013, the RegA RMCP Credit per effective MW is only 1.68 times higher than the RegD RMCP Credit per effective MW. Were the marginal benefit factor correctly applied to settlements, the RegA RMCP Credit per effective MW would be equal to the RegD RMCP credit per effective MW.

Figure 10-9 Comparison of monthly average RegA and RegD RMCP Credits per Effective MW: 2013

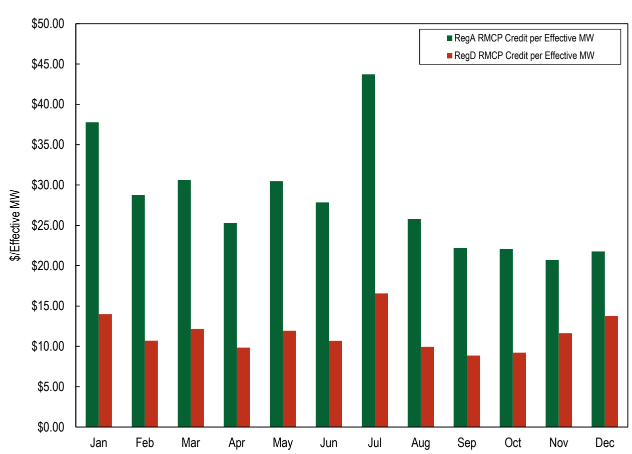


Table 10-19 provides a comparison of the average price and cost for PJM Regulation. The difference between the Regulation Market price and the actual cost of regulation was less in 2013 than it was in 2012. This is an improvement which resulted from the use of actual within-hour five-minute LOC based on real-time LMP instead of forecast LMP as was done prior to the implementation of shortage pricing on October 1, 2012.

Table 10-19 Comparison of average price and cost for PJM Regulation, 2007 through 2013

Period	Weighted Regulation Market Price	Weighted Regulation Market Cost	Regulation Price as Percent Cost
2007	$36.86	$52.91	70%
2008	$42.09	$64.43	65%
2009	$23.56	$29.87	79%
2010	$18.08	$32.07	56%
2011	$16.21	$29.28	55%
2012	$20.35	$26.41	77%
2013	$30.14	$34.57	87%

Primary Reserve

Reserves are sources of energy that can be made available within a defined time for the purpose of correcting an imbalance between supply and demand. The PJM markets have three types of reserves to satisfy three classes of imbalance. Regulation is short-term reserve that can be adjusted up or down following either a slow or fast signal to keep the ACE within defined bounds. Primary Reserve is ten minute reserve which can be sustained for up to thirty minutes to correct a disturbance.[19,20]

PJM utilizes two products, synchronized reserve and non-synchronized reserve, to provide primary reserve, both of which are available within ten minutes. Synchronized reserve is on line and synchronized to the grid. Non-synchronized reserve may be provided by any unit not synchronized to the grid but capable of

19 NERC uses the term contingency reserves, which are reserves available within 15 minutes and that may be on line or off line. PJM criteria require response within 10 minutes. PJM meets the NERC requirements through primary reserves.

20 The NERC defines reporting and response requirements for disturbance events in "NERC Performance Standard BAL-002-0, Disturbance Control Performance" and PJM defines its corresponding obligations in Manual M-12. See PJM. "Manual 12. Balancing Operations" Revision 30. Attachment D. "Disturbance Control Performance/Standard" (December 1, 2013), p. 85.

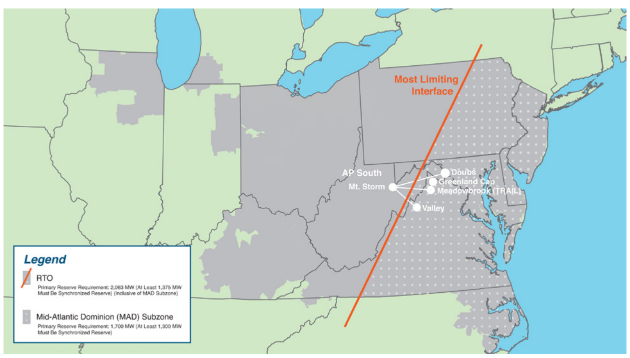
providing energy within ten minutes, for example run of river hydro, pumped hydro, CTs, some CCs and diesels.

Requirements

For the RTO Reserve Zone the primary reserve requirement is 150 percent of the largest contingency in the PJM footprint. The primary reserve requirement for the RTO is currently 2,063 MW. Exceptions to this requirement can occur when grid maintenance or outages change the largest contingency. The actual hourly average RTO primary reserve requirement was 2,085 MW in 2013.

PJM recognizes that transmission constraints limit the deliverability of reserves within the RTO, and therefore creates a subzone within the RTO called the Mid-Atlantic Dominion (MAD) Subzone. Of the 2,063 MW requirement for primary reserve in the RTO, 1,700 MW must be deliverable to the Mid-Atlantic Dominion Subzone (Figure 10-10).

Figure 10-10 PJM RTO geography and primary reserve requirement



Of 2,063 MW of primary reserve, PJM requires that at least 1,375 MW be on line and synchronized to the grid. The synchronized reserve requirement is 100 percent of the largest contingency. Of the 1,375 MW of synchronized reserve requirement for the RTO, 1,300 MW must be deliverable to the Mid-Atlantic Dominion Subzone.

The Mid-Atlantic Dominion Reserve Subzone is defined dynamically by the most limiting constraint. In approximately 58 percent of hours in 2013, that constraint was the Bedington–Black Oak Figure 10-10 transfer interface constraint. Between January 1, 2013, and May 31, 2013, the reserve interface was defined by the set of all resources with a three percent or greater DFAX raise help on the constrained side of the Bedington–Black Oak constraint. From June 1, 2013, through December 31, 2013, PJM determined the most limiting interface in real time.[21] The changes to the reserve interface increased the supply of tier 1 synchronized reserve available in the Mid-Atlantic Dominion Subzone thereby decreasing the amount of tier 2 synchronized reserve required (Figure 10-11).

The components of the Mid-Atlantic Dominion Primary Reserve Zone primary reserve solution in order of increasing cost are: tier 1 synchronized reserve available within the Mid-Atlantic Dominion Primary Reserve Zone; tier 1 synchronized reserve available across the most limiting constraint from the west as seen by the short term market solution; demand response which is tier 2 synchronized reserve; inflexible tier 2 generation reserve scheduled and priced economically by the hourly solution; and flexible tier 2 synchronized reserve scheduled by the short term market solution intra-hour if needed.

Figure 10-11 Components of Mid-Atlantic Dominion Subzone primary reserve and reserve clearing prices (Daily Averages): 2013

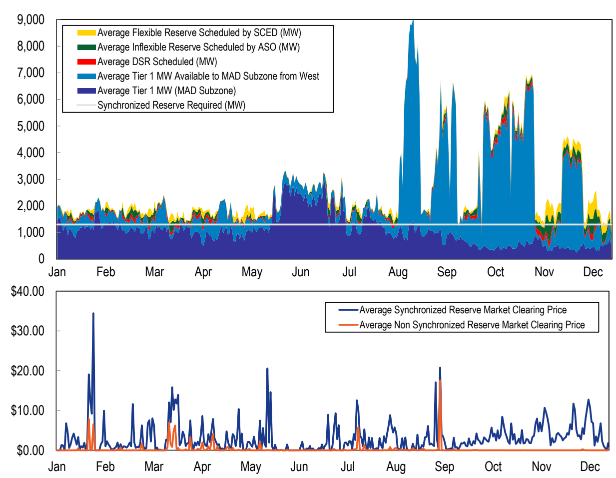


Figure 10-11 shows that tier 1 synchronized reserve remains the major contributor to satisfying the reserve requirements and tier 1 synchronized reserve available inside the subzone from the RTO Zone is a major contributor to satisfying the Mid-Atlantic Dominion (MAD) subzone synchronized reserve requirement.

21 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 62 (January 6, 2014), p. 66.

On October 1, 2012, PJM created a new Non-Synchronized Reserve Market and established a requirement that all on-line, non-emergency, generation capacity resources must offer tier 2 synchronized reserve in accordance with the resources' capability to provide these reserves.[22]

If PJM issues a primary reserve warning, voltage reduction warning, or manual load dump warning, all off line non-emergency generation capacity resources available to provide energy must submit an offer for tier 2 synchronized reserve.[23] This rule ensures that short-term and intermediate-term market software solutions will be able to make accurate estimates of the amount of primary reserve available.

Synchronized Reserve Market

PJM operates a Synchronized Reserve Market in the RTO Synchronized Reserve Zone. The Synchronized Reserve Market clears Tier 2 synchronized reserve to satisfy the synchronized reserve requirement minus the Tier 1 MW available. Both Tier 1 and Tier 2 consist of units synchronized to the grid.

Tier 2 synchronized reserve units can be flexible or inflexible. Inflexible units are scheduled by the hourly market solution sixty minutes before the operating hour, are committed to provide synchronized reserve for the entire hour, and are paid the higher of the SRMCP or their offer price plus LOC (demand response resources are paid SRMCP). Flexible units can be assigned to either synchronized reserve or to energy depending on the economic solution.

Market Structure

Supply

For 2013, the supply of offered and eligible tier 2 synchronized reserve was stable and adequate in both the RTO Reserve Zone and the Mid-Atlantic Dominion Reserve Subzone. The contribution of demand resources to the Tier 2 Synchronized Reserve Market was significant. On December 6, 2012, PJM increased the DR limit from 25 percent to 33 percent of the total synchronized reserve requirement.

The Tier 2 Synchronized Reserve Market cleared an hourly average 153.8 MW in 2013. The DR share of the total Tier 2 Synchronized Reserve Market increased from 29.8 percent in 2012 to 48.1 percent in 2013.[24] A change to the way the most limiting constraint was calculated and the integration of the EKPC zone on June 1, 2013 made more Tier 1 reserve available to the MAD subzone (Figure 10-11).

Between October 1, 2013 and December 31, 2013, PJM implemented several changes in the way tier 1 available MW is estimated.[25] The effect of these changes was to reduce the estimates of tier 1 and to increase the amount of tier 2 MW cleared (Figure 10-11). The changes included: capping the tier 1 estimate at the lesser of a generator's economic maximum or its spinning maximum value (spinning maximum is a parameter defined as the maximum output a unit can attain within ten minutes); excluding hydro units from tier 1 estimates; excluding combined cycle units from tier 1 estimates unless they have a spinning maximum value less than their economic maximum value; and excluding any unit requiring manual dispatch. The impact of these changes can be seen in Figure 10-11.

Demand

The default hourly required synchronized reserve requirement is 1,375 MW and the requirement for the MAD subzone is 1,300 MW.[26]

Table 10-20 Tier 2 Synchronized Reserve Markets required MW, RTO Zone and Mid-Atlantic Dominion Subzone, December 2008 through December 2013

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

Exceptions to the requirement can occur when grid maintenance or outages change the largest contingency. Exceptions in 2013 are listed in Table 10-21.

22 FERC Order 755, p. 195.

23 See PJM. "Manual 11: Energy and Ancillary Services Market Operations" Revision 64, (January 6, 2014), p. 63.

24 The cap on demand response participation is defined in MW terms. There is no cap on the proportion of cleared demand response consistent with the MW cap.

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

26 NERC defines reporting and response requirements for disturbance events in "NERC Performance Standard BAL-002-0, Disturbance Control Performance" and PJM defines its corresponding obligations in Manual M-12. See PJM. "Manual 12: Balancing Operations" Revision 30, Attachment D, "Disturbance Control Performance/Standard" (December 1, 2013), p. 85.

Table 10-21 Exceptions to RTO Zone Synchronized Reserve requirement: 2013

From Day	To Day	Temporary Synchronized Reserve Requirement (MW)
2-Feb	3-Feb	1,780
4-Sep	8-Sep	1,650
25-Sep	27-Sep	2,572
22-Oct	23-Oct	2,572
26-Oct	27-Oct	1,725
11-Nov	18-Nov	2,140
18-Nov	20-Nov	1,761
20-Nov	23-Nov	2,320
16-Dec	21-Dec	2,640

The market demand for tier 2 synchronized reserve in the Mid-Atlantic Dominion subzone is determined by subtracting the amount of forecast tier 1 synchronized reserve available in the subzone plus the amount of tier 1 available from the RTO Zone from the subzone's requirement each five-minute period. Market demand is also reduced by subtracting the amount of self-scheduled tier 2 resources.

Figure 10-12 shows the average monthly synchronized reserve required and the average monthly Tier 2 synchronized reserve MW scheduled in 2013, for the Mid-Atlantic Dominion Reserve Market.

Supply and Demand

In the RTO Synchronized Reserve Zone 14.5 percent of hours cleared a synchronized reserve market in 2013 averaging 251.6 MW. The change to the estimates of tier 1 had a significant impact on the frequency of clearing an RTO Synchronized Reserve Market. An RTO Tier 2 Synchronized Reserve Zone Market was cleared in fewer than 3.0 percent of hours from January through September but in 49.6 percent of the hours from October 1 through December 31.

In the Mid-Atlantic Dominion Subzone a Tier 2 Synchronized Reserve Market was cleared in 45.9 percent of hours at an average of 153.8 MW for cleared hours. This is a reduction from the average of 448.0 MW cleared in all of 2012. The change to the estimates of tier 1 had a significant impact on the frequency of clearing an RTO Synchronized Reserve Market. An RTO Tier 2 Synchronized Reserve Zone Market was cleared in 33.5 percent of hours from January through September but in 83.2 percent of hours from October through December.

In 2013, the average Tier 2 Synchronized Reserve Market Clearing Price in the RTO Zone for all cleared hours was $7.98. In 2013 the average Tier 2 synchronized reserve market clearing price in the MAD subzone for all cleared hours was $6.98.

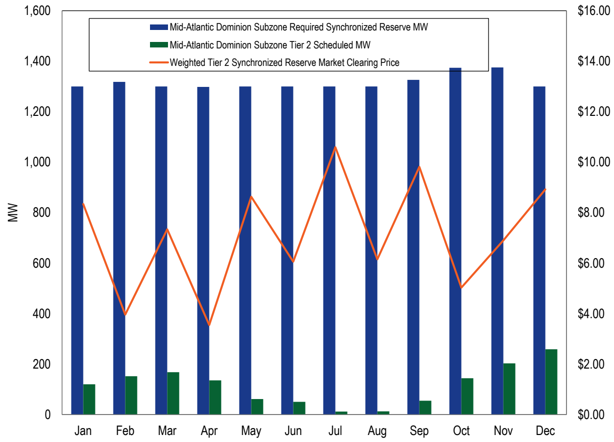
A synchronized reserve shortage occurs when the combination of Tier 1 and Tier 2 synchronized reserve is not adequate to meet the synchronized reserve requirement. No synchronized reserve shortages were identified by PJM in 2013. A primary reserve shortage occurs when the combination of tier 1, tier 2, and non-synchronized reserve is not adequate to meet the primary reserve requirement. No primary reserve shortages were identified by PJM in 2013.

The ratio of offered and eligible synchronized reserve MW to the synchronized reserve required (1,300 MW) was 1.29 for the Mid-Atlantic Dominion subzone for 2013, a decrease from the 1.40 ratio in 2012.

In late May and early June, PJM made several changes to the Tier 2 Synchronized Reserve Market which increased the reserve available in the RTO Zone, the tier 1 available across the interface into the MAD subzone, and the available tier 2 inside the MAD subzone. The reserve interface was made dynamic with the most limiting constraint calculated in real time. The calculation of the interface limit was changed from calculating the effect of all units with a three percent or greater raise help on the constrained side of the interface to calculating the effect from all units. The EKPC Region was integrated into the RTO Zone on June 1, 2013.

In 58 percent of hours in 2013, Bedington-Black Oak was the most limiting interface. In 38 percent of hours, AP South was the most limiting interface. In 4 percent of hours, the Western Interface was the most limiting interface.

Figure 10-12 Mid-Atlantic Dominion Reserve Subzone average hourly synchronized reserve required vs. tier 2 synchronized reserve scheduled MW: 2013



Market Concentration

The HHI for settled tier 2 synchronized reserve during cleared hours of the Mid-Atlantic Dominion subzone Tier 2 Synchronized Reserve Market for 2013 was 4205, which is defined as highly concentrated. The HHI for 2012 for the Mid-Atlantic Subzone Tier 2 Synchronized Reserve Market was 3570, which is also defined as highly concentrated. 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, unchanged from 2012. Most Tier 2 synchronized reserve is provided by inflexible scheduled resources.[27] When there is not enough Tier 2 during the market hour or when the intermediate or short term market solution identifies a need, flexible reserve units are assigned spinning. The amount of flexible synchronized reserve assigned is 12.2 percent of all tier 2 synchronized reserve in the MAD subzone in 2013. The hourly average HHI in 2013 was 8743 for flexible resources actually assigned during the hour.

The market structure results indicate that the Mid-Atlantic Dominion subzone Tier 2 Synchronized Reserve Market, the only synchronized reserve market that clears on a regular basis, is not structurally competitive.

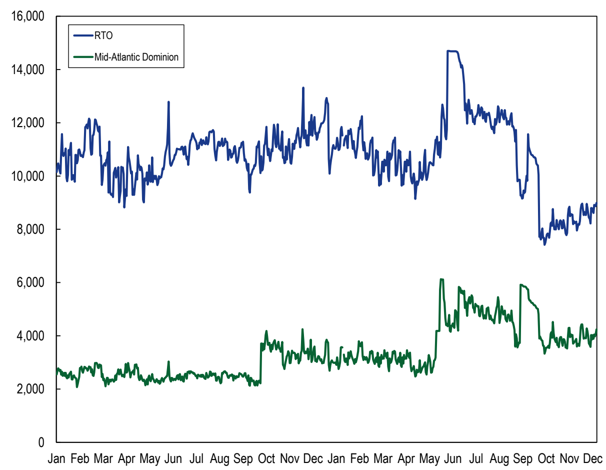
Market Behavior

Offers

Daily cost based offer prices are submitted for each unit by the unit owner. The synchronized reserve offer made by the unit owner is subject to an offer cap of marginal cost plus $7.50 per MW, plus lost opportunity cost. All suppliers are paid the higher of the market clearing price or their offer plus their unit specific opportunity cost. Figure 10-13 shows the daily average of hourly offered tier 2 synchronized reserve MW for both the RTO Synchronized Reserve Zone and the Mid-Atlantic Dominion Synchronized Reserve Subzone.

After October 1, 2012, PJM adopted a new rule making synchronized reserve a must-offer requirement for all generation that is on-line, non-emergency, and available to produce energy. Compliance with this rule has been slow. As of late December 2013, approximately 13.7 percent of eligible resources do not comply with this requirement.

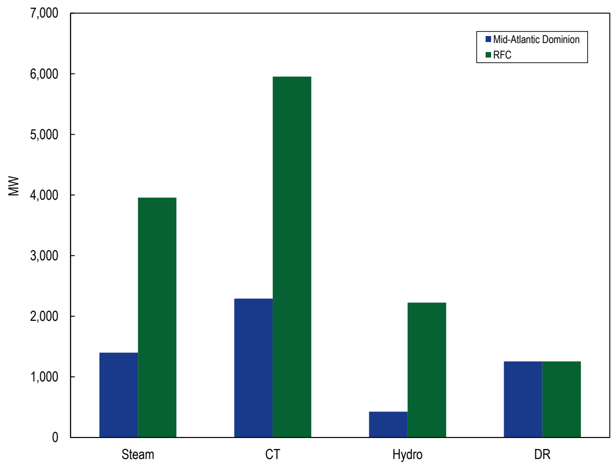
Figure 10-13 Tier 2 synchronized reserve daily average offer volume (MW): January 2012 through December 2013



Synchronized reserve is offered by steam, CT, hydroelectric and DR resources. Figure 10-14 shows average offer MW volume by market and unit type.

27 See the *2013 State of the Market Report for PJM*, Volume II, Appendix F, Ancillary Service Markets, Synchronized Reserve Market Clearing. With shortage pricing, PJM divided synchronized reserve into flexible and inflexible. A synchronized reserve resource can be either flexible or inflexible, but not both. Inflexible resources must be dispatched, which means incurring lost opportunity costs and/or startup and fuel costs associated with their synchronized reserve dispatch point. Flexible units can respond more quickly to a spinning event and need not be moved from their economic dispatch at the time the ASO or IT-SCED runs.

Figure 10-14 Average daily tier 2 synchronized reserve offer by unit type (MW): 2013



DR

Demand resources are a significant part of the Synchronized Reserve Market. In 2013, DR was 38 percent of all cleared Tier 2 synchronized reserves, compared to 36 percent for 2012.

Market Performance

Price

Figure 10-15 shows the weighted average tier 2 price and the cost per MW to meet synchronized reserve demand in the Mid-Atlantic Dominion subzone. The price of tier 2 synchronized reserve is the synchronized reserve market clearing price (SRMCP).

Table 10-22 shows the monthly weighted average SRMCP, all credits including LOC credits, credits paid to tier 1 resources when the Non Synchronized Reserve Market Clearing Price is above $0, MW scheduled by PJM, MW self scheduled, and MW added by either the intermediate or short term market solution software for the Mid-Atlantic Dominion subzone. The weighted average price for synchronized reserve in the Mid-Atlantic Dominion subzone 2013 was $6.98 while the cost of synchronized reserve was $13.07. The price for synchronized reserve in 2012 was $8.02 while the cost was $12.71.

The RTO Reserve Zone synchronized reserve requirement was satisfied by Tier 1 in 97 percent all hours of January through September 2013. In October through December, 2013, after the change to the calculation of estimated tier 1 synchronized reserve, the RTO Reserve Zone requirement was satisfied by tier 1 in only 52 percent of hours. The MAD reserve subzone synchronized reserve requirement was satisfied by tier 1 in 54 percent of hours in January through September of 2013. In October through December, 2013 after the change to the calculation of estimated tier 1 synchronized reserve, the MAD reserve subzone synchronized reserve requirement was satisfied by tier 1 in only 16 percent of hours.

For all of 2013, in the MAD subzone, in the tier 2 synchronized reserve market the average synchronized reserve market clearing price was $6.98. The maximum synchronized reserve market clearing price was $210.07.

In 9.5 percent of the hours in which synchronized reserve was cleared, all cleared MW were DR. In the hours when

Table 10-22 Mid-Atlantic Dominion Subzone weighted synchronized reserve market clearing prices, credits, and MWs: 2013

Year	Month	Weighted Tier 2 Synchronized Reserve Market Clearing Price	Tier 2 Synchronized Reserve Credits	Tier 1 Credits When NSR Prices are Above $0	PJM Tier 2 and DSR Scheduled Synchronized Reserve (MW)	Flexible Tier 2 Synchronized Reserve Added by SCED (MW)	Self Scheduled Tier 2 Synchronized Reserve MW
2013	Jan	$8.34	$1,241,545	$1,201,252	66,682	15,270	102
2013	Feb	$3.96	$1,237,024	$264,087	86,561	41,251	598
2013	Mar	$7.34	$2,303,326	$2,408,969	124,913	14,727	0
2013	Apr	$3.55	$981,153	$1,208,482	103,897	3,362	165
2013	May	$8.63	$783,952	$696,039	45,746	5,815	140
2013	Jun	$6.06	$354,786	$293,787	22,207	3,432	0
2013	Jul	$10.59	$1,798,168	$2,523,518	70,652	7,029	0
2013	Aug	$6.15	$817,829	$1,213,299	61,389	4,649	291
2013	Sep	$9.81	$1,444,831	$2,071,443	79,412	13,660	892
2013	Oct	$5.03	$1,683,055	$136,521	150,382	26,727	14,478
2013	Nov	$6.90	$2,570,725	$6,459	165,272	15,816	100,888
2013	Dec	$8.92	$2,781,599	$112,207	156,749	5,355	158,239
Total		$6.98	$17,997,993	$12,136,062	1,133,862	157,093	275,793

all cleared MW were DR, the weighted average SRMCP was $1.21. The weighted average SRMCP for all cleared hours was $6.98.

Table 10-23 Weighted average 2013 SRMCP with and without DR: Mid-Atlantic Dominion Sub-zone

Year	Month	Average SRMCP for all cleared hours	Average SRMCP when all Cleared synchronized reserve is DR	Percent of cleared hours all synchronized reserve is DR
2013	Jan	$8.34	$0.14	17%
2013	Feb	$3.96	$0.07	10%
2013	Mar	$7.34	$0.06	19%
2013	Apr	$3.55	$0.00	19%
2013	May	$8.63	$0.46	23%
2013	Jun	$6.06	$0.00	8%
2013	Jul	$10.59	$0.07	6%
2013	Aug	$6.15	$0.70	29%
2013	Sep	$9.81	$1.90	25%
2013	Oct	$5.03	$2.44	36%
2013	Nov	$6.90	$2.43	15%
2013	Dec	$8.92	NA	0%

Shortage pricing rules require that tier 1 synchronized reserve be paid the tier 2 synchronized reserve clearing price when the non-synchronized reserve clearing price is above $0. Tier 1 synchronized reserve has always been available to respond optionally to spinning events, but now it is also paid when the non-synchronized reserve price rises above zero. Payment for tier 1 synchronized reserve that responds to a spinning event is compensated at the average of the five-minute energy LMPs plus $50/MWh.[28] This rule significantly increases the cost of tier 1 synchronized reserves with no operational or economic reason to do so. PJM is not actually reserving any tier 1, but simply paying substantially more for the same product without any additional performance requirements.

Table 10-24 Comparison of yearly weighted average price and cost for PJM Tier 2 Synchronized Reserve, 2005 through 2013

Year	Weighted Average Tier 2 Synchronized Reserve Market Price	Weighted Average Tier 2 Synchronized Reserve Cost	Weighted Average Tier 2 Synchronized Reserve Price as Percent of Cost
2005	$13.29	$17.59	76%
2006	$14.57	$21.65	67%
2007	$11.22	$16.26	69%
2008	$10.65	$16.43	65%
2009	$7.75	$9.77	79%
2010	$10.55	$14.41	73%
2011	$11.81	$15.48	76%
2012	$8.02	$12.71	63%
2013	$6.98	$13.07	53%

Although tier 1 synchronized reserve adds no cost in most hours, PJM's shortage pricing filing resulted in extremely large charges for tier 1 reserves for a small number of hours. The rule change requires paying all Tier 1 reserves the full Tier 2 synchronized reserve clearing price in the hours when the non-synchronized reserve market clearing price is greater than zero. In 2013, 40.3 percent of payments for tier 1 synchronized reserve were paid for tier 1 synchronized reserve when it was not needed (Table 10-22). This is a windfall payment to Tier 1 reserves.

When more tier 2 was cleared after the late September change in the tier 1 calculation, there were fewer hours in which non-synchronized reserve prices rose above $0. Payments to spinning resources for Tier 1 declined in October through December 2013, because there were few spinning events and few hours in which non-synchronized reserve was cleared.

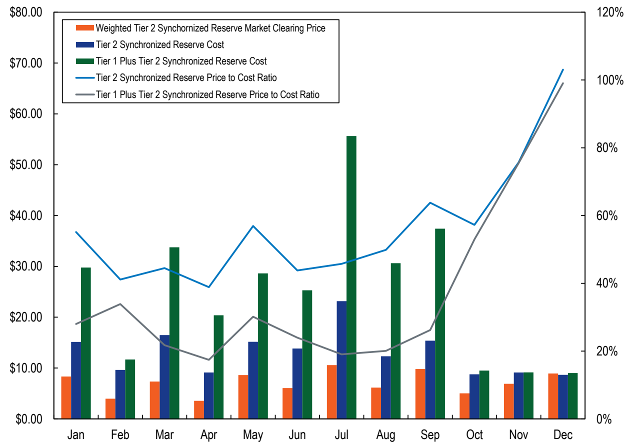
The MMU recommends that the rule requiring the payment of tier 1 synchronized reserve resources when the non-synchronized reserve price is above zero be eliminated immediately. Table 10-24 shows the price and cost history of the Tier 2 Synchronized Reserve Market since 2005.

Price and Cost

A price to cost ratio close to 1.0 is an indicator of an efficient synchronized reserve market design. In the Mid-Atlantic Dominion Subzone of the RFC Tier 2 Synchronized Reserve Market for 2013, the price of Tier 2 synchronized reserves was 56 percent of the cost. In 2012, the price to cost ratio was 63 percent. There was a significant improvement in the price to cost ratio in the MAD Tier 2 Synchronized Reserve Market in October through December, 2013 (Figure 10-15).

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

Figure 10-15 Comparison of Mid-Atlantic Dominion Subzone Tier 2 synchronized reserve weighted average price and cost (Dollars per MW): 2013



Tier 1 Bias

Each market clearing engine (hour ahead, intermediate and short term) can have its tier 1 estimate biased. Biasing means modifying the demand for synchronized reserve from the level defined by the market software. Negative tier 1 estimate biasing refers to the manual subtraction from the Tier 1 estimate that the market clearing engines uses to determine how much tier 2 MW to schedule. A negative bias reduces the amount of tier 1 estimated to be available and therefore increases the amount of tier 2 which must be purchased. Tier 1 biasing can be used by PJM dispatchers to compensate for uncertainty in short term load forecasting, generator performance, constraint binding, or uncertainly in the accuracy of the tier 1 estimate of the market solution.

PJM reduced its use of tier 1 biasing in 2013 (Figure 10-16). From July through October 2013, Tier 1 estimate was biased in 39 hours. Tier 1 biasing was not used in November or December. In 33 hours of the 39 hours it was biased negatively averaging -217 MW. In the remaining six hours it was biased positively averaging 47 MW. During the hours of negative bias the SRMCP averaged $28.22. The average SRMCP was $2.77 during all hours between July 1 and October 31.

A negative tier 1 bias means purchasing more inflexible Tier 2 MW than the market clearing software estimates it needs before the hour. The increased inflexible tier 2 resources need to be compensated for their LOC and they must be paid even if they are not needed in real time (Figure 10-17).

Figure 10-16 Use of hourly market solution tier 1 estimate biasing in the Middle Atlantic Dominion sub-zone: 2013

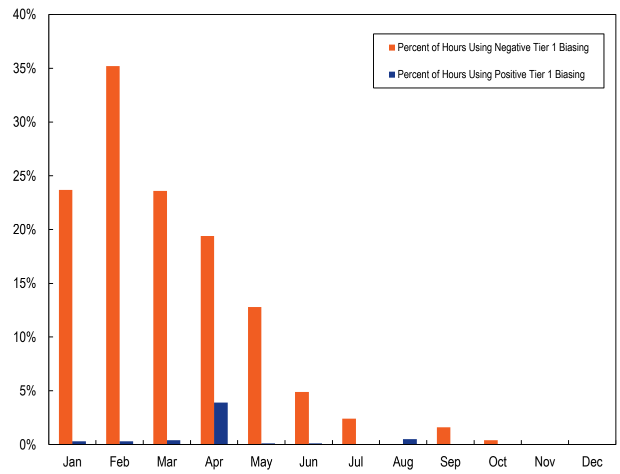
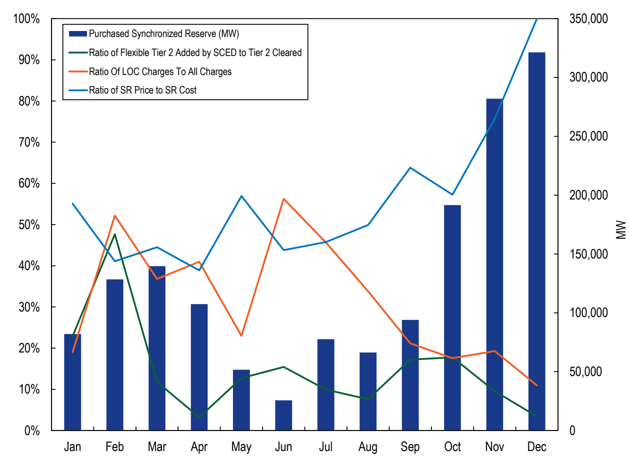


Figure 10-17 Impact of flexible tier 2 synchronized reserve added to the Mid-Atlantic Dominion Subzone Tier 2 Market: 2013



The MMU recommends that PJM be more explicit about why tier 1 biasing is used. The MMU recommends that PJM define rules for calculating available tier 1 MW and for the use of biasing during any phase of the market solution and then identify the relevant rule for each instance of biasing.

Compliance

Non-compliance in the Tier 2 Synchronized Reserve Market remains a problem. Non-compliance has two major components: failure to deliver scheduled tier 2 Synchronized Reserve MW during spinning events; and failure of non-emergency, generation resources capable of providing energy to provide a daily synchronized reserve offer.

The MMU has identified the issue of noncompliance by tier 2 synchronized reserve resources during spinning events since 2011.[29] When synchronized reserve resources clear the Tier 2 Synchronized Reserve Market they are obligated to provide their full cleared Tier 2 MW in a spinning event. The MMU has reported a wide range of spinning event response levels and recommended PJM take action to increase compliance rates. In May 2013, PJM initiated an effort to increase the penalty for non-compliance of scheduled synchronized reserve resources during spinning events. An enhanced penalty structure was approved by the PJM Operations Committee on September 30, 2013. PJM filed with the FERC and the new penalty structure was approved December 17. Penalties can be assessed for any spinning event greater than 10 minutes during which flexible or inflexible synchronized reserve was scheduled either by the resource owner or by PJM. In 2013, eight spinning events occurred that met these criteria.

Table 10-25 Synchronized reserve events greater than 10 minutes, Mid-Atlantic Dominion Tier 2 Response Compliance 2013

2013 Qualifying Spinning Events (DD-MON-YYYY HR)	Event Duration (minutes)	MAD Synchronized Reserve Market Clearing Price	Tier 2 plus DR Cleared MW	Tier 2 plus DR Added MW	Percent Tier 2 Penalized for Non Compliance	Percent DR Penalized for Non Compliance	Overall Percent of Synchronized Reserve Penalty for Non Compliance
25-JAN-2013 15	19	$150.85	34	444	20%	0%	20%
17-FEB-2013 23	13	$2.08	587	0	47%	69%	54%
17-APR-2013 01	11	$0.00	516	0	44%	48%	46%
30-JUN-2013 01	10	$5.89	689	0	37%	33%	36%
03-JUL-2013 20	13	$11.79	476	264	38%	49%	41%
15-JUL-2013 18	29	$7.49	361	0	14%	62%	35%
10-SEP-2013 19	68	$0.00	67	0	98%	73%	97%
28-OCT-2013 11	33	$3.00	264	163	0%	58%	35%

For the eight qualifying spinning events that occurred in 2013, 37 percent of all scheduled Tier 2 synchronized reserve MW were not delivered and were penalized. Of the 4,126 MW of committed synchronized reserve, 1,542 MW of failed to perform during spinning events.

The new penalty structure will increase the number of consecutive days that an underperforming resource is penalized from three days to the average number of days between spinning events. The average number of days between spinning events is currently 15 days. In addition, a resource will be penalized for the amount of MW it falls short of its offer for the entire hour, not just for the portion of the hour covered by the spinning event.[30]

A second compliance issue is failure to comply with the must offer requirement. The shortage pricing changes introduced on October 1, 2012, included a must offer requirement for Tier 2 synchronized for most generators under normal conditions, and an expanded set of generators under well-defined conditions related to peak load. For all hours, all on-line, non-emergency, generating resources that are providing energy and are capable of providing synchronized reserve are deemed available for Tier 1 and Tier 2 synchronized reserve and they must have an offer and be available for reserve. When PJM issues a primary reserve warning, voltage reduction warning, or manual load dump warning, all other non-emergency, off-line available generation capacity resources must have an offer and be available for reserve. As of December 31, 2013, the MMU estimates that 13.7 percent of eligible energy resources are not in compliance with the synchronized reserve must-offer requirement.

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

30 M-28 Operating Agreement Accounting Rev. 63, December 19, 2013, p. 43. See PJM "Energy & Ancillary Services Market Operations," rev. 64, January 6, 2014, pg. 74.

History of Spinning Events

Spinning events (Table 10-26) are usually caused by a sudden generation outage or transmission disruption (disturbance) requiring PJM to load synchronized reserve.[31] PJM also calls spinning events for non-disturbance events, which it characterizes as low ACE. The reserve remains loaded until system balance is recovered. From 2010 through 2013, PJM experienced 116 spinning events, or between two and three events per month. Spinning events had an average length of 13.3 minutes.

Table 10-26 Spinning events, 2010 through 2013

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

The spinning event of September 10, called by PJM due to low ACE, lasted 68 minutes, which is the longest spinning event in the last five years. PJM's systems did not anticipate the event, clearing low levels of tier 2 synchronized reserve as a result of overestimating the amount of tier 1 available. When the event was called, resources estimated to have available tier 1 did not respond as expected and did not resolve the imbalance. During the day of September 10, tier 2 synchronized reserve and non-synchronized reserve prices were $0.00 for 22 hours. The event spanned two market hours, 1600 and 1700. The event began in hour 1600 when the MAD SRMCP was $0, and 1700 when the SRMCP was $3.18. Low ACE that is not the result of a generator outage or transmission interruption indicates a problem with short-term load forecasting, dispatch solution, reserve measurement and/or generator compliance with instructions. Tier 1 response to the September 10 spinning event was low, approximately 20 percent. PJM has created an Energy/Reserve Pricing & Interchange Volatility (ERPIV) study group charged with understanding this event and similar hot day spinning events, reserves, and interchange behavior in the last two quarters of 2013 and recommending solutions to ensure adequate reserve response and prevent load shedding.

Analysis of spinning events similar to the 68 minute event of September 10 (RTO-wide, hot days, and longer than 12 minutes) show that the tier 1 response of September 10 was not unusual (Table 10-27).

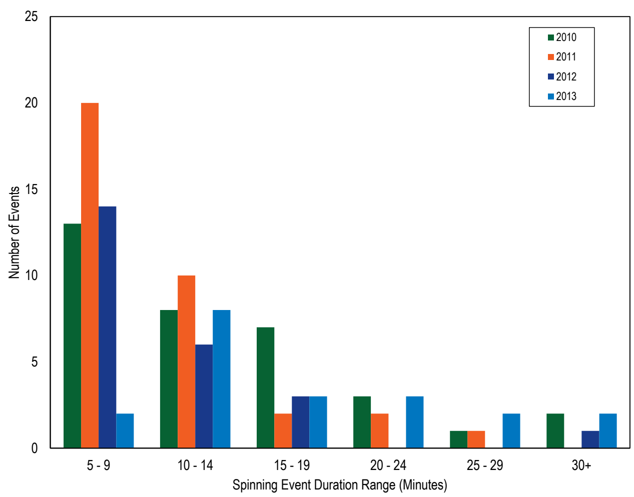
31 See PJM. "Manual 12, Balancing Operations," Revision 30 (December 1, 2013), pp. 36-37.

Table 10-27 Tier 1 Response to spinning events July 3, July 15, September 10, October 28

Market Hour	Duration (Minutes)	MAD Synchronized Reserve Market Clearing Price	RTO Synchronized Reserve Market Clearing Price	MAD Tier 1 Estimate	RTO Available Tier 1 Estimate	RTO Total Tier 1 Available	RTO Total Tier 1 Response	Percent of Tier 1 Capability Responded
July 3, 2013 Hr. 17	13	$11.79	$0.00	582	118	1837	360	20%
July 15, 2013 Hr. 15	17	$7.49	$0.00	805	530	7377	3237	44%
July 15, 2013 Hr. 16	12	$1.00	$0.00	799	543	7223	2076	29%
July 10, 2013 Hr. 16	12	$0.00	$0.00	843	388	6124	355	6%
July 10, 2013 Hr. 17	56	$3.18	$3.18	701	520	6278	1555	25%
October 28, 2013 Hr. 9	16	$2.17	$0.00	511	536	4528	902	20%
October 28, 2013 Hr. 10	17	$3.00	$0.00	508	353	4702	908	19%

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

Figure 10-18 Spinning events duration distribution curve, 2010 to 2013



Non-Synchronized Reserve Market

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 balance of primary reserve can be made up of non-synchronized reserve. Examples of equipment that generally qualify in this category are run of river hydro, pumped hydro, combustion turbines, combined cycles and diesels.[32]

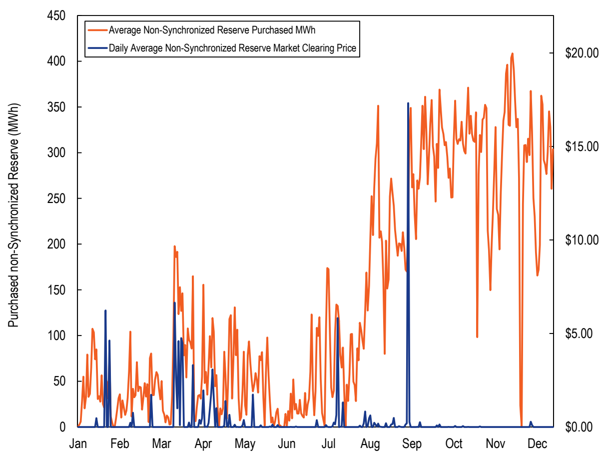
Almost all non-synchronized reserve enabled resources are CTs, with some diesels. Startup time for these units is not subject to testing. There is no non-synchronized reserve offer price. Prices are determined by the lost opportunity cost created by any deviation from economic merit order required to maintain the non-synchronized reserve commitment. In most hours the non-synchronized reserve clearing price is zero.

Figure 10-19 shows the daily average non-synchronized reserve market clearing price and average scheduled MW. The Mid-Atlantic Dominion Reserve Zone non-synchronized reserve market had a clearing price greater than zero in 228 hours in 2013 at an average price of $9.71 and a maximum of $210.07 on September 11, 2013. The non-synchronized reserve market clearing price for the RTO Reserve Zone cleared in 73 hours in 2013 at an average price of $1.81 with a maximum clearing price of $9.40 on August 24, 2013.

In 228 hours in 2013, the Non-Synchronized Reserve Market for the Mid-Atlantic Dominion Subzone cleared at greater than $0.00, averaging $9.71 with a maximum clearing price of $210.07 on September 11. Non-synchronized reserve only clears when synchronized reserve also clears.

32 See PJM. "Manual 11, Energy & Ancillary Services Market Operations" Revision 64 (January 6, 2014), p. 77.

Figure 10-19 Daily average Non-Synchronized Reserve Market clearing price and MW purchased: 2013



Day-Ahead Scheduling Reserve (DASR)

The Day-Ahead Scheduling Reserve Market is a market based mechanism for the procurement of supplemental, 30-minute reserves on the PJM System.[33]

The DASR 30-minute reserve requirements are determined by the reliability region.[34] In the ReliabilityFirst (RFC) region, reserve requirements are calculated based on historical under-forecasted load rates and generator forced outage rates.[35] The RFC and Dominion DASR requirements are added together to form a single RTO DASR requirement which is obtained via the DASR Market. The requirement is applicable for all hours of the operating day. If the DASR Market does not result in procuring adequate scheduling reserves, PJM is required to schedule additional operating reserves.

Market Structure

In 2013, the required DASR is 6.91 percent of peak load forecast, down from 7.03 percent in 2012.[36] The DASR requirement is a sum of the load forecast error and the forced outage rate. The load forecast error increased from 1.97 percent in 2012 to 2.13 percent in 2013 and the forced outage rate decreased from 4.93 percent to 4.66 percent. Added together, the 2013 DASR requirement is 6.91 percent. The DASR MW purchased averaged 6,805 MW per hour for 2013, a slight decrease from 6,841 MW per hour in 2012.

In 2013, no hours failed the three pivotal supplier test in the DASR Market. No hours failed the three pivotal supplier test in 2012.

All generation resources are required to offer DASR.[37] Load response resources which are registered in PJM's Economic Load Response and are dispatchable by PJM are also eligible to provide DASR. No demand resources offered in the DASR market in 2013.

Market Conduct

PJM rules allow any unit with reserve capability that can be converted into energy within 30 minutes to offer into the DASR Market.[38] Units that do not offer have their offers set to $0.00 per MW.

Economic withholding remains an issue in the DASR Market. The direct marginal cost of providing DASR is zero. However, there is a positive opportunity cost in addition to this direct marginal cost, which is not part of the offer price but is calculated by PJM. As of December 31, 2013, 12 percent of all units offered DASR at levels above $5 per MW. The impact on DASR prices of high offers was minor as a result of a favorable balance between supply and demand.

Market Performance

For 82 percent of hours in 2013, DASR cleared at a price of $0.00 (Figure 10-20). For 2013, the weighted DASR price was $0.70. The highest price was $230.10 on July 17, 2013. DASR prices are calculated as the sum of the offer price plus the opportunity cost. For most hours the price is comprised entirely of the offer price. When the DASR clearing price is greater than $0.00, 84 percent of the time the price consists solely of the offer price. The offer and LOC components of price are in Figure 10-20.

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

34 See PJM. "Manual 13, Emergency Requirements," Revision 55 (January 1, 2014), p. 11.

35 See PJM. "Manual 10, Pre-Scheduling Operations," Revision 29 (November 1, 2013), pp. 19-20.

36 See the *2012 State of the Market Report for PJM*, Volume II, Section 9, "Ancillary Services" at Day Ahead Scheduling Reserve (DASR).

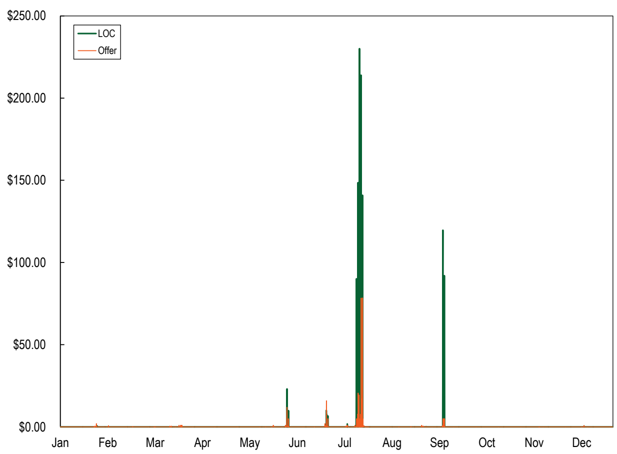
37 See PJM "Manual 11 " Revision 64, (January 6, 2014) p. 138 at Day-ahead Scheduling Reserves Market Rules.

38 See PJM. "Manual 11, Emergency and Ancillary Services Operations," Revision 63 (January 6, 2014), p. 143.

Table 10-28 PJM Day-Ahead Scheduling Reserve Market MW and clearing prices: 2012 and 2013

Year	Month	Average Required Hourly DASR (MW)	Minimum Clearing Price	Maximum Clearing Price	Weighted Average Clearing Price	Total DASR MW Purchased	Total DASR Credits
2013	Jan	6,965	$0.00	$2.00	$0.01	5,182,020	$45,337
2013	Feb	6,955	$0.00	$0.75	$0.00	4,673,491	$20,062
2013	Mar	6,543	$0.00	$1.00	$0.02	4,861,811	$75,071
2013	Apr	5,859	$0.00	$0.05	$0.00	4,218,720	$8,863
2013	May	6,129	$0.00	$23.37	$0.20	4,560,238	$873,943
2013	Jun	7,262	$0.00	$15.88	$0.12	5,228,554	$615,557
2013	Jul	8,129	$0.00	$230.10	$6.76	6,015,476	$37,265,364
2013	Aug	7,559	$0.00	$1.00	$0.01	5,623,824	$55,766
2013	Sep	6,652	$0.00	$119.62	$1.23	4,789,728	$5,245,835
2013	Oct	6,077	$0.00	$0.05	$0.00	4,497,258	$2,363
2013	Nov	6,479	$0.00	$0.10	$0.00	4,665,156	$5,123
2013	Dec	7,033	$0.00	$0.80	$0.01	5,232,625	$25,192
2012	Jan	6,944	$0.00	$0.02	$0.00	5,166,216	$604
2012	Feb	6,777	$0.00	$0.02	$0.00	4,716,710	$2,037
2012	Mar	6,180	$0.00	$0.05	$0.00	4,591,937	$5,031
2012	Apr	5,854	$0.00	$0.10	$0.00	4,214,993	$5,572
2012	May	6,491	$0.00	$5.00	$0.05	4,829,220	$226,881
2012	Jun	7,454	$0.00	$156.29	$2.39	5,366,935	$11,422,377
2012	Jul	8,811	$0.00	$155.15	$3.69	6,520,522	$20,723,970
2012	Aug	8,007	$0.00	$55.55	$0.51	5,956,318	$2,601,271
2012	Sep	6,656	$0.00	$7.80	$0.12	4,805,769	$540,586
2012	Oct	6,022	$0.00	$0.04	$0.00	4,454,997	$5,878
2012	Nov	6,371	$0.00	$1.00	$0.02	4,584,792	$75,561
2012	Dec	6,526	$0.00	$0.05	$0.00	5,179,876	$5,975

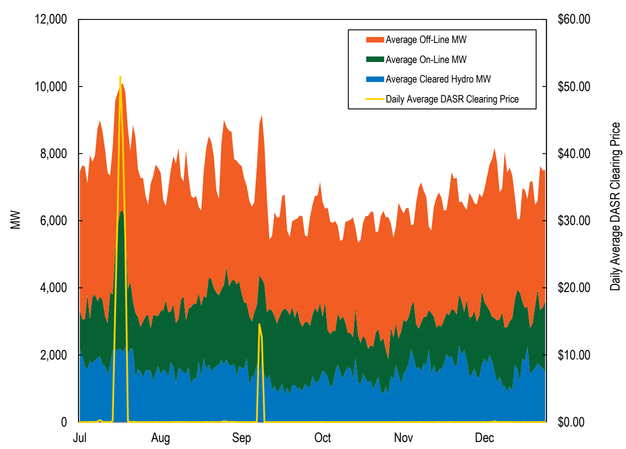
Figure 10-20 Hourly components of DASR clearing price: 2013



The secondary reserve requirement (DASR) is usually satisfied at no cost and with no need to redispatch energy resources. The amount of reserve available from hydro and off-line resources is relatively static. But when energy demand is high the reserve requirement cannot be filled without redispatching online resources which significantly affects the price. Figure 10-20 shows the impact on price when online resources must be redispatched to satisfy the DASR requirement.

Figure 10-21 illustrates the sensitivity of DASR prices to high energy dispatch and the resource types (on-line, off-line, and hydro) used for secondary reserve. DASR prices remain very low even at high energy dispatch levels. DASR prices are high only at extreme peaks.

Figure 10-21 Daily average DASR prices and MW by classification: July – December, 2013



The 68-minute spinning event of September 10, 2013, was declared as a result of low ACE. Different classes of reserve exist for different classes of imbalance. A

68-minute inability to bring ACE into balance with no sudden generator outage is the type of imbalance that 30-minute secondary reserve was created to recover from. On September 10, 2013, the 30-minute reserve requirement was 8,893 MW. That requirement was cleared day-ahead for every hour of the day. In nine hours, the price was above $0.

In real time, an average of 7,393 MW of secondary reserve was actually available in each hour and resources were paid $2,685,038 for secondary reserve throughout the day. It is not clear why secondary reserve was either unavailable to the dispatchers or was never called. PJM dispatch called on tier 1, tier 2, and non-synchronized reserve and was unable to restore balance for 68 minutes. Tier 1 response was substantially less than the estimated available tier 1 MW. It is not clear why the secondary reserve, already paid for, was not called.

The MMU recommends that PJM determine why secondary reserve was either unavailable or not dispatched on September 10, 2013 and that PJM evaluate replacing the DASR market with a real time secondary reserve product that is available and dispatchable in real time.

Black Start Service

Black start service is necessary to help ensure the reliable restoration of the grid following a blackout. Black start service is the ability of a generating unit to start without an outside electrical supply, or the demonstrated ability of a generating unit to automatically remain operating when disconnected from the grid.

PJM does not have a market to provide black start service, but compensates black start resource owners on the basis of an incentive rate or for the costs associated with providing this service.

Individual transmission owners, with PJM, identify the black start units included in each transmission owner's system restoration plan. PJM defines required black start capability zonally and ensures the availability of black start service by charging transmission customers according to their zonal load ratio share and compensating black start unit owners.

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

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

Black start payments are non-transparent payments made to units on the behalf of load to maintain adequate reliability to restart the system in case of a blackout. Current rules appear to prevent the publishing detailed data regarding these black start resources, hindering transparency and competitive replacement RFPs. The MMU recommends PJM revise the current confidentiality rules in order to specifically allow a more transparent disclosure of information regarding black start resources and their associated payments in PJM.

Total black start charges is the sum of black start revenue requirement charges and black start operating reserve charges. Black start revenue requirements for black start units consist of fixed black start service costs, variable black start service costs, training costs, fuel storage costs, and an incentive factor. Section 18 of Schedule 6A of the OATT specifies how to calculate each component of the revenue requirement formula. Black start operating reserve charges are paid for scheduling in the Day-Ahead Energy Market or committing in real time units that provide black start service. Total black start charges are allocated monthly to PJM customers proportionally to their zone and non-zone peak transmission use and point to point transmission reservations.

In 2013, total black start charges were $107.5 million with $20.9 million in revenue requirement charges.

Table 10-29 shows total revenue requirement charges from 2008 through 2013. (Prior to December 2012, PJM did not define a black start operating reserve category.)

Table 10-29 Black start revenue requirement charges: 2008 through 2013

Period	Revenue Requirement Charges
2008	$13,146,539
2009	$12,329,456
2010	$9,984,687
2011	$20,091,680
2012	$18,577,185
2013	$20,939,804

Black start zonal charges in 2013 ranged from $0.03 per MW-day in the ATSI Zone (total charges were $126,644) to $9.71 per MW-day in the AEP Zone (total charges were $82,588,453). For each zone, Table 10-30 shows black start charges, the sum of monthly zonal peak loads multiplied by the number of days of the month in which the peak load occurred, and black start rates (calculated as charges per MW-day). For black start service, point-to-point transmission customers paid on average $0.05 per MW of reserve capacity.

Table 10-30 Black start zonal charges for network transmission use: 2013

Zone	Revenue Requirement Charges	Operating Reserve Charges	Total Charges	Peak Load (MW-day)	Black Start Rate ($/MW-day)
AECO	$581,124	$41,138	$622,262	1,025,285	$0.61
AEP	$649,333	$81,939,120	$82,588,453	8,507,639	$9.71
APS	$267,202	$3,063	$270,264	3,111,370	$0.09
ATSI	$124,525	$2,119	$126,644	4,932,938	$0.03
BGE	$6,095,115	$10,301	$6,105,416	2,555,730	$2.39
ComEd	$4,097,259	$56,996	$4,154,255	8,614,329	$0.48
DAY	$241,080	$5,252	$246,332	1,280,092	$0.19
DEOK	$667,936	$8,662	$676,599	1,988,923	$0.34
Dominion	$508,734	$21,152	$529,886	4,138,535	$0.13
DPL	$558,101	$31,314	$589,415	1,501,647	$0.39
DLCO	$58,154	$7,928	$66,082	1,114,747	$0.06
EKPC	$214,758	$8,380	$223,138	509,919	$0.44
JCPL	$554,197	$14,945	$569,142	2,270,081	$0.25
Met-Ed	$789,692	$55,639	$845,330	1,108,286	$0.76
PECO	$1,405,096	$28,121	$1,433,217	3,120,385	$0.46
PENELEC	$510,881	$6,835	$517,716	1,061,420	$0.49
Pepco	$300,675	$24,095	$324,770	2,453,056	$0.13
PPL	$184,305	$0	$184,305	2,694,248	$0.07
PSEG	$2,094,342	$32,992	$2,127,334	3,821,477	$0.56
RECO	$0	$0	$0	0	NA
(Imp/Exp/Wheels)	$1,037,296	$4,295,829	$5,333,124	2,905,037	$1.84
Total	$20,939,804	$86,593,879	$107,533,683	58,715,141	$1.83

Table 10-31 shows new black start NERC critical infrastructure protection (CIP) capital costs being recovered by black start units in PJM. These costs were located in multiple zones, including ComEd, DEOK, DLCO, JCPL, Met-Ed, PENELEC and Pepco. These costs are recoverable through Schedule 6A of the tariff, and include both physical security and cyber security investments in order to protect black start units deemed critical. This included equipment necessary to restrict access to both physical sites, as well as firewall and software upgrades necessary protect cyber assets and monitor unit operations.

Table 10-31 NERC CIP Costs: 2013

Capital Cost Requested	Cost Recovered in 2013	Number of Units	MW
$1,736,971	$630,521	33	678

Reactive Service

Reactive Service, Reactive Supply and Voltage Control from Generation or Other Sources Service, is provided by generation and other sources (such as static VAR compensators and capacitor banks) of reactive power (measured in VAR).[39] Reactive power helps maintain appropriate voltages on the transmission system and is essential to the flow of real power (measured in MW). Without Reactive Service in the necessary amounts across the RTO footprint, transmission system voltages fall, generating units and transmission lines shut down, and no real power flows.

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

39 OATT Schedule 2.

reserve charges are allocated daily to the zone or zones where the reactive service was provided.

In 2013, total reactive service charges were $616.6 million compared to $368.3 million in 2012.[40] Total charges in 2013 ranged from $340.0 thousand in the RECO Zone to $76.8 million in the ATSI Zone. For each zone in 2013, Table 10-32 shows Reactive Service operating reserve charges, revenue requirement charges and total charges (the sum of operating reserve and revenue requirement charges).

Table 10-32 Reactive zonal charges for network transmission use: 2013

Zone	2012 Operating Reserve Charges	2012 Revenue Requirement Charges	2012 Total Charges	2013 Operating Reserve Charges	2013 Revenue Requirement Charges	2013 Total Charges
AECO	$1,610,237	$5,118,435	$6,728,673	$4,673,542	$5,132,697	$9,806,239
AEP	$3,377,039	$39,965,891	$43,342,930	$36,194,483	$40,300,353	$76,494,836
APS	$1,081,129	$21,881,530	$22,962,659	$10,688,148	$21,942,502	$32,630,649
ATSI	$15,913,491	$14,521,977	$30,435,468	$61,085,799	$15,741,841	$76,827,641
BGE	$6,287,524	$7,749,618	$14,037,141	$16,976,343	$7,771,212	$24,747,555
ComEd	$1,993,906	$24,878,682	$26,872,588	$22,192,595	$24,568,280	$46,760,875
DAY	$375,657	$8,413,711	$8,789,368	$3,759,513	$8,437,155	$12,196,668
DEOK	$522,480	$5,742,932	$6,265,412	$5,964,175	$5,758,935	$11,723,110
Dominion	$297,882	$29,842,049	$30,139,931	$3,267,018	$29,925,202	$33,192,220
DPL	$3,186,612	$9,665,346	$12,851,958	$22,979,048	$10,051,706	$33,030,754
DLCO	$18,049,249	NA	$18,049,249	$50,938,709	NA	$50,938,709
EKPC	NA	NA	$0	$2,387,655	$1,069,929	$3,457,584
JCPL	$4,945,378	$6,240,146	$11,185,523	$13,049,937	$6,257,533	$19,307,471
Met-Ed	$1,685,968	$7,458,870	$9,144,838	$3,709,406	$7,479,654	$11,189,060
PECO	$4,722,240	$17,334,300	$22,056,540	$10,155,174	$17,622,191	$27,777,365
PENELEC	$9,040,276	$4,637,417	$13,677,693	$36,562,731	$4,650,339	$41,213,069
Pepco	$5,030,624	$5,550,579	$10,581,202	$7,080,243	$5,257,464	$12,337,707
PPL	$6,962,007	$17,303,867	$24,265,874	$9,753,227	$18,872,215	$28,625,443
PSEG	$10,050,718	$27,190,537	$37,241,255	$17,688,214	$27,266,302	$44,954,516
RECO	$157,882	NA	$157,882	$339,964	NA	$339,964
(Imp/Exp/Wheels)	NA	$19,469,555	$19,469,555	NA	$19,055,365	$19,055,365
Total	$95,290,298	$272,965,442	$368,255,740	$339,445,925	$277,160,875	$616,606,800

40 See the *2013 State of the Market Report for PJM*, Volume II, Section 4, "Energy Uplift."