SECTION 6 - ANCILLARY SERVICE MARKETS

The United States Federal Energy Regulatory Commission (FERC) defined six ancillary services in Order 888: 1) scheduling, system control and dispatch; 2) reactive supply and voltage control from generation service; 3) regulation and frequency response service; 4) energy imbalance service; 5) operating reserve – synchronized reserve service; and 6) operating reserve – supplemental reserve service.[1] Of these, PJM currently provides regulation, energy imbalance, synchronized reserve, and operating reserve – supplemental reserve services through market-based mechanisms. PJM provides energy imbalance service through the Real-Time Energy Market. PJM provides the remaining ancillary services on a cost basis. Although not defined by the FERC as an ancillary service, black start service plays a comparable role. Black start service is provided on the basis of incentive rates or cost.

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

Both the Regulation and Synchronized Reserve Markets are cleared on a real-time basis. A unit can be selected for either regulation or synchronized reserve, but not for both. The Regulation and the Synchronized Reserve Markets are cleared interactively with the Energy Market and operating reserve requirements to minimize the cost of the combined products, subject to reactive limits, resource constraints, unscheduled power flows, interarea transfer limits, resource distribution factors, self-scheduled resources, limited fuel resources, bilateral transactions, hydrological constraints, generation requirements and reserve requirements.

1 75 FERC ¶ 61,080 (1996).

2 Regulation is used to help control the area control error (ACE). See the *2010 State of the Market Report for PJM*, Volume II, Appendix F, "Ancillary Service Markets," for a full definition and discussion of ACE. Regulation resources were almost exclusively generating units in 2010.

The purpose of the Day-Ahead Scheduling Reserve (DASR) market is to satisfy supplemental (30-minute) reserve requirements with a market-based mechanism that allows generation resources to offer their reserve energy at a price and compensates cleared supply at the market clearing price.[3]

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

The Market Monitoring Unit (MMU) analyzed measures of market structure, conduct and performance for the PJM Regulation Market, the two regional Synchronized Reserve Markets, and the PJM DASR Market for the first three months of 2011.

Table 6-1 The Regulation Market results were not competitive[4]

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

- The Regulation Market structure was evaluated as not competitive because the Regulation Market had one or more pivotal suppliers which failed PJM's three pivotal supplier (TPS) test in 94 percent of the hours.

- Participant behavior was evaluated as competitive because market power mitigation requires competitive offers when the three pivotal

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

4 As Table 6-1 indicates, the Regulation Market results are not the result of the offer behavior of market participants, which was competitive as a result of the application of the three pivotal supplier test. The Regulation Market results are not competitive because the changes in market rules, in particular the changes to the calculation of the opportunity cost, resulted in a price greater than the competitive price in some hours, resulted in a price less than the competitive price in some hours, and because the revised market rules are inconsistent with basic economic logic. The competitive price is the actual marginal cost of the marginal resource in the market. The competitive price in the Regulation Market is the price that would have resulted from a combination of the competitive offers from market participants and the application of the prior, correct approach to the calculation of the opportunity cost. The correct way to calculate opportunity cost and maintain incentives across both regulation and energy markets is to treat the offer on which the unit is dispatched for energy as the measure of its marginal costs for the energy market. To do otherwise is to impute a lower marginal cost to the unit than its owner does and therefore impute a higher or lower opportunity cost than its owner does, depending on the direction the unit was dispatched to provide regulation. If the market rules and/or their implementation produce inefficient outcomes, then no amount of competitive behavior will produce a competitive outcome.

supplier test is failed and there was no evidence of generation owners engaging in anti-competitive behavior.

- Market performance was evaluated as not competitive, despite competitive participant behavior, because the changes in market rules, in particular the changes to the calculation of the opportunity cost, resulted in a price greater than the competitive price in some hours, resulted in a price less than the competitive price in some hours, and because the revised market rules are inconsistent with basic economic logic.

- Market design was evaluated as flawed because while PJM has improved the market by modifying the schedule switch determination, the lost opportunity cost calculation is inconsistent with economic logic and there are additional issues with the order of operation in the assignment of units to provide regulation prior to market clearing.

Table 6-2 The Synchronized Reserve Markets results were competitive

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

- The market structure was evaluated as not competitive because of high levels of supplier concentration and inelastic demand.

- Participant behavior was evaluated as competitive because the market rules require cost based offers.

- Market performance was evaluated as competitive because the interaction of the participant behavior with the market design results in prices that reflect marginal costs.

- Market design was evaluated as effective because market power mitigation rules result in competitive outcomes despite high levels of supplier concentration by offer capping those suppliers.

Table 6-3 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 market structure was evaluated as competitive because the market failed the three pivotal supplier test in only a very limited number of hours.

- Participant behavior was evaluated as mixed because while most offers appeared consistent with marginal costs, about five 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 should be added to the market to ensure that market power cannot be exercised at times of system stress.

Highlights

- The load weighted regulation market clearing price for the first three months of 2011 was $11.51, 35 percent lower than the $17.84 price for the first three months of 2010. Regulation total costs per MW for the first three months of 2011 were $24.83, a decrease of 19 percent from the $30.69 total cost in the first three months of 2010. For the first three months of 2011 the total cost of regulation per MW was 116 percent higher than the market clearing price. For the first three months of 2010 the total cost of regulation was 72 percent higher than the market clearing price.

- Total self-scheduled regulation MW in the first three months of 2011 was 18 percent of all regulation, an increase from 16 percent in the first three months of 2010. The supply of eligible regulation increased by four percent in the first three months of 2011 relative to the same period of 2010.

- Of the LSEs' obligation to provide regulation during the first three months of 2011, 79 percent was purchased in the spot market, 18 percent was self scheduled, and 3 percent was purchased bilaterally.

- The load weighted synchronized reserve market price in the first three months of 2011 was $10.96 per MWh, $3.94 higher than the price during the first three months of 2010. The total cost of synchronized reserves per MWh during the first three months of 2011 was $13.22, a 38 percent increase over the cost of synchronized reserves ($9.54) during the same period of 2010. The cost to price ratio of synchronized reserve during the first three months of 2011 was 120 percent, a decrease from the cost to price ratio of 136 percent in the first three months of 2010.

- In December of 2010 PJM Market Operations changed the Tier 1 synchronized reserve transfer capacity across the AP South interface from 15 percent of available Tier 1 to 5 percent.[5] Less Tier 1 synchronized reserve available means more Tier 2 synchronized reserve is required in the Mid-Atlantic Subzone in order to satisfy the 1,300 MW requirement. This has resulted in significant increases in scheduled Tier 2 synchronized reserves in the Mid-Atlantic Subzone Synchronized Reserve market.

- The load weighted price of DASR in the first three months of 2011 was $0.02 per MW. In the first three months of 2010, the load weighted price of DASR was $0.05 per MW.

- Black start zonal charges in the first three months of 2011 ranged from $0.03 per MW in DLCO zone to $0.61 per MW in PSEG zone.

Summary Recommendations

- In this *2011 State of the Market Report for PJM: January through March*, the recommendations from the 2010 State of the Market Report for PJM remain MMU recommendations.

5 See the *2010 State of the Market Report for PJM*, Section 6, "Ancillary Service Markets", p. 452.

Overview

Regulation Market

The PJM Regulation Market in the first three months of 2011 continued to be operated as a single market. There have been no structural changes since December 1, 2008. On December 1, 2008, PJM implemented four changes to the Regulation Market: introducing the three pivotal supplier test for market power; increasing the margin for cost-based regulation offers; modifying the calculation of lost opportunity cost (LOC); and terminating the offset of regulation revenues against operating reserve credits.

Market Structure

- **Supply.** In the first three months of 2011, the supply of offered and eligible regulation in PJM was both stable and adequate. Although PJM rules allow up to 25 percent of the regulation requirement to be satisfied by demand resources, none qualified to make regulation offers in the first three months of 2011. The ratio of eligible regulation offered to regulation required averaged 3.09 for the first three months of 2011. This is a five percent increase over the first three months of 2010 when the ratio was 2.94.

- **Demand.** The on-peak regulation requirement is equal to 1.0 percent of the forecast peak load for the PJM RTO for the day and the off-peak requirement is equal to 1.0 percent of the forecast valley load for the PJM RTO for the day. The average hourly regulation demand for the first three months of 2011 was 893 MW (830 MW off peak, and 964 MW on peak). This is a 3 MW decrease in the average hourly regulation demand for the first three months of 2010 (837 MW off peak, and 959 MW on peak).

- **Market Concentration.** During the first three months of 2011, the PJM Regulation Market had a load weighted, average Herfindahl-Hirschman Index (HHI) of 1785 which is classified as "moderately concentrated."[6] The minimum hourly HHI was 916 and the maximum hourly HHI was 3550. The largest hourly market share in any single hour was 54 percent, and 89 percent of all hours had a maximum market share greater than

6 See the *2010 State of the Market Report for PJM*, Volume II, Section 2, "Energy Market, Part I," at "Market Concentration" for a more complete discussion of concentration ratios and the Herfindahl-Hirschman Index (HHI). Consistent with common application, the market share and HHI calculations presented in the SOM are based on supply that is cleared in the market in every hour, not on measures of available capacity.

20 percent.[7] In the first three months of 2011, 94 percent of hours had one or more pivotal suppliers which failed PJM's three pivotal supplier test. The MMU concludes from these results that the PJM Regulation Market in the first three months of 2011 was characterized by structural market power in 94 percent of the hours.

Market Conduct

- **Offers.** Daily regulation offer prices are submitted for each unit by the unit owner. Owners are required to submit unit specific cost based offers and owners also have the option to submit price based offers. Cost based offers apply for the entire day and are subject to validation using unit specific parameters submitted with the offer. All price based offers remain subject to the $100 per MWh offer cap.[8] In computing the market solution, PJM calculates a unit specific opportunity cost based on forecast LMP, and adds it to each offer. The offers made by unit owners and the opportunity cost adder comprise the total offer to the Regulation Market for each unit. Using a supply curve based on these offers, PJM solves the Regulation Market and then tests that solution to see which, if any, suppliers of eligible regulation are pivotal. The offers of all units of owners who fail the three pivotal supplier test for an hour are capped at the lesser of their cost based or price based offer. The Regulation Market is then re-solved.

  As part of the changes to the Regulation Market implemented on December 1, 2008, cost based offers may include a margin of $12.00 rather than the prior maximum margin of $7.50.[9] The impact of this change was to increase cost based offer prices compared to what they would have been with the $7.50 maximum margin.

Market Performance

- **Price.** For the PJM Regulation Market in the first three months of 2011, the load weighted, average price per MW (the Regulation Market clearing price, including opportunity cost) associated with meeting PJM's demand for regulation was $11.51 per MW. This was a decrease of $6.33, or 35 percent, from the average price for regulation during the same period in 2010. The total cost of regulation decreased by $5.43 from $30.69 per MW for the first three months of 2010, to $24.83, or 19 percent. The Regulation Market clearing price was only 46 percent of the total regulation cost per MW.

Synchronized Reserve Market

PJM retained the two synchronized reserve markets it implemented on February 1, 2007. The RFC Synchronized Reserve Zone reliability requirements are set by the Reliability*First* Corporation. The Southern Synchronized Reserve Zone (Dominion) reliability requirements are set by the Southeastern Electric Reliability Council (SERC).

PJM made no changes to the Synchronized Reserve Market structure during the first three months of 2011. In 2009, PJM made a structural change to address the problem of excessive after-market Tier 2 added by dispatchers when the market did not adequately provide for Tier 2 synchronized reserve in constrained, heavy-load, and/or off-peak hours. The structural change was to change the transfer interface which defines the Eastern sub-zone from Bedington—Black Oak to AP South. In addition, PJM made a non-structural change to address the same issue by changing the Tier 1 transfer capability of the AP South interface from 70 percent to 15 percent. The AP South interface transfer capability is a parameter (changeable by PJM Market Operations) specifying the percent of Tier 1 synchronized reserve west of AP South that can be considered available to the Mid-Atlantic Subzone. The more Tier 1 synchronized reserve available, the less Tier 2 synchronized reserve needs to be cleared. In December, 2010 PJM lowered the transfer capability further to five percent. This had the effect of increasing the amount of Tier 2 synchronized reserve that had to be cleared in the Mid Atlantic Subzone, effectively segregating the RFC Synchronized Reserve Zone and Mid-Atlantic Subzone into two markets. Synchronized reserves added out of market were one percent of all synchronized reserves during the first three months of 2011, down from two percent for the same time period in 2010. Opportunity cost payments accounted for 17 percent of total costs during the first three months of 2011 compared to 25 percent for 2010.

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

8 See PJM. "Manual 11: Scheduling Operations," Revision 45 (June 23, 2010), p. 39.

9 All existing PJM tariffs, and any changes to these tariffs, are approved by FERC. The MMU describes the full history of the changes to the tariff provisions governing the Regulation Market in the *2010 State of the Market Report for PJM*, Volume II, Section 6, "Ancillary Service Markets."

Market Structure

- **Supply.** In the first three months of 2011 the offered and eligible excess supply ratio was 1.05 for the Mid-Atlantic Subzone.[10] For the first three months of 2010 the eligible excess supply ratio in the Mid Atlantic subzone was 1.25. For the RFC zone, the excess supply ratio was 3.09. For the first three months of 2010 the eligible excess supply ratio RFC zone was 2.33. The excess supply ratio is determined using the administratively required level of synchronized reserve. The requirement for Tier 2 synchronized reserve is lower than the required reserve level for synchronized reserve because there is usually a significant amount of Tier 1 synchronized reserve available. The contribution of DSR to the Synchronized Reserve Market remains significant. Demand side resources are low cost, and their participation in this market lowers overall Synchronized Reserve prices.

- **Demand.** PJM made several changes to the hourly required synchronized reserve requirement in 2010. On July 17, 2010, the synchronized reserve requirement for the Mid-Atlantic Subzone was increased from 1,200 MW to 1,300 MW. The synchronized reserve requirement for the Mid Atlantic Subzone remained at 1,300 MW for the first three months of 2011. During the first three months of 2010 the synchronized reserve requirement for the Mid-Atlantic Subzone was 1,150 MW. For the RFC zone the synchronized reserve requirement remained at its 2010 level of 1,350 MW. During the first three months of 2010 the synchronized reserve requirement was 1,320 MW. The synchronized reserve requirement in the RFC zone was raised to 1,700 MW on February 9 and 10, 2011 for double spinning.

  For the first three months of 2011, in the Mid-Atlantic Subzone, a Tier 2 synchronized reserve market was cleared in all but three hours (99.9 percent). In the first three months of 2010 a Tier 2 synchronized reserve market was cleared in 1,877 hours (89 percent).The reduction of the transfer capability to five percent across the AP South interface required that more synchronized reserve be provided within the Mid Atlantic Subzone. For the first three months of 2011, the average required Tier 2 synchronized reserve (including self scheduled) was 742 MW. For the first three months of 2010 the average required Tier 2 synchronized reserve was 450 MW. This 65 percent increase in required tier 2 synchronized reserves was a result of the reduction in the transfer capacity of the AP South interface.

  Synchronized reserves added out of market were one percent of all Mid-Atlantic Subzone synchronized reserves in the first three months of 2011. Synchronized reserves added out of market were also one percent of all Mid-Atlantic Subzone synchronized reserves in the first three months of 2010.

  Market demand for Tier 2 is less than the requirement for synchronized reserve by the amount of forecast Tier 1 synchronized reserve available at the time a Synchronized Reserve Market is cleared. As a result of the level of Tier 1 reserves in the RFC Synchronized Reserve Zone, no hours cleared a Tier 2 Synchronized Reserve Market in the RFC during the first three months of 2011. Similarly a Tier 2 Synchronized Reserve Market was not cleared for the Southern Synchronized Reserve Zone during the first three months of 2011.

- **Market Concentration.** The average load weighted cleared Synchronized Reserve Market HHI for the Mid-Atlantic Subzone for the first three months of 2011 was 2562, which is classified as "highly concentrated."[11] For purchased synchronized reserve (cleared plus added) the HHI was 2606. In the first three months of 2011, 46 percent of hours had a maximum market share greater than 40 percent, compared to 58 percent of hours in the same period of 2010.

  In the Mid-Atlantic Subzone, in the first three months of 2011, 88 percent of hours that cleared a synchronized reserve market had three or fewer pivotal suppliers. In the same period of 2010, 59 percent of hours had three or fewer pivotal suppliers. The MMU concludes from these TPS results that the Mid-Atlantic Subzone Synchronized Reserve Market in the first quarter of 2011 was characterized by structural market power.

Market Conduct

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

10 The Synchronized Reserve Market in the Southern Region cleared in so few hours that related data for that market is not meaningful.

11 See the *2010 State of the Market Report for PJM*, Volume II, Section 2, "Energy Market, Part I," at "Market Concentration" for a more complete discussion of concentration ratios and the Herfindahl-Hirschman Index (HHI).

Total MW of demand side resources increased in the first quarter of 2011 over first quarter 2010 (from 50,008 MW to 80,540 MW) but their share of the total Synchronized Reserve Market declined from 18.7 percent to 16.0 percent. Demand side resources satisfied 100 percent of the Tier 2 Synchronized Reserve market in only one percent of hours in the first three months of 2011 compared to four percent of hours on the first three months of 2010.

Market Performance

- **Price.** The load weighted, average price for Tier 2 synchronized reserve in the Mid-Atlantic Subzone was $10.96 per MW in the first three months of 2011, a $3.93 per MW increase from the same period in 2010. The market clearing price was 83 percent of the total synchronized reserve cost per MW in the first three months of 2011, up from 63 percent in the same time period of 2010. This reduction in the dispatch of out of market synchronized reserves was a result of lowering the AP South transfer capability metric to five percent.

- **Adequacy.** A synchronized reserve deficit occurs when the combination of Tier 1 and Tier 2 synchronized reserve is not adequate to meet the synchronized reserve requirement. Neither PJM Synchronized Reserve Market experienced a deficit in the first three months of 2011.

DASR

On June 1, 2008 PJM introduced the Day-Ahead Scheduling Reserve Market (DASR), as required by the RPM settlement.[12] The purpose of this market is to satisfy supplemental (30-minute) reserve requirements with a market-based mechanism that allows generation resources to offer their reserve energy at a price and compensates cleared supply at a single market clearing price. The DASR 30-minute reserve requirements are determined for each reliability region.[13] 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

- **Concentration.** In the first three months of 2011, no hours in the DASR market failed the three pivotal supplier test.

- **Demand.** In 2011, the required DASR was 7.11 percent of peak load forecast, up from 6.88 percent in 2010. [14] DASR requirement is a sum of the load forecast error and the forced outage rate. From 2010 the load forecast error declined from 1.90 percent to 1.87 percent. The forced outage rate increased from 4.98 percent to 5.23 percent. Added together the 2011 DASR requirement is now 7.11 percent. The DASR MW purchased averaged 5,731 MW per hour for the first three months of 2011, a small increase from 5,695 MW per hour during the same period in 2010.

Market Conduct

- **Withholding.** Economic withholding remains a problem in the DASR Market. The first three months of 2011 continued a pattern that has existed since the inception of the DASR Market. Five percent of units offered at $50 or more with four percent offering at more than $900, in a market with an average clearing price of $0.02 and a maximum clearing price of $1.00. PJM rules require all units with reserve capability that can be converted into energy within 30 minutes to offer into the DASR Market.[15] Units that do not offer will have their offers set to $0/MW.

- **DSR.** Demand side resources do participate in the DASR Market, but remain insignificant. No demand resource cleared the DASR Market in the first three months of 2011.

Market Performance

- **Price.** In the first three months of 2011, the load weighted price of DASR was $0.02 per MW. In the first three months of 2010, the load weighted price of DASR was $0.05 per MW.

12 See 117 FERC ¶ 61,331 (2006).
13 See PJM. "Manual 13: Emergency Operations," Revision 42, (January 21, 2011); pp 11-12.
14 See the *2010 State of the Market Report for PJM*, Volume II, Section 6, "Ancillary Services" at Day Ahead Scheduling Reserve *(DASR)*.
15 PJM. "Manual 11, Emergency and Ancillary Services Operations," Revision 45 (June 23, 2010), p. 122.

Black Start Service

Black start service is necessary to help ensure the reliable restoration of the grid following a blackout. Black start service is the ability of a generating unit to start without an outside electrical supply, or is the demonstrated ability of a generating unit with a high operating factor to automatically remain operating at reduced levels when disconnected from the grid.[16]

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.

PJM does not have a market to provide black start service, but compensates black start resource owners on the basis of an incentive rate or for all costs associated with providing this service, as defined in the tariff. For the first three months of 2011, charges were $2.86 million. This is 22 percent higher than the first three months of 2010, when total black start service charges were $2.34 million. There was substantial zonal variation.

Ancillary Services costs per MW of load: 2001 - 2011

Table 6-4 shows PJM ancillary services costs from 2001 through the first three months of 2011 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.

16 OATT Schedule 1 § 1.3BB.

Table 6-4 History of ancillary services costs per MW of Load: 2001 through the first three months of 2011

Year	Regulation	Scheduling, System Control, and Dispatch	Reactive	Synchronized Reserve	Supplementary Operating Reserve
2001	$0.50	$0.44	$0.22		$1.08
2002	$0.46	$0.54	$0.22	$0.00	$0.74
2003	$0.50	$0.62	$0.24	$0.16	$0.86
2004	$0.50	$0.62	$0.26	$0.12	$0.92
2005	$0.80	$0.50	$0.26	$0.12	$0.96
2006	$0.52	$0.52	$0.30	$0.08	$0.44
2007	$0.64	$0.52	$0.30	$0.06	$0.62
2008	$0.71	$0.39	$0.32	$0.08	$0.62
2009	$0.34	$0.32	$0.36	$0.05	$0.48
2010	$0.35	$0.38	$0.40	$0.07	$0.74
2011	$0.27	$0.39	$0.39	$0.12	$0.71

Conclusion

The MMU continues to conclude that the results of the Regulation Market are not competitive.[17]

The structure of each Synchronized Reserve Market has been evaluated and the MMU has concluded that these markets are not structurally competitive as they are characterized by high levels of supplier concentration and inelastic demand. (The term Synchronized Reserve Market refers only to Tier 2 synchronized reserve.) As a result, these markets are operated with market-clearing prices and with offers based on the marginal cost of producing the service plus a margin. As a result of these requirements, the conduct of market participants within these market structures has been consistent with competition, and the market performance results have been competitive.

The MMU concludes that the DASR Market results were competitive in the first three months of 2011.

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

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

Overall, the MMU concludes that the Regulation Market results were not competitive in the first three months of 2011 as a result of the identified market design changes and their implementation. This conclusion is not the result of participant behavior, which was generally competitive. The MMU concludes that the Synchronized Reserve Market results were competitive in the first three months of 2011. The MMU concludes that the DASR Market results were competitive in the first three months of 2011.

Regulation Market

Market Structure

Supply

Table 6-5 PJM regulation capability, daily offer[18] and hourly eligible: January through March, 2011 (See 2010 SOM, Table 6-5)

Period	Regulation Capability (MW)	Average Daily Offer (MW)	Percent of Capability Offered	Average Hourly Eligible (MW)	Percent of Capability Eligible
All Hours	7,847	5,790	74%	2,754	35%
Off Peak	7,847			2,545	32%
On Peak	7,847			2,990	38%

Demand

Table 6-6 PJM Regulation Market required MW and ratio of eligible supply to requirement: January through March, 2011 (See 2010 SOM, Table 6-6)

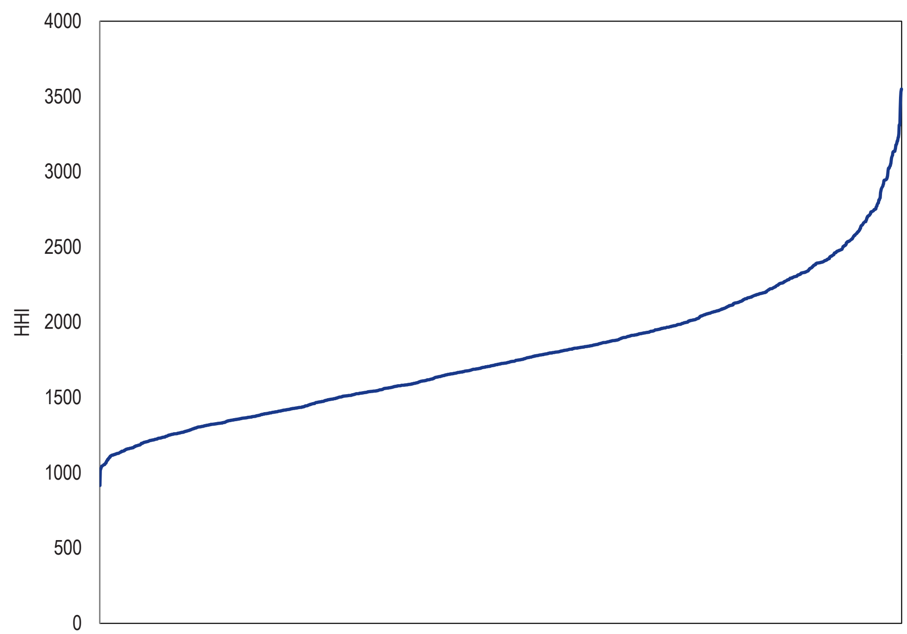
Month	Average Required Regulation (MW)	Ratio of Supply To Requirement
Jan	960	3.19
Feb	897	3.06
Mar	823	3.01

Market Concentration

Table 6-7 PJM cleared regulation HHI: January through March, 2011 (See 2010 SOM, Table 6-7)

Market Type	Minimum HHI	Load-weighted Average HHI	Maximum HHI
Cleared Regulation, January through March, 2011	916	1785	3550

Figure 6-1 PJM Regulation Market HHI distribution: January 1 through March 31, 2011 (See 2010 SOM, Figure 6-1)



18 Average Daily Offer MW exclude units that have offers but make themselves unavailable for the day.

Table 6-8 Highest annual average hourly Regulation Market shares: January through March, 2011 (See 2010 SOM, Table 6-8)

Company Market Share Rank	Cleared Regulation Top Yearly Market Shares
1	27%
2	17%
3	13%
4	11%
5	9%

Table 6-9 Regulation market monthly three pivotal supplier results: January through March, 2011 (See 2010 SOM, Table 6-9)

Month	Percent of Hours When Marginal Supplier is Pivotal
Jan	95%
Feb	93%
Mar	94%

Market Conduct

Offers

Figure 6-2 Off peak and on peak regulation levels: January through March, 2011 (See 2010 SOM, Figure 6-2)

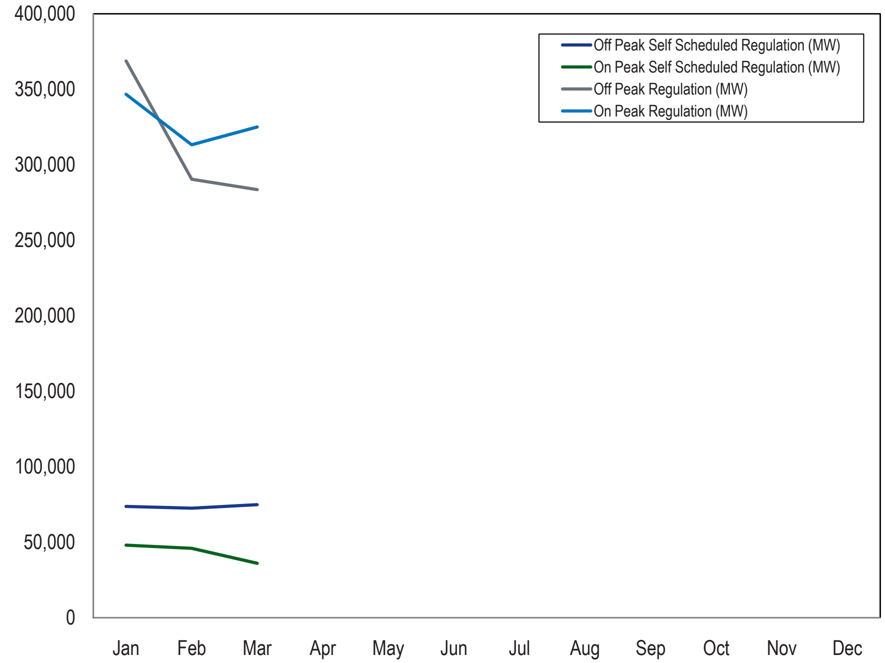


Table 6-10 Regulation sources: spot market, self-scheduled, bilateral purchases: January through March, 2011 (See 2010 SOM, Table 6-10)

Month	Spot Regulation (MW)	Self Scheduled Regulation (MW)	Bilateral Regulation (MW)
Jan	$576,029	$116,421	$16,670
Feb	$462,394	$114,568	$17,553
Mar	$463,708	$107,791	$28,109

Market Performance

Price

Figure 6-3 PJM Regulation Market daily average market-clearing price, opportunity cost and offer price (Dollars per MWh): January through March, 2011 (See 2010 SOM, Figure 6-3)

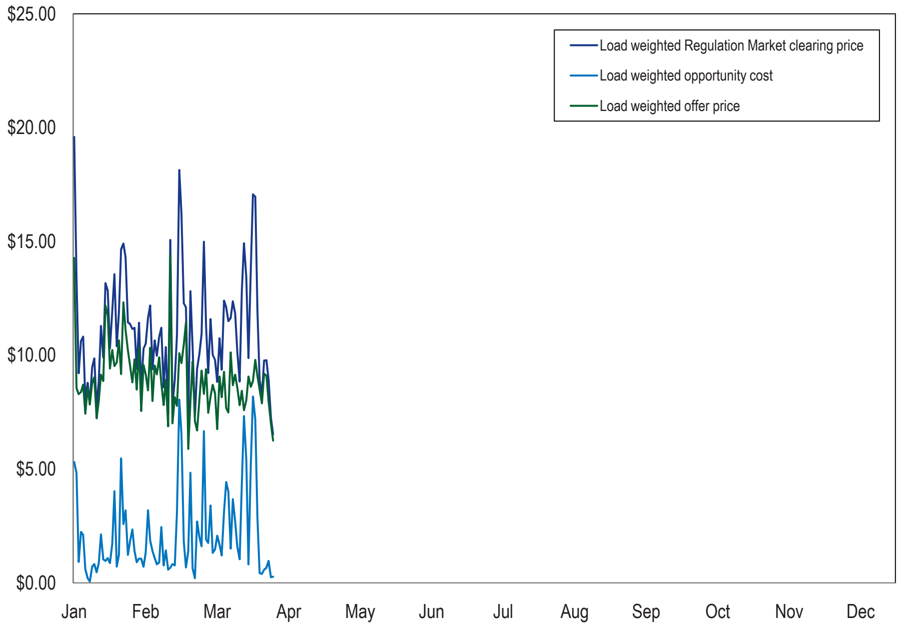


Figure 6-4 Monthly average regulation demand (required) vs. price: January through March, 2011 (See 2010 SOM, Figure 6-4)

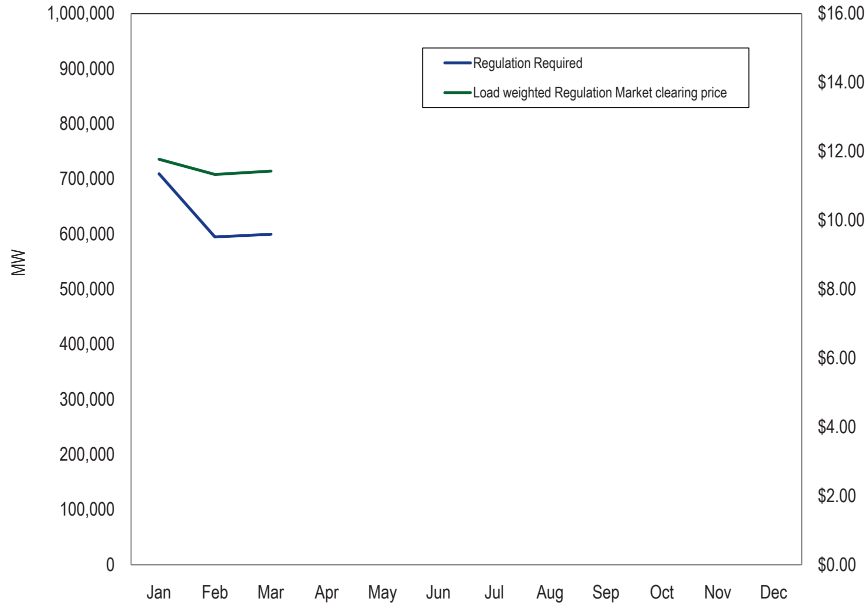


Figure 6-5 Monthly load weighted, average regulation cost and price: January through March, 2011 (See 2010 SOM, Figure 6-5)

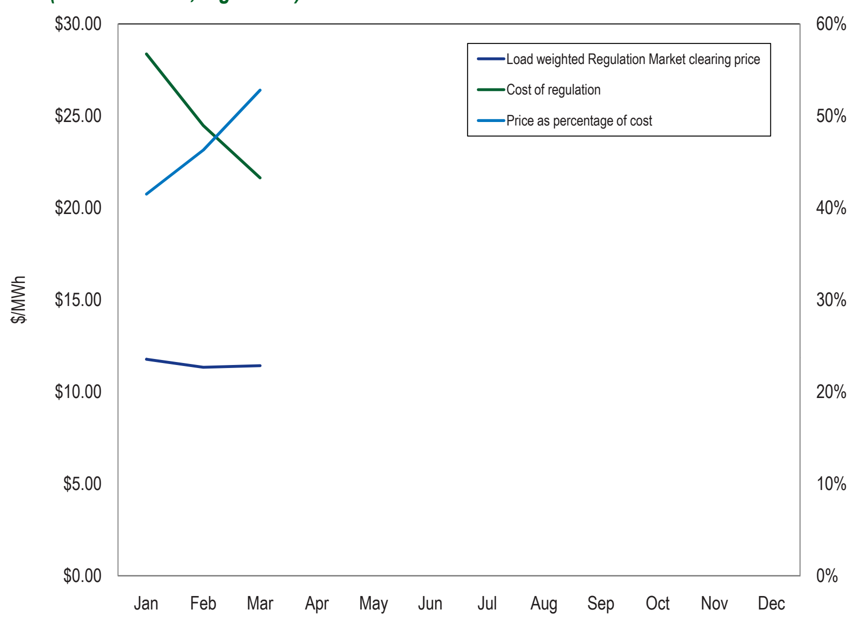


Table 6-11 Total regulation charges: January through March, 2011 (See 2010 SOM, Table 6-11)

Month	Scheduled Regulation (MW)	Total Regulation Charges	Load Weighted Regulation Market Clearing Price	Cost of Regulation
Jan	709,121	$20,116,704	$11.77	$28.37
Feb	594,515	$14,551,995	$11.33	$24.48
Mar	599,608	$12,967,924	$11.42	$21.63

Table 6-12 Comparison of load weighted price and cost for PJM Regulation, August 2005 through March 2011[19] (See 2010 SOM, Table 6-12)

Year	Load Weighted Regulation Market Price	Load Weighted Regulation Market Cost	Regulation Price as Percent Cost
2005	$64.03	$77.39	83%
2006	$32.69	$44.98	73%
2007	$36.86	$52.91	70%
2008	$42.09	$64.43	65%
2009	$23.56	$29.87	79%
2010	$18.08	$32.07	56%
2011	$11.51	$24.83	46%

Analysis of Regulation Market Changes

Table 6-13 Summary of changes to Regulation Market design (See 2010 SOM, Table 6-13)

Prior Regulation Market Rules (Effective May 1, 2005 through November 30, 2008)	New Regulation Market Rules (Effective December 1, 2008)
1. No structural test for market power.	1. Three Pivotal Supplier structural test for market power.
2. Offers capped at cost for identified dominant suppliers. (American Electric Power Company(AEP) and Virginia Electric Power Company (Dominion)) Price offers capped at $100 per MW.	2. Offers capped at cost for owners that fail the TPS test. Price offers capped at $100 per MW.
3. Cost based offers include a margin of $7.50 per MW.	3. Cost based offers include a margin of $12.00 per MW.
4. Opportunity cost calculated based on the offer schedule on which the unit is dispatched in the energy market.	4. Opportunity cost calculated based on the lesser of the price-based offer schedule or the highest cost-based offer schedule in the energy market.
5. All regulation net revenue above offer plus opportunity cost credited against operating reserve credits to unit owners.	5. No regulation market revenue above offer plus opportunity cost credited against operating reserve credits to unit owners.

19 The PJM Regulation Market in its current structure began August 1, 2005. See the *2005 State of the Market Report for PJM*, "Ancillary Service Markets." pp. 249-250.

Increase Offer Margin from $7.50 to $12.00

Table 6-14 Impact of $12 adder to cost based regulation offer: December 2008 through March 2011 (See 2010 SOM, Table 6-14)

Year	Month	Load Weighted Regulation Market Clearing Price	Load Weighted Regulation Market Clearing Price With Old Rule	Total Regulation Credits	Regulation Credits Attributable to New Rule	Percent Increase in Total Credits Due to Increase of Markup from $7.50 to $12.00
2008	Dec	$24.79	$23.47	$25,608,465	$890,749	3.5%
2009	Jan	$21.04	$19.91	$26,614,105	$813,654	3.1%
2009	Feb	$25.17	$23.95	$20,972,293	$734,061	3.5%
2009	Mar	$19.90	$19.37	$17,618,413	$316,889	1.8%
2009	Apr	$16.84	$16.36	$12,171,811	$258,778	2.1%
2009	May	$32.41	$31.93	$21,166,797	$265,494	1.3%
2009	Jun	$32.59	$32.19	$24,566,721	$312,979	1.3%
2009	Jul	$24.10	$23.25	$20,065,104	$414,408	2.1%
2009	Aug	$23.89	$23.37	$23,010,216	$369,407	1.6%
2009	Sep	$20.09	$19.32	$15,216,790	$497,484	3.3%
2009	Oct	$17.20	$16.31	$12,882,665	$445,635	3.5%
2009	Nov	$14.06	$13.48	$10,695,843	$269,283	2.5%
2009	Dec	$17.75	$16.72	$17,303,919	$600,585	3.5%
2010	Jan	$20.66	$20.49	$29,465,392	$125,523	0.4%
2010	Feb	$16.17	$16.13	$16,640,892	$29,265	0.2%
2010	Mar	$16.70	$16.57	$14,156,600	$76,654	0.5%
2010	Apr	$17.43	$17.10	$13,124,014	$167,101	1.3%
2010	May	$19.36	$18.83	$18,674,880	$299,170	1.6%
2010	Jun	$19.65	$19.42	$21,783,561	$138,358	0.6%
2010	Jul	$23.47	$23.38	$31,927,050	$60,049	0.2%
2010	Aug	$21.32	$21.22	$27,062,825	$71,696	0.3%
2010	Sep	$19.25	$19.10	$18,341,488	$84,500	0.5%
2010	Oct	$13.53	$13.47	$10,158,529	$27,076	0.3%
2010	Nov	$11.78	$11.70	$11,392,510	$42,183	0.4%
2010	Dec	$14.04	$14.03	$25,225,775	$96,809	0.4%
2011	Jan	$11.77	$11.76	$18,852,265	$45,866	0.2%
2011	Feb	$11.33	$11.31	$13,581,735	$33,442	0.2%
2011	Mar	$11.42	$11.26	$11,908,985	$142,190	1.2%
Total				$530,189,642	$7,629,288	1.4%

Eliminate Offset Against Balancing Operating Reserves Credits

Table 6-15 Additional credits paid to regulating units from no longer netting credits above RMCP against operating reserves: December 2008 through March 2011 (See 2010 SOM, Table 6-15)

Year	Month	Balancing Operating Reserve Credits No Longer Offset	Total Regulation Credits	Percent of Regulation Credits No Longer Offsetting Operating Reserves
2008	Dec	$253,165	$25,608,465	1.0%
2009	Jan	$127,036	$26,614,105	0.5%
2009	Feb	$220,460	$20,972,293	1.1%
2009	Mar	$79,726	$17,618,413	0.5%
2009	Apr	$8,893	$12,171,811	0.1%
2009	May	$182,624	$21,166,797	0.9%
2009	Jun	$274,916	$24,566,721	1.1%
2009	Jul	$191,538	$20,065,104	1.0%
2009	Aug	$267,116	$23,010,216	1.2%
2009	Sep	$252,136	$15,216,790	1.7%
2009	Oct	$169,130	$12,882,665	1.3%
2009	Nov	$166,112	$10,695,843	1.6%
2009	Dec	$104,496	$17,303,919	0.6%
2010	Jan	$64,990	$29,465,392	0.2%
2010	Feb	$64,727	$16,640,892	0.4%
2010	Mar	$109,344	$14,156,600	0.8%
2010	Apr	$134,738	$13,246,951	1.0%
2010	May	$74,352	$18,674,880	0.4%
2010	Jun	$41,065	$21,783,561	0.2%
2010	Jul	$85,961	$31,927,050	0.3%
2010	Aug	$110,610	$27,062,825	0.4%
2010	Sep	$58,587	$18,341,488	0.3%
2010	Oct	$34,911	$10,158,529	0.3%
2010	Nov	$33,676	$11,392,510	0.3%
2010	Dec	$126,074	$25,225,775	0.5%
2011	Jan	$43,498	$18,852,265	0.2%
2011	Feb	$30,394	$13,581,735	0.2%
2011	Mar	$70,768	$11,908,985	0.6%
Total		$3,381,041	$530,312,579	0.6%

Synchronized Reserve Market

Market Structure

Demand

Figure 6-6 RFC Synchronized Reserve Zone monthly average synchronized reserve required vs. Tier 2 scheduled MW: January through March, 2011 (See 2010 SOM, Figure 6-6)

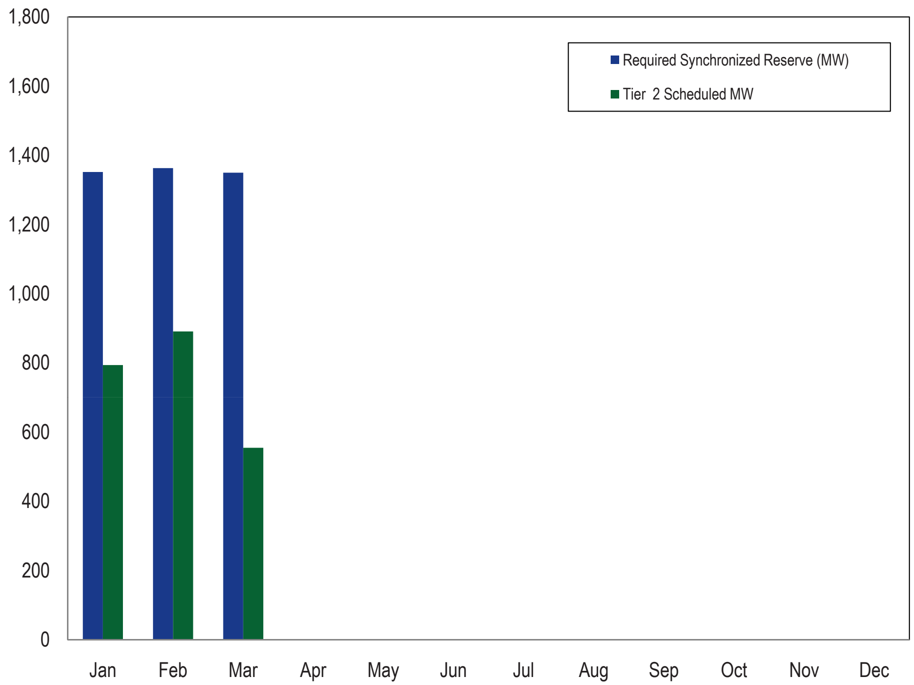


Figure 6-7 Mid-Atlantic Subzone average hourly synchronized reserve required vs. Tier 2 scheduled: January through March, 2011 (See 2010 SOM, Figure 6-7)

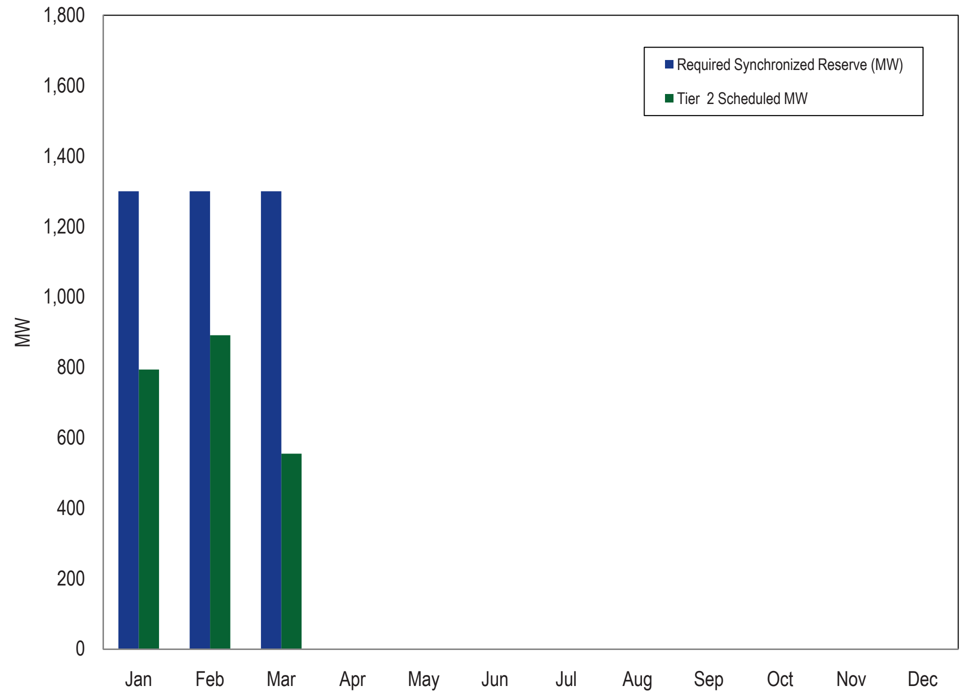
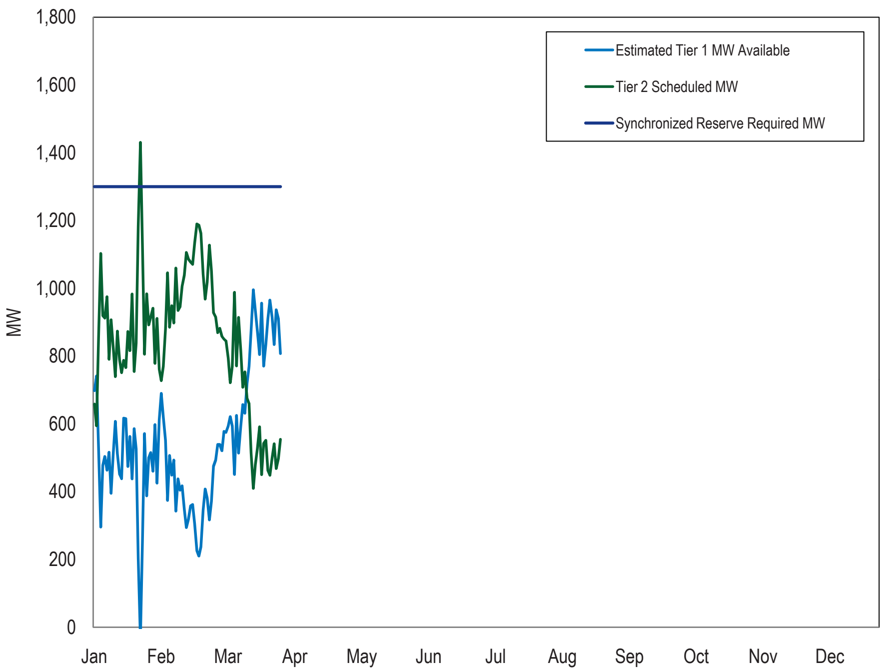


Figure 6-8 Mid-Atlantic Subzone daily average hourly synchronized reserve required, Tier 2 MW scheduled, and Tier 1 MW estimated: January through March, 2011 (See 2010 SOM, Figure 6-8)



Market Concentration

Table 6-16 Mid-Atlantic Subzone Tier 2 Synchronized Reserve Market cleared market shares: January through March, 2011 (See 2010 SOM, Table 6-16)

Company Market Share Rank	Cleared Synchronized Reserve Average Market Share
1	33%
2	30%
3	16%
4	14%
5	14%

Market Conduct

Offers

Figure 6-9 Tier 2 synchronized reserve average hourly offer volume (MW): January through March, 2011 (See 2010 SOM, Figure 6-9)

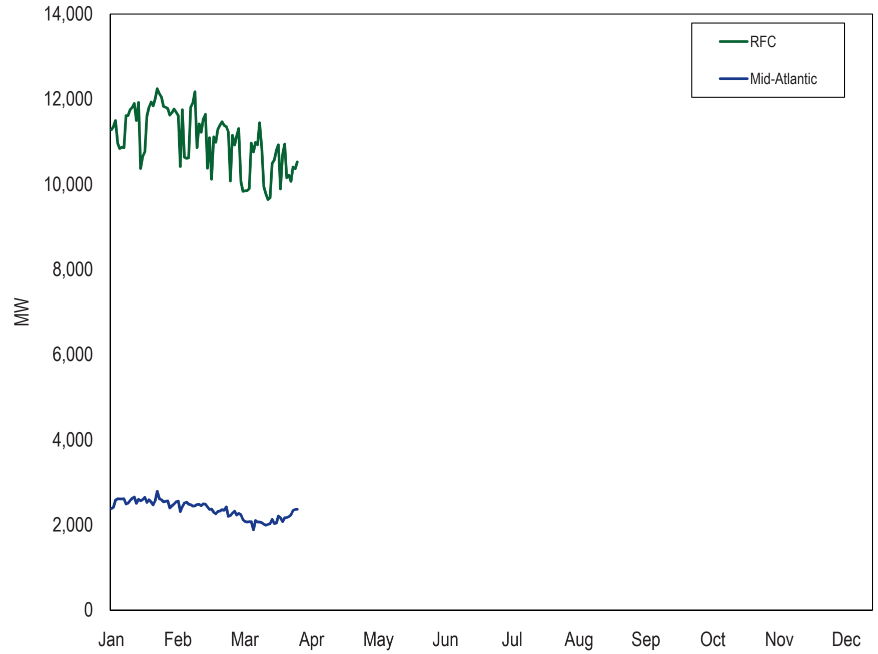


Figure 6-10 Average daily Tier 2 synchronized reserve offer by unit type (MW): January through March, 2011 (See 2010 SOM, Table 6-10)

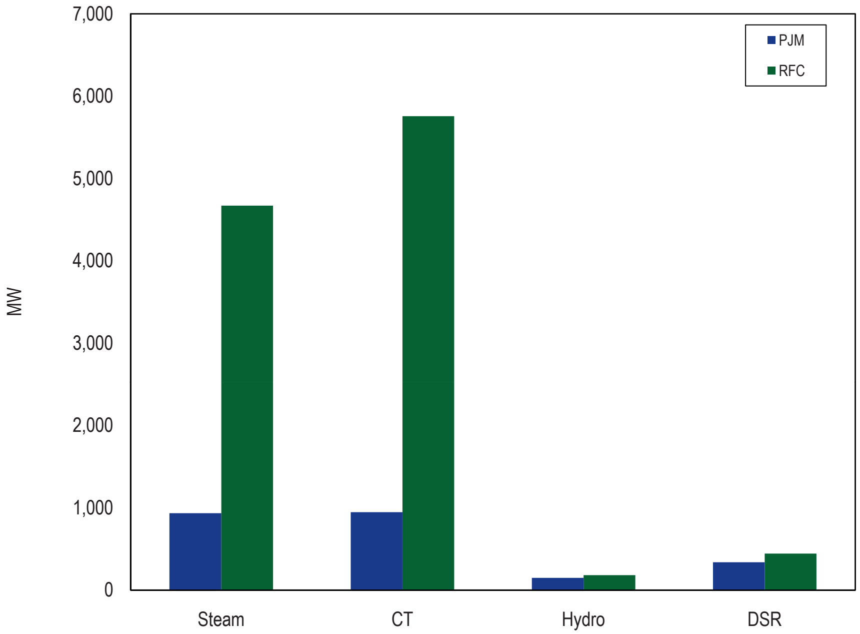
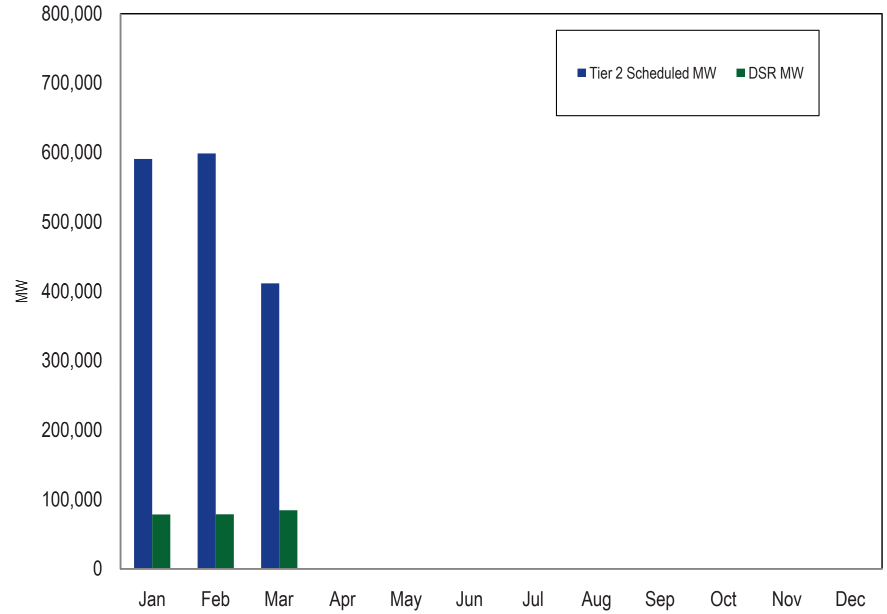


Figure 6-11 PJM RFC Zone Tier 2 synchronized reserve scheduled MW: January through March, 2011 (See 2010 SOM, Figure 6-11)



DSR

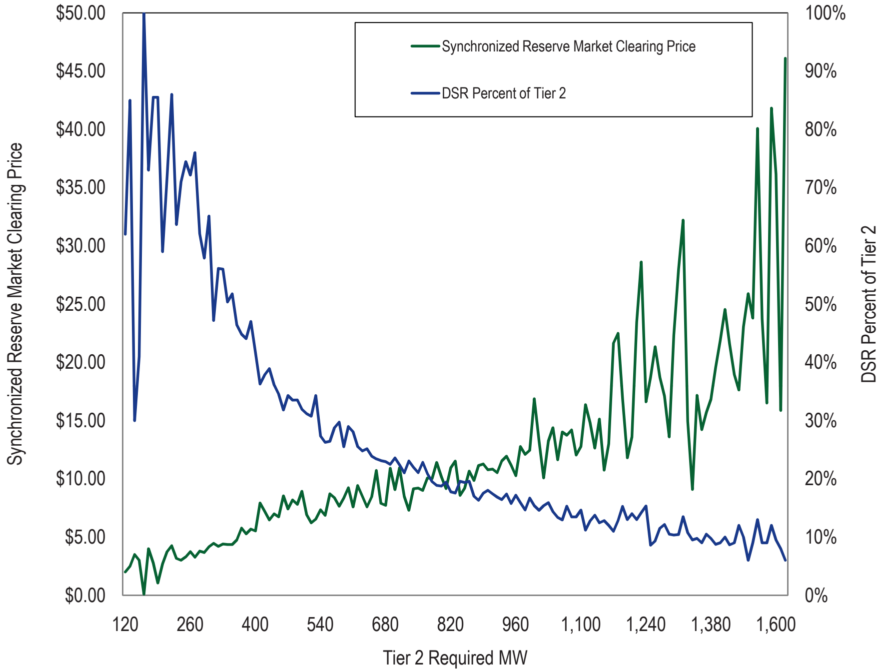
Table 6-17 Average SRMCP when all cleared synchronized reserve is DSR, average SRMCP, and percent of all cleared hours that all cleared synchronized reserve is DSR: January through March 2010 and January through March 2011 (See 2010 SOM, Table 6-17)

Year	Month	Average SRMCP	Average SRMCP when all cleared synchronized reserve is DSR	Percent of cleared hours all synchronized reserve is DSR
2010	Jan	$5.84	$2.03	4%
2010	Feb	$5.97	$0.10	1%
2010	Mar	$8.45	$2.03	6%
2011	Jan	$10.75	$0.10	0%
2011	Feb	$10.91		0%
2011	Mar	$11.33	$2.04	2%

Market Performance

Price

Figure 6-12 Required Tier 2 synchronized reserve, Synchronized Reserve Market clearing price, and DSR percent of Tier 2: January through March, 2011 (See 2010 SOM, Figure 6-12)



Price and Cost

Figure 6-13 Tier 2 synchronized reserve purchases by month for the Mid-Atlantic Subzone: January through March, 2011 (See 2010 SOM, Figure 6-13)

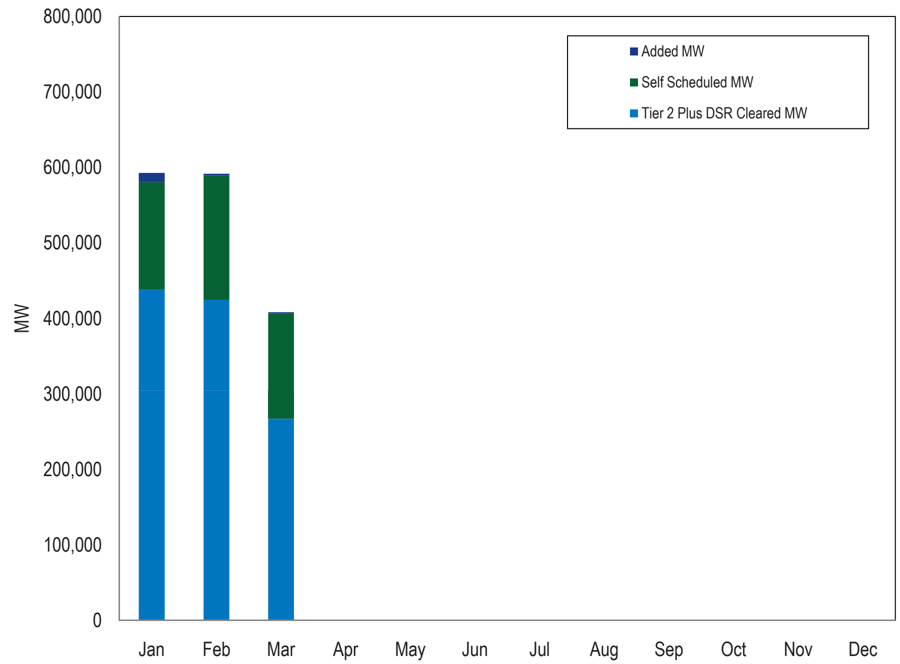


Figure 6-14 Impact of Tier 2 synchronized reserve added MW to the Mid-Atlantic Subzone: January through March, 2011 (See 2010 SOM, Figure 6-14)

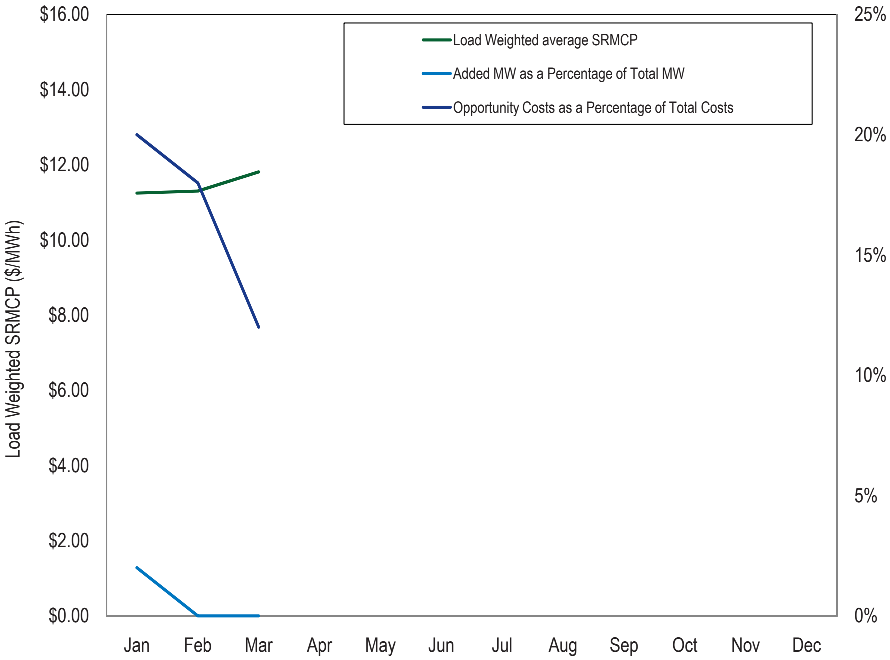


Figure 6-15 Comparison of Mid-Atlantic Subzone Tier 2 synchronized reserve price and cost (Dollars per MW): January through March, 2011 (See 2010 SOM, Figure 6-15)

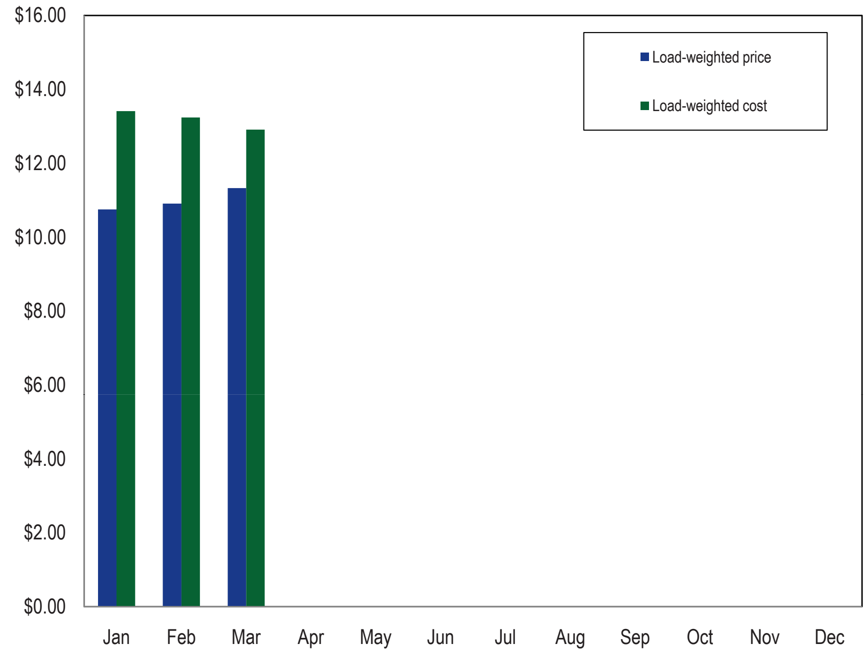


Table 6-18 Comparison of load weighted price and cost for PJM Synchronized Reserve, January 2005 through March 2011 (See 2010 SOM, Table 6-18)

Year	Load Weighted Synchronized Reserve Market Price	Load Weighted Synchronized Reserve Cost	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	$10.96	$13.22	83%

Day Ahead Scheduling Reserve (DASR)

Market Conduct

Table 6-19 Count of units by unit type offering DASR at $900/MW: January through March, 2011 (See 2010 SOM, Table 6-19)

Unit Type	Distinct Units
CT	21
Diesel	2
Nuclear	10
Steam	6
Wind	5

Market Performance

Table 6-20 PJM, Day-Ahead Scheduling Reserve Market MW and clearing prices: January through March, 2011 (See 2010 SOM, Table 6-20)

Month	Average Required Hourly DASR (MW)	Minimum Clearing Price	Maximum Clearing Price	Average Load Weighted Clearing Price	Total DASR MW Purchased	Total DASR Credits
Jan	6,536	$0.00	$1.00	$0.03	4,862,520	$127,837.00
Feb	6,180	$0.00	$1.00	$0.02	4,152,665	$61,682.00
Mar	5,720	$0.00	$1.00	$0.01	4,249,733	$45,835.00

Black Start Service

Table 6-21 Black start yearly zonal charges for network transmission use: January through March, 2011 (See 2010 SOM, Table 6-21)

Zone	Network Charges	Black Start Rate
AECO	$97,979	$0.37
AEP	$148,254	$0.07
AP	$36,436	$0.05
BGE	$137,342	$0.22
ComEd	$1,027,440	$0.52
DAY	$35,302	$0.12
DLCO	$8,162	$0.03
DPL	$90,675	$0.25
JCPL	$120,773	$0.21
Met-Ed	$113,979	$0.43
PECO	$219,676	$0.28
PENELEC	$88,994	$0.33
Pepco	$72,465	$0.12
PPL	$35,616	$0.05
PSEG	$591,219	$0.61