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 a cost basis.

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 *2009 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 the first three months of 2010.

On June 1, 2008 PJM introduced the Day-Ahead Scheduling Reserve Market (DASR), as required by the settlement in the RPM case.[3] 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 the market clearing price.

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 2010.

Overview

Regulation Market

The PJM Regulation Market in 2010 continues 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. At the FERC's direction, the MMU prepared and submitted a report on November 30, 2009, on the impact of these changes.[4] The findings of the report have been updated and corrected and the results are presented below. The changes to the Regulation Market rules resulted in a significant (35 percent) increase in payments to the providers of regulation compared to what they

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

4 The MMU report filed in Docket No. ER09-13-000 is posted at: <http://www.monitoringanalytics.com/reports/Reports/2009/IMM_PJM_Regulation_Market_Impact_20081201_Changes_20091130.pdf>(465 KB).

would have otherwise received and compared to what they would have received in a competitive market design for the first three months of 2010.

Market Structure

- **Supply.** During the first three months of 2010, the supply of offered and eligible regulation in PJM was generally 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 2010. The ratio of eligible regulation offered to regulation required averaged 2.94 throughout the first three months of 2010, a decrease from the 2009 ratio of 2.98.

- **Demand.** Beginning August 7, 2008, PJM began to define separate on-peak and off-peak regulation requirements. The on-peak 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. Previously the requirement had been fixed daily at 1.0 percent of the daily forecast operating load. The average hourly regulation demand for the first three months of 2010 was 896 MW, compared to 898 MW for the first three months of 2009.

- **Market Concentration.** During the first three months of 2010, the PJM Regulation Market had a load weighted, average Herfindahl-Hirschman Index (HHI) of 1442 which is classified as "moderately concentrated."[5] The minimum hourly HHI was 921 and the maximum hourly HHI was 2983. The largest hourly market share in any single hour was 51 percent, and 87 percent of all hours had a maximum market share greater than 20 percent. For the first three months of 2010, 76 percent of hours had one or more pivotal suppliers. The MMU concludes from these results that the PJM Regulation Market for the first three months of 2010 was characterized by structural market power in 76 percent of the hours.

Market Conduct

- **Offers.** Daily regulation offer prices are submitted for each unit by the unit owner. Beginning December 1, 2008, owners are required to submit unit specific cost based offers and owners also have the option to submit price based offers. All offers remain subject to the $100 per MWh cap.[6] In computing the market solution, PJM adds opportunity cost. 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. All units of owners who fail the three pivotal supplier test for an hour have their offers 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. The impact of this change was to increase cost based offer prices.

  As part of the changes to the regulation market implemented on December 1, 2008, PJM calculates opportunity costs using LMP forecasts and the lesser of the available price based offer or the most expensive available cost based offer as the reference, rather than the offer on which the unit is operating.[7] PJM adds this opportunity cost to the offers of the market participants. The impact of this change was to increase cost based and price based offer prices.

Market Performance

- **Price.** For the PJM Regulation Market during the first three months of 2010, the load weighted, average price per MWh (the regulation market clearing price, including opportunity cost) associated with meeting PJM's demand for regulation was $17.82. This was a decrease of $4.22, or 18 percent, from the average price for regulation during the first three months of 2009.

- **Price and Opportunity Cost.** Prices in the PJM Regulation Market during the first three months of 2010 were approximately 25 percent higher than they would have been but for the change to the definition of opportunity cost.

5 See the *2009 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).

6 See PJM. "Manual 11: Scheduling Operations," Revision 43 (September 24, 2009), p.39.

7 See PJM. "Manual 11: Scheduling Operations," Revision 44 (January 1, 2010), p. 43: "SPREGO utilizes the lesser of the available price-based energy schedule or most expensive available cost-based energy schedule (the "lost opportunity cost energy schedule"), and forecasted LMPs to determine the estimated opportunity cost each resource would incur if it adjusted its output as necessary to provide its full amount of regulation. "

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 two significant changes to the Synchronized Reserve Market in 2009. These changes were intended to ensure that the synchronized reserve requirement accurately reflects the needs of PJM dispatch. This includes ensuring that the forecast amount of Tier 1 synchronized reserve is actually available to PJM dispatch during the operating hour. PJM changed the primary constraint which defines the Mid-Atlantic Subzone within the RFC Synchronized Reserve Market from Bedington—Black Oak to AP South. PJM reduced from 70 percent to 15 percent the percentage of Tier 1 available west of the AP South interface that it will consider as available to the Mid-Atlantic Subzone when it calculates the amount of Tier 2 required. These changes were made to address the fact that PJM Dispatch needed more synchronized reserve than was defined as the requirement to be met by the market. This problem has existed in the Synchronized Reserve Market since late 2007. These changes reduced the amount of additional, out of market, synchronized reserve required by PJM dispatch, which reduced opportunity cost payments and aligned the total cost of synchronized reserves more closely with Synchronized Reserve Market prices. Synchronized reserves added out of market were two percent of all synchronized reserves during January through March of 2010, while they were 55 percent for the same time period in 2009. Opportunity cost payments accounted for 25 percent of total costs during January through March of 2010 compared to 62 percent during the same time period in 2009.

Market Structure

- **Supply.** For January through March of 2010, synchronized reserve offers were somewhat higher than the equivalent period in 2009. The offered and eligible excess supply ratio was 1.26 for the PJM Mid-Atlantic Synchronized Reserve Region.[8] For the RFC zone, the excess supply ratio was 2.33. The excess supply ratio is determined using the administratively required level of synchronized reserve. The actual requirement for Tier 2 synchronized reserve is lower than the required reserve level because there is usually a significant amount of Tier 1 synchronized reserve available. In the first three months of 2010, the contribution of DSR resources to the Synchronized Reserve Market remained significant and resulted in lower overall Synchronized Reserve prices.

- **Demand.** The average synchronized reserve requirements were 1,320 MW for the RFC Synchronized Reserve Zone and 1,150 MW for the Mid-Atlantic Subzone. Market demand is less than the requirement by the amount of forecast Tier 1 synchronized reserve available at the time a Synchronized Reserve Market is cleared.

  Demand for Tier 2 synchronized reserve in the Mid-Atlantic Subzone was normal in the first three months of 2010. In 11 percent of hours no Tier 2 synchronized reserve was needed. The average required Tier 2 (including self scheduled) was 450 MW.

  Synchronized reserves added out of market were two percent of all synchronized reserve during January through March of 2010.

  As a result of the level of Tier 1 reserves in the RFC Synchronized Reserve Zone, only one percent of hours cleared a Tier 2 Synchronized Reserve Market in the RFC. A Tier 2 Synchronized Reserve Market has not yet been cleared for the Southern Synchronized Reserve Zone in the first three months of 2010. In the PJM Mid-Atlantic Synchronized Reserve Region, 87 percent of hours cleared a Tier 2 Synchronized Reserve Market. The average demand for Tier 2 synchronized reserve in the Mid-Atlantic Subzone of the RFC Synchronized Reserve Zone was 450 MW. Much of the demand is satisfied by the high level of self scheduled, averaging 226 MW, so the market had to clear an average of 224 MW.

- **Market Concentration.** The average load weighted cleared Synchronized Reserve Market HHI for the Mid-Atlantic Subzone of the RFC Synchronized Reserve Zone for the first three months of 2010 was 2972 which is classified as "highly concentrated."[9] For purchased synchronized reserve (cleared plus added) the HHI was 3002. In 58 percent of hours the maximum market share was greater than 40 percent (compared to 36 percent of hours in 2009).

  In the Mid-Atlantic Subzone of the RFC Synchronized Reserve Market, for the first three months of 2010, 59 percent of hours had three or

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

9 See the *2009 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).

fewer pivotal suppliers. The MMU concludes from these results that the PJM Synchronized Reserve Markets in the first three months of 2010, are 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.

  Demand side resources remained significant participants in the Synchronized Reserve Market in the first three months of 2010. In four percent of hours in which a Tier 2 Synchronized Reserve Market was cleared for the Mid-Atlantic Subzone, all synchronized reserves were provided by DSR.

Market Performance

- **Price.** The load weighted, average PJM price for Tier 2 synchronized reserve in the Mid-Atlantic Subzone of the RFC Synchronized Reserve Market was $7.02 per MW for the first three months of 2010, a $0.44 per MW decrease from 2009.

- **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 during the first three months of 2010.

DASR

On June 1, 2008 PJM introduced the Day-Ahead Scheduling Reserve Market (DASR), as required by the RPM settlement.[10] 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.[11] 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.** The DASR Market for the first three months of 2010 had no pivotal suppliers.

Market Conduct

- **Withholding.** Economic withholding remains a problem in the DASR Market. Continuing a pattern seen since the inception of the DASR Market, a significant number of units offered at levels effectively guaranteed not to clear. Five percent of units offered at $50 or more and four percent of units offered at $990 or more, in a market with an average clearing price of $0.05 and a maximum clearing price of $0.75.

- **DSR.** Demand side resources do participate in the DASR Market but remain insignificant.

Market Performance

- **Price.** For the first three months of 2010, the load weighted price of DASR was $0.05, including the 25 percent of hours when the market cleared at a price of $0.00.

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.[12]

Individual transmission owners, with PJM, identify the black start units included in each transmission owner's system restoration plan. PJM

10 See PJM Interconnection, L.L.C., 117 FERC ¶ 61,331 (2006).

11 PJM Manual 13, Emergency Requirements, Revision 39, (January 1, 2010); pp 11-12.

12 PJM OATT Schedule § 1.3BB, Second Revised Second Revised Sheet No. 33.01, March 1, 2007.

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 for all costs associated with providing this service, as defined in the tariff. For 2009, charges were about $12.3 million. For the first three months of 2010 changes were $2.3 million. There was substantial zonal variation.

As a consequence of PJM's filing to revise its formula rate for black start service to allow for the recovery of the costs of compliance with Critical Infrastructure Protection standards, black start costs likely will increase substantially. The revised filing also provides a better match between the sellers' commitment period and the cost recovery period.

The MMU recommends that PJM, FERC and state regulators reevaluate the way in which black start service is procured in order to ensure that procurement is done in a least cost manner for the entire PJM market.

Conclusion

The *2009 State of the Market Report for PJM* summarized the history of the issues related to the Regulation Market.[13]

The MMU has updated the calculations, improved the calculations and made corrections as necessary, based in part on PJM's comments.[14] This updated and improved analysis is presented below.

Together, the changes to the tariff related to the Regulation Market resulted in an increase in payments to the providers of regulation of $77 million over the 16 month period from December 2008 through March 2010, compared to what they would have received in the absence of these three changes. This represents an increase in total regulation payments of 25 percent for the 16 month period. While these results are based on estimates of how the market would have worked in the absence of the changes in market design, the calculations reflect detailed hourly data about the individual units in the Regulation Market supply curve. There is no question that the changes in market design significantly increased the payments for regulation service, regardless of any disagreements about the details of the calculation methods.

The MMU concludes, based on the analysis of the Regulation Market operating under the revised rules, that the results of the Regulation Market are not competitive. The results of the Regulation Market are not competitive because the changes in market rules, in particular the changes to the calculation of the opportunity cost, resulted in offers greater than competitive offers and therefore in prices greater than competitive prices. The competitive price is the price that would have resulted from a combination of the competitive offers from market participants and the application of the prior, correct and consistent approach to the calculation of the opportunity cost. The offers from market participants are not at issue, as PJM directly calculates and adds opportunity costs to the offers of participants, following the revised market rules. The Regulation Market results are the result of the market design changes and are not the result of the behavior of market participants, which was competitive as a result of the application of the three pivotal supplier test.

The MMU recommends that the modification to the definition of opportunity cost be reversed and that the elimination of the offset against operating reserve credits be reversed based on the MMU conclusion that these features result in a non-competitive market outcome, and because they are inconsistent with the treatment of the same issues in other PJM markets and inconsistent with basic economic logic.

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 recommends that the DASR Market rules be modified to incorporate the application of the three pivotal supplier test. The MMU concludes that the DASR Market results were competitive in the first three months of 2010.

13 See the *2009 State of the Market Report for PJM*, Volume II, "Ancillary Service Markets."

14 Comments of PJM Interconnection, L.L.C. to Report of Independent Market Monitor filed in ER09-13 (December 30, 2009). The Illinois Commerce Commission also filed comments on the MMU's report: Comments of the Illinois Commerce Commission filed in ER09-13 (January 6, 2010).

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 2010. The MMU concludes that the Synchronized Reserve Market results were competitive in the first three months of 2010. The MMU concludes that the DASR Market results were competitive in the first three months of 2010.

Regulation Market

Market Structure

Supply

Demand

Table 6-1 PJM Regulation Market required MW and ratio of supply to requirement: January through March 2010 (See 2009 SOM, Table 6-1)

Month	Average Required Regulation (MW)	Ratio of Supply To Requirement
Jan	948	2.94
Feb	942	3.05
Mar	800	2.84

Market Concentration

Table 6-2 PJM regulation capability, daily offer and hourly eligible: January through March 2010 (See 2009 SOM, Table 6-2)

Period	Regulation Capability (MW)	Average Daily Offer (MW)	Percent of Capability Offered	Average Hourly Eligible (MW)	Percent of Capability Eligible
All Hours	7,367	5,775	78%	2,650	36%
Off Peak	7,367			2,369	32%
On Peak	7,367			2,964	40%

Table 6-3 PJM cleared regulation HHI: January through March 2010 (See 2009 SOM, Table 6-3)

Market Type	Minimum HHI	Load-weighted Average HHI	Maximum HHI
Cleared Regulation, 1st Quarter, 2010	921	1442	2983

Figure 6-1 Figure 6-1 PJM Regulation Market HHI distribution: January through March 2010 (See 2009 SOM, Figure 6-1)

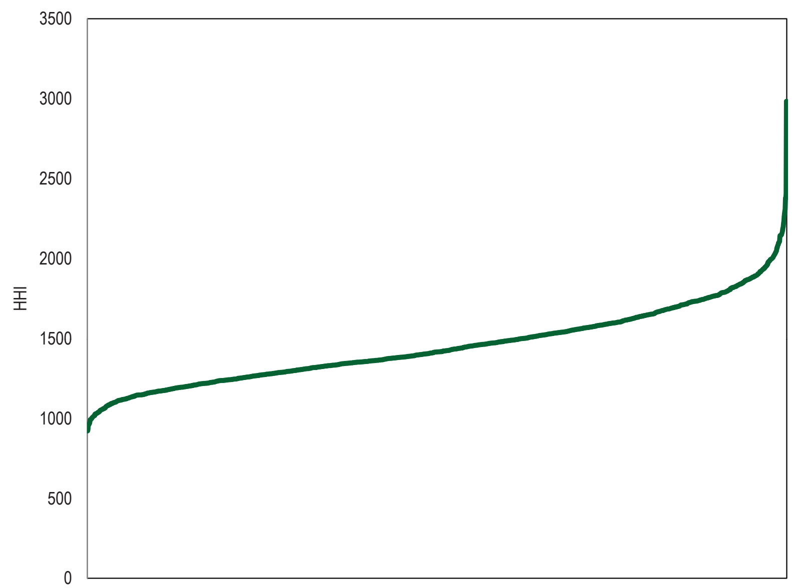


Figure 6-2 Off peak and on peak regulation levels: January through March 2010 (See 2009 SOM, Figure 6-2)

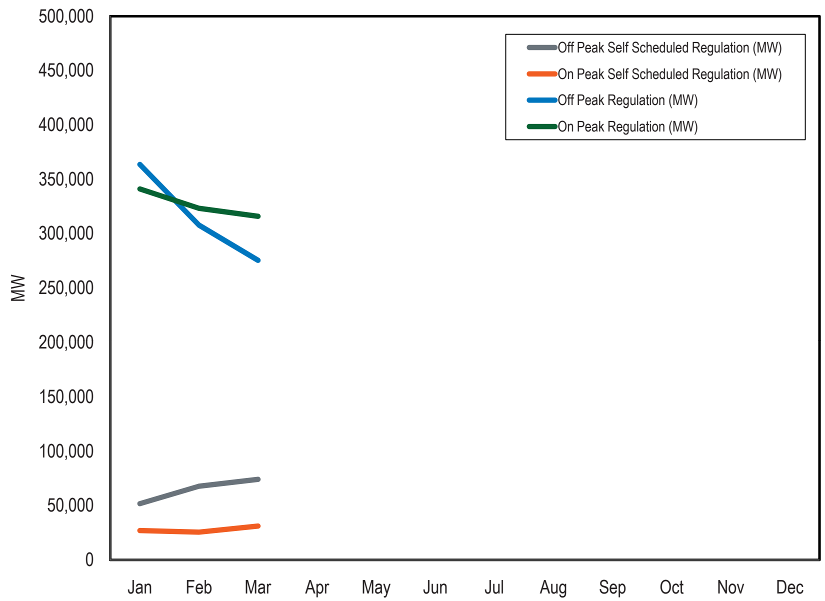


Table 6-4 Highest annual average hourly Regulation Market shares: January through March 2010 (See 2009 SOM, Table 6-4)

Company Market Share Rank	Cleared Regulation Top Yearly Market Shares
1	20%
2	16%
3	14%
4	13%
5	10%

Table 6-5 Regulation market monthly three pivotal supplier results: January through March 2010 (See 2009 SOM, Table 6-5)

Month	Percent of Hours With Three Pivotal Suppliers
Jan	74%
Feb	70%
Mar	83%

Market Performance

Price

Table 6-6 Percent of hours when marginal unit supplier was pivotal: January through March 2010 (See 2009 SOM, Table 6-6)

Month	Percent of Hours When Marginal Supplier is Pivotal
Jan	67%
Feb	58%
Mar	73%

Figure 6-3 PJM Regulation Market daily average market-clearing price, opportunity cost and offer price (Dollars per MWh): January through March 2010 (See 2009 SOM, Figure 6-3)

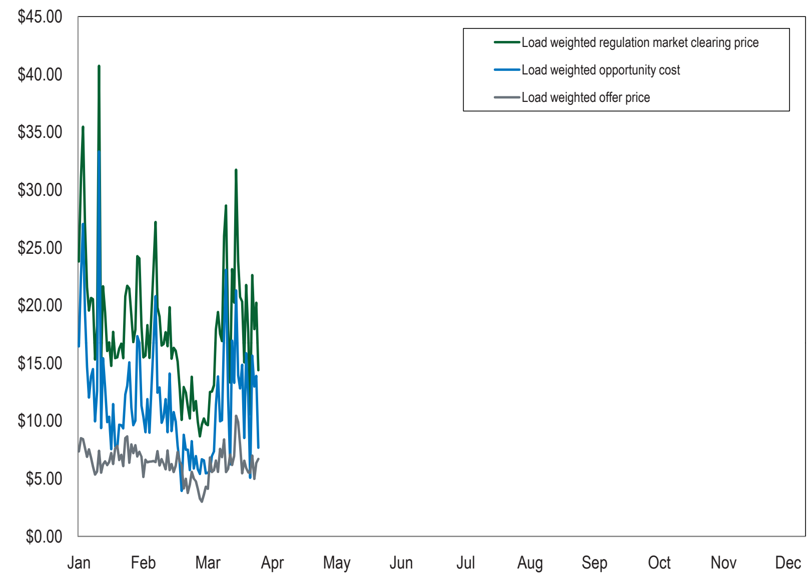


Figure 6-4 Monthly average regulation demand (required) vs. price: January through March 2010 (See 2009 SOM, Figure 6-4)

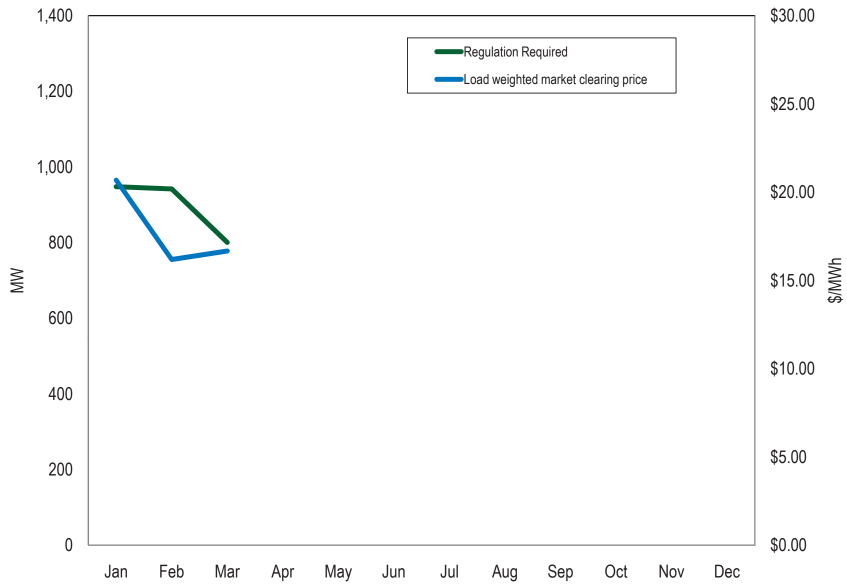


Figure 6-5 Monthly load weighted, average regulation cost and price: January through March 2010 (See 2009 SOM, Figure 6-5)

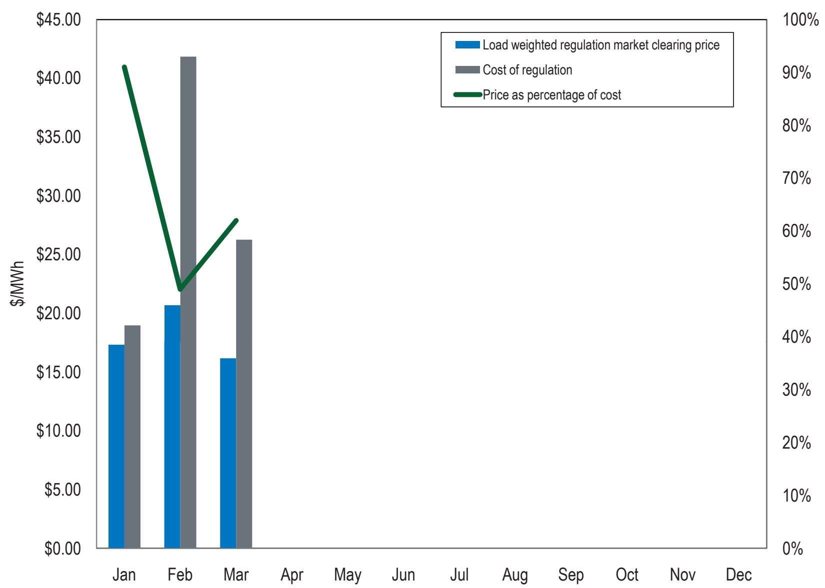


Table 6-7 Total regulation charges: January through March 2010 (See 2009 SOM, Table 6-7)

Month	Scheduled Regulation (MW)	Total Regulation Charges	Load Weighted Regulation Market Clearing Price ($/MWh)	Cost of Regulation ($/MWh)
Jan	704,362	$29,479,645	$20.66	$41.85
Feb	632,007	$16,673,515	$16.17	$26.38
Mar	591,046	$14,058,674	$16.62	$23.79

Analysis of Regulation Market Changes

Table 6-8 Summary of changes to Regulation Market design (See 2009 SOM, Table 6-8)

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.

Introduction of TPS Testing

Table 6-9 Regulation Market pivotal supplier test results: December 2008 through March 2010 and December 2007 through March 2009 (See 2009 SOM, Table 6-9)

Year	Month	Percent of Hours With Three Pivotal Suppliers	Year	Month	Percent of Hours With Three Pivotal Suppliers
2008	Dec	92%	2007	Dec	79%
2009	Jan	84%	2008	Jan	84%
2009	Feb	61%	2008	Feb	83%
2009	Mar	42%	2008	Mar	89%
2009	Apr	39%	2008	Apr	88%
2009	May	31%	2008	May	97%
2009	Jun	37%	2008	Jun	77%
2009	Jul	39%	2008	Jul	75%
2009	Aug	35%	2008	Aug	80%
2009	Sep	47%	2008	Sep	74%
2009	Oct	64%	2008	Oct	89%
2009	Nov	62%	2008	Nov	59%
2009	Dec	80%	2008	Dec	92%
2010	Jan	74%	2009	Jan	84%
2010	Feb	70%	2009	Feb	61%
2010	Mar	83%	2009	Mar	42%

Increase Offer Margin from $7.50 to $12.00

Table 6-10 Impact of $12 adder to cost based regulation offer: January through March 2010 (See 2009 SOM, Table 6-10)

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
2010	Jan	$20.66	$16.91	$29,479,645	$2,641,053	9%
2010	Feb	$16.17	$13.22	$16,673,515	$1,861,195	11%
2010	Mar	$16.66	$13.63	$14,058,674	$1,438,051	11%
Total				$60,211,834	$5,940,299	9.9%

Change in the Definition of Opportunity Cost

Table 6-11 Impact to Regulation Market Clearing Price of using lesser of price based energy schedule or most expensive cost-based energy schedule: January through March 2010 (See 2009 SOM, Table 6-11)

			New Rule		Old Rule			
Year	Month	Average Regulation Required (MW)	Load Weighted RMCP Using Lesser Schedule for Opportunity Cost	Using Lesser Schedule For Opportunity Costs, Total Charges	Load Weighted RMCP Using Current Dispatch Schedule for Opportunity Costs	Using Current Dispatch Schedule for Opportunity Costs, Total Charges	Additional Regulation Credits Paid Using New Rule	Pecentage Increase in Regulation Credits
2010	Jan	950	$20.66	$29,479,645	$11.56	$23,065,981	$6,413,664	22%
2010	Feb	944	$16.17	$16,490,553	$9.93	$12,730,541	$3,760,012	23%
2010	Mar	802	$16.66	$13,780,240	$8.71	$9,205,222	$4,575,018	33%
Total				$59,750,438		$45,001,744	$14,748,694	25%

Eliminate Offset Against Balancing Operating Reserves Credits

Table 6-12 Additional credits paid to regulating units from no longer netting credits above RMCP against operating reserves: January through March 2010 (See 2009 SOM, Table 6-12)

Year	Month	Balancing Operating Reserves No Longer Offset	Total Regulation Credits	Percent of Regulation Credits No Longer Offsetting Operating Reserves
2010	Jan	$64,990	$29,479,645	0%
2010	Feb	$66,223	$16,673,515	0%
2010	Mar	$135,728	$14,058,674	1%

Summary

Table 6-13 Summary of additional charges paid as a result of December 1, 2008 changes to Regulation Market rules: January through March 2010, including December 2008 through December 2009 totals (See 2009 SOM, Table 6-13)

			Increasing Markup from $7.50 to $12.00		Opportunity Cost Calculated Using Lower of Price Based or Cost Based Price		Regulation Credits Above Cost Plus Opportunity Costs no Longer Offset Against Operating Reserves		Changes for Three Pivotal Supplier Testing, December 1, 2008 - Summary	
Year	Month	Total Regulation Credits	RMCP Credits Attributable to Marginal Units Cost Offer > Costs Plus $7.50	Percent Increase in Total Credits Due to Marginal Unit With Offer > Cost Plus $7.50	Additional Regulation Credits Paid Due to New Opportunity Cost Calculation	Percentage Increase in Regulation Credits Due to New Opportunity Cost Calculation	Balancing Operating Reserve Credits No Longer Offset	Percent of Regulation Credits No Longer Offsetting Operating Reserves	Total Additional Generator Credits	Total Percent of Regulation Credits Additional
2010	Jan	$29,479,645	$2,641,053	9%	$6,413,664	22%	$64,990	0%	$9,119,707	31%
2010	Feb	$16,673,515	$1,861,195	11%	$3,760,012	23%	$66,223	0%	$5,687,430	34%
2010	Mar	$14,058,674	$1,438,051	10%	$4,575,018	33%	$135,728	1%	$6,148,797	44%
Jan-Mar 2010 Total		$60,211,834	$5,940,299	9.9%	$14,748,694	24%	$266,941	0%	$20,955,934	35%
Dec 08 - Dec 09 Total		$247,893,142	$6,189,406	2.5%	$47,463,833	19%	$2,297,348	1%	$55,950,587	23%
Dec 08 - Mar 10 Total		$308,104,976	$12,129,705	3.9%	$62,212,527	20%	$2,564,289	1%	$76,906,521	25%

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 2010 (See 2009 SOM, Figure 6-6)

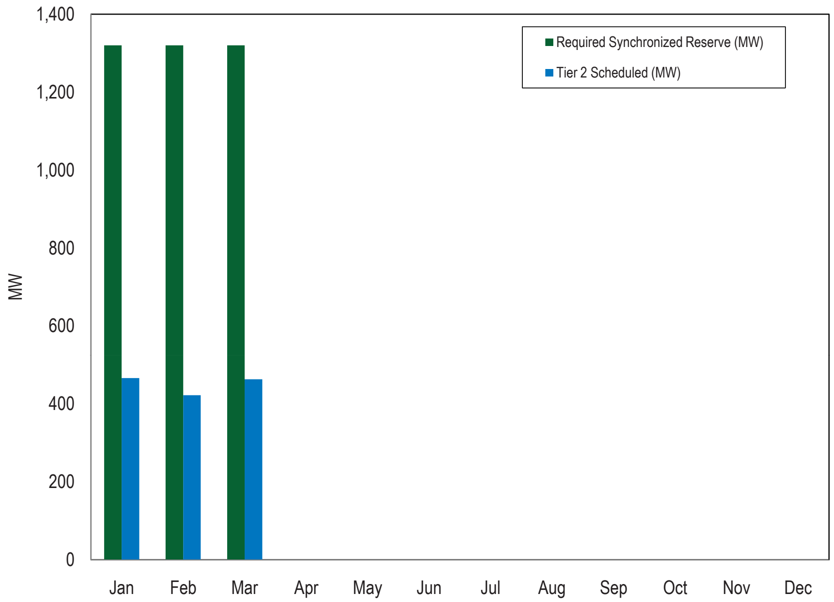
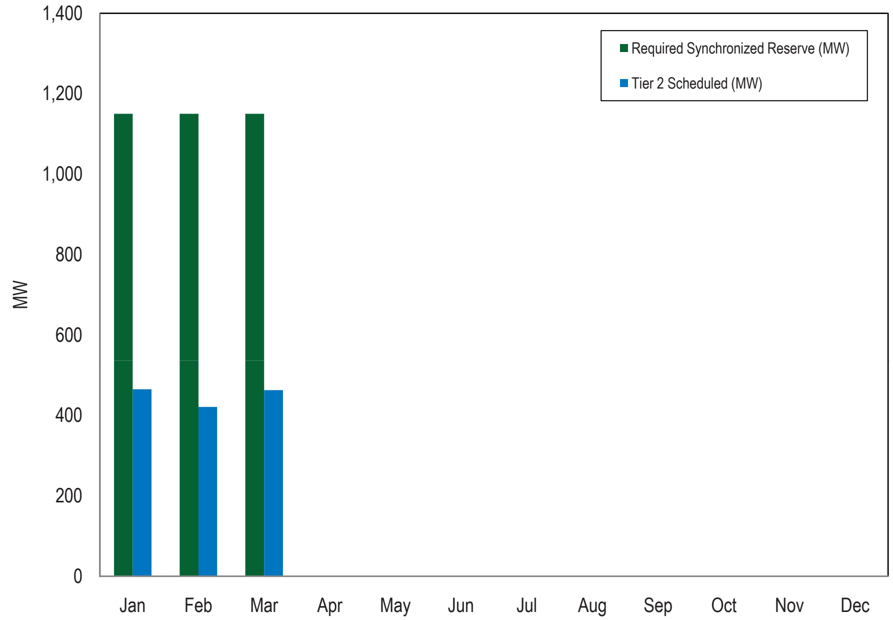


Figure 6-7 RFC Synchronized Reserve Zone, Mid-Atlantic Subzone average hourly synchronized reserve required vs. Tier 2 scheduled: January through March 2010 (See 2009 SOM, Figure 6-7)



Market Concentration

Figure 6-8 Purchased Mid-Atlantic Subzone RFC Tier 2 Synchronized Reserve Market seasonal HHI: January through March 2010 (See 2009 SOM, Figure 6-8)

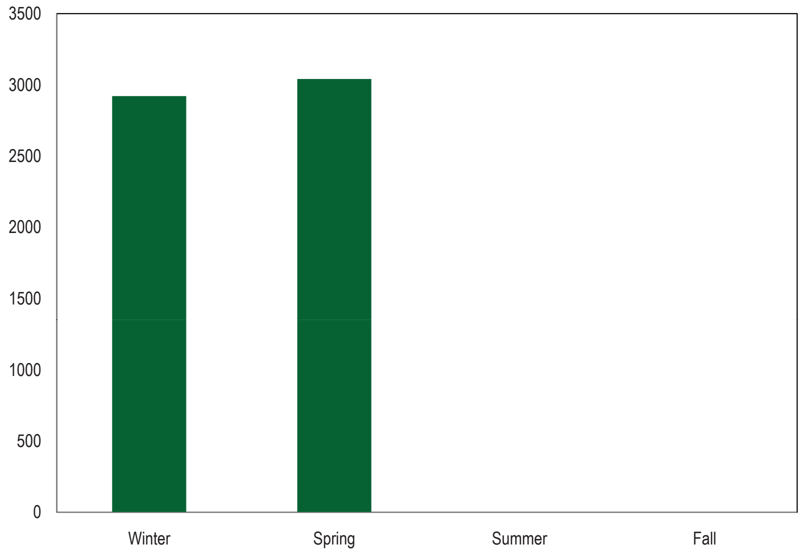


Table 6-14 Mid-Atlantic Subzone RFC Tier 2 Synchronized Reserve Market's cleared market shares: January through March 2010 (See 2009 SOM, Table 6-15)

Company Market Share Rank	Cleared Synchronized Reserve Top Market Shares
1	40%
2	30%
3	22%
4	16%
5	8%

Market Conduct

Offers

Figure 6-9 Tier 2 synchronized reserve average hourly offer volume (MW): January through March 2010 (See 2009 SOM, Figure 6-9)

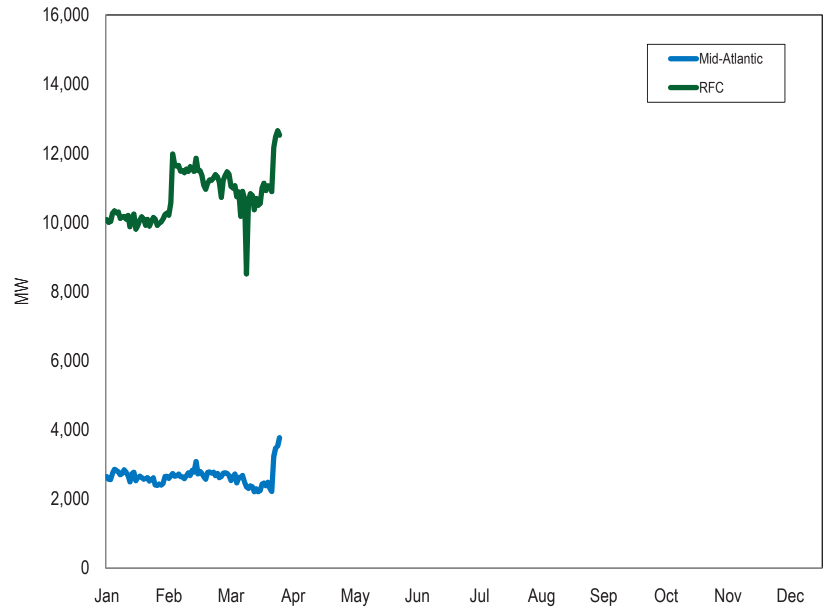


Figure 6-10 Average daily Tier 2 synchronized reserve offer by unit type (MW): January through March 2010 (See 2009 SOM, Figure 6-10)

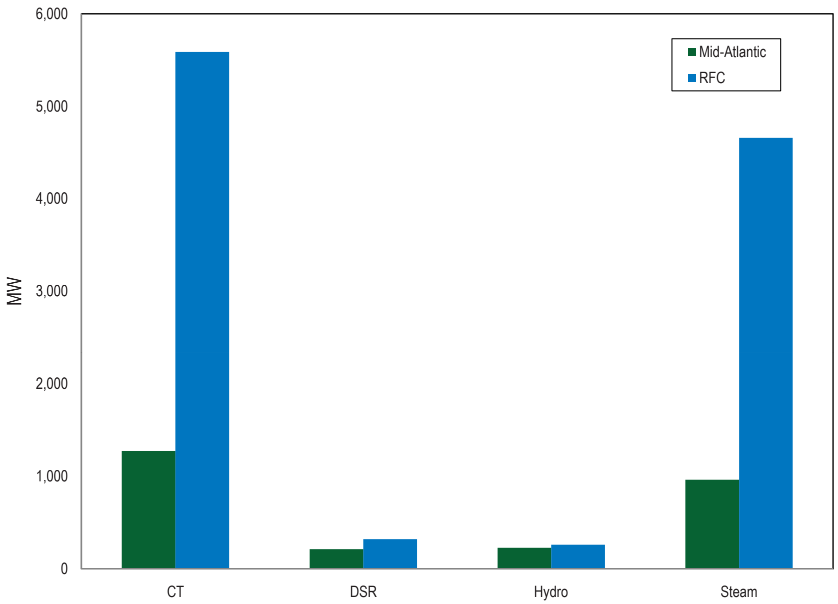
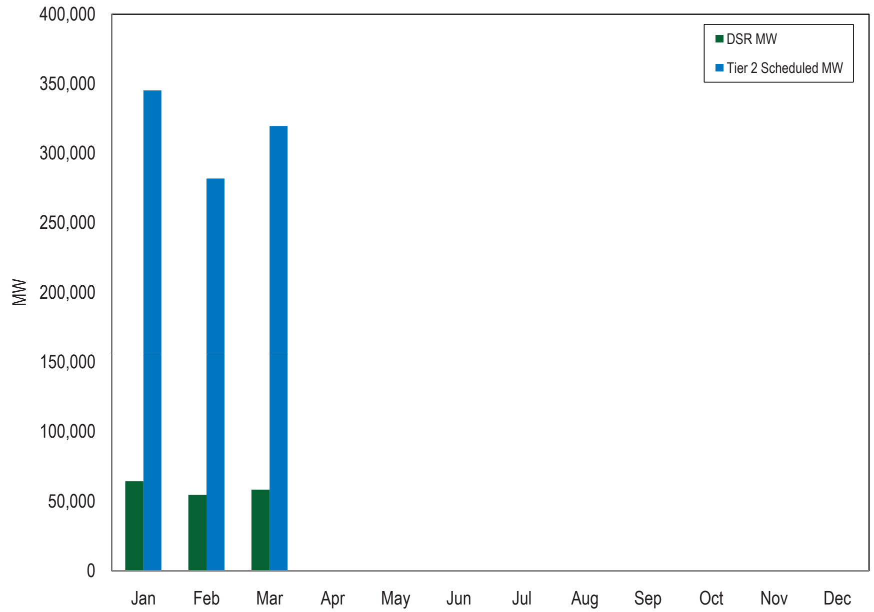


Figure 6-11 PJM RFC Zone Tier 2 synchronized reserve scheduled MW: January through March 2010 (See 2009 SOM, Figure 6-11)



DSR

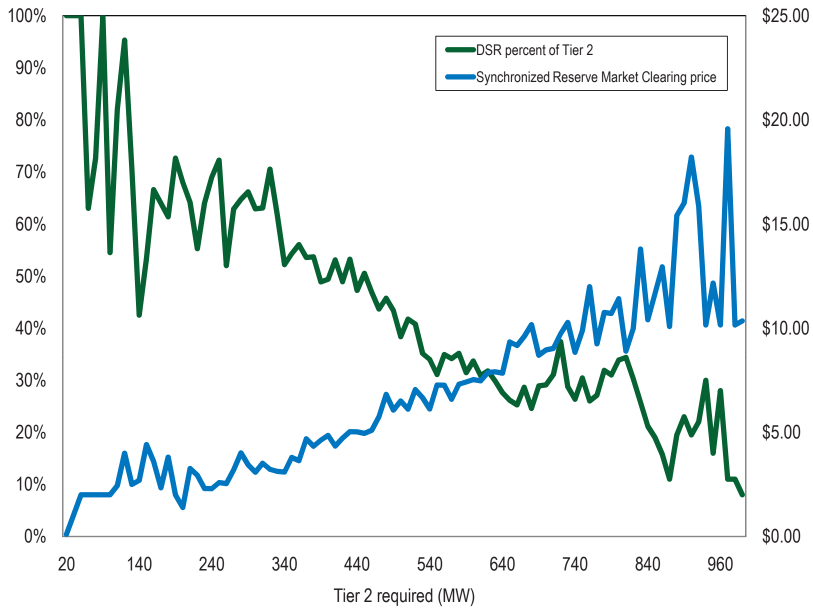
Table 6-15 Average RFC SRMCP when all cleared synchronized reserve is DSR, average SRMCP, and percent of all cleared hours that all cleared synchronized reserve is DSR: January through March 2010 (See 2009 SOM, Table 6-16)

Month	Average SRMCP when all cleared synchronized reserve is DSR	Percent of scheduled synchronized reserve is DSR	Average SRMCP	Percent of cleared hours all synchronized reserve is DSR
Jan	$5.84	33%	$2.03	4%
Feb	$5.97	31%	$0.10	1%
Mar	$8.45	39%	$2.03	6%

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 2010 (See 2009 SOM, Figure 6-12)



Price and Cost

Figure 6-13 RFC Synchronized Reserve Zone, Mid-Atlantic Subzone daily average hourly synchronized reserve required, Tier 2 MW scheduled, and Tier 1 MW estimated: January through March 2010 (See 2009 SOM, Figure 6-13)

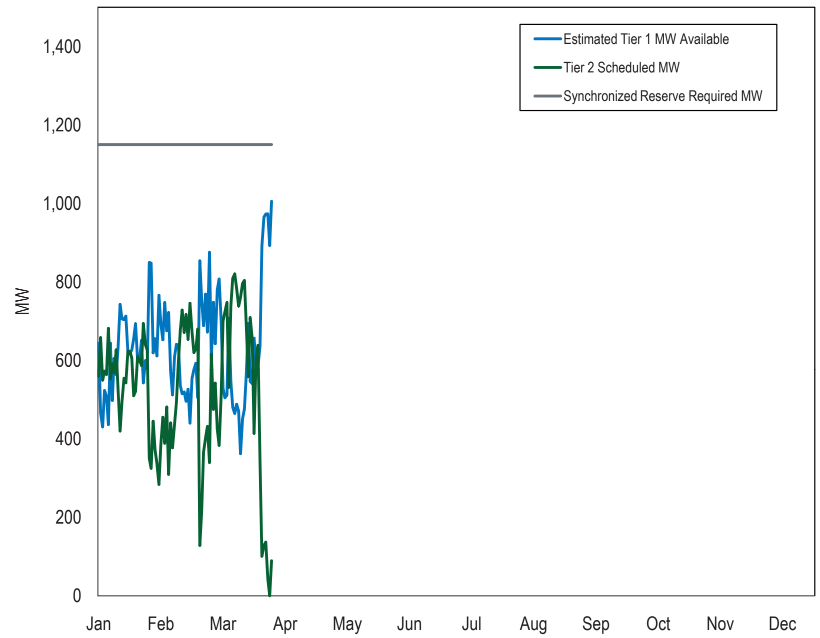


Figure 6-14 Tier 2 synchronized reserve purchases by month for the Mid-Atlantic Subzone: January through March 2010 (See 2009 SOM, Figure 6-14)

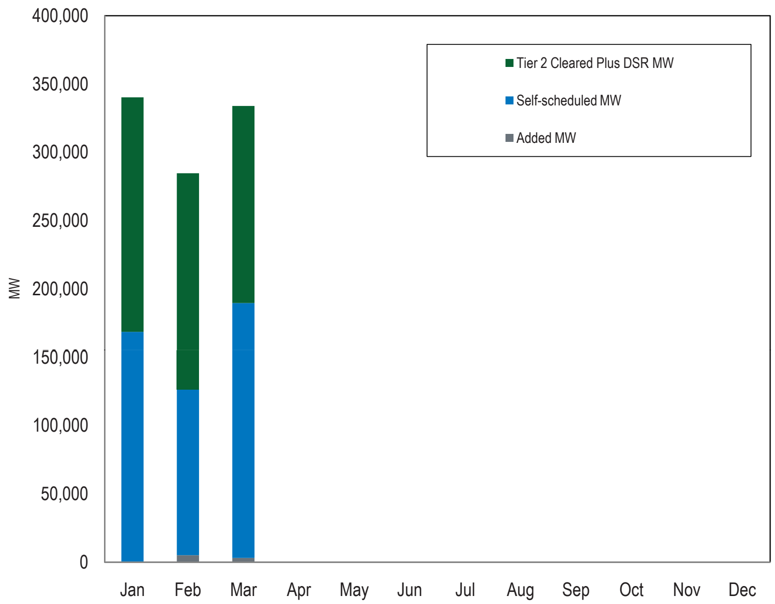


Figure 6-15 Figure 6-15 Impact of Tier 2 synchronized reserve added MW to the RFC Synchronized Reserve Zone, Mid-Atlantic Subzone: January through March 2010 (See 2009 SOM, Figure 6-15)

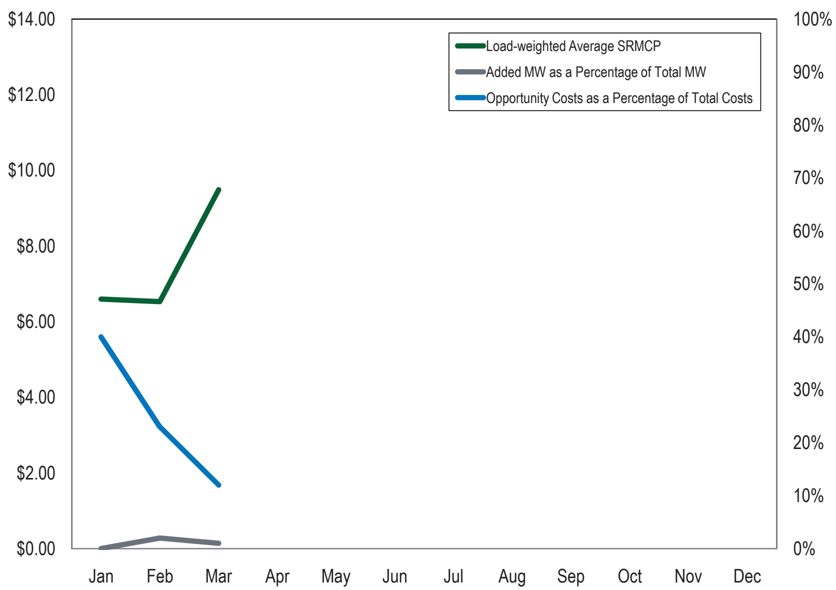
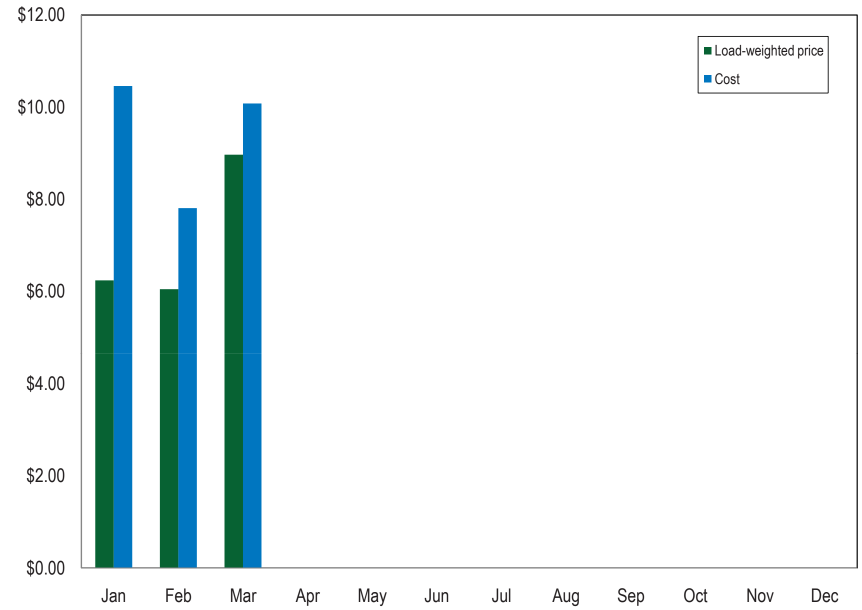


Figure 6-16 Comparison of RFC Mid-Atlantic Subzone Tier 2 synchronized reserve price and cost (Dollars per MW): January through March 2010 (See 2009 SOM, Figure 6-16)



Day Ahead Scheduling Reserve (DASR)

Table 6-16 2009 PJM, Day-Ahead Scheduling Reserve Market MW and clearing prices: January through March 2010 (See 2009 SOM, Table 6-17)

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	6,246	$0.00	$0.75	$0.05	4,647,334	$242,018
Feb	6,191	$0.00	$0.50	$0.06	4,160,064	$228,087
Mar	5,441	$0.00	$0.50	$0.03	4,042,540	$109,862

Black Start Service

Table 6-17 Black Start yearly zonal charges for network transmission use: January through March 2010 (See 2009 SOM, Table 6-18)

Zone	Network Charges
AECO	$92,809
AEP	$183,837
AP	$34,005
BGE	$120,471
ComEd	$925,229
DAY	$36,547
DPL	$97,576
DLCO	$6,668
JCPL	$109,132
Met-Ed	$101,468
PECO	$181,492
PENELEC	$84,560
Pepco	$55,756
PPL	$38,706
PSEG	$236,763
UGI	$38,706