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.

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.

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

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 2010.

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 73 percent of the hours.

- Participant behavior was evaluated as competitive because market power mitigation requires competitive offers when the three pivotal supplier test is failed and there was no evidence of generation owners engaging in anti-competitive behavior.

- Market performance was evaluated as not competitive because, 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.

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.

- 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 and New Analysis

- Regulation prices were 23.3 percent lower in 2010 than in 2009 and lower than in any year since the current Regulation Market structure was introduced in 2005. Regulation total costs per MW were 7.4 percent higher in 2010 than in 2009. The total cost of regulation per MW was 77.4 percent higher than the market clearing price in 2010. The result was a decrease in the ratio of price to cost. With the exception of 2009, the ratio of price to cost has declined in every year since 2005, and the ratio of price to cost is at its lowest level since 2005.

- Total self-scheduled regulation MW in 2010 was 15.5 percent of all regulation, an increase from 10.9 percent in 2009. The supply of eligible regulation increased by two percent in 2010 relative to 2009 levels.

- Synchronized reserve prices were 36.1 percent higher in 2010 than in 2009, but lower than in any other year since 2005. Synchronized reserves total costs per MW were 47.5 percent higher in 2010 than in 2009. The total cost of synchronized reserves per MW was 36.6 percent higher than the market clearing price in 2010. The result was a decrease in the ratio of price to cost.

- Since 2001, the cost of ancillary services per MW of load has been relatively low and stable.

- Of the LSEs' obligation to provide regulation, 82.2 percent was purchased in the spot market, 15.4 percent was self scheduled, and 2.3 percent was purchased bilaterally.

- DASR prices are closely related to energy prices, peaking in the summer months. In 2010, the load weighted price of DASR was $0.16 per MW. In 2009, the load weighted price of DASR was $0.05 per MW. The maximum clearing price was $39.99 per MW in July.

- Black start zonal charges ranged from $0.03 per MW in DLCO zone to $0.55 per MW in PSEG zone.

Summary Recommendations

- The Regulation Market design and implementation continue to be flawed and require a detailed review to ensure that the market will produce competitive outcomes. Some of the flaws identified by the MMU were addressed by PJM in 2010, but some remain. The MMU recommends a number of market design changes designed to improve the performance of the Regulation Market, including use of a single clearing price based on actual LMP, modifications to the LOC calculation methodology, a software change to save some data elements necessary for verifying market outcomes, and further documentation of the implementation of the market design through SPREGO.

- The MMU recommends that the single clearing price for synchronized reserves be determined based on the actual LMP. This consistent with PJM's recommendation on this topic in the scarcity pricing matter. The MMU also recommends that documentation of the Tier 1 synchronized reserve deselection process be published.

- The MMU recommends that the DASR Market rules be modified to incorporate the application of the three pivotal supplier test in order to address potential market power issues.

- The MMU recommends that PJM, FERC, reliability authorities 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.

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.[5] The MMU also reported on the impact of these changes in the *2009 State of the Market Report*.[6] In September 2010, PJM fixed an error that had been identified by the MMU, which resulted in too small a number of switches to a different offer schedule for the opportunity cost calculation.[7] Despite this fix, several implementation issues remain in addition to the market design issues.

The MMU has continued to analyze the functioning of the Regulation Market. The MMU recognized flaws in its quantification of the impact of the Regulation Market changes in prior reports.[8] [9] The MMU determined that the MMU's prior quantification of the impact on the clearing price of the changed calculation of opportunity cost was not correct. A complete quantification of the impact is not required as a precondition to modifying the flawed market design. Differences from PJM estimates of the impact were the result of incorrect calculations by the MMU, which accounted for much of the difference, but were also the result of incorrect implementation of the rules by PJM, the failure by PJM to save some data required to check clearing prices, and a lack of transparency of the market clearing process. A continuing issue in carrying out analysis of the Regulation Market is that some data that are critical to the market clearing process are not saved, which makes it impossible to validate or check the final clearing price and its determinants. The MMU has requested that these data items be saved for future analysis. Absent these data items, it is not possible to determine the full dollar impact of the rules changes of December 2008 or confirm that the current market implementation is consistent with the current market rules. Equally important, absent these data items it is not possible to verify the Regulation Market prices to ensure consistency with economic fundamentals.

Market Structure

- **Supply.** In 2010, 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 2010. The ratio of eligible regulation offered to regulation required averaged 2.95 for 2010, essentially unchanged from the 2009 ratio of 2.98.

- **Demand.** Beginning August 7, 2008, PJM began to define separate on-peak and off-peak regulation requirements, resulting in a decrease in total demand for regulation. 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 at 1.0 percent of the daily forecast operating load. The average hourly regulation demand for 2010 increased to 893 MW, from 849 MW for 2009, as a result of increased forecast loads.

5 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).

6 See the *2009 State of the Market Report for PJM*, Volume II, Section 6, "Ancillary Service Markets."

7 See "Minutes" of the Market Implementation Committee. Agenda Item #9, pg. 5 <http://www.pjm.com/~/media/committees-groups/committees/mic/20101109/20101109-minutes.ashx, 11/09/2010> November 9, 2010.

8 See the 2010 Quarterly State of the Market Report for PJM, January through June, pg. 155, fn 15.

9 See the 2010 Quarterly State of the Market Report for PJM, January through September, pg. 166, fn 18.

- **Market Concentration.** During 2010, the PJM Regulation Market had a load weighted, average Herfindahl-Hirschman Index (HHI) of 1464 which is classified as "moderately concentrated."[10] The minimum hourly HHI was 763 and the maximum hourly HHI was 3675. The largest hourly market share in any single hour was 53 percent, and 79 percent of all hours had a maximum market share greater than 20 percent.[11] In 2010, 73 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 2010 was characterized by structural market power in 73 percent of the hours.

Market Conduct

- **Offers.** Daily regulation offer prices are submitted for each unit by the unit owner. As of December 1, 2008, 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.[12] 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.[13] 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.

  As part of the changes to the Regulation Market implemented on December 1, 2008, PJM was to calculate unit specific opportunity costs using the lesser of the available price based energy offer or the most expensive available cost based energy offer as the reference, rather than the offer on which the unit was operating in the energy market.[14] Depending on whether the units affected by the rule change are backed down or raised to regulate, the application of the rule change increased or decreased the unit's applicable opportunity costs relative to the correct definition of opportunity cost used prior to December 1, 2008. The impact of these changes to

10 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.

11 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.

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

13 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."

14 See PJM. "Manual 11: Scheduling Operations," Revision 45 (June 23, 2010), p. 59: "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."

the calculation is that the hourly Regulation Market clearing price was either higher or lower than the outcome that would have occurred under the correct opportunity cost calculation used prior to December 1, 2008. However, PJM did not correctly implement this rule change until the third quarter of 2010.[15] The actual impact of the changed definition of opportunity cost was reduced as a result of the incorrect implementation of the rule.

Market Performance

- **Price.** For the PJM Regulation Market in 2010, the load weighted, average price per MW (the Regulation Market clearing price, including opportunity cost) associated with meeting PJM's demand for regulation was $18.08 per MW. This was a decrease of $5.48, or 23 percent, from the average price for regulation during 2009. The total cost of regulation increased by $2.13 from $29.63 per MW, for all of 2009, to $32.07, or 7 percent. The difference between total regulation cost per MW and regulation price remains high. The Regulation Market clearing price was only 57 percent of the total regulation cost per MW.

- **Price and Opportunity Cost.** Prices in the PJM Regulation Market in 2010 were higher than they would have been in some hours and lower than they would have been in some hours as a result of the change to the definition of opportunity cost in the December 2008 Regulation Market changes. The modified definition of opportunity cost resulted in a switch of the offer schedule used for the calculation of opportunity cost and therefore resulted in an impact on the Regulation Market clearing price.

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 2010. 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 where it remained throughout 2010.[16] Synchronized reserves added out of market were five percent of all synchronized reserves during 2010, while they were 15 percent for the same time period in 2009. Opportunity cost payments accounted for 27 percent of total costs during 2010 compared to 32 percent for 2009.

15 PJM staff reported the error at the November 9, 2010 meeting of the Market Implementation Committee and stated that the implementation was corrected on September 17, 2010.
16 See the *2009 State of the Market Report for PJM*, Volume II, Section 6, p. 40.

Market Structure

- **Supply.** In 2010, synchronized reserve offers were somewhat higher than in 2009. The offered and eligible excess supply ratio was 1.16 for the PJM Mid-Atlantic Synchronized Reserve Region.[17] For the RFC zone, the excess supply ratio was 2.68. 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 May 5, 2010, the synchronized reserve demand in the Mid-Atlantic Subzone was increased from 1,150 MW to 1,200 MW. This change was made to accommodate a dynamically changing largest contingency for the AP South constraint. In addition, double spinning was declared for May 24 and 25 of 1,800 MW because of a planned outage. On July 17, 2010, the synchronized reserve requirement for the Mid-Atlantic Subzone was increased from 1,200 MW to 1,300 MW. On September 21 and 22 the synchronized reserve requirement for the Mid-Atlantic Subzone was temporarily increased to 1,600 MW. Between November 15 and November 20 the synchronized reserve requirement for the Mid-Atlantic Subzone was increased to 1,630 MW. On October 12 and 13 the synchronized reserve requirement for the Mid-Atlantic Subzone was increased to 2,500 MW. For 2010, average synchronized reserve requirements were 1,246 MW for the Mid-Atlantic Subzone.

  For 2010, in the Mid-Atlantic Subzone, no Tier 2 synchronized reserve was needed in 33 percent of hours. The average required Tier 2 (including self scheduled) was 358 MW. The average required Tier 2 fell to 198 MW for the June through September period. For January through May and October through December the average was 438 MW. The decrease in the demand for Tier 2 was the result of an increase in Tier 1 during the summer months.

  In the PJM Mid-Atlantic Synchronized Reserve Subzone, 67 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 358 MW. The demand was met by self scheduled synchronized reserves, which averaged 129 MW, and cleared Tier 2 synchronized reserves, which averaged 220 MW in 2010.

  Synchronized reserves added out of market were five percent of all PJM Mid-Atlantic subzone synchronized reserves in 2010.

  For the first six months of 2010, the synchronized reserve requirement was 1,320 MW for the RFC Synchronized Reserve Zone. On July 1, 2010, the requirement for the RFC Synchronized Reserve Zone was increased from 1,320 MW to 1,350 MW, to accommodate the largest single unit contingency. Additionally, there were 85 hours between September 20 and September 29 when the synchronized reserve requirement for the RFC Synchronized Reserve Zone was increased to 1,700 MW as a result of outages.

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

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, less than one percent of hours cleared a Tier 2 Synchronized Reserve Market in the RFC. A Tier 2 Synchronized Reserve Market was cleared for the Southern Synchronized Reserve Zone for only 11 hours in 2010.

- **Market Concentration.** The average load weighted cleared Synchronized Reserve Market HHI for the Mid-Atlantic Subzone of the RFC Synchronized Reserve Zone for 2010 was 3222, which is classified as "highly concentrated."[18] For purchased synchronized reserve (cleared plus added) the HHI was 3268. In 2010, 68 percent of hours had a maximum market share greater than 40 percent, compared to 36 percent of hours in 2009.

  In the Mid-Atlantic Subzone of the RFC Synchronized Reserve Market, in 2010, 62 percent of hours that cleared a synchronized reserve market had three or fewer pivotal suppliers. In the full RFC Synchronized Reserve Market (which cleared only 27 hours in 2010) 100 percent of hours that cleared a synchronized reserve market had three or fewer pivotal suppliers. In the Southern Synchronized Reserve Zone (which cleared only 11 hours in 2010) none of those hours had three or fewer pivotal suppliers. The MMU concludes from these TPS results that the RTO zone and Mid-Atlantic subzone Synchronized Reserve Markets in 2010 were 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 2010. In eight percent of hours in which a Tier 2 Synchronized Reserve Market was cleared for the Mid-Atlantic Subzone, all synchronized reserves were provided by demand side resources.

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 $10.55 per MW in 2010, a $2.80 per MW increase from 2009. The market clearing price was only 63 percent of the total synchronized reserve cost per MW in 2010, lower than in 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 in 2010.

18 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).

DASR

On June 1, 2008 PJM introduced the Day-Ahead Scheduling Reserve Market (DASR), as required by the RPM settlement.[19] 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.[20] 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 2010, the three pivotal supplier test was failed in the DASR Market in 1.3 percent of hours, all of which were in the months of June, July, August, and September.

- **Demand.** In 2010, the required DASR was 6.88 percent of peak load forecast, up from 6.75 percent in 2009.[21] As a result of increased demand for energy, reflected in higher forecast peak loads and increased DASR requirements, the DASR MW purchased increased by 9 percent in 2010 over 2009.

Market Conduct

- **Withholding.** Economic withholding remains a problem in the DASR Market. Continuing a pattern seen since the inception of the DASR Market, five percent of units offered at $50 or more and 45 units offered at more than $900, in a market with an average clearing price of $0.16 and a maximum clearing price of $39.99. PJM rules require all units with reserve capability that can be converted into energy within 30 minutes to offer into the DASR Market.[22] Units that do not offer will have their offers set to $0/MW. Every unit type had significant offers at $10/MW or lower.

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

Market Performance

- **Price.** DASR prices are closely related to energy prices, peaking in the summer months. In 2010, the load weighted price of DASR was $0.16 per MW. In 2009, the load weighted price of DASR was $0.05 per MW. The maximum clearing price was $39.99 per MW in July.

19 See 117 FERC ¶ 61,331 (2006).
20 See PJM. "Manual 13: Emergency Operations," Revision 42, (January 21, 2011); pp 11-12.
21 See the *2010 State of the Market Report for PJM*, Volume II, Section 6, "Ancillary Services" at Day Ahead Scheduling Reserve *(DASR)*.
22 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.[23]

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 2009, charges were about $12.3 million. In 2010, total black start service charges were $10.0 million. There was substantial zonal variation.

As a consequence of new NERC standards related to Critical Infrastructure Protection and PJM's filing to revise its formula rate for black start service to allow for the recovery of the costs necessary for compliance with the new NERC standards, black start costs likely will increase substantially.

The MMU recommends that PJM, FERC, reliability authorities 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 rather than a separate zone by zone basis. Elements of such reform should include, at a minimum, the clear assignment of responsibility to PJM for determining a single system restoration plan that identifies locations where black start units are needed. PJM should assume an explicit obligation to secure black start service on a least cost basis and implement a method to evaluate competitive alternatives to providing black start service at identified locations on a rolling basis as service obligations of existing providers terminate.

Ancillary Services costs per MW of load: 2001 - 2010

Table 6-4 shows PJM ancillary services costs from 2001 through 2010 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; Blackstart Services; Direct Assignment Facilities; and Reliability First Corporation charges. Supplementary Operating Reserve includes Day-Ahead Operating Reserve; Balancing Operating Reserve; and Synchronous Condensing.

23 OATT Schedule 1 § 1.3BB.

Table 6-4 History of ancillary services costs per MW of Load: 2001 through 2010

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

Conclusion

While the MMU has identified a number of issues with the design and implementation of the Regulation Market, these issues can be resolved as a single package in a timely manner. The MMU recommends that such a resolution be pursued in 2011 with the goal of implementing the appropriate changes in 2011.

The design of the Regulation Market can be improved. The MMU recommends that, as part of a package of modifications to improve the Regulation Market design, the clearing price for regulation be determined based on the actual LMP. The regulation clearing price is generally too low because it is based on forecast LMP, which appears to systematically understate actual LMP. The proposed modifications to the pricing of regulation by both PJM and the MMU in their scarcity pricing recommendations will result in revenue increases that are expected to exceed any revenue loss from correcting the opportunity cost calculation.[24] The MMU recommends that when this modification is implemented, the margin be reduced to no higher than its current level. The result would be to make Regulation Market prices more transparent and more reflective of the actual cost of providing regulation and is expected to increase revenues to the providers of regulation, after accounting for all the recommended changes.

The MMU continues to conclude that the results of the Regulation Market are not competitive.[25] The MMU's conclusion is not the result of the behavior of market participants, which was competitive, in part as a result of the application of the three pivotal supplier test, but is the result of the market design changes. 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, are inconsistent with basic economic logic, and because of incorrect implementation of the market rules. For

24 See, *e.g.*, PJM compliance filing in Docket No. ER09-1063-004 (June 18, 2010); Protest and Compliance Proposal of the Independent Market Monitor for PJM, Docket No. ER09-1063-004, (July 19, 2010).

25 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."

example, the changes to the calculation of the opportunity cost resulted in offers greater than competitive offers in some hours and therefore in prices greater than competitive prices in some hours, and resulted in offers less than competitive offers in some hours and therefore in prices less than competitive prices in some hours. The competitive price is the price that would have resulted from a combination of 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 MMU recommends that the December 1, 2008, modification to the definition of opportunity cost be reversed and that the elimination of the offset against operating reserve credits also 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 MMU also recommends that, to the extent that it is believed that additional revenue to generation owners is needed to maintain the outcome of the settlement in the short run, revenue neutrality be maintained by modifying the margin from its current level of $12.00 per MW at the same time that the opportunity cost definition is corrected. This change would maintain transparent incentives consistent with an effective market design.

The MMU also recommends that PJM save all data necessary to reproduce the market clearing results to ensure transparency of the price formation process and to permit checking the Regulation Market results for consistency with economic fundamentals.

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 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 2010 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 2010. The MMU concludes that the DASR Market results were competitive in 2010.

Detailed Recommendations

- The Regulation Market design and implementation continue to be flawed and require a detailed review to ensure that the market will produce competitive outcomes. Some of the flaws identified by the MMU were addressed by PJM in 2010, but some remain. The MMU recommends a number of market design changes designed to improve the performance of the Regulation Market, including use of a single clearing price based on actual LMP, modifications to the LOC calculation methodology, a software change to save some data elements necessary for verifying market outcomes, and further documentation of the implementation of the market design through SPREGO.

  - The MMU recommends that the single clearing price for regulation be determined based on the actual LMP. This is expected to result in a net increase in payments to providers of regulation as a result of an increase in the regulation clearing price which more than offsets unit specific reductions in unit specific, post clearing opportunity cost payments. This would improve the transparency of the Regulation Market as the resulting price of regulation would internalize some of the costs currently being collected through uplift and would thereby make the market price more reflective of the actual costs of providing the service.

  - The MMU recommends that the December 1, 2008, 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 MMU recommends that the December 1, 2008 modification to the net revenue offset elimination be reversed and that the net revenues earned in the Regulation Market be offset against operating reserve credits in the same manner that all net revenues from all other PJM markets are offset against operating reserve credits and in the same manner that Regulation Market credits were offset against operating reserve credits prior to December 1, 2008.

  - The MMU recommends that, to the extent that it is believed that additional revenue to generation owners is needed to maintain the outcome of the settlement in the short run, revenue neutrality be maintained by modifying the margin from its current level of $12.00 per MW at the same time that the opportunity cost definition is corrected.

  - The MMU recommends that PJM save all data necessary to reproduce the market clearing results to ensure transparency of the price formation process and to permit checking the Regulation Market results for consistency with economic fundamentals.

  - The MMU recommends that PJM improve the documentation it creates and maintains with respect to the detailed processes for clearing the Regulation Market.

- The MMU recommends that the synchronized market price signal be improved and the market rules be made more transparent.

  - The MMU recommends that the single clearing price for synchronized reserves be determined, after the fact, on the actual LMP. This is expected to result in a net increase in payments to providers of synchronized reserves as a result of an increase in the clearing price which more than offsets unit specific reductions in unit specific, post clearing opportunity cost payments. This would improve the transparency of the synchronized reserve market as the resulting price of synchronized reserve would internalize some of the costs currently being collected through uplift and would make the more reflective of the actual costs of providing the service.

  - Dispatchers can deselect a unit from regulation, Tier 1 or Tier 2 synchronized reserve, or unit dispatch prior to running the market solution. This is the equivalent of imposing a constraint on the market solution. The MMU recommends that a full list of potential reasons for unit deselection be published in PJM's M-11 Scheduling Operations Manual. The MMU recommends mandatory documentation of reasons for Tier 1 deselection as a way to improve transparency.

- The MMU recommends that the DASR Market rules be modified to incorporate the application of the three pivotal supplier test in order to address the identified market power issues.

- The MMU recommends that PJM, FERC, reliability authorities 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. Elements of such reform should include, at a minimum, the clear assignment of responsibility to PJM for determining a single system restoration plan that identifies locations where black start units are needed. Transmission owners should play an advisory role. PJM should assume an explicit obligation to secure black start service on a least cost basis and implement a method to evaluate competitive alternatives to providing black start service at identified locations on a rolling basis as service obligations of existing providers terminate.

Regulation Market

Market Structure

The market structure of the 2010 PJM Regulation Market remains unchanged since December, 2008. The rule changes of December 1, 2008, significantly affected the design of the Regulation Market. Both PJM and the MMU have done extensive analysis of these changes in 2010 resulting in several technical improvements to the market solution software.

Supply

The supply of regulation can be measured as regulation capability, regulation offered, or regulation offered and eligible. For purposes of evaluating the Regulation Market, the relevant regulation supply is the level of supply that is both offered to the market on an hourly basis and is eligible to participate in the market on an hourly basis. This is the only supply that is actually considered in the determination of market prices. The level of supply that clears in the market on an hourly basis is called cleared regulation. Assigned regulation is the total of self-scheduled and cleared regulation. Assigned regulation is selected from regulation that is eligible to participate.

Regulation capability is the sum of the maximum daily offers for each unit and is a measure of the total volume of regulation capability as reported by resource owners.

Regulation offered represents the level of regulation capability offered to the PJM Regulation Market. Resource owners may offer those units with approved regulation capability into the PJM Regulation Market. PJM does not require a resource capable of providing regulation service to offer its capability to the market. Regulation offers are submitted on a daily basis.

Regulation offered and eligible represents the level of regulation capability offered to the PJM Regulation Market and actually eligible to provide regulation in an hour. Some regulation offered to the market is not eligible to participate in the Regulation Market as a result of identifiable offer parameters specified by the supplier. As an example, the regulation capability of a unit is included in regulation offered based on the daily offer and availability status, but that regulation capability is not eligible in one or more hours because the supplier sets the availability status to unavailable for one or more hours of that same day. The availability status of a unit may be set in both a daily offer and an hourly update table in the PJM market user interface. As another example, the regulation capability of a unit is included in regulation offered if the owner of a unit offers regulation, but that regulation capability is not eligible if the owner sets the unit's economic maximum generation level equal to its economic minimum generation level. In that case, the unit cannot provide regulation and is not eligible to provide regulation. As another example, the regulation capability of a unit is included in regulation offered, but that regulation capability is not eligible if the unit is not operating, unless the unit meets specific operating parameter requirements. A unit whose owner has not submitted a cost based offer will not be eligible to regulate even if the unit is a regulation resource.

Only those offers eligible to provide regulation in an hour are part of supply for that hour, and only eligible offers are considered by PJM for purposes of clearing the market. Regulation assigned represents those regulation resources selected through the Regulation Market clearing mechanism to provide regulation service for a given hour.

During 2010, the PJM Regulation Market total capability was 8,053 MW.[26] Total capability is a theoretical measure which is never actually achieved. The level of regulation resources offered on a daily level and the level of regulation resources eligible to participate on an hourly level in the market were lower than the total regulation capability. In 2010, the average daily offer level, excluding units with offers which were made unavailable for the day, was 5,645 MW or 70 percent of total capability while the average hourly eligible offer level was 2,591 MW or 32 percent of total capability. In 2009, the average hourly eligible offer level was 33 percent of the average daily offer level. Although regulation is offered daily, eligible regulation changes hourly. Typically less regulation is eligible during off-peak hours because fewer steam units are running during those hours. Table 6-5 shows capability, daily offer and average hourly eligible MW for all hours as well as for off-peak and on-peak hours.

26 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 6-5 PJM regulation capability, daily offer and hourly eligible: Calendar year 2010[27]

Period	Regulation Capability (MW)	Average Daily Offer (MW)	Percent of Capability Offered	Average Hourly Eligible (MW)	Percent of Capability Eligible
All Hours	8,053	5,645	70%	2,591	32%
Off Peak	8,053			2,335	29%
On Peak	8,053			2,872	36%

The average eligible regulation supply-to-requirement ratio in the PJM Regulation Market during 2010 was 2.94. When this ratio equals 1.0, it indicates that offered supply exactly equals demand for the referenced time period. Even during periods of diminished supply such as off-peak hours, eligible regulation supply was adequate to meet the regulation requirement.

Demand

Demand for regulation does not change with price, i.e. demand is price inelastic. The demand for regulation is set administratively based on reliability objectives and forecast load. Regulation demand is also referred to in the *2010 State of the Market Report for PJM* as “required regulation.”

The PJM regulation requirement is set by PJM Interconnection in accordance with NERC control standards. In August 2008, the requirement was adjusted to be 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. In 2010, the PJM regulation requirement ranged from 502 MW to 1,365 MW. The average required regulation off-peak was 811 MW and the average required regulation on-peak was 981 MW (Table 6-6). In 2010, PJM scheduled a total of 9,037,733 MW of regulation compared to 8,254,358 MW in 2009.

Table 6-6 PJM Regulation Market required MW and ratio of eligible supply to requirement: Calendar year 2010

Period Type	Average Required Regulation (MW)	Ratio of Supply to Requirement
2010	893	2.95
Fall	797	3.22
Spring	775	2.80
Summer	1,046	2.88
Winter	952	2.88
Off Peak	811	2.94
On Peak	981	2.95

Market Concentration

Hourly HHI values were calculated based on cleared regulation. HHI values showed less variability in 2010 than in 2009. HHI ranged from a maximum of 3675 to a minimum of 763, with a load weighted average value of 1449, which is categorized as moderately concentrated by the FERC

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

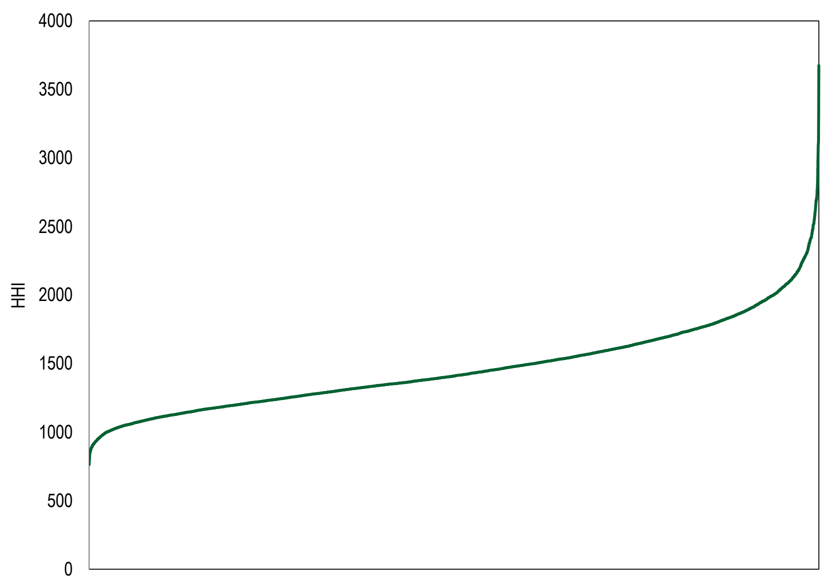
definitions. Table 6-7 summarizes the 2010 PJM Regulation Market HHIs. The maximum HHI and the average HHI were higher in 2010 than in 2009.

Table 6-7 PJM cleared regulation HHI: Calendar year 2010

Market Type	Minimum HHI	Load-weighted Average HHI	Maximum HHI
Cleared Regulation, 2010	763	1449	3675

In 2010, two percent of all periods had an HHI less than 1000 and 14 percent of all periods had an HHI greater than 1800, with a maximum HHI of 3675.[28] An HHI of 1800 is the threshold for "highly concentrated" by the FERC definitions. The maximum period HHI in 2009 was 9405. See the HHI distribution curve in Figure 6-1.

Figure 6-1 PJM Regulation Market HHI distribution: Calendar year 2010



The highest hourly market share was 53 percent (compared to the highest hourly market share in 2009 of 97 percent). Seventy nine percent of all hours had a maximum market share greater than 20 percent in 2010. The largest annual average hourly market share by a company was 18 percent. The top five annual average hourly market shares for cleared regulation in 2010 are listed in Table 6-8.

28 See the *2010 State of the Market Report for PJM*, Volume II, Section 2, "Energy Market, Part 1," 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.

Table 6-8 Highest annual average hourly Regulation Market shares: Calendar year 2010

Company Market Share Rank	Cleared Regulation Top Yearly Market Shares
1	18%
2	16%
3	15%
4	15%
5	9%

In 2010, 73 percent of hours failed the three pivotal supplier test. This means that for 73 percent of hours the total regulation requirement could not be met in the absence of the three largest suppliers. One supplier of regulation was pivotal in 98 percent of pivotal hours. A second company was pivotal in 93 percent of the pivotal hours. A third company was pivotal in 86 percent of pivotal hours. Table 6-9 includes a monthly summary of three pivotal supplier results.

Table 6-9 Regulation market monthly three pivotal supplier results: Calendar year 2010

Month	Percent of Hours With Three Pivotal Suppliers
Jan	74%
Feb	70%
Mar	83%
Apr	82%
May	79%
Jun	81%
Jul	75%
Aug	69%
Sep	70%
Oct	47%
Nov	63%
Dec	89%

Thus, in addition to failing the three pivotal supplier test in a significant number of hours, the pivotal suppliers in the Regulation Market were the same suppliers in the majority of hours when the test was failed. This is a further indication that the structural market power issue in the Regulation Market remained persistent and repeated during 2010.

The MMU concludes from these results that the PJM Regulation Market in 2010 was characterized by structural market power. This conclusion is based on the results of the three pivotal supplier test.

Market Conduct

Offers

PJM implemented the three pivotal supplier test in the Regulation Market in December 2008. As a result, generators wishing to participate in the PJM Regulation Market must submit cost based regulation offers for specific units by 1800 Eastern Prevailing Time (EPT) of the day before the operating day. Generators may also submit price based offers. The regulation cost based offer price is limited to costs plus $12.00. The costs are validated in accordance with unit specific operating parameters entered with the cost based offer. A unit is not required to provide these parameters if its offer is less than $12.00. The unit specific operating parameters are heat rate at economic maximum, heat rate at regulation minimum, variable operating and maintenance (VOM) rate and fuel cost. Regulation offers are applicable for the entire 24 hour period for which they are submitted. As in any competitive market, regulation offers at marginal cost are considered to be competitive.

The cost based and price based offers and the associated cost related parameters are the only components of the regulation offer applicable for the entire operating day. The following information must be included in each offer, but can be entered or changed up to 60 minutes prior to the operating hour: regulating status (i.e., available, unavailable or self-scheduled); regulation capability; regulation minimum (may be increased but not decreased); and regulation maximum (may be decreased but not increased). The Regulation Market is cleared on a real-time basis and regulation prices are posted hourly throughout the operating day. The amount of self-scheduled regulation is confirmed 60 minutes before each operating hour, and regulation assignments are made at least 30 minutes before each operating hour.

PJM's Regulation Market is cleared hourly, based on both offers submitted by the units and the hourly lost opportunity cost of each unit, calculated based on the forecast LMP at the location of each regulating unit.[29] The total offer price is the sum of the unit specific offer and the opportunity cost. In order to clear the market, PJM ranks the offers of all offered and eligible regulating resources in ascending total offer price order; it does the same for synchronized reserve. PJM then determines the least expensive set of resources necessary to provide regulation, synchronized reserve and energy for the operating hour, taking into account any resources self-scheduled to provide any of these services. Prior to clearing and assignment of regulation in a given hour, the Regulation Market is subject to market power screening via the TPS test.

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 (Figure 6-2).[30] Increased self scheduled regulation lowers the requirement for cleared regulation, resulting in fewer MW cleared in the market and lower clearing prices. Total self-scheduled regulation MW in 2010 was 15.5 percent of all regulation, which is an increase from 10.9 percent in 2009. The amount of self scheduled regulation was higher during off peak hours than during on

29 PJM estimates the opportunity cost for units providing regulation based on a forecast of locational marginal price (LMP) for the upcoming hour. In May 2009, PJM also began including the lost opportunity cost impact in adjoining hours of dispatching a unit to its regulation set point. As part of the settlement that included the implementation of the three pivotal supplier test on December 1, 2008, the opportunity cost calculator now uses the lesser of the available price based energy schedule or the most expensive available cost based energy schedule.

30 See PJM "Manual 28: Operating Agreement Accounting," Revision 46, (October 1, 2010); para 4.3, pp 14-15.

peak hours while the amount of cleared regulation is higher during on peak hours than during off peak hours (Table 6-10).

Figure 6-2 Off peak and on peak regulation levels: Calendar year 2010

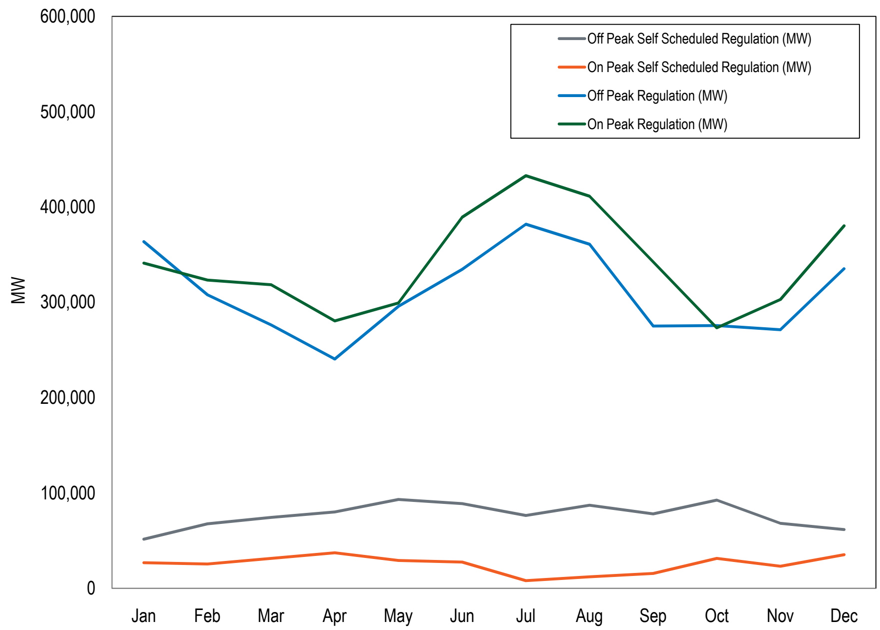


Table 6-10 Regulation sources: spot market, self-scheduled, bilateral purchases: Calendar year 2010

Month	Spot Regulation (MW)	Self Scheduled Regulation (MW)	Bilateral Regulation (MW)
Jan	617,411	75,684	11,267
Feb	524,440	92,380	15,188
Mar	475,724	103,919	14,736
Apr	394,591	113,441	10,494
May	457,088	116,602	14,761
Jun	534,164	106,595	18,079
Jul	631,078	76,177	16,067
Aug	640,608	94,115	15,801
Sep	498,707	86,209	13,515
Oct	356,136	115,314	13,046
Nov	458,101	88,133	17,995
Dec	607,322	93,502	14,540
Total	6,195,368	1,162,072	175,489

Market Performance

Price

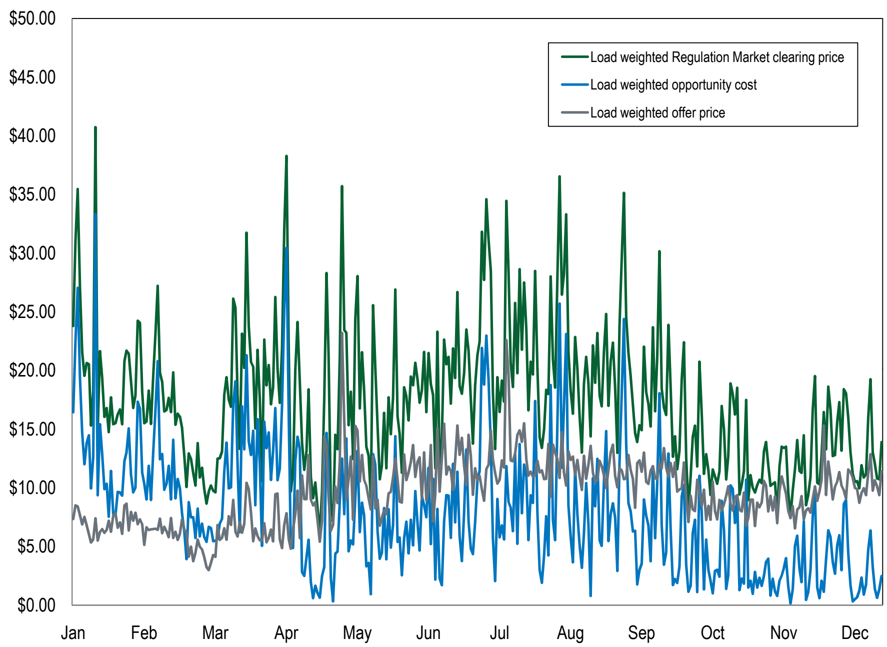
Figure 6-3 shows the daily average Regulation Market clearing price and the opportunity cost component for the marginal units in the PJM Regulation Market. All units chosen to provide regulation received as payment the higher of the clearing price, based on the forecast LMP, multiplied by the unit's assigned regulating capability, or the unit's regulation offer plus the individual unit's real-time opportunity cost, based on actual LMP, multiplied by its assigned regulating capability.[31]

Regulation credits are awarded to generation owners that have either self-scheduled or sold regulation into the market. Regulation credits for units self-scheduled to provide regulation are equal to the clearing price times the unit's self-scheduled regulating capability. Regulation credits for units that offer regulation into the market and are selected to provide regulation are the higher of the clearing price times the unit's assigned regulating capability, or the unit's regulation offer plus the unit's specific after the fact opportunity cost, times its assigned regulating capability. Although most units are paid the clearing price (RMCP) times their assigned regulation MWh, a substantial portion of the RMCP is the opportunity cost calculated during market clearing based on forecast LMP and cost of the marginal unit. This means that a substantial portion of the total cost of regulation is determined by opportunity cost. As shown in Figure 6-3, about half of the regulation price is the opportunity cost of the marginal unit. Opportunity cost is a greater percentage of price when prices are high since offers tend to remain constant.

The load weighted, average offer (excluding opportunity cost) of the marginal unit for the PJM Regulation Market during 2010 was $9.28 per MWh, an increase from the load weighted average offer in 2009 of $8.79. Although higher than in 2009, offers remain low compared to prior years as a result of the application of the three pivotal supplier test, which prevents non competitive offers from setting price. The load weighted, average opportunity cost of the marginal unit for the PJM Regulation Market in 2010 was $8.01. In the PJM Regulation Market the marginal unit opportunity cost averaged 47 percent of the RMCP. This is a slight reduction from the 2009 level of 49 percent.

31 See PJM. "Manual 28: Operating Agreement, Accounting," Revision 46, Section 4, "Regulation Credits" (October 1, 2010), p. 13. PJM uses estimated opportunity cost to clear the market and real-time opportunity cost to compensate generators that provide regulation and synchronized reserve. Real-time opportunity cost is calculated using real-time LMP.

Figure 6-3 PJM Regulation Market daily average market-clearing price, opportunity cost and offer price (Dollars per MWh): Calendar year 2010

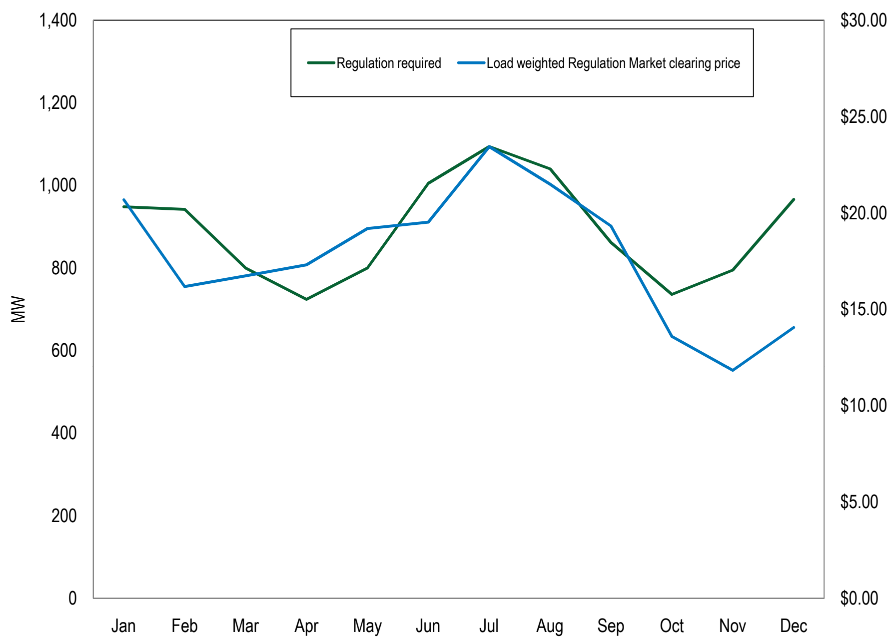


On a shorter term basis, regulation prices follow daily and weekly patterns. The supply of regulation is largest during on-peak hours, between 0600 and 2300 EPT, Monday through Friday.

During the off-peak hours fewer steam generators are running and available to regulate. At times, units must be kept running for regulation that are not economic for energy, resulting in an increase in the opportunity cost portion of the clearing price. At other times, expensive combustion turbine generators must be started to meet regulation requirements.

Figure 6-4 shows the level of demand for regulation by month in 2010 and the corresponding level of regulation price.

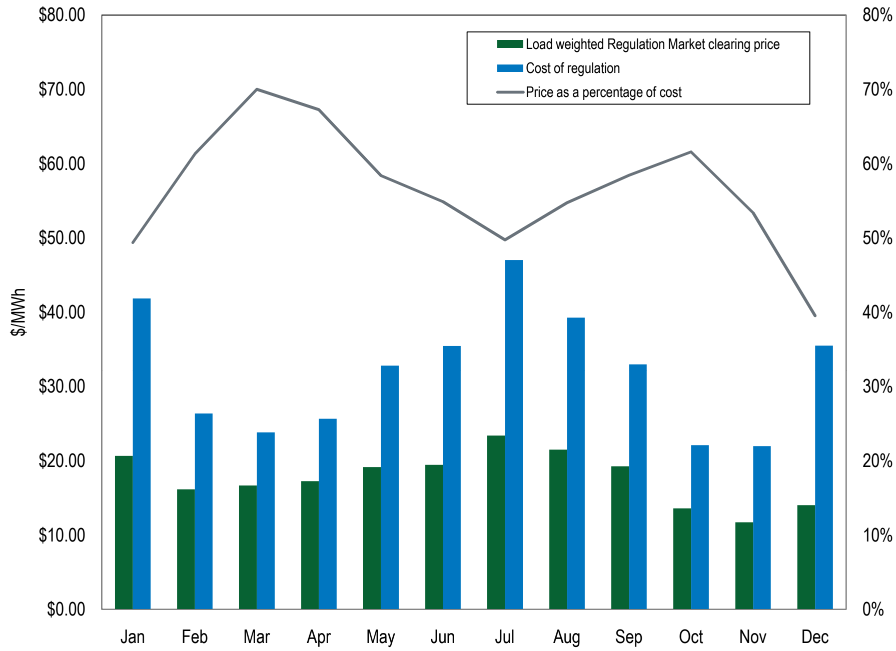
Figure 6-4 Monthly average regulation demand (required) vs. price: Calendar year 2010



The total cost of regulation per MW exceeds the price per MW because some regulation is procured out of the market, regulation MW actually delivered differs from regulation MW offered and cleared, or because there are adjustments to unit specific opportunity cost after the market clears. A well designed and efficient market will minimize this difference. Units which provide regulation are paid the higher of the RMCP, or their offer plus their unit specific opportunity cost. The offer plus the unit specific opportunity cost may be higher than the RMCP for a number of reasons. If real-time LMP is greater than the LMP forecast prior to the operating hour and included in the RMCP, unit specific opportunity costs will be higher than forecast. Such higher LMPs can be local, because of congestion, or more general, if system conditions change. Other reasons include unit redispatch because of constraints or unanticipated unit performance problems. When some units are paid more than the RMCP based on unit specific lost opportunity costs, the result is that PJM's regulation cost per MWh is higher than the RMCP. Figure 6-5 compares the regulation total cost per MWh (clearing price plus post market opportunity costs) with the regulation clearing price to show the difference between the per MWh price of regulation and the per MWh total cost of regulation. The results in Figure 6-5 show that a significant portion of the costs of regulation are not incorporated in the Regulation Market clearing price. This discrepancy results in a lack of transparency in the Regulation Market.

PJM may call on resources not otherwise scheduled to run in order to provide regulation, in accordance with PJM's obligation to minimize the total cost of energy, operating reserves, regulation, and other ancillary services. This often increases total regulation costs. If a resource is called on by PJM for the purpose of providing regulation, the resource is guaranteed recovery of regulation lost opportunity costs as well as start-up, no-load, and energy costs.

Figure 6-5 Monthly load weighted, average regulation cost and price: Calendar year 2010



Total scheduled regulation MWh, total regulation charges, regulation price and regulation cost are listed in Table 6-11.

Table 6-11 Total regulation charges: Calendar year 2010

Month	Scheduled Regulation (MW)	Total Regulation Charges	Load Weighted Regulation Market Clearing Price	Cost of Regulation
Jan	704,362	$29,479,645	$20.66	$41.85
Feb	632,007	$16,673,515	$16.17	$26.38
Mar	594,378	$14,167,033	$16.69	$23.84
Apr	518,526	$13,307,387	$17.26	$25.66
May	588,452	$19,307,043	$19.16	$32.81
Jun	658,837	$23,355,270	$19.46	$35.45
Jul	723,322	$34,017,913	$23.39	$47.03
Aug	750,524	$29,482,419	$21.50	$39.28
Sep	598,431	$19,734,114	$19.27	$32.98
Oct	484,496	$10,705,184	$13.61	$22.10
Nov	545,214	$11,983,314	$11.73	$21.98
Dec	715,364	$25,403,910	$14.04	$35.51

For 2010, the load weighted, average regulation price was $18.08 per MWh. The average regulation cost was $32.07 per MWh. The difference between the Regulation Market price and the actual cost of regulation was greater in 2010 than it was in 2009. The cost of regulation was 77 percent higher than the market price of regulation. The payment of a large portion of regulation charges on a unit specific basis rather than on the basis of a market clearing price remains a cause for concern as it results in a weakened market price signal to the providers of regulation and effectively pays a substantial proportion of Regulation Market revenues on an as bid basis rather than on the basis of the clearing price.

Regulation prices were 23.3 percent lower in 2010 than in 2009 and lower than in any year since the current Regulation Market structure was introduced in 2005. Regulation total costs per MW were 7.4 percent higher in 2010 than in 2009. The total cost of regulation per MW was 77.4 percent higher than the market clearing price in 2010. The result was a decrease in the ratio of price to cost. With the exception of 2009, the ratio of price to cost has declined in every year since 2005, and the ratio of price to cost is at its lowest level since 2005.

A key source of the difference between the market clearing price and the cost per MW of regulation results from differences in opportunity cost between the forecast LMP and actual LMP. To address this issue, the MMU recommends that the hourly clearing price for regulation be determined after the close of the hour. All units cleared in the Regulation Market in the hour prior would be paid the market-clearing regulation price based on the actual LMP rather than the forecast LMP. This is expected to result in a net increase in payments to providers of regulation as a result of an increase in the regulation clearing price which more than offsets unit specific reductions in unit specific, post clearing opportunity cost payments. This would improve the transparency of the Regulation Market as the resulting price of regulation would internalize some of the costs currently being collected through uplift and would make the market price more reflective of the actual costs of providing the service.

Table 6-12 Comparison of load weighted price and cost for PJM Regulation, August 2005 through December 2010[32]

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%

Issues in the Regulation Market Design

The MMU has identified several significant issues with the design and implementation of the Regulation Market. These are broad statements of the issues and do not include an exhaustive list of all concerns. The issues address economic efficiency and competitiveness, and transparency.

32 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.

- The definition of opportunity cost for units providing regulation is not correct. The result is a clearing price not reflective of the actual opportunity cost and therefore not efficient or competitive. The correct way to calculate opportunity cost and maintain incentives across both markets is to treat the offer on which the unit is dispatched as the measure of its marginal costs for both the energy market and the Regulation Market.

- PJM does not save some data elements that are necessary in order to replicate Regulation Market clearing prices. As a result, the opportunity cost used in the clearing price cannot be calculated and the clearing price cannot be calculated. While it may be possible to recreate data that is not saved, that is not the same as saving the data and making it available.

- It is not clear at what stages in the market clearing process the opportunity cost calculation includes shoulder hour opportunity costs. The documentation should be updated to clarify when shoulder hour opportunity costs are included in the market clearing process.

- The MMU analysis of the Regulation Market following the December 1, 2008, market rule changes resulted in the discovery that a significant number of marginal units whose schedule should have been switched to the lower of the price or cost based offer under the new rule were not switched. The MMU communicated this to PJM. PJM subsequently modified the market clearing process, effective September 9, 2010. The MMU has not been provided an updated design document for these changes. It is not clear that PJM's approach is a complete fix but it is difficult to evaluate in the absence of documentation.

Analysis of Regulation Market Changes

There were significant changes made to the Regulation Market effective December 1, 2008. The rule changes are summarized in Table 6-13. The changes were the result of a filing by PJM that reflected a compromise among market participants in the PJM process.[33] The MMU filed comments supporting the filing with the caveat that if the MMU review of the actual impact of the changes "results in a conclusion that these features result in non-competitive market outcomes, the Market Monitor will request that one or more of these provisions be removed or modified."[34]

33 See Filing initiating Docket No. ER09-13-000 (October 1, 2008).
34 *Id.* at 2.

Table 6-13 Summary of changes to Regulation Market design

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.

As directed by the FERC, the MMU performed an analysis of these Regulation Market rule changes, delivering a report on November 30, 2009.[35]

Introduction of TPS Testing

The implementation of the TPS test is consistent with the longstanding MMU recommendation that real-time, hourly market structure tests be implemented in the Regulation Market, that market power mitigation be applied only for hours in which the market structure is noncompetitive and that market power mitigation be applied only to the companies failing the market structure tests.

Increase Offer Margin from $7.50 to $12.00

The tariff modifications included an increase of the margin that may be added to cost-based regulation offers from $7.50 to $12.00 per MW. The average cost based regulation offer is less than $10.00 per MW, so this margin represents a substantial adder to costs, more than 100 percent of the average cost of regulation. The MMU does not now recommend reducing the margin to the prior level of $7.50 per MW.

While there was no analytical support provided for the increased margin, it is simply a direct increase in payments. If an increase in payments for regulation is the goal, this is the best mechanism for implementing that goal as it is transparent and does not require inconsistent changes in market rules to increase revenues to the owners of regulation units.

Table 6-14 shows the additional revenues that are paid as a result of the rule change that increased the margin on cost based offers from $7.50 to $12.00 per MWh (Table 6-14). The impact of the increased margin is calculated using the offer margin of all offering units, creating a new supply

35 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).

curve, and re-solving for the new marginal unit and new RMCP. The calculation assumes that synchronized reserve assignments and operating reserve allocations remain the same as in the existing solution. The increase in credits paid, of $6,814,605, is a result of the higher offer margin permitted under the new rules.

Table 6-14 Impact of $12 adder to cost based regulation offer: December 2008 through December 2010

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%
Total				$485,846,657	$7,407,790	1.5%

Change in the Definition of Opportunity Cost

The market clearing price of regulation is a sum of the regulation offer and the lost opportunity cost (LOC), including any applicable shoulder LOC, and in the case of off-line CTs a start-up cost. Offers in the Regulation Market consist of a cost based offer and, optionally, a price-based offer.

The December 1, 2008, tariff modifications included a significant change in the definition of LOC. In the Regulation Market the direct offer price is made by the market participant and the opportunity cost is calculated by PJM based on forecast LMP for the next hour and added by PJM to the direct offer price to get the total offer price. The opportunity cost is, on average, approximately half the total offer price (Figure 6-3). Any modification to the measurement of opportunity cost will have a significant impact on the Regulation Market. The opportunity cost is also directly affected by the levels of LMP.

Under the prior rules, opportunity cost was defined as the difference between the LMP and the offer on which the unit was dispatched in the energy market. Under the December 1, 2008, tariff modifications, opportunity cost is defined as the difference between the LMP, and the lesser of the available price-based energy schedule or the most expensive available cost-based energy schedule. Thus, for units backing down to provide regulation, the new rules result in higher calculated opportunity costs.

The change to the tariff is inconsistent with the definition of opportunity cost, is inconsistent with the way in which opportunity cost is calculated elsewhere in the PJM tariff and is inconsistent with the way in which opportunity cost has been calculated for regulation under the PJM tariff for approximately ten years. The MMU recommends that this modification be reversed and that the correct definition of opportunity cost be reinstated for regulation. In addition to getting the price right, the concept and application of opportunity cost is critical to ensuring an efficient allocation of resources between the energy market and the ancillary services markets. The goal is to hold generators neutral to the decision whether to sell MWh in the energy market or to regulate, in order to ensure that the energy markets and the ancillary markets all clear in an efficient and consistent manner. The goal is also to ensure that regulation offers are taken in merit order based on their actual marginal costs, including their correctly calculated opportunity cost.

The correct way to calculate opportunity cost and maintain incentives across both markets is to treat the offer on which the unit is dispatched as the measure of its marginal costs for both the energy market and the Regulation Market. To do otherwise is to impute a lower marginal cost to the unit than its owner does and therefore impute a higher opportunity cost than the owner does.

A quantification of the financial impact of this rule is not possible because PJM does not save all of the data used to determine the final opportunity cost and market clearing price.[36]

In addition, the implementation of the December 1, 2008, changes was not done correctly. Had the revised opportunity cost rule been implemented correctly the MMU estimates that the schedule switching of marginal units in the Regulation Market would have occurred in 3,793 hours during the 25 month period of December 2008 through December 2010 of which 2,088, 55.0 percent, would have resulted in higher opportunity costs, and 1,621, 42.7 percent, would have resulted in lower opportunity costs being added to the marginal regulation offer. In the remaining 83 hours the schedule switch would not have affected the opportunity cost calculation of the marginal unit.

As actually implemented by PJM, schedule switching of marginal units occurred in 2,074 hours, of which 1,327, 64.0 percent, had higher than correct opportunity costs and 680 hours, 32.8 percent, had lower than correct opportunity costs added to the marginal regulation offer. In the remaining 67

36 The MMU has communicated this concern to PJM and been informed that steps are underway to make additional data available to the MMU.

hours the schedule switch would not have affected the opportunity cost calculation of the marginal unit.

PJM made a change to the market software (SPREGO) effective September 9, 2010 to address the identified issue with schedule switching.[37]

Eliminate Offset Against Balancing Operating Reserves Credits

The tariff modifications eliminated the offset of the net revenues earned in the Regulation Market against operating reserve credits. There was no specific rationale advanced for this change. This tariff modification is directly counter to the fundamentals of the PJM markets and the purpose of operating reserve credits. The MMU recommends that this modification be reversed and that the net revenues earned in the Regulation Market be offset against operating reserve credits in the same manner that all net revenues from all other PJM markets are offset against operating reserve credits and in the same manner that Regulation Market credits were offset against operating reserve credits prior to December 1, 2008.

The logic of including all market revenues in the calculation of operating reserve credits is clear. The goal is to ensure that unit owners are never required to run their units without compensation of all marginal costs, but all market compensation is included when determining whether there is a shortfall. The exclusion of the regulation revenues is arbitrary and results in an increase in operating reserve charges and a shift of revenues to the owners of regulating units from those who pay operating reserve charges. There is no reason to modify a fundamental market rule in order to provide greater incentives in the Regulation Market. This argument is reinforced by the appropriately increased scrutiny paid to operating reserves in recent years and given the overall goal to reduce these non market payments. If there is actually a need for greater incentives, it should be established directly and the incentive payment made directly in the Regulation Market, for example through the offer margin.

Table 6-15 shows the additional revenue paid as a result of the rule change that no longer nets regulation revenue against balancing operating reserves. This rule change did not change the Regulation Market clearing price. The increase in total regulation credits paid, of $3,236,381, is a result of the elimination of the offset against operating reserve credits that result from the new rules.

37 See "Minutes," Market Implementation Committee , 11/09/2010, Agenda Item #9, pg. 5. <http://www.pjm.com/~/media/committees-groups/committees/mic/20101109/20101109-minutes.ashx>.

Table 6-15 Additional credits paid to regulating units from no longer netting credits above RMCP against operating reserves: December 2008 through December 2010

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%
Total		$3,236,381	$485,969,594	0.7%

Summary

The changes in market design increased the payments for regulation service. The impact on the Regulation Market that resulted from the December 1, 2008 rule eliminating the netting of credits against balancing operating reserves was $3,236,381. The impact on the Regulation Market of the December 2008 change increasing the allowable price offer markup from $7.50 to $12 was $6,814,605. These two rule changes increased regulation costs by $10,050,986 over the 25 month period from December 1, 2008 through December 31, 2010.

The dollar impact of changing the lost opportunity cost definition cannot be determined at this time primarily because the necessary data have not been saved by PJM. The rule would likely have changed the price in approximately 21 percent of hours between December 1, 2008, and December 31, 2010, (hours in which the marginal unit would have a schedule switch for the LOC calculation) and that in approximately 65 percent of those hours the marginal unit reduced output to regulate, meaning that the corresponding schedule switch would increase lost opportunity cost compared to the correct value. In the other 35 percent of the hours, the marginal unit increased output to regulate, meaning that the corresponding schedule switch would tend to reduce lost opportunity cost compared to the correct value.

The addition of the three pivotal supplier test to the Regulation Market improved the competitiveness of the Regulation Market results, compared to the prior market design, by eliminating the non-competitive behaviors that had existed in prior years. However, the other changes in the rules for the Regulation Market, in particular the change to the calculation of the opportunity cost, produced market results that were not competitive. The other changes in the rules resulted in prices in the Regulation Market that deviated from the competitive price that would have resulted without these changes.

Regulation Market prices were lower in 2010 than in 2009. Supply was up slightly and self-scheduled regulation increased significantly.

The competitive price is the price that would have resulted from the application of the prior, correct approach to the calculation of the opportunity cost and to the calculation of the offset against operating reserves. These Regulation Market results are not based on the behavior of market participants, which is competitive as a result of the application of the three pivotal supplier test. As a result, the MMU concludes that the results of the Regulation Market were not competitive in 2010.

Synchronized Reserve Market

Market Structure

PJM continued to operate the two synchronized reserve markets it implemented on February 1, 2007: the RFC Synchronized Reserve Zone Market; and the Southern Synchronized Reserve Zone (Dominion) Market. The RFC Synchronized Reserve Zone Market's reliability requirements are set by the Reliability*First* Corporation. PJM sets the synchronized reserve requirement for the RFC Synchronized Reserve Zone as the larger of Reliability*First* Corporation's imposed minimum requirement or the largest contingency on the system. Although the RFC Synchronized Reserve Market is one market, transmission constraints often limit the amount of Tier 1 synchronized reserve that can be made available to the PJM Mid-Atlantic Subzone of the RFC. This subzone is defined as the RFC Synchronized Reserve Zone exclusive of parts of AP, parts of AEP, DAY, DLCO, and ComEd zones.[38] PJM must clear enough Tier 2 synchronized reserve in the Mid-Atlantic Subzone of the RFC Synchronized Reserve Market to ensure that the Mid-Atlantic locational synchronized reserve requirement of 1,300 MW is met, after accounting for available Tier 1 supply. This results in a separate Mid-Atlantic Subzone clearing price.

38 See PJM. "Manual 11: Energy & Ancillary Services Market Operations," Revision 45 (June 23, 2010), p. 66.

The Southern Synchronized Reserve Zone (Dominion) Market's reliability requirements are set by the Southeastern Electric Reliability Council (SERC).

Supply

Synchronized reserve is an ancillary service defined as generation or curtailable load that is synchronized to the system and capable of producing output or shedding load within 10 minutes. Synchronized reserve can, at present, be provided by a number of resources, including steam units with available ramp, condensing hydroelectric units, condensing combustion turbines (CTs) and CTs running at minimum generation. Synchronized reserve can also be supplied by DSR resources subject to the limit that they provide no more than 25 percent of the total synchronized reserve requirement. Synchronized reserve DSR resources can be provided by behind the meter generation or by load reductions.

All of the resources that participate in the Synchronized Reserve Markets are categorized as Tier 2 synchronized reserve. Tier 1 resources are those resources that are online, following economic dispatch, and able to respond to a spinning event by ramping up from their present output. All resources operating on the PJM system are considered potential Tier 1 resources, except for those explicitly assigned to Tier 2 synchronized reserve. Tier 2 resources include units that are backed down to provide synchronized reserve capability, condensing units synchronized to the system and available to increase output and demand side resources.

Under Synchronized Reserve Market rules, Tier 1 resources are paid when they respond to an identified spinning event as an incentive to respond when needed.[39] Tier 1 synchronized reserve payments or credits are equal to the integrated increase in MW output above economic dispatch from each generator over the length of a spinning event, multiplied by the synchronized reserve energy premium less the hourly integrated LMP. The synchronized reserve energy premium is defined as the average of the five minute LMPs calculated during the spinning event plus $50 per MWh. All units called on to supply Tier 1 or Tier 2 synchronized reserve have their actual MW monitored. Tier 1 units are not penalized if their output fails to match their expected response as they are only compensated for their actual response.

Under Synchronized Reserve Market rules, Tier 2 synchronized reserve resources are paid to be available as synchronized reserve, regardless of whether the units are called upon to generate in response to a spinning event, and are subject to penalties if they do not provide synchronized reserve when called. The price for Tier 2 synchronized reserve is determined in the Synchronized Reserve Market. Several steps are necessary before the hourly Synchronized Reserve Market is cleared. Ninety minutes prior to the start of the hour, PJM estimates the amount of Tier 1 reserve available from every unit. Sixty minutes prior to the start of the hour, self-scheduled Tier 2 units are identified. Thirty minutes prior to the hour, Tier 1 is estimated again. If synchronized reserve requirements are not met by Tier 1 and self-scheduled Tier 2 resources, then a Tier 2 market is cleared at least 30 minutes prior to the start of the hour. The Tier 2 market clearing price is equivalent to the price of the highest-priced, Tier 2 resource needed to meet the demand for synchronized

39 See PJM. "Manual 11: Energy & Ancillary Services Market Operations," Revision 45 (June 23, 2010), p. 75.

reserve requirements, the marginal unit, based on the simultaneous clearing of the Regulation Market and the Synchronized Reserve Market.[40]

The Synchronized Reserve Market is characterized by structural market power. As a result, the synchronized reserve offer submitted for a unit can be no greater than the unit's incremental operating and maintenance cost plus a $7.50 per MWh margin.[41,42] The market clearing price is comprised of the marginal unit's synchronized reserve offer price, the cost of energy use, the startup cost (if the unit is not running) and the unit's lost opportunity cost. Opportunity cost is calculated by PJM based on forecast LMPs and generation schedules from the unit dispatch system. Opportunity cost for demand-side resources is always zero. All units cleared in the Synchronized Reserve Markets are paid the higher of either the market-clearing price or the unit's synchronized reserve offer plus the unit specific opportunity cost and the cost of energy use incurred.

For the RFC Synchronized Reserve Zone in 2010, the offered and eligible excess supply ratio was 2.68. Within the Mid-Atlantic Subzone of the RFC Synchronized Reserve Zone, the offered and eligible excess supply ratio was 1.16.[43] These excess supply ratios are determined using the administratively established requirement for synchronized reserve. Actual market demand for Tier 2 synchronized reserve is lower than the synchronized reserve requirement because a significant amount of Tier 1 synchronized reserve is usually available.

Demand

The market demand for Tier 2 synchronized reserve is determined by subtracting the amount of forecast Tier 1 synchronized reserve available from each synchronized reserve zone's synchronized reserve requirement for the period. Market demand is further reduced by subtracting the amount of self scheduled Tier 2 resources. The total synchronized reserve requirement is different for the two Synchronized Reserve Markets. The synchronized reserve requirement is determined at the discretion of PJM to ensure system reliability and to maintain compliance with applicable NERC and regional reliability organization requirements. RFC and Dominion reserve requirements are determined on at least an annual basis. Mid-Atlantic Subzone requirements are established on a seasonal basis.[44]

Currently the RFC synchronized reserve requirement is the greater of the Reliability*First* Corporation's imposed minimum requirement or the system's largest contingency. The actual synchronized reserve requirement for the RFC Zone for January 2010, through June 2010, was 1,320 MW. For the rest of 2010 it has remained at 1,350 MW. Exceptions to this requirement can occur when grid maintenance or outages change the largest contingency. Such a condition occurred between September 20 and September 29, when the synchronized reserve requirement was set to 1,700 MW. Between November 15 and November 19 it was set to 1,725 MW. Between October 11 and October 13 it was set to 2,500 MW. Figure 6-6 shows the average monthly synchronized reserve required and the average monthly Tier 2 synchronized reserve MW scheduled during 2010 for the RFC Synchronized Reserve Market.

40 Although it is unusual, a PJM dispatcher can deselect units which have been committed after the clearing price has been established. This only happens if real-time system conditions require dispatch of a spinning unit for constraint control, or problems with a generator or monitoring equipment are reported.

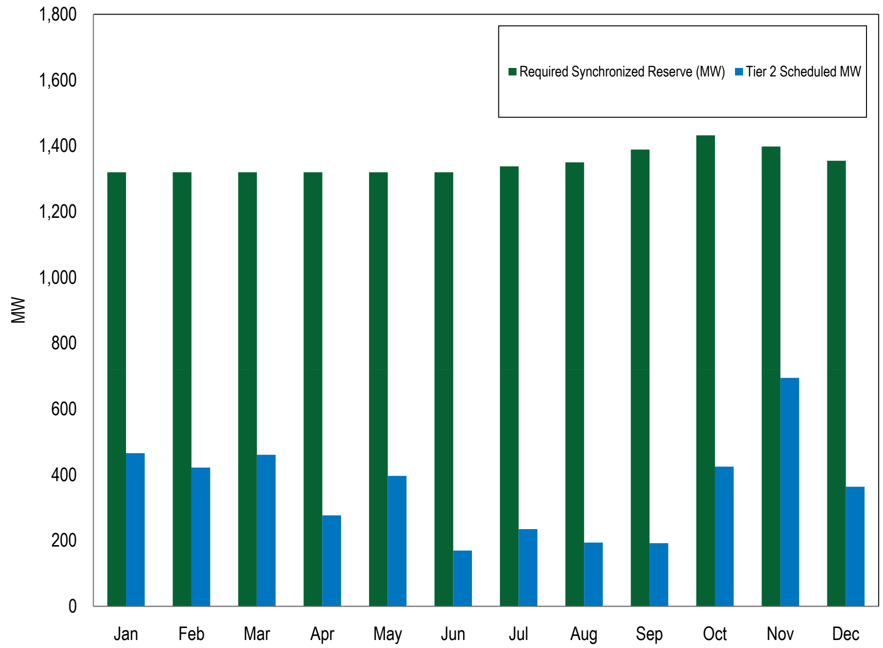
41 See PJM. "Manual 11: Energy & Ancillary Services Market Operations," Revision 45 (June 23, 2010), p. 65.

42 See PJM. "Manual 15: Cost Development Guidelines," Revision 15 (October 27, 2010), p. 37.

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

44 See PJM. "Manual 10: Pre-Scheduling Operations," Revision 25 (January 1, 2010), p. 18.

Figure 6-6 RFC Synchronized Reserve Zone monthly average synchronized reserve required vs. Tier 2 scheduled MW: Calendar year 2010



The RFC Synchronized Reserve Zone is large and some available Tier 1 must be physically located in the Mid-Atlantic Subzone as a result of transmission limits between the western and eastern portions of the zone. PJM calculates the transfer capability of these transmission facilities. The calculation of Mid-Atlantic Subzone Tier 1 includes what is available in the east plus the amount of Tier 1 synchronized reserve in the west that can be transferred into the east. The Synchronized Reserve Market solution is especially sensitive to this limit (known as transfer capacity). The higher this transfer capacity, the greater is the amount of Tier 1 synchronized reserve available in the East and so the less Tier 2 synchronized reserve that needs to be cleared to satisfy the synchronized reserve requirement. From 2007 through mid-March 2009, PJM market operations had estimated this transfer capacity at 70 percent of available RFC Tier 1 not exclusively in the Eastern subzone. However, PJM dispatch frequently observed a more restrictive limitation on transfer capacity in real-time operations on the western interface (Bedington—Black Oak) and needed to add additional synchronized reserve outside of the market solution in order to cover the requirement. This was the source of Added Synchronized Reserve resulting in lost opportunity costs being added to synchronized reserve costs.[45]

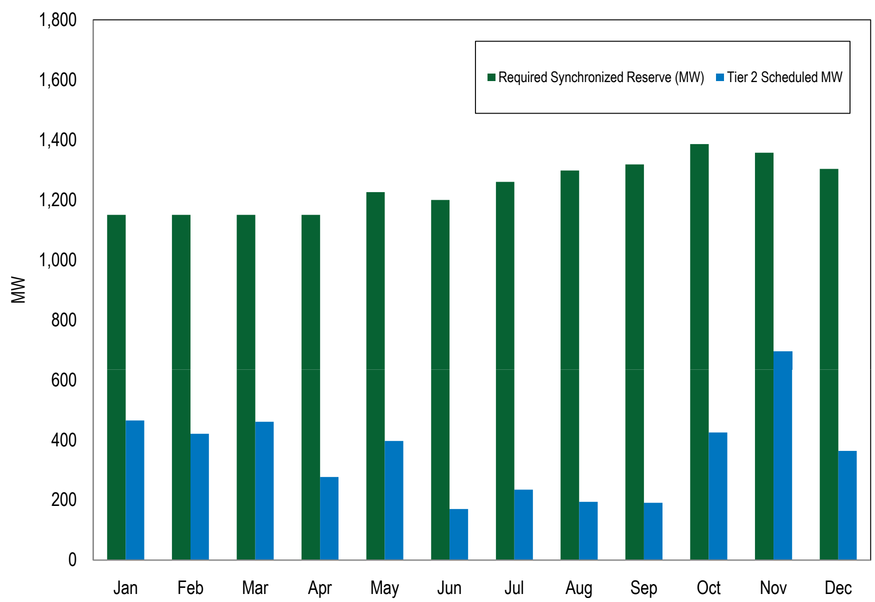
In mid March of 2009, PJM reset the transfer capacity from 70 percent to 15 percent. PJM also changed the transfer interface from Bedington – Black Oak to AP South. As a result, less Tier 1 synchronized reserve was available to the Mid-Atlantic Subzone for the market solution, increasing

45 See *2007 State of the Market Report*, Volume II, section 6 Ancillary Service Markets pp. 299, 300. Also *2008 State of the Market Report for PJM*, Volume II, section 6 Ancillary Service Markets, p. 328.

the amount of Tier 2 that had to be cleared to satisfy the requirement. This also reduced the amount of Tier 2 synchronized reserve that had to be added by PJM dispatch after market.[46]

As a whole, the RFC Synchronized Reserve Zone almost always has enough Tier 1 to cover its synchronized reserve requirement. Available Tier 1 in the western part of the RFC Synchronized Reserve Zone generally exceeds the total synchronized reserve requirement in the west. In 2010, the RFC Synchronized Reserve Zone cleared a Tier 2 Synchronized Reserve Market in less than one percent of all hours. This is not the case in the Mid-Atlantic Subzone. As a result, there is frequently a Tier 2 synchronized reserve requirement only in the Mid-Atlantic Subzone and a separate clearing price only for the Mid-Atlantic Subzone. The Mid-Atlantic Subzone of the RFC Synchronized Reserve Zone cleared a separate Tier 2 market in 67 percent of all hours. Figure 6-7 compares the required synchronized reserve MW to the scheduled Tier 2 MW for the Mid-Atlantic Subzone only.

Figure 6-7 RFC Synchronized Reserve Zone, Mid-Atlantic Subzone average hourly synchronized reserve required vs. Tier 2 scheduled: Calendar year 2010

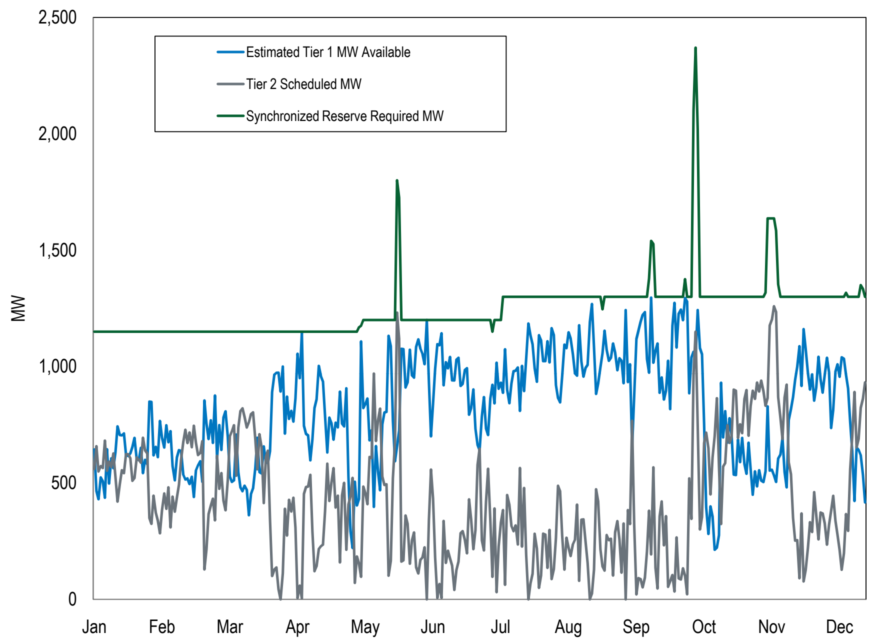


The actual synchronized reserve requirement for the Mid-Atlantic Subzone for 2010 was usually 1,300 MW but there were several days when temporary grid conditions created a double contingency which increased the requirements. Required synchronized reserve was as high as 2,500 MW on October 11-13, 2010. Throughout 2010, the average synchronized reserve required MW in the Mid-Atlantic Subzone was 1,247 MW. The difference between the level of required synchronized reserve and the level of Tier 2 synchronized reserve scheduled is the amount of Tier 1 synchronized reserve available on the system.

46 See *2009 State of the Market Report*, Volume II, section 6 Ancillary Service Markets pp. 384, Table 6-14.

Figure 6-8 shows the relationship among the PJM Mid-Atlantic synchronized reserve required, the estimated Tier 1 available and the amount of Tier 2 synchronized reserve needed to be purchased. The more Tier 1 is available the less Tier 2 is required.

Figure 6-8 RFC Synchronized Reserve Zone, Mid-Atlantic Subzone daily average hourly synchronized reserve required, Tier 2 MW scheduled, and Tier 1 MW estimated: Calendar year 2010



The Southern Synchronized Reserve Zone is part of the Virginia and Carolinas Area (VACAR) subregion of SERC. VACAR specifies that available, 15 minute quick start reserve can be subtracted from Dominion's share of the largest contingency to determine synchronized reserve requirements.[47] The amount of 15 minute quick start reserve available in VACAR is sufficient to make Tier 2 synchronized reserve demand zero for most hours. The actual hourly Southern Synchronized Reserve Zone's synchronized reserve requirement was usually zero because Dominion's share of the largest contingency within VACAR was offset by its quick start capability. The Southern Synchronized Reserve Zone cleared a Tier 2 market for only 11 hours in 2010.

Market Concentration

The RFC Tier 2 Synchronized Reserve Market was slightly more concentrated in 2010 than it had been in 2009. The RFC Synchronized Reserve Market remains highly concentrated and dominated by a relatively small number of companies. The participation of demand resources in the market continues to have a significant impact on the market solution, resulting in lower prices and less concentration. The HHI for the Mid-Atlantic Subzone of the 2010 RFC Synchronized Reserve Market was 3222, which is defined as "highly concentrated."

47 See PJM. "Manual 11: Energy & Ancillary Services Market Operations," Revision 45 (June 23, 2010), p. 66.

The largest hourly market share was 98 percent and 68 percent of all hours had a maximum market share greater than or equal to 40 percent. In less than one percent of Mid-Atlantic Subzone hours during which a market was cleared in 2010, a single company had 90 percent or more of the market share. The highest annual average market share for a single company for all hours in which it had any market share, was 43 percent. In other words, a single company sold 43 percent of synchronized reserves on average for all hours in which it had market share over the entire year (Table 6-16).

Table 6-16 Mid-Atlantic Subzone RFC Tier 2 Synchronized Reserve Market's cleared market shares: Calendar year 2010

Company Market Share Rank	Cleared Synchronized Reserve Average Market Share
1	43%
2	25%
3	25%
4	17%
5	12%

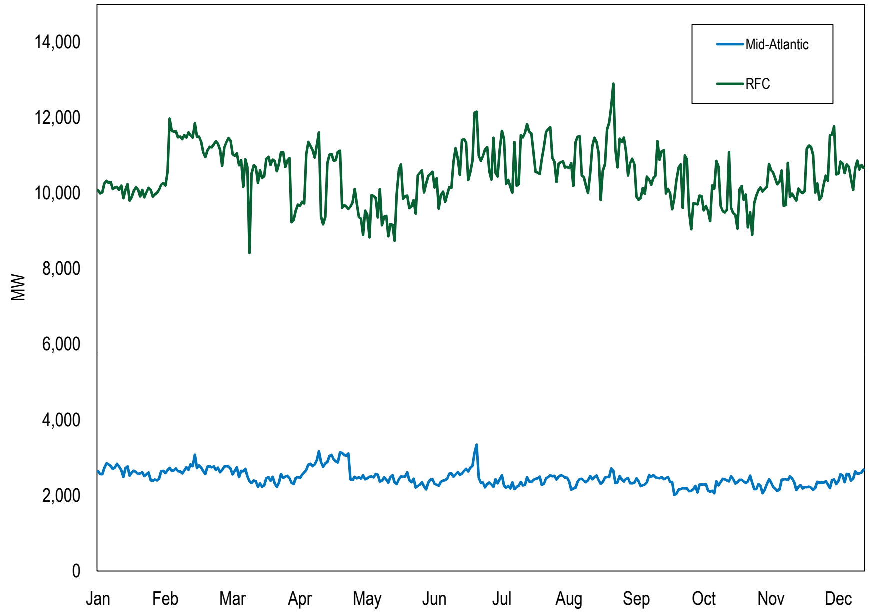
In 2010, 62 percent of hours in the Mid-Atlantic Subzone of the RFC Synchronized Reserve Market failed the three pivotal supplier test. One company was pivotal in 99 percent of all pivotal hours, a second company was pivotal in 47 percent of all pivotal hours, and a third company was pivotal in 34 percent of all pivotal hours. These results indicate that the Mid-Atlantic Subzone of the RFC Synchronized Reserve Market, the only synchronized reserve market that clears on a regular basis, is not structurally competitive.

Market Conduct

Offers

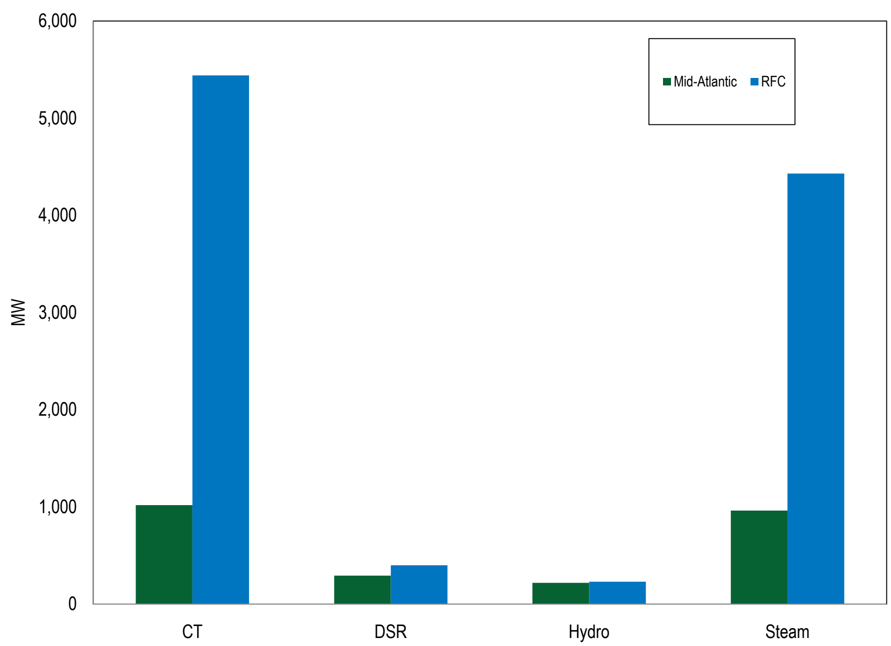
Figure 6-9 shows the daily average hourly offered Tier 2 synchronized reserve MW. For steam units, offered MW are eligible only if the offering unit is running. For that reason, the eligible offer volume shows weekly variability based on off-peak/on-peak operating cycles as well as seasonal variability.

Figure 6-9 Tier 2 synchronized reserve average hourly offer volume (MW): Calendar year 2010



Synchronized reserve is offered by steam, CT, hydroelectric and DSR resources. Figure 6-10 shows average offer MW volume by market and unit type.

Figure 6-10 Average daily Tier 2 synchronized reserve offer by unit type (MW): Calendar year 2010



The contribution of DSR resources to the Synchronized Reserve Market remained significant in 2010. The significance of DSR in the Synchronized Reserve Markets is greater than its eligible offer MW as illustrated in Figure 6-10. In 2010, DSR accounted for 20 percent of all cleared Tier 2 synchronized reserves. In 8 percent of hours when a synchronized reserve market was cleared all cleared MW was DSR. In the hours when all supply was DSR, the unweighted average SRMCP was $1.39. The unweighted average SRMCP for all cleared hours was $8.49. As defined by PJM, demand-side resources may at times be generation that is behind the meter.

DSR

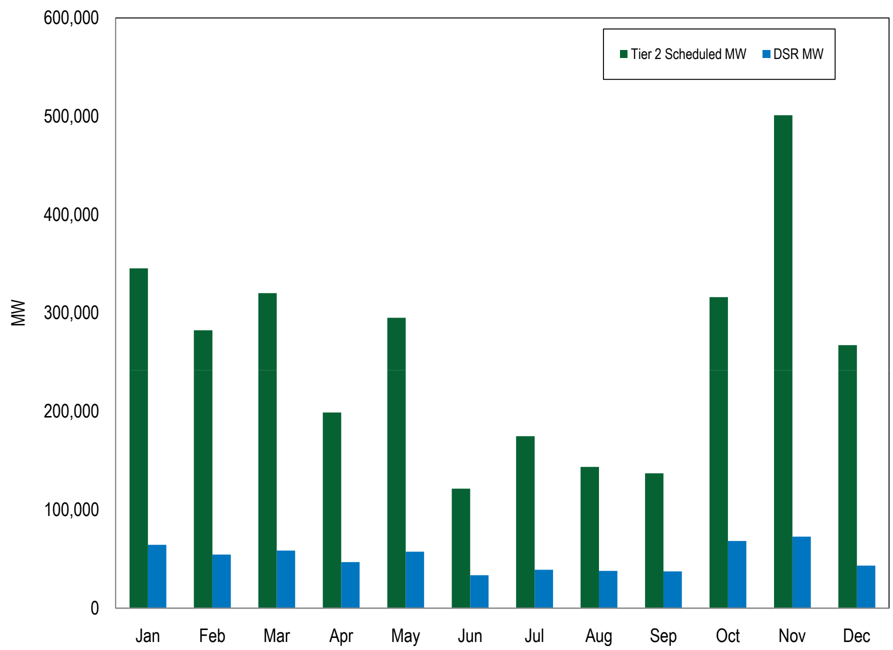
Demand-side resources were permitted to participate in the Synchronized Reserve Markets effective August 2006. DSR continues to have a significant impact on the Synchronized Reserve Market. In 8 percent of hours where a synchronized reserve market was cleared in the Mid-Atlantic Subzone of the RFC (see Table 6-17), all cleared synchronized reserve was DSR synchronized reserve. The clearing price for those hours was significantly lower than the average clearing price overall.

Table 6-17 Average RFC SRMCP when all cleared synchronized reserve is DSR, average SRMCP, and percent of all cleared hours that all cleared synchronized reserve is DSR: Calendar year 2010

Month	Average SRMCP	Average SRMCP when all cleared synchronized reserve is DSR	Percent of cleared hours all synchronized reserve is DSR
Jan	$5.84	$2.03	4%
Feb	$5.97	$0.10	1%
Mar	$8.45	$2.01	6%
Apr	$7.84	$1.86	17%
May	$9.98	$1.68	15%
Jun	$9.61	$0.74	9%
Jul	$16.30	$0.79	7%
Aug	$11.17	$0.93	12%
Sep	$10.45	$1.15	12%
Oct	$8.21	$1.06	8%
Nov	$9.59	$0.36	1%
Dec	$12.49	$0.88	4%

Figure 6-11 shows total cleared plus self-scheduled monthly synchronized reserve MW and cleared plus self-scheduled MW for DSR synchronized reserve. Participation of demand response in the Synchronized Reserve Market remained strong in 2010. Demand response remained significantly less expensive than other forms of synchronized reserve. Demand resources typically offer at a lower price, and demand resources do not have lost opportunity costs added to their offer in market clearing. Furthermore demand resources add some diversity to the supply of synchronized reserve, reducing market concentration.

Figure 6-11 PJM RFC Zone Tier 2 synchronized reserve scheduled MW: Calendar year 2010



Market Performance

Price

Figure 6-12 shows the relationship among required Tier 2 synchronized reserve, Synchronized Reserve Market clearing price, and percent of cleared synchronized reserve satisfied by DSR in the Mid-Atlantic Subzone of the RFC Synchronized Reserve Market. This figure shows both that the synchronized reserve clearing price tends to increase with demand and that DSR satisfies a large percentage of Tier 2 synchronized reserve when the demand is low.

Figure 6-12 Required Tier 2 synchronized reserve, Synchronized Reserve Market clearing price, and DSR percent of Tier 2

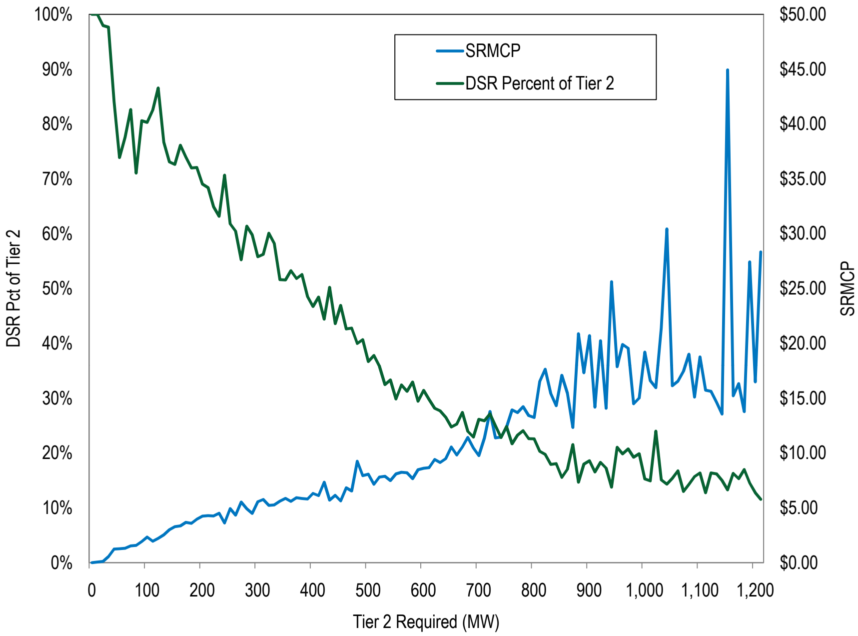


Figure 6-15 shows the load weighted, average Tier 2 price and the cost per MW associated with meeting PJM demand for synchronized reserve. The price of Tier 2 synchronized reserve is the Synchronized Reserve Market-clearing price (SRMCP). Resources which provide synchronized reserve are paid the higher of the SRMCP or their offer plus their unit specific opportunity cost. The offer plus the unit specific opportunity cost may exceed the SRMCP for a number of reasons. If real-time LMP is greater than the LMP forecast prior to the operating hour and included in the SRMCP, unit specific opportunity cost will be higher than forecast. Such higher LMPs can be local because of congestion or more general if system conditions change. The additional costs of noneconomic dispatch are added to the total cost of synchronized reserve. When some units are paid the value of their offer plus their unit specific opportunity cost, the result is that PJM's synchronized reserve cost per MW is higher than the SRMCP.

The load weighted, average price for synchronized reserve in the PJM Mid-Atlantic Subzone of the RFC Synchronized Reserve Market in 2010 was $10.55 while the corresponding cost of synchronized reserve was $14.41.

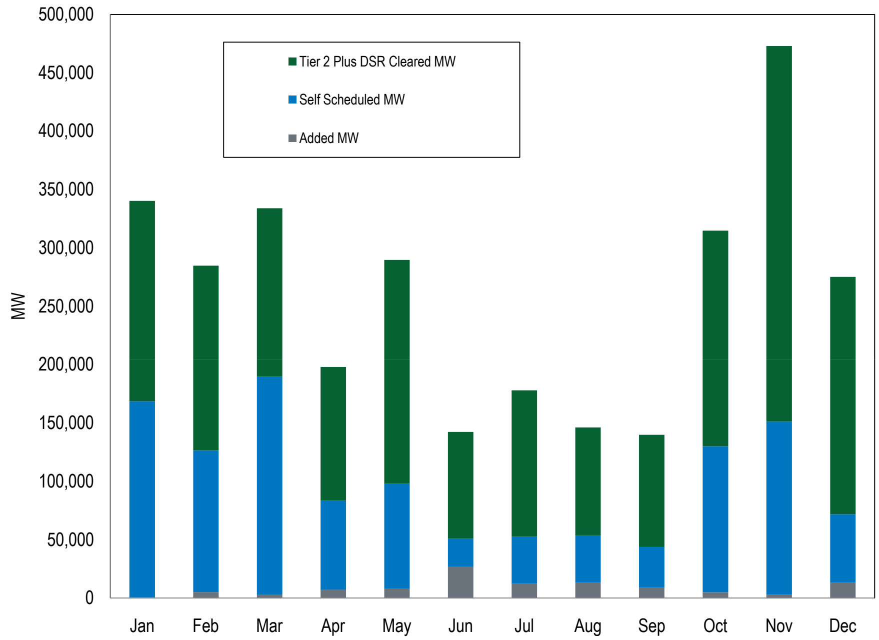
The RFC Synchronized Reserve Market cleared as a single market less than one percent of all hours in 2010 with a load weighted average $0.80 clearing price.

Price and Cost

A high price to cost ratio is an indicator of an efficient market design, where the costs are the result of the economic solution. A low price to cost ratio is in part a result of out-of-market purchases of Tier 2 synchronized reserve by PJM dispatchers who need the reserves for reliability reasons.

The primary reason for the relatively low price to cost ratio is the difference in opportunity cost calculated using the forecast LMP and the actual LMP.

Figure 6-13 Tier 2 synchronized reserve purchases by month for the Mid-Atlantic Subzone: Calendar year 2010



The problem of out-of-market purchases of Tier 2 synchronized reserve was greatly diminished by the March 13, 2009 change in the transfer capacity used in the market solution (Figure 6-13). The difference between the Tier 2 Synchronized Reserve Market price and the cost for Tier 2 synchronized reserve in 2010 was slightly higher than it had been in 2009 (Figure 6-14). In the Mid-Atlantic Subzone of the RFC Synchronized Reserve Market for 2010, the cost of Tier 2 synchronized reserves was 37 percent higher than the load-weighted price. In 2009 this difference had been 26 percent.

Figure 6-14 Impact of Tier 2 synchronized reserve added MW to the RFC Synchronized Reserve Zone, Mid-Atlantic Subzone: Calendar year 2010

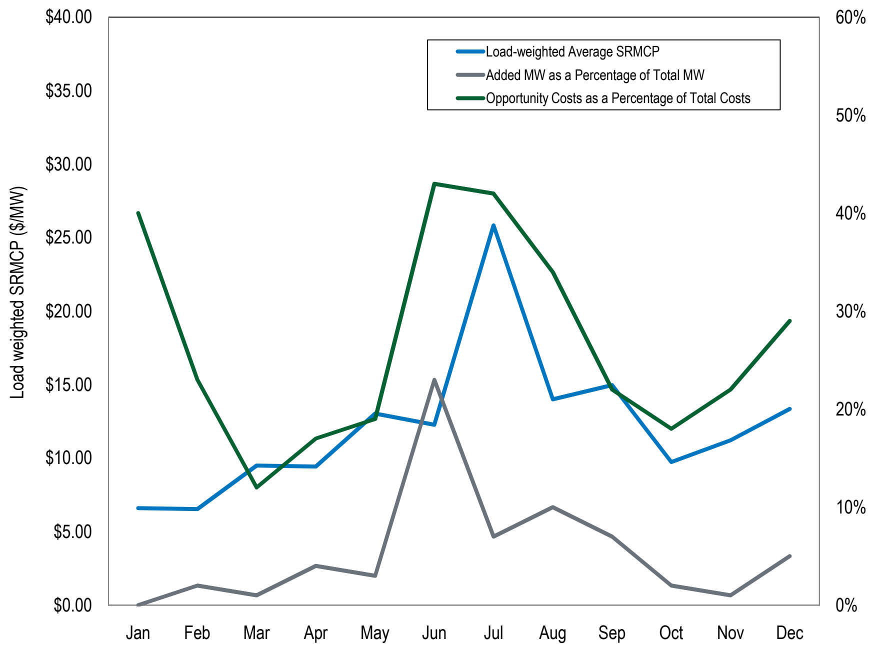
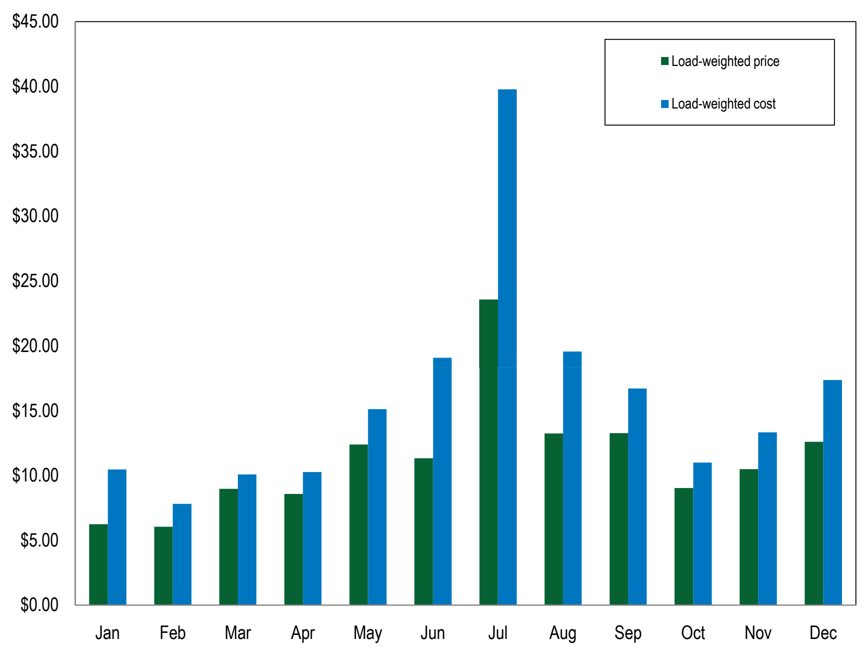


Figure 6-15 Comparison of RFC Mid-Atlantic Subzone Tier 2 synchronized reserve price and cost (Dollars per MW): Calendar year 2010



A high price to cost ratio is an indicator of an efficient market design, where the costs are the result of the economic solution. Table 6-18 shows the price and cost history of the Synchronized Reserve Market since 2005. In March of 2009, PJM took steps to reduce the amount of aftermarket added synchronized reserve being added by the dispatchers. As a result, the price to cost ratio increased in 2009.

Synchronized reserve prices were 36.1 percent higher in 2010 than in 2009, but lower than in any other year since 2005. Synchronized reserves total costs per MW were 47.5 percent higher in 2010 than in 2009. The total cost of synchronized reserves per MW was 36.6 percent higher than the market clearing price in 2010. The result was a decrease in the ratio of price to cost.

A key source of the difference between the market clearing price and the cost per MW of synchronized reserve results from differences in opportunity cost between the forecast LMP and actual LMP. To address this issue, the MMU recommends that the hourly clearing price for synchronized reserve be determined after the close of the hour. All units cleared in the synchronized reserve market in the hour prior would be paid the market-clearing price based on the actual LMP rather than the forecast LMP.

Table 6-18 Comparison of load weighted price and cost for PJM Synchronized Reserve, January 2005 through December 2010

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%

Market Solution and Actual Dispatch of Ancillary Services

The actual dispatch of ancillary services can and does differ from the market solution at times, as a result of reliability concerns. The result is usually that total costs per MW (credits/MW) are higher than the clearing price (RMCP). The MMU analyzes this cost/price differential and reports the cost and price.

The market solution software (SPREGO) optimizes regulation and spinning using a theoretical unit dispatch and estimated Tier 1 synchronized reserve based on forecast load. Dispatchers can deselect a unit from regulation, Tier 1 or Tier 2 synchronized reserve, or unit dispatch prior to running the market solution. This is the equivalent of imposing a constraint on the market solution.

The MMU recommends that a full list of potential reasons for unit deselection be published in PJM's M-11 Scheduling Operations Manual. The MMU also recommends that dispatchers document all actual unit deselections and the reasons for deselection.

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, nor the Mid-Atlantic subzone of the RFC market experienced deficits in 2010.

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.[48] Prior to June 1, 2008, PJM obtained supplemental reserves from several sources including available unused capacity of generating units that had been dispatched for energy, available capacity of units not dispatched for energy but capable of coming online in 30 minutes and dispatch of additional units for the purpose of making supplemental reserve available.

On June 1, 2008, PJM introduced the Day-Ahead Scheduling Reserve Market (DASR), as required by the settlement in the RPM case.[49] 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. The DASR 30-minute reserve requirements are determined by the reliability region.[50] In the Reliability*First* (RFC) region, reserve requirements are calculated based on historical under-forecasted load rates and generator forced outage rates.[51] Under-forecasted load rates are based on the 80th percentile of a rolling three-year average (November 1 – October 31). For 2010, the load forecast error component of this calculation was 1.90 percent of peak load forecast. The forced outage rate component of the calculation is based on a three-year rolling average of the forced outage rate that occurs from 1800 of the scheduling day through the operating day at 2000. For 2010, the forced outage component of the Day-Ahead Scheduling Reserve was 4.98 percent. For 2010 the Day-Ahead Scheduling Reserve for RFC areas of PJM was 6.88 percent times Peak Load Forecast for RFC. Dominion Day-Ahead Scheduling Reserve is based on its share of the VACAR Reserve Sharing agreement and is set annually. In 2010 VACAR scheduling reserve was set at 418 MW. The RFC and Dominion Day-Ahead Scheduling Reserve 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.

DASR is an offer-based market that clears for all hours of the day at 1600 EPT day-ahead. DASR Market clearing is simultaneous with the Day-Ahead Energy Market.

48 PJM uses the terms "supplemental operating reserves" and "scheduling operating reserves" interchangeably.
49 See, 117 FERC ¶ 61,331 (2006).
50 PJM. "Manual 13, Emergency Requirements," Revision 41 (October 1, 2010), pp. 11-12.
51 PJM. "Manual 10, Pre-Scheduling Operations," Revision 25 (January 1, 2010), p. 17.

Market Structure

All generating resources capable of increasing their output in 30 minutes are eligible to provide DASR. Load response resources which are registered in PJM's Economic Load Response and are dispatchable by PJM are also eligible to provide DASR. All DASR offers must be submitted by 1200 EPT day-ahead. There is a must offer requirement in the DASR Market, but any offer price will satisfy the requirement. Resources which are eligible for DASR but which have not offered into the market will have their offers set to $0.00.

In 2010, the three pivotal supplier test was failed in the DASR Market in a total of 122 hours (1.3 percent of all hours), all of which were in June, July, August, and September.

Demand side resources do participate in the DASR Market, but remain insignificant. Demand side resources began to offer and clear the DASR market in November 2008. No demand side resources cleared the DASR market in 2010.

In 2010, the required DASR was 6.88 percent of peak load forecast, up from 6.75 percent in 2009.[52] As a result of increased demand for energy, reflected in higher forecast peak loads and increased DASR requirements, the DASR MW purchased increased by 9 percent in 2010 over 2009.

Market Conduct

PJM rules require all units with reserve capability that can be converted into energy within 30 minutes to offer into the DASR Market.[53] Units that do not offer will have their offers set to $0/MW. In 2010, 54 percent of all generating units had no DASR offers or offers of $0. Every unit type had significant offers at $10/MW or lower. Economic withholding remains an issue in the DASR Market. Continuing a pattern seen since the inception of the DASR Market, five percent of units offered at $50 or more and 45 units offered at more than $900, in a market with an average clearing price of $0.16 and a maximum clearing price of $39.99. Such offers are high enough to ensure that the unit will never clear and thus constitute economic withholding. The level of economic withholding has been small enough that it has not affected prices. The DASR Market has been characterized by low prices.

Table 6-19 lists the unit types offering at $990/MW. Of the 24 CTs, four offered at $990/MW in January and February but changed their offer to $0 for the other 10 months of 2010. All of these units, with the exception of four CTs, had offer prices of $990 for the entire year in 2010. The Market User Interface does provide a mechanism for a unit not to offer for a particular day although none of the units offering at $990/MW chose to use this option.

52 See the *2010 State of the Market Report for PJM*, Volume II, Section 6, "Ancillary Services" at Day Ahead Scheduling Reserve *(DASR)*.
53 PJM. "Manual 11, Emergency and Ancillary Services Operations," Revision 45 (June 23, 2010), p. 122.

Table 6-19 Count of units by unit type offering DASR at $990/MW

Unit Type	Unit Count
Diesel	2
CT	24
Nuclear	10
Steam	6
Wind	3

Market Performance

DASR prices are closely related to energy prices, peaking in the summer months. In 2010, the load weighted price of DASR was $0.16 per MW. In 2009, the load weighted price of DASR was $0.05 per MW. The maximum clearing price in 2010 was $39.99 per MW in July.

Table 6-20 2010 PJM, Day-Ahead Scheduling Reserve Market MW and clearing prices

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	$110,074
Apr	4,871	$0.00	$0.42	$0.01	3,789,115	$45,352
May	5,487	$0.00	$2.00	$0.05	4,082,028	$164,277
Jun	6,864	$0.00	$5.00	$0.18	4,941,835	$838,178
Jul	7,464	$0.00	$39.99	$0.76	5,553,319	$3,606,940
Aug	7,131	$0.00	$12.00	$0.38	5,305,750	$1,754,295
Sep	5,889	$0.00	$5.00	$0.06	4,239,965	$241,840
Oct	5,074	$0.00	$0.04	$0.00	3,775,214	$10,421
Nov	5,412	$0.00	$0.05	$0.01	3,912,897	$33,543
Dec	6,328	$0.00	$2.00	$0.03	4,707,794	$129,790

The MMU concludes that the results of the DASR Market were competitive in 2010. The MMU concludes that the DASR Market was structurally competitive in 2010. The MMU concludes that participant behavior was mixed as a result of the economic withholding by some units. This behavior was limited to a relatively small number of units and had no impact on DASR prices in 2010 as a result of a favorable balance between supply and demand, but that balance could change quickly as a result of weather or other factors and the impacts could be significant. The MMU recommends that the DASR Market rules be modified to incorporate the application of the three pivotal supplier test in order to address potential market power issues.

Black Start Service

PJM and its transmission owners must provide for sufficient and appropriately located resources that are capable of providing black start service in the PJM region. To accomplish this, transmission owners prepare system restoration plans that identify critical resources for reenergizing the grid following a possible blackout. Individual transmission owners, with PJM, identify the black start units included in each transmission owner's system restoration plan. PJM ensures the availability of black start by charging transmission customers according to their zonal load ratio share and compensating black start unit owners according to an incentive rate or their revenue requirements (Table 6-21). PJM defines a minimum critical black start for each transmission zone.[54]

Black start service is necessary to help ensure the reliable restoration of the grid following a black out. 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 with a high operating factor to automatically remain operating at reduced levels when disconnected from the grid.[55]

Table 6-21 Black start yearly zonal charges for network transmission use: Calendar year 2010

Zone	Network Charges	Black Start Rate ($/MW)
AECO	$371,700	$0.38
AEP	$628,476	$0.07
AP	$135,825	$0.04
BGE	$499,080	$0.21
ComEd	$3,773,721	$0.49
DAY	$137,622	$0.11
DLCO	$28,835	$0.03
DPL	$359,691	$0.30
JCPL	$444,216	$0.25
Met-Ed	$414,618	$0.46
PECO	$779,523	$0.31
PENELEC	$334,265	$0.37
Pepco	$250,259	$0.13
PPL	$150,145	$0.06
PSEG	$1,676,711	$0.55

Schedule 6A of the PJM OATT makes available formula rates for units identified as "critical" in system restoration plans to collect their costs and authorizes PJM to perform billing and settlement of these costs (including costs collected pursuant to separately filed and eligible FERC tariffs). Schedule 6A was originally implemented in a manner most suited to the needs of existing older units that were equipped to provide black start service. Because the investment in the equipment needed to provide black start service by these units was made some time ago, the purpose of

54 See PJM. "Manual 36, System Restoration," Revision 12 (January 1, 2010) p. 53.
55 OATT, Sheet No. 33.01.

Schedule 6A was primarily to provide a level of compensation sufficient to encourage the owners of identified critical resources to continue providing the service.[56] These provisions established a rolling two-year commitment, appropriate for older units with no requirement for new investment in black start related equipment.

In 2003, PJM, working with American Electric Power Service Corporation ("AEP"), determined that new black start capability was needed at a certain location on the AEP system, partly as a result of the retirement of a legacy black start service unit. PJM issued a request for proposal, and received only offers from suppliers who would need to install new equipment in order to provide the service. PJM selected from the few potentially viable projects, Constellation's offer to provide black start service from its Big Sandy Peaker Plant ("Big Sandy"). Big Sandy required approximately $667,000 to install a 750 kW diesel generator and associated controls. Constellation deemed the recovery provisions included in Schedule 6A inadequate, especially in light of the maximum two-year commitment to which AEP would agree. Constellation therefore sought and obtained FERC approval to collect its entire capital investment over that two-year period, citing as precedent a comparable arrangement between University Park Energy, LLC ("UPE") and Commonwealth Edison Company ("ComEd") that PJM grandfathered in the course of integrating ComEd's system into PJM. Constellation indicated to the Commission its expectation that Big Sandy, like UPE, expected to collect payment under Schedule 6A's formula rates after completing recovery of 100 percent of its investment. This might also have served as the pattern for the procurement of black start services from Lincoln Generating Facility, LLC, except that, partly in response to concerns raised by the MMU, Lincoln agreed to file for a longer five-year commitment period, although full investment cost recovery was accelerated to the first two years.

The MMU had concerns that Schedule 6A was not providing an appropriate framework for the procurement of black start service from new resources. The fundamental problem was that transmission customers in the PJM Region were paying over a short time the cost of substantial capital investments in black start capable resources with no assurance that those resources would continue to provide black start service after the expiration of the initial two-year term. Moreover, the rates of return for a new black start unit that recovered its full capital cost in two years and then reverted to the incentive structure under the formula rates, recovering its cost twice, were far in excess of returns typical for services procured under cost-of-service ratemaking.

In late 2007, PJM reactivated the Black Start Service Working Group ("BSSWG") in order to consider how to recover the new costs of compliance with the NERC standards for Critical Infrastructure Protection (CIP) applicable specifically to black start units and to update an outdated reference in the formula to the pre-RPM "Capacity Deficiency Rate." PJM's stakeholders agreed to also develop modifications to provide for a mechanism that conforms the commitment period to provide black start service to the period for recovery of the costs of new investment in black start equipment. The revisions to Schedule 6A developed by the BSSWG to address these and other issues were filed with the FERC on February 19, 2009.[57] By order issued May 29, 2009, the Commission approved the reforms.[58] The Commission did not approve a measure supported by the MMU that would have prevented double recovery of revenues by certain black start units that received accelerated

56 See PJM filing initiating FERC Docket No. ER02-2651-000 at 4 (September 30, 2002)("2002 Schedule 6A Filing").
57 PJM filed the revised Schedule 6A in FERC Docket No. ER09-730-000.
58 127 FERC ¶ 61,197.

recovery of investment in black start equipment prior to the reforms becoming effective on April 21, 2009.[59]

Structure

There is no organized market for black start service in PJM and there is unlikely to be a competitive market for black start service given the very local nature of the requirements. PJM in conjunction with its transmission owners identifies locations where critical black start units are needed and conducts requests for proposals to procure service at those locations. Proposals are accepted from any party willing and able to provide the service at the required location. No customers or their representatives are involved in this process. The MMU is not aware that any request for proposal process has received more than a handful of offers. This result is not unexpected, as there are a very limited number of existing facilities at particular locations indentified in PJM's system restoration plans eligible to provide the service needed. The MMU has concerns that there is a disconnect between a service that is required for system reliability and the need to secure voluntary participation in the system restoration plans from the relatively few potentially cost-effective providers at the critical locations identified. Clearly, the owners of the few facilities able to respond to the requests for proposal have local market power in the provision of black start services as a result both of inelastic demand and the small size of the local market. The significantly increasing costs and risks associated with providing this service as a result of more rigorous and enforceable security standards may aggravate this problem, despite PJM's efforts to address this issue.

Conduct

Consistent with its limited and shared authority, PJM generally has managed the request for proposals process in an orderly and transparent manner. PJM and transmission owners have ensured the provision of black start service, but there is no basis for confidence that black start service has been obtained at least cost. The MMU is concerned that the process does not ensure adequate scrutiny of the proposals or meaningful competition.

Performance

Although the procurement process is transparent and administered well, it is not a "competitive" process. The request for proposal process cannot be relied upon to ensure just and reasonable rates for black start service because the market is characterized by inelastic demand and substantial local market power. PJM has correctly described Schedule 6A and its formula rates as "designed to provide generators with an adequate incentive to supply Black Start Service but not to result in excessive payments," and its performance should be evaluated in that framework.[60]

As revised, the formula under Schedule 6A allows black start service providers to recover the costs of new investment and reasonably conforms the terms of commitment by the providers of black start service to the period over which investment costs are recovered. However, the inclusion of

59 See Motion for Leave to Answer and Answer of the Independent Market Monitor for PJM filed in ER09-730-002 (August 28, 2009); 128 FERC ¶ 61,249 at PP 18—20 (September 17, 2009).
60 2002 Schedule 6A Filing at 4.

CIPS costs applicable to black start service may lead to substantial increases in the cost of black start service. Certain units may incur these costs and continue to be included in system restoration plans even though the plans could be developed in a manner that would provide the same service at much lower cost. The principal obstacle is that PJM does not have the authority to develop a comprehensive system restoration plan or a clear mandate to conduct procurement in manner that results in a least cost solution for the entire system. There is no clear representation in the process afforded to those responsible to pay for the service. Accordingly, the MMU recommends that PJM, FERC, reliability authorities and state regulators reevaluate how black start service is procured in order to ensure that procurement is done in a least cost manner for the entire PJM market.

The current process provides for PJM and transmission owners to jointly develop and administer the black start service plan for each transmission zone. These rules should be revised to assign responsibility for administering the plan to PJM and allow transmission owners to play an advisory role. This is especially important to address situations where transmission owners have affiliates providing black start service in the PJM region. PJM should administer the plan on a regional basis.

PJM also needs to reform the procurement process. Currently, PJM stakeholders are considering an approach that would conduct an RFP for black start service before approving an incumbent provider's request to recover through black start service rates the costs of substantial investment. This is especially important when the investment relates to the ability of the host unit to remain in service, not just the equipment needed solely for the purpose of providing black start service. This discussion, however, is much too limited. There is no reason why PJM should not procure black start service on an efficient and least cost basis through an orderly and non discriminatory RFP process. At present, providers may exit service commitments as their service obligations expire, but there is no comparable process for the purchasers of black start service to evaluate alternatives as purchase obligations expire. It is not clear whether the problem is the rules or how those rules have been implemented. In any event, a clearly defined regional black start procurement process is needed, as well more explicit provisions concerning how purchasers will be represented in that process. Clarification could come in the form of a clear statement of PJM's fiduciary as well as reliability responsibilities as it procures black start service (as well as other non market ancillary services).